Technical Training Center
Chattanooga, Tennessee

WESTINGHOUSE TECHNOLOGY SYSTEMS MANUAL

July 2020

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

HRTD
Human Resources
Training & Development

Westinghouse Technology Systems Manual

Chapter 1

INTRODUCTION

Section

Westinghouse Technology Systems Manual

Section 1.0

LIST OF ACRONYMS

"READ ONLY SELF STUDY MATERIAL"

2-D	two-dimensional
3-D	three-dimensional
AABVS	auxiliary/annex building ventilation subsystem
ABB	Asea Brown Boveri Company
ABWR	advanced boiling-water reactor
ac/AC	alternating current
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ADAMS	Agency wide Documents Access and Management System Public Electronic Reading Room
ADGFOSS	ancillary diesel generator fuel oil supply system
ADS	automatic depressurization system
ADS-4	automatic depressurization system-Stage 4
ADVs	atmospheric dump valves
AEOD	NRC Office for Analysis and Evaluation of Operational Data
AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
AHUs	air handling units
AI	automatic isolation
AICC	adiabatic isochoric complete combustion
AISC	American Institute of Steel Construction
AISI	American Iron and Steel Institute
ALARA	as low as is reasonably achievable
ALWR	advanced light water reactor
AM	accident management
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrences
AOV	air operated valves
APEX	Advanced Plant Experiment
APWR	advanced pressurized water reactor
ARM	area radiation monitor
ART	adjusted reference temperature
ASB	Auxiliary Systems Branch
ASB	auxiliary/shield building
ASCE	American Society of Civil Engineers
ASHRAE	American Society of Heating, Refrigerating and Air Conditioning
ASIs	adverse systems interactions
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials

ATC	automatic turbine control
ATWS	anticipated transient without scram
AVT	all-volatile treatment
AWS	American Welding Society
B&W	Babcock and Wilcox
B&WOG	B&W Owner's Group
BAC	bounding analysis curve
BAT	boric acid tank
BE	best estimate
BOC	beginning-of-cycle
BTP	branch technical position
BWR	boiling water reactor
BWROG	Boiling Water Reactor Owners' Group
CAS	central alarm station
CAS	compressed and instrument air system
CASS	cast austenitic stainless steel
CAV	cumulative absolute velocity
CB	circuit breakers
CBP	computer-based procedures
CCF	common cause failure
CCFP	conditional containment failure probability
CCI	core-concrete interaction
CCS	component cooling water system
CCW	component cooling water
CDF	core damage frequency
CE	Combustion Engineering
CET	containment event tree
CF	chemistry factor
CFD	computational fluid dynamics
CFE	early containment failure
CFI	intermediate containment failure
CFL	late containment failure
CFR	Code of Federal Regulations
CFS	condensate and feedwater system
CHF	critical heat flux
CI	containment isolation
CIS	containment isolation system
CIV	containment isolation valves
CIWH	condensation induced water hammer
CMS	condenser air removal system
CMT	core makeup tank
COL	combined license
COLR	Core Operating Limits Report
COMMON Q	common qualified platform
COTS	commercial off-the-shelf
CP	construction permit
CPG	containment performance goal
CPS	condensate polishing system
CR	control room

CRDM	control rod drive mechanism
CRD	control rod drive
CRDS	control rod drive system
CREATCS	control room emergency air temperature control system
CREFS	control room emergency filtration system
CS	core support
CSF	critical safety function
CsI	cesium iodide
CST	condensate storage tank
CUF	cumulative usage factor
CV	check valve
C_V	Charpy V-notch
CVCS	chemical and volume control system
CVS	chemical and volume control system
CWS	circulating water system
D-RAP	design reliability assurance program
DAC	derived air concentration
DAC	design acceptance criteria
DAS	diverse actuation system
DBA	design-basis accident
DBPB	design basis pipe break
DBT	design basis tornado
dc/DC	direct current
DC	design certification
DCD	design control document
DCH	direct containment heating
DDS	data and display processing system
DECLG	double-ended cold leg guillotine
DEDVI	double-ended direct vessel injection
DEH	digital electrohydraulic
DEI	dose equivalent iodine
DF	decontamination factor
DG	diesel generator
DHR	decay heat removal
DID	defense-in-depth
DMIMS	digital metal impact monitoring system
DNB	departure from nucleate boiling
DNBR	departure from nucleate boiling ratio
DOFs	degrees of freedom
DOP	dioctyl-phthalate polydispersed
DOS	standby diesel and auxiliary boiler fuel oil system
DOT	Department of Transportation
DSER	draft safety evaluation report
DTS	demineralized water treatment system
DVI	direct vessel injection
DWS	demineralized water transfer and storage system
DWST	demineralized water storage tank
EAB	exclusion area boundary
ECC	equilibrium cycle core
ECCS	emergency core cooling system

EDI	electro-deionization
EDO	NRC Executive Director for Operations
EDS	non-class 1E dc and UPS system
EF	error factor
EFDS	equipment and floor drainage system
EFPY	effective full-power year
EFW	emergency feedwater
EFWS	emergency feedwater system
EHT	effluent holdup tanks
ELS	plant lighting system
EM	evaluation model
EMC	electromagnetic compatibility
EMI	electromagnetic interference
EOC	end-of-cycle
EOF	emergency operations facility
EOL	end of life
EOP	emergency operating procedures
EP	emergency planning
EPA	Environmental Protection Agency
EPRI/MRP	EPRI Materials Reliability Project
EPRI	Electric Power Research Institute
EQ	equipment qualification
EQDP	equipment qualification data package
ERDS	Emergency Response Data System
ERG	emergency response guidelines
ERI	Energy Research, Inc.
ERVC	external reactor vessel cooling
ESF	engineered safety feature
ESFA	engineered safety features actuation
ESFAS	engineered safety features actuation system
ESP	early site permit
ESW	essential service water
ET	eddy current testing
ETS	emergency trip system
FBACS	fuel building air cleanup system
FBTA	function-based task analysis
FCC	first cycle core
FCI	fuel-coolant interactions
FCU	fan coil unit
FDA	final design approval
FE	finite element
FEMA	Federal Emergency Management Agency
FHA	fuel-handling accident
FHAVS	fuel handling area ventilation subsystem
FIV	flow-induced vibration
FLB	feedwater line break
FME	foreign material exclusion
FMEA	failure modes and effects analysis
FN	ferrite number

FPDS	flat panel display system
FPS	fire protection system
FRS	floor response spectra
FSAR	final safety analysis report
FSER	final safety evaluation report
FV&V	final verification and validation
FVW	Fussell-Vesely Worth
FW	feedwater
GALE	gaseous and liquid effluent
GDC	general design criteria/criterion
GE	General Electric
GL	generic letter
GRCAs	gray rod cluster assemblies
GSI	generic safety issue
GSS	turbine gland seal system
H2TS	hierarchical, two-tiered scaling
HAZ	heat-affected zone
HCF	high cycle fatigue
HCLPF	high confidence that the particular SSC will have a low probability of failure
HCMS	hydrogen concentration monitoring system
HCSD	hot/cold shutdown
HEDs	human engineering discrepancies
HEL	high-energy line
HELB	high-energy line break
HEM	homogenous equilibrium model
HEP	human error probability
HEPA	high-efficiency particulate air
HFE	human factors engineering
HFP	hot full-power
HFS	Human Factors Society
HIC	high-integrity containers
HICB	Instrumentation and Controls Branch
HLHS	heavy load handling system
HPCI	high-pressure coolant injection
HPI	high-pressure injection
HPME	high-pressure core melt ejection
HPSI	high-pressure safety-injection
HRA	human reliability analysis
HSI	human-system interface
HVAC	heating, ventilation, and air conditioning
HX	heat exchanger
HZP	hot zero-power
I/O	input/output
I&C	instrumentation and control
IAEA	International Atomic Energy Agency
IAS	instrument air system
IASCC	irradiation-assisted stress-corrosion cracking
IC	intact containment

ICC	inadequate core cooling
ICCDP	incremental conditional core damager probability
ICSB	Instrumentation and Control Systems Branch
IDS	Class 1E dc system
IEB	Inspection and Enforcement bulletin
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IFM	intermediate flow mixing
IHP	integrated head package
IIS	in-core instrumentation system
ILRT	integrated leak rate testing
IN	information notice
INEEL	Idaho National Engineering and Environmental Laboratory
INEL	Idaho National Engineering Laboratory
INPO	Institute of Nuclear Power Operations
INSAG	International Nuclear Safety Advisory Group
IPSAC	investment protection short-term availability controls
IRWST	in-containment refueling water storage tank
ISA	Instrument Society of America
ISI	inservice inspection
ISLOCA	intersystem loss-of-coolant accident
ISLOCA	interfacing systems loss-of-coolant
IST	inservice testing
ITAAC	inspection, test, analyses, and acceptance criteria
ITG	Issue Task Group
ITP	initial test program
LBB	leak-before-break
LBHSs	large-bore hydraulic snubbers
LBLOCA	large-break loss-of-accident accident
LCF	low cycle fatigue
LCO	limiting condition for operation
LCSs	local control stations
LDS	leakage detection system
LEFM	linear elastic fracture mechanics
LER	licensee event report
LERF	large early release fraction
LLHS	light load handling system
LLOCA	large LOCA
LMFW	loss of main feedwater
LOCA	loss-of-coolant accident
LOFT	loss-of-flow tests
LOFTRAN	transient and SGTR computer analysis code
LONF	loss of normal feedwater
LOOP	loss of offsite power
LP	low pressure
LPSI	low pressure safety injection
LPZ	low population zone
LRA	license renewal application
LRF	large release frequency

LST	large-scale tests
LTC	long-term cooling
LTOP	low-temperature overpressure protection
LWR	light water reactor
M-G	motor-generator
M-MIS	man-machine interface system
MAAP	Modular Accident Analysis Program
MCC	motor control center
MCR	main control room
MCRE	main control room envelope
MFCS	main feedwater control system
MFCV	main feedwater control valve
MFIV	main feedwater isolation valve
MFRV	main feedwater regulation valve
MFW	main feedwater
MFWS	main feedwater system
MIL	military
ML	mid-loop
MLOCA	medium LOCA
MOV	motor operated valve
MRP	Materials Reliability Program
MS	main steam
MS&FW	main steam and feedwater
MSGTR	multiple steam generator tube rupture
MSIV	main steam isolation valve
MSLB	main steam line break
MSSS	main steam supply system
MSSVs	main steam safety valves
MTC	moderator temperature coefficient
MUX	multiplexer
NACE	National Association of Corrosion Engineers
NCC	natural convection cooldown
NCIG	Nuclear Construction Issues Group
NDE	nondestructive examination
NDT	nil-ductility temperature
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Association
NI	nuclear island
Ni-Cr-Fe	nickel-chromium-iron
NOAA	National Oceanic and Atmospheric Administration
NOTRUMP	small break LOCA computer analysis code
NPP	nuclear power plant
NPS	nominal pipe size
NPSH	net positive suction head
NRC	U.S. Nuclear Regulatory Commission
NRCA	non-radiologically controlled area
NS	non-seismic
NSAL	Nuclear Service Advisory Letter
NSR	non-safety-related

NSSS	nuclear steam supply system
NUREG	NRC technical report designation (US Nuclear Regulatory Commission Regulation)
O-RAP	operational reliability assurance process
OBE	operating-basis earthquake
OCS	operation and control centers system
ODCM	offsite dose calculation manual
OECD	Organization for Economic Cooperation and Development
OER	operating experience review
OL	operating license
OM	operation and maintenance
OPDMS	on-line power distribution monitoring system
OPS	onsite power systems
OSA	operational sequence analysis
OSC	operational support center
OSU	Oregon State University
P/T	pressure and temperature
P&ID	piping & instrumentation diagram (AP600)
P&ID	piping and instrumentation drawings
PAM	post-accident monitoring
PAR	passive autocatalytic recombiner
PASS	post-accident sampling system
PCA	primary coolant activity
PCCS	passive containment cooling system (AP600)
PCCWST	passive containment cooling water storage tank
PCP	process control program
PCS	passive containment cooling system (AP1000)
PCT	peak cladding temperature
PGA	peak ground acceleration
PGS	plant gas systems
PIRT	phenomena identification and ranking table
PIV	pressure isolation valve
PLC	programable logic controller
PLHR	peak linear heat rate
PLS	plant control system
PMF	probable maximum flood
PMP	probable maximum precipitation
PMS	protection and safety monitoring system
PORV	power-operated relief valve
POV	power-operated valve
PRA	probabilistic risk assessment
PREACS	pump room exhaust air cleanup system
PRHR HX	passive residual heat removal heat exchanger
PRHR	passive residual heat removal system
PSAI	plant specific action items
PSARV	pressurizer safety and relief valve
PSB	Power Systems Branch
PSD	power spectral density
PSDF	power spectral density function

PSI	preservice inspection
PSS	primary sampling system
PSV	pressurizer safety valve
PTLR	pressure-temperature limits report
PTS	pressurized thermal shock
PVRC	Pressure Vessel Research Council
PWHT	post weld heat treatment
PWR	pressurized water reactor
PWS	potable water system
PWSCC	primary water stress corrosion cracking
PXS	passive core cooling system
PZR	pressurizer
QA	quality assurance
QDPS	qualified data processing system
QG	NRC Quality Group
QMS	quality management system
RAI	request for additional information
RAMI	reliability, availability, maintainability, and inspection
RAP	reliability assurance program
RAT	reserve auxiliary transformer
RAW	risk achievement worth
RC	reactor coolant
RCA	radiologically controlled area
RCCA	rod cluster control assembly
RCDT	reactor coolant drain tank
RCL	reactor coolant loop
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCs	release categories
RCS	reactor coolant system
rem	roentgen equivalent man (unit of radiation exposure)
RES	NRC Office of Nuclear Regulatory Research
RETS	radiological effluent technical specifications
RFA	robust fuel assemblies
RFI	radio frequency interference
RG	regulatory guide
RH	relative humidity
RHR	residual heat removal
RMI	reflective metallic insulation
RMS	radiation monitoring system
RNS	normal residual heat removal system
RO	reactor operator
RO	reverse osmosis
ROAAM	Risk Oriented Accident Analysis Methodology
ROSA	Rig of Safety Assessment
RPS	reactor protection system
RPV	reactor pressure vessel
RRW	risk reduction worth
RSB	Reactor Systems Branch

RSR	remote shutdown room
RSS	remote shutdown station
RSW	remote shutdown workstation
RT	reactor trip
RTD	resistance temperature detector
RTDP	revised thermal design procedure
RTNSS	regulatory treatment of non-safety systems
RTP	rated thermal power
RTS	reactor trip system
RV	reactor vessel
RVH	reactor vessel head
RVHV	reactor vessel head vent
RVLIS	reactor vessel level indication system
RWS	raw water system
RWST	refueling water storage tanks
SACF	single active component failure
SAFDL	specified acceptable fuel design limit
SAM	seismic anchor motions
SAMDA	severe accident mitigation design alternative
SAT	systematic approach to training
SBLOCA	small-break loss-of-coolant accident
SBO	station blackout
SC	seismic category
SCC	stress-corrosion cracking
SCMP	software configuration management plan
SEA	Science and Engineering Associates, Inc.
SECY	Office of the Secretary of the Commission
SER	safety evaluation report
SFCV	startup feedwater control valve
SFD	severe fuel damage
SFIV	startup feedwater isolation valve
SFP	spent fuel pool
SFPCPS	spent fuel pool cooling and purification system
SFS	startup feedwater system
SFS	spent fuel pool cooling system
SFW	startup feedwater
SG	steam generator
S/G	steam generator
SGBS	steam generator blowdown system
SGD	subgroup design
SGS	steam generator system
SGSV	steam generator safety valve
SGTR	steam generator tube rupture
SLB	steam line break
SMA	seismic margin analysis
SMACNA	Sheet Metal and Air Conditioning Contractors' National Association
SMS	special monitoring system
SOERs	Significant Operating Event Reports
SOMP	software operation and maintenance plan

SPDS	safety parameter display system
SPES	Simulatore per Esperienze di Sicurezza
SPLB	NRC Plant Systems Branch
SPM	software program manual
SQAP	software quality assurance plan
SR	safety-related
SR	surveillance requirement
SRM	staff requirements memorandum
SRO	senior reactor operator
SROA	safety-related operator action
SRP	Standard Review Plan
SRSS	square root of the sum of squares
SRST	spent resin storage tank
SRV	safety relief valve
SRXB	Reactor Systems Branch
SS	shift supervisor
SSAR	standard safety analysis report (AP600)
SSCs	structures, systems and components
SSDs	System Specification Documents (AP600)
SSE	safe-shutdown earthquake
SSI	soil-structure interaction
SSP	software safety plan
SSS	secondary sampling system
SST	small scale test
STA	shift-technical advisor
STD	standard
STS	standard technical specification
SUFS	startup feedwater system
SUFWS	startup feedwater system
SVVP	software verification and validation plan
SWMS	solid waste management system
SWS	service water system
T-H	thermal-hydraulic
TASCS	thermal stratification, cycling and striping
Tavg	average temperature
TCS	turbine building closed cooling system
TDS	turbine island vents, drains, and relief system
TEDE	total effective dose equivalent
TGSCC	transgranular stress corrosion cracking
THD	total harmonic distortion
the Code	ASME Boiler and Pressure Vessel Code
THERP	technique for human error rate prediction
TID	total integrated dose
TMI	Three Mile Island
TS	technical specifications
TSC	technical support center
TSP	trisodium phosphate
UAT	unit auxiliary transformers
UBC	Uniform Building Code
UCSB	University of California, Santa Barbara

UET	unfavorable exposure time
UHS	ultimate heat sink
UPS	uninterruptable power supply
URD	Utility Requirements Document
URS	ultimate rupture strength
USE	upper-shelf energy
USI	unresolved safety issues
UT	ultrasonic testing
V&V	verification and validation
VAPORE	valve and pressure operating related experiments
VAS	radiologically controlled area ventilation system
VBS	nuclear island nonradioactive ventilation system
VCS	containment recirculation cooling system
VDU	video display unit
VES	main control room emergency habitability system
VFS	containment air filtration system
VHP	vessel head penetration
VHS	health physics and hot machine shop HVAC system
VRS	radwaste building HVAC system
VTS	turbine building ventilation system
VWS	central chilled water system
VXS	annex/auxiliary buildings non-radioactive HVAC system
VYS	plant hot water heating system
VZS	diesel generator DG building heating and ventilation system
WCAP	Westinghouse Commercial Atomic Power (report)
WCOBRA/TRAC	Westinghouse large break LOCA and long term cooling computer analysis code
WDT	water distribution tests
WG	water gauge
WGOTHIC	Westinghouse-GOTHIC analysis code
WGS	gaseous radwaste system
WLS	liquid radwaste system
WOG	Westinghouse Owners Group
WRC	Welding Research Council
WRS	radioactive waste drain system
WSS	solid radwaste system
WWS	waste water system
ZOS	onsite standby power system
ZPA	zero period acceleration

Westinghouse Technology Systems Manual

Section 01.1

Reference Documents

“READ ONLY SELF STUDY MATERIAL”

TABLE OF CONTENTS

ATTACHMENT A

ATTACHMENT B

1.1 REFERENCE DOCUMENTS

Learning Objectives:

The students should be able to identify the following reference documents by giving a statement of their contents and/or functions:

- 10CFR50, specifically:
  - 50.2, Definitions
  - 50.34, Application
  - 50.36, Technical Specifications (TS)
  - 50.46, Emergency Core Cooling System (ECCS) Acceptance Criteria
  - 50.49, Environmental Qualification (EQ)
  - 50.55(a), Codes and Standards
  - 50.62, Anticipated Transient Without Scram (ATWS)
  - 50.63, Station Black Out (SBO)
  - Appendix A, General Design Criteria (GDC)
  - Appendix J, Primary Containment Leakage Rate Testing
- 10CFR100, Reactor Site Criteria (Part 100 limits)
- Final Safety Analysis Report (FSAR)
- NUREG 0800 Standard Review Plan (SRP)
- Technical Specifications (TS)
- Regulatory Guides
- ASME Codes
- IEEE Codes
- Generic Communications (Generic Letters, Bulletins, IN, RIS, etc.)

The student should be able to define the following terms as stated in the reference documents:

a. Anticipated Operational Occurrence (AOO)
b. Design Basis (DB),
c. Loss of Coolant Accident (LOCA),
d. Reactor Coolant Pressure Boundary,
e. Single Failure,
f. Safe Shutdown and
g. Safety Related.

1.1.1 Introduction

The nuclear regulatory process provides a system for establishing requirements for nuclear power plants (including regulations, orders and licenses), for developing guidance to implement the requirements, for communicating with the licensees and the public, and for oversight and enforcement of the regulations. The process also establishes mechanisms for changes to operating licenses. Finally, the U.S. Nuclear Regulatory Commission has management and control processes for implementing and changing the regulatory process.

The agency and the industry recognize that there is a significant number of experienced people who are knowledgeable of the development and evolution of the nuclear regulatory process who will soon retire. This creates a challenge for knowledge transfer to the new work force that will be responsible in the near future for the regulatory process. This document is intended to review the regulatory process and the documents that licensees are held accountable for in their operation of a nuclear site. This document is concise and in no way comprehensive of all references. For the new employee this will show why it is necessary to understand the technology and where to look for the referenced requirements to evaluate the licensee's performance. The technology is meant to provide a basic understanding of the design and how it meets the regulations that provide for public safety.

This document presents a basic description of the nuclear regulatory process and its requirements for operating nuclear power plants. It is intended to provide a foundation for maintaining a common understanding of the nuclear regulatory process, to refresh the knowledge of the nuclear regulatory process and to provide a foundation for transferring knowledge to professionals newly entering the nuclear work force.

Many data sources were used in the preparation of this manual that provided specific information on the systems and operation of the typical Westinghouse facility. Included in these sources are examples of the Final Safety Analysis Report (FSAR) for a nuclear facility, Westinghouse topical reports (WCAPs), Westinghouse system descriptions, and training manuals from various Westinghouse facilities. These documents may provide specific system information. There are also documents which provide information related to the minimum requirements for the design, operation, and testing of the systems, structures, and components (SSCs) involved in operating a commercial nuclear facility. Documents included in this group are the Code of Federal Regulations (CFR), Technical Specifications, Regulatory Guides, and various industry standards. The following sections provide a brief description of each of the major documents.

For illustrative purposes, Attachment A to this section contains selected copies of sections of the reference documents described in this chapter. Attachment B is a review of the regulatory process intended to tie it all together. NUREG-0800 Chapter 15 is the Standard Review Plan (SRP) for Transient and Accident Analysis and is reviewed to show the importance of systems to be covered and why they are required in the FSAR and Technical Specifications. This chapter has links to the various referenced documents throughout to enable you to see the documents being discussed.

1.1.2 Code of Federal Regulations (CFR)

The Code of Federal Regulations (CFR) is a compilation of rules published in the Federal Register by the executive departments and agencies of the Federal Government. The Code of Federal Regulations is kept up to date by the individual issues of the Federal Register. These two publications are used together to determine the latest version of any given rule. Each year a new publication of the code is issued with changes incorporated in it.

The code is divided into 50 titles which represent broad areas subject to federal regulations. Each title is divided into chapters, which usually bear the names of the issuing agencies. Each chapter is divided into parts covering the specific regulatory areas.

Regulations associated with the Nuclear Regulatory Commission are contained in Title 10 - Energy, Chapter 1 - Nuclear Regulatory Commission, Parts 0 - 199. The regulations are cited using the title, part, section, and paragraph designations. For example, 10 CFR 50.34(b) refers to Title 10 of the Code of Federal Regulations, Part 50, Section 34, paragraph (b).

The following is a list and brief description of the parts of 10CFR50 that primarily apply to NRC licensed commercial nuclear reactors: (See Attachment A)

- Part 2 Policy and procedures related to issuing, amending, or revoking an operating license; enforcement actions; and public rule making.
- Part 34 Contents of License Applications
- Part 36 Technical Specifications (TS)
- Part 46 Emergency Core Cooling System (ECCS) Acceptance Criteria
- Part 49 Environmental Qualification (EQ)
- Part 55a Codes and Standards: ASME III/XI/OM Code/ISI & IST, IEEE, RG 1.84, RG 1.147, RG 1.192
- Part 62 Requirements for reduction of risk from ATWS events.
- Part 63 Loss of Alternating Current Power
- Part 69 Risk Informed Treatment of SSCs for Nuclear Plants
- Part 70 Inspections – unfettered access.
- Part 71 Maintenance of Records, Making of Reports
- Part 73 License Event Reports
- Part 109 Backfitting
- Part 120 Training and Qualification of Nuclear Plant Personnel

- Part 150 Aircraft Impact Assessment
- Part 155 Mitigation of Beyond Design Basis Events
    - Appendix A - General Design Criteria (GDC)
    - Appendix B - Quality Assurance (QA) Criteria
    - Appendix E – Emergency Planning and Preparedness for Production and Utilization Facilities
    - Appendix J – Primary Reactor Containment Leakage Testing for Water-Cooled Reactors
    - Appendix K – ECCS Evaluation Models
    - Appendix R – Fire Protection Program for Nuclear Power Facilities
    - Appendix S – Earthquake Engineering Criteria for Nuclear Power Plants

The following is a list and brief description of the parts of 10CFR that primarily apply to NRC licensed commercial nuclear reactors:

- 10 CFR 19 Requirements for disseminating information to nuclear plant workers concerning radiological working conditions, enforcement actions, etc. Rules of conduct for NRC inspections.
- 10 CFR 20 Standards for protection against radiation
- 10 CFR 21 Reporting of defects and noncompliance
- 10 CFR 50 Domestic Licensing of Production and Utilization Facilities
- 10 CFR 54 Requirements for Renewal of Operating Licenses for Nuclear Power Plants

- 10 CFR 55 Rules and procedures for the licensing of reactor operators.
- 10 CFR 71 Requirements for packaging, shipping and transportation of radioactive material.
- 10 CFR 73 Requirements related to physical protection of the facility to protect against radiological sabotage and theft of special nuclear material.
- 10 CFR 100 Reactor site criteria including population density and seismic and geologic evaluations. (See Attachment A)
    - Appendix A - Seismic and Geologic Siting Criteria for Nuclear Power Plants

Included in all these parts are definitions of terms important to understanding the regulations. For example, the following terms are defined in 10 CFR 50:

1. Anticipated Operational Occurrence (AOO), as defined in Appendix A to 10 CFR Part 50, are those conditions of normal operation that are expected to occur one or more times during the life of the nuclear power unit. The Standard Review Plan (SRP) uses the term AOOs to refer to the events that are categorized in Regulatory Guide 1.70 and in Regulatory Guide 1.206 as incidents of moderate frequency (i.e., events that are expected to occur several times during the plant's lifetime) and infrequent events (i.e., events that may occur during the lifetime of the plant).

2. “Design basis” means that information which identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as bounding values for the design of the SSC.
3. “Loss of coolant accident” (LOCA) means a postulated accident that results from the loss of reactor coolant at a rate in excess of the capability of the reactor coolant makeup system from breaks in the reactor coolant pressure boundary, up to and including a break equivalent in size to the double-ended rupture of the largest pipe of the reactor coolant system.
4. “Reactor coolant system (RCS) pressure boundary” means all those pressure-containing components of water-cooled nuclear power reactors, such as pressure vessels, piping, pumps, and valves which are: (1) part of the reactor coolant system, or (2) connected to the reactor coolant system, up to and including (a) the outermost containment isolation valve in system piping which penetrates primary reactor containment, (b) the second of two valves normally closed during normal reactor operation in system piping which does not penetrate primary reactor containment, (c) the reactor coolant system safety and relief valves.
5. "Single failure" means an occurrence which results in the loss of capability of a component to perform its intended safety functions. A system is considered to be designed against an assumed single failure if neither (1) a single failure of any active component nor (2) a single failure of any passive component results in a loss of the capability of the system to perform its safety functions.
6. “Safe Shutdown” (non-design basis accident (non-DBA)) for station blackout means bringing the plant to those shutdown conditions specified in plant technical specifications as Hot Standby or Hot Shutdown, as appropriate (plants have the option of maintaining the RCS at normal operating temperatures or at reduced temperatures).
7. “Safety-Related” structures, systems and components (SSCs) means those structures, systems and components that are relied upon to remain functional during and following design basis events to assure:
    a. (1) The integrity of the reactor coolant pressure boundary
    b. (2) The capability to shut down the reactor and maintain it in a safe shutdown condition; or
    c. (3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the applicable guideline exposures set forth in § 50.34(a)(1) or § 100.11 of this chapter, as applicable.

Title 10 of the U.S. Code of Federal Regulations (CFR) 52.79(a)(1)(iii) states that a Final Safety-Analysis Report, which is part of the Combined Operating License application process for nuclear power plants, must address:

> The seismic, meteorological, hydrologic, and geologic characteristics of the proposed site with appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding

area and with sufficient margin for the limited accuracy, quantity, and time in which the historical data have been accumulated.

10 CFR 52.79(a)(4)(i) states that the minimum design requirements for the principal design criteria are established by 10 CFR Part 50, Appendix A, General Design Criteria for Nuclear Power Plants. Appendix H to part 100 of the US-CFR regulations (Ref. 6) defines 2 seismic levels, OBE and SSE with specific safety requirement defined for each level.

- "Safe Shutdown Earthquake" (SSE) - The *Safe Shutdown Earthquake Ground Motion (SSE)* is the vibratory ground motion for which certain structures, systems, and components important to nuclear safety must be designed to remain functional. SSE is defined in 10 CFR 100 as that earthquake which is based upon an evaluation of the maximum earthquake potential considering the regional and local geology and seismology. The "safe shutdown earthquake" defines that earthquake which has commonly been referred to as the "design basis earthquake." It is that earthquake for which certain structures, systems, and components (SSCs) are designed to remain functional.
- “Operational Based Earthquake” (OBE) - The *Operating Basis Earthquake Ground Motion (OBE)* is the vibratory ground motion for which those features of the nuclear power plant necessary for continued operation without undue risk to the health and safety of the public will remain functional. OBE ground motion is used as a damage parameter to determine the need to shut down the plant if at the site there is a measured earthquake ground motion. Since OBE is not explicitly a design loading it must be defined as one-third of the design ground motion or less. In Appendix B of RG 1.166 it states, "The value of the OBE is set by the applicant." Also, in section 4.1.1 of RG 1.166 allows the lower of 1) the spectrum used in the certified standard design, or 2) any other spectrum used in the design of any other Seismic Category 1 structure.
- Probable Maximum Flood (PMF), a probable maximum flood (PMF) is the hypothetical flood generated in the drainage area by a probable maximum precipitation (PMP) event. The probable maximum storm surge (PMSS) is generated by the probable maximum hurricane (PMH) or the probable maximum windstorm (PMWS). These events are defined by the American National Standards Institute (ANSI) and American Nuclear Society (ANS) in ANSI/ANS-2.8-1992 (ANS 1992). Nuclear power plants need to be protected from the adverse effects of flooding. To assist in determining the potential for adverse flooding effects, the U.S. Nuclear Regulatory Commission (NRC) provides guidance for estimating design-basis floods in Regulatory Guide 1.59 (NRC 1977). 10 CFR 52.17(a)(1)(vi) includes a similar statement for Early Site Permit applications.

  10 CFR 100.20 requires nuclear power plant site evaluation to include meteorological, hydrological, seismic, and geologic characteristics that may affect the acceptability of a site for a stationary power reactor. 10 CFR 100.20

also requires evaluation of the nature and proximity of man-related hazards such as dams.

1.1.3 Final Safety Analysis Report (FSAR)

A Final Safety Analysis Report (FSAR) is submitted with each application for an operating license and includes a description of the facility, the design bases and limits on its operation, and a safety analysis of the structures, systems, and components of the facility. The function of the FSAR is to demonstrate the applicant's qualifications, capability, and planned controls to assure safe plant operation within the constraints of plant design, operating limitations and regulatory requirements.

The requirement for having an FSAR and the minimum information required to be included in it is established in 10 CFR 50.34(b). (See Attachment A) For example, this regulation, in part, requires an evaluation and analysis of the emergency core cooling system (ECCS) cooling performance following postulated loss-of-coolant accidents to ensure that the requirements of 10 CFR 50.46, "ECCS Design Acceptance Criteria," are met. This analysis is usually included in FSAR Chapter 15, "Accident Analysis," along with evaluations to show safe plant response for other postulated normal and abnormal plant conditions. Other examples of information contained in the FSAR include the methods with which the licensee plans to meet the 10 CFR 50 Appendix B Quality Assurance Criteria and the results of environmental and meteorology monitoring programs as they pertain to 10 CFR 100 requirements. The plant is required to maintain the FSAR current and to submit the most up-to-date version to the NRC on a yearly basis (commonly referred to as the Updated FSAR or UFSAR).

10 CFR 50.71(e) Maintenance of Records, Making of Reports states (e) Each person licensed to operate a nuclear power reactor under the provisions of § 50.21 or § 50.22, and each applicant for a combined license under part 52 of this chapter, shall update periodically, as provided in paragraphs (e) (3) and (4) of this section, the final safety analysis report (FSAR) originally submitted as part of the application for the license, to assure that the information included in the report contains the latest information developed. This submittal shall contain all the changes necessary to reflect information and analyses submitted to the Commission by the applicant or licensee or prepared by the applicant or licensee pursuant to Commission requirement since the submittal of the original FSAR, or as appropriate, the last update to the FSAR under this section.

The submittal shall include the effects of all changes made in the facility or procedures as described in the FSAR; all safety analyses and evaluations performed by the applicant or licensee either in support of approved license amendments or in support of conclusions that changes did not require a license amendment in accordance with § 50.59(c)(2) or, in the case of a license that references a certified design, in accordance with § 52.98(c) of this chapter; and all analyses of new safety issues performed by or on behalf of the applicant or licensee at Commission request. The updated information shall be appropriately located within the update to the FSAR.

1.1.4 Technical Specifications (TS)

The requirement for including Technical Specifications as part of the license application is set forth in 10 CFR 50.36. (See Attachment A.) The NRC-approved Technical Specifications are issued to the facility as part of the operating license. (See Attachment A for an example of a facility operating license.) The Technical Specifications establish minimum operating limits for the facility. Failure to comply with these limits may require the reduction of the allowable operating power level or, in some cases, even a complete shutdown and cooldown of the unit.

The bases for the operating limits established in Technical Specifications are the analyses and evaluations included in the FSAR. Operating within the established limits ensures that the assumptions made in the safety analyses are true for all operating conditions. Technical Specifications are required to include the following sections:

1. Safety limits and limiting safety system settings. Safety limits are limits upon important process variables which are found to be necessary to protect the integrity of the physical barriers which guard against the uncontrolled release of radioactivity to the environment. If any safety limit is exceeded, the reactor shall be shutdown.

   Limiting safety system settings are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting will assure that automatic protective action will correct the abnormal situation before a safety limit is exceeded. Appropriate action for exceeding a limiting safety system setting may include shutting down the reactor.

2. Limiting conditions for operation (LCOs) are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When an LCO is exceeded, remedial action is required within a specified time frame. (See Attachment A for an example of a Technical Specification LCO.)
3. Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary system or component quality is maintained.
4. Design features are those features of the facility such as materials of construction and geometric arrangements which, if altered or modified, would have a significant effect on safety and are not covered in Sections 1-3.
5. Administrative controls are provisions related to organization and management, procedures, record keeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner.

A bases section is included with the Technical Specifications as part of a facility's operating license application, as required by 10 CFR 50.36, and provides the reason(s) for each individual specification. (See Attachment A for an example of a Technical Specification basis entry.) The bases section is included with the Technical Specifications for information but is not part of the Technical Specifications.

1.1.5 Technical Requirements Manual (TRM)

The NRC made some rule changes in the mid-1990's that simplified a critical component of a nuclear power plant's licensing basis. This reduced the paperwork burden on both the NRC and the sites. It also gave birth to a new kind of licensing basis document. (See Attachment A this document)

The Technical Requirements Manual (TRM) is a document that is part of the plant's licensing basis, but any changes to it do not have to be approved in advance by the NRC like they do with changes to the Technical Specifications. In other words, a license amendment request is not needed to modify the TRM.

The Technical Specifications (often referred to as Tech Specs) are governed by 10 CFR 50.36. Other associated documents find their origin in this section too, such as the Tech Spec Bases and the TRM.

DEVELOPMENT HISTORY: The TRM came about because of a rule modification the NRC made in 1995. The original technical requirements definition included in 10 CFR 50.36 was vague, created originally to implement a certain section of the Atomic Energy Act. It required, simply, that the technical specifications be derived from analyses and evaluations supplied in the safety analysis report (SAR) and its later revisions (UFSAR).

Ultimately, plants began putting much more than the minimum required information in the Tech Specs. Since the Tech Specs (TS) require license amendment requests to be reviewed and approved by the NRC prior to the associated modification package (mod package) being implemented, and since the TS contained details extraneous to the minimal TS requirements, the NRC was inundated by the number of license amendment requests it received. As you can imagine, plants were requesting permission to make changes that they really shouldn't have had to ask permission for. The NRC explained this in the background information published in association with the 1995 rule change:

> This extensive use of technical specifications was **due in part to a lack of well-defined criteria** (in either the body of the rule or in some other regulatory document) for what should be included in technical specifications. Since 1969, this use has contributed to the volume of technical specifications and to the several-fold increase in the number of license amendment applications to effect changes to the technical specifications. **It has diverted both NRC staff and licensee attention from the more important requirements in these**

> **documents to the extent that it has resulted in an adverse but unquantifiable impact on safety.** (Emphasis added.)

FOUR SCREENING CRITERIA: The first attempt to simplify the TS requirements was initiated by the NRC in the early 1980's, but it took until the end of the decade and into the beginning of the 1990's to draw up a final formulation of the simplifying criteria. The NRC, in conjunction with industry groups, came up with four criteria that would more clearly and precisely define what requirements should be left in the Tech Specs. Those criteria are listed in 10 CFR 50.36 and are as follows:

1. Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.
2. A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.
3. A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.
4. A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

The focus of these criteria are the plant's <u>limiting conditions of operation (LCOs)</u>. Any LCOs that did not meet any one of these criteria could be removed from the Tech Specs. The NRC explained:

> LCOs that do not meet any of the criteria, and their associated actions and surveillance requirements, may be proposed for relocation from the technical specifications to licensee- controlled documents, such as the FSAR.

This is how the technical requirements manual (TRM) was born. Many of the extraneous Tech Spec requirements were relocated into this new central location, often with references to associated Tech Specs, to assist operators in performing their daily requirements. Just because these requirements could be removed from the TS did not mean they could be disposed of; operators still needed to ensure these requirements were enforced in their daily routines, so bundling them into a single, clearly written document was intended to make their job easier.

The NRC's primary thrust in making this rule change was to increase public safety. It stated that "the Commission believes that implementation of the criteria contained in this rule will produce an improvement in the safety of nuclear power plants through the use of more operator-oriented technical specifications, improved technical specification bases, reduced action statement induced plant transients, and more efficient use of NRC and industry resources."

1.1.6 Codes and Standards

Since the CFR is written in general terms, supplementary documentation is necessary to further define the requirements stated in the CFR. Each FSAR contains a list of the specific codes and standards to which a particular licensee has committed to fulfill regulatory obligations. The following sections describe three of the most used supplementary documents with examples of each.

1.1.6.1 American National Standards Institute (ANSI) Standards

ANSI Standards cover a wide range of subjects. Codes and Standards says:

(vii) *Section XI condition: Section XI references to OM Part 4, OM Part 6, and OM Part 10 (Table IWA–1600–1)*. When using Table IWA–1600–1, "Referenced Standards and Specifications," in the Section XI, Division 1, 1987 Addenda, 1988 Addenda, or 1989 Edition, the specified "Revision Date or Indicator" for ASME/ANSI OM part 4, ASME/ANSI part 6, and ASME/ANSI part 10 must be the OMa–1988 Addenda to the OM–1987 Edition. These requirements have been incorporated into the OM Code, which is incorporated by reference in paragraph (a)(1)(iv) of this section.

1.1.6.2 American Society of Mechanical Engineers (ASME) Code

Starting in 1914 with the first issuance of its Boiler & Presser Vessel (B&PV) Code, ASME is the leading international developer of codes and standards associated with the art, science, and practice of mechanical engineering. These codes & standards cover a breadth of topics, including pressure technology, nuclear plants, elevators/escalators, construction, engineering design, standardization, and performance testing.

Developing and revising ASME codes and standards occurs year-round. More than 5,000 dedicated volunteers — engineers, scientists, government officials, and others — contribute their technical expertise to protect public safety, while reflecting best practices of industry. The results of their efforts are being used in over 100 nations. ASME was founded in 1880 as the American Society of Mechanical Engineers, ASME is the premier professional membership organization for more than 130,000 mechanical engineers in over 150 countries

The ASME boiler and pressure vessel code is used to provide design criteria for fabrication, inspection, and construction of systems and vessels. The most referenced sections with regard to nuclear plant systems are sections III, XI, and

OM-2012 Inservice Inspection Guidance (see Attachment A). These sections are discussed below.

Section III, Rules for Construction of Nuclear Power Plant Components. The rules of this section constitute requirements for the design, construction, stamping, and overpressure protection of nuclear power plant items such as vessels, concrete reactor vessels and concrete containments, storage tanks, piping systems, pumps, valves, core support structures, and component supports for use in, or containment of, portions of the nuclear power system of any power plant.

ASME has played a vital role in supporting the nuclear power industry since the first publication of the ASME BPVC, Section III, "Rules for Construction of Nuclear Facility Components" in 1963. The commencement of the ASME Nuclear Certification Program in 1968 has only strengthened that support.

N-type Certificates of Authorization issued by ASME signifies that a Certificate Holder has been through a rigorous survey to verify the adequacy and effective implementation of the quality assurance program. The N-type Certificates of Authorization allow Certificate Holders to certify and stamp newly constructed components, parts, and appurtenances used at a nuclear facility with the Certification Mark in accordance with Section III of the ASME BPVC. The Society issues six different N-type certificates, and an owner's certificate that authorizes the following scope of activities:

- N - Vessels, pumps, valves, piping systems, storage tanks, core support structures, concrete containments, and transport packaging
- NA - Field installation and shop assembly of all items
- NPT - Parts, appurtenances, welded tubular products, and piping subassemblies
- NS - Supports
- NV - Pressure relief valves
- N3 - Transportation containments and storage containments
- OWN - Nuclear power plant owner

Section XI, – Flaw Evaluations. ... The ASME Code Section XI provides standards for the examination, in-service testing and inspection, and repair and replacement of nuclear power plant components, pressure vessels and piping. The code details if a flaw found within a component is acceptable for continued operation, or if the component instead requires repair or replacement. Addresses in-service inspection requirements for Class 1, 2, and 3 systems, components, and supports, and steel and concrete containment vessels, describe requirements for qualification of nondestructive examination personnel and performance of nondestructive examination, explain basic requirements for flaw evaluation and acceptance, how to identify Section XI requirements for repair, replacement, modification, maintenance activities, and pressure testing. There are recent revisions to Section XI, and they relate to 10CFR50.55a and NRC Regulatory Guides, Bulletins, Generic Letters, and

Regulatory Issue Summaries to Inservice inspection, nondestructive examination, repair, replacement, and modification.

The ASME code is frequently revised. To know which editions and addenda are required for a particular facility, 10 CFR 50.55a defines applicability according to the issue date of the facility's construction permit. In addition, the FSAR contains information on the codes and standards that are followed during the design and construction of plant systems. (See table below)

Nuclear

AG-1-2019	Code on Nuclear Air and Gas Treatment
BPVC.III.1.NB-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 1, Subsection NB, Class 1 Components
BPVC.III.1.NC-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 1, Subsection NC, Class 2 Components
BPVC.III.1.ND-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 1, Subsection ND, Class 3 Components
BPVC.III.1.NE-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 1, Subsection NE, Class MC Components
BPVC.III.1.NF-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 1, Subsection NF, Supports
BPVC.III.1.NG-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 1, Subsection NG, Core Support Structures
BPVC.III.2-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 2, Code for Concrete Containments
BPVC.III.3-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 3, Containment Systems for Transportation and Storage of Spent Nuclear Fuel and High-Level Radioactive Material
BPVC.III.5-2019	Section III, Rules for Construction of Nuclear Facility Components, Division 5, High Temperature Reactors
BPVC.III.A-2019	Section III, Rules for Construction of Nuclear Facility Components, Subsection NCA, General Requirements for Division 1 and Division 2
BPVC.III.NCA-2019	Section III, Rules for Construction of Nuclear Facility Components, Subsection NCA, General Requirements for Division 1 and Division 2
BPVC.XI-2017	Rules for Inservice Inspection of Nuclear Power Plant Components
BPVC.XI.1-2019	Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, Division 1, Rules for Inspection and Testing of Components of Light-Water-Cooled Plants
BPVC.XI.2-2019	Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components, Division 2, Requirements for Reliability and Integrity Management (RIM) Programs for Nuclear Power Plants
NML-1-2019	Rules for the Movement of Loads Using Overhead Handling Equipment in Nuclear Facilities
OM-2017	Operation and Maintenance of Nuclear Power Plants
QME-1-2012	Qualification of Active Mechanical Equipment Used in Nuclear Facilities (QME-1 - 2012)

1.1.6.3 Institute of Electrical and Electronic Engineers (IEEE) Standards

IEEE standards are used in the design, operation, and testing of nuclear power plant electrical and instrumentation components and systems. Some of the standards developed by the IEEE are listed below.

1. Criteria for Protection Systems for Nuclear Power Generating Stations,
2. Guide to the Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems,
3. Guide for Qualification Testing of Nuclear Power Plant Protection Systems,
4. Guide for Qualification of Engineered Safety Feature Motors for Nuclear Fueled Generating Stations,

5. Guide for Qualification Testing of Electrical Cables Used in Nuclear Power Plants, and
6. Guide for Qualification Testing of Electrical Penetrations in Nuclear Plant Containments.

IEEE standards define as Class 1E, electrical equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing significant release of radioactive material to the environment.

1.1.7 Regulatory Guides (RG) and NUREGs

NRC Regulatory Guides were formerly called Safety Guides. They are not legal documents or requirements. However, they make available to the public methods acceptable to the NRC staff for complying with specific portions of 10 CFR. In some cases a Regulatory Guide endorses an industry standard wholly or in part.

Applications for the use of Regulatory Guides are as follows:

1. To amplify the Code of Federal Regulations,
2. To endorse and/or supplement industry standards, or
3. To provide guidance in ensuring specific regulatory requirements are met.

Each Regulatory Guide consists of four parts:

1. **Introduction** - References to applicable codes, standards, and Code of Federal Regulations associated with a particular subject.
2. **Discussion** - Information on the development of standards associated with the subject. The discussion may address areas of disagreement, if any exists, concerning those standards.
3. **Regulatory Position** - Definitions acceptable to the NRC, and criteria, the basis for the criteria, and any additional information required to establish the NRC's position on the particular subject.
4. **Implementation** - A discussion of the NRC staff use of the Regulatory Guide and any alternative methods acceptable for fulfilling the requirements discussed in the Regulatory Guide.

Some Example are:

- Reg Guide 1.29, "Seismic Design Classification," (see Attachment A) amplifies 10 CFR 50 and 10 CFR 100 requirements. This guide also provides the definition of the term “Seismic Category I”. Seismic Category I refers to those plant structures, systems and components which are important to safety and are designed to remain functional in the event of a "Safe Shutdown Earthquake." Seismic Category I structures, systems, and components are necessary to assure the:

1. Integrity of the reactor coolant pressure boundary,
2. Capability to shut down the reactor and maintain it in a safe shutdown condition, or
3. Capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10CFR100.

- Reg Guide 1.147, "Inservice Inspection Code Case Acceptability ASME Section XI,Division 1" This regulatory guide (RG) lists the American Society of Mechanical Engineers (ASME) Section XI Code Cases that the U.S. Nuclear Regulatory Commission (NRC) has approved for use as voluntary alternatives to the mandatory ASME *Boiler and Pressure Vessel* (BPV) Code provisions that are incorporated by reference into Title 10, Part 50, of the *Code of Federal Regulations* (10 CFR Part 50), "Domestic Licensing of Production and Utilization Facilities" (Ref. 1).
- Reg Guide 1.192, This regulatory guide (RG) lists the American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (OM Code) (Ref. 1) Code Cases that the U.S. Nuclear Regulatory Commission (NRC) has approved for use as voluntary alternatives to the mandatory

  ASME OM Code provisions that are incorporated by reference into Title 10, Part 50, of the *Code of Federal Regulations* (10 CFR Part 50), "Domestic Licensing of Production and Utilization Facilities" (Ref. 2).
- Reg Guide 1.84, General Design Criterion (GDC) 1, "Quality Standards and Records," of Appendix A, "General Design Criteria for Nuclear Power Plants," to Title 10, Part 50, of the *Code of Federal Regulations* (10 CFR Part 50), "Domestic Licensing of Production and Utilization Facilities" (Ref. 1), requires, in part, that structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Where generally recognized codes and standards are used, Criterion 1 requires that they be identified and evaluated to determine their applicability, adequacy, and sufficiency and be supplemented or modified as necessary to ensure a quality product in keeping with the required safety function.
- Reg Guide 1.70, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants.

NUREG-Series Publications: *Reports or brochures on regulatory decisions, results of research, results of incident investigations, and other technical and administrative information.*

- Publications Prepared by NRC Staff NUREG-(nnnn)
- Brochures Prepared by NRC Staff NUREG/BR-(nnnn)
- Conference Proceeding Prepared by NRC Staff or Contractors NUREG/CP-(nnnn)

- Publications Prepared by NRC Contractors NUREG/CR-(nnnn)
- Publications Resulting from International Agreements NUREG/IA-(nnnn)
- Publications Prepared by NRC Staff for Knowledge Management NUREG/KM-(nnnn)
- Publications Available in the Agency wide Documents Access and Management System (ADAMS)
- Drafts for Comment

Some Examples are:

- NUREG-0050, Recommendations Related to Browns Ferry Fire
- NUREG-0800, Standard Review Plan of Safety Analysis Reports for Nuclear Plants (Formerly issued as NUREG-75/087) (See Attachment A – Chapter 15 this document.)
- NUREG-0814, Methodology of Evaluation of Emergency Response Facilities
- NUREG-0933, Resolution of Generic Safety Issues
- NUREG-1022, Event Reporting Guidelines: 10 CFR 50.72 and 50.73
- NUREG-1407, Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities
- NUREG-1409, Backfitting Guidelines
- NUREG-1430, Standard Technical Specifications Babcock and Wilcox Plants
- NUREG-1431, Standard Technical Specifications Westinghouse Plants
- NUREG-1432, Standard Technical Specifications Combustion Engineering Plants
- NUREG-1600, General Statement of Policy and Procedure for NRC Enforcement Actions
- NUREG-1804, Yucca Mountain Review Plan
- NUREG-2194, Standard Technical Specifications Westinghouse AP1000
- NUREG-2201, Probabilistic Risk Assessment and Regulatory Decision-making: Some Frequently Asked Questions
- NUREG-2215, Standard Review Plan for Spent Fuel Dry Storage System and Facilities

1.1.8 Generic Communications

Generic communications address generic concerns that evolve from nuclear reactor operating experience and regulatory initiatives that have broad applicability. Under the current Generic Communication Program, the NRC can issue bulletins, generic letters (GLs), regulatory issue summaries (RISs), and information notices (INs). Each of these regulatory guidance documents is discussed below. None of these generic communications may be used to impose new requirements.

Historically, the industry has commented that the NRC's generic communications were imprecisely understood. As a result, the NRC revised its Generic Communication Program in an effort to: (1) distinguish the role of bulletins and generic letters and (2) clarify that bulletins and generic communications would no longer be used to convey requirements. RISs, in particular, are now used to clarify the interpretation of agency regulations.

Generic Letters (GL)

Generic Communication or Generic Letters (GL) are used to address industry issues and resolution. Some Examples are:

- GL-81-04 Emergency Procedures and Training for Station Blackout Events
- GL-88-03 Resolution of Generic Safety Issue 93, "Steam Binding of Auxiliary Feedwater Pumps"
- GL 89-10 Safety-Related Motor-Operated Valve Testing and Surveillance,
- GL 89-13 Service Water System Problems Affecting Safety-Related Equipment,
- GL-98-04 Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment,
- GL-04-02 Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors,
- GL-08-01 Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems.

They are tracked on the Generic Issues Dashboard and summarized in semiannual reports. NUREG-0933 Is Resolution of Generic Safety Issues and addresses prioritization.

1.1.9 Commission Documents - COMSECYs and COMs

Documents pertaining to the meetings and the activities of the commission are:

- Recently Released Commission Documents
- Commission Papers (SECY)
- Staff Requirements Memoranda (SRM)
- Commission Voting Records (CVR)
- Commission Action Memoranda (COMs and COMSECYs)
- Commission Meetings, Agendas, Slides, Transcripts, Meeting SRMs, and Full Written Explanation for Closed Meetings
- Commission Orders
- Commission Speeches
- Commission Correspondence
- Commission Responses to GAO Reports
- Commission Policy Statements
- Combined Index of Related Commission Documents
- Weekly Information Report

In a number of cases, attachments to Commission Papers (SECY), SRMs, and Voting Records may not be available in electronic form. This is particularly true for large technical reports, Commissioners' handwritten vote sheets, graphical figures, tables, and non-NRC documents. Older documents are less likely to be available electronically. The NRC Public Document Room maintains paper and/or microfiche copies of these documents and can assist you in obtaining them.

As a general policy, COMs and COMSECYs will be released to the public unless they contain specific limited types of information which warrant protection. Missing numbers in the listing indicate that these papers involve matters which the Commission has specifically agreed should be withheld: Classified, Safeguards, Allegation, Investigation, Security-Related, Proprietary, Privacy Act Information, Federal/State/Foreign Government and International Agency-Controlled Information, Adjudicatory, Enforcement, Lawyer-Client or Legal Work Product, and limited sensitive matters which contain a specific withhold recommendation and supporting justification. (Reference Internal Commission Procedures, Chapter II.)

1.1.10 Summary

The interrelationships between the various reference documents can be illustrated using seismic design considerations as an example. General Design Criterion 2 of 10 CFR 50, Appendix A requires that certain systems be designed for protection against natural phenomena such as earthquakes. 10 CFR 100, Appendix A (also in Attachment A) provides more specific requirements regarding the evaluations and analyses that must be done to ensure adequate seismic suitability of the site and design of the plant. These required evaluations and analyses are documented in the plant's FSAR. Individual Technical Specifications set forth the associated operating requirements to ensure that plant parameters are monitored, and plant systems function as assumed in the FSAR, with the bases section tying the particular specification back to the FSAR analyses. Any Regulatory Guides or industry standards that were used in the evaluation process may be referenced in the FSAR discussion and/or the Technical Specification bases.

NUREG-0800 Chapter 3 addresses seismic design, NUREG/CR-6919 has Recommendations for Revision of Seismic Design Calculations, NUREG/CR-7230 has Seismic Design Standards and Calculational Methods, NUREG/CR-7237 Correlates Seismic Performance in Similar SSCs, and more NUREGs yet to mention. Knowledge of the vendor design to meet the Regulatory requirements helps the staff to ask better questions and reference the station's analysis to the requirements during inspections and reviews.

Attachment A - Passages from Selected Regulatory Documents

NUREG-1482 - Guidelines for Inservice Testing at Nuclear Power Plants

The U.S. Nuclear Regulatory Commission (NRC) staff issued Revision 2 to NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plant,” to assist the nuclear power plant licensees in establishing a basic understanding of the regulatory basis for pump and valve Inservice Testing (IST) programs and dynamic restraints (snubbers) inservice examination and testing programs. Since the Revision 1 issuance of NUREG-1482, certain tests and measurements required by earlier editions and addenda of the American Society of Mechanical Engineers (ASME) Code for Operation and Maintenance of Nuclear Power Plants (OM Code) have been clarified, updated, revised or eliminated. The revision to NUREG-1482 incorporates and addresses those changes and includes the IST programs guidelines related to new reactors. The revised guidance incorporates lessons learned and experience gained since the last issue. This paper provides an overview of the contents of the NUREG-1482 and those changes and discusses how they affect NRC guidance on implementing pump and valve Inservice Testing (IST) programs. For the first time, this revision added dynamic restraint (snubber) inservice examination and testing program guidelines along with pump and valve IST programs. This paper highlights important changes to NUREG-1482 but is not intended to provide a complete record of all changes to the document. The NRC intends to continue to develop and improve its guidance on IST methods through active participation in the ASME OM Code consensus process, interactions with various technical organizations, user groups, and through periodic updates of NRC-published guidance and issuance of generic communications as the need arises. Revision 2 to NUREG-1482 incorporates regulatory guidance applicable to the 2004 Edition including 2005 and 2006 Addenda to the ASME OM Code.

Revision 0 and Revision 1 to NUREG-1482 are still valid and may continue to be used by those licensees who have not been required to update their IST program to the 2004 Edition including the 2005 and 2006 Addenda (or later Edition) of the ASME OM Code. The guidance provided in many sections herein may be used for requesting relief from or alternatives to ASME OM Code requirements. However, licensees may also request relief or authorization of an alternative that is not in conformance with the guidance. In evaluating such requested relief or alternatives, the NRC uses the guidelines/recommendations of the NUREG, where applicable.

The guidelines and recommendations provided in this NUREG and its Appendix A do not supersede the regulatory requirements specified in Title 10 of the Code of Federal Regulations (10 CFR) 10 CFR 50.55a, “Codes and standards”. Further, this NUREG does not authorize the use of alternatives to, grant relief from, the ASME OM Code requirements for inservice testing of pumps and valves, or inservice examination and testing of dynamic restraints (snubbers), incorporated by reference in 10 CFR 50.55a.

10 CFR 50.36 - Technical Specifications (TS).

(a) Each applicant for a license authorizing operation of a production or utilization facility shall include in his application proposed technical specifications in accordance with the requirements of this section. A summary statement of the bases or reasons for such specifications, other than those covering administrative controls, shall also be included in the application, but shall not become part of the technical specifications.

(b) Each license authorizing operation of a production or utilization facility of a type described in § 50.21 or § 50.22 will include technical specifications. The technical specifications will be derived from the analyses and evaluation included in the safety analysis report, and amendments thereto, submitted pursuant to § 50.34. The Commission may include such additional technical specifications as the Commission finds appropriate.

(c) Each applicant for a design certification or manufacturing license under part 52 of this chapter shall include in its application proposed generic technical specifications in accordance with the requirements of this section for the portion of the plant that is within the scope of the design certification or manufacturing license application.

(d) Technical specifications will include items in the following categories:

(1) *Safety limits, limiting safety system settings, and limiting control settings*. (i)(A) Safety limits for nuclear reactors are limits upon important process variables that are found to be necessary to reasonably protect the integrity of certain of the physical barriers that guard against the uncontrolled release of radioactivity. If any safety limit is exceeded, the reactor must be shut down. The licensee shall notify the Commission, review the matter, and record the results of the review, including the cause of the condition and the basis for corrective action taken to preclude recurrence. Operation must not be resumed until authorized by the Commission. The licensee shall retain the record of the results of each review until the Commission terminates the license for the reactor, except for nuclear power reactors licensed under § 50.21(b) or § 50.22 of this part. For these reactors, the licensee shall notify the Commission as required by § 50.72 and submit a Licensee Event Report to the Commission as required by § 50.73. Licensees in these cases shall retain the records of the review for a period of three years following issuance of a Licensee Event Report.

(B) Safety limits for fuel reprocessing plants are those bounds within which the process variables must be maintained for adequate control of the operation and that must not be exceeded in order to protect the integrity of the physical system that is designed to guard against the uncontrolled release or radioactivity. If any safety limit for a fuel reprocessing plant is exceeded, corrective action must be taken as stated in the technical specification or the affected part of the process, or the entire process if required, must be shut down, unless this action would further reduce the margin of safety. The licensee shall notify the Commission, review the matter, and record the results of the review, including the cause of the condition and the basis for corrective action taken to preclude recurrence. If a portion of the process or the entire process has been shutdown, operation must not be resumed until authorized by the

Commission. The licensee shall retain the record of the results of each review until the Commission terminates the license for the plant.

(ii)(A) Limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded. If, during operation, it is determined that the automatic safety system does not function as required, the licensee shall take appropriate action, which may include shutting down the reactor. The licensee shall notify the Commission, review the matter, and record the results of the review, including the cause of the condition and the basis for corrective action taken to preclude recurrence. The licensee shall retain the record of the results of each review until the Commission terminates the license for the reactor except for nuclear power reactors licensed under § 50.21(b) or § 50.22 of this part. For these reactors, the licensee shall notify the Commission as required by § 50.72 and submit a Licensee Event Report to the Commission as required by § 50.73. Licensees in these cases shall retain the records of the review for a period of three years following issuance of a Licensee Event Report.

(B) Limiting control settings for fuel reprocessing plants are settings for automatic alarm or protective devices related to those variables having significant safety functions. Where a limiting control setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that protective action, either automatic or manual, will correct the abnormal situation before a safety limit is exceeded. If, during operation, the automatic alarm or protective devices do not function as required, the licensee shall take appropriate action to maintain the variables within the limiting control-setting values and to repair promptly the automatic devices or to shut down the affected part of the process and, if required, to shut down the entire process for repair of automatic devices. The licensee shall notify the Commission, review the matter, and record the results of the review, including the cause of the condition and the basis for corrective action taken to preclude recurrence. The licensee shall retain the record of the results of each review until the Commission terminates the license for the plant.

(2) *Limiting conditions for operation*. (i) Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met. When a limiting condition for operation of any process step in the system of a fuel reprocessing plant is not met, the licensee shall shut down that part of the operation or follow any remedial action permitted by the technical specifications until the condition can be met. In the case of a nuclear reactor not licensed under § 50.21(b) or § 50.22 of this part or fuel reprocessing plant, the licensee shall notify the Commission, review the matter, and record the results of the review, including the cause of the condition and the basis for corrective action taken to preclude recurrence. The licensee shall retain the record of the results of each review until the Commission terminates the license for the nuclear reactor or the fuel reprocessing plant. In the case of nuclear power reactors licensed under § 50.21(b) or § 50.22,

the licensee shall notify the Commission if required by § 50.72 and shall submit a Licensee Event Report to the Commission as required by § 50.73. In this case, licensees shall retain records associated with preparation of a Licensee Event Report for a period of three years following issuance of the report. For events which do not require a Licensee Event Report, the licensee shall retain each record as required by the technical specifications.

(ii) A technical specification limiting condition for operation of a nuclear reactor must be established for each item meeting one or more of the following criteria:

(A) *Criterion 1*. Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

(B) *Criterion 2*. A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

(C) *Criterion 3*. A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

(D) *Criterion 4*. A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

(iii) A licensee is not required to propose to modify technical specifications that are included in any license issued before August 18, 1995, to satisfy the criteria in paragraph (c)(2)(ii) of this section.

(3) *Surveillance requirements*. Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

(4) *Design features*. Design features to be included are those features of the facility such as materials of construction and geometric arrangements, which, if altered or modified, would have a significant effect on safety and are not covered in categories described in paragraphs (c) (1), (2), and (3) of this section.

(5) *Administrative controls*. Administrative controls are the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner. Each licensee shall submit any reports to the Commission pursuant to approved technical specifications as specified in § 50.4.

(6) *Decommissioning*. This paragraph applies only to nuclear power reactor facilities that have submitted the certifications required by § 50.82(a)(1) and to non-power reactor facilities which are not authorized to operate. Technical specifications involving safety limits, limiting safety system settings, and limiting control system

settings; limiting conditions for operation; surveillance requirements; design features; and administrative controls will be developed on a case-by-case basis.

(7) *Initial notification*. Reports made to the Commission by licensees in response to the requirements of this section must be made as follows:

(i) Licensees that have an installed Emergency Notification System shall make the initial notification to the NRC Operations Center in accordance with §50.72 of this part.

(ii) All other licensees shall make the initial notification by telephone to the Administrator of the appropriate NRC Regional Office listed in appendix D, part 20, of this chapter.

(8) *Written Reports*. Licensees for nuclear power reactors licensed under § 50.21(b) and § 50.22 of this part shall submit written reports to the Commission in accordance with § 50.73 of this part for events described in paragraphs (c)(1) and (c)(2) of this section. For all licensees, the Commission may require Special Reports as appropriate.

(e)(1) This section shall not be deemed to modify the technical specifications included in any license issued prior to January 16, 1969. A license in which technical specifications have not been designated shall be deemed to include the entire safety analysis report as technical specifications.

(2) An applicant for a license authorizing operation of a production or utilization facility to whom a construction permit has been issued prior to January 16, 1969, may submit technical specifications in accordance with this section, or in accordance with the requirements of this part in effect prior to January 16, 1969.

(3) At the initiative of the Commission or the licensee, any license may be amended to include technical specifications of the scope and content which would be required if a new license were being issued.

(f) The provisions of this section apply to each nuclear reactor licensee whose authority to operate the reactor has been removed by license amendment, order, or regulation.

NUREG-0800 - Standard Review Plan (SRP)

Chapter 15 - Transient and Accident Analysis

The evaluation of the safety of a nuclear power plant requires analyses of the plant's responses to postulated equipment failures or malfunctions. Such analyses help to determine the limiting conditions for operation, limiting safety system settings, and design specifications for safety-related components and systems to protect public health and safety. These analyses are a focal point of the license amendment request (LAR), design certification (DC), and combined license (COL) reviews.

AREAS OF REVIEW

The specific areas of review are as follows:

1. Categorization of Transients and Accidents. The reviewer ensures that the applicant's selection and assembly of the plant transient and accident analyses represent a sufficiently broad spectrum of transients and accidents or initiating events.

   Initiating events are categorized according to expected frequency of occurrence and by type. Categorization by frequency of occurrence provides a basis for selection of the applicable analysis acceptance criteria for each initiating event. Categorization of initiating events by type provides a basis for comparison between events, which makes it possible to identify and evaluate the limiting cases (i.e., the cases that can challenge the analysis acceptance criteria).

   A. Categorization According to Frequency of Occurrence. Each initiating event is categorized as either an anticipated operational occurrence (AOO) or as a postulated accident.

      AOOs, as defined in Appendix A to 10 CFR Part 50, are those conditions of normal operation that are expected to occur one or more times during the life of the nuclear power unit.

      The SRP uses the term AOOs to refer to the events that are categorized in Regulatory Guide 1.70 and in Regulatory Guide 1.206 as incidents of moderate frequency (i.e., events that are expected to occur several times during the plant's lifetime) and infrequent events (i.e., events that may occur during the lifetime of the plant).

      Incidents of moderate frequency and infrequent events are also known as Condition II and Condition III events, respectively, in the commonly used, often cited but unofficial American Nuclear Society (ANS) standards. The reviewer will continue to evaluate applications, according to the categorizations and acceptance criteria of References 4 and 5, for licensees that have these categorizations in their licensing bases, or if they wish, according to the categorizations and acceptance criteria of this SRP section. The reviewer will evaluate new applications (i.e., those pertaining to plants that are not yet constructed) according to the categorizations and acceptance criteria of this SRP section.

      The following are some examples of AOOs in pressurized-water reactor (PWR) and boiling-water reactor (BWR) designs:

      - Inadvertent control rod or rod group withdrawal (PWR and BWR)
      - Loss or interruption of core coolant flow, excluding reactor coolant pump locked rotor (PWR)
      - Inadvertent moderator cooldown (PWR and BWR)
      - Inadvertent chemical shim dilution (PWR)
      - Depressurization by spurious operation of an active element, such as a relief valve (PWR and BWR)
      - Blowdown of reactor coolant through a safety valve (PWR and BWR)
      - Loss of normal feedwater (PWR and BWR)
      - Loss of condenser cooling (PWR and BWR)
      - Steam generator tube leaks (PWR)
      - Reactor-turbine load mismatch, including loss of load and turbine trip (PWR and BWR)
      - Control rod drop (inadvertent addition of absorber) (PWR)
      - Single error of an operator (PWR and BWR)
      - Single failure of a control component (PWR and BWR)

- Single failure in the electrical system (PWR and BWR)
- Minor reactor coolant system (RCS) leak or loss of reactor coolant such as from a small ruptured pipe or from a crack in a large pipe (PWR and BWR)
- Minor secondary system break (PWR)
- Loss of offsite power (PWR and BWR)
- Operation with a fuel assembly in an improper position (PWR and BWR)
- Inadvertent blowdown of RCS (BWR)
- Loss of feedwater heating (PWR and BWR)
- Trip of any or all recirculation pumps (BWR)
- Inadvertent pump start in a hot recirculation loop (BWR)
- Condenser tube leak (BWR)
- Startup of an idle recirculation pump in a cold loop (BWR)
- Reactor overpressure with delayed scram

The individual event sections of the SRP address specific AOOs and their appropriate variations (e.g., design-specific variations).

Anticipated transients without scram (ATWSs) are AOOs in which a reactor scram is demanded but fails to occur because of a common-mode failure in the reactor scram system. ATWS events, therefore, are AOOs that postulate complete failure of the required (single-failure proof) protection system. As such, they are beyond the design basis, and consequently, ATWS events are addressed separately (see SRP Section 15.8).

Postulated accidents are unanticipated occurrences (i.e., they are postulated but not expected to occur during the life of the nuclear power plant).

Postulated accidents are also known as Condition IV events in the unofficial ANS standards.

The following are some examples of postulated accidents in PWRs and BWRs of current designs:

- Major rupture of a pipe containing reactor coolant up to and including double-ended rupture of the largest pipe in the reactor coolant pressure boundary (PWR and BWR)
- Ejection of a control rod assembly (PWR)
- Control rod drop accident (BWR)
- Major secondary system pipe rupture up to and including double-ended rupture (PWR and BWR)
- Single reactor coolant pump locked rotor (PWR)
- Seizure of one recirculation pump (BWR)

The sections of the SRP dealing with the individual events address specific postulated accidents and appropriate variations (e.g., design-specific variations).

B. Categorization According to Type. AOOs and postulated accidents are also categorized according to type. The type of AOO or postulated accident is defined by its effect on the plant. For example, one type of AOO or postulated accident will cause the RCS to pressurize and possibly jeopardize RCS integrity. Another type will cause the RCS to depressurize and possibly jeopardize fuel cladding integrity. It is useful to categorize and organize analyses of AOOs and postulated accidents according to type, so that analysts can compare them on common bases, effects, and safety limits. Such comparisons can help to identify limiting events and cases for detailed examination and eliminate nonlimiting cases from further consideration.

AOOs and postulated accidents can be grouped into the following seven types:

1. Increase in heat removal by the secondary system

2. Decrease in heat removal by the secondary system
3. Decrease in RCS flow rate
4. Reactivity and power distribution anomalies
5. Increase in reactor coolant inventory
6. Decrease in reactor coolant inventory
7. Radioactive release from a subsystem or component

The review of AOOs and postulated accident analyses, within a type, can (and should) encompass a variety of cases, each designed to produce effects or results that challenge designated safety limits. For example, one case study of the turbine trip event, an AOO that causes a decrease in heat removal by the secondary system, can be designed to yield a high peak RCS pressure, and another case study of the same AOO can be designed to yield a low, minimum thermal margin. The former case tests the safety limit for RCS pressure boundary integrity, while the latter case tests the safety limit that protects fuel cladding integrity.

The reviewer considers the possible case variations of AOOs and postulated accidents presented to verify that the licensee has identified the limiting cases. The reviewer evaluates licensees' claims that individual AOOs and postulated accidents are limiting or nonlimiting, or bounded by other AOOs and postulated accidents, with particular attention to the bases used for comparison. Comparison of AOOs to other AOOs within a type, for example, is easily justified. Comparison of AOOs of one type to postulated accidents of another type requires closer scrutiny and more justification from the licensee.

2. Analysis Acceptance Criteria. If the risk of an event is defined as the product of the event's frequency of occurrence and its consequences, then the design of the plant should be such that all the AOOs and postulated accidents produce about the same level of risk (i.e., the risk is approximately constant across the spectrum of AOOs and postulated accidents). This is reflected in the general design criteria (GDC), which generally prohibit relatively frequent events (AOOs) from resulting in serious consequences but allow the relatively rare events (postulated accidents) to produce more severe consequences.

   The reviewer will consider the results of licensees' analyses and evaluations of individual initiating events to ascertain whether the licensee has satisfied the applicable analysis acceptance criteria for each of the events. The licensee may propose the use of alternate acceptance criteria appropriate to the particular plant design and operation (e.g., for new reactor design applications). In such cases, the reviewer will consider the alternate criteria and determine whether they are equivalent, in function and consequences, to the current criteria (see below).

   A. Analysis Acceptance Criteria for AOOs. The following are the specific criteria necessary to meet the requirements of GDC for AOOs:

      i. Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

      ii. Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit for PWRs and that the critical power ratio (CPR) remains above the minimum critical power ratio (MCPR) safety limit for BWRs.

      The reviewer applies a third criterion, based on the ANS standards to ensure that there is no possibility of initiating a postulated accident with the frequency of occurrence of an AOO. Some of the questions that licensees must answer to justify making plant modifications without advance review (see 10 CFR 50.59) by the NRC staff reflect this concern.

iii. An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

For licensees that have the categorizations of References 4 or 5 (i.e., ANS Condition II, III, and IV events) in their licensing bases, the reviewer will apply the following acceptance criteria:

1) Condition II events

   a) Same as Criterion (1) (above), for AOOs.

   b) Same as Criterion (2) (above), for AOOs.

   c) By itself, a Condition II incident cannot generate a more serious incident of the Condition III or IV category without other incidents occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

2) Condition III events

   a) No more than a small fraction of the fuel elements in the reactor are damaged, although sufficient fuel element damage might occur to preclude resumption of operation for a considerable outage time.

   b) For PWRs, the release of radioactive material may exceed guidelines of 10 CFR Part 20 but shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius.

   c) For BWRs, the offsite release of radioactive material is limited to a small fraction of the guidelines of 10 CFR Part 100, which may be the result of the failure of a small fraction of the fuel elements in the reactor.

   d) A Condition III incident shall not, by itself, generate a Condition IV fault or result in a consequential loss of function of the RCS or reactor containment barriers.

3) Condition IV events

   ANS Condition IV events are postulated accidents. The reviewer will apply the acceptance criteria for postulated accidents (below) to evaluate Condition IV events.

B Analysis Acceptance Criteria for Postulated Accidents. Unlike an AOO, a postulated accident could result in sufficient damage to preclude resumption of plant operation. A list of the basic criteria necessary to meet the requirements of GDC for postulated accidents appears below. Individual sections of the SRP may specify additional criteria pertaining to certain postulated accidents.

i. Pressure in the RCS and main steam system should be maintained below acceptable design limits, considering potential brittle as well as ductile failures.

ii. Fuel cladding integrity will be maintained if the minimum DNBR remains above the 95/95 DNBR limit for PWRs and the CPR remains above the MCPR safety limit for BWRs. If the minimum DNBR or MCPR does not meet these limits, then the fuel is assumed to have failed.

iii. The release of radioactive material shall not result in offsite doses in excess of the guidelines of 10 CFR Part 100.

iv. A postulated accident shall not, by itself, cause a consequential loss of required functions of systems needed to cope with the fault, including those of the RCS and the reactor containment system.

For loss-of-coolant accidents (LOCAs), the following analysis acceptance criteria of 10 CFR 50.46 also apply:

i. The calculated maximum fuel element cladding temperature shall not exceed 2200 EF.

ii. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

iii. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

iv. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

v. After any calculated successful initial operation of the emergency core cooling system (ECCS), the calculated core temperature shall should be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

3. Plant Characteristics Considered in the Safety Evaluation. The reviewer ensures that the application contains the key plant parameters considered in the safety evaluation (e.g., core power, core inlet temperature, reactor system pressure, core flow, axial and radial power distribution, fuel and moderator temperature coefficient, void coefficient, reactor kinetics parameters, available shutdown rod worth, and control rod insertion characteristics). The reviewer checks that the range of values for plant parameters is representative of fuel exposure or core reload, and that the range is sufficiently broad to cover the predicted fuel cycle ranges, to the extent practicable, based on the fuel design and acceptable analytical methodology at the time of the LAR, DC, or COL application.

   The reviewer also ensures that the application specifies the permitted fluctuations and uncertainties associated with reactor system parameters and assumes the appropriate conditions, within the operating band, as initial conditions for transient analysis.

4. Assumed Protection and Safety Systems Actions. The reviewer ensures that the application lists the settings of all the protection and safety systems functions that are used (i.e., credited) in the safety evaluation. Typical protection and safety systems functions include reactor trips, isolation valve closures, ECCS initiation and ECCS. In evaluations of AOOs and postulated accidents, the performance of each credited protection or safety system is required to include the effects of the most limiting single active failure. This verifies satisfaction of the GDC criteria that require protection and safety systems to adequately perform their intended safety functions in the presence of single active failures. The reviewer also ascertains that the application lists the expected limiting delay time for each protection or safety system function and describes the acceptable methodology for determining uncertainties (from the combined effects of calibration error, drift, instrumentation error, and other factors) to be included in the establishment of the trip setpoints and allowable values specified in the plant technical specifications.

5. Evaluation of Individual Initiating Events. The reviewer ensures that the application includes an evaluation of each initiating event, using the format in Subsection I.6 of this SRP section. For initiating events that are determined to be not limiting, the reviewer may evaluate qualitative justifications and conduct comparisons with the corresponding, more limiting initiating events.

6. Event Evaluation

   A. Identification of Causes and Frequency Classification. For each initiating event evaluated, the reviewer ensures that the application includes a description of the occurrences that can lead to the event and a categorization of the event as either an AOO or postulated accident. The reviewer also checks for clear definitions of the analysis acceptance criteria appropriate to the specific nature of the initiating event, as well as the event's categorization.

B. Sequence of Events and Systems Operation. The reviewer verifies that the application addresses the following considerations for each initiating event:

i. Step-by-step sequence of events, from event initiation to the final stabilized condition (i.e., identification on a time scale of each significant occurrence, including flux monitor trips, insertion of control rods, attainment of primary coolant safety valve set points, opening and closing of safety valves, generation of containment isolation signals, and containment isolation) and identification of all operator actions credited in the transient and accident analyses for consequence mitigation

ii. Extent to which normally operating plant instrumentation and controls are assumed to function

iii. Extent to which plant and reactor protection systems are required to function 15.0-9 Revision 3 - March 2007

iv. Credit taken for the functioning of normally operating plant systems

v. Credited operation of engineered safety systems

vi. Assurance of consistency between the safety analyses and the emergency response guidelines/emergency procedure guidelines or emergency operating procedures with respect to the operator response (including action time) and available instrumentation The reviewer verifies that the applicant has specified only safety-related systems or components for use in mitigating AOO and postulated accident conditions, and has included the effects of single active failures in those systems and components. The reviewer may consider the licensee's technical justifications for the operation of non-safety-related systems or components (e.g., when they are used as backup protection and when they are not disabled, except by a detectable, random, and independent failure).

The reviewer ascertains that the applicant has evaluated the effects of single active failures and operator errors and that the licensee's application contains sufficient detail to permit independent evaluation of the adequacy of systems, as they relate to the subject events.

C. Core, System, and Barrier Performance

i. Evaluation Model. The reviewer ensures that the applicant has discussed the evaluation model used and any simplifications or approximations introduced to perform the analyses and identified digital computer codes used in the analysis. If the analysis uses more than one computer code, the applicant should describe the method used to connect the codes. The reviewer verifies that the applicant has discussed the important output of the codes under "results" with emphasis on the input data and the extent or range of variables investigated and that the applicant has included detailed descriptions of evaluation models and digital computer codes or listings by referencing documents that are available to the NRC.

The reviewer ensures that the applicant has provided a table listing the titles of topical reports (TRs) that describe models or computer codes used in transient and accident analyses and listed the associated NRC safety evaluation reports approving those TRs. The reviewer checks that implementations of NRC-approved models or codes are within the applicable ranges and conditions and that the applicant has demonstrated compliance with each of the conditions and limitations imposed by the NRC staff in its safety evaluation reports that approve the TRs.

ii. Input Parameters and Initial Conditions. The reviewer verifies that the applicant has (1) identified the major input parameters and initial conditions used in the analyses; (2) included the initial values of other variables and parameters in the application if they are used in the analyses of the particular event under study; (3) ensured that the parameters and initial conditions used in the analyses are suitably conservative; and (4) discussed the bases (including the degree of conservatism) used to select the numerical values of the input parameters.

iii. Results. The reviewer ensures that the applicant has presented the results of the analyses, including key parameters as a function of time during the course of the transient or accident. The following are examples of parameters that should be included:

- Neutron power
- Thermal power
- Heat fluxes, average and maximum
- RCS pressure
- DNBR or CPR, as applicable
- Core and recirculation loop coolant flow rates for BWRs
- Coolant conditions, including inlet temperature, core average temperature (for PWRs), core average steam volume fraction (for BWRs), average exit and hot channel exit temperatures, and steam volume fractions
- Temperatures, including maximum fuel centerline temperature, maximum clad temperature, or maximum fuel enthalpy
- Reactor coolant inventory, including total inventory and coolant level in various locations in the RCS
- Secondary (power conversion) system parameters, including steam flow rate, steam pressure and temperature, feedwater flow rate, feedwater temperature, and steam generator inventory
- ECCS flow rates and pressure differentials across the core, as applicable
- Containment pressure
- Relief and/or safety valve flow rate
- Flow rate from the RCS to the containment system, if applicable
- Pressurizer water volume (for PWRs)

In addition, the discussion of the results should emphasize the margins between the predicted values of various core parameters, as well as the values of those parameters that would represent limiting acceptable conditions.

Review Interfaces

Other SRP sections interface with this section as follows:

1. Design basis radiological consequence analyses associated with design basis accidents are reviewed under SRP Section 15.0.3.

The specific acceptance criteria and review procedures are contained in the referenced SRP section.

II. ACCEPTANCE CRITERIA

Acceptance criteria are based on meeting the relevant requirements of the following Commission regulations:

1. 10 CFR Part 20, “Standards for Protection Against Radiation”

2. 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities” (especially 10 CFR 50.46 and Appendix A)
3. 10 CFR Part 100, “Reactor Site Criteria”
4. 10 CFR Part 52, “Early Site Permits; Standard Design Certification; and Combined Licenses for Nuclear Power Plants”

The following GDC from Appendix A to 10 CFR Part 50 are relevant to SRP Section 15:

1. GDC 2, as it relates to the seismic design of structures, systems, and components (SSCs) whose failure could cause an unacceptable reduction in the capability of the residual heat removal system.
2. GDC 4, as it relates to the requirement that SSCs important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accident conditions, including such effects as pipe whip and jet impingement.
3. GDC 5, as it relates to the requirement that any sharing among nuclear power units of SSCs important to safety will not significantly impair their safety function.
4. GDC 10, as it relates to the RCS being designed with appropriate margin to ensure that specified acceptable fuel design limits are not exceeded during normal operations including AOOs.
5. GDC 13, as it relates to instrumentation and controls provided to monitor variables over anticipated ranges for normal operations, for AOOs, and for accident conditions.
6. GDC 15, as it relates to the RCS and its associated auxiliaries being designed with appropriate margin to ensure that the pressure boundary will not be breached during normal operations, including AOOs. 15.0-12 Revision 3 - March 2007
7. GDC 17, as it relates to the requirement that an onsite and offsite electric power system be provided to permit the functioning of SSCs important to safety. The safety function for each system (assuming the other system is not working) shall be to provide sufficient capacity and capability to ensure that the acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded during an AOO and that core cooling, containment integrity, and other vital functions are maintained in the event of an accident.
8. GDC 19, as it relates to the requirement that a control room be provided from which personnel can operate the nuclear power unit during both normal operating and accident conditions, including a LOCA.
9. GDC 20, as it relates to the reactor protection system being designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that the plant does not exceed specified acceptable fuel design limits during any condition of normal operation, including AOOs.
10. GDC 25, as it relates to the requirement that the reactor protection system be designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control system, such as accidental withdrawal of control rods.
11. GDC 26, as it relates to the reliable control of reactivity changes to ensure that specified acceptable fuel design limits are not exceeded even during AOOs. This is accomplished by ensuring that the applicant has allowed an appropriate margin for malfunctions such as stuck rods.
12. GDC 27 and 28, as they relate to the RCS being designed with an appropriate margin to ensure that acceptable fuel design limits are not exceeded and that the capability to cool the core is maintained.
13. GDC 29, as it relates to the design of the protection and reactivity control systems and their performance (i.e., to accomplish their intended safety functions) during AOOs.
14. GDC 31, as it relates to the RCS being designed with sufficient margin to ensure that the boundary behaves in a nonbrittle manner and that the probability of propagating fracture is minimized.

15. GDC 34, as it relates to the capability to transfer decay heat and other residual heat from the reactor so that fuel and pressure boundary design limits are not exceeded.
16. GDC 35, as it relates to the RCS and associated auxiliaries being designed to provide abundant emergency core cooling.
17. GDC 55, as it relates to the isolation requirements of small-diameter lines connected to the primary system.
18. GDC 60, as it relates to the radioactive waste management systems being designed to control releases of radioactive materials to the environment.
19. GDC 61, as it relates to the requirement that the fuel storage and handling, radioactive waste, and other systems that may contain radioactivity be designed to ensure adequate safety under normal and postulated accident conditions.

SRP Acceptance Criteria

Specific SRP acceptance criteria acceptable to meet the relevant requirements of the NRC's regulations identified above are as follows for the review described in this SRP section. The SRP is not a substitute for the NRC's regulations, and compliance with it is not required.

However, an applicant is required to identify differences between the design features, analytical techniques, and procedural measures proposed for its facility and the SRP acceptance criteria and evaluate how the proposed alternatives to the SRP acceptance criteria provide acceptable methods of compliance with the NRC regulations.

Subsection I.2 of this SRP section discusses general acceptance criteria, and SRP Chapter 15 subsections discuss specific acceptance criteria for transients or accidents.

III. REVIEW PROCEDURES

The reviewer will select material from the procedures described below, as may be appropriate for a particular case.

These review procedures are based on the identified SRP acceptance criteria. For deviations from these acceptance criteria, the staff should review the applicant's evaluation of how the proposed alternatives provide an acceptable method of complying with the relevant NRC requirements identified in Subsection II.

To evaluate the LAR, DC, or COL application, the reviewer verifies that the applicant has performed the applicable transient and accident analyses needed to demonstrate conformance to the regulations.

SRP Chapter 15 subsections discuss specific review procedures for transients or accidents.

IV. EVALUATION FINDINGS

The reviewer verifies that the applicant has provided sufficient information and that the review and calculations (if applicable) support conclusions of the following type to be included in the staff's safety evaluation report. The reviewer also states the bases for those conclusions.

SRP Chapter 15 subsections discuss the statements and conclusions of evaluation findings for transients or accidents.

V. IMPLEMENTATION

The staff will use this SRP section in performing safety evaluations of DC applications and license applications submitted by applicants pursuant to 10 CFR Part 50 or 10 CFR Part 52. Except when the applicant proposes an acceptable alternative method for complying with specified portions of the Commission's regulations, the staff will use the method described herein to evaluate conformance with Commission regulations.

The provisions of this SRP section apply to reviews of applications submitted six months or more after the date of issuance of this SRP section.

The referenced regulatory guides contain implementation schedules for conformance to parts of the method discussed here.

VI. DEFINITIONS

Term	Definition
Anticipated Operational Occurrences (AOOs)	Conditions of normal operation that are expected to occur one or more times during the life of the nuclear power unit and include but are not limited to loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, and loss of all offsite power. AOOs are also known as Condition II and III events.
Anticipated Transient Without Scram (ATWS)	AOO followed by the failure of the reactor trip portion of the protection system specified in GDC 20, because of common-mode failure.
Common-mode failure	The result of an event which, because of dependencies, causes a coincidence of failure states of components in two or more separate channels of a redundancy system, leading to the failure of the defined system to perform its intended function.
Critical Power Ratio (CPR)	That power in the assembly that will cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
Departure from Nucleate Boiling (DNB)	The DNB acceptance criterion for an AOO is met when there is a 95 percent probability at a 95 percent confidence level (the 95/95 DNB criterion) that DNB will not occur, and the fuel centerline temperature stays below the melting temperature. de sign basis Information that identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for design. These values may be (1) restraints derived from generally accepted state of the art practices for achieving functional goals, or (2) requirements derived from analysis (based on calculation and/or experiments) of the effects of a postulated accident for which a structure, system, or component must meet its functional goals
Design-Basis Accidents (DBA)	Postulated accidents that are used to set design criteria and limits for the design and sizing of safety-related systems and components. design-basis events Conditions of normal operation, including AOOs, design-basis accidents, external events, and natural phenomena, for which the plant must be designed to ensure functions of safety-related electric equipment that ensures the integrity of the reactor coolant pressure boundary; the capability to shut down the reactor and maintain it in a safe shutdown condition; or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures.
General Design Criteria (GDC)	Reference 1 lists the GDC. The GDC that mention AOOs are 10, 13, 15, 17, 20, 26, 29, 60, and 64. The GDC that mention postulated accidents are 4, 16, 17, 22, 27, 28, 31, 41, 51, 61, and 64.
Loss-Of-Coolant Accident (LOCA)	A postulated accident that results in the loss of reactor coolant at a rate in excess of the replacement capability of the reactor coolant makeup system.

Classification of Plant Conditions from Trojan UFSAR

Term	Definition
MCPR safety limit	This limit ensures that during normal operation and during AOOs, at least 99.9 percent of the fuel rods in the core do not experience transition boiling.
Minimum Critical Power Ratio (MCPR)	The smallest CPR that exists in the core for each class of fuel.
Overpressurization	The condition that occurs when pressure exceeds the design pressure of the component of interest by more than 10 percent, in accordance with the ASME Code.
Postulated Accidents	Unanticipated conditions of operation (i.e., not expected to occur during the life of the nuclear power unit). Postulated accidents are also known as Condition IV events.
Protection system	The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety. (GDC 20)
single failure	An occurrence that results in a component's loss of capability to perform its intended safety functions.

VII. <u>REFERENCES</u>

1. Appendix A to 10 CFR Part 50, "General Design Criteria for Nuclear Plants."
2. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants."
3. Regulatory Guide 1.206, "Combined License Applications for Nuclear Power Plants (LWR Edition)."
4. ANS 51.1, "Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants" (replaces ANSI N18.2), 1983 (withdrawn in 1998).
5. ANSI/ANS-52.1-1978, "Nuclear Safety Criteria for the Design of Stationary Boiling Water Reactor Plants" (withdrawn in 1998).
6. 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water Cooled Nuclear Power Plants."
7. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," Article NB-7000, "Protection Against Overpressure," American Society of Mechanical Engineers.
8. SECY-77-439, "Single-Failure Criterion," August 1977 (ADAMS Accession No. ML060260236).
9. 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities."
10. 10 CFR Part 52, "Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Plants."

10 CFR 50, Appendix A

Definitions and Explanations

Nuclear power unit. A nuclear power unit means a nuclear power reactor and associated equipment necessary for electric power generation and includes those structures, systems, and components required to provide reasonable assurance the facility can be operated without undue risk to the health and safety of the public.

Loss of coolant accidents. Loss of coolant accidents mean those postulated accidents that result from the loss of reactor coolant at a rate in excess of the capability of the reactor coolant makeup system from breaks in the reactor coolant pressure boundary, up to and including a break equivalent in size to the double-ended rupture of the largest pipe of the reactor coolant system.[1]

Single failure. A single failure means an occurrence which results in the loss of capability of a component to perform its intended safety functions. Multiple failures resulting from a single occurrence are considered to be a single failure. Fluid and electric systems are considered to be designed against an assumed single failure if neither (1) a single failure of any active component (assuming passive components function properly) nor (2) a single failure of a passive component (assuming active components function properly), results in a loss of the capability of the system to perform its safety functions.[2]

Anticipated operational occurrences. Anticipated operational occurrences mean those conditions of normal operation which are expected to occur one or more times during the life of the nuclear power unit and include but are not limited to loss of power to all recirculation pumps, tripping of the turbine generator set, isolation of the main condenser, and loss of all offsite power.

Criteria

I. Overall Requirements

Criterion 1--Quality standards and records. Structures, systems, and components important to safety shall be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems, and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Criterion 2--Design bases for protection against natural phenomena. Structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems, and components shall reflect: (1) Appropriate consideration of the most severe of the natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time in which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

Criterion 3--Fire protection. Structures, systems, and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety. Firefighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems, and components.

10 CFR 100, Appendix A

I. Purpose

General Design Criterion 2 of Appendix A to part 50 of this chapter requires that nuclear power plant structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without loss of capability to perform their safety functions. It is the purpose of these criteria to set forth the principal seismic and geologic considerations which guide the Commission in its evaluation of the suitability of proposed sites for nuclear power plants and the suitability of the plant design bases established in consideration of the seismic and geologic characteristics of the proposed sites.

These criteria are based on the limited geophysical and geological information available to date concerning faults and earthquake occurrence and effect. They will be revised as necessary when more complete information becomes available.

II. Scope

These criteria, which apply to nuclear power plants, describe the nature of the investigations required to obtain the geologic and seismic data necessary to determine site suitability and provide reasonable assurance that a nuclear power plant can be constructed and operated at a proposed site without undue risk to the health and safety of the public. They describe procedures for determining the quantitative vibratory ground motion design basis at a site due to earthquakes and describe information needed to determine whether and to what extent a nuclear power plant need be designed to withstand the effects of surface faulting. Other geologic and seismic factors required to be taken into account in the siting and design of nuclear power plants are identified.

The investigations described in this appendix are within the scope of investigations permitted by § 50.10(c)(1) of this chapter.

Each applicant for a construction permit shall investigate all seismic and geologic factors that may affect the design and operation of the proposed nuclear power plant irrespective of whether such factors are explicitly included in these criteria. Additional investigations and/or more conservative determinations than those included in these criteria may be required for sites located in areas having complex geology or in areas of high seismicity. If an applicant believes that the particular seismology and geology of a site indicate that some of these criteria, or portions thereof, need not be satisfied, the specific sections of these criteria should be identified in the license application, and supporting data to justify clearly such departures should be presented.

These criteria do not address investigations of volcanic phenomena required for sites located in areas of volcanic activity. Investigations of the volcanic aspects of such sites will be determined on a case-by-case basis.

III. Definitions

As used in these criteria:

(a) The *magnitude* of an earthquake is a measure of the size of an earthquake and is related to the energy released in the form of seismic waves. *Magnitude* means the numerical value on a Richter scale.

(b) The *intensity* of an earthquake is a measure of its effects on man, on man-built structures, and on the earth's surface at a particular location. Intensity means the numerical value on the Modified Mercalli scale.

(c) The *Safe Shutdown Earthquake*[1] is that earthquake which is based upon an evaluation of the maximum earthquake potential considering the regional and local geology and seismology and specific characteristics of local subsurface material. It is that earthquake which produces the maximum vibratory ground motion for which certain structures, systems, and components are designed to remain functional. These structures, systems, and components are those necessary to assure:

(1) The integrity of the reactor coolant pressure boundary,

(2) The capability to shut down the reactor and maintain it in a safe shutdown condition, or

(3) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of this part.

TR 3.3.5 Seismic Monitoring Instrumentation

3.3.5 Seismic Monitoring Instrumentation

TR 3.3.5The seismic monitoring instrumentation listed in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: At all times.

ACTIONS

---NOTES--

1.TR 3.0.3 and TR 3.0.4 are not applicable.

2.Separate Condition entry is allowed for each seismic monitoring instrument.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required seismic monitoring instruments inoperable.	A.1 Restore instrument(s) to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Prepare and submit a report to the NRC in accordance with 10 CFR 50.4 outlining the cause(s) of the malfunction(s) and the plans for restoring the instrument(s) to OPERABLE status.	10 days

(continued)

Example of TR

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more required seismic monitoring instruments actuated during a seismic event.	C.1	Restore instrumentation to OPERABLE status.	24 hours
	AND		
	C.2	Perform a CHANNEL CALIBRATION on actuated instrument(s).	24 hours
	AND		
	C.3	Analyze data retrieved from actuated instrumentation to determine the magnitude of the vibratory ground motion.	10 days
	AND		
	C.4	Prepare and submit a report to the NRC in accordance with 10 CFR 50.4 describing the magnitude and frequency spectrum of the seismic event and the resultant effect upon facility features important to safety.	10 days

TECHNICAL REQUIREMENT SURVEILLANCES

---NOTE---

Refer to Table 3.3.5-1 to determine which TRSs apply for each seismic monitoring instrument.

SURVEILLANCE		FREQUENCY
TRS 3.3.5.1	Perform CHANNEL CHECK.	31 days
TRS 3.3.5.2	Perform COT.	6 months
TRS 3.3.5.3	Perform CHANNEL CALIBRATION.	18 months

Example of TR

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENT AND SENSOR LOCATION	MEASUREMENT RANGE	REQUIRED NUMBER OF INSTRUMENTS	SURVEILLANCE REQUIREMENTS
1. Triaxial Time-History Recording Accelerographs			
a. ST 6336 - Containment Base Slab	0 - 2 g	1	TRS 3.3.5.1[(a)] TRS 3.3.5.2 TRS 3.3.5.3
b. ST 6336 - Containment Wall	0 - 2 g	1	TRS 3.3.5.1[(a)] TRS 3.3.5.2 TRS 3.3.5.3
c. ST 6336 - Fuel Building, Elev. 93'	0 - 2 g	1	TRS 3.3.5.1[(a)] TRS 3.3.5.2 TRS 3.3.5.3
d. ST 6336 - Cable Spreading Room	0 - 2 g	1	TRS 3.3.5.1[(a)] TRS 3.3.5.2 TRS 3.3.5.3
e. ST 6336 - Free Field	0 - 2 g	1	TRS 3.3.5.1[(a)] TRS 3.3.5.2 TRS 3.3.5.3
2. Triaxial Peak Accelerographs			
a. SR 6340 - Emergency Diesel Generator	0 - 2 g	1	TRS 3.3.5.3
b SR 6340 - CCW Heat Exchanger	0 - 2 g	1	TRS 3.3.5.3
c. SR 6340 - Top of Control Building	0 - 2 g	1	TRS 3.3.5.3
d. SR 6340 - Top of Fuel Building	0 - 2 g	1	TRS 3.3.5.3
e. SR 6340 - Top of Intake Structure	0 - 2 g	1	TRS 3.3.5.3
f. SR 6340 - Top of Containment	0 - 2 g	1	TRS 3.3.5.3
g. SR 6340 - Bottom of Containment	0 - 2 g	1	TRS 3.3.5.3
3. Triaxial Response - Spectrum Recorders			
a. SR 6341 - Containment Foundation	-	1[(b)]	TRS 3.3.5.1 TRS 3.3.5.2 TRS 3.3.5.3

1. (a) Except seismic trigger.

   (b) With control room indication.

Attachment B - A Summary of the Regulatory Process

1 INTRODUCTION

This document presents a basic description of the nuclear regulatory process and its elements for operating nuclear power plants. It is intended to be an overview, which will provide the reader a firm grasp of the fundamental elements of the regulatory process and how it is intended to function. It does not attempt to address all aspects of the process; for example, it does not discuss the process of obtaining a construction permit, operating license, or the Part 52 processes, nor does it discuss the hearing process, or the fee recovery formula for the NRC budget. However, this document will provide the reader with a fundamental understanding of the basic structure and principles of the regulatory process, which will enable further study of the details.

The document presents an overall description of the legal authorities from which the U.S. Nuclear Regulatory Commission responsibilities were created and an overview of the technical basis for regulatory decision-making. In carrying out its basic responsibilities, the NRC imposes and communicates technical requirements and provides guidance for licensees in a variety of ways. Because there is a large variation in the formality of these communications, the authority of each element of the regulatory process must be thoroughly understood. This document categorizes the types of information in the regulatory arena into the basic areas listed below. Each is discussed in a section of this document. A focus of the discussion is on the proper establishment and revision of regulatory requirements.

This regulatory process description is organized, as much as possible, in a hierarchical manner, beginning with the legislative authority, through requirements, guidance, communications, oversight and enforcement, the licensee's role, and finally administrative management and control of the process. Refer to the figure below, which corresponds to the sections of the paper.

Section 2, The Role of the Nuclear Regulatory Commission, describes the organization and functions of the NRC, its legal bases (including **AEA**, the Atomic Energy Act), and its relationships with other entities, including the federal legislative, executive and judicial branches, states, licensees and the general public.

Section 3, NRC Requirements, discusses binding requirements on licensees. The section describes regulations (and how they are developed), orders and licenses and plant technical specifications.

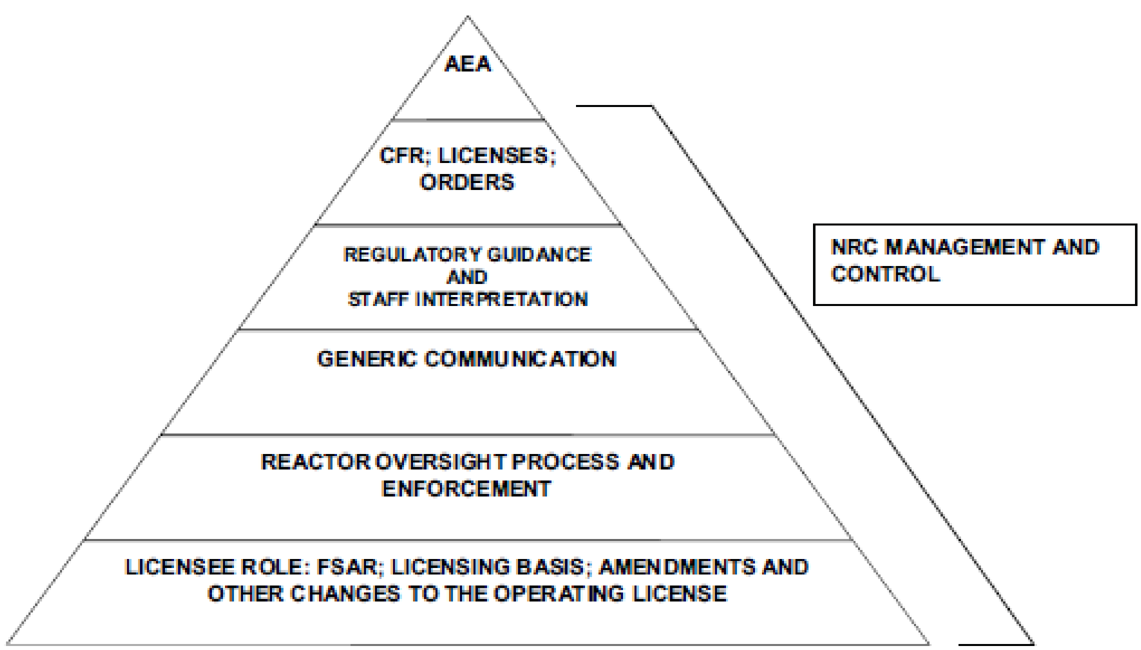
Section 4, NRC Regulatory Guidance and Staff Interpretations, discusses detailed technical guidance that provides acceptable methods of meeting the requirements in the regulations. Guidance documents and staff interpretations do not establish or revise requirements; rather, they represent approaches that are acceptable to the NRC staff for meeting the requirements. Alternative approaches may be used if determined to be acceptable to the NRC.

Section 5, NRC Generic Communications, describes the various means by which the NRC communicates to all licensees. They consist of bulletins, generic letters, regulatory information summaries and information notices. These communications are used to request information from, or provide information to, licensees, and may not be used to implement new requirements.

Section 6, NRC Reactor Oversight and Enforcement Process, describes how the NRC inspects licensees to assure compliance with the regulations; how it determines the significance of regulatory violations; how it assesses the overall performance of licensees and when additional inspection oversight is necessary; and the enforcement process.

Section 7, The Licensee Role in the Regulatory Process. An NRC licensee has primary responsibility for safe operation of the nuclear facility. Once the NRC issues an operating license, a plant owner must ensure compliance with the license. Since a plant's design and operation are not static, certain changes are necessary over the course of the plant's life. Licensees must follow NRC processes to justify and make those changes.

Section 8, NRC Management and Control of the Regulatory Process, discusses the formal mechanisms that exist to ensure the NRC acts in a legal, structured and disciplined manner in its licensing and oversight of nuclear power plants. These management and control mechanisms include statutes and regulations, commission direction to the staff, and specific procedures to ensure that the NRC achieves its legislative mandate and provides due process to its licensees.



2 THE ROLE OF THE NUCLEAR REGULATORY COMMISSION

2.1 ORGANIZATION AND FUNCTIONS

The U.S. Nuclear Regulatory Commission is the federal agency responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process. The NRC's responsibilities include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security and assuring conformity with antitrust laws. To carry out its mission of regulating licensed nuclear material, the NRC functions by: standards setting and rulemaking; technical reviews and studies; conduct of public hearings; issuance of authorizations, permits and licenses; inspection, investigation and enforcement; evaluation of operating experience; and confirmatory research.

As differentiated from the agency itself (referred to as the NRC), the *commission* is composed of five individuals appointed by the president and confirmed by the United States Senate. One commissioner is designated by the president as chairman and acts as the principal executive officer and official spokesman of the commission. The commission works as a collegial body to formulate policies, develop regulations governing nuclear reactor (and nuclear material) safety, issue orders to licensees and adjudicate legal matters. The NRC's executive director for operations (EDO) carries out the policies and decisions of the commission and directs the activities of the NRC program offices.

2.2 LEGAL BASES FOR NRC AUTHORITY

The process of implementing the NRC's mandate has been an evolutionary one. The Atomic Energy Act of 1946 created the Atomic Energy Commission (AEC) and gave the AEC authority over nuclear material. At that time, Congress recognized the national interest in regulating nuclear material but the private (non-military) use of nuclear material was largely non-existent.

In the Atomic Energy Act of 1954 (AEA), Congress gave the AEC broad powers to develop, use and control the private use of nuclear facilities and nuclear material. The statute required that the development, use and control of atomic energy be directed so as to promote world peace, improve the general welfare, increase the standard of living, and strengthen free competition in private enterprise. It required that civilian uses of nuclear materials and nuclear facilities (including, but not limited to, power reactors) be licensed, and authorized the AEC to govern the use of atomic energy as the commission may deem necessary or desirable in order to protect health and safety and minimize danger to life or property. Under the AEA, the AEC both promoted and regulated the civilian uses of nuclear materials and nuclear facilities. The commission also retained responsibility for the military application of nuclear materials and development of weapons.

The Energy Reorganization Act of 1974 (ERA) abolished the AEC and transferred its licensing, inspection, and related regulatory functions, and control over the civilian use of nuclear facilities and material, to the newly formed NRC. AEC jurisdiction over the military and promotional uses of atomic energy was transferred to the Energy Research and Development Agency and later to the U.S. Department of Energy. Thus, with the enactment of the ERA, the agency was no longer charged to promote the industry that it regulated.

The AEA remains the primary authority for the NRC's implementing regulations (set forth in Title 10 of the Code of Federal Regulations) and NRC activities. The AEA specified the agency's organization and the nuclear materials and nuclear facilities that the NRC is to license and regulate. Further, it established the processes for issuing NRC licenses (including public hearings), inspecting facilities, promulgating regulations and imposing enforcement sanctions.

Other statutes that govern or significantly affect the activities of the NRC include:

- The Administrative Procedure Act
- The Low-Level Radioactive Waste Policy Amendments Act of 1985
- The National Environmental Policy Act
- The Nuclear Non-Proliferation Act of 1978
- The Nuclear Waste Policy Act of 1982, as amended
- The Uranium Mill Tailings Radiation Control Act of 1978
- The Energy Policy Act of 2005

A detailed discussion of these statutes is beyond the scope of this paper; however, the importance of the Administrative Procedure Act to the regulatory process will be discussed in several sections. The NRC's Web site provides a brief summary of each of these federal laws as they affect the functioning of the NRC.

2.3 NRC'S RELATIONSHIPS WITH OTHER ENTITIES

The NRC is an independent federal regulatory agency. It is not part of the executive branch and answers to Congress rather than the president. There are currently several congressional committees and subcommittees with oversight and authorization jurisdiction over NRC activities. The president nominates NRC commissioners (with Senate confirmation) and selects the chairman. The Office of Management and Budget (OMB) provides budgetary oversight. The Environmental Protection Agency has responsibility for radiation standards, and also standards for license termination (decommissioning), and the storage and disposal of used nuclear fuel, specifically, Yucca Mountain. The NRC also interacts with other federal agencies, including the Department of Transportation, the Occupational Safety and Health Administration, the Federal Emergency Management Agency, and the Department of Homeland Security.

Final NRC actions are subject to judicial review by the federal courts, whose decisions may require the agency to modify its regulations or other programs. The NRC also interacts with stakeholders outside of the federal government, including the nuclear industry, the general public, and special interest groups that may support or oppose the use of nuclear energy. The NRC also interacts with the states. The AEA authorizes a limited degree of state participation, on a cooperative basis, in the uses of nuclear material and the oversight of nuclear power reactors through inspections or other functions; however, the NRC retains ultimate, exclusive authority to regulate the radiological safety and security aspects of facility construction and operation, the importing or exporting of nuclear licensed materials or facilities, spent fuel storage and disposal of licensed material. The NRC may "discontinue" or, in effect, cede to a state its regulatory authority over source, byproduct and special nuclear material below a critical mass, under the Agreement States Program. States that have assumed this authority are commonly referred to as "Agreement States." Currently, 39 of the 50 states administer Agreement State programs (2020 data).

Another important role of state and local governments is offsite emergency planning. State and local government officials have the overall responsibility of deciding and implementing the appropriate protective actions for the public during a nuclear power plant radiological emergency. They are responsible for notifying the public to take protective actions. State and local officials base their decisions on the protective action recommendations by the nuclear power plant operator and their own radiological or health organization. The NRC provides advice, guidance, and support to the state and local government officials. Neither the nuclear power plant operator nor the NRC can order the public to take protective actions.

The NRC does not have exclusive jurisdiction over all uses of nuclear material. The NRC does not license or regulate most uses of nuclear material by DOE or the Department of Defense; DOE's production of nuclear material for military applications; or nuclear reactors used for defense (e.g., nuclear powered warships). While the NRC has jurisdiction over sources, it does not have jurisdiction over other discrete naturally occurring radioactive material (NORM), such as radon, which is regulated by the states. DOE did submit a license application to the NRC in 2008 for High-Level Waste Geologic Repository at Yucca Mountain.

3 NRC REQUIREMENTS

3.1 BINDING REQUIREMENTS: REGULATIONS, ORDERS AND LICENSES

The NRC implements its statutory mandate in several ways. The AEA authorizes the agency to impose binding legal requirements through rules, regulations and orders. The NRC also issues licenses, including licenses to manufacture, produce, transfer, acquire, possess, use, import or export licensed material, and licenses for utilization and production facilities. NRC licensees must comply with the terms of their licenses, unless they are specifically not required to comply (e.g., through the granting of formal exemptions or relief requests). Additionally, the NRC verifies that plants are being operated in accordance with the agency's regulations through its inspection and enforcement processes, addressed in Section 6.

To establish legally binding requirements, the NRC must promulgate those requirements in accordance with the applicable procedures specified in the

Administrative Procedure Act (APA). NRC requirements established by rulemaking or by adjudication in accordance with the APA are the only requirements that are directly enforceable. These requirements (NRC regulations, orders and licenses) must be met by NRC applicants and licensees to maintain compliance.

A *rule* is an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy. (An NRC regulation is the same as an NRC rule.) An *order* is a final disposition, whether affirmative, negative, injunctive or declaratory in form, of an agency in a matter other than rulemaking but including licensing. At the end of the licensing process, the NRC may issue a *license:* an agency permit, certificate, approval, registration, charter, membership, statutory exemption or other form of permission.

The APA governs each of these processes. Certain procedural and due process protections apply to each of these forms of agency actions, including an opportunity for affected persons to participate through submission of written data, comments or arguments. The agency is also required to make its decisions publicly available, along with a general statement of basis and purpose. In general, the decision whether to use rulemaking or adjudication (orders) to address a regulatory problem or issue is within the discretion of the agency. The NRC uses both of these processes to impose new requirements on licensees, individuals, and vendors where applicable.

3.2 THE RULEMAKING PROCESS

In addition to establishing legally binding obligations by adjudication (orders), the NRC also imposes enforceable obligations by rules (regulations). NRC rules are developed by an open process referred to as "rulemaking," which is conducted in conformance with APA procedures. The need for a new or amended NRC regulation can arise from various sources, including: (1) a new statute requiring new regulatory requirements; (2) a commission directive or NRC staff initiative indicating a need for further regulation to resolve a safety, safeguards or environmental problem; or (3) commission receipt of a petition for rulemaking from an interested person.

To understand the agency's internal rulemaking process in any detail, one must consult NRC guidance documents, which are provided in NRC Management Directive 6.3, *The Rulemaking Process*. Procedures and guidance for rulemaking development are also provided in LIC-300, *Rulemaking Procedures*.

Before it begins the formal rulemaking, the NRC initiates an internal vetting process for the issue(s) in question to ensure that any subsequent rulemaking activities are conducted in an orderly, systematic manner with due attention to schedule and NRC resources. As part of this preparation for rulemaking, the agency may consider various proposed solutions (both regulatory and non-regulatory) to the issue(s) in question. The NRC also considers possible technical bases for a new rule, the extent to which there is NRC policy support for the rule and underlying technical basis, the cost-benefit analysis associated with changing existing NRC requirements, the anticipated effect on NRC licensees and on the agency itself, safety benefits, reductions in regulatory burden and other factors.

If a rulemaking action is approved, a draft rulemaking plan is typically prepared, along with a schedule of activities. At this stage, the agency considers the need for review of the rulemaking package by the Advisory Committee on Reactor Safeguards, the Advisory Committee on Nuclear Waste, and the Committee to Review Generic Requirements; whether an environmental assessment (EA) or environmental impact statement (EIS) should be prepared; and the priority of the rulemaking, among other factors. The draft rulemaking plan package goes through an internal review and concurrence process.

If the rulemaking moves forward, the NRC continues to follow detailed internal procedures intended to ensure that the agency fully considers the impacts of the proposed rule. A proposed rule package is prepared. This package includes the *Federal Register* notice (containing the text of the proposed rule and any supplementary information). It also includes supporting documents, such as the regulatory analysis (which examines the economic impact of alternatives considered in developing the proposed rule), the EA or EIS addressing potential environmental impacts, the backfit analysis, a clearance request to the OMB (in connection with any information collection requirements subject to the Paperwork Reduction Act), congressional letters, a press release and regulatory guidance. If the proposed rule is to go to the commission, a commission paper transmitting the rulemaking from the executive director for operations (EDO) to the commission is prepared.

After completion of the internal concurrence review, the commission votes on the proposed rule package and sends the EDO a Staff Requirements Memorandum (SRM) containing the results of its vote and commission direction (if any) regarding any changes to be made to the rulemaking package. NRC obtains OMB approval for each new or amended information collection requirement under the Paperwork Reduction Act. After any necessary changes are made, the proposed rule package is published in the *Federal Register*.

During the course of a rulemaking, NRC staff may elect to conduct one or more public meetings or workshops to obtain public input. Meeting topics may range from a specific regulatory issue or a portion of the regulations that is a candidate for amendment, to specific draft rule language under consideration at either the proposed or final rule stage. In most cases, the NRC makes publicly available draft rulemaking language prior to the issuance of a proposed rule. This information sharing is intended to facilitate stakeholder involvement and allow resolution of associated issues prior to publication of the proposed rule.

After the proposed rule is published and public comments on the rule have been submitted, the NRC considers those comments and decides how to resolve them in the final rule. The NRC staff develops a final rulemaking package, including the supporting documents and the disposition of the public comments. After internal review and concurrence, the NRC publishes a final rule in the *Federal Register*. The rule becomes effective on whatever effective date is set forth in the final rule. NRC regulations are codified in Title 10 of the Code of Federal Regulations (CFR) after they are promulgated.

3.2.1. APA Statutory Requirements Governing NRC Rulemaking

The open rulemaking process used by the NRC involves public notice and comment procedures. An agency must first (1) publish a general notice in the *Federal Register*, (2) give interested persons an opportunity to participate in the rulemaking through submission of written data, views or arguments, and (3) incorporate a concise general statement of the rule's basis and purpose. The *Federal Register* notice must include a statement of the time, place and nature of the public rulemaking proceeding and the legal authority under which the rule is proposed. The notice must also describe either the terms or substance of the proposed rule or a description of the subjects and issues involved. In practice, the text of the proposed and final rule is published.

When an advanced notice of proposed rulemaking, a proposed rule, a final rule or a direct final rule is published in the *Federal Register*, Supplementary Information (formerly designated the Statements of Consideration) is included, which satisfies APA requirements that the rulemaking notice provide a concise general statement of the basis and purpose of the proposed rule and the public comments thereon. The Supplementary Information section in NRC rulemaking notices typically contains useful background information, the regulatory history of the rule, an explanation of the rule's underlying intent and basis and, for final rules, a discussion of how the NRC staff addressed public comments. Often this section sets forth the NRC's view on how the rule language should be interpreted. In sum, the Supplementary Information explains the NRC staff's rationale for the regulation in sufficient detail to provide the courts with a factual and reasoned explanation to serve as a basis for judicial review. Commission language in the Supplementary Information accompanying an NRC rule provides insights regarding the commission's intent in the particular rulemaking.

3.3 ORDERS

NRC requirements established by adjudication include orders of the commission, NRC staff confirmatory orders, and Atomic Safety and Licensing Board orders. This category also includes operating licenses, since they are a form of order issued by adjudication. License requirements include license conditions and technical specifications. (Note that technical specifications are incorporated into the license under 10 CFR 50.36.)

The NRC imposes binding regulatory requirements via order when the NRC staff finds that a certain action on the part of one or more licensees is necessary to protect the health and safety of the public or the common defense and security. An order is a written NRC directive to modify, suspend or revoke a license; to cease and desist from a given practice or activity; or to take such other action as may be proper. Orders also may be issued in lieu of, or in addition to, civil penalties for Severity Level I, II or III violations.

Orders can be considered either compliance orders or safety orders. *Compliance orders* are issued to mandate compliance or additional actions in light of a noncompliance. Typically, the NRC regional office or the NRC program office responsible for the inspection area or activity initiates compliance orders. *Safety orders,* typically imposing new requirements beyond the current existing regulatory framework, may be imposed in unusual circumstances to provide reasonable assurance of public health and safety. In such circumstances, the NRC Office of Nuclear Reactor Regulation (NRR) may issue a modification order to impose additional requirements; to modify, suspend or revoke the license; or take other action that is incorporated as a condition of the operating license. Procedures and guidance for development of safety orders are found in NRR Office Instruction LIC-106, *Issuance of Safety Orders*.

3.4 NRC LICENSES AND TECHNICAL SPECIFICATIONS

The NRC is authorized to license and to regulate nuclear facilities (e.g. commercial nuclear power reactors, research reactors, uranium enrichment facilities, fuel fabrication facilities, spent nuclear fuel storage facilities, high-level radioactive waste disposal facilities) and nuclear materials (radioactive source material, special nuclear material and byproduct material).

A comprehensive discussion of the NRC licensing process (which applies to facility licenses and materials licenses) is beyond the scope of this paper. In brief, N RC regulations govern the process of applying for a license, amending a license after it is issued, extending a license and decommissioning a license for a nuclear facility. Each NRC license is issued for a specific period of time; for example, reactor operating licenses (OLs) are issued for a period of 40 years. The issuance and amendment of reactor operating licenses is governed by NRC regulations in 10 CFR Part 50; the renewal of reactor operating licenses is governed by 10 CFR Part 54. More recently, NRC has promulgated regulations in 10 CFR Part 52 that apply to the issuance of Early Site Permits, Design Certifications, and Combined Operating Licenses (COLs).

The AEA and NRC regulations require that nuclear power plant OL applications include technical specifications (tech specs) relating to the amount, kind, and source of special nuclear material required, the place of usage, the facility's characteristics, and other information, as well as the basis for each tech spec proposed. When the NRC issues a reactor operating license, the OL typically contains tech specs that define mandatory operating limits and other requirements and actions that must be taken to ensure protection of public health and safety and the environment. Section 10 CFR 50.36 addresses tech spec content, which must include: (1) safety limits, limiting safety system settings and limiting control settings; (2) limiting conditions for operation; (3) surveillance requirements; (4) design features; and (5) administrative controls. The AEA specifies that tech specs are a part of the license. Prior NRC approval is required to deviate from tech spec requirements. The licensee's role in requesting changes to the operating license, the technical specifications and the design basis and current licensing basis are discussed in Section 7.

4 NRC REGULATORY GUIDANCE AND STAFF INTERPRETATIONS

4.1 OVERVIEW

The NRC routinely interprets, or otherwise clarifies, the agency's regulatory requirements in either a generic guidance document (e.g., NUREGs, regulatory guides, and branch technical positions) or in case-specific actions (e.g., safety evaluations, inspection reports, enforcement actions). It is important to note that staff interpretations are informal and non-binding on the commission. **Except as specifically authorized by the commission, no interpretation of the meaning of the regulations by any officer or employee of the commission other than the general counsel will be recognized as legally binding.**

NRC guidance is used to communicate approaches acceptable to the NRC staff for meeting NRC requirements. As opposed to NRC regulations, orders and licenses, the NRC's regulatory guidance, staff interpretations, and information documents do not (in and of themselves) have the force of legally binding *requirement*s. NRC staff interpretations and guidance are not issued in accordance with the APA and (unless they are imposed in an order) do not constitute legal requirements. The enforceability of NRC staff guidance and interpretations flows from the underlying regulatory obligations, not from the NRC guidance document itself. Because NRC guidance documents are not the equivalent of NRC rules, the staff interpretations in these documents may be subject to challenge. Methods and solutions different from those set out in the NRC guidance documents may be acceptable to the NRC based upon plant-specific review.

4.2 STANDARD REVIEW PLANS

The NRC has developed Standard Review Plans (SRPs) for reviewing various types of licensee submittals to ensure consistency of NRC staff reviews and to ensure the technical adequacy of the licensee's submittal. According to NRC regulations, the SRP was issued to establish criteria that the NRC staff intends to use in evaluating whether an applicant/licensee meets the commission's regulations. The SRP contains *guidance for NRC staff reviewers* for performing safety reviews for applications to construct or operate nuclear power plants, or to obtain operating license amendments. SRPs address: (1) responsibilities of NRC staff reviewers; (2) matters that are reviewed; (3) the commission's regulations and acceptance criteria necessary for the review; (4) how the review is accomplished; (5) the conclusions that are appropriate; and (6) implementation requirements. SRPs also serve to make information about regulatory matters widely available and to improve communication and understanding of the NRC staff review process by stakeholders. Of particular interest to reactor licensees is NUREG-0800, *Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants*.

The NRC recognizes that: "The SRP is not a substitute for the regulations, and compliance is not a requirement." However, NRC regulations require power reactor operating license applicants to evaluate their facility against the SRP in effect six months prior to the docket date of the license application. This evaluation must include "an identification and description of all differences in design features, analytical techniques, and procedural measures" proposed for a new facility and those corresponding features in the SRP. Where a difference exists, the evaluation must discuss “how the alternative [to the SRP acceptance criteria] proposed provides an acceptable method of complying” with the NRC's regulations underlying the acceptance criteria.

The SRP is part of a continuing regulatory standards development activity that not only documents current methods of review, but also provides a base for modification of the review process in the future. It is updated periodically as the need arises. A major project was underway to update the SRP to support new plant applications. Procedures and guidance for development of SRP sections are provided in NRR Office Instruction LIC-200, *Standard Review Plan (SRP) Process (2020 data)*.

4.3 BRANCH TECHNICAL POSITIONS

Branch technical positions (BTPs) are guidelines intended to supplement the acceptance criteria in NRC regulations and regulatory guides and are provided as appendices to the SRP. As technical issues or questions of interpretation arise in the detailed reviews of plant designs, the staff must determine an acceptable resolution for each case to complete its review of a particular application. Where the same technical issue or question of interpretation recurs, the staff’s determination on the point at issue is formalized in a BTP. Thus, BTPs are primarily instructions to NRC staff reviewers that outline an acceptable approach to, or position on, a previously considered technical safety or design matter, and that are intended to ensure a uniform treatment of the issue by staff reviewers. BTPs can contain or reference properly established regulatory requirements but *cannot be used* to establish new regulatory requirements or revise existing ones.

4.4 REVIEW STANDARDS

As an adjunct to the comprehensive SRP (NUREG-0800), the NRC has also developed several review standards. Review standards were created in response to an Advisory Committee on Reactor Safeguards recommendation concerning the need for an SRP to enhance the consistency, quality, and completeness of the NRC staff’s review of complex licensing actions with which the NRC has not yet had much experience. Currently, there are two review standards dealing with power uprate applications and early site permit applications. In an effort to standardize NRC staff reviews of complex licensing actions, the review standards are intended to provide: (1) a clear definition of the review standards and scope, (2) references to existing review criteria (i.e., applicable SRP sections, BTPs, office instructions, information notices, generic letters, bulletins, NUREGs, industry standards, etc.), and (3) template safety evaluations. As with other staff interpretations, the guidance contained in review standards does not establish regulatory requirements.

4.5 REGULATORY GUIDES

Regulatory guides (RGs) are typically issued to define approaches acceptable to the NRC that licensees may take to comply with regulatory requirements. RGs may also provide sufficient information to help the NRC staff perform its function. RGs provide guidance for preparing a license application. They also describe acceptable methods for implementing NRC regulations, techniques used by the NRC staff in evaluating specific problems or postulated accidents, and data needed by the staff in its review of license applications and amendments. A licensee may choose to docket a commitment to a regulatory guide when it applies for or modifies its license.

Regulatory guides are not a substitute for regulation, and do not establish regulatory requirements. In most cases, methods outlined in the RG are not the only method acceptable to the NRC staff for implementing NRC regulations; solutions different from those in the RG may be acceptable if a basis that is equivalent in the level of protection or effectiveness is demonstrated. A licensee is free to rely on the RG approach, or to take alternative approaches if it can show that the underlying legal requirements are being met. RGs also may endorse, or endorse with exceptions, industry standards from organizations such as the American Society of Mechanical Engineers, the Institute of Electrical and Electronics Engineers, the American Nuclear Society, the Electric Power Research Institute and the Nuclear Energy Institute.

Three regulatory guides are cited in 10 CFR 50.55a, Codes and Standards. This, in effect, establishes these guidance documents as regulatory requirements.

4.6 NUREGS

The NRC NUREG series includes NRC staff and NRC contractor reports on unclassified scientific, technical and administrative information dealing with licensing and regulation of nuclear facilities and materials. These publications present information that may be used to support regulatory decisions, guidance for meeting regulations, results of task force investigations of specific topics or incidents, results of NRC or contractor research programs, resolution of generic safety issues, analyses of certain regulatory programs, proceedings of conferences and workshops, etc. Reports of this type are identified by an alphanumeric designator in the NUREG series (NUREG for a report, NUREG/BR for a brochure, NUREG/CR for a contractor report, NUREG/CP for conference proceedings). Some NUREGs are used to publish Standard Review Plans (for example, NUREG-1800, *Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants*).

NUREG documents do not contain legally binding regulatory requirements, although the NRC staff may incorporate part, or all, of the information in them into the regulations using the formal rulemaking process.

4.7 INTERIM STAFF GUIDANCE

Interim Staff Guidance (ISG) documents are issued by an NRC office to clarify an aspect of the SRP or to address issues not discussed in an SRP. As suggested by its name, an ISG document serves as a placeholder guidance document until it is incorporated into the next revision of the applicable (permanent) guidance document. ISGs are currently being used by: Division of Spent Fuel Storage and Transportation; License Renewal; Fuel Cycle Safety and Safeguards; and High-Level Waste Repository Safety. If the NRC staff determines that development of an ISG is appropriate, it issues a *Federal Register* notice requesting comments on the proposed ISG. At any step during the process, a proposed ISG can be modified or determined to be unnecessary. In the latter situation, the NRC staff will document the closure of the issue in a letter to the interested stakeholders and a *Federal Register* notice. The guidance contained in ISGs does not establish regulatory requirements.

5 NRC GENERIC COMMUNICATIONS

Generic communications address generic concerns that evolve from nuclear reactor operating experience and regulatory initiatives that have broad applicability. Under the current Generic Communication Program, the NRC can issue bulletins, generic letters (GLs), regulatory issue summaries (RISs), and information notices (INs). Each of these regulatory guidance documents is discussed below. None of these generic communications may be used to impose new requirements.

Historically, the industry has commented that the NRC's generic communications were imprecisely understood. As a result, the NRC revised its Generic Communication Program in an effort to: (1) distinguish the role of bulletins and generic letters and (2) clarify that bulletins and generic communications would no longer be used to convey requirements. RISs, in particular, are now used to clarify the interpretation of agency regulations.

5.1 BULLETINS

An NRC bulletin requests information, requests specific action and requires a written response from the addressees regarding matters of safety, safeguards or environmental significance, in accordance with 10 CFR 50.54(f). The NRC issues bulletins to address urgent and significant issues with generic applicability. A bulletin cannot establish legally binding regulatory requirements. A bulletin is subject to Committee to Review Generic Requirements (CRGR) review. (CRGR will be discussed in Section 8.) The commission has requested that it be kept informed of the NRC staff's intention to issue a bulletin.

Recipients may be asked to respond to a bulletin by taking compensatory action commensurate with the urgency of the issue being addressed, to provide requested information, and to perform and submit analyses by a specified time. A bulletin may not request continuing or long-term actions. A bulletin may *request* new or revised licensee commitments based on analyses performed and licensee-proposed corrective actions; however, a bulletin may not require licensee commitments.

5.2 GENERIC LETTERS

The NRC uses Generic Letters (GL) to address emergent or routine generic technical issues, where the NRC staff has concluded that a generic communication is an appropriate means to effect resolution. Generic letters can also be used for a risk-significant compliance matter that the NRC staff has concluded should be brought to the attention of the nuclear industry without extensive prior interaction. A GL may request information and/or specified action by the recipient regarding matters of safety, safeguards or environmental significance. GL recipients may be asked to report the completion of actions requested by the NRC in their docketed response to the GL. A GL may request that recipients perform analyses and submit them for staff review, provide descriptions of proposed corrective actions for staff review, and take corrective actions by a specified time.

A GL may *request* new or revised licensee commitments based on analyses performed and proposed corrective actions. It may not *require* licensee commitments or establish regulatory requirements. The NRC staff may exercise discretion in preparing information requests by not always requiring a written response in accordance with 10 CFR 50.54(f). A generic letter is subject to CRGR review and the commission has requested that it be informed of the NRC staff's intention to issue a generic letter. Proposed generic letters are published in draft form in the *Federal Register* for public comment.

5.3 INFORMATION REQUESTS PURSUANT TO 10 CFR 50.54(F)

Typically, requests for information identified in bulletins and generic letters cite the provisions of 10 CFR 50.54(f). The NRC may request information needed to (1) review situations that may involve serious questions regarding plant safety (e.g., unreviewed safety questions), and (2) determine the need to modify, suspend, or revoke an NRC license. Section 10 CFR 50.54(f) provides that: "Except for information sought to verify licensee compliance with the current licensing basis for that facility, the NRC must prepare the reason or reasons for each information request prior to issuance to ensure that the burden to be imposed on respondents is justified in view of the potential safety significance of the issue to be addressed in the requested information."

NRC Management Directive 8.4, *NRC Program for Management of Plant-Specific Backfitting of Nuclear Power Plants*, provides guidance for NRC staff implementation of 10 CFR 50.109 and 10 CFR 50.54(f). In addition, procedures and guidance for the use of 10 CFR 50.54(f) are provided in NRR Office Instruction LIC-202, *Procedures for Managing Plant-Specific Backfits and 50.54(f) Information Requests.*

5.4 REGULATORY INFORMATION SUMMARIES

Regulatory Information Summaries (RISs) are informational documents that the NRC uses to communicate with the nuclear industry on a broad spectrum of matters with generic applicability. The NRC has used RISs to:

- Document NRC endorsement of industry-developed issue resolutions, or industry guidance on technical or regulatory matters.
- Provide the status of staff-industry interaction on certain matters.
- Request licensees' voluntary participation in NRC-sponsored pilot programs.
- Inform licensees of opportunities for regulatory relief.
- Announce NRC staff technical/policy positions, particularly on matters not previously communicated to the nuclear industry or not fully understood.

- Provide guidance on regulatory matters, such as the scope/detail of information that should be provided in licensing applications to facilitate staff review.
- Announce the availability of regulatory documents (topical reports, NUREGs, documents discussing the closeout of generic safety issues).
- Request voluntary submittal of information to assist in the regulatory process.
- Announce changes in agency practice that could impact licensees.

The NRC now uses a RIS to address all matters previously reserved for NRC administrative letters. A RIS does not involve a request for action or information unless the request is “strictly voluntary.” A draft RIS may be published for public comment in the *Federal Register* in order to benefit from stakeholder comment prior to issuance. Although a RIS is not typically subject to CRGR review, the NRR staff may, in its discretion, refer a RIS to the CRGR for review.

5.5 NRC INFORMATION NOTICES

The NRC uses Information Notices (INs) to inform the nuclear industry of recently identified, significant operating experience that may have generic applicability. While an IN cannot establish or imply new regulatory requirements or new interpretations, NRC licensees are expected to review the information for applicability to their facilities or operations and consider actions, as appropriate, to avoid similar problems. An information notice is not subject to CRGR review and is not published in draft form in the *Federal Register* for public comment.

6 NRC REACTOR OVERSIGHT AND ENFORCEMENT PROCESS

It is the policy of the NRC to provide oversight of nuclear power plant activities to verify that the plants are being operated in accordance with NRC rules and regulations. The regulated licensee is ultimately responsible for the safety of its activities and the safeguarding of nuclear facilities and materials used in its operation. The NRC ensures that the licensee adequately discharges this ultimate responsibility through an inspection and enforcement program. The inspection program uses a sampling approach to provide reasonable assurance of protection of public health and safety.

6.1 INSPECTION AND ENFORCEMENT AUTHORITY

The NRC’s inspection and enforcement authority derives from the AEA and the Energy Reorganization Act of 1974. NRC regulations implementing this statutory authority are set forth in 10 CFR Part 2, subpart B. In addition to conducting inspections and investigations and issuing orders, the NRC may take various forms of enforcement action, up to and including modifying, suspending or revoking licenses (e.g., for material false statements, for a licensee’s failure to build or operate a facility in accordance with its license, for violations of NRC regulations, and for conditions that would have warranted refusal of an original license). The NRC may also impose civil penalties and, in some cases, criminal penalties (monetary fines or imprisonment). Alleged or suspected criminal violations are referred to the U.S. Department of Justice.

6.2 REACTOR OVERSIGHT PROCESS

The NRC's Reactor Oversight Process (ROP), implemented in April 2000, integrates inspection, enforcement and assessment of nuclear power plants in a risk-informed, performance-based system to ensure the appropriate level of NRC oversight of licensees. The process is designed to focus on those plant systems, structures, components and activities that are most risk significant. The ROP provides a "closed loop" oversight process: The level of oversight increases as licensee performance declines, and decreases to a minimum baseline of oversight as performance

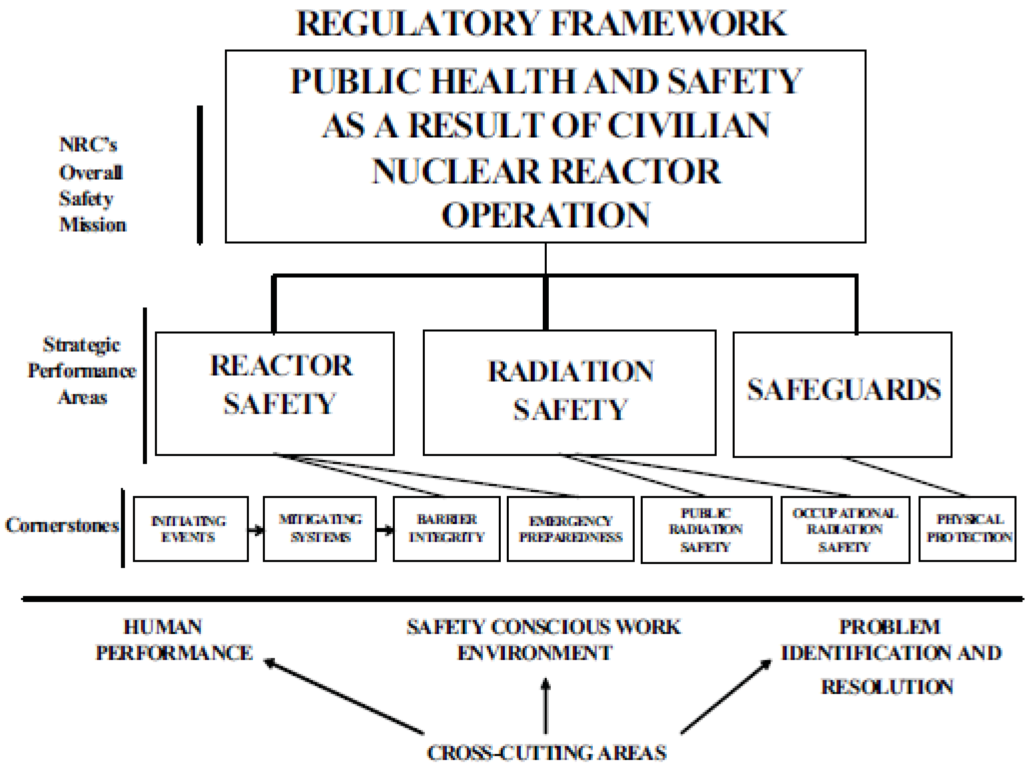
improves. NRC conducts a minimum baseline inspection of about 2000 hours per reactor per year. These inspections are conducted by the resident inspectors (there are at least two resident inspectors at each plant site full time) and specialists from the regional or national headquarters. Inspection findings and performance indicators are used to assess licensee safety performance. Licensee safety performance determines the level of NRC oversight, which is increased above a minimum baseline of inspection as plant performance declines and decreases back to the baseline as performance improves. Management Directive 8.13, *Reactor Oversight Process*, describes the process.

The NRC's regulatory framework for reactor oversight (shown in Figure 6.1) is a risk-informed, tiered approach to ensuring plant safety. It includes three strategic performance areas: reactor safety, radiation safety and safeguards. Within each strategic performance area are cornerstones that reflect the essential safety aspects of facility operation. The cornerstones are: (1) initiating events, (2) mitigating systems, (3) integrity of barriers to release of radioactivity, (4) emergency preparedness, (5) occupational radiation safety, (6) public radiation safety, and (7) physical protection. Satisfactory licensee performance in the cornerstones provides reasonable assurance that the facility is operating safely, and that the NRC's safety mission is being accomplished.

In addition to the cornerstones, the ROP features three cross-cutting areas that can affect each of the cornerstones. The cross-cutting areas include:

- Human performance
- Safety-conscious work environment (SCWE)
- Problem identification and resolution (e.g., the licensee's corrective action program)

The NRC's review and assessment of these cross-cutting areas play an important role in the ROP program. A recent change in how cross-cutting issues are assessed and integrated in the program began July 1, 2006 and may be subject to additional changes as more experience is gained.



Nuclear plant safety performance outcomes are measured by a combination of objective Performance Indicators (PI) and by the NRC inspection program. PIs use objective data to monitor performance within each of the cornerstones. Licensees generate the data that make up the PIs and submit them to the NRC quarterly. Each PI is measured against established thresholds of performance that are related to their effect on safety. The PIs are evaluated and integrated with the findings of the inspection program.

The ROP includes baseline inspections common to all nuclear plants. These inspections are conducted by resident inspectors (there are at least two resident inspectors at each nuclear power plant site) and by regional and headquarters staff. The baseline inspection program, based on the cornerstone areas, focuses on areas and systems that are risk significant. The baseline inspection program has three parts:

- Inspection in areas not covered by PIs or where a PI does not fully cover inspection area
- Inspections to verify the accuracy of the licensee's reports on performance indicators
- A thorough review of the licensee's effectiveness in finding and resolving problems

Inspections beyond the baseline are performed at plants with performance below established thresholds. Additional inspections may also be performed in response to a specific event or problem at a plant. Special inspections, including those conducted by an Augmented Inspection Team (AIT), are used to review the circumstances surrounding more significant events.

The NRC staff evaluates inspection findings identified during the inspection for safety significance using a significance determination process (SDP). Where possible, the SDP uses quantitative analysis (probabilistic risk analysis) to determine the risk significance. PI data is compared against prescribed risk-informed thresholds. These two distinct items — inspection findings and PIs — are used to conduct the plant assessment. Both aspects of safety performance are evaluated and given a color designation based on their safety significance. Green inspection findings or PIs indicate very low risk significance. White, yellow, or red inspection findings or PIs represent an increasing degree of safety significance. NRC determines the appropriate level of agency response based on the plant assessment information, which may include supplemental inspection and pertinent regulatory actions ranging from management meetings to orders for plant shutdown. Each plant assessment will fall in to one of the five columns of the NRC action matrix, ranging from performance that only requires baseline inspection and oversight (Licensee Response Column) to unacceptable performance, which may result in an order to modify, suspend or revoke licensed activities:

- Licensee Response Column
- Regulatory Response Column
- Degraded Cornerstone Column
- Multiple/Repetitive Degraded Cornerstone Column
- Unacceptable Performance Column

Enforcement action is taken on safety significant inspection findings, as appropriate. The NRC communicates the results of its performance assessment and its inspection plans and other planned actions in publicly available correspondence, on its Web site, and through public meetings with each licensee.

In conducting inspections, NRC inspectors follow guidance in the NRC Inspection Manual, which contains objectives and procedures to use for each type of inspection. The Inspection Manual does not contain regulatory requirements and cannot be used to establish any new regulatory requirements or new regulatory guidance.

NRC issues inspection reports to document inspection findings. They may cover a specific time period for the baseline inspection, or a particular event or problem examined in a reactive inspection. Inspection reports are intended to be factual and not reflect inspector opinion.

The results of the ROP, including inspection and assessment reports, performance indicators and inspection findings, are posted on the NRC's public Web site, with the exception of security related issues, which are withheld from public access.

6.3 ENFORCEMENT PROGRAM

The purpose of the NRC enforcement program is to support the NRC's overall safety mission in protecting the public and the environment. Consistent with that purpose, enforcement actions are used as a deterrent to emphasize the importance of compliance with requirements and to encourage comprehensive correction of violations. NRC's enforcement policy is contained in NUREG-1600, *NRC Enforcement Policy*.

The enforcement policy separates violations associated with inspection findings into two groups, depending on whether the Significance Determination Process (SDP) can be used to assess significance. When possible, the SDP is used to evaluate the safety significance of violations. The NRC response to assess the extent of the condition and the adequacy of the corrective actions taken is in accordance with the action matrix. Violations associated with findings evaluated as having very low safety significance (i.e., green) and that are addressed in the licensee's corrective action program are not normally cited. Violations associated with findings evaluated as having a greater significance (i.e., greater than green) are normally cited in a notice of violation (NOV). These violations are not normally subject to civil penalties. In all cases, the licensee must restore compliance with the regulations.

Violations that result in actual consequences, impede the regulatory process, or involve willful acts are processed under the traditional enforcement program since the regulatory importance of these issues is not limited to the underlying technical significance of the findings. These violations are assigned a severity level and licensees are subject to civil penalties in accordance with the criteria described in the NRC enforcement policy. Violations processed under the traditional enforcement program may not receive direct consideration under the action matrix.

Both the traditional enforcement program and the assessment program are exercised for cases in which a violation satisfies the criteria for traditional enforcement and is associated with a finding that has an underlying significance that can be processed under the SDP. Specifically, the violation would be given a severity level and would be considered for a civil penalty. In addition, the significance of the finding would be processed under the SDP and the result would be entered into the action matrix, as appropriate.

7 THE LICENSEE ROLE IN THE REGULATORY PROCESS

7.1 FACILITY DESIGN BASIS AND LICENSING BASIS

The NRC licensee has primary responsibility for operating its plant safely and in compliance with its license. Since a plant's design and operation are not static, certain changes are necessary over the course of the facility's operating life. Reactor licensees must follow NRC regulations to justify and implement changes in the *design basis* and *licensing basis* for their facilities. This section describes the licensee's role in maintaining and updating the licensing basis.

According to 10 CFR 50.2, *design bases* means "that information which identifies the specific functions to be performed by a structure, system, or component of a facility, and the specific values chosen for controlling parameters as reference bounds for design."

The *licensing basis* for a plant is comprised of selected information exchanged between a licensee and the NRC relating to design features, equipment descriptions, operating practices, site characteristics, programs and procedures, and other factors that describe a plant's design, construction, maintenance, and operation. Licensing basis information is contained in a variety of document types (e.g., final safety analysis report, license amendments, etc.). Each licensing basis document has certain characteristics in terms of change control mechanisms, reporting of changes to the NRC, dealing with discrepancies, and the possible involvement of the public.

NRC regulations related to license renewal define a facility's *current licensing basis* (CLB) as follows:

> "The set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71 and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports." (10 CFR 54.3)

7.1.1 Final Safety Analysis Reports and Updated Final Safety Analysis Reports

A final safety analysis report (FSAR) must be included in each application for a license to operate a nuclear reactor facility. The FSAR is intended to describe the facility, present the design bases and the limits on plant operation, and provide a safety analysis of the Structures, Systems and Components (SSC) and of the facility as a whole. Detailed requirements relating to FSAR content are addressed in 10 CFR 50.34(b). The applicant's FSAR is the principal document upon which the NRC bases its safety evaluation supporting the issuance of a facility operating license (OL). The updated FSAR (updated FSAR or UFSAR) incorporates changes made in accordance with 10 CFR 50.71(e). The UFSAR serves as a major source of information on the current plant design and supporting analyses and is considered part of the current licensing basis.

7.2 REGULATORY PROCESS CONTROLS USED BY NRC LICENSEES

Once the NRC issues a license for a nuclear facility, the licensee must operate the facility in compliance with its license. Since a plant's design and operation are not static, certain changes are necessary over the course of its life. Licensees must follow NRC regulations to justify and implement those changes in the design basis and licensing basis. The principal processes, procedures and regulatory vehicles that NRC licensees use in an effort to manage the NRC's licensing and regulatory process are discussed below.

7.2.1 10 CFR 50.59 Reviews (Changes, Tests, and Experiments)

Section 10 CFR 50.59 establishes the framework under which licensees may make changes to the facility or procedures and conduct tests or experiments without prior NRC approval, and without submitting a license amendment request. A licensee may modify the plant and associated documents (procedures, drawings, updated final safety analysis report, etc.) without prior NRC approval unless the license or technical specifications must be revised to permit implementation of the modification, or the modification meets one or more of the eight criteria specified in 10 CFR 50.59(c)(2). These criteria are:

a. Result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the final safety analysis report (as updated);
b. Result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system or component (SSC) important to safety previously evaluated in the final safety analysis report (as updated);
c. Result in more than a minimal increase in the consequences of an accident previously evaluated in the final safety analysis report (as updated);
d. Result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the final safety analysis report (as updated);
e. Create a possibility for an accident of a different type than any previously evaluated in the final safety analysis report (as updated);
f. Create a possibility for a malfunction of an SSC important to safety with a different result than any previously evaluated in the final safety analysis report (as updated);
g. Result in a design basis limit for a fission product barrier as described in the FSAR (as updated) being exceeded or altered; or
h. Result in a departure from a method of evaluation described in the FSAR as (updated) used in establishing the design bases or in the safety analyses.

Plants with general license independent spent fuel Storage installations are also subject to 10 CFR 72.48, *Changes, Tests, and Experiments*. Plants typically add 72.48 to their 50.59 compliance guidance documents because it is a similar, parallel regulation.

7.2.2 License Amendments

Changes to NRC-issued licenses are made through license amendments, and the license amendment process is governed by NRC regulations and regulatory guidance. A reactor operating license may be amended hundreds of times during its term. A licensee must submit a License Amendment Request (LAR) to the NRC for prior approval if the licensee proposes to modify the license terms and conditions or the technical specifications, or if a proposed change, test or experiment meets the criteria of 10 CFR 50.59(c)(2). It is incumbent upon licensees to provide quality and timely submittals to the NRC to minimize requests for additional information and to avoid unnecessary delays.

License Amendment Requests (LARs) are governed by regulations in 10 CFR 50.90 and 10 CFR 50.92. Procedures and guidance for development and review of license amendments are provided in NRR Office Instruction LIC- 101, *License Amendment Review Procedures*.

The applicant (typically the facility licensee) must submit an amendment request in “the form prescribed for original applications,” to the extent applicable, and must “fully describe” the changes required, consistent with the procedural requirements in 10 CFR 50.4. Additionally, Section 50.91(a) requires that LARs for reactor licenses include the licensee’s analysis of the issue of “no significant hazards consideration,” using the requirements in Section 50.92. (This is discussed further below.)

The NRC staff documents its safety analysis of the LAR in a Safety Evaluation (SE) providing the technical, safety, and legal basis for the NRC’s disposition of the LAR. The SE includes a brief description of the proposed change, the regulatory requirements associated with the change, and an evaluation explaining why the proposed change satisfies the applicable regulatory requirements. The NRC staff also performs an evaluation of the potential environmental consequences of the license amendment and documents its conclusions in an environmental assessment or environmental impact statement. The NRC Atomic Safety and Licensing Board (ASLB) will conduct a hearing on the proposed license amendment in those cases where a hearing request by an individual member of the public or other entity is made and granted. In most instances, the license amendment may be issued before the hearing is held.

Emergency and Exigent License Amendment Requests

In addition to routine LARs, NRC regulations also contemplate the submittal of emergency LARs and exigent LARs. The NRC will generally issue an *emergency license amendment* if the LAR demonstrates that an “emergency” situate ion exists, in that failure to act in a timely way would result in derating or shutdown of a nuclear power plant, or in prevention of either resumption of operation or of increase in power output up to the plant’s licensed power level. NRC may issue an *exigent license amendment* if the LAR demonstrates that exigent circumstances exist, in that a licensee and the commission must act quickly and that time does not permit the commission to publish a *Federal Register* notice allowing 30 days for prior public comment. An exigent LAR is generally interpreted as one in which the license amendment is needed in more than seven days but less than four or five weeks. For emergency or exigent license amendment applications, opportunities for public comment on the proposed amendment are typically accelerated or deferred.

“Significant Hazards Consideration” Determinations for LARs

Once the NRC receives an applicant’s LAR for review, it publishes a *Federal*

Register notice indicating receipt of the license amendment, either as an individualized notice or as part of a periodic (biweekly) notice of proposed licensing actions indicating each LAR received and each amendment issued. In either case, the *Federal Register* notice for a proposed license amendment will describe the amendment sought, provide the NRC staff's proposed "significant hazards consideration" determination, and allow a 30-day public comment period on the proposed determination.

The NRC's determination of "Significant Hazards Considerations" (SHC) is often referred to informally as the "Sholly" process. As noted above, the LAR must include the applicant's analysis of whether the proposed amendment involves a "significant hazards consideration," which evaluates whether operation of the facility in accordance with the proposed LAR will: (1) involve a significant increase in the probability or consequences of an accident previously evaluated, (2) create the possibility of a new or different kind of accident from any accident previously evaluated, or (3) involve a significant reduction in a margin of safety.

The NRC then performs its own SHC evaluation, using these same criteria. In conducting the SHC evaluation, the NRC is particularly sensitive to a LAR that involves irreversible consequences (such as one that permits a significant increase in the amount of effluents or radiation emitted by a nuclear power plant). The NRC staff may inform the public about the final disposition of a proposed LAR for which it has issued a preliminary "no SHC" determination by issuing an additional *Federal Register* notice. The NRC will not make and will not publish a final determination on the significant hazards consideration issue unless it receives a request for a hearing on the license amendment request.

It should be noted that the "significant hazards consideration" determination is a procedural, rather than substantive, finding by the staff. The SHC determination governs whether a person seeking a hearing on a license amendment is entitled to that hearing before or after the license amendment is issued. The SHC determination is *not* related to the technical licensing determination that the NRC staff makes in connection with the LAR.

During its review of a LAR, the NRC can issue a Request for Additional Information (RAI) to the licensee to further support the technical rationale for the LAR. NRC reviewers are expected to formulate a single, comprehensive set of questions to elicit pertinent additional information in areas of concern. Multiple rounds of RAIs are to be minimized. In order to achieve this, licensees must ensure that their responses are complete. RAIs and licensees' RAI responses are not to be used to reinterpret regulatory requirements or guidance or produce new regulatory positions. It is also not appropriate for the NRC staff to require or impose commitments unrelated to the requested amendment.

Consolidated Line Item Improvement Process

The Consolidated Line Item Improvement Process (CLIIP) streamlines the NRC review of proposed license amendments that are applicable to multiple plants. Licensees may request license amendments that have been previously assessed and approved by the NRC staff. Regulatory Issue Summary 2000-06, *Consolidated Line Item Improvement Process for Adopting Standard Technical Specifications Changes for Power Reactors*, describes the process by which NRC staff will review a proposed change to technical specifications that is expected to be requested by multiple plant licensees. This standardized process is also described in LIC-101, rev. 3*, License Amendment Review Procedures*. Thus far, the process has been limited to the implementation of NRC-approved changes to the standard technical specifications.

7.2.3 Exemption Requests

An NRC licensee may apply for an exemption from a requirement when it finds that it is not possible or practical to meet some portion of the requirements of a particular rule. Provisions governing a request for exemption by an NRC reactor licensee are found in 10 CFR 50.11 and 10 CFR 50.12. The NRC staff must review exemption requests and will either approve or deny each one. Guidance for development and review of exemption requests are provided in NRR Office Instruction LIC-103, *Requests for Exemption from NRC Regulations*. In essence, the applicant for an exemption must demonstrate that the exemption requested is authorized by law (that is, not otherwise prohibited), will not present an undue risk to public health and safety and is consistent with common defense and security and, most importantly, that "special circumstances" support granting the exemption.

7.2.4 Notices of Enforcement Discretion

An NRC Notice of Enforcement Discretion (NOED) is a regulatory tool for addressing urgent cases in which a noncompliance with technical specifications may require a plant to shut down even though the noncompliance is not associated with a safety concern. The circumstances in which the NRC may exercise enforcement discretion in the form of an NOED are discussed in Part 9900 of the NRC Inspection Manual and in the NRC enforcement policy, Section VII.C.

The issuance of an NOED *does not revise* the licensing bases for a facility. Rather, an NOED acknowledges the noncompliance with the license technical specifications and provides notice to the licensee that enforcement action will not be taken. Significantly, issuance of a NOED does not preclude enforcement action for the underlying conditions that led to the need for the NOED. NOED requests provide for an expedited NRC review and approval or denial. A verbal approval is typically given prior to issuance of a formally documented safety evaluation. It is the NRC's expectation that NOEDs normally be followed by a license amendment request to formally change the licensing basis as needed. On that point, NRC issued guidance in RIS 2005-01, *Changes to Notice of Enforcement Discretion (NOED) Process and Staff Guidance* (2005), in which it indicated the NRC staff's preference that licensees submit an emergency license amendment instead of a request for enforcement discretion.

7.2.5 Licensee Relief Requests

NRC reactor licensees may submit "relief requests" to the NRC for certain programs that are incorporated into the code of federal regulations by reference. Typically, a relief request may be used when the NRC staff has reviewed and approved certain regulation-mandated programs (e.g. inservice inspection programs) separately from the license. If the licensee subsequently finds that a part of the program has become difficult to perform, for any number of reasons, it may request relief from that portion of the program. The NRC staff must review and approve relief requests by issuing a safety evaluation. As an example, 10 CFR 50.55a specifies the processes for requesting alternatives to, or relief from, the inservice inspection and testing requirements of the ASME Code. Procedures and guidance for development and review of Relief Requests are provided in NRR Office Instruction LIC-102, *Relief Request Reviews*.

7.2.6 Licensee-Initiated Changes to Programs and Plans

A reactor licensee's proposed quality assurance (QA) program, emergency planning/preparedness program, and security plan will be initially approved by the NRC. Subsequent changes to the QA program may be made *without* prior NRC approval, provided that the change does not reduce the commitments made in the program or plan description (10 CFR 50.54(a)). Subsequent changes to the emergency planning/preparedness program and security plan may be made *without* prior NRC approval, provided that the change does not reduce the effectiveness of the program (10 CFR 50.54(q) applies to emergency plans and 10 CFR 50.54(p) applies to the security plan).

7.3 INDUSTRY DOCUMENTS

7.3.1 Topical Reports

Vendors, nuclear steam system supplier (NSSS) owners' groups and the Electric Power Research Institute submit reports to the NRC for review and approval if a safety assessment is required. Typically, such reports involve component design, analytical models or techniques, operational issues, or performance testing of systems/components. NRC documents its assessment by issuing a safety evaluation (SE). In many cases, individual licensees may submit a license amendment as a pilot application of the topical report or after the NRC SE has been used.

Resolution of issues related to review fees, treatment of proprietary information and intended application by licensees are crucial to efficient and timely review by NRC Staff.

7.3.2 Industry Initiatives and Guidelines

The nuclear industry has historically developed programs and guidelines that have successfully addressed operational, technical and regulatory issues. Such guidelines are strictly voluntary unless they are made a provision in a formal industry initiative.

Formal industry positions (industry initiatives) represent an agreement by each utility chief nuclear officer to undertake a policy level position or implement a specific course of action as a unified industry. Such actions are taken by the Nuclear Energy Institute (NEI) and represent a commitment within the industry. Note, however, that these formal initiatives are not regulatory commitments to the NRC.

Implementation of an industry initiative that involves programs or processes that fall within the scope of 10 CFR 50 may be subject to NRC inspection and enforcement. Guidance documents developed to support implementation of such initiatives may be submitted to NRC for review and endorsement, as appropriate. NRC approval is not typically documented in an SE; rather regulatory guides, generic communications and NRC response letters may be used depending on the issue being addressed.

7.4 CODES AND STANDARDS

The National Technology Transfer and Advancement Act of 1995 (Pub. L. 104-113) directed federal agencies to use technical standards developed and adopted by voluntary consensus standards bodies. It further directed federal agencies to consult with and participate in voluntary, private sector, consensus standard bodies when such participation is in the public interest and is compatible with the agency mission, priorities and budget. If an agency determines that use of a voluntary consensus standard is inconsistent with applicable law or otherwise impractical, the agency must report to the Office of Management and Budget and provide an explanation. Each federal agency is required to submit an annual report on the nature and extent of participation in the development and use of voluntary consensus standards.

The act also directed the National Institute of Standards and Technology (NIST) to develop a plan for implementing the provisions of the Act dealing with standards conformity. OMB Circular A-119, "Federal Participation in the Development and Use of Voluntary Consensus Standards and Conformity Assessment," effective February 19, 1998, was issued to provide policy guidance to federal agencies. This circular defines use as “incorporation of a standard in whole, in part, or by reference in regulation.”

This statute and associated guidance were intended to:

- encourage federal agencies to benefit from the private sector
- promote federal agency participation in such bodies to ensure creation of standards that are usable by federal agencies
- reduce reliance on government-unique standards where an existing voluntary standard would suffice

Independent federal agencies were exempted from this law. However, the NRC chose to voluntarily meet the intent of the law. NRC issued Management Directive 6.5, *NRC Participation in the Development and Use of Consensus Standards*, in November 1999. This directive contains organizational responsibilities and guidance for staff participation in the development of consensus standards including identifying and prioritizing needs for new and revised standards; and the use of consensus standards for endorsement including exceptions, and limitations and modifications of standards. The NRC intends to incorporate in the supplementary information for proposed rules or interim final rules statements soliciting comment on NRC intent to use a consensus standard, or its intent to use a government-unique standard with an explanation. Each NRC office has responsibility for implementation and overall coordination is assigned to a standards executive in the Office of Research.

The NRC currently identifies approximately 4,000 codes and standards in regulations, regulatory guides, branch technical positions, the standard review plan, inspection procedures and NUREG documents. According to SECY 99-029, approximately 20 voluntary consensus standards are mandated in NRC regulations. Clearly, a vast number of codes and standards are incorporated into plant design and licensing bases without the need for a regulatory mandate.

8 NRC MANAGEMENT AND CONTROL OF THE REGULATORY PROCESS

Formal mechanisms exist to ensure that NRC conducts its activities in a legal, structured, and disciplined manner in its licensing and oversight of nuclear power plants. These management and control mechanisms include statutes and regulations, commission direction to the staff, backfitting regulations and specific procedures to ensure NRC achieves its legislative mandate and provides “due process” to its licensees.

8.1 LEGISLATIVE

8.1.1 Administrative Procedure Act

As discussed elsewhere in this paper, the Administrative Procedure Act (APA) governs the processes of federal administrative agencies. The original focus of this federal statute was on rulemaking and adjudication. APA requirements can be viewed as functioning as a check or control on the NRC’s licensing and regulatory process in the sense that the APA requires that affected persons be given adequate notice of, and an opportunity to comment on, proposed rules. It provides that, in cases in which another statute requires that the agency provide a hearing on

the record, the parties are given adequate opportunity to present facts and argument. It provides interested persons the right to petition an agency for the issuance, amendment, or repeal of a rule, and provides standards for judicial review of agency actions.

The APA now incorporates several other acts that cover a range of processes. Three of these incorporated acts, the Freedom of Information Act, the Government in the Sunshine Act, and the Privacy Act, deal with access to information. The requirement that the NRC must comply with these other statutes may similarly be viewed as a form of control over the way that the agency

does business.

8.1.2 Paperwork Reduction Act (OMB clearances)

The Paperwork Reduction Act of 1995 also affects the NRC's management of its regulatory process, in the sense that this law stipulates that federal agencies justify to the OMB their information collection needs and prepare "industry burden" estimates relating to the proposed collection of information. The OMB has granted generic clearance numbers to be used by NRC program offices when issuing generic communications, so that the NRC is not unduly restricted by having to obtain advance OMB approval for each information request. As a condition for using a generic clearance, NRC staff must ensure that the burden estimate prepared to obtain the generic clearance is accurate.

8.2 COMMISSION DIRECTION

8.2.1 Policy Statements

Policy statements, developed by the NRC staff and approved by the commission, are formal explanations of the NRC's stance on particular issues. As noted in Section 3, NRC may create new or amended substantive rules only by using the "notice and comment" rulemaking process set forth in the APA. However, the APA's requirements for "notice and comment" rulemaking do not apply to "interpretive rules, general statements of policy, or rules of agency organization, procedure, or practice." For the purposes of this paper, it is important to note that the NRC does issue *policy statements*, which (similar to interpretive rules) are exempt under the APA from requirements for notice and comment rulemaking procedure. Thus, NRC statements of policy fall into a different category than legally binding and enforceable regulations.

Policy statements are generally intended to guide the agency staff in the exercise of its discretionary power. The NRC utilizes policy statements both to guide the staff (e.g., the Enforcement Policy) and to establish expectations for licensees (e.g., the Safety Conscious Work Environment Policy). As opposed to an NRC rule, an NRC policy statement does not establish a "binding norm." A policy statement announces the agency's tentative intentions for the future. It leaves the agency and its decision makers free to exercise discretion and does not impose any rights or obligations.

A policy statement, unlike an NRC regulation, is not directly enforceable. Any action to enforce the commission interpretation or policy in a specific case must be by subsequent rule or order issued in accordance with the APA and subject to the NRC's Backfitting Rule, 10 CFR 50.109. However, NRC policy statements do reflect the official views of the commission and, as such, are entitled to considerable deference.

8.2.2 SECY and Staff Requirements Memoranda

Commission papers, known as SECY papers, constitute the principal instrument by which the commission receives information needed for making decisions. They are prepared by the NRC staff and signed by the executive director for operations. The three types of commission papers, affirmation, notation, and information include:

- An affirmation paper requires a commission decision and a commission meeting. Affirmation papers present relatively major policy issues, such as final rules and regulations or proposed commission orders in adjudicatory matters. Commissioners vote through a written notation process and affirm their votes at a public affirmation session.
- A notation paper also requires a commission decision but does not require affirming of commission votes in a public meeting. Similar to an affirmation paper, the commissioners vote through a written notation process on a notation paper.
- An information paper sends to the commission information on significant matters and requires no commission action.

Staff requirements memoranda (SRM) are the commission response to SECYs. After consideration of the issues discussed in a SECY, the NRC commissioners jointly issue an SRM. This SRM may approve, disapprove or modify the NRC staff recommendations in a SECY. SRMs that do not address final rules or orders cannot be used to establish regulatory requirements. However, these commission documents guide the actions of the staff in implementing policy. SRMs and SECYs are not always made publicly available until commission action has been taken.

A commission action memorandum (COM) can come in the form of a SECY. When it is, the document is called a COMSECY. COMSECYs are written exchanges among commissioners about agency issues or NRC staff requests to the commission for guidance.

8.3 BACKFITTING RULE AND CRGR

8.3.1 Backfitting Rule

Backfitting means adding, eliminating or modifying structures, systems or components of a facility after it is licensed. The backfit concept also adds protection from unwarranted, costly, NRC imposed operational and design changes and modifications that would not result in substantial increases in the overall protection of the public health and safety or the common defense and security. In 10 CFR 50.109, backfitting is defined as:

“the modification of or addition to systems, structures, components, or design of a plant or a facility; or the design approval or manufacturing license for a facility; or the procedures or organization required to design, construct, or operate a plant or a facility; any of which may result from a new or amended provision in the commission rules or the imposition of a regulatory staff position interpreting the commission rules that is either new or different from a previously applicable staff position after [certain dates].”

The NRC’s backfitting rule relates to the agency actions that impose new or revised staff positions or requirements on licensees. Any changes made under 10 CFR 50.59 at the request of the licensee or voluntarily implemented by the licensee do not constitute backfitting.

Backfitting is a process that can include both plant-specific and generic changes applied to one or more classes of power reactors. There are three types of backfit: compliance, adequate protection, and cost-justified substantial increase in safety.

The NRC staff is responsible for evaluating all proposed new or revised staff positions to determine whether the positions are backfits, and for identifying facility-specific and generic backfits.

A backfitting analysis is not required when ensuring compliance with the existing regulatory requirements or written licensee commitments. For compliance backfits, the staff need not consider the costs. It is not permissible for the NRC to redefine what constitutes compliance and then apply the compliance backfit aspect of the regulation to avoid a proper backfit analysis. Such redefinition of what compliance is itself a backfit and must be analyzed per the regulation before the new definition is implemented. A backfitting analysis is also not required if imposition of a backfit is necessary to ensure that the facility provides adequate protection to the public health and safety or common defense and security.

For all the backfits other than compliance or adequate protection exceptions, the NRC staff must perform a backfit analysis. Additionally, the NRC staff may also be required to prepare a regulatory analysis to show that certain improvements in safety or security are justified on the basis of the associated costs balanced against the improvement in plant safety.

Information and procedures for backfitting are found in: LIC-400, *Procedures for Controlling the Development of New and Revised Generic Requirements for Power Reactor Licensees*; MD 8.4, *Management of Plant-Specific Backfitting of Nuclear Power Plants; and LIC*-202, *Procedures for Managing Plant-Specific Backfits and 50.54(f) Information Requests*

8.3.2 Committee to Review Generic Requirements

The Committee to Review Generic Requirements (CRGR) consists of NRC senior managers from the Offices of the General Counsel (OGC), Nuclear Regulatory Research (RES), Nuclear Reactor Regulation (NRR), Nuclear Materials Safety and Safeguards (NMSS), Nuclear Security and Incident Response (NSIR), and one of the regional offices on a rotational basis. The CRGR reports to the executive director for operations (EDO), who appoints the committee chair and members. The CRGR conducts its activities in accordance with the committee's charter Revision 7, dated November 7, 1999, which describes the committee's mission, scope of activities, and operating procedures. RES provides technical and administrative support to the committee.

The CRGR's mission is to ensure that new or revised generic requirements proposed by the NRC staff to impose on licensed power reactor and nuclear materials licensees are appropriately justified based on the backfit provisions of the applicable NRC regulations and the commission's backfit guidance and pertinent policy. Revision 4 of NUREG/BR-0058, *Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission*, dated July 2004, provides guidance relevant to the required regulatory analysis.

The primary responsibilities of the CRGR are to recommend to the EDO either approval or disapproval of the staff's proposed generic actions and to assist the NRC program offices in ensuring consistency with the implementation of the commission's regulations, directives and guidance.

To accomplish its mission, the CRGR reviews proposed new or revised regulatory requirements related to nuclear power reactors; NUREG-series reports; safety evaluation reports (SERs) that endorse generic vendor initiatives; generic communications, such as information requests pursuant to 10 CFR 50.54(f); regulatory guides; and NRC staff guidance on licensing, inspection, assessment and enforcement, which could imply or inadvertently impose an unjustified backfit. The CRGR reviews selected nuclear materials issues and proposed new or revised nuclear materials-related requirements, generic communications and regulatory guidance. In addition, the CRGR holds periodic meetings with stakeholders as part of its responsibility for monitoring the overall effectiveness of NRC's generic backfit management process. As part of its responsibility for regulatory effectiveness, the CRGR may conduct periodic audits of NRC's administrative controls for facility-specific backfitting to assess their effectiveness.

8.4 MANAGEMENT DIRECTIVES AND NRR OFFICE INSTRUCTIONS

In addition to the technical guidance to the staff discussed in Section 4, NRC also issues management directives and NRR office instructions to manage and control the regulatory process. Management directives specify policy, objectives, responsibilities, and authorities in specific functional areas. They guide, inform, and instruct NRC employees in the performance of their jobs and communicate policies to enable employees to work effectively within the agency, with other agencies, and with the public.

NRR has established a set of procedures and guidance for its staff to meet the requirements and performance goals established in legislation, regulations, the agency's strategic plan, and office level operating plans. They are typically issued to address (1) significant, repetitive activities that include responsibilities for two or more NRR divisions (e.g., licensing actions), or (2) important activities or responsibilities that are not adequately addressed by higher level guidance.

A partial list of management directives and NRR office instructions that address various topics discussed in this white paper is included in the appendix. Neither management directives nor office instructions can revise, modify or interpret regulatory requirements.

APPENDIX: REFERENCED NRC MANAGEMENT DIRECTIVES AND OFFICE INSTRUCTIONS

Relevant Management Directives

MD 6.3, *The Rulemaking Process*: When developing rulemaking actions several activities must be performed. Offices must coordinate together and ensure that staff resources are used efficiently. Schedules for rulemaking actions must be met and Agreement States must be provided an opportunity for comments. The public and stakeholders must have the maximum opportunity to participate in proceedings. MD 6.3 provides guidance for all of the above issues and documents the proper method for initiation, planning and approval or denial of a final rule.

Management Directive 6.3, The Rulemaking Process (updated in 2018 and 2019), and NMSS P&P (Policy and Procedure) 6-10, (NMSS Policy and Procedures 6-10, “NMSS Procedures for Preparation and Review of Rulemaking Packages,” September 28, 2018 (ML18227A110) are the primary reference documents for NRC’s rulemaking program.

MD 6.5, *NRC Participation in the Development and Use of Consensus Standards:* Organizational responsibilities and guidance are provided for (1) staff participation in the development of consensus standards, including identifying and prioritizing needed new and revised technical standards, selecting and nominating staff as authorized agency representatives on standards developing organization (SDO) committees, and coordinating standards activities with SDOs and other stakeholders, and (2) NRC use of consensus standards including identifying and prioritizing standards for endorsement, timely endorsement, annual reporting, exceptions to using a consensus standard, and monitoring and assessing the NRC standards program.

MD 8.4, *Management of Plant-Specific Backfitting of Nuclear Power Plants*: The purpose of this directive is to ensure that backfitting of a nuclear power reactor or materials facility is appropriately justified and documented and that the executive director for operations is responsible for ensuring proper implementation of the backfit process and that the NRC is not unnecessarily burdened. This directive is also intended to ensure that NRC-licensed facilities provide adequate protection of public health and safety and common defense and security.

MD 8.13, *Reactor Oversight Process*: The reactor oversight process (ROP) is necessary to obtain information about operations at reactor facilities, identify significant safety concerns and determine the causes of declining performance. Assessment of performance must be communicated effectively to both internal and external stakeholders. MD 8.13 is used to evaluate the risk significance of issues to ensure that all parties involved respond appropriately. Regulatory responses are measured and provided on the basis of safety significance.

MD 8.18, NRC Generic Communications Program: MD 8.18 is sufficient guidance for staff and NRR rescinded LIC-503 in 2014. Management Directive (MD) 8.18 provides criteria for using generic communications (bulletins, generic letters, regulatory issue summaries and information notices) to address generic concerns. Generic issues evolve from nuclear reactor operating experience and regulatory initiatives and have broad applicability. MD 8.18 also provides guidance and procedures for generic issue preparation, distribution, follow-up and closeout. NRR staff determined that OVRST-101 no longer met the NRR criteria to maintain an office instruction and rescinded the OI in 2017.

Relevant NRR & NMSS Office Instructions:

COM-203, *Informal Interfacing and Exchange of Information with Licensees and Applicants*: The objective of this office instruction is to provide guidance for interfacing with licensees and applicants in less formal circumstances, and for documenting such interfaces. It applies to licensing actions associated with operating reactors, license renewal and new reactor license applications. The guidance applies to informal meetings and discussions, phone calls, e-mails, facsimiles, exchange or review of draft information, and receipt of unsolicited information.

LIC-100, *Control of Licensing Bases for Operating Reactors*: This office instruction provides NRR staff with the basic framework for making decisions about creating, revising or deleting licensing bases information for operating power reactors. These procedures are intended to enhance NRR's efficiency in responding to the needs of both the licensees and the public. Specific objectives include the following: (1) ensure the effective use of NRC's regulatory processes maintains the public health and safety, (2) promote public confidence in NRC licensing processes by establishing a common reference, an understandable framework for licensing bases decisions, and a common understanding of roles, responsibilities and opportunities for participation, (3) reduce unnecessary regulatory burdens by establishing a common understanding of the control of licensing bases and by promoting the use of the most appropriate licensing process to achieve the desired results, and (4) increase the effectiveness, efficiency, and realism of nuclear licensing by establishing a common reference for processes, communications, and decision-making.

LIC-101*, License Amendment Review Procedures*: This document provides NRR staff with the basic framework for processing license amendment (and other licensing actions, where applicable) applications. The goal is to: (1) ensure the public health and safety are maintained, (2) promote consistency in processing of license amendments, (3) improve internal and external communications, (4) increase technical consistency for similar licensing actions, (5) reduce delays in the issuance of license amendments (meet licensing action timeliness goals) of 96 percent less than 1 year old and 100 percent less than 2 years old), and (6) ensure that staff RAIs are adding value to the regulatory process.

LIC-102, *Relief Request Reviews*: The objective of this office instruction is to give guidance for handling licensee's relief requests submitted in accordance with 10 CFR 50.55a. Guidance is provided on methods to permit a licensee to deviate from regulatory requirements related to codes and standards, as well as guidance on the content of the safety evaluations and cover letters authorizing alternatives, granting relief or approving later code editions and addenda pursuant to various 10 CFR 50.55a paragraphs.

LIC-103, *Requests for Exemption from NRC Regulations*: This office instruction provides NRR staff members with a basic framework for processing requests for exemptions submitted under Sections 20.2301, 40.14, 50.12, 51.6, 52.93(a), 54.15, 55.11, and 70.17, and exemptions granted by the commission on its own initiative.

These procedures are intended to enhance NRR's efficiency in responding to the needs of licensees and the public. The document is intended to promote consistency in the processing of exemption requests by giving the NRR staff an improved framework for processing them.

LIC-105, *Managing Regulatory Commitments Made by Licensees to the NRC*: This document provides NRR staff with guidance on managing regulatory commitments. The guidance is consistent with available industry guidance and is intended to ensure common understanding (by the staff, licensees, and other agency stakeholders) of the handling of regulatory commitments. With this office instruction, the NRC aims to reduce unnecessary regulatory burden by establishing a common understanding of the control of regulatory commitments and by promoting the use of regulatory commitments when it is appropriate to achieve the desired results. In addition, the document is expected to increase the effectiveness and efficiency of the licensing process by establishing a common reference for processes, communications, and decision making involving regulatory commitments.

LIC-106, *Issuance of Safety Order:* This office instruction is intended to provide the NRR staff guidance on the process, preparation and issuance of safety orders and ensure that the NRR staff performs the appropriate regulatory and technical reviews of information in support of proposed safety orders. The scope of this office instruction is limited to orders that impose additional regulatory requirements and actions beyond the current regulatory framework, i.e., license modification orders, referred to as safety orders. Compliance orders that enforce compliance within the existing regulatory framework are not addressed in this office instruction. Orders that include both compliance issues and safety issues shall be processed in the same manner as compliance orders. Process procedures for compliance orders are delineated in the enforcement manual.

LIC-200, *Standard Review Plan (SRP) Process:* This instruction provides guidance for using the SRP in review of license and design certification applications under 10 CFR Part 50 and Part 52. LIC-200 also provides guidance for identifying and reviewing operational programs in combined license applications. Future guidance will be available to aid the NRC staff in the review and inspection of systems, structures, and components in accordance with risk-significant determinations.

LIC-202, *Procedures for Managing Plant-Specific Backfits and 50.54(f) Information Requests*: The backfit rule is detailed in 10 CFR 50.109. The backfit rule enables the NRC staff to research information necessary to determine if a plant's license must be modified, revoked or suspended. This instruction ensures that any backfitting by the NRC is properly justified and documented. Responsibilities of the NRR staff are also detailed in the instruction. LIC-202 should be used in conjunction with LIC-100.

LIC-400, *Procedures for Controlling the Development of New and Revised Generic Requirements for Power Reactor Licensees*: The NRC must have an effective program for controlling the development and revision of generic requirements imposed on power reactor licensees. This office instruction details the responsibilities of the Committee to Review Generic Requirements (CRGR). The CRGR charter was developed for generic backfits. The CRGR is responsible for reviewing and approving all new generic requirements developed after November 12, 1981. The CRGR also reviews selected requirements and staff positions.

LIC-500, Revision 3, *Processing Requests for Reviews of Topical Reports*: This describes the process by which NRR staff and managers process topical reports and thereby improve NRR's efficiency and consistency. It contains guidance on review fees, treatment of proprietary information and plant-specific licensing actions.

Westinghouse Technology Systems Manual

Section 1.2

Introduction to Pressurized Water Reactor Generating Systems

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1.2 INTRODUCTION TO PRESSURIZED WATER REACTOR GENERATING SYSTEMS

Learning Objectives:

1. Define the following terms:

   a. Primary cycle,
   b. Secondary cycle, and
   c. Reactor coolant system (RCS) average temperature (T_{avg}).

2. Explain why T_{avg} is programmed to increase with an increasing plant load.

1.2.1 General Description

The Pressurized Water Reactor (PWR) generating system described in this manual is a dual cycle unit. The two cycles are called the primary and the secondary. As shown in Figure 1.2-1, the unit consists of a primary cycle that includes the reactor vessel, the pressurizer, and four closed reactor coolant loops connected in parallel (of which only one loop is shown). The secondary cycle includes the steam system, the high and low pressure turbines, and the condensate and feedwater system. The secondary systems together are sometimes referred to as the power conversion system. The sole function of the power conversion system is to generate electricity.

As shown, the primary cycle is located entirely inside the containment building. This building is designed to act as a shield to minimize the exposure of plant personnel to radiation. In addition, the design of the containment structure prevents or minimizes the release of radioactive material to the environment during normal operation or under an accident condition. The use of a dual cycle design reduces the amount of radioactive material transferred to the power conversion system components. By minimizing the amount of radioactivity transferred to the secondary, the potential exposure of plant personnel is reduced, and any potential releases of radioactive material to the atmosphere are minimized.

1.2.2 Primary Cycle - Reactor Coolant System (RCS)

Each of the four reactor coolant loops contains a Reactor Coolant Pump (RCP), a Steam Generator (SG), piping, and associated instrumentation (Figure 1.2-2). Attached to one of the four loops is an electrically heated Pressurizer (PZR). The pressurizer maintains the pressure of the reactor coolant at a high value, which prevents the high temperature (>500°F) coolant from boiling. Reactor coolant (pure water with boric acid in solution) is pumped through the reactor core to remove the heat generated by nuclear fission. The heated water exits the reactor vessel, passes through loop piping and enters the steam generator.

Inside the steam generator, reactor coolant flows through U-tubes and transfers heat to the feedwater inside the steam generator (secondary system). The U-tubes act as a barrier between the primary and secondary cycles. Reactor coolant, now cooler, exits the steam generator and is directed to the suction of the reactor coolant pump. The reactor coolant pump returns the reactor coolant to the reactor vessel, completing the primary cycle.

1.2.3 Secondary Cycle (Power Conversion System)

The power conversion system begins in the shell sides of the four steam generators. At these locations the feedwater contacts the U-tubes and picks up heat from the hot reactor coolant. Since the pressure in the secondary side is less than that of the primary, the heated feedwater boils and becomes **saturated steam**. Saturated steam is steam that is at the same temperature as boiling water for a given pressure.

The saturated steam produced in the shell sides of the steam generators exits via the main steam lines. The steam flows through the Main Steamline Isolation Valves (MSIVs) to the high-pressure turbine. After flowing through the high-pressure turbine, the low-energy, moisture-laden steam is routed to the Moisture Separator Reheaters (MSRs). Each MSR, as its name implies, removes moisture from this low pressure steam and reheats it. The moisture-free steam is superheated by extraction steam from the high pressure turbine and by steam from the main steam lines. Superheated steam is steam that is at a temperature which is greater than the saturation temperature for a given pressure. The dry, superheated steam is directed to the low-pressure turbines. This steam passes through the low-pressure turbine blades and exits to the main condenser. The high- and low-pressure turbines are mounted on a common shaft that drives the main generator.

The main generator produces electrical power, which is supplied to the utility's distribution network or "grid."

Inside the condenser, the exhausted steam is condensed (cooled and depressurized) by passing over tubes containing water from the condenser circulating water system. The condensed steam (now called condensate) is collected in the condenser's hotwell. The condensate is pumped from the condenser hotwell by condensate pumps. The condensate pumps discharge the condensate through condensate demineralizers, which remove impurities. The condensate then passes through several stages of low pressure feedwater heaters, in which the temperature of the condensate is increased by heat transfer from steam extracted from the low pressure turbines. The condensate exits the low-pressure feedwater heaters and enters the suctions of the high-pressure main feedwater pumps.

The main feedwater pumps (normally driven by steam turbines) increase the pressure of the condensate (now called feedwater) so that it can enter the steam generators. From the discharge of the main feedwater pumps, the feedwater is heated in the high-pressure feedwater heaters by extraction steam from the high-pressure turbine. After this final heating, the feedwater passes through the Feedwater Regulating Valves (FRVs), enters the containment, and finally enters the

Steam Generators (SGs), thereby completing the secondary cycle.

1.2.4 Support and Emergency Systems

In order to provide a means of makeup water during normal and emergency conditions the reactor and RCS has support system to ensure cooling and chemistry control (example: boron for fission control as a soluable neutron absorber in the RCS fluid). The RCS has Emergency Core Cooling Systems (ECCS) to ensure a safe shutdown under all conditions. Two of these ECCS systems provide safety related and non-safety related functions.

Attached to each reactor coolant loop cold leg and isolated by a check valve are accumulators, pressurized with nitrogen and filled with borated water. The purpose of the accumulator is to inject borated water into the RCS if the reactor coolant system pressure boundary ruptures (i.e., a Loss Of Coolant Accident (LOCA) occurs) and the RCS depressurizes. When the pressure in the RCS drops below the pressure in the accumulators, the nitrogen forces the borated water out of the accumulators into the RCS, providing water to both cover and cool the reactor core and boron (a neutron absorber) to keep the reactor shutdown.

The low pressure Residual Heat Removal (RHR) system is designed to provide both safety-related and non-safety-related functions using motor driven centrifugal pumps. It’s safety-related function is to provide borated water at a low pressure and a high flow rate to the RCS following a loss of coolant accident. The RHR system pumps water from the Refueling Water Storage Tank (RWST) to the RCS for the short-term injection cooling and later can be aligned to recycle water from the containment building sump back into the reactor coolant system for long term recirculation cooling. Its non-safety-related function is to remove decay heat from the core after a shutdown. Decay heat removal is accomplished by pumping hot water from an RCS hot leg through RHR heat exchangers and then back into the RCS via the cold legs.

The intermediate pressure Safety Injection (SI) system is another Emergency Core Cooling System (ECCS) located in the Auxiliary Building (AB). Its function is to inject borated water from the RWST into the RCS after a LOCA using motor driven centrifugal pumps. Although the SI system discharge flow capacity is much less than that of the RHR system, its discharge pressure is greater.

The high pressure Chemical and Volume Control System (CVCS) fills a non-safety related function to maintains the purity of the reactor coolant by means of demineralizer beds that continuously purify a small letdown stream from the RCS. This purified water is charged back into the RCS at a controlled rate to maintain the proper volume of water in the RCS. The CVCS also removes or adds boron for reactivity control and can add chemicals to maintain ph or oxygen control. The CVCS safety related function is to use the high-pressure low flow motor driven centrifugal charging pumps to put borated water into the RCS under all design pressures. Their function is to supply borated water from the RWST during injection cooling period or from the RHR pump discharge if needed during the recirculation period of accident mitigation. (NOTE: some plants also use Positive Displacement

Pumps)

In the event of a LOCA, the hot reactor coolant spills from the RCS into the containment and flashes to steam. This action causes a pressure increase inside the containment building.

The Containment Spray (CS) system is designed to transfer water from the Refueling Water Storage Tank (RWST) to spray rings located high inside the top of the containment. The cool water sprayed into the containment quenches the steam and maintains the pressure inside of the containment within design limits. This action prevents the rupture of the containment building and the subsequent uncontrolled release of radioactive materials to the environment.

The Component Cooling Water (CCW) system provides a cooling medium to various potentially radioactive components, such as the CVCS letdown heat exchanger ECCS pumps, and the RHR heat exchangers. This system is a closed loop system and is cooled by the Service Water System (SWS), which receives its water from a nearby river, lake, cooling tower, ocean or ultimate heat sink. Both the CCW and SW systems are safety systems and are required to function in order to mitigate the consequences of analyzed accidents.

1.2.5 Plant Layout

See Figure 1.2-3. The entire RCS, including the steam generators, is located within the containment building. This structure isolates the radioactive reactor coolant from the environment in the event of a leak or a Loss Of Coolant Accident (LOCA). The containment building is designed to withstand the pressure resulting from the complete rupture of a reactor coolant or main steam line pipe. The containment must be able to perform this safety function during and following a “design basis earthquake.” The containment building is therefore designated as a Seismic Category I structure.

A "design basis earthquake" also called a “safe shutdown earthquake” (SSE)) is defined in 10 CFR Part 100, Appendix A, of the Code of Federal Regulations as the maximum ground motion potential considering local and regional geology and seismology. It is that earthquake which produces the maximum vibratory ground motion for which certain structures, systems, and components are designed to remain functional. "Safety-related" Systems, Structures, and Components (SSCs) are designed to remain functional during a design basis earthquake are designated "Seismic Category I."

Safety-related and potentially radioactive auxiliary systems are located inside the Seismic Category I Auxiliary Building (AB). This building is normally located between the Turbine Building (TB) and the Containment Building (CB). Ventilation from the auxiliary building is passed through high efficiency particulate filters and/or charcoal filters to minimize the release of radioactive material to the environment. A Fuel Building (FB)) (sometimes a part of the auxiliary building) is provided for the handling and storage of new and spent reactor fuel. The fuel storage building is also designated as a Seismic Category I building. The control building (also sometimes part of the auxiliary building) is a Seismic Category I structure, which houses the main control room, the cable spreading room, the auxiliary instrument room, the plant computer, and the battery rooms.

The Turbine Building (TB) is **not** safety related and contains most of the secondary cycle equipment and secondary support systems. The main turbine, moisture separator reheaters, main condenser, condensate and feedwater pumps, and feedwater heaters are all located inside the turbine building.

1.2.6 Plant Control

The power output of the reactor and the outlet temperature of the coolant from the reactor core are controlled by manipulating several factors which affect the core's reactivity (a measure of neutron population change). The position of neutron absorbing control rods, the concentration of soluable boric acid in the RCS, and the steam flow rate can be changed to affect reactor power and the reactor coolant outlet temperature.

The automatic control systems are designed to provide power change (load change) capability between 15% and 100% of rated power at 5% per minute (ramp) or with a 10% instantaneous (step) change in power without causing an automatic reactor shutdown (trip). Additionally, the plant's steam dump system is designed to direct steam at a high rate of flow to the main condenser, allowing the unit to accept a large power reduction (load rejection) without tripping the reactor.

The power level of the reactor is normally changed by selecting a desired electrical load and load rate via the turbine control system and allowing the reactor to follow the turbine load change. Various methods are possible for controlling the reactor's power, as the turbine load is changed, and are discussed below.

High Pressure systems must be protected from over pressurization and rupture. The reactor coolant system and main steam system are protected from overpressure rupture by safety valves that can handle maximum pressure and temperature relief.

1.2.7 Reactor Control

The basic formula defining heat (or power) transferred across a heat exchanger (in this case, the steam generators) is:

$$\dot{Q} = UA\Delta T$$

where:

$\dot{Q}$ = the rate of heat transfer,

U = the heat transfer coefficient,

A = the area of heat transfer, and

ΔT = the differential temperature across the heat exchanger (in this case, the difference between the average temperature of the reactor coolant [T_{avg}] and the temperature of the steam [T_{stm}]).

For all practical purposes, both the heat transfer coefficient (U) and the heat transfer area (A) are constant, since the heat transfer coefficient is a function of the materials used in the construction of the steam generator and the U-tubes are completely covered with water. The equation may be reduced to:

$$\dot{Q} \propto \Delta T$$

, or

$$\dot{Q} \propto (T_{avg} - T_{stm})$$

There are three basic modes of controlling a pressurized water reactor with U-tube steam generators. Each of these modes of control could be used to adjust reactor power in response to change in one of two measurable parameters. These parameters are as follows:

1. T_{avg} - the average reactor coolant system temperature:

$$T_{avg} = \frac{T_h + T_c}{2}$$

where:

T_h = hot leg temperature, and

T_c = cold leg temperature.

2. Steam pressure - the secondary steam pressure either at the outlet of the steam generator or the inlet to the main turbine.

1.2.7.1 Constant Tavg Control Mode

With a constant T_{avg} control scheme (Figure 1.2-4), the reactivity of the core is adjusted to maintain a constant reactor coolant average temperature as turbine load is varied. For example, increasing the output of the turbine causes a decrease in T_{avg}, because the turbine uses more energy than that produced by the reactor. The rod control system senses this temperature decrease and withdraws the control rods, adding positive reactivity to the core and returning T_{avg} to the programmed value. An anticipatory signal comparing turbine load and reactor power might also be utilized to optimize the transient response of this control scheme.

The constant T_{avg} control mode has the advantage of an unchanging RCS temperature and density, regardless of power level. Since the coolant volume does not change, the pressurizer level is constant for all load conditions.

A major disadvantage of the constant T_{avg} control is that it produces an unacceptable secondary system pressure when the turbine is fully loaded. As shown above, the rate of heat transfer from the reactor coolant across the steam generator tubes to produce steam is proportional to the differential temperature between the reactor coolant and the secondary water. If the reactor coolant T_{avg} remains constant, then the saturation temperature (T_{stm}) in the shell side (secondary) of each steam generator must drop when the steam demand (load) increases. This effect produces a significant decrease in steam pressure (P_{stm}) as secondary power is increased from hot zero power to full load. The low steam pressure produces unacceptable steam conditions at the main turbine inlet.

Large PWR generating stations with U-tube steam generators do not use constant T_{avg} control. The advantage of a constant pressurizer level is greatly offset by the disadvantage of low steam pressure.

1.2.7.2 Constant Steam Pressure Control Mode

With a constant steam pressure control scheme (Figure 1.2-5), the reactivity of the reactor core is adjusted to maintain a constant pressure in the steam system as turbine load is changed. As described in the previous section, increasing turbine load causes steam pressure (P_{stm}) to decrease. The rod control system would sense this decrease in P_{stm} and withdraw control rods to increase the reactor coolant temperature.

With this type of reactor control, the ΔT between primary and secondary is increased by raising T_{avg} and allowing T_{stm} (and therefore P_{stm}) to remain constant. This produces ideal steam conditions at the main turbine inlet for all loads from hot zero power to 100% load.

The disadvantage of this type of control scheme is that it results in a high reactor outlet (hot leg) temperature (T_h), which approaches saturation values. The constant steam pressure control may be used in other PWR vendor designs but is impractical for plants with U-tube steam generators.

1.2.7.3 Sliding T_{avg} Control Mode

A sliding T_{avg} control scheme (Figure 1.2-6) is a compromise between a constant T_{avg} and a constant steam pressure control scheme. This control scheme incorporates the advantages of both but also retains some of their disadvantages.

With a sliding (programmed) T_{avg} control scheme, the reactivity in the reactor core is adjusted to maintain a programmed T_{avg} as the turbine load is varied. As with the previously described control schemes, varying the load on the turbine causes T_{avg} and steam pressure to change. To compensate, the rod control system repositions the control rods to add positive or negative reactivity to the reactor core and maintain T_{avg} equal to its programmed value for a given load.

The heat transfer rate from the primary cycle to the secondary cycle is directly proportional to the value of the temperature difference (ΔT) between the primary and the secondary. This ΔT is also a direct indication of power. As shown in Figure 1.2-5, as secondary power increases, the difference between T_{avg} and T_{stm} increases. The ΔT increases with an increasing load on the turbine generator as (1) the turbine control valves open (causing the steam pressure to decrease), and (2) control rods withdraw or operators dilute the reactor coolant (adding positive reactivity and increasing reactor coolant temperature).

This mode of control produces acceptable steam conditions at the main turbine inlet at 100% power, while requiring a lower T_h than does the constant steam pressure control mode. Most Westinghouse designed nuclear units use some form of a sliding T_{avg} control program. One difference in the various control programs is the value of the programmed range of temperature control. The programmed temperature range varies from 12°F to the most often used value of 30°F. Another difference is in the value of the no-load setpoint (the programmed T_{avg} at 0% power). The most commonly used values of no-load T_{avg} are 547°F and 557°F.

1.2.8 Summary

Pressurized water reactor units use a dual cycle concept, in which the closed primary cycle is separate from the secondary cycle. The point of heat transfer between the two cycles is the steam generator(s). The RCS is the primary cycle and is located inside the containment building. The secondary cycle includes the steam system, the turbine generator (where steam energy is used to generate electric power), and the condensate and feedwater systems. Secondary cycle systems, subsystems, and components are principally located in the turbine building.

Support and emergency systems serve many purposes affecting both the primary and the secondary. Systems, components, structures, and buildings which have safety functions or are required to maintain the integrity of the RCS or the reactor core, under accident conditions, must be built to Seismic Category I standards. Safety systems, components, and structures built to Seismic Category I specifications will provide their intended safety functions during the maximum credible seismic event.

The constant T_{avg} and constant steam pressure reactor control modes are viable control modes but are not generally used at Westinghouse designed plants. The control scheme most often selected to control the reactor is the sliding T_{avg} control mode. This mode of control programs T_{avg} to increase as secondary load increases. The sliding T_{avg} mode is a compromise between the other two modes of control and contains some of the advantages and disadvantages of each.

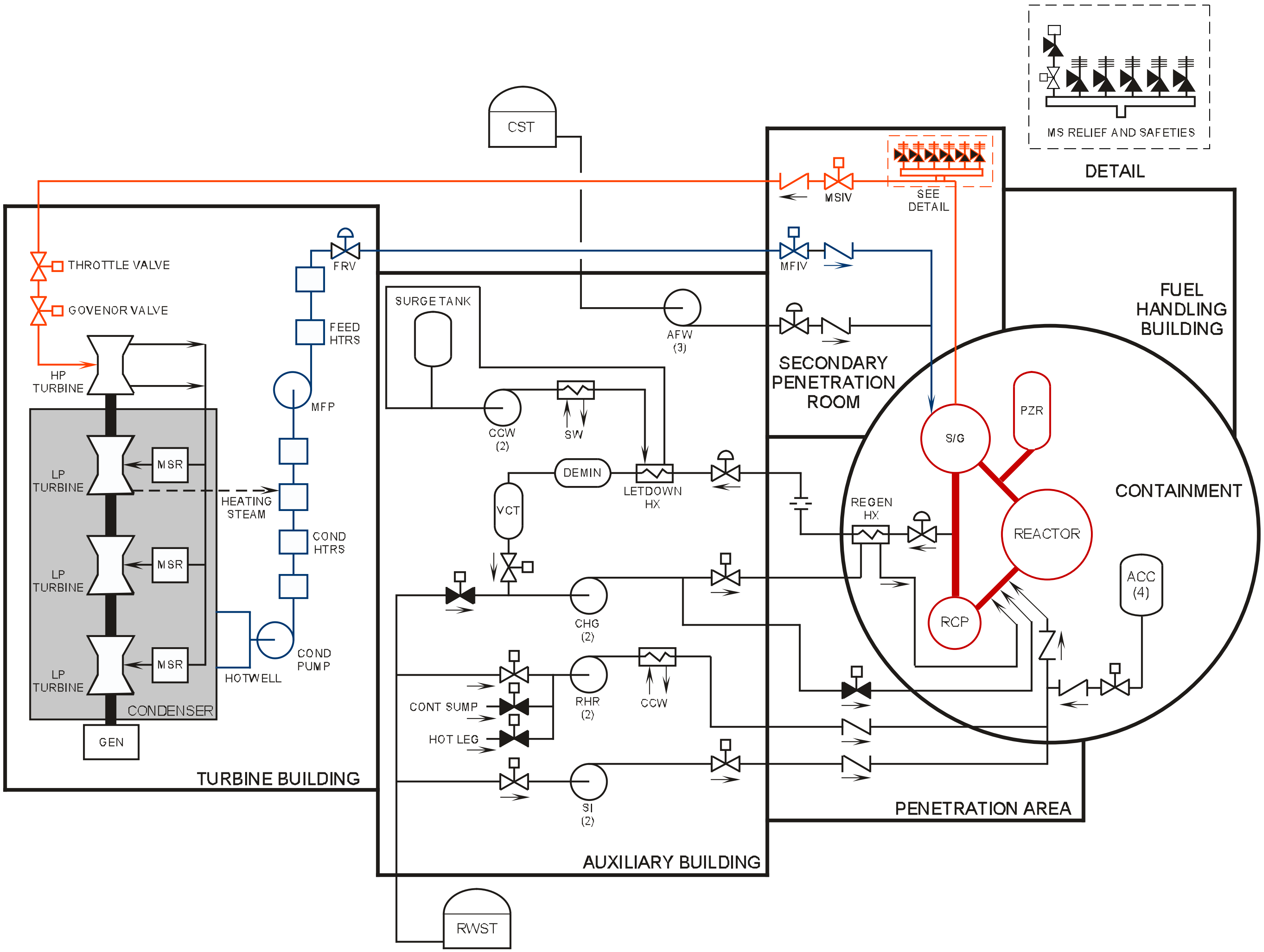

Figure 1.2-1 Plant Systems Composite

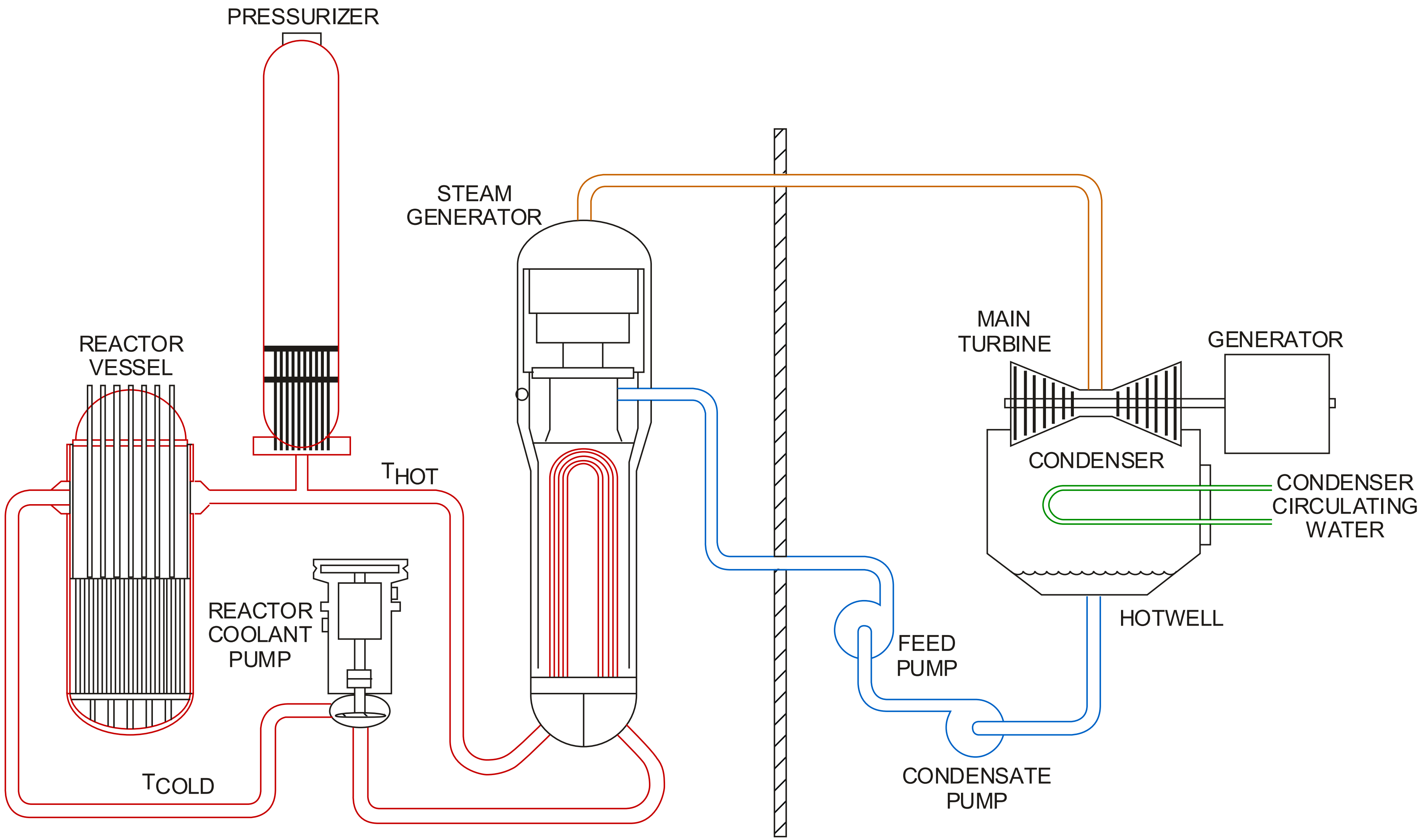

Figure 1.2-2 PWR Cycles

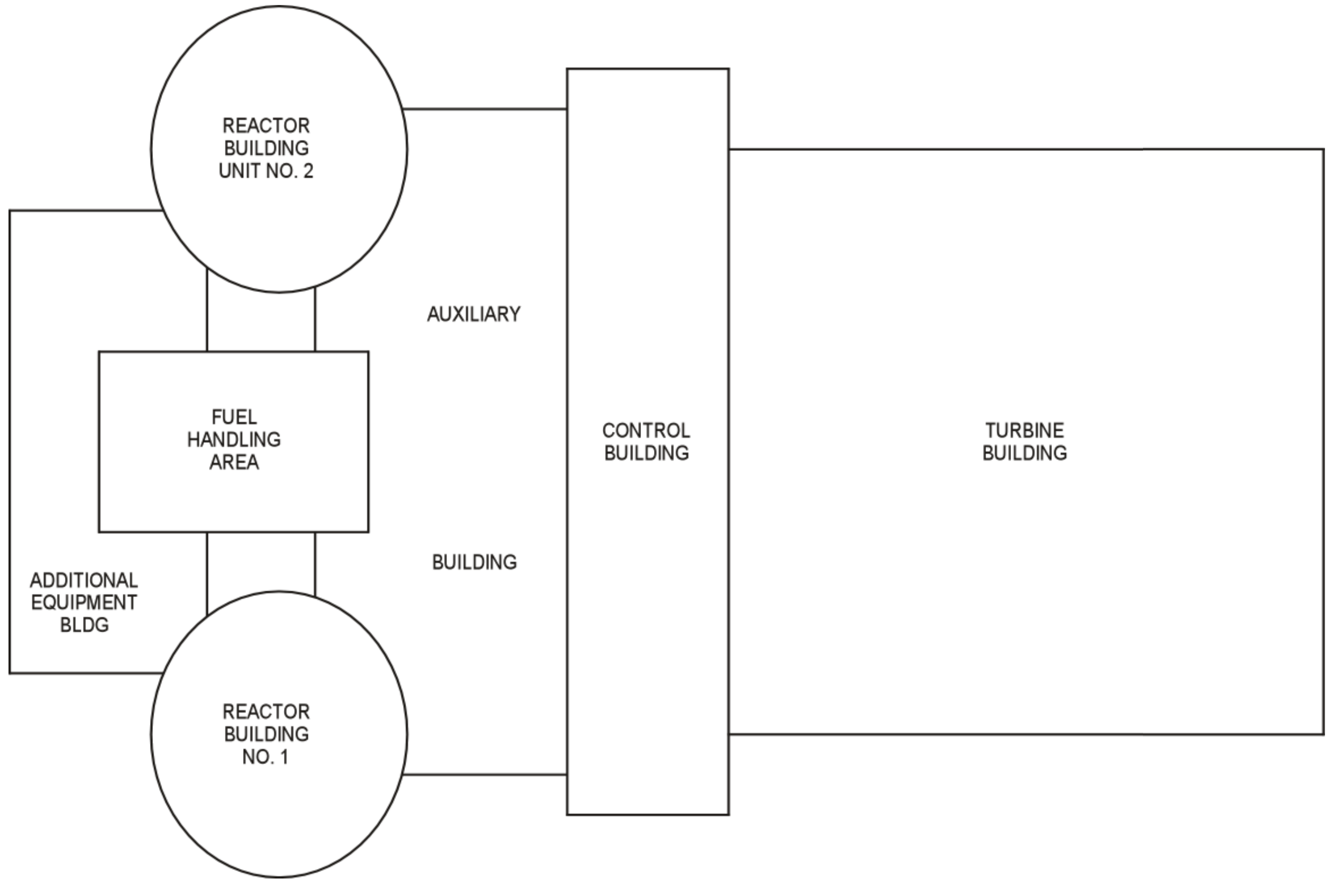

Figure 1.2-3 Plant Layout

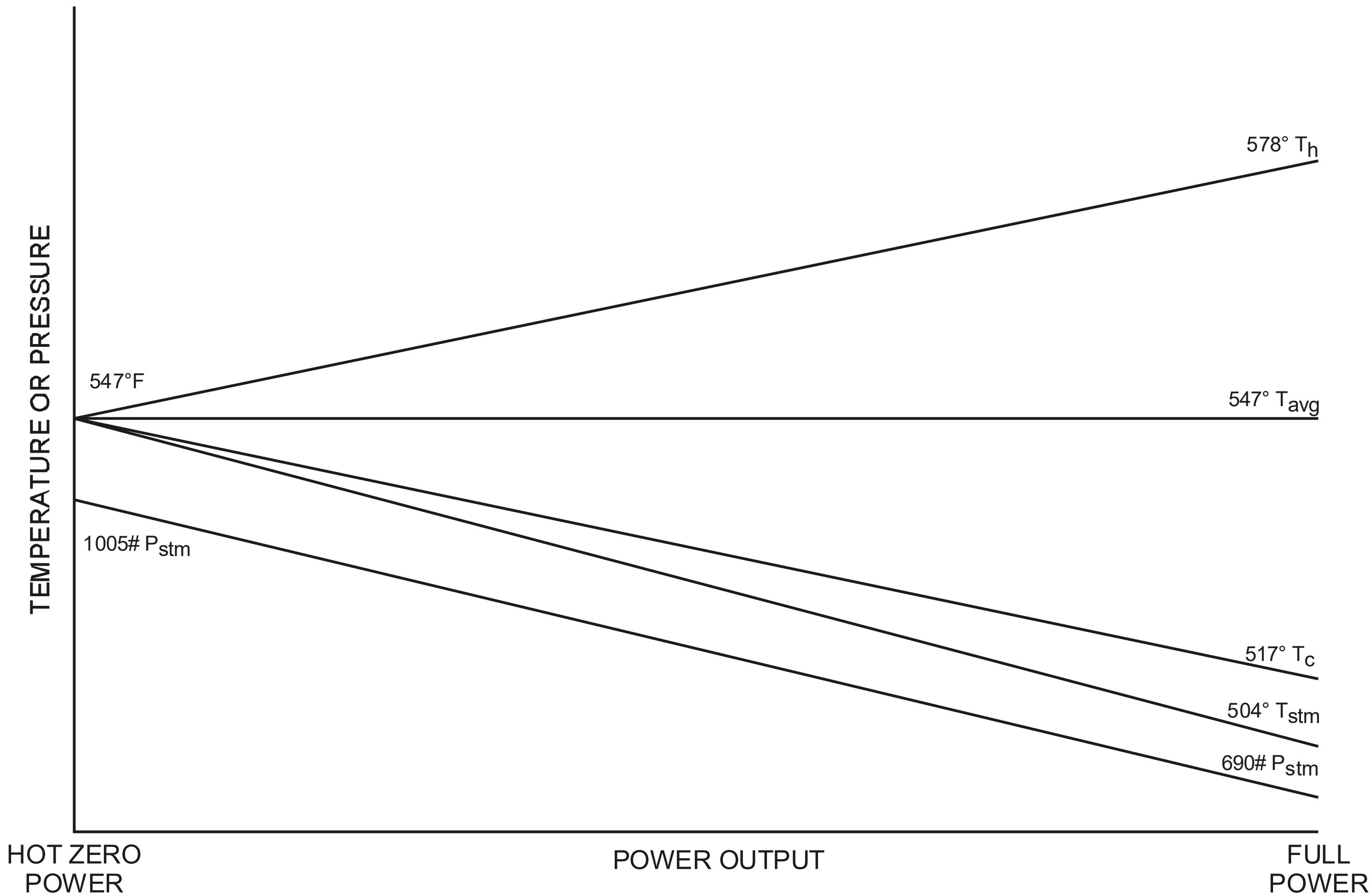

Figure 2.2-4 Characteristics of a Constant Average Temperature Program

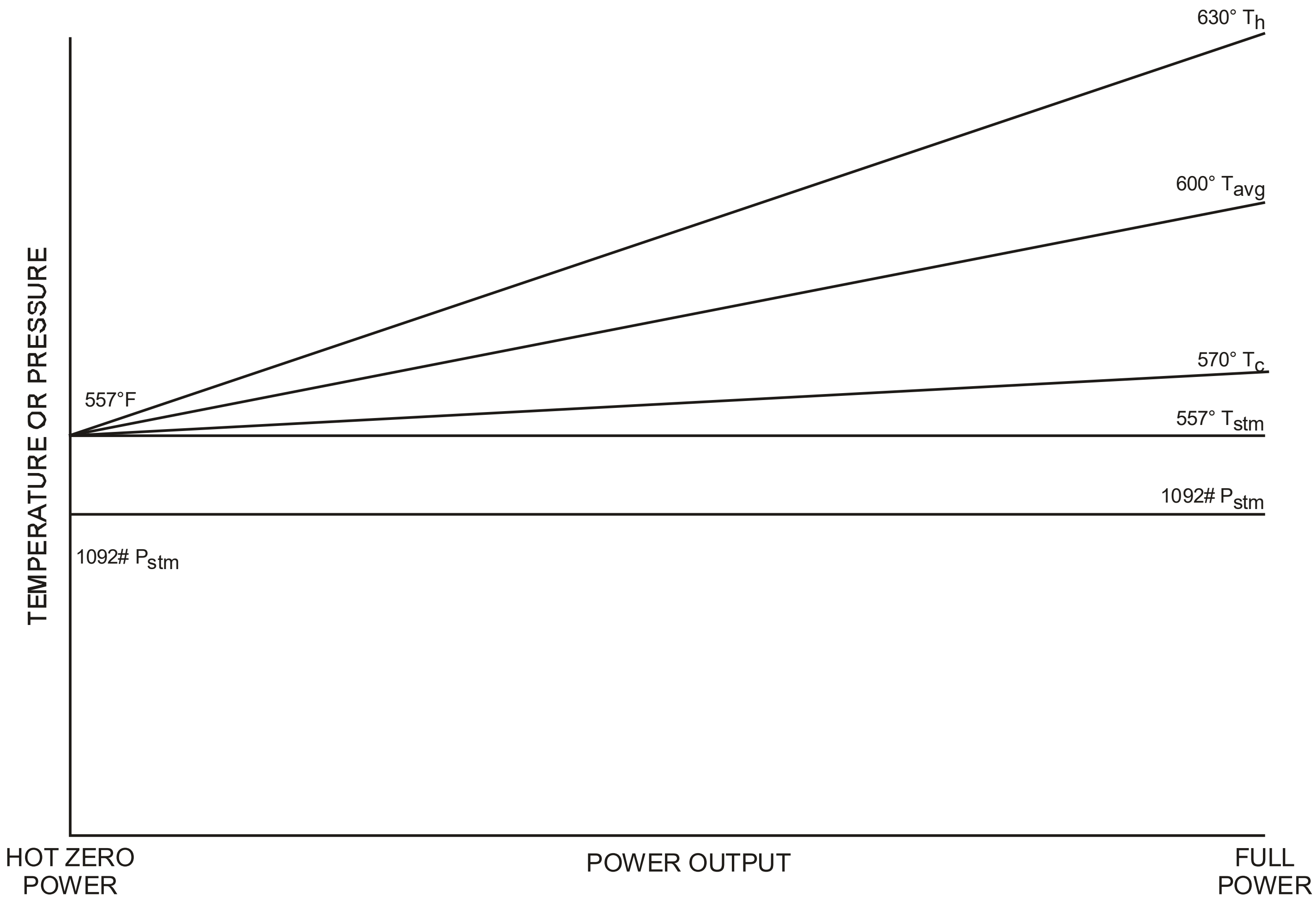

Figure 1.2-5 Characteristics of a Constant Steam Pressure Program

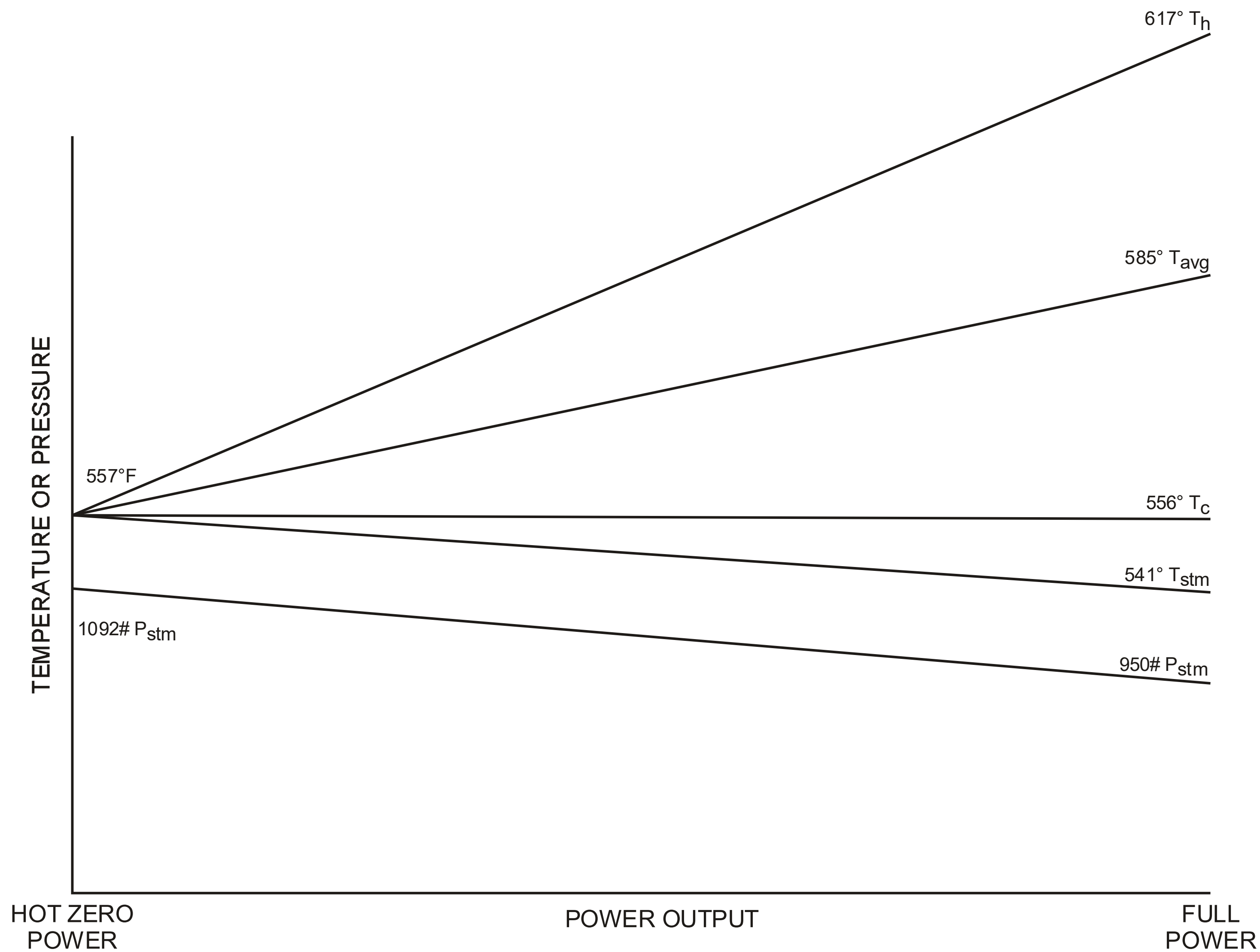

Figure 1.2-6 Characteristics of a Sliding Average Temperature Program

Westinghouse Technology Systems Manual

Section 1.3

Instrumentation and Controls

"READ ONLY SELF STUDY MATERIAL"

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1.3 INSTRUMENTATION AND CONTROLS

Learning Objectives:

1. Describe the types of sensing instruments used to sense pressure, temperature, and flow.

2. Explain how the properties of pressure, temperature, and flow are converted into electrical outputs.

3. Explain how the following controllers respond to a step change and ramp change in input:

   a. Bistable,
   b. Proportional,
   c. Proportional plus integral, and
   d. Proportional plus derivative.

4. Explain the input and output relationships of the standard logic circuits.

1.3.1 Introduction

This section addresses the detection of process variables and the conversion of these measured values into electrical or pneumatic signals. These signals will then be used for indication and control functions. The basic controllers used in power plant control systems will be discussed including their response to various input signals. In addition, a brief discussion of simple logic circuits will conclude this section. The information in this chapter is discussed in greater detail in chapters 14 & 15 of the PPE training required to take this series. This chapter is intended as a quick review.

1.3.2 Pressure Sensing Instruments

Pressure, defined as force per unit area, is one of the measured and controlled properties. Pressure measurements range from the high pressure of the reactor coolant system measured in pounds per square inch (psi) to the vacuum in the main condenser measured in inches of mercury (in. Hg). The devices listed in this section are used for the measurement of system pressure.

1.3.2.1 Bourdon Tube

The simple bourdon tube, shown in Figure 1.3-1, consists of an oval tube rolled into an arc of a circle. One end is open to the process variable to be measured and the other end is closed. The surface area on the outer portion of the arc is larger than the surface area of the inner portion, and when pressure (force per unit area) is applied, the tube tends to straighten out very slightly. If the pressure is removed, the elasticity of the tube causes it to return to its original shape. The pressure of the fluid is converted to a mechanical motion by the bourdon tube. This motion can be converted into an electrical or pneumatic signal, or can drive a pointer on a local indicating gage for measurement of the applied pressure. The helical element, shown in Figure 1.3-2(b), is a variation of the simple bourdon tube. It is similar to the bourdon tube except that it is wound in the form of a spiral containing four or five turns. The helical element amplifies the movement of the closed end of the bourdon tube. The spiral type of measuring element is a second modification (Figure 1.3-2(a)) of the bourdon element. It is a thin-walled tube that has been flattened on opposite sides to produce an approximately elliptical cross section. The tube is then formed into a spiral. When pressure is applied to the open end, the tube tends to uncoil.

1.3.2.2 Bellows Pressure Sensor

The bellows pressure sensor, shown in Figure 1.3-3(a), is made up of a metallic bellows enclosed in a shell, with the shell connected to a pressure source. Pressure acting on the outside of the bellows compresses the bellows and moves its free end against the opposing force of the spring. A rod attached to the bellows transmits this motion to the pressure transmitter.

1.3.2.3 Diaphragm Pressure Sensor

The diaphragm pressure sensor, shown in Figure 1.3-3(b) consists of a metallic diaphragm (rigidly supported at each end), a spring, and a force bar that is connected to the diaphragm. When pressure is applied, the diaphragm moves in opposition to the spring, which causes motion of the force bar. When pressure is removed, the elasticity of the diaphragm and action of the spring return the sensor to its zero pressure condition.

1.3.2.4 Mechanical to Electrical Signal Conversion

In the sensors described above, the application of pressure results in a mechanical signal. Two devices are available for the conversion of this mechanical signal into an electrical signal that can be used in the plant control or protection systems. The use of one device, the force balance transmitter, results in a current (milliampere, ma) output; the use of the other device, the movable core transformer transmitter, results in a voltage output.

Force Balance Transmitter

Force balance refers to the system whereby the free motion of the sensor is limited and actively opposed by some mechanical or electrical means. In Figure 1.3-4 a simplified force balance transmitter is shown. As pressure increases, the diaphragm is moved to the left. This motion, in turn, causes movement of the force bar (the force bar is pivoted at the sealed flexure). The force bar motion causes movement of the reference arm, which closes the gap between the error detector transformer coils and the ferrite disk attached to the reference arm. When the gap of the error detector becomes smaller, the magnetic coupling between the transformer coils increases, increasing the output of the error detector transformer. The output of the error detector is amplified and applied to the force feedback coil. The increased current in the force feedback coil exerts a greater pull on its armature moving the reference arm in the opposite direction, thus restoring the system balance. The amount of current required to maintain the system in balance is proportional to pressure and, therefore, can be used in the indicating and control loops. Two current ranges, 4 to 20 ma or 10 to 50 ma, are generally used for this transmitter=s output circuitry.

Movable Core Transmitter

In the movable core transmitter, show in Figure 1.3-5 the pressure sensor's mechanical linkage is connected to the core of a linear variable differential transformer (LVDT). The LVDT consists of a primary coil and two secondary coils. The movement of the core changes the magnetic flux coupling between the primary coil and the secondary coils which, in turn, causes a change in the voltage output of the secondary coils. The secondary coils are connected in series opposition so that the two voltages in the secondary circuit have opposite phases. With the core in the center position of the transformer, the voltage output is zero. This will give a normal voltage range of -10 to 0 to +10 v.

Variable Capacitance Transmitter

Another type of transmitter is being installed at nuclear power plants currently under construction. This type of transmitter is called a variable capacitance transmitter (see Figure 1.3-6) and it consists of a set of parallel capacitor plates with a sensing diaphragm placed between the plates. The capacitor is filled with silicon oil. The need for a pressure-sensing element, such as a bellows or bourdon tube, and its mechanical linkage has been eliminated by connecting the process fluid to a separate isolating diaphragm. One side of the isolation diaphragm is in contact with the process stream, while the other side is in contact with the silicon fill oil. When pressure is applied to the isolating diaphragm, the force is transmitted through the silicon oil to the sensing diaphragm causing it to deflect. The deflection of the sensing diaphragm is detected by the capacitor plates. The change in capacitance, because of the sensing diaphragm deflection, is converted to a 4-to-20-ma output that is transmitted to the plant protection and/or control systems.

1.3.3 Flow Sensing Instruments

Selected pressure detection devices may be used to provide a reliable measurement of process flow. To measure flow in this, manner, a differential pressure (ΔP) is created by some type of primary device, such as an orifice plate, a flow nozzle, or a flow venturi. Flow rate measured in this manner is proportional to the square root of the ΔP. The ΔP is sensed and converted from a mechanical movement to an electrical signal for flow measurement.

1.3.3.1 Primary Devices

Orifice Plate

The orifice plate, Figure 1.3-7 (a), in its most common form, is merely a circular hole in a thin, flat plate that is clamped between the flanges at a joint in the system piping. The orifice plate is inexpensive and accurate, but as shown in Figure 1.3-7(a) it has poor pressure recovery (i.e. high-pressure loss).

Flow Nozzle

The flow nozzle, Figure 1.3-7 (b) provides better pressure recovery (i.e., less pressure loss) than the orifice plate. It consists of a rounded inlet cone and an outlet nozzle.

Flow Venturi

The flow venturi, Figure 1.3-7 (c), has the best pressure recovery characteristics and is used in those systems where a high-pressure drop across the primary element is undesirable. The venturi consists of rounded inlet and outlet cones connected by a constricted middle section. As the velocity increases in the constriction, the pressure decreases. A pressure tap is provided in this low-pressure area.

1.3.3.2 Bellows Flow Sensor

The bellows flow sensor (Figure 1.3-8) consists of two bellows: one that senses the high side (inlet) pressure of the primary device and another that senses the low side (outlet) pressure of the primary device. The difference in force exerted by the two bellows is proportional to the differential pressure developed by the primary element. A mechanical connection is made to the force bar of the force balance transmitter or the core of the movable core transformer (Paragraph 1.3.2.4) to convert the differential pressure signal to an electrical signal. Since the flow rate is proportional to the square root of the ΔP, a square root extractor circuit is required to convert the electrical output into flow indication.

1.3.3.3 Diaphragm Flow Sensor

Again, the principle of opposing forces created by the differential pressure across the primary device is used to sense flow with the diaphragm flow sensor (Figure 1.3-9). The displacement of the diaphragm causes motion of the force bar of the force balance transmitter or the core of the movable core transformer (Paragraph 1.3.2.4) and converts the ΔP signal to an electrical signal. A square root extractor is again required. The majority of the flow transmitters in the plant use diaphragm flow sensors.

1.3.3.4 Magnetic Flow Sensors

Unlike the previous flow sensors discussed in this section, the magnetic flow sensor (Figure 1.3-10) does not require a primary element. The magnetic flow transmitter works on the principle that voltage can be generated if relative motion exists between a conductor and a magnetic field. The liquid is used as the conductor. The flow transmitter generates the magnetic field, and the flow of the liquid provides relative motion. Electrodes located in the piping detect the generated voltage.

1.3.4 Level Sensing Instruments

Most measurements of level are based on a pressure measurement of the liquid's hydrostatic head. This hydrostatic head is the weight of the liquid above a reference or datum line. At any point, its force is exerted equally in all directions and is independent of the volume of liquid involved or the shape of the vessel. The measurement of pressure as a result of level head can be translated to level height above the datum line as follows:

$H = P/\rho$

where:

H =height of liquid

P = pressure resulting from hydrostatic head

ρ = density of liquid.

Different pressure sensors, both bellows and diaphragm (Paragraphs 1.3.3.2 and 1.3.3.3) are used to sense level. On tanks that are vented, the low side of the differential pressure sensor is open to atmospheric pressure. Pressurized tanks such as the core flood tanks have reference legs that tap into the gas space of the tank; therefore, the level indication is not affected by changes in tank pressure. The pressurizer and steam generators use a filled (wet) reference leg, and level (ΔP) is sensed in accordance with the following equation:

$\Delta P = H_r \rho_r - H_v \rho_v$

where:

H_r = height of the reference leg

ρ_r = density of the reference leg

H_v = height of the variable leg

ρ_v = density of the variable leg

The reference legs are kept full by condensate pots that tap into the steam space of both vessels. It should be noted from the above formula that a density change in either the reference or variable leg will affect the ΔP that is seen by the sensor; also when the vessel is full, the ΔP is equal to zero. Both flow and level sensors are referred to as differential pressure cells or transmitters.

1.3.4.1 Variable Capacitance Differential Pressure Transmitters

A detector similar in construction to the variable capacitance pressure detector (Paragraph 1.3.2.5) is used to measure the differential pressure caused by level or flow. As seen in Figure 1.3-11, two isolating diaphragms (one diaphragm for the high-pressure input and one diaphragm for the low-pressure input) are used. The differential pressure exerts a force through the silicon fill oil to change the position of the sensing diaphragm. The change in sensing diaphragm position is detected by the capacitor plates. The change in capacitance is electronically converted to an output with a range of 4 to 20 ma.

1.3.5 Temperature Sensing Instruments

Temperature is one of the most measured and controlled variables in the nuclear plant. Uses of temperature measurements range from inputs into the reactor protection system to measurement and control of the chilled water temperature from the station air conditioning system. Three basic types of temperature detectors are used, the fluid-filled system, the thermocouple, and the resistance temperature detector. Each of these temperature detectors is discussed in the following sections.

1.3.5.1 Fluid-Filled Systems

Fluid-filled temperature sensors are usually gas-filled “pressure” detectors (Figure 1.3-12). When the temperature of a gas changes, its pressure also changes. The pressure change of the gas is sensed by a bourdon-tube-type pressure sensor, in which the bourdon tube is connected to a pointer that travels across a scale calibrated in temperature units. The primary use of these systems is local temperature indication.

1.3.5.2 Thermocouples

When two dissimilar metals are welded together and this junction is heated, a voltage is developed at the free ends. The magnitude of the voltage is proportional to the temperature difference between the hot and cold junctions (see Figure 1.3-13) and a function of the types of materials used in thermocouple construction. Because connections must be made to the thermocouple at the cold junction and at the measuring device, all thermoelectric systems consist of three separate thermocouples: the thermocouple proper, the external lead wire, and the reference junction. The voltage developed in the circuit is then a combination of the voltages generated by all three junctions. If the temperature at the reference junction changes, the total voltage of the circuit changes, and the proportionality between the process temperature and measured voltage is destroyed. The temperature of the reference junction must be kept constant, or changes in this temperature may be compensated for by a temperature sensitive resistor. The temperature sensitive resistor will provide a voltage drop in the circuit to compensate for reference junction temperature changes. The incore system uses thermocouples as temperature sensors.

1.3.5.3 Resistance Temperature Detectors

In Figure 1.3-14, a typical bridge circuit is shown. The bridge consists of three known resistances and the resistance temperature detector (RTD). The RTD's resistance varies with temperature. As temperature increases, the resistance of the RTD also increases. As the resistance of the RTD changes, the voltage difference between points A and B of the bridge circuit changes. This voltage difference is proportional to the temperature that is sensed by the RTD and is used as an input to the indication and control circuits. The RCS hot- and cold-leg temperature detectors are RTDs.

1.3.6 Controllers

In order to control some physical process, (Figure 1.3-18) at least three items must be considered. First, the desired value of the parameter must be chosen. This desired value is called the setpoint for the control system and may be supplied either manually or as a function of a related variable. Second, the actual value of the process must be known. The input of this variable is provided by a detector which senses the value of the process that is to be controlled. Finally, some device must be installed to cause the parameter to achieve its desired value. This device will be controlled by the difference between the setpoint and actual value of the process. The difference between the setpoint and actual value of the parameter is derived in a summing circuit (Σ) and is called an error signal.

The simplest form of controller is a bistable. A bistable turns on or off in response to a control signal. For example a bistable can be used in the control system of a process instrument. In the pressurizer heater control system a bistable controls the operation of the pressurizer heaters in response to pressurizer level. At 17% or less pressurizer level the pressurizer heaters are deenergized. This is in response to the pressurizer level instrument. At 17% level a bistable turns off, preventing operation of the pressurizer heaters in a steam environment. Once pressurizer level is greater than 17% the operator can restore the operation of the pressurizer heaters.

1.3.6.1 Proportional Control

In this paragraph, the basic concepts of a control system are applied to a hypothetical process. It is desired to control the level in a tank (Figure 1.3-19) at a constant value. This tank has an inlet supply of water and a valve installed on the outlet line. A level setpoint of 50% has been chosen and a level transmitter (detector) with the capability of measuring the contents of the tank over the range of 0 to 100% has been installed. The controlled device is the outlet control valve. The following assumptions are made:

1. The inlet flow to the tank can be varied to introduce a disturbance into the system.
2. The outlet flow through the control valve can match inlet flow.
3. The output of the controller will be a value equal to 50% when the tank level is at setpoint, i.e., the error signal is equal to zero.

4. There exists a one to one correspondence between controller output and valve position.

Initial conditions are the tank level at 50% with a given inlet flow equal to outlet flow. Since the tank is at 50% level, the controller output and outlet control valve position are also at 50%, Figure 1.3-19(b). The change in controller output for a change in tank level is represented by the 45E line. Now consider the response of the system if inlet flow is suddenly stopped. First of all, with no inlet flow and the outlet valve positioned at 50%, tank level will drop. As tank level starts to drop, the output of the level transmitter starts to change. In the summing unit (Σ) the change in transmitter output will be sensed resulting in an error signal, Figure 1.3-19(c). The error signal causes a change in controller output which, in turn, causes the outlet valve to start to close. The decrease in tank level will not be terminated until the outlet valve is fully closed and this will occur when the controller output is zero. Unfortunately the output of the controller will equal zero only when the tank is empty. An empty tank falls far short of the goal of controlling tank level at 50%. Conversely, if the level in the tank was at 50% and the inlet flow was increased to its maximum value, then inlet flow would be greater than outlet flow causing tank level to increase.

The increase in tank level is sensed by the level transmitter. The change in the output of the level transmitter is compared with the setpoint in the summing unit (Σ) resulting in an error signal. The error signal causes an increase in the output of the controller resulting in the opening of the outlet control valve. In order to stop the increase in tank level, the outlet valve must be fully open. The outlet valve will be 100% open when the tank is full. Again, the control system will not control the tank level at setpoint. From these two examples, it is evident that the controller will not operate correctly in its present configuration. However, if the output of the controller can be increased by a value that is proportional to the change in the error signal, then the outlet valve will achieve its required position sooner. This will prevent gross oscillations in tank level. Such a controller is called a proportional controller because its output is proportional to the input error signal.

output = (k) (error signal)

where:

k is the proportionality constant.

To illustrate the effect of the proportionality constant, values of k equal to 2 and 5 will be arbitrarily chosen while maintaining a 50% controller output with a zero error signal. As shown in Figure 1.3-19(a) with k equal to 2, if the error signal increases by 25% then the output of the controller will increase to 100%. In the opposite direction a change in the error signal of 25% will result in a controller output of 0%. Formally k is called the Again@ of the controller and is defined as follows:

Gain = Δ output / Δ input

The output of the control system versus tank level for the two different values of gain is shown in Figure 1.3-19(b). The effects of these two values of gain will be examined with perturbations in inlet flow.

Note on Figure 1.3-19(c) that tank level is at 50% (setpoint). At time t=1, the inlet flow is stopped. With output flow greater than inlet flow, tank level begins to decrease. The decrease in tank level will continue until the outlet valve is fully closed. The value of tank level resulting in closure of the outlet valve can be determined from Figure 1.3-19(b). With a gain of 2 the valve will be closed when tank level is 25%. At time t=4, inlet flow is increased from zero to its maximum value. Since inlet flow is greater than outlet flow, tank level will rise. The increase in tank level will stop when outlet and inlet flows are equal. This will occur when the outlet valve is 100% open. Again, the tank level corresponding to the full open valve position can be determined from Figure 1.3-19(b). Since the controller has a gain of 2, the level increase will be stopped at 75%.

Now, using a gain of 5 for the same conditions as described above with the previous gain of 2. At time t=1, with the tank level at 50% (setpoint), the inlet flow is stopped. With output flow greater than inlet flow, tank level begins to decrease. The decrease in tank level will continue until the outlet valve is fully closed. The value of tank level resulting in closure of the outlet valve can be determined from Figure 1.3-19(c). With a gain of 5 the valve will be closed when tank level is 40%. When k is equal to 5, changes in the error signal of -10% to +10% correspond to controller output of 0% and 100% respectively. With a gain of 5, the increase in tank level will be terminated at 60%.

It should be noted that tank level is not controlled at setpoint in either case. This is a characteristic of a proportional controller. A proportional controller will not control at setpoint because a change in the error signal is required to cause a change in the output of the controller. Although the proportional controller will not control at setpoint, it will control within a band around the setpoint. This leads to the definition of the proportional band (PB). The proportional band of a controller is the change in input required to cause a 100% change in the output. The proportional band is the reciprocal of gain as illustrated on Figure 1.3-19(c) and the following:

Table 1.3-1 Gain and Proportional Band

Gain	Proportional Band (in %)
0.5	200%
1.0	100%
2.0	50%
5.0	20%

At a glance it would appear that increasing the gain would cause the controller to control closer to setpoint. While this is true, limitations on gain do exist. Equipment or process time delays must be taken into consideration when choosing values of gain.

1.3.6.2 Proportional Plus Integral Control

In order to eliminate the proportional controller's offset between the actual value of the parameter and the process setpoint, integral control action is added to the control system (see Figure 1.3-20). The integral action eliminates the offset by integrating the proportional band and adding this signal to the controller output. Prior to examining the operation of integral action, two terms need to be defined. The first term is "reset rate" and is defined as the number of times the magnitude of the change in controller output caused by the proportional band deviation will be added to the controller output per unit time. Reset rate is expressed in repeats per minute (RPM). The other term is "reset time" and is defined as the time required to repeat the magnitude of the change caused by the proportional band action. Reset rate and reset time are reciprocal terms. To illustrate this, assume a controller has a proportional band of 200% (gain = 0.5) and a reset rate of 2 RPM. If a step change of 20% occurs in the process variable, the magnitude of the change in the controller output due to proportional band action is 10%. A reset rate of 2 RPM will cause a change of an additional 20% every minute the error exists. A reset rate of 2 RPM corresponds to a reset time of 0.5 minutes; therefore, the output of the controller will be changed an additional 10% every 30 seconds.

For review, the actions of the control system in response to a step change from 50% to 70% with a gain of 0.5 and a reset rate of 1 RPM are as follows:

1. The controller output due to proportional controller action will increase from 50% to 60% (20% Δ input x 0.5 gain = 10%).
2. The change of 10% due to proportional action will cause a change of 10% every minute for a 1 RPM reset rate.
3. The output of the integral action will be combined with the output of the proportional controller to cause a greater opening of the tank outlet control valve for each percent level error.
4. A greater opening of the control valve will increase the outlet flow from the tank. If outlet flow is increased, then tank level will decrease.
5. As the level decreases, the output of the controller will decrease closing down on the outlet control valve. This action will continue until the setpoint of 50% is reached.

Now use the same initial conditions as above, with the exception that the reset rate is changed to 2 RPM. The actions of the control system in response to a step change from 50% to 70%, with a gain of 0.5 and a reset rate of 2 RPM, are as follows:

1. The controller output due to proportional controller action will increase from 50% to 60% (20% Δ input x 0.5 gain = 10%).
2. The change of 10% due to proportional action will cause a change of 20% every minute for a 2 RPM reset rate.
3. The output of the integral action will be combined with the output of the proportional controller to cause a greater opening of the tank outlet control valve for each percent level error.
4. A greater opening of the control valve will increase the outlet flow from the tank. If outlet flow is increased, then tank level will decrease.

5. As the level decreases, the output of the controller will decrease closing down on the outlet control valve. This action will continue until the setpoint of 50% is reached.

The addition of integral action to the controller will achieve the desired result of having the control system control at setpoint because controller output will continue to change as long as an offset between the actual value of the parameter and its setpoint exists. As the value of the controller changes, the controlled device will be modulated. This action will restore the parameter to setpoint.

1.3.6.3 Proportional Plus Derivative Control

The installation of derivative action into the control scheme gives the system the ability to start action based upon the rate of change of the control systems input. This is sometimes referred to as an anticipatory circuit. A derivative controller “anticipates” the change in the process variable by the addition of a signal that is proportional to the rate of change of the input signal. The change in controller output due to derivative action is called “rate gain” and is defined as the multiplication of the change in proportional action due to a step change in the process parameter. A step change is used here as a reference condition.

As an example, if a step change of 10% causes a proportional controller’s output to change by 5% (200% proportional band), then the addition of derivative action with a rate gain of 5 would cause an additional increase in the controllers output of 25%. Figure 1.3-21 illustrates the effects of adding derivative action to the control system. Inlet flow to the tank is adjusted to give a rate of increase in level of 10% per minute It will be assumed that the increase in controller output does not decrease the rate of level increase (no feedback). As tank level begins to increase at a rate of 10% per minute, the output of the controller due to proportional action begins to increase at 5% per minute (gain times the change in input). The rate of change of level is constant; therefore, the output of the derivative circuit will increase from 0% to 10% (rate gain of 2 times the 5% change in output due to proportional band action) and remain constant.

The increase in controller output positions the level control valve to a greater opening per percent level error restoring tank level to setpoint sooner. A comparison of the proportional control output graph, and the proportional plus derivative graph, shows that the time required to reach a particular controller output is decreased by the addition of derivative action. This reduction in time is called “rate time” and is defined as the decrease in time it would take the controller output to reach the same value that would be obtained by only proportional action when the process parameter is changing from setpoint at a constant rate.

Figure 1.3-21 shows a transient involving a step change in tank level. The step change causes an increased controller output due to proportional plus derivative action. After the step change has occurred, the rate of change of level deviation is zero. This causes the derivative signal to be reduced to zero over a given period of time.

The time required for the output to decay by 63.2% of the signal due to the action of the derivative portion of the controller is called the “time constant.” The output of the controller is an exponential function and will change by 63.2% of the controller’s maximum value in one time constant. The output of the derivative portion of the controller will equal zero after 5 time constants. If the deviation between setpoint and the process parameter, as shown in Figure 1.3-21 is increasing, the portion of the controller output due to derivative action will reach its steady state value in five time constants.

1.3.6.4 Proportional Plus Integral Plus Derivative (PID) Controllers

The proportional plus integral plus derivative (PID) controller is the most sophisticated controller used in the power plant and can be used to summarize the previous types of controllers. The proportional component of the PID provides an output that is proportional to its input. The input signal to the controller is the error that results from the comparison of the actual value of the parameter and its desired value (setpoint).

The proportionality constant is called gain. Since a change in the input is required to cause a repositioning of the controlled device, an inherent offset would exist. The addition of the integral portion of the PID controller eliminates the offset of the proportional action. The integral portion of the controller accomplishes this function by adding the integral of the proportional deviation to the output of the controller. This increase in controller output changes the status of the controlled device and causes the process parameter to achieve the desired value. Finally, the derivative action adds an anticipatory feature to the controller. This anticipatory feature is performed by adding a signal to the controller output that is proportional to the rate of change (the derivative) of the proportional band deviation. Response of the PID controller to various input signals without feedback is shown on Figure 1.3-23.

1.3.7 Logic Diagrams

The concept of logic diagrams was introduced to provide complete system information to personnel in an easily interpreted format. These diagrams, through the use of standard symbols, explain specific system or component control, protection and operational capabilities without requiring detailed research of complex electrical or mechanical system diagrams. With the use of a few standard symbols and a basic knowledge of the system’s functions and capabilities, a large quantity of useful information may be obtained. To illustrate the concept of logic diagrams and their component parts, the basic symbols will be introduced and briefly discussed and an example given of their application.

The symbols to be discussed will not be all inclusive; however, those discussed are the most common. In every case of logic diagram usage by a vendor, architect engineer, or utility, an explanation sheet of symbols is included.

1.3.7.1 “OR” Logic

The “OR” logic is represented in Figure 1.3-26(a). This logic symbolizes an input and an output function. In the “OR” logic flow, any input signal is considered to be passed through to produce an output. The loss of all inputs will cause a loss of the output.

1.3.7.2 "AND" Logic

The "AND" logic is represented in Figure 1.3-26(b). Multiple input functions are required to produce an output function. In the "AND" logic, all input functions or a specified number of the input functions must be present to produce an output.

1.3.7.3 "NOT" Logic

The "NOT" logic represented in Figure 1.3-26(c) illustrates a function that will produce an output with no input signal. Likewise, with an input signal present, no output is produced.

1.3.7.4 Retentive Memory

This logic function in Figure 1.3-26(d) will either produce an output or not produce an output depending on its last energized input. If the last input signal received is the input aligned with the output, an output signal is allowed to pass. If the last input signal received is not aligned with the output, the output signal will be terminated.

1.3.8 Electrical Relay

Figure 1.3-27 illustrates the physical layout of a relay and the electrical circuit representations. There are two types of auxiliary contacts used in relays. The "A" contacts are shut when the main relay contacts are shut, and open when the main relay contacts are open. The "B" contacts are open when the main relay contacts are shut and shut when the main relay contacts are open. These "A" and "B" contacts are used as part of the instrumentation and control circuits for the system controlled by the relay.

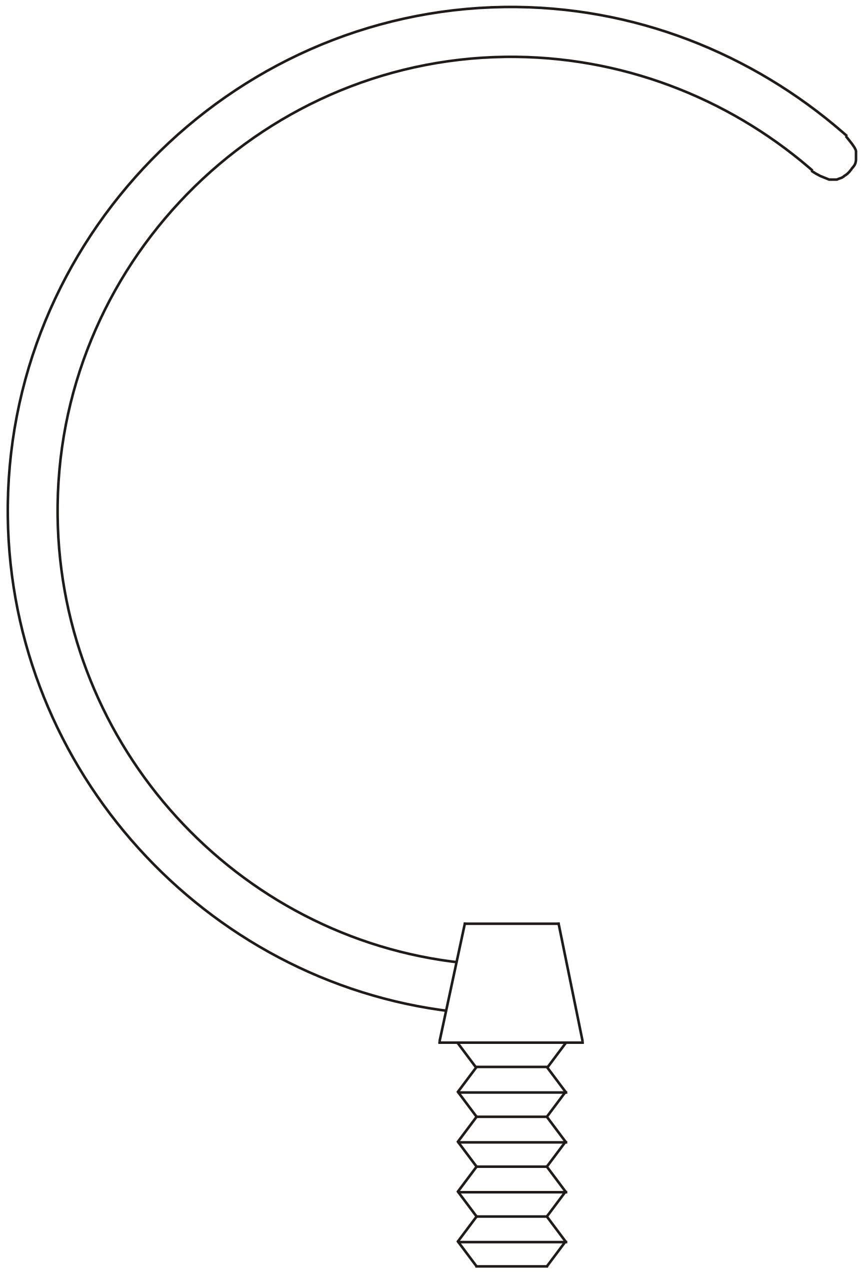
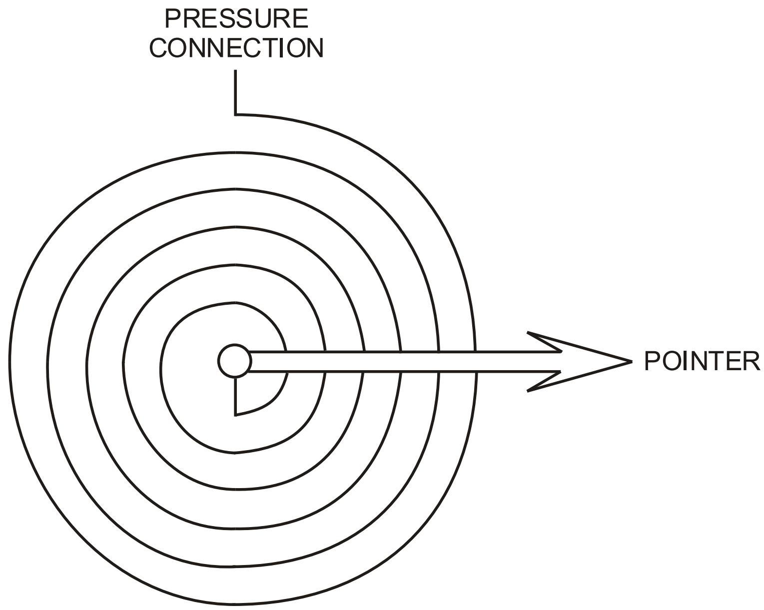
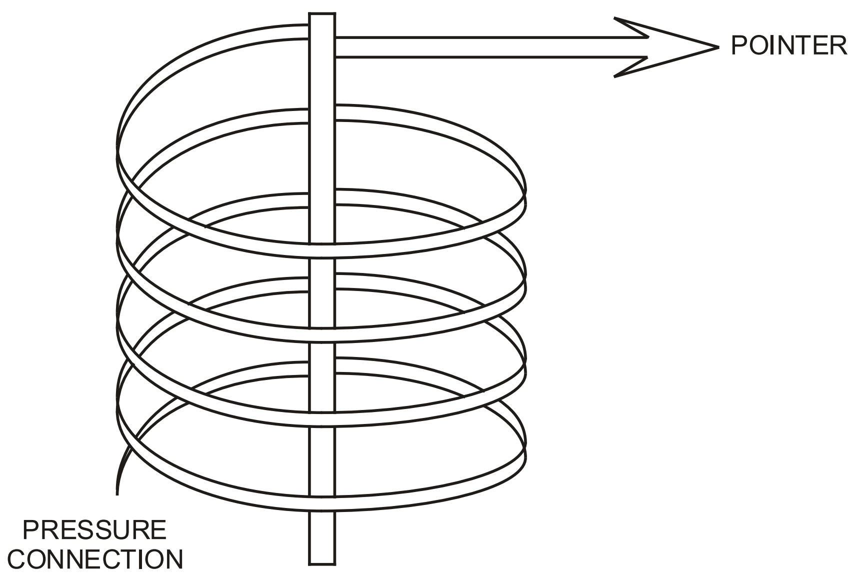


Figure 1.3-1 Simple Bourdon Tube

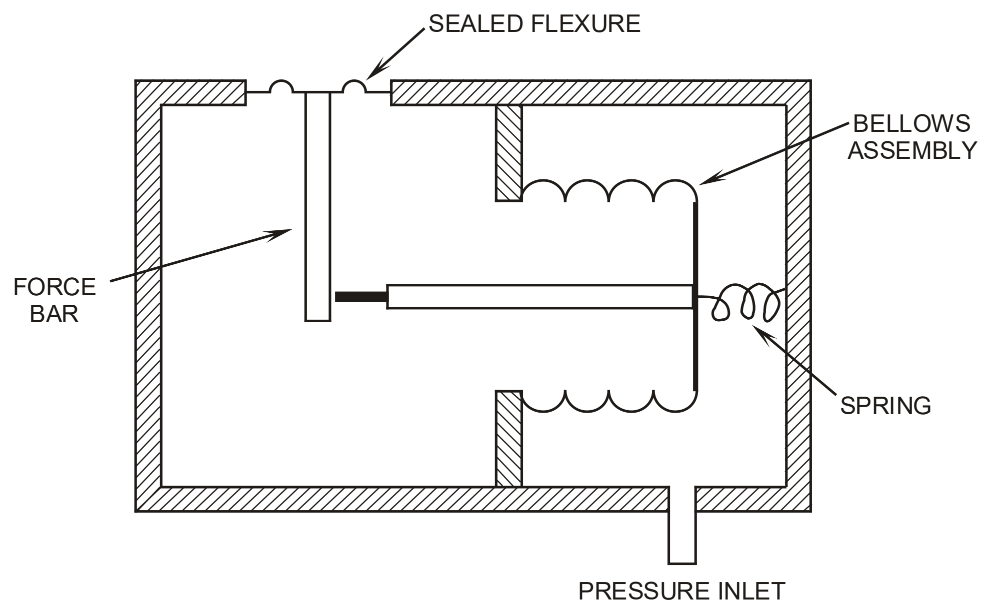


(a) Spiral pressure detector

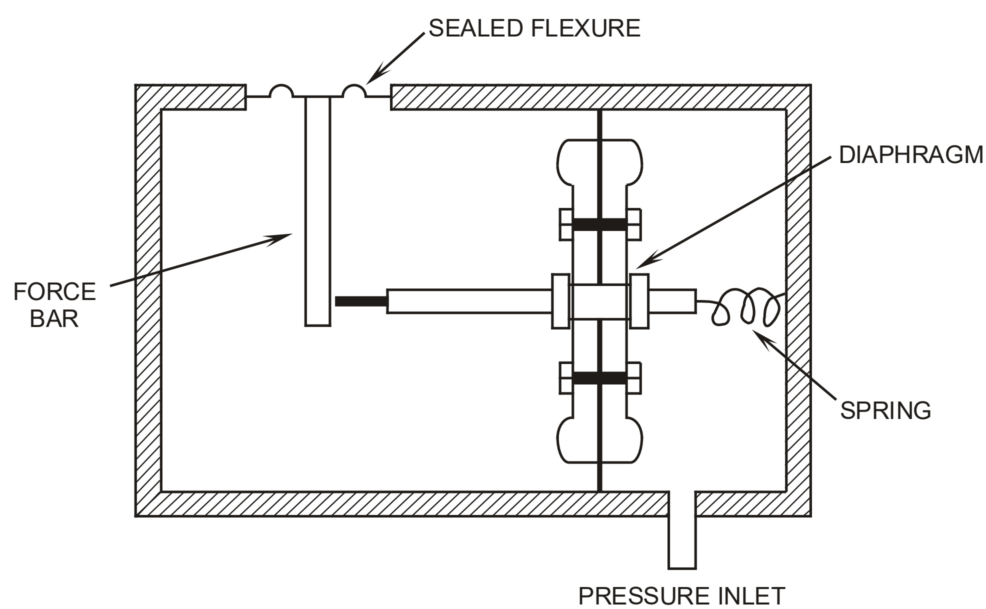


(b) Helical pressure detector

Figure 1.3-2 Wound Pressure Detectors



(b) Bellows Pressure Sensor



(b) Diaphragm Pressure Sensor

Figure 1.3-3 Sealed Pressure Detectors

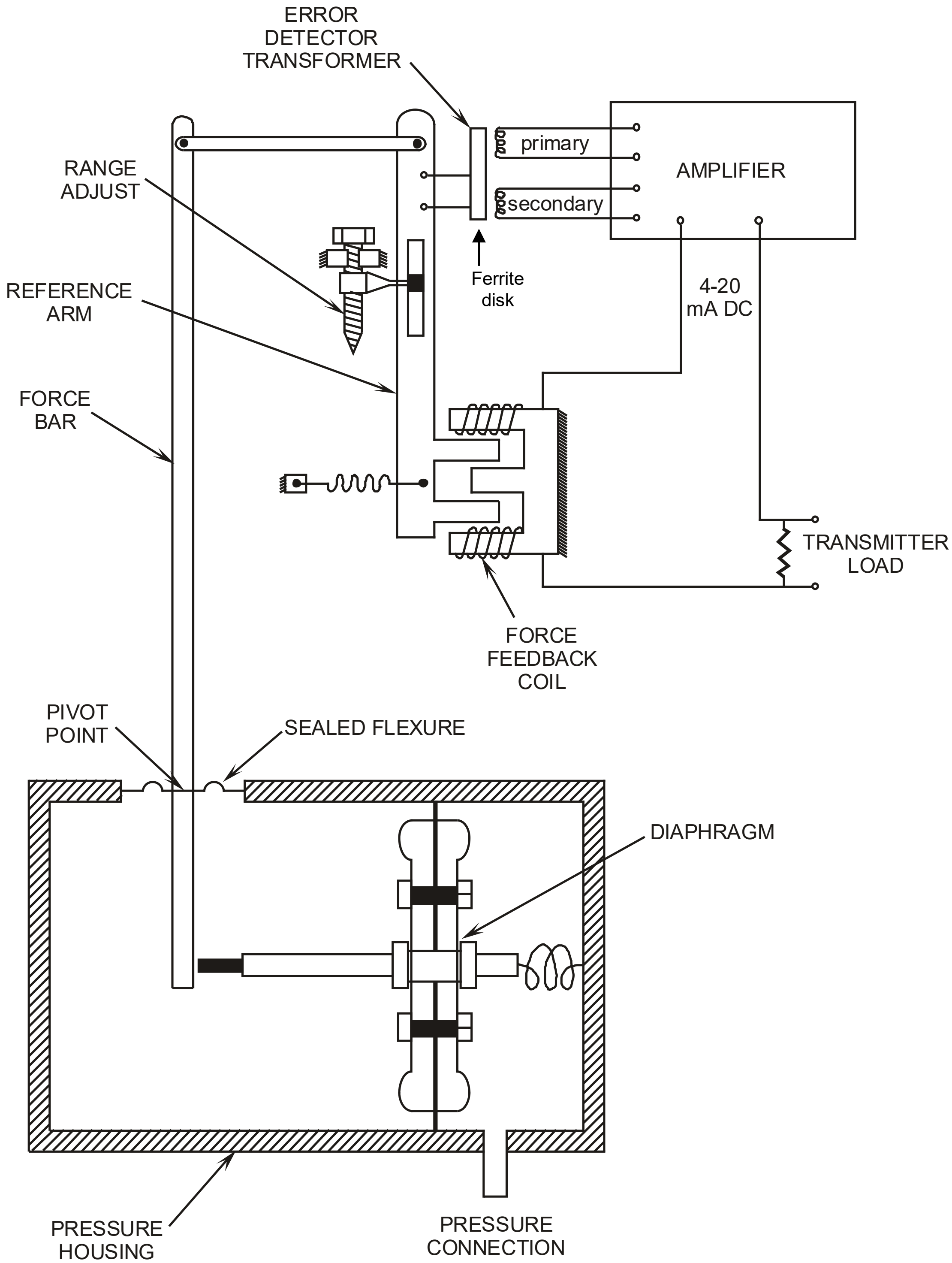


Figure 1.3-4 Force Balance Transmitter

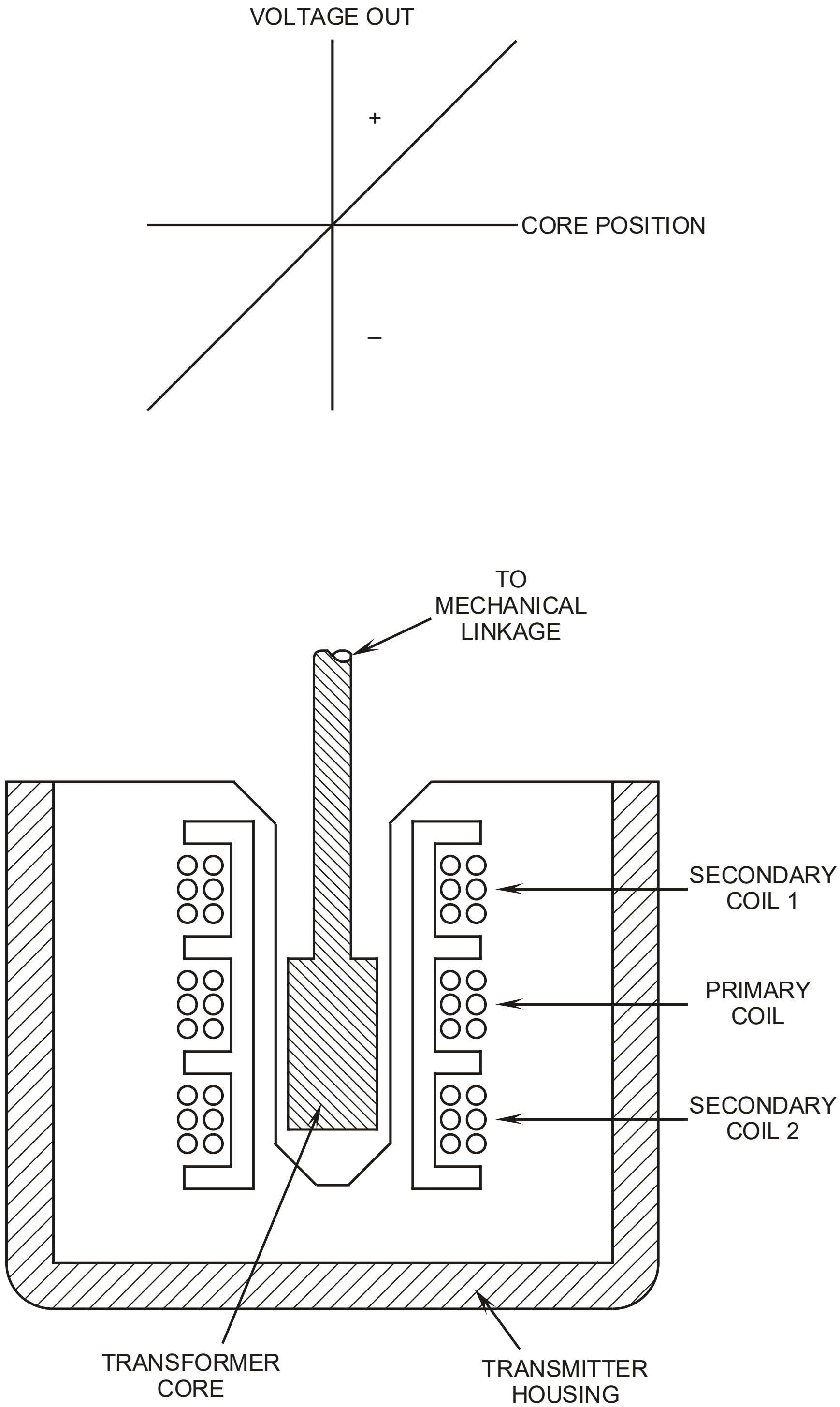


Figure 1.3-5 Movable Core Transmitter

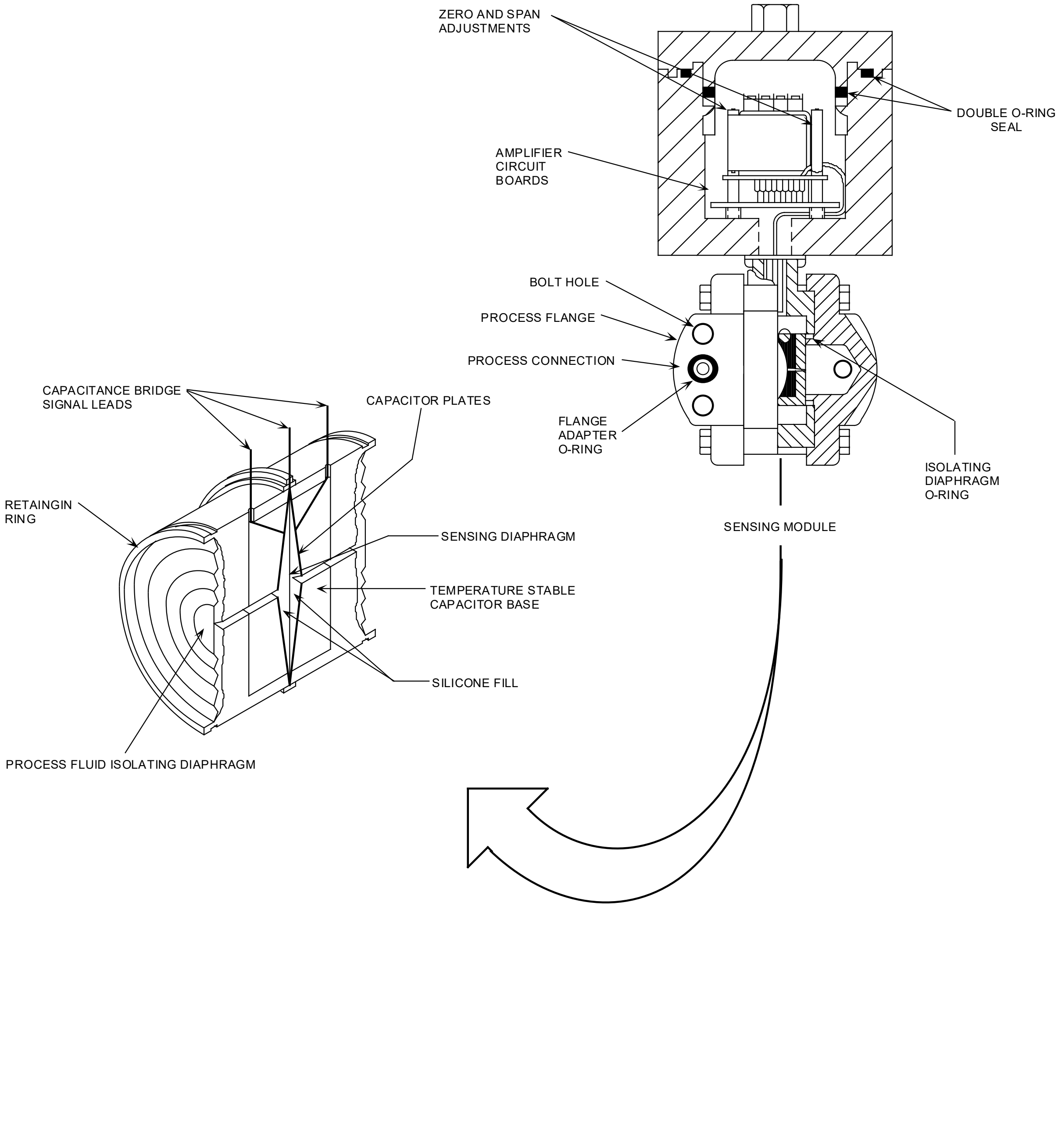


Figure 1.3-6 Variable Capacitance Transmitter

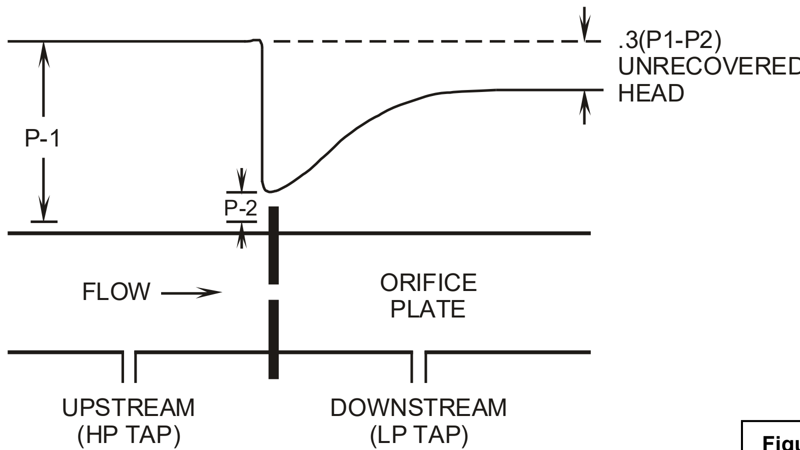


Figure 1.3-7(a)

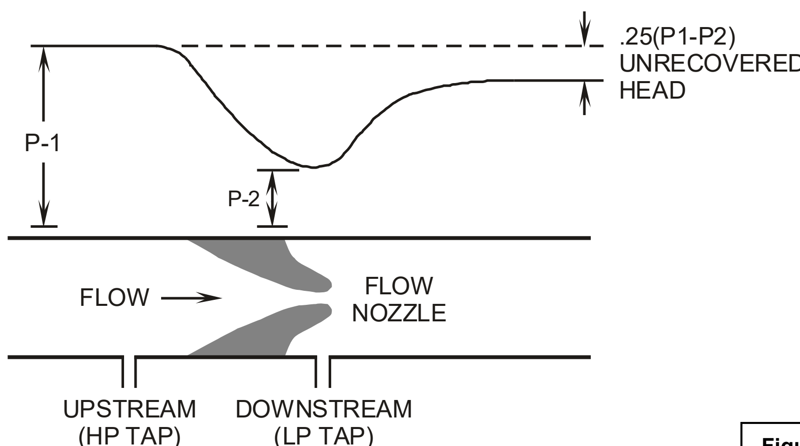


Figure 1.3-7(b)

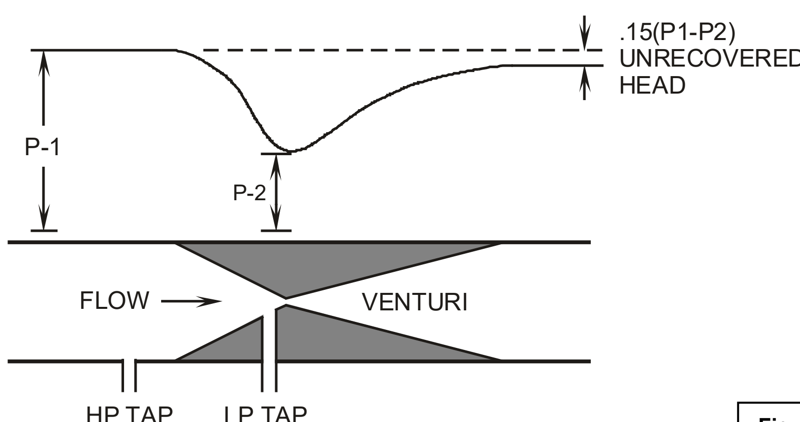


Figure 1.3-7(c)

Figure 1.3-7 Primary Devices

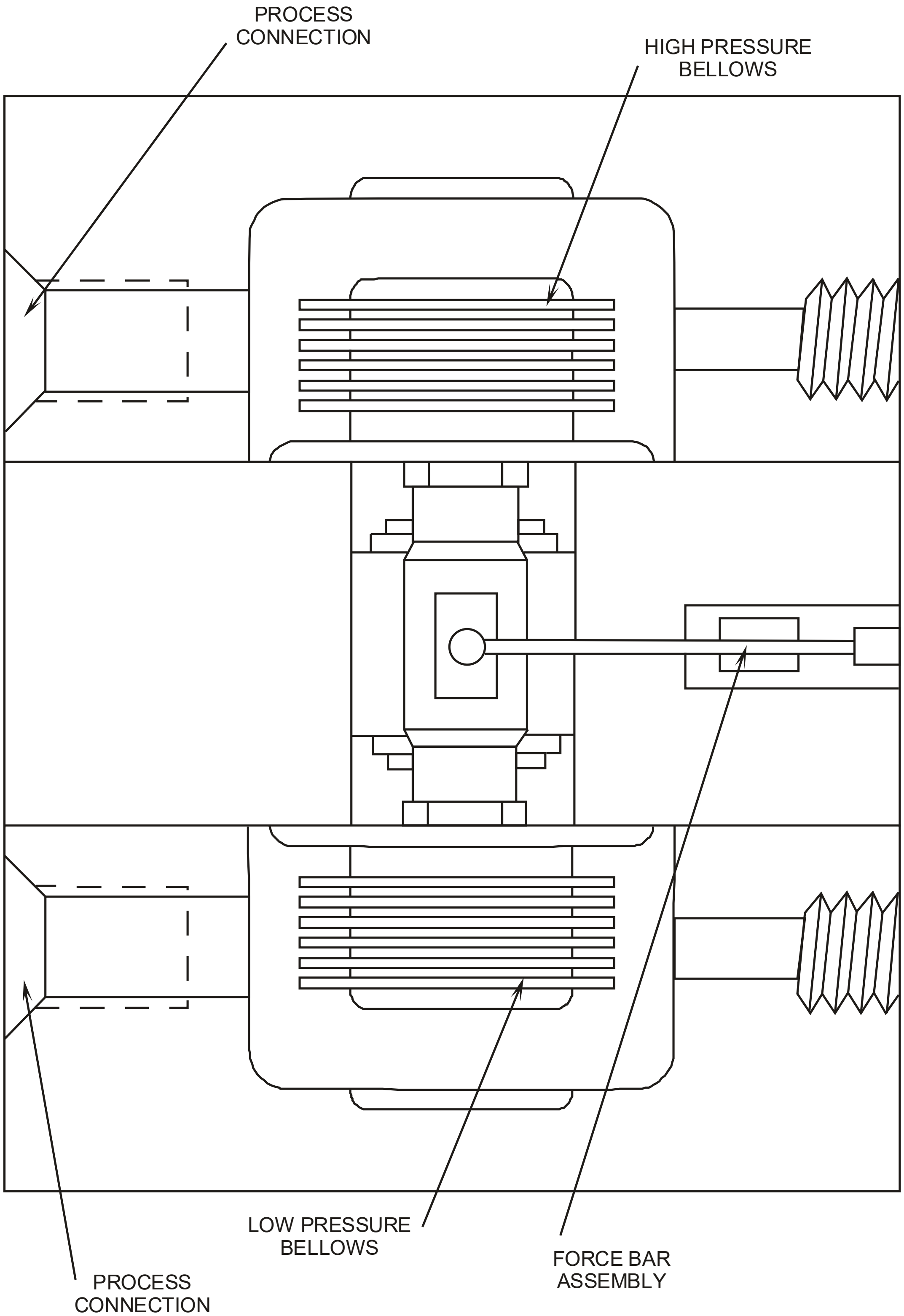


Figure 1.3-8 Bellows Flow Sensor

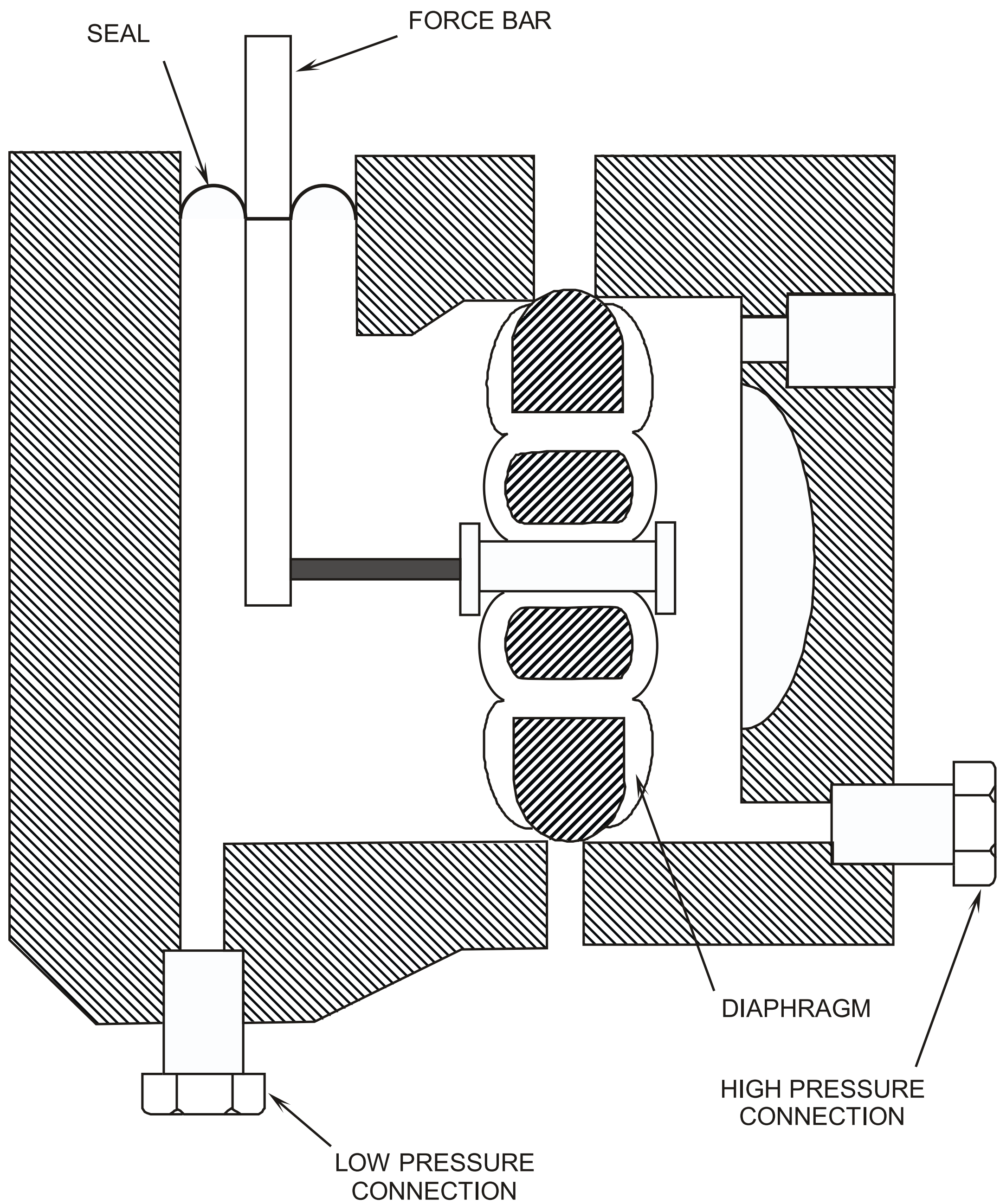


Figure 1.3-9 Diaphragm Flow Sensor

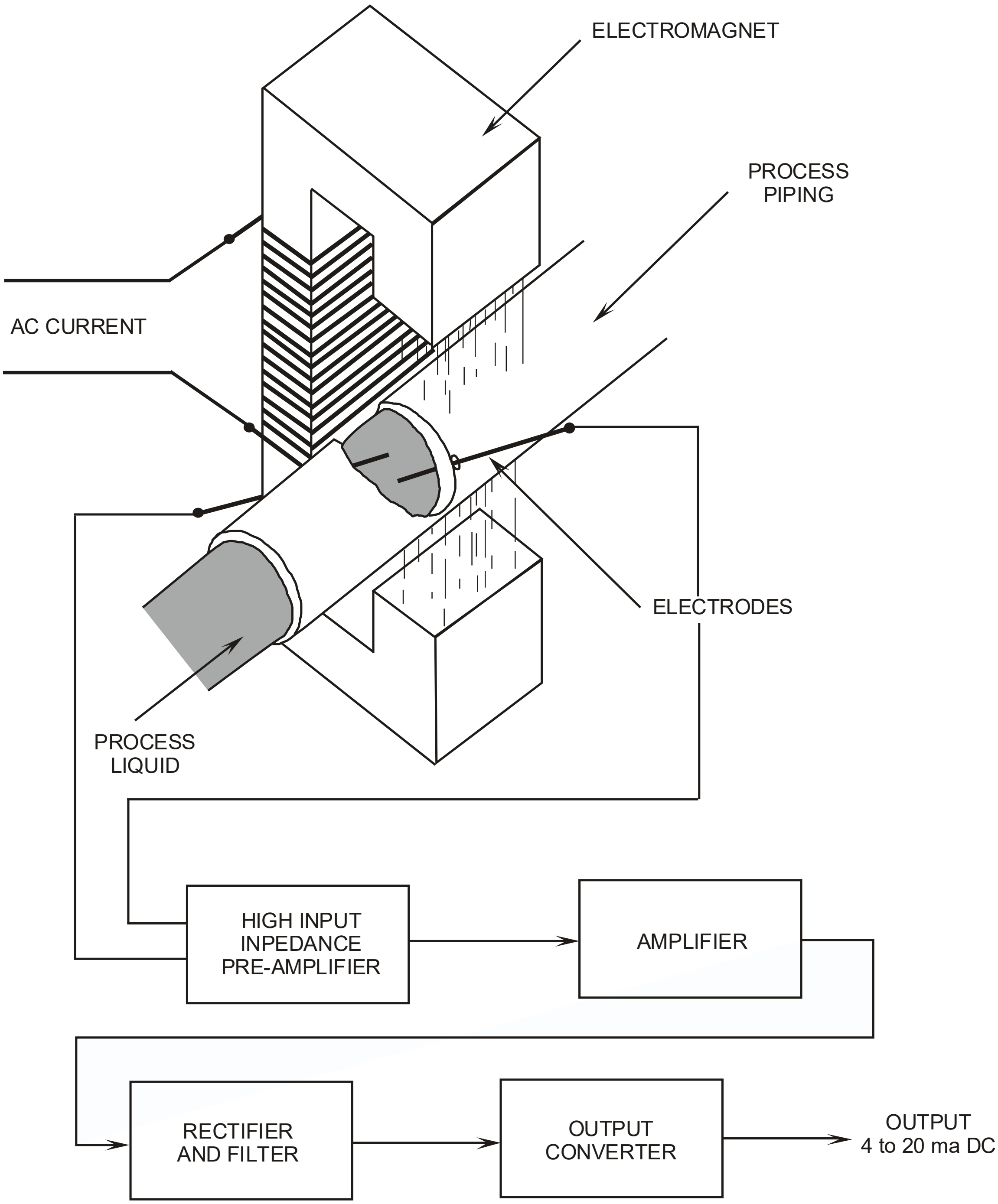
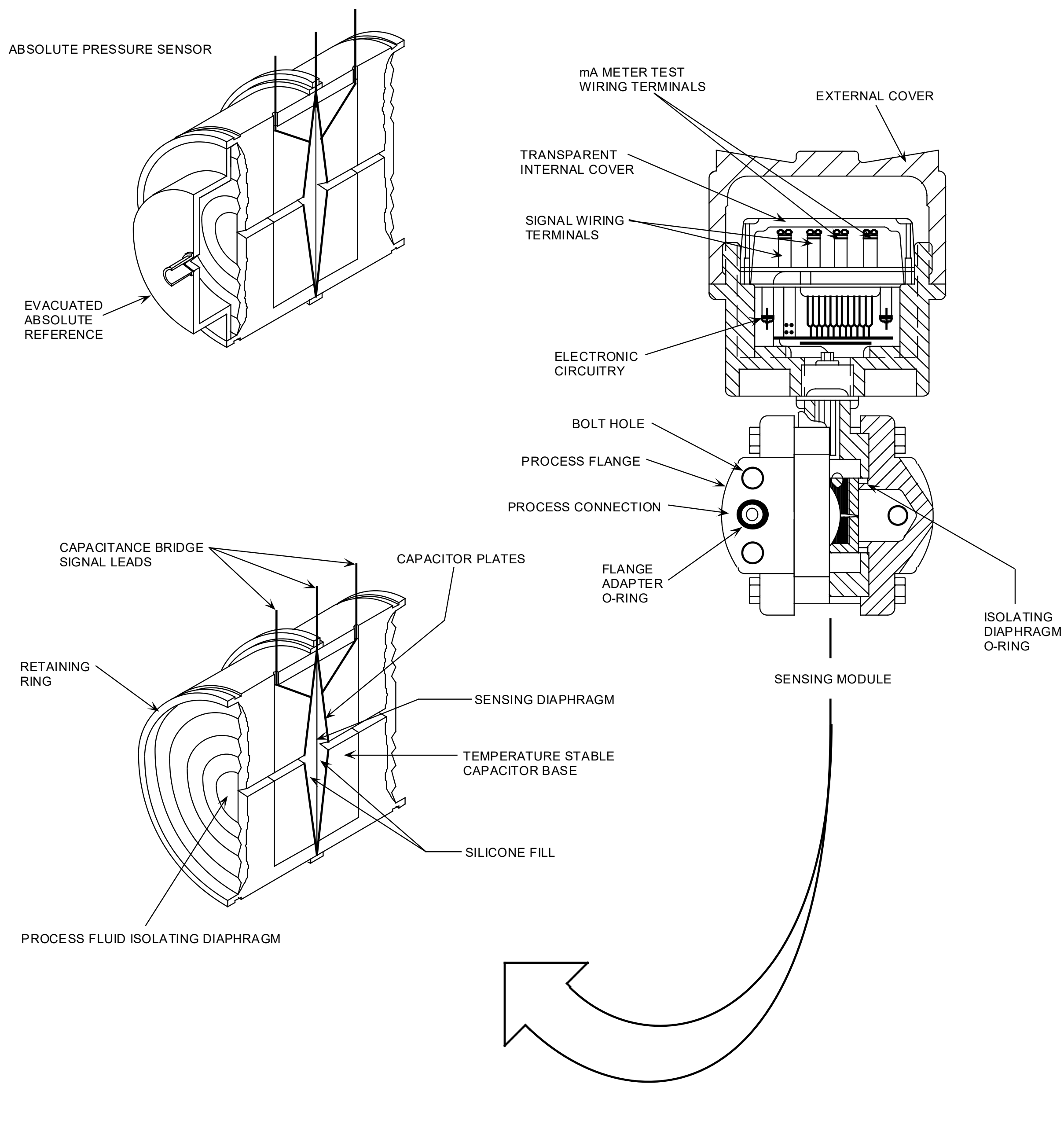


Figure 1.3-10 Magnetic Flow Sensor



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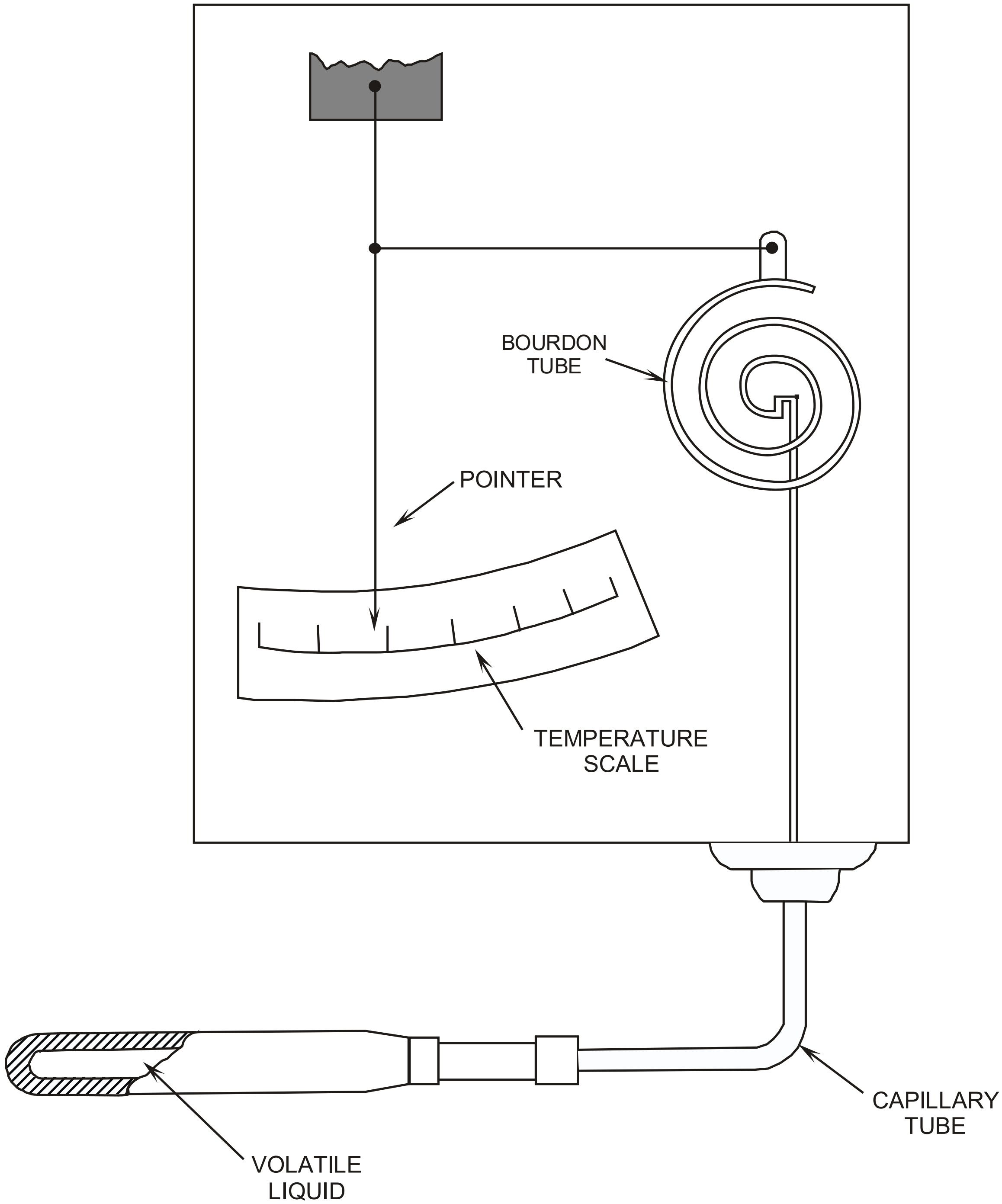

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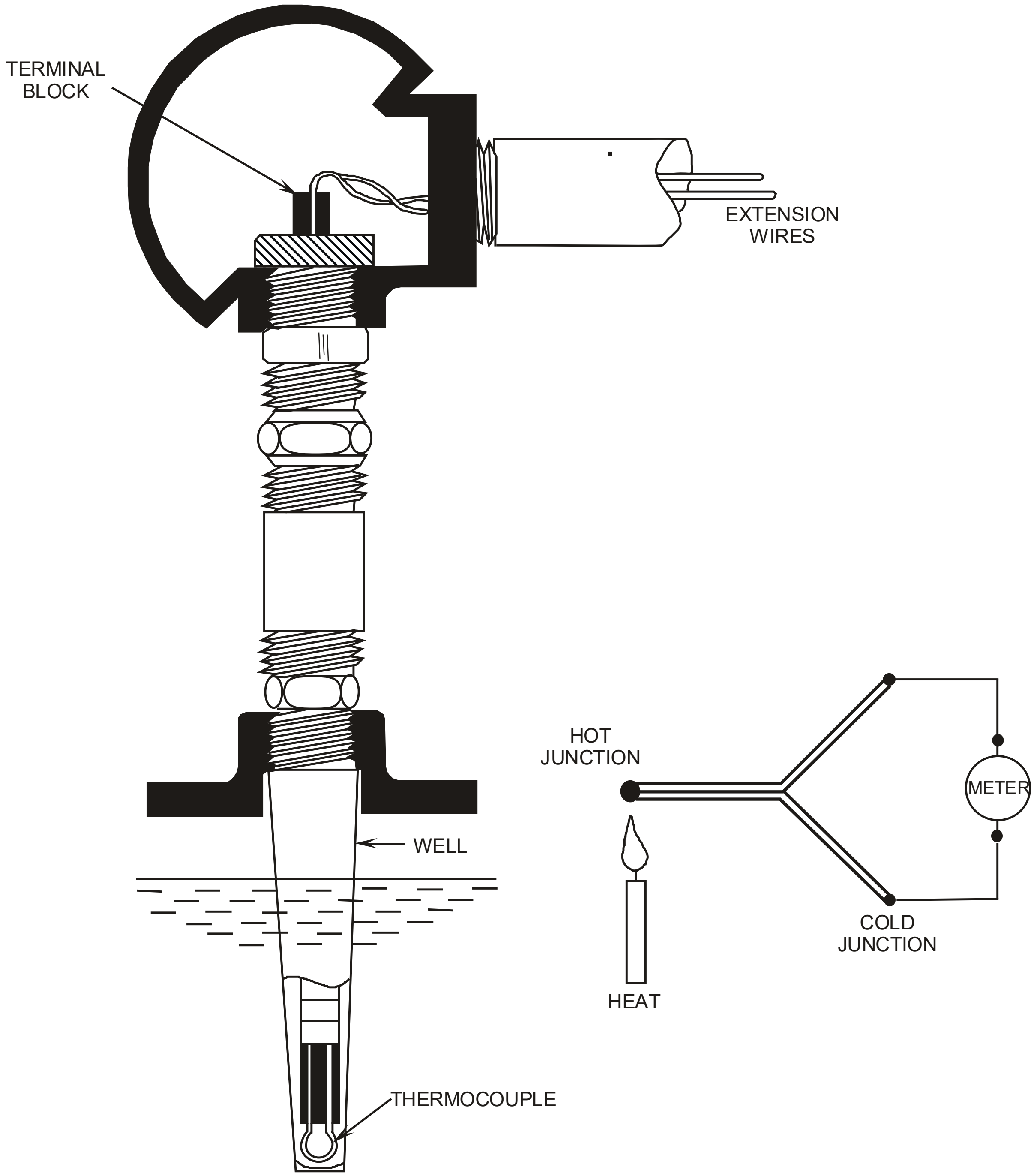

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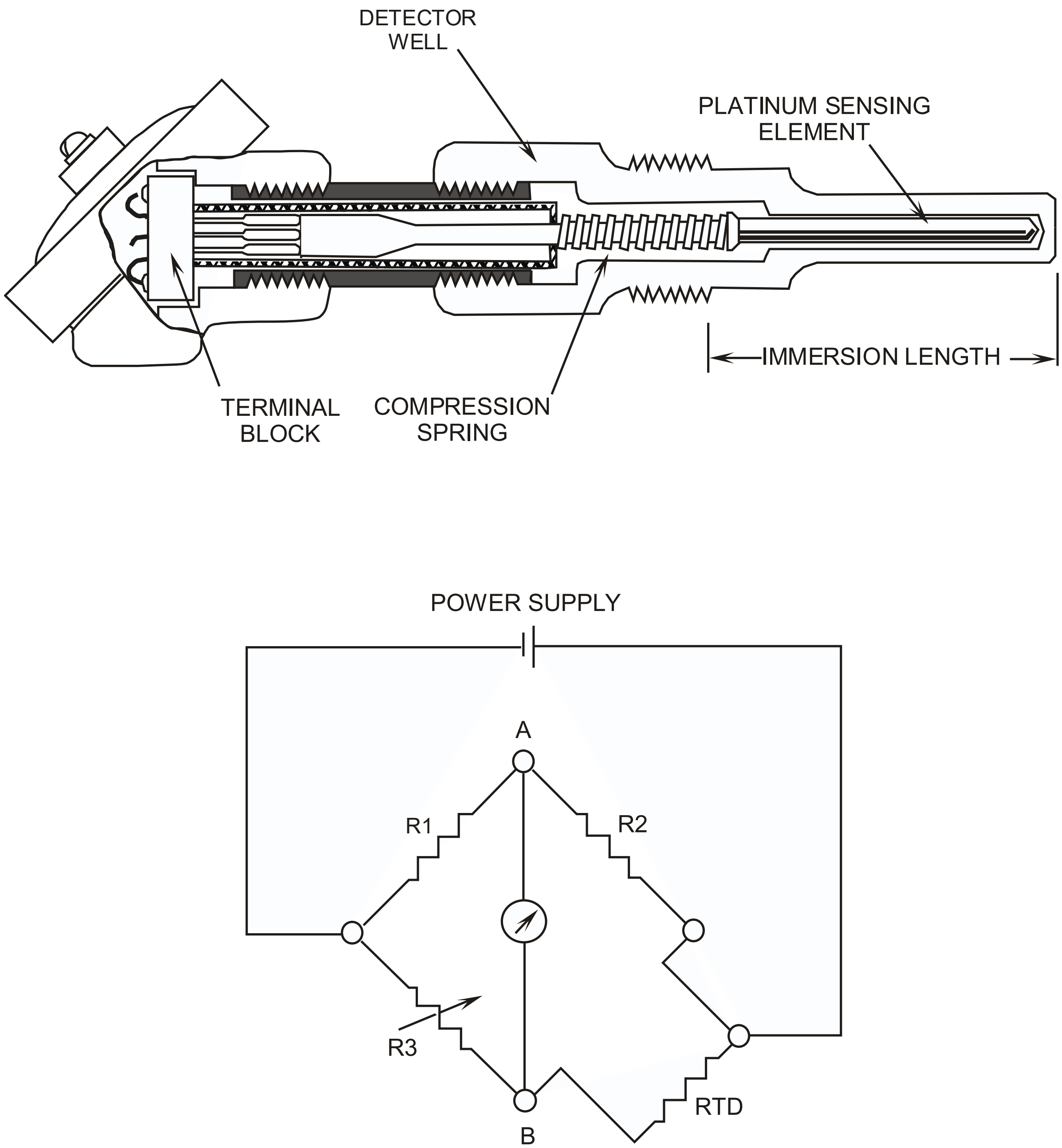

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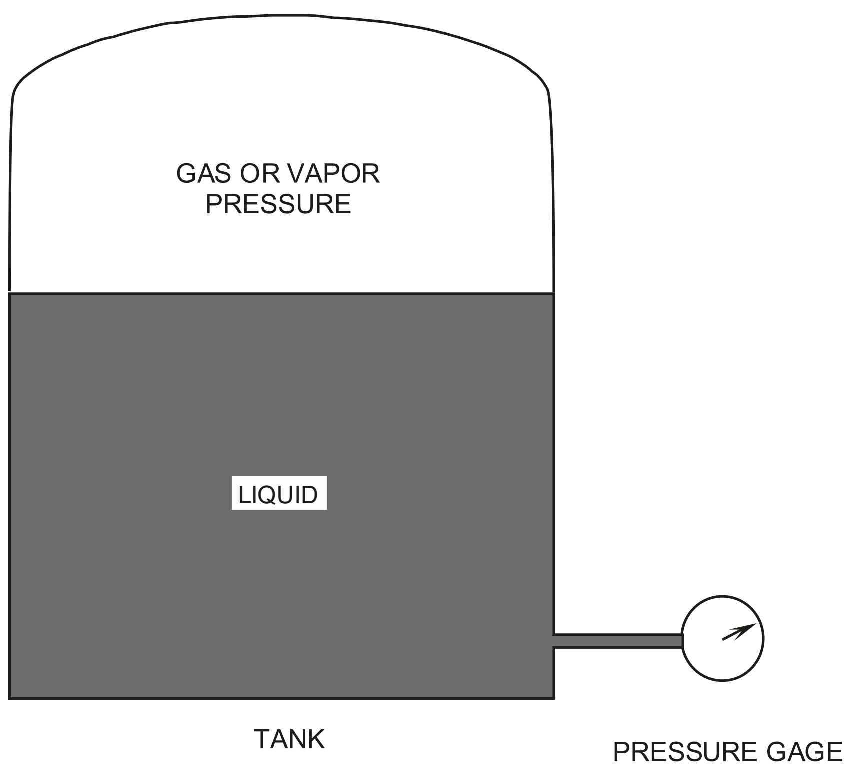

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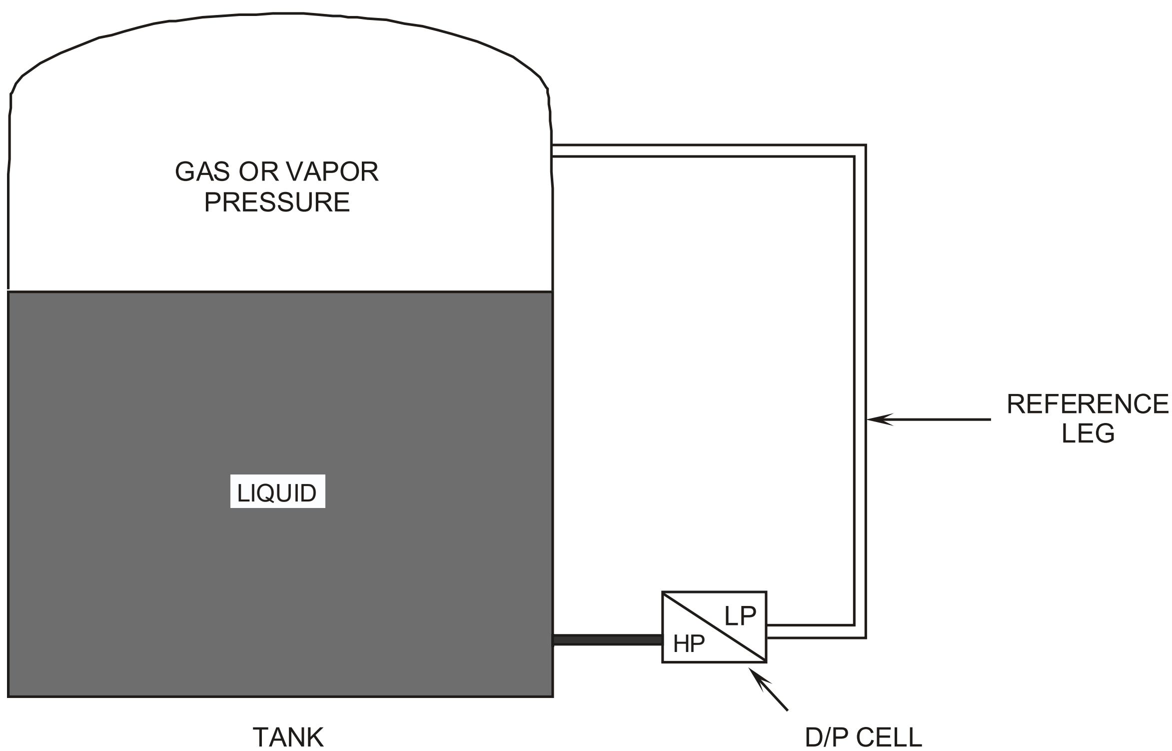

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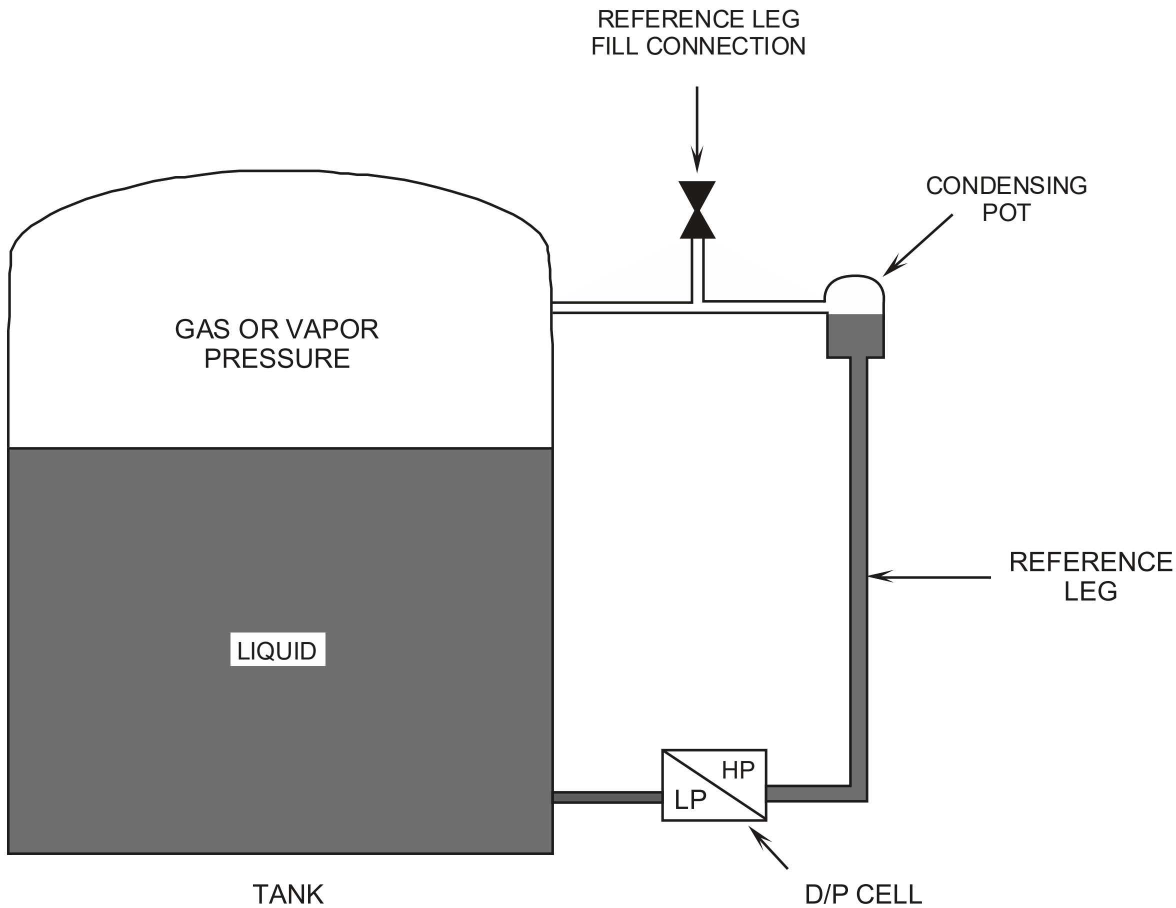

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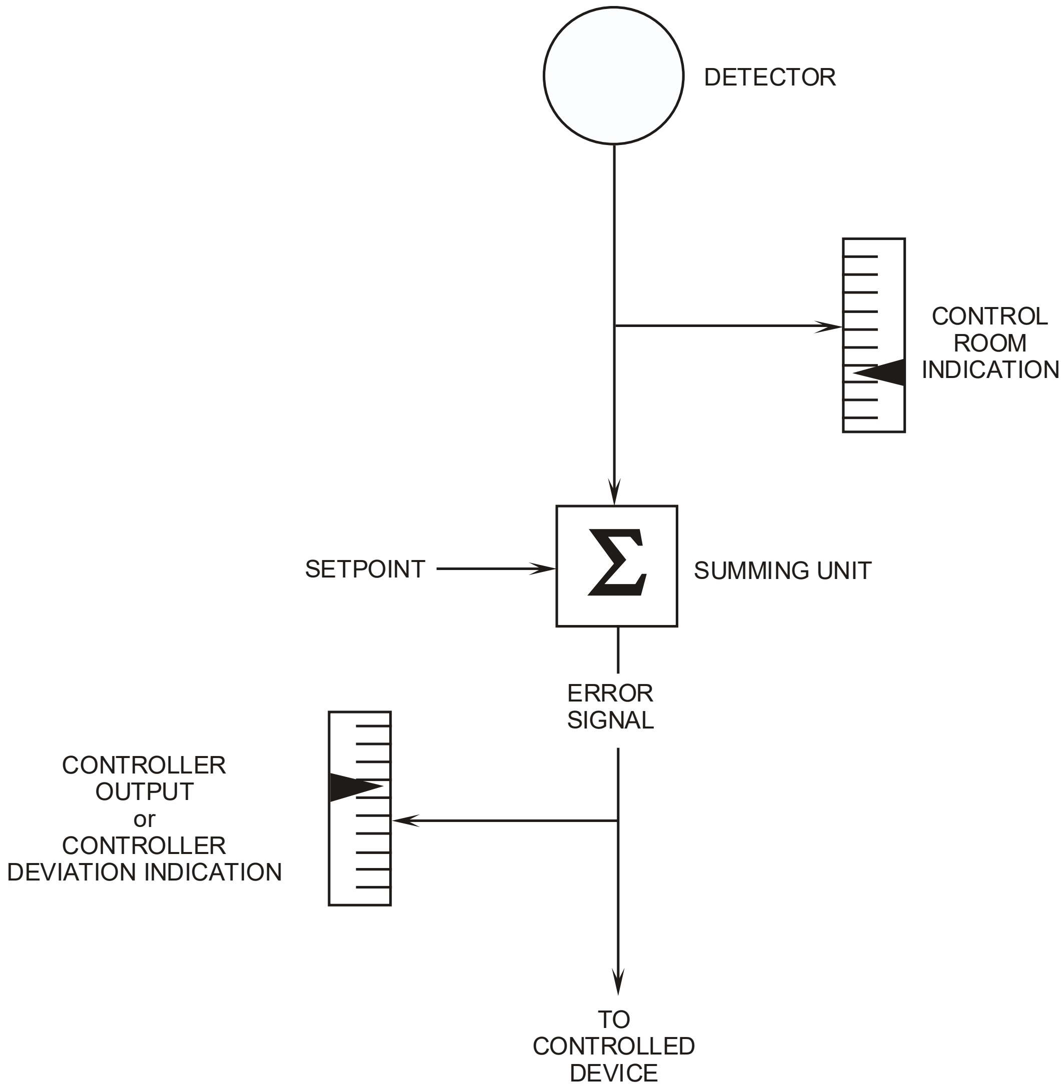

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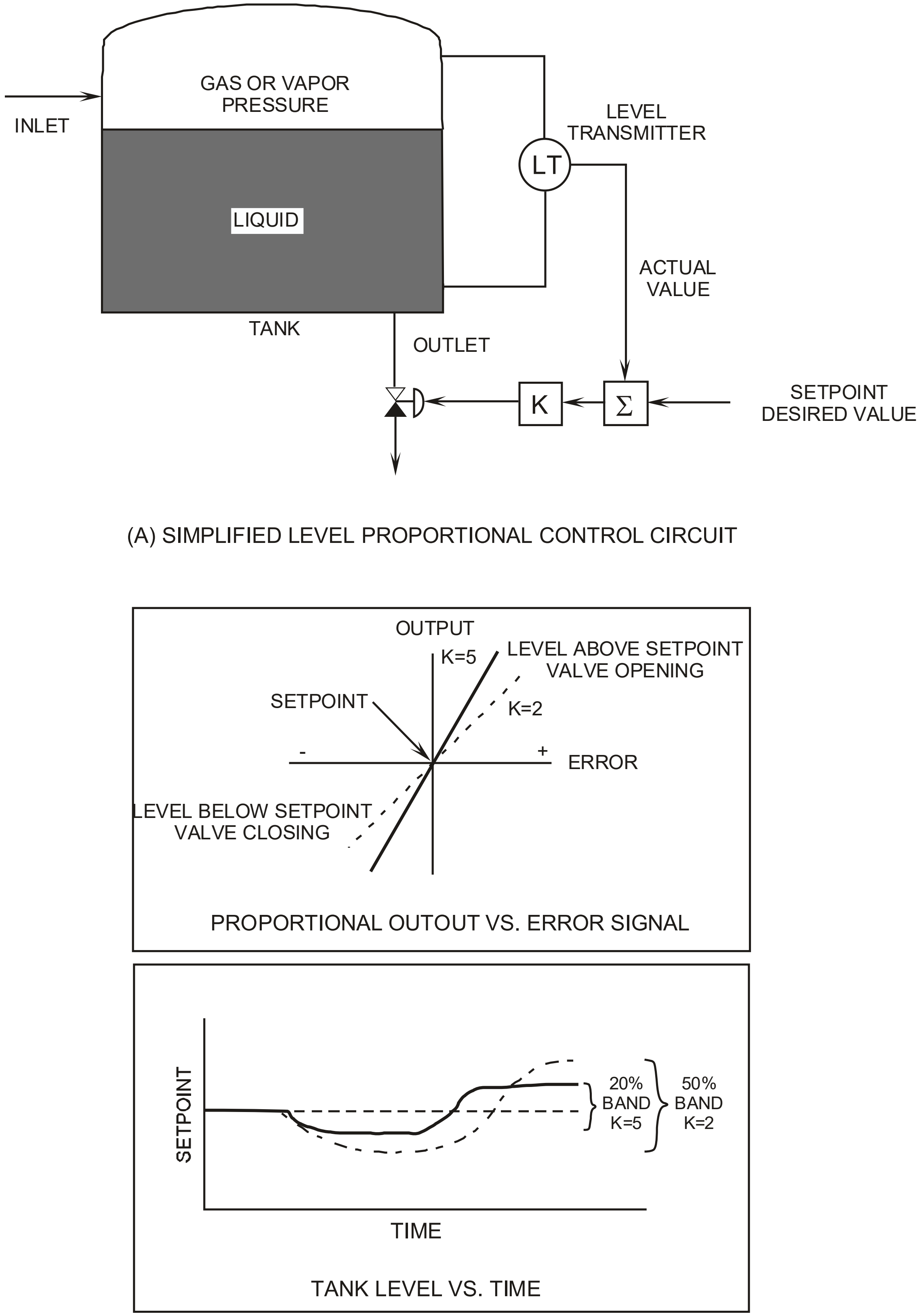

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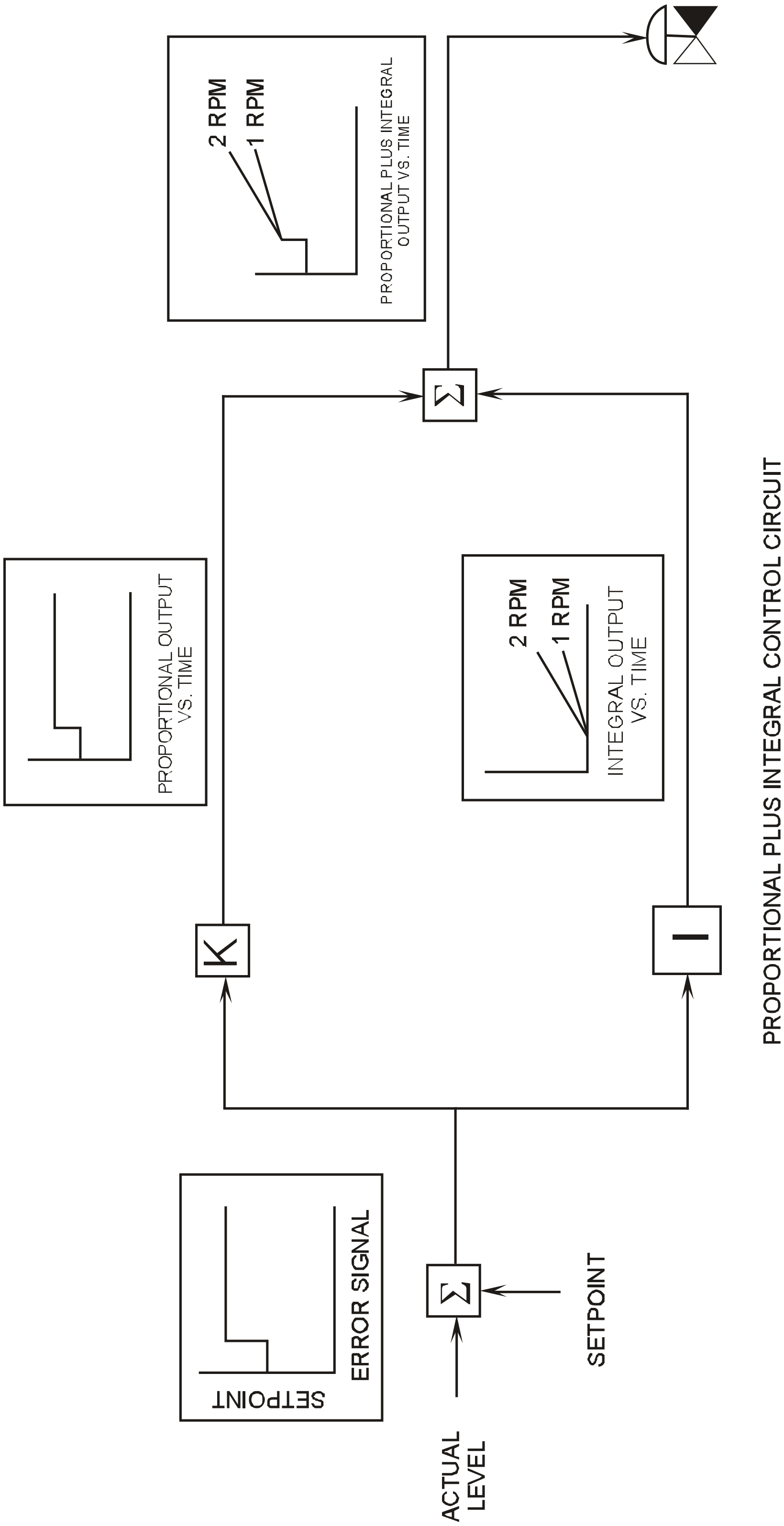

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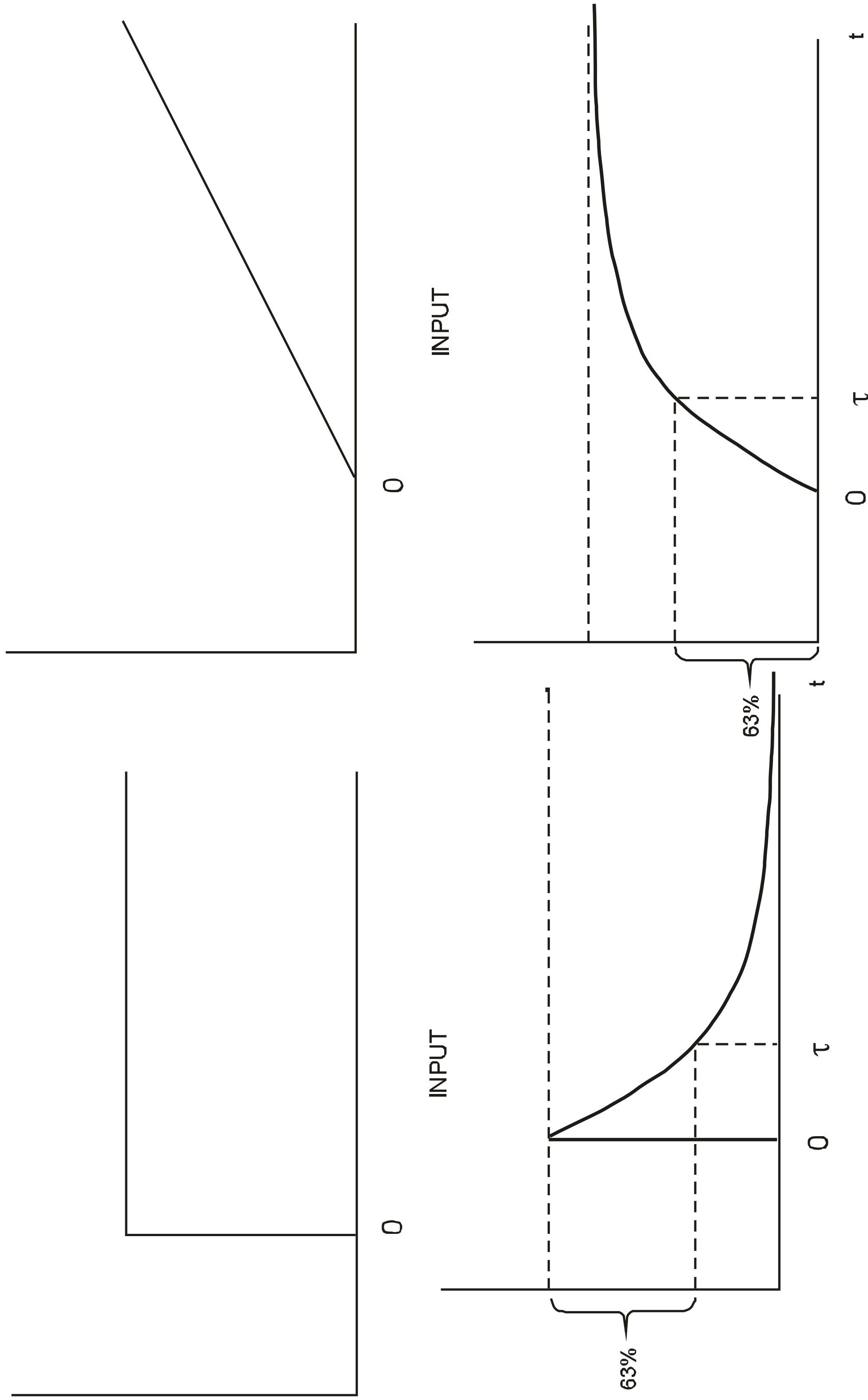

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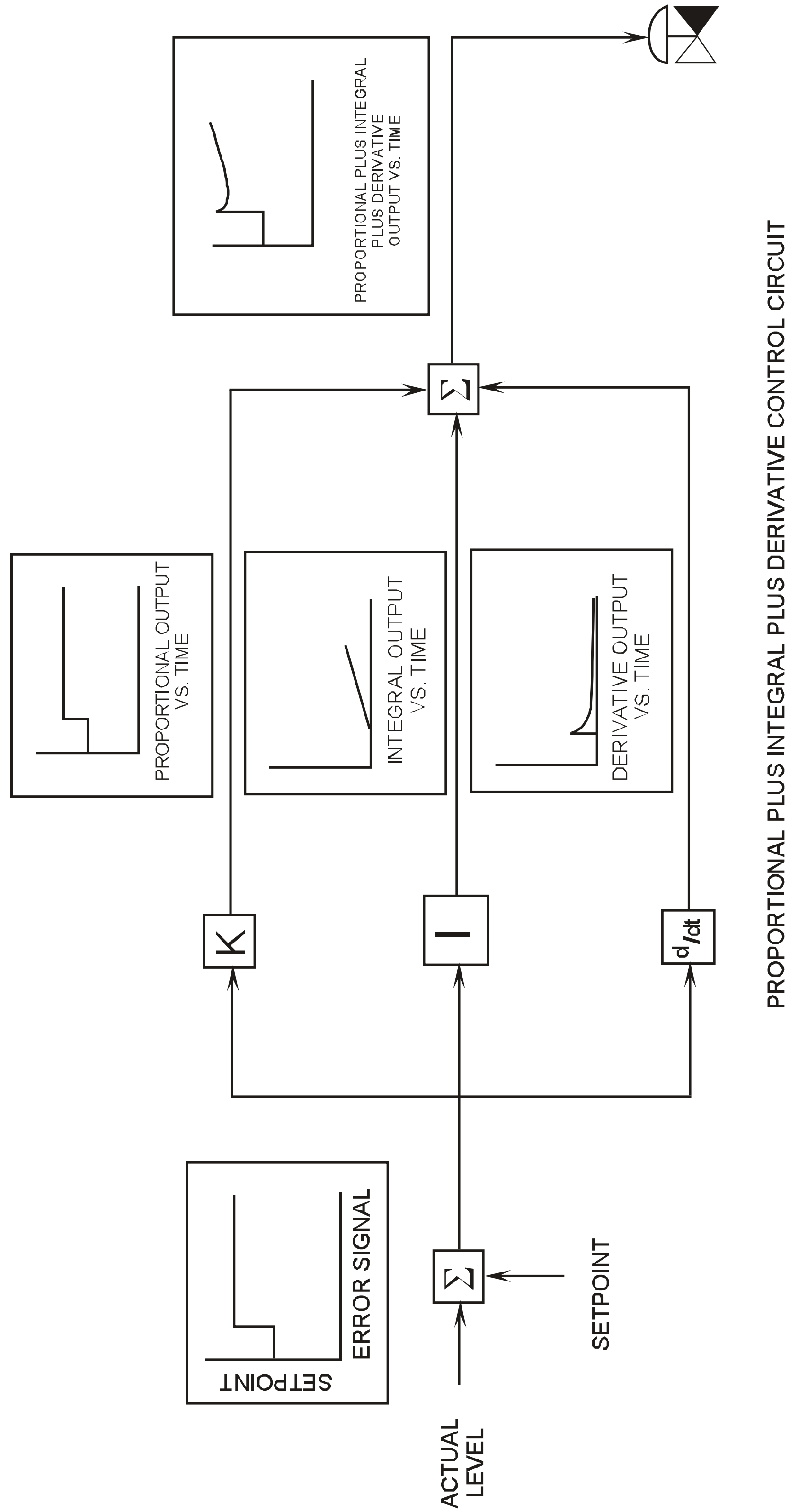

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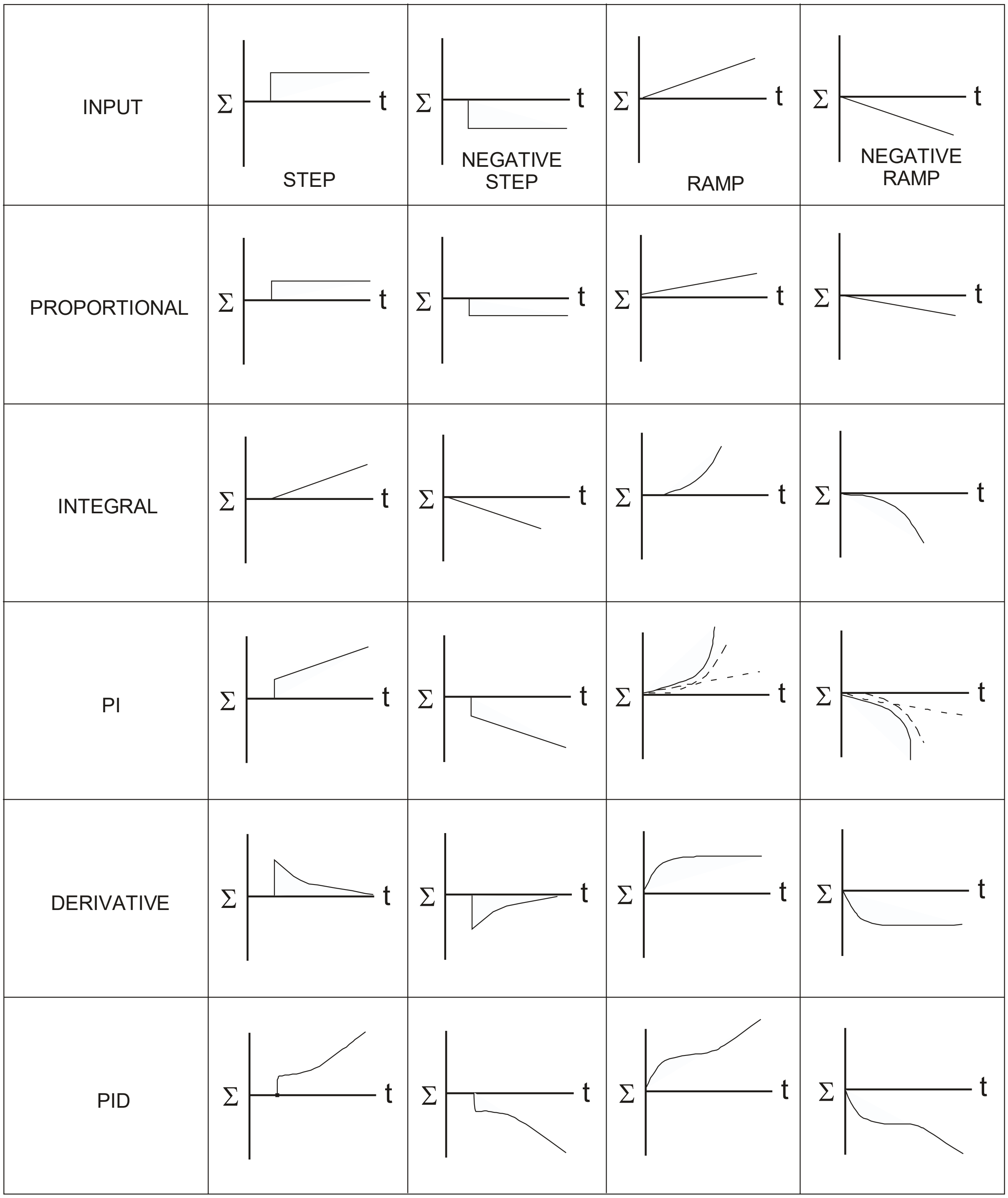

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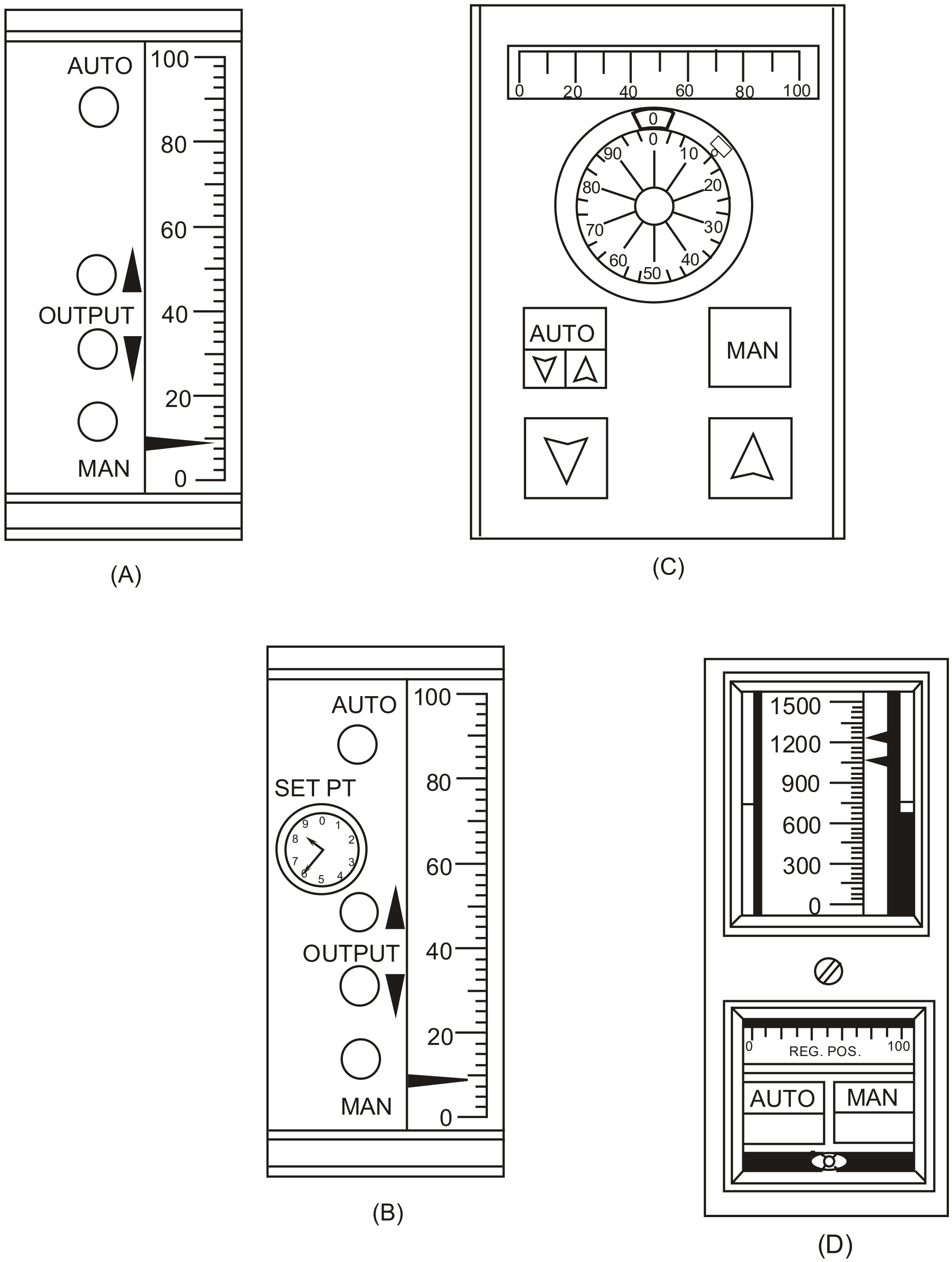

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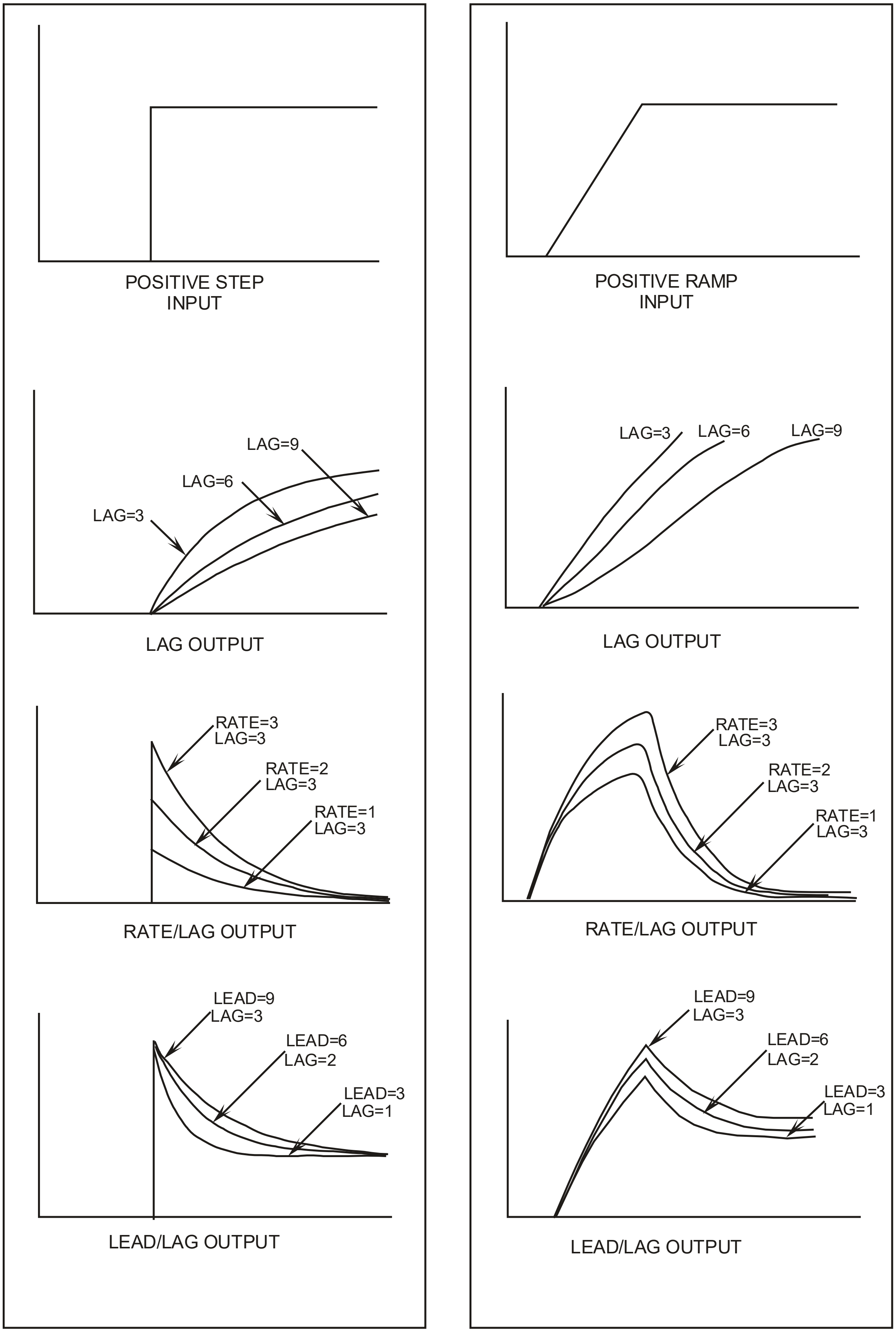

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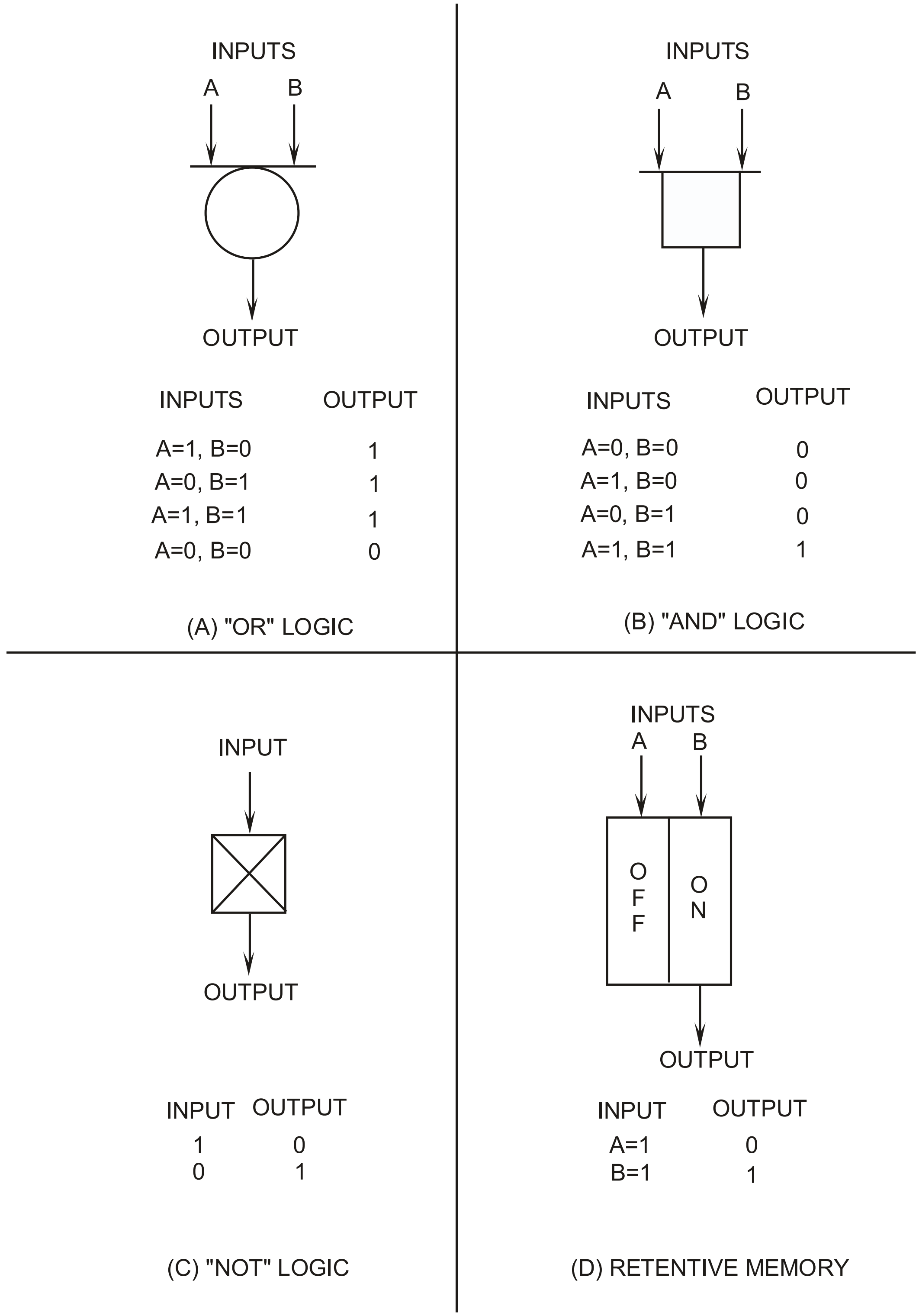

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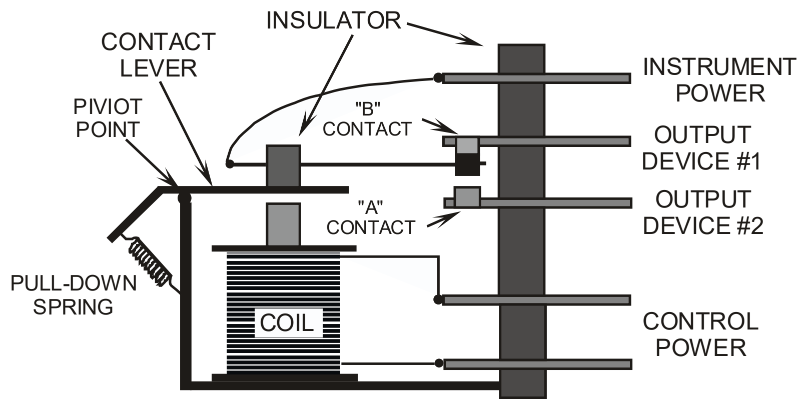
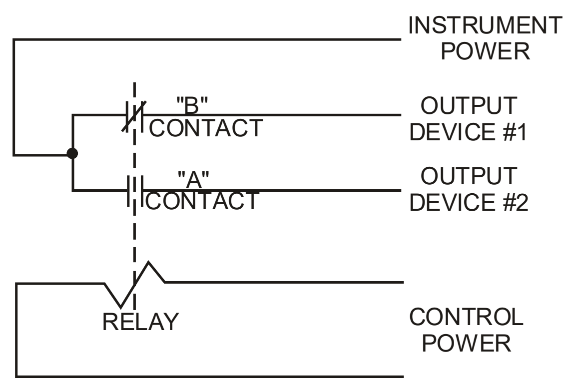


RELAY - MECHANICAL OPERATION

RELAY SHOWN DE-ENERGIZED



RELAY - ELECTRICAL OPERATION

RELAY SHOWN DE-ENERGIZED

Figure 1.3-27 Relay

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Chapter 2

CORE CHARACTERISTICS

Section

2.0 CORE CHARACTERISTICS

This chapter provides an introduction to some of the terms, theories, operations and controls that are used in association with the pressurized water reactor core. The two sections in this chapter are Core Physics, Section 2.1, and Power Distribution Limits, Section 2.2.

Section 2.1, Core Physics, introduces the fission process, which is the heart of heat production in the core. This section discusses the neutron life cycle, from the production of the neutron until it is absorbed within or escapes from the core. The fission process can be affected by both naturally occurring and operator initiated factors. The origin and control of these factors is also be discussed.

Section 2.2, Power Distribution Limits, addresses the need for establishing limits on the power produced in the core. Two major areas of concern in this section are the thermal-hydraulic characteristics and the neutron (power) distribution within the core. In order to preclude any damage to the core during normal operations and to limit the amount of core damage under accident conditions, licensing limits are placed upon the operation of the core. These limits are discussed in this section.

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Section 2.1

Reactor Physics Review

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2.1 REACTOR PHYSICS REVIEW

Learning Objectives:

1. Define the following terms:

    a. K_{eff}
    b. Reactivity
    c. Reactivity coefficient
    d. Power defect
    e. Poison
    f. Critical
    g. Supercritical
    h. Subcritical
    i. Startup rate

2. Describe the following reactivity coefficients and explain how their values change with core life and reactor power level:

    a. Moderator temperature
    b. Doppler-only power
    c. Void
    d. Power

3. Explain the relative effects of the following poisons in plant operations:

    a. Xenon
    b. Samarium

4. Explain how the following controllable poisons affect core reactivity:

    a. Control rods
    b. Chemical shim

5. Explain the inherent response of the reactor to the following transients:

    a. Secondary load changes
    b. Reactivity additions from control rod motion or boron concentration changes

6. Explain how the neutron population of a subcritical reactor changes in response to reactivity changes.

2.1.1 Introduction

This section represents a summary of basic nuclear physics and nuclear reactor design principles and terminology. The material presented is broader in scope than can be conveniently covered in the classroom time allotted; therefore, all the written material is not covered in detail. Basic explanations and definitions of concepts are given in the classroom. It is emphasized that the written material is only a summary of the subject.

2.1.2 Fission Process

Nuclear fission is the splitting of the nucleus of an atom into two or more separate nuclei accompanied by the release of a large amount of energy. The reaction can be induced by a nucleus absorbing a neutron, or it can occur spontaneously, because of the unstable nature of some of the heavy isotopes. Very few isotopes have been excited to the state where the fission reaction occurs. These have been in the heavy elements, generally uranium and above on the chemical scale.

Nearly all of the fissions in a reactor are generated in the fuel by neutron absorption, which can result in the splitting of the fissionable atoms that make up the fuel. Only a few of the heavy isotopes are available in quantities large enough or present a sufficient probability of fission to be used as reactor fuel. These are uranium-233 (U-233), uranium-235, (U-235), uranium-238 (U-238) for fast or high-energy fission only, plutonium-239 (Pu-239), and plutonium-241 (Pu-241). Several other isotopes undergo some fission, but their contribution is always extremely small. U-235 and U-238 are naturally occurring isotopes with very long half-lives; they are generally the fuels used for reactors. Artificially produced fuels include U-233, which is produced by the irradiation of thorium-232 (Th-232) in a reactor, and Pu-239 (produced by irradiation of U-238 in a reactor). Th-232 and U-238 are called fertile materials and are generally placed in the core or in a blanket surrounding the reactor for the express purpose of producing fuel (fissionable material) as the original fuel is used up in fission. The ratio of the amount of fuel that is produced in a reactor to the amount that is used during any period of time is called the conversion ratio of the reactor. If the amount of fuel produced is greater than the amount consumed, then the excess fuel produced is called a breeding gain. The fissile nucleus absorbs a neutron, and almost immediately, fission occurs. In the case of U-235, the reaction is represented by the following:

U-235 + n --> (U-236)*

(U-236)*--> FP_1 + FP_2 + 2.43 n + Energy

where FP = fission product,

n = neutron, and

"*" indicates the isotope is unstable.

In atomic studies it has become the practice to express energies in "electron volt" units, abbreviated "eV." It has been determined that gamma energies are frequently on the order of a million electron volts (MeV); the MeV has thus become a convenient unit for stating these (and related) energies.

The fission of any of the fissionable isotopes produces gammas, neutrons, betas, and other particles. The total energy released per fission is about 207 MeV for U-235; this energy is distributed as shown in Table 2.1-1.

The energy of the neutrinos, which accompany the radioactivity, is not available for producing power because these particles do not interact appreciably with matter;

thus, the net energy available is 197 MeV, or roughly 200 MeV per fission. Table 2.1-1 lists the particles and the energy each particle produces per fission event.

Neutron production (neutrons per fission) varies with the different fissionable isotopes and with the energy at which the fission reaction is caused to take place. Table 2.1-2 shows some relative values for neutrons per fission for some of the common fuels that are now being used in reactors.

More than 99.3% of the neutrons produced are produced within 10^{-14} seconds; these are called prompt neutrons. It should be noted that each fission event does not produce the same number of neutrons. The number of neutrons per fission given in the referenced table represents an average number produced per fission.

The neutrons released from fission are not monoenergetic neutrons (neutrons having a single energy); they vary in energy from essentially thermal energy up to about 15 MeV. The energy distribution of these prompt neutrons is shown in Figure 2.1-1. The horizontal axis shows the range of prompt neutron energy distribution in MeV and the vertical axis shows the fractional neutron distribution in an incremental band (delta) around a selected energy level. The units for the vertical axis are fractional distribution per MeV. It can be seen that the area under the curve in an incremental band around 0.65 MeV yields the highest fraction of neutrons. Using the area under the curve it can also be seen that approximately 98% of all prompt neutrons are born at an energy level less than 8 MeV, and the average prompt neutron energy is approximately 2 MeV.

2.1.3 Moderation

In an actual operating reactor, the probability of fission for typical reactor fuels is dependent on the energy of the incident neutrons. Fission neutrons are born fast (at high energies), and the probability that they will cause a fission in U-235 at that energy is very small. It is necessary to reduce this kinetic energy in order to increase the chance that they will cause fission. This is accomplished by interposing relatively non-absorbing nuclei as collision media to absorb the kinetic energy of fission neutrons through the process of elastic scattering. This medium is called the “moderator.” It acts to slow down or “thermalize” the fission neutrons.

Typical moderators are hydrogen, beryllium, and carbon. It should be clear that fewer collisions are necessary in a hydrogen medium to cause complete moderation than in carbon, since the nuclear mass of hydrogen is smaller and therefore more likely to absorb the kinetic energy of the neutron by the elastic scattering process.

The amount of moderator in a multiplying system (a reactor, for instance) greatly influences the degree of slowing down that occurs. If there is too little moderator, the neutrons are not adequately slowed down. Therefore, the probability of fission is small when compared with optimum. If there is too much moderator, then the probability that a thermal neutron will be captured by the moderator (or some other nonfissionable material) is greatly increased. Figure 2.1-2 shows a snapshot of the neutron energy spectrum for a light water moderated reactor. The horizontal axis is neutron energies in electron volts (eV) on a logarithmic scale, while the vertical axis is the neutron flux per unit energy. Neutron flux, ϕ, is the product of the neutron density (typical unit of measurement: neutrons/cm^3) and the neutron velocity (typical unit: cm/sec), and is usually expressed in terms of neutrons/cm^2•sec. As shown in this figure two peaks occur. The first peak is at fast neutron energies due to the prompt neutron production (within 10^{-14} sec) of the fission events. The second peak occurs at thermal neutron energy levels. This is caused by the diffusion of the thermal neutrons until they are absorbed by either a poison or the U-235 fuel. The time it takes a neutron to slow down from fast to thermal energy is relatively short, 5 microseconds, as compared to the thermal diffusion time of 210 microseconds. This results in a relatively low number of intermediate energy neutrons and the peak at the thermal energy level.

2.1.4 Nuclear Cross Section

The previous discussions of neutron reactions alluded to the fact that they have different probabilities of occurrence. A measure of the relative probability that a given reaction will occur is defined as the cross section of the nucleus for that specified reaction. More precisely, this measure is referred to as the microscopic cross section. In an approximate sense, the microscopic cross section may be considered as the effective area for interaction that the nucleus presents to the neutron.

The microscopic cross section has units of area (cm^2), and it is often expressed in units of barns (1 barn = 10^{-24} cm^2) for ease of manipulation. The microscopic cross section is represented by the symbol σ. It is made up of several component parts. The total cross section, σ_T is a combination of σ_c (capture), σ_s (scattering), and sometimes σ_f (fission), given by:

$$\sigma = \sigma_T = \sigma_c + \sigma_s + \sigma_f$$

where:

σ_c is the area presented for neutron capture; a neutron approaching an atom is exposed to an area of this apparent size.

σ_s is the area of the nucleus that will scatter or deflect the neutron.

σ_f, present in only a few of the many hundred nuclei, is the area that is presented for a neutron to strike the nucleus and cause a fission to occur.

These component cross sections are a function of the target nucleus (U-235, boron-10, etc.) and the incident neutron's energy (thermal, epithermal, or fast). In general, the probability of a given reaction is determined by the neutron's energy. The probability of absorption of neutrons for fission tends to follow an inverse velocity trend. Figure 2.1-3 shows this general trend in U-235. The horizontal axis is neutron energy in electron volts (eV) on a logarithmic scale, while the vertical axis is total neutron cross section (fission, capture, and scattering) in barns. For energy levels above 100 eV, the predominant cross section is scattering. The neutrons collide with and bounce off the nucleus, but no further interaction takes place.

The peaks in the middle of the curve are due to resonance capture. A qualitative explanation of resonance capture relates to the fact that nuclei have discrete excited states. If the energy of the incident neutron is such that the energy of the resultant compound nucleus is equal to one of these states, then the neutron has a high probability of being captured with no resultant fission. These discrete energies determine where these isotopes will have abrupt increases in their capture cross sections. These spikes in the cross-section curve are referred to as resonance peaks.

Light element resonances are not as observable, since their peaks are very broad and give the effect of a smooth curve. Below 1 eV the predominant cross section is the fission cross section. The probability of fission increases as the energy level of the neutron decreases. This is referred to as the 1/v region and is approximately a linear function.

The total effective cross section presented by all of the nuclei of a given isotope in a cubic centimeter is referred to as the macroscopic cross section (Σ):

$$\Sigma = N\sigma$$

where N = the number of individual atoms (or nuclei) per cubic centimeter.

The macroscopic cross section has dimensions of reciprocal length (cm^{-1}). It is sometimes convenient to consider the macroscopic cross section as the probability of neutron interaction per unit track length. The reciprocal of Σ is called the neutron mean free path (denoted by λ); it is a measure of the average distance a neutron will travel in the substance before it experiences the nuclear reaction under consideration. If a material contains several isotopes (i.e., a compound or a naturally occurring material with several isotopes), then the effective macroscopic cross section is:

$$\Sigma_T = \Sigma_1 + \Sigma_2 + \ldots + \Sigma_i$$

$$= N_1\sigma_1 + N_2\sigma_2 + \ldots + N_i\sigma_i$$

2.1.5 Neutron Multiplication

This chapter has thus far discussed the fission process, moderation, and cross sections. In this section, these three topics are combined into the quantity called the “multiplication factor,” which describes all the possible events in the life of a neutron and effectively describes the state of a nuclear reactor.

The multiplication factor in a nuclear system is a measure of the change in the fission neutron population from one neutron generation to the subsequent generation. If the multiplication factor for a reactor core (or any nuclear assembly) is less than 1.0, a condition known as subcritical, then the system is decaying or dying out and will never be self-sustaining. With a multiplication factor greater than 1.0, a condition referred to as supercritical, a nuclear system is producing more neutrons than are needed to be self-sustaining and is subjected to an increasing chain reaction that must be controlled by some exterior factor. The stable or critical condition of a nuclear system occurs when the multiplication factor is equal to 1.0

and there is no change in neutron population from one generation to the next. The effective multiplication factor is defined as:

$$K_{eff} = \varepsilon L_f p L_{th} f \eta$$

These symbols are defined and considered in detail in the following paragraphs.

In reactor operation, K_{eff} is the most significant property with regard to reactor control. At any specific power level or condition of the reactor, K_{eff} is kept as near to the value of 1.0 as possible. At this point in operation, the neutron balance is kept to exactly one neutron completing the life cycle for each original neutron absorbed in the fuel. An example of this balance is shown in Table 2.1-3.

The operational factors that affect reactor control are all-important because of the ways that they change the factors that make up K_{eff}. If any one of the contributing factors to K_{eff} (Table 2.1-3) changes, the ratio of 1.0 is not maintained. This resultant change in K_{eff} makes the reactor either subcritical or supercritical.

2.1.5.1. Fast Fission Factor

The fast fission factor, ε, is the contribution to neutron multiplication from the fissions that occur at higher-than-thermal energies. This contribution is from the fast fission in U-235 and U-238. The probability for a fission reaction in U-238 is relatively low, but there is so much of this isotope in the reactor core that there is a contribution to the multiplication factor. The fast fission factor is defined as the ratio of the neutrons produced by fissions at all energies to the number of neutrons produced in thermal fission. As core temperature is increased, the value of ε is increased because more fast neutrons are present to cause fission the U-238 due to poorer moderating properties of the water. There is only a slight, almost insignificant, change over the core lifetime due to loss of U-238 by conversion to Pu-239.

2.1.5.2. Fast Nonleakage

The fast nonleakage factor, L_f, is the fraction of neutrons that is not lost due to leakage from the core system during the slowing down process from fission energies to thermal energies. It is also the probability that a neutron will remain in the core and become a thermal neutron without being lost by fast leakage. It is represented by:

$$L_f = \frac{\text{the number of fast neutrons that do not leak from the reactor core during the slowing down process}}{\text{the number of fast neutrons produced by fissions at all energies}}$$

As the temperature of the core increases, L_f decreases because of the increase in how far fast neutrons travel before being thermalized. The change in L_f over core life is almost insignificant; a change in L_f would be primarily due to a change in the core's metal-to-water ratio, which is relatively constant as the core ages.

2.1.5.3. Resonance Escape Probability

The resonance escape probability, symbolized by p, is the probability that a neutron will be slowed to thermal energy and will escape resonance capture. It is also the fraction of neutrons that escape capture during the slowing-down process. It is always less than 1.0 when there is any amount of U-238 or Pu-240 present in the core, which means that high-energy capture by these isotopes always removes some of the neutrons from the neutron life cycle.

As the reactor temperature increases, the resonance escape probability decreases in value because of the decrease in the ratio of the water-moderating atoms to fuel atoms and the broadening of the resonance capture cross sections. The resonance escape probability increases with core lifetime due to the decrease in fuel temperature. These changes in the resonance escape probability will be discussed further in section 2.1.6.1, "Fuel Temperature Coefficient."

2.1.5.4. Thermal Nonleakage Factor

The thermal nonleakage factor, L_{th}, is the fraction of the neutrons that do not leak out of the core during the neutron diffusion (thermalization) process but remain to contribute to the chain reaction. L_{th} is also the probability that a thermal neutron will remain and be utilized in the core.

$$L_{th} = \frac{\text{the number of neutrons that do not leak from the reactor core during the neutron diffusion (thermalization) process}}{\text{the number of neutrons that reach thermal energies}}$$

As the temperature of the core increases, L_{th} decreases because of the increase in how far neutrons travel before being thermalized. As the core is operated and fuel is consumed, the value of L_{th} decreases as a result of fuel burnup.

Since the core is very large compared to the travel distance of neutrons, leakage plays an almost insignificant role in reactor response.

2.1.5.5. Thermal Utilization Factor

The thermal utilization factor, f, is the ratio of the probability that a neutron will be absorbed in the fuel (fissile nuclides) to the probability that the neutron will be absorbed in all the material that makes up the core. This factor is the one that the plant operator has the greatest control over. It is described by the following equation:

$$f = \frac{\Sigma_a(\text{fuel})}{\Sigma_a(\text{fuel}) + \Sigma_a(\text{other})}$$

where Σ_a= macroscopic absorption cross section, which is the sum of the capture cross section, Σ_c, and the fission cross section, Σ_f.

$$\Sigma_a = \Sigma_c + \Sigma_f$$

An examination of the thermal utilization factor shows that the Σ_a (fuel) comprises only the absorption by the U-235 at the beginning of core life. As the amount of Pu-239 increases because of the irradiation of U-238 in the core, it is necessary to consider the change of fuel concentration in determining the value of f at different times in the core lifetime. The reactor operator can change Σ_a(other) by positioning of the control rods and by addition or removal of boric acid from the moderator.

2.1.5.6. Neutron Production Factor

The neutron production factor, η, is the average number of neutrons produced per thermal neutron absorbed in the fuel (fissile nuclides). It is based on physical measurement for each type of fuel used in a reactor.

The numerical value of η does not change with core temperature over the range considered for most reactors. There is essentially no change in η over the lifetime of the reactor core because the values for U-235 and Pu-239 are very close.

2.1.6 Reactivity and Reactivity Coefficients

In reactor physics, it is more convenient to use a term called reactivity rather than K_{eff} to describe the state of the reactor core. Reactivity (ρ or $\Delta K/K$) is defined in terms of K_{eff} by the following equation:

$$\rho = \frac{K_{eff} - 1}{K_{eff}}$$

Based on this equation, when K_{eff} is equal to 1.0, the reactivity of the core is zero, and the reactor is said to be critical. If K_{eff} is less than 1.0, reactivity of the core is negative, and the reactor is subcritical. Values of K_{eff} greater than 1.0 make the reactivity positive, and the reactor would be supercritical.

Mathematically, reactivity is a dimensionless quantity, but units are commonly applied. The most common units are %ΔK/K and pcm. A reactivity of 0.01 could be expressed as 1 %ΔK/K or 1000 pcm.

As any operating condition of the moderator or fuel (temperature, pressure, or void fraction) changes, the reactivity of the core changes accordingly. It is difficult to change any operating parameter and not affect every other property of the core. Once a change has been made to the core, it is necessary to make some compensating change to maintain criticality at the same power. For instance, assume that the reactor is critical at 50% power and that the reactor operator wants to increase power to 75%. The operator must first bring the reactor supercritical by making a positive reactivity change (control rod withdrawal or boron dilution) to initiate the power increase. As the power increases, the values of core parameters such as moderator temperature and fuel temperature change, causing a negative reactivity effect. If the added negative reactivity offsets the original positive reactivity change, then the reactor returns to the critical condition, and power stabilizes at the new value. The inherent properties of a reactor system that result in positive or negative reactivity additions upon changes in certain parameter values are generally described by reactivity coefficients.

A reactivity coefficient is defined as the change of reactivity per unit change in some operating parameter of the reactor. The coefficients that are significant in the reactor are the fuel temperature (Doppler) coefficient, moderator temperature coefficient, void coefficient, and pressure coefficient. In addition to these coefficients, one other coefficient is considered. It is called the power coefficient. The power coefficient is the combination of the first three coefficients. Most of the reactivity coefficients for the core are important to the safety of reactor operation because they act in a negative manner to oppose any power change in the nuclear system.

The response of the reactor core to plant conditions or operator adjustments during normal operation, as well as the response to abnormal or accidental transients, is evaluated by means of a detailed plant simulation. In these calculations, reactivity coefficients are required to couple the response of the core neutron multiplication to the variables which are set by conditions external to the core. Since the reactivity coefficients change during the life of the core, a range of coefficient values are established to ensure the correct response of the plant throughout its life.

2.1.6.1. Fuel Temperature Coefficient

The fuel temperature coefficient, also called the Doppler coefficient of reactivity, is the reactivity change per degree change in fuel temperature; it exists because the resonance cross sections of the fuel change with a change in fuel temperature. It is related to the resonance cross section broadening of some fuel materials, principally U-238 and Pu-240. Figure 2.1-4 is a plot of the total cross section vs. energy levels for the resonance region of U-238. The solid line represents the cross section of the fuel at cold temperatures (547°F). The dashed line represents the cross section of the fuel at hot temperatures (1500°F). As the temperature of the fuel increases, the heights of the resonance peaks decrease, and the bases of the peaks broaden. The broadened peaks result in a larger percentage of neutrons having energies that are susceptible to capture in the fuel pellets. With colder fuel, only neutrons very close to the resonance-peak energy are absorbed. With hotter fuel, neutrons that are only somewhat close to the resonance-peak energy are also absorbed. Although the probability of resonance absorption by any particular fuel nucleus is unchanged at the hotter temperature, a neutron near a resonance energy must “run the gauntlet” of concentrated resonance absorbers (nuclei with fairly large absorption cross sections) in a fuel pin and thus will not avoid capture. This phenomenon leaves fewer neutrons per generation to cause fissions and is thus a negative reactivity effect.

Figure 2.1-5 is a plot of Doppler coefficient vs. effective fuel temperature. The effective fuel temperature is a weighted average temperature. The temperature profile across the fuel pellet makes this temperature lower than the average temperature and closer to the temperature the neutrons will be exposed to when they interact with the fuel. The terms BOL and EOL represent beginning of life and end of life. For this discussion and all others that follow, this is equivalent to new unirradiated fuel (BOL), and the fuel at the end of the first core cycle (EOL). Note that the EOL case is more negative than the BOL case for cooler fuel temperatures. This is caused by the buildup of plutonium-240, which has a higher cross section at lower temperatures. The difference at higher temperatures is minimal due to the broadening of the resonance peaks. Note that the Doppler coefficient is always negative.

In the event of an addition of a positive reactivity to the reactor core, the Doppler coefficient of reactivity would be the first and most important effect in controlling that addition. It is effective almost instantaneously, because an addition of positive reactivity causes the fission rate to increase and produce more heat in the fuel, which in turn causes an addition of negative reactivity. As quickly as the heating rate is increased, the Doppler coefficient becomes effective.

Since the effective fuel temperature cannot be measured, the Doppler-only power coefficient used for reactor transients is a function of power. The Doppler coefficient used in the remainder of this text is defined as the change in core reactivity as the result of a change in the reactor power level. It is in units of $\Delta\rho/\Delta\%$power, or change in reactivity per percent change in power. Figure 2.1-6 shows the Doppler-only power coefficient as a function of power. The results presented do not include any moderator coefficient even though the moderator temperature changes with power level.

The numerical value of the Doppler-only power coefficient changes with both reactor temperature and time in core life. As fuel temperature is increased, the U-238 resonance peaks broaden. However, the rate of broadening diminishes at higher temperatures, yielding a Doppler-only power coefficient with a smaller negative value at higher reactor power levels. Three important factors influence the Doppler-only power coefficient during core lifetime; these are: thermal conductivity of the gases in the gap between the fuel and the cladding, plutonium production, and fuel-clad gap reduction. Dealing with these factors one at a time will lead to the conclusion that the Doppler-only power coefficient is more negative at BOL than it is at EOL.

1. Initially the fuel rods are pressurized with helium gas, which yields a given fuel-clad gap thermal conductivity coefficient, but as fission gases such as xenon and krypton are produced, they tend to pollute the helium gas causing a reduction in the fuel-clad gap thermal conductivity coefficient. The result of this is an increased fuel temperature for any given power level, and the Doppler-only power coefficient becomes more negative as the core ages.
2. Plutonium buildup is the result of the conversion of U-238 to the plutonium isotopes. Pu-240 has a large thermal resonance for parasitic capture of neutrons. As Pu-240 builds in, the Doppler-only power coefficient becomes more negative as the core ages.
3. The fuel-clad gap reduction is the most dominant effect, outweighing the other two factors combined. The reduction of the gap between the fuel pellets and the cladding is a result of swelling of the fuel pellets and clad creep. Fuel pellet swelling occurs because fission gases cause the pellet to swell and crack. The

pellet occupies a larger volume. At the same time, the cladding is distorted by outside pressure. These two effects result in direct fuel-clad contact. With direct contact, the overall thermal conductivity increases due to conductive heat transfer, which results in a lower effective fuel temperature for the same power level over core life. This causes the Doppler-only power coefficient to become less negative over core life. In the beginning of life case, the fuel temperature rises approximately 1000°F for a 0-100% power change, or 10°F/% power. For the end of life case with direct fuel-clad contact, the temperature rise is approximately 800°F, or 8°F/%power.

As a result of the three combined effects, the Doppler-only power coefficient will be more negative early in core life and become less negative throughout the rest of core life, resulting in the EOL value being slightly less negative than the BOL value. Consequently, it is less effective for controlling power increases at EOL.

Figure 2.1-7 is a plot of the Doppler-only power defect vs. power. For this discussion and all others that follow, "defect" is defined as the total amount reactivity added to the core due to a change in power. The differences in the BOL and EOL values have been explained in the preceding paragraph. An operator would use this graph to determine the total amount of reactivity added to the core solely by the change in fuel temperature associated with a desired load change. For example, changing load from 80% to 100% at EOL would result in a Doppler-only reactivity defect of -225 pcm. This value is calculated as follows:

Final reactivity - Initial reactivity = Defect

-1025pcm - (-800pcm) = -225pcm

2.1.6.2. Moderator Temperature Coefficient

The next important reactivity coefficient is the moderator temperature coefficient (MTC). MTC is defined as the change in reactivity per degree change in moderator temperature; it is expressed in pcm/°F.

When the moderator temperature increases, its density decreases, so fewer moderator molecules are available to slow fast and epithermal neutrons and bring them to thermal energy. Decreasing the density of the moderator has two effects. First, if the density of the moderator is less, it increases the leakage probability of the neutrons. Second, if the neutrons are not slowing, they stay at a higher energy for a longer period, which increases the probability of non-fission capture of these neutrons. Both effects together cause a net decrease in the neutron population that adds negative reactivity to the core.

Moderator density changes are not linear. At high temperatures an increase in the moderator temperature causes a larger reduction in density than an identical increase at low moderator temperatures. This is illustrated by the zero (0) ppm curve (bottom curve) in Figure 2.1-8. Notice how the slope of this curve becomes more negative as the temperature of the moderator increases. This is a graphical representation of the non-linear density change of the moderator. This curve also displays the reactivity effect due to a 1°F change in the temperature of the moderator. As shown, if the moderator temperature changes from its present value (horizontal axis), a certain amount of reactivity, in pcm (vertical axis), is added to the core. As an example, using the 0 ppm curve, if the moderator temperature is initially at 500°F and its temperature is increased by 1°F, -17 pcm of reactivity would be added to the core.

Historically, commercial reactors sold by Westinghouse have been designed with a water volume to fuel volume ratio such that the value of the MTC is negative. The negative MTC and the negative fuel temperature coefficient ensure stable power operation of the reactor core. As explained in the previous paragraph, if the temperature of the moderator is increased, negative reactivity is added to the core. This negative reactivity causes reactor power to decrease, which acts against any further increase in temperature or power. Therefore, a condition that could cause an increase in reactor power is limited by the negative reactivity added by the increase in the moderator temperature.

Operating with a negative MTC is desired due to the negative feedback mechanism discussed above and to its favorable operational characteristics during power changes. When the operator increases the load on the turbine, governor valves supplying steam to the high-pressure turbine open. This action increases the steam demand, causing steam pressure, the saturation temperature in the steam generators, and the moderator temperature to decrease. Reducing the temperature of the moderator adds positive reactivity to the core, causing reactor power to increase.

If the secondary load is reduced by the operator, the governor valves on the turbine close, reducing the steam demand of the turbine. The reduced steam demand causes the following to increase: steam pressure, saturation temperature, and the moderator temperature. Increasing the temperature of the moderator adds negative reactivity, which reduces reactor power. Therefore, the two above examples display how reactor power follows secondary steam demand due to the negative reactivity feedback caused by the MTC.

When the reactor is designed, excess reactivity in the form of fuel is added to the core so that it can operate at 100% power for an extended period. With excess fuel added to the reactor, the reactor could be taken critical and power could be escalated with the rods greatly inserted into the core. However, various operating limits require the rods to be fully withdrawn from the core (the all rods out [ARO] condition), so an additional poison must be added to the core. This poison addition is accomplished by adding soluble boron to the reactor coolant. By adding boron to the reactor coolant, negative reactivity is inserted uniformly throughout the core. Since boric acid is dissolved in the coolant, the excess reactivity in the core can be controlled by boron changes without creating flux distribution problems associated with the control rods.

Consider what happens to the MTC when the moderator contains both light water and boron. Boron is a poison. When it is added to the reactor coolant (moderator), it adds negative reactivity to the core in a similar fashion as the control rods. By adding a certain amount of boron to the reactor coolant, the power of the reactor can be maintained at its desired values of power and temperature with the control rods fully withdrawn from the core.

Although it is true that adding boron to the moderator has a negative reactivity effect on the core's reactivity, it has the opposite effect on MTC. As previously discussed, increasing the temperature of the moderator (0 ppm curve) has a negative reactivity effect. Now consider what happens when the temperature of the boron solution is increased.

During a temperature increase boric acid is expanded out of the core along with the moderator. Since boric acid is a poison, and it is expanding out of the core, positive reactivity is added. (The positive reactivity addition due to the expansion of boron out of the core offsets the negative reactivity addition due to the expansion of the moderator out of the core). As an example, using the 500 ppm curve on Figure 2.1-8, it is shown that for an initial temperature of 500°F, a 1°F increase adds -8 pcm of reactivity.

As explained earlier, -17 pcm was added to the core due to the density decrease of the moderator. For the conditions in the above example the same -17 pcm of reactivity was added to the core via the moderator expansion out of the core, but due to the concurrent expansion of boron out of the core, the net effect was -8 pcm.

The amount of positive reactivity added to the core depends upon the initial concentration of boron in the moderator. With high concentrations of boric acid, the positive effect could be large enough to overcome the negative effect of the moderator loss. In other words, a net positive reactivity addition could result from a moderator temperature increase. At boric acid concentrations greater than approximately 1400 ppm, the MTC is positive.

Once, all Westinghouse-designed cores were required by technical specifications to operate with a negative MTC. This effectively limited the boric acid concentration of the reactor coolant. To reduce the dissolved poison requirement for control of excess reactivity, burnable poisons were incorporated in the core design, as discussed in Chapter 3.1. However, today, utilities are demanding the vendors to design cores that can operate from 18 to 24 months at full power. To operate this long, more fuel and burnable poisons must be added to the core. In addition, the boron concentration also has to increase. The increase in boron concentration is large enough in magnitude that the MTC has become positive. This has resulted in technical specification changes that allow operation of the plant with a positive MTC for certain conditions.

Operating with a positive MTC makes the operating characteristics of the core less stable. Ignoring the effect of fuel temperature changes, consider what would happen if MTC is positive. With a positive MTC, a 1°F increase in moderator temperature adds positive reactivity to the core, causing reactor power to increase. As reactor power increases, more energy is added to the moderator. As the moderator temperature increases, more positive reactivity is added to the core, further increasing power and raising the moderator temperature, etc. Reactor power is thus self-escalating. Fortunately, the fuel temperature coefficient, which is always negative and stronger than the MTC, cannot be ignored. Therefore, the scenario described above (self-escalating reactor power) does not occur.

2.1.6.3. Void Coefficient

The next coefficient of reactivity that acts in response to a reactivity insertion is the void coefficient. It is defined as the change in reactivity as the result of boiling of the moderator in the core region and has the units of $\Delta\rho/\Delta$%void.

The formation of voids in the core has the same effect as the temperature increase of the moderator (decreasing the density of the moderator.) Therefore, the moderating ability of the core is reduced. If the moderator is borated, the decrease in moderator density also reduces the boron concentration. In general, void formation could have a positive or negative effect on reactivity depending on both boron concentration and the departure from the optimum fuel-to-moderator ratio. The void content of the core is about one-half of one percent. The void coefficient varies from -30 pcm/%void at BOL and low temperatures to -250 pcm/%void at EOL and operating temperatures.

2.1.6.4. Pressure Coefficient

The pressure coefficient is the change in reactivity caused by a change in pressure of the primary system. It is affected by the same mechanism that changes the moderator temperature and void coefficients. As pressure increases, the only change that takes place is in the density of the cooling and moderating water. The pressure coefficient is given in units of $\Delta\rho/\Delta P$. The pressure coefficient of reactivity has a slight positive effect on reactivity as the pressure of the system is increased if boron concentration is very low or absent. At high boron concentrations, an increase in pressure produces a slightly negative effect on reactivity.

2.1.6.5. Power Coefficient and Power Defect

The power coefficient combines the Doppler, moderator temperature, and void coefficients. It is expressed as a change in reactivity per change in percent power, $\Delta\rho/\Delta$% power. It is negative at all times in core life but is more negative at the end of life primarily due to the change in the moderator temperature coefficient. Figure 2.1-9 shows the values of the power coefficient vs. percent power at BOL and EOL. This graph can be used to calculate the reactivity change associated with 1% incremental changes in power. Figure 2.1-10 is the integrated power coefficient, or power defect, vs percent power at BOL and EOL. This graph is more useful to the operator for calculating the total reactivity change for any power change.

Operators need to be concerned about the effect of the power defect. As power is increased the power defect has a negative reactivity effect to the core. Therefore, an equal amount of positive reactivity must be added to keep the reactor critical or near critical. This positive reactivity will be in the form of rod withdrawal or boron dilution. When power is decreased quickly, as it will after a trip, power defect is a positive reactivity effect to the core, and the resulting rod insertion must be sufficient to make the reactor subcritical. An alternate method, boron addition, is not rapid enough to overcome this positive reactivity addition.

To ensure that the rods can shut down the reactor, they must be maintained above a minimum rod height. Since the magnitude of the power defect is dependent on total power, the minimum rod height is also increased with increasing power.

2.1.7 Poisons

In a reactor system, poisons absorb neutrons without causing fission. These neutrons are no longer in the neutron life cycle. Control rods and soluble boron are examples of poisons which are controllable. Xenon and samarium are examples of poisons which are uncontrollable.

2.1.7.1. Uncontrollable Poisons

In the fission process the nucleus absorbs a neutron and the resulting nucleus breaks into two or more parts called fission fragments. A detailed investigation of the thermal neutron fission of U-235 has shown that the resultant nucleus splits in many different ways, yielding more than 350 primary fission products (or fission fragments). In Figure 2.1-11, the percent fission yields of U-235 are plotted against the mass numbers. Note that each mass number represents several isotopes.

During power operation, the isotope xenon-135 (Xe-135) is formed as one of fission products. This isotope has an extremely large capture cross section (2.6 million barns). Xe-135 is formed in two ways; directly as a fission product (0.3% of the total fission products) and indirectly from the radioactive decay of tellurium-135 (5.9% of the total fission products). The radioactive decay chain of tellurium-135 is as follows:

$$\text{Te-135} \xrightarrow[19.2\text{ sec}]{\beta^-} \text{I-135} \xrightarrow[6.6\text{ hr}]{\beta^-} \text{Xe-135} \xrightarrow[9.1\text{ hr}]{\beta^-} \text{Cs135 (stable)}$$

Xe-135 is lost in two ways; it can capture a thermal neutron, forming Xe-136, which is stable and has a very small capture cross section, or it can decay to Cs-135. When the reactor is first brought to power, the concentration of Xe-135 (atoms/cm^3) is slowly built up to an equilibrium value. This is due primarily to the relatively long half-lives of iodine-135 (6.6 hours) and Xe-135 (9.1 hours). Because of the high thermal neutron cross section of Xe-135, as the concentration of the isotope increases, the macroscopic absorption cross section of the core increases.

Operationally, as Xe-135 builds up, other poisons in the core (control material such as control rods or boric acid) must be removed to maintain criticality. Provided there is enough control material to remove during this xenon buildup, equilibrium will be reached after approximately 48 hours of power operation. After this 48-hour time period a condition is reached where the production of Xe-135 is equal to the removal of Xe-135 by neutron capture plus the loss of Xe-135 through radioactive decay.

The equilibrium value for the amount of xenon in the core at any time is a function of the reactor's neutron flux (power) (see Figure 2.1-12). Since a neutron absorber (poison) is added to the reactor when xenon is built into the system, its effect on the chain reaction can be described in terms of reactivity. The multiplication factor is lowered primarily through the decrease in thermal utilization with a secondary effect on the thermal nonleakage probability caused by decreasing the thermal diffusion length. The reactivity effect can be shown to be approximately equal to the ratio of the macroscopic absorption cross section of the xenon to that of the fuel.

A change in power will cause a transient in xenon concentration. At the end of the transient, which will take about 2 days, the xenon concentration will reach its new equilibrium, assuming that power is left constant after the change. Three cases will be discussed: a power increase, a power decrease, and a shutdown.

Referring to Figure 2.1-13, following a xenon-free startup, a reactor has reached an equilibrium xenon concentration (time = 48 hr), and then power is increased. There is only a small increase in production of xenon because the production as a direct fission product is small (about 0.3%), and the iodine concentration cannot change very quickly, so the production by decay of iodine remains practically constant. Removal of xenon is increased significantly due to increased burnout (xenon absorbs neutrons). The decay of xenon to cesium remains almost constant initially.

These are only the initial effects, but it can be seen that the removal of xenon has increased more than the production, so xenon concentration decreases. This will continue for a few hours until the iodine concentration has increased enough that xenon production by iodine decay is greater than xenon removal. Eventually, the xenon concentration will reach a higher equilibrium value than that existing before the transient. This will happen when production and removal rates are again equal (time=96 hr).

Later when power is decreased (time=150 hr), the production is again changed very little initially, but removal by burnout is reduced and xenon concentration increases initially. As iodine concentration decreases, production of xenon will decrease until removal is greater than production. Then xenon concentration will decrease until a new lower equilibrium is reached (time= 200 hr).

A shutdown is similar to a power decrease, but more severe (refer to Figure 2.1-14). Production of xenon directly from fission and removal by burnout almost cease. What is left is radioactive decay of iodine to produce xenon, and radioactive decay of xenon to remove it. The xenon concentration increases initially, just as in the power decrease case. However, the increase continues longer and reaches much higher levels before decreasing. The peak occurs about 8 or 9 hours after shutdown. Since iodine is no longer being produced, its concentration continues to decrease as it decays to xenon. The xenon, also decaying away, is almost gone in about 3 days.

In some cases, Xenon-135 presents moderately sensitive reactor operating conditions. Consider a reactor that has operated at power long enough to establish a high xenon concentration. Assume that the reactor trips and that a rapid recovery to full power is achieved simultaneously with the point in time at which “peak” xenon occurs. In returning the reactor to power, the negative reactivity associated with the xenon is overcome, as indicated above, by withdrawing the control rods to a higher position than usual. With the high flux of full power operation acting to “burnout” the accumulated Xe-135 and the decay of Xe-135 due to the shutdown, the concentration quickly falls off, and the result is a positive reactivity insertion. It should be pointed out that properly designed power reactors will overcome the xenon burnout quite adequately with proper control system operation.

Figure 2.1-15 shows reactor trips and returns to power at various power levels. Note the drop-off in xenon concentration during the restart. At EOL there is a possibility that there is not enough positive reactivity remaining in the fuel to overcome the negative reactivity added by xenon. In such a case the reactor restart is delayed until the xenon has decayed to lower values.

Another important fission product poison encountered in reactor operation is samarium-149 (Sm-149). This stable isotope has a capture cross section of about 4 x 10^4 barns. It enters the system as the end product of the following decay chain:

$$\text{Nd-149} \xrightarrow[1.7\text{ hr}]{\beta^-} \text{Pm-149} \xrightarrow[53\text{ hr}]{\beta^-} \text{Sm-149 (stable)}$$

(Nd: neodymium, Pm: promethium)

These products occur in about 2.1% of U-235 fissions. Because Sm-149 is stable, its equilibrium concentration in any reactor produces about -0.65% ΔK/K or -650 pcm of reactivity, independent of the neutron flux (power level) as shown in Figures 2.1-16 and 2.1-17. The rate at which the Sm-149 concentration approaches this equilibrium is related to the Pm-149 (53-hour) half-life. Upon reactor shutdown (Figures 2.1-18 and 2.1-19), the Sm-149 concentration builds up to an asymptotic value dependent on the equilibrium concentration of promethium, which is power-level dependent.

2.1.7.2. Controllable Poisons

Two controllable conditions existing in a nuclear reactor greatly affect the reactivity balance within the system. These are control rod position and soluble poison concentration.

Control rods are made of a material or materials with an extremely high capture cross section for neutrons. Consider a just-critical reactor in which a control rod is partially inserted. If the rod is withdrawn slightly, K_{eff} will increase to a value slightly greater than 1.0. By withdrawing the control rod, neutron absorbing material is removed from the core. The effect is an increase in the thermal utilization factor, and (as seen in the six-factor formula discussed earlier) K_{eff} is increased. Control rod reactivity effects vary with their location in the core. If a control rod is located at the midplane of the core, its worth per step of movement is greater than if it were almost totally withdrawn or inserted.

A typical differential control rod worth (Δρ/Δ rod position) curve is shown in Figure 2.1-20(a). Note that the maximum differential worth is found when the rod is positioned at about 40% withdrawn. This curve can be integrated to provide a determination of total control rod worth, which is defined as that amount of reactivity change associated with a given total movement of the control rod. Figure 2.1-20(b) shows the integrated control rod worth curve for the given differential rod worth.

Reactivity control is also maintained by using soluble boron poison in the moderator or coolant that passes through the reactor core. Addition of boron reduces the thermal utilization factor and requires that the control rods be further removed from the core to sustain the just-critical system. In most large pressurized water reactors today, large amounts of positive reactivity are held down by a soluble poison such as boric acid. Boron-10 is the principal absorber in this solution. When used as gross control, the plant can operate with almost all control rods fully removed. This works to optimize the power distribution and heat transfer through the core and at the same time enhances the available shutdown safety margin.

Soluble poisons are injected through the makeup portion of the chemical and volume control system. As reactor fuel is consumed and the installed excess reactivity drops, the soluble poison is removed through the chemical and volume control system, compensating for the reactivity loss due to fuel depletion.

2.1.8 Reactor Response to Reactivity Changes

The preceding sections have described the reactivity effects associated with reactor parameters and fission product poisons. This section discusses how reactivity effects interact to control the reactor's response to transient conditions, with a particular emphasis on the reactor's inherent response when actions to control plant parameters at their desired values are not taken.

If the moderator temperature coefficient is negative and reactor power is greater than the point of adding heat, reactor power follows secondary power. If the turbine load changes from one steady-state value to another, reactor power will undergo the same change, even if no actions (manual or automatic) are taken to control reactor power. Also, if plant operators add reactivity (positive or negative) by changing control rod positions or the coolant boron concentration without changing the turbine load, the final reactor power will be unchanged; the net result of the reactivity addition will be a new steady-state coolant temperature.

Consequently, during normal operations at power, PWR plant operators control reactor power by adjusting the output of the secondary plant (usually the turbine load). Operators adjust control rod positions and coolant boron concentration to maintain the coolant temperature at the desired value for a given power level (i.e., to conform to the sliding T_{avg} program described in Section 1.2).

The terms "secondary power" and "turbine load" are often used interchangeably, because during normal operation, secondary power *is* the turbine load. However, steam exiting the steam generators can also leak from steam piping, or it can travel directly to the condenser via the steam dump valves. Under these circumstances, the total secondary power equals the turbine load PLUS the equivalent power associated with the other steam flows. Therefore, secondary power is a more inclusive term.

At equilibrium, two conditions are always satisfied: reactor power equals secondary power, AND net reactivity equals zero (K_{eff} = 1; the reactor is critical). Following an upset that affects power or coolant temperature, the plant will inherently (without control action) find a new equilibrium state in which those conditions are again satisfied, unless a reactor trip setpoint is reached while the plant “tries” to get there.

Consider an increase in secondary power. The inherent plant response is that reactor power increases to the new higher power level, and the coolant T_{avg} drops to a new lower steady-state value. Increasing the secondary power increases the rate of energy removal from the reactor coolant in the steam generators, thereby reducing the coolant temperature. With a negative MTC, the drop in temperature adds positive reactivity:

Reactivity (moderator) = (MTC)(ΔT);

$\Delta T = T_{avg(FINAL)} - T_{avg(INITIAL)}$

(In the above expression, MTC and ΔT are both negative.) The positive reactivity addition causes reactor power, and thus fuel temperature, to increase. The fuel temperature increase adds negative reactivity:

Reactivity (fuel) = (DOPC) (Δ%power);

DOPC = Doppler-only power coefficient, and

Δ%power = $power_{FINAL}$ - $power_{INITIAL}$

(In the above expression, the DOPC is negative and Δ%power is positive.) Reactor power increases until it again equals secondary power. At that point, the rate of energy transfer to the coolant from the reactor equals the rate of energy removal from the coolant in the steam generators, and the coolant temperature stops decreasing. The coolant T_{avg} decreases to a value for which the positive reactivity from the coolant temperature decrease completely offsets the negative reactivity from the reactor power (fuel temperature) increase. At the new equilibrium, reactor power again equals secondary power (at a higher power level) and net reactivity again equals zero (with different constituent reactivities).

Contrast the inherent response to the “controlled” response. For an increase in secondary power, the sliding T_{avg} program calls for T_{avg} to increase. If the MTC is negative, increasing the coolant temperature over the power change will add negative reactivity. Fuel temperature will also increase and, because of the negative DOPC, also add negative reactivity. To offset both of these negative reactivity additions (combined, they constitute the power defect described in Section 2.1.6.5), the operators must add positive reactivity by withdrawing control rods (or allowing them to automatically withdraw) or by diluting the reactor coolant. These operator-controlled actions are NOT required to make the reactor power follow the secondary power; they are required to maintain T_{avg} at its programmed value.

As a second example, consider a reduction in turbine load from 60% to 50%. This 10% reduction causes an imbalance between reactor power and secondary power; the reactor is adding energy to the coolant at a faster rate than the steam generators (ultimately, the turbine) are removing energy from the coolant. As a result, T_{avg} rises. The increase in T_{avg} adds negative reactivity ($-\rho$) to the reactor (recall that MTC is negative). This $-\rho$ makes the reactor subcritical, and reactor power begins to drop. The decrease in reactor power adds positive reactivity ($+\rho$) via the DOPC (the fuel temperature is decreasing). This $+\rho$ from the power decrease offsets the $-\rho$ from the T_{avg} increase.

For illustrative purposes, consider that the above changes in power and temperature take place in small sequential increments. Assume that the value of the MTC is -20 pcm/°F, and that the value of the DOPC is -10 pcm/%. Each time T_{avg} rises 1°F, the reactor becomes subcritical by 20 pcm, causing reactor power to decrease. When power has decreased by 2%, +20 pcm will have been added by the reactor power change, returning the reactor to an exactly critical condition ($\rho = 0$). Thus, it can be said that each increase in T_{avg} results in a corresponding drop in reactor power that returns the reactor to an exactly critical condition. In this example, five such incremental steps will lower reactor power by 10%. T_{avg} will eventually rise 5°F (adding -100 pcm of reactivity), and reactor power will lower 10% (adding +100 pcm).

As described above, when the operator initially decreases turbine load, the power mismatch between the primary and the secondary causes T_{avg} to rise. Each incremental rise in T_{avg} adds $-\rho$, which causes reactor power to decrease. Each time power decreases, the decrease in fuel temperature adds $+\rho$ to offset the $-\rho$ from the change in moderator temperature. These changes (T_{avg} increasing, reactor power decreasing) continue until reactor power reaches the new value of turbine load. At the new equilibrium state, reactor power equals secondary power, and T_{avg} stops changing. Net reactivity is zero; the $-\rho$ from the increase in T_{avg} has been offset by the $+\rho$ from the drop in reactor power.

To summarize, the inherent effect of lowering turbine load with no primary control actions is that reactor power drops to equal secondary power, and T_{avg} rises.

In a final example, the operators withdraw control rods without changing turbine load. The rod withdrawal adds $+\rho$, causing reactor power to rise. As the power increases, the fuel temperature increase adds $-\rho$ via the DOPC, which offsets the $+\rho$ from the rod withdrawal. Now the reactor is again exactly critical (net $\rho = 0$), but reactor power exceeds secondary power, so T_{avg} rises. The rise in T_{avg} adds $-\rho$, which causes reactor power to drop. When power drops, the decrease in fuel temperature adds $+\rho$, which offsets the $-\rho$ from the T_{avg} increase and returns the reactor to an exactly critical condition. As in the previous example, T_{avg} continues to rise until reactor power equals secondary power. At the end of the transient, T_{avg} is higher than its starting value, and reactor power has returned to its original value (which equals the unchanged turbine load). In the new equilibrium reactivity balance, $+\rho$ from the rod withdrawal has effectively been exchanged with $-\rho$ from the moderator temperature increase.

The above discussion is slightly oversimplified. Actually, a change in reactor coolant temperature changes the conditions for heat transfer in the steam generators; the resultant change in steam pressure can affect the power level. (Recall the expression introduced in Section 1.2 for primary-to-secondary heat transfer: $Q = UA[T_{avg} - T_{ref}]$.) Some turbine control schemes can respond to steam pressure changes in order to maintain the desired turbine load. However, the predominant effect is that reactor power follows turbine load, and that the reactor coolant temperature assumes whatever value is necessary to return net reactivity to zero. In addition, a change in reactor coolant temperature also changes the conditions for heat transfer from the fuel to the coolant, and thus affects the fuel temperature. (The temperature differential between the fuel and the coolant must remain about the same for heat transfer from the fuel to the coolant to remain constant.) However, any resultant change in fuel temperature is insignificant when compared to the fuel temperature change associated with a power change. It is therefore useful to consider fuel temperature to be a function of reactor power only.

2.1.9 Reactor Kinetics

Consider a reactor in which K_{eff} is exactly 1.0. With equilibrium established, the neutrons entering into the self-sustaining reaction are a mixture of prompt and delayed neutrons. The fraction of this mixture that are delayed neutrons at steady state is known as $\bar{\beta}$. Each fuel has a characteristic β due to its yield of delayed neutron producers. A mixture of fuels, such as what would be present in a commercial reactor after it has operated, has a $\bar{\beta}$ which is a weighted average of the βs for the fuels present. For a reactor with only U-235, $\bar{\beta}$ is about .007 or 0.7%. Even though this is a small fraction of the neutrons, delayed neutrons are essential to reactor control. Delayed neutrons do not appear until about 13 seconds after the fission that results in a delayed neutron producer. The long time delay is because the delayed neutron producer must decay before a neutron is released.

After the release of the delayed neutron, it will go through the same life cycle with the prompt neutrons, which were released immediately after the fission. The lifetime for a prompt neutron is about 10^{-4} seconds, but the lifetime for a delayed neutron is about 13 seconds ($13 + 10^{-4} \sim 13$). The life cycle time or generation time is a weighted average of the lifetimes for prompt and delayed neutrons. Since the delayed neutron fraction is $\bar{\beta}$, then the prompt neutron fraction is ($1-\bar{\beta}$). These are used as the weighting factors. The generation time is about 0.1 seconds. The reactor would be uncontrollable with a generation time of 10^{-4} seconds but is controllable with 0.1 seconds, as can be seen in the following discussion.

As previously stated, if the fuel is U-235 and the reactor is critical, 0.7% of the fission neutrons are delayed. That means that 99.3% are prompt. Assume now that an adjustment has been made so that K_{eff} is increased to 1.001, or 0.1% supercritical. The system is now multiplying at a given rate proportional to the number of neutrons present within the system. After the transient effects decay out, the rise in the neutron level can be described by a single exponential equation:

$$n(t) = n_0 e^{t/T}$$

where n_0 = the neutron level at time zero

t = the time in seconds

T = the stable reactor period (the time it takes the neutron level to increase by a factor of e)

At the instant the reactor is made supercritical, the neutrons in the core are a mixture of 0.7% delayed and, in this instance, about 99.4% prompt neutrons (99.3 + 0.1%).

If K_{eff} were increased to 1.007, then the reactor would be critical on prompt neutrons alone, no waiting for delayed neutrons would be necessary, and it would be uncontrollable by normal means. The effect of the delayed neutrons on generation time is lost. To put it another way, the power would be increasing at such a rapid rate that it would be impossible to control the reactor short of spontaneous shutdown on its own inherent mechanisms.

The relationship between reactivity and the reactor period can be expressed mathematically. The period of the reactor is useful in equations for reactor analysis. The more useful term for reactor operation is the related startup rate (SUR). The startup rate is expressed in terms of the reactor period in accordance with the following equation:

$$SUR = 26/T$$

where SUR = startup rate in decades per minute

T = period in seconds.

Therefore, if the reactor power level increases by a factor of 10 every minute, then the reactor SUR is 1 decade per minute, which is equal to a period of 26 seconds. Figure 2.1-21 is a plot of reactivity addition versus reactor startup rate. If a reactor operator wished to establish a 1 dpm startup rate from a critical condition it would require an addition of 175 pcm of positive reactivity. The startup rate can also be used to predict power changes if the time the SUR will be in effect and the starting power level are known.

The power of the reactor can be expressed by:

$$p = p_0 10^{SUR \bullet t}$$

where: p_0 = power at time zero

SUR = startup rate in decades/min

t = time in minutes

2.1.10 Subcritical Multiplication

There is a third category of neutrons, in addition to prompt and delayed neutrons, that are not fission neutrons, but are very important during startup and shutdown operations when the reactor is subcritical. These are known as "source neutrons," and they come from sources other than neutron-induced fission. These sources include spontaneous fission of certain nuclides and source assemblies specifically loaded into the core to emit neutrons. (Source assemblies are described in Section 3.1.) Without source neutrons, the neutron population in the core would gradually dwindle toward 0; each neutron generation would have fewer neutrons than the previous one because K_{eff} is less than 1.0. With source neutrons, the population remains at levels that can be measured by the source range nuclear instruments, so that operators can always ascertain how fast the neutron population is changing.

When the reactor is made subcritical after operating at a critical state, the neutron population at first undergoes nearly a step decrease with the rapid reduction in prompt neutrons, and after a short time begins to decrease exponentially with a startup rate of -1/3 decade per minute. This rate of decrease is the result of the delay of the longest-lived delayed neutron producers. Without source neutrons, the decrease would continue until the core neutron population is negligible. However, the neutron population eventually levels off, because at equilibrium the addition of source neutrons just makes up for the losses from the neutron life cycle. The source neutrons enter the life cycle and experience the same environment that fission neutrons experience. For a defined source strength of S neutrons per neutron generation, the core neutron population contains:

S	neutrons from the current generation,
$S \cdot K_{eff}$	neutrons from the immediately previous generation,
$S \cdot (K_{eff})^2$	neutrons from two generations ago, and…
$S \cdot (K_{eff})^n$	neutrons from n generations ago.

The total core neutron population, N, is thus:

$$N = S(1 + K_{eff} + [K_{eff}]^2 + \ldots + [K_{eff}]^n)$$

The above expression converges to:

$$N = \frac{S}{1 - K_{eff}} \text{ for } K_{eff} < 1$$

Hence, the neutron population of a subcritical reactor does not decrease to 0; it reaches an equilibrium value which depends on the source neutron strength and the value of K_{eff}. The indication of the source range neutron detectors (a measured count rate; see Section 9.1) would be a value proportional to N in the above expression ($CR \propto N$).

The above expression explains what happens to the core neutron population when the value of K_{eff} is changed. During a startup, for example, an initially subcritical reactor is driven to criticality via a series of discrete rod withdrawals. After each withdrawal, the operators pause to allow the reactor to attain equilibrium. On the way to criticality, the value of K_{eff} is made closer and closer to 1.0, and the equilibrium neutron population becomes larger and larger. Put another way, after each rod withdrawal, the core neutron population increases and then levels off at a higher value determined by the new larger (but still subcritical) K_{eff} value. Eventually, of course, enough positive reactivity is added to make the reactor critical, at which time K_{eff} = 1.0, and the source neutrons become inconsequential.

Also, the amount of time it takes to reach equilibrium after a reactivity change increases as K_{eff} approaches 1.0. In other words, as criticality is approached, it takes longer for the count rate measured by the source range instruments to level off. The reason is evident in the series expression above; as K_{eff} increases, more terms in the series are significant, meaning that more previous generations of source neutrons contribute to the present population.

A decrease in K_{eff} for a subcritical reactor would cause similar changes in the opposite direction. If K_{eff} is changed from one subcritical value to a smaller one, the neutron population decreases until it levels off at a new lower equilibrium value determined by the neutron population equations defined above.

One use of the count rate is to predict the point of criticality as fuel assemblies are added or reactivity is increased. However, because the source range CR gets infinitely large as K_{eff} approaches 1.0 (recall that the CR is proportional to N), the inverse of CR is plotted. As criticality is approached, 1/CR approaches zero; the value of 1/CR thus provides operators with an effective tool for monitoring the approach to criticality.

Table 2.1-1 Particles and Energy Produced per Fission Event

Instantaneous Energy Release	MeV/fission
Kinetic energy of fission fragments	165
Prompt γ energy	5
Capture γ energy	5
Kinetic energy of prompt neutrons	7
Total	182
Delayed Energy Release	
β Energy from fission products	7
γ Energy from fission products	8
Neutrinos	10
Total	25

Table 2.1-2 Neutrons per Fission

Isotope	Neutrons
U-233	2.51
U-235	2.43
U-238 (fast fission)	2.47
Pu-239	2.90
Pu-241	3.06

Table 2.1-3 Typical Neutron Balance for U-235

Neutron Generation Stage	Number	Factor	Gain/Loss
Beginning of generation: fast neutrons from thermal fission	1000		
Fast neutrons from thermal fission and fast fission	1175	ε = 1.175	+175
Fast neutrons remaining after fast leakage	1151	L_f = 0.98	-20
Neutrons that escaped resonance capture while slowing down to thermal energies	1001	p = 0.87	-150
Thermal neutrons remaining after thermal leakage, to be absorbed by core materials	981	L_t = 0.98	-20
Thermal neutrons absorbed by fuel (fissile nuclides), not absorbed by non-fuel core materials	488	f = 0.497	-493
Fast neutrons resulting from thermal fission in fuel (end of generation and beginning of next generation)	1000	η = 2.05	+512

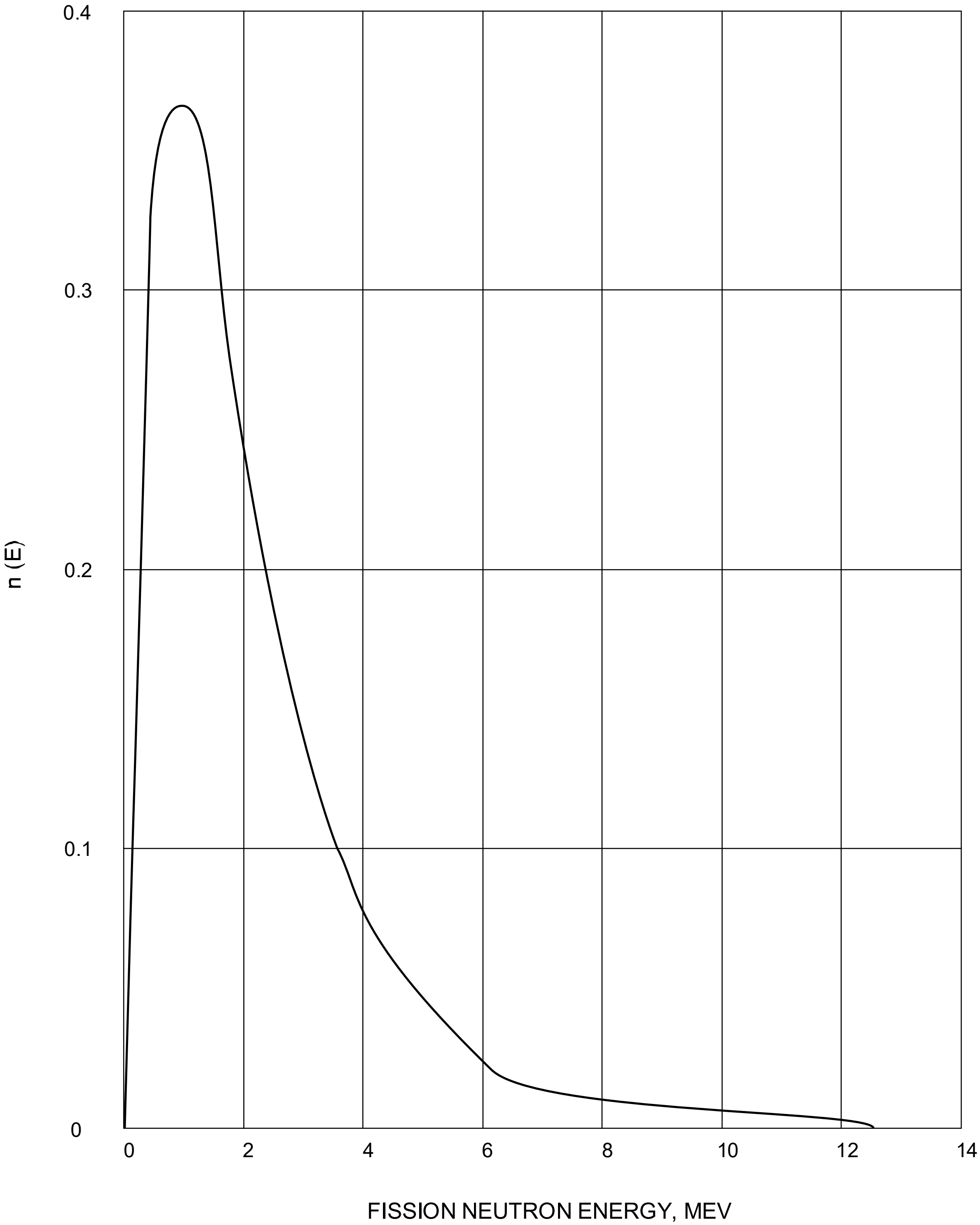


Figure 2.1-1 Fission Neutron Energy

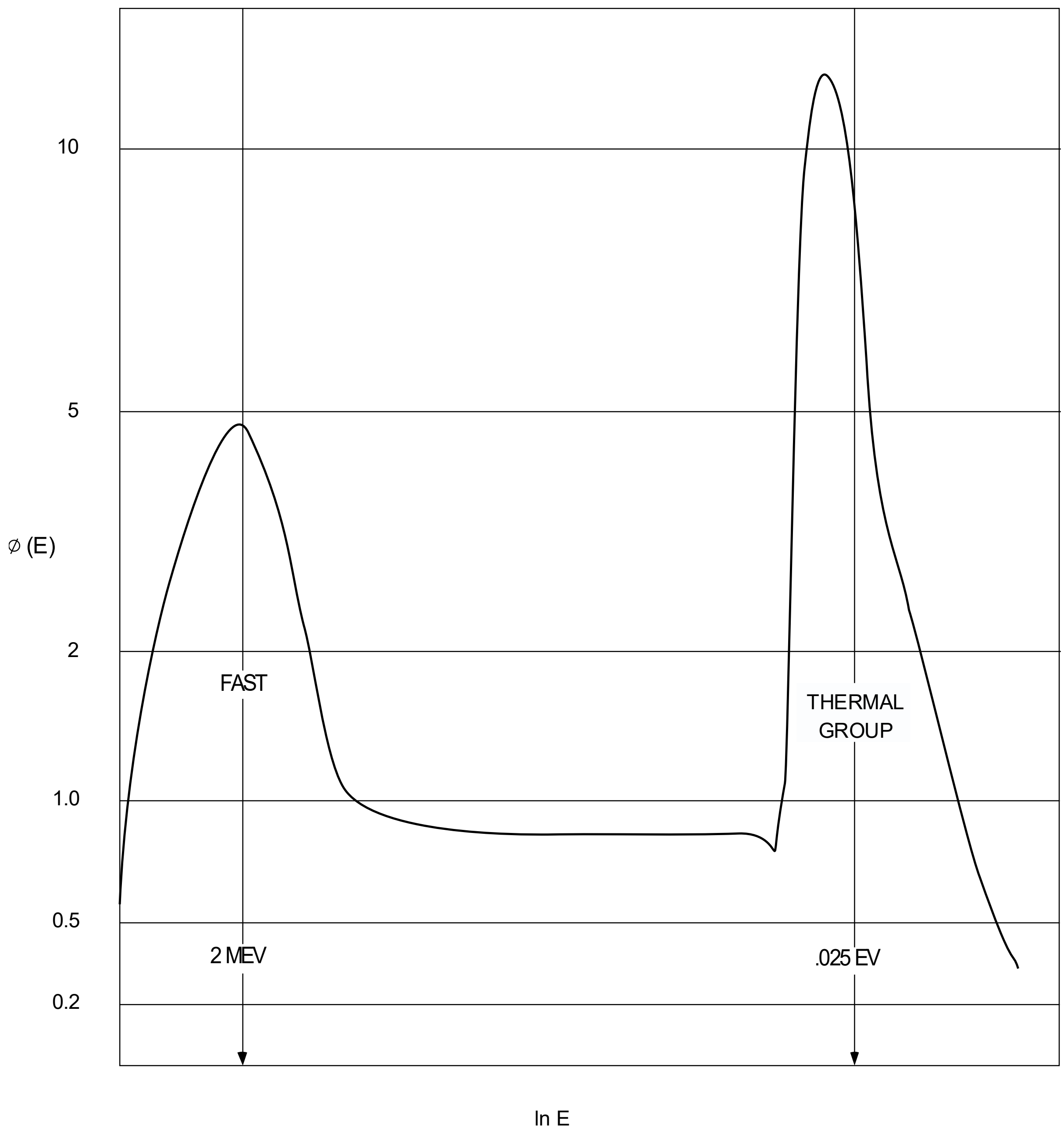


Figure 2.1-2 Flux Distribution

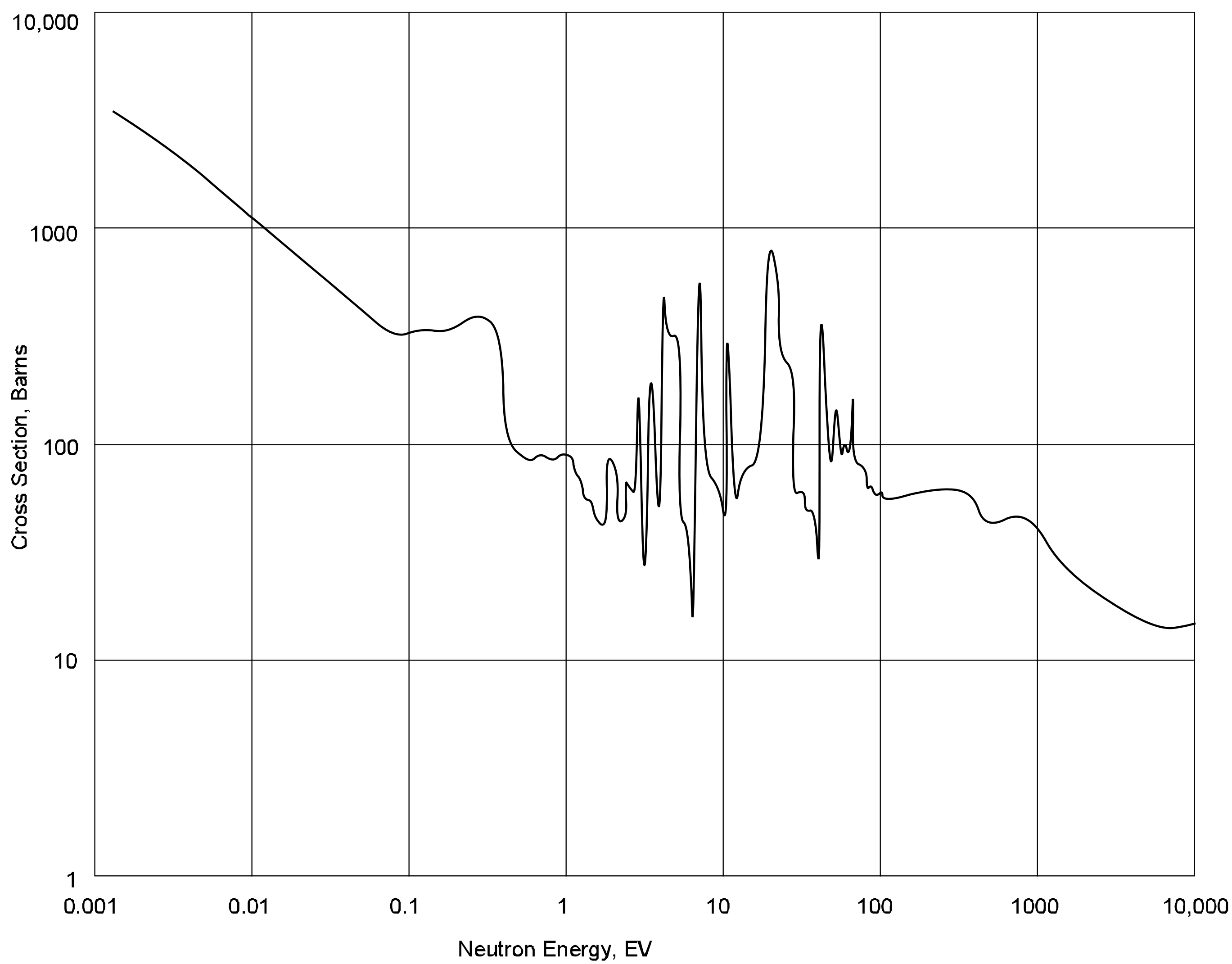


Figure 2.1-3 Total Cross Section for U-235

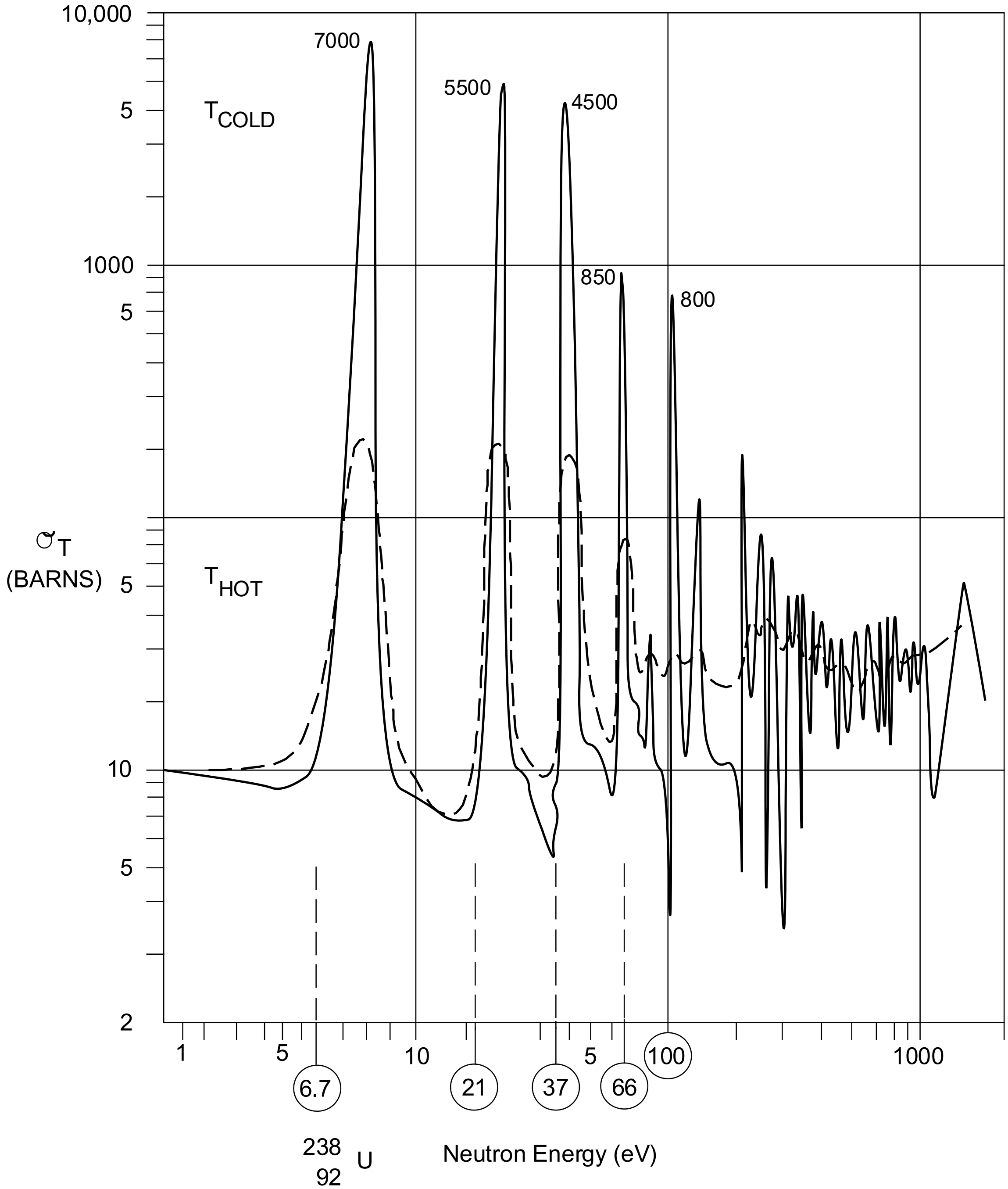


Figure 2.1-4 Cross Section Curve

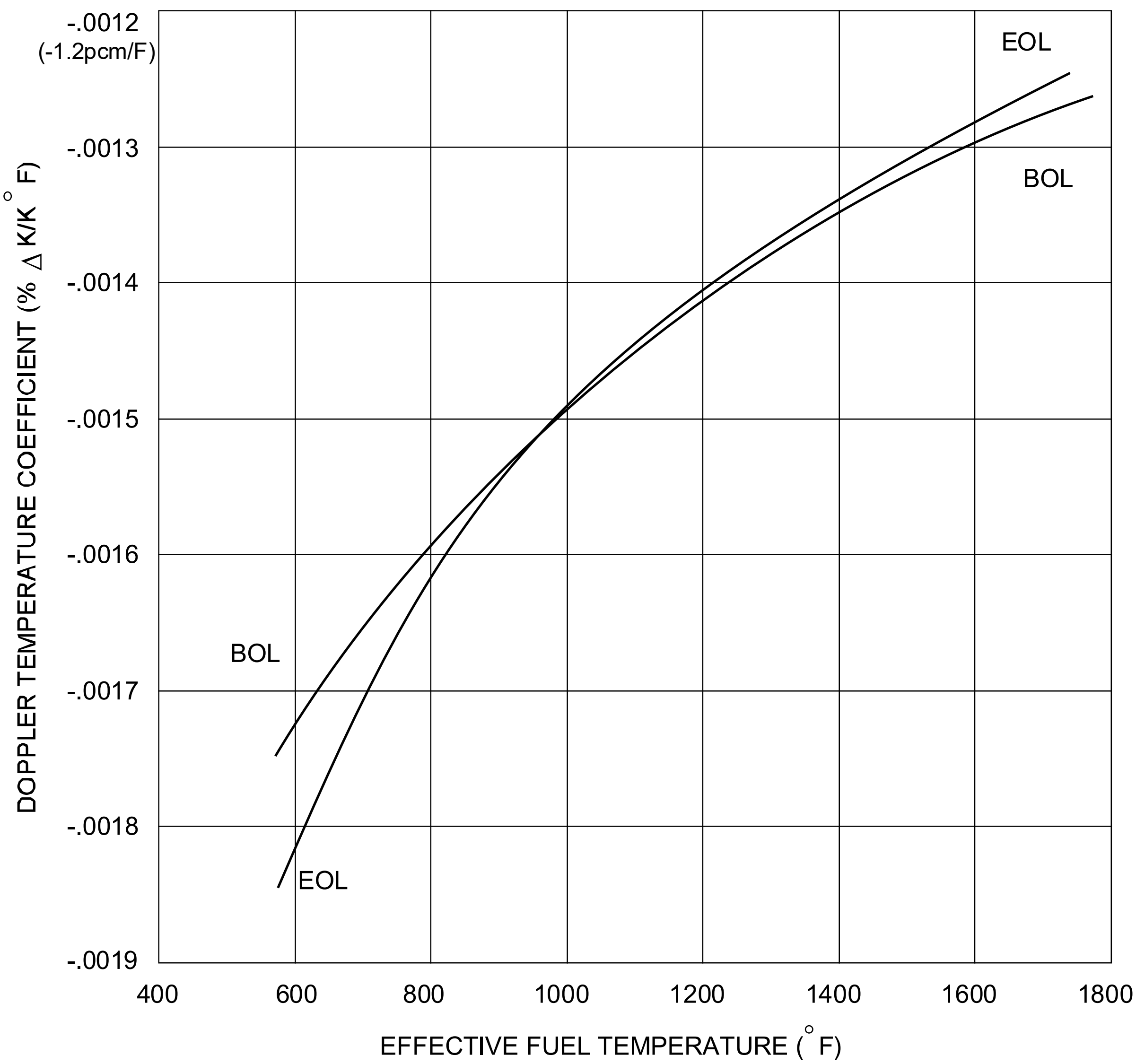


Figure 2.1-5 Doppler Temperature Coefficient, BOL and EOL

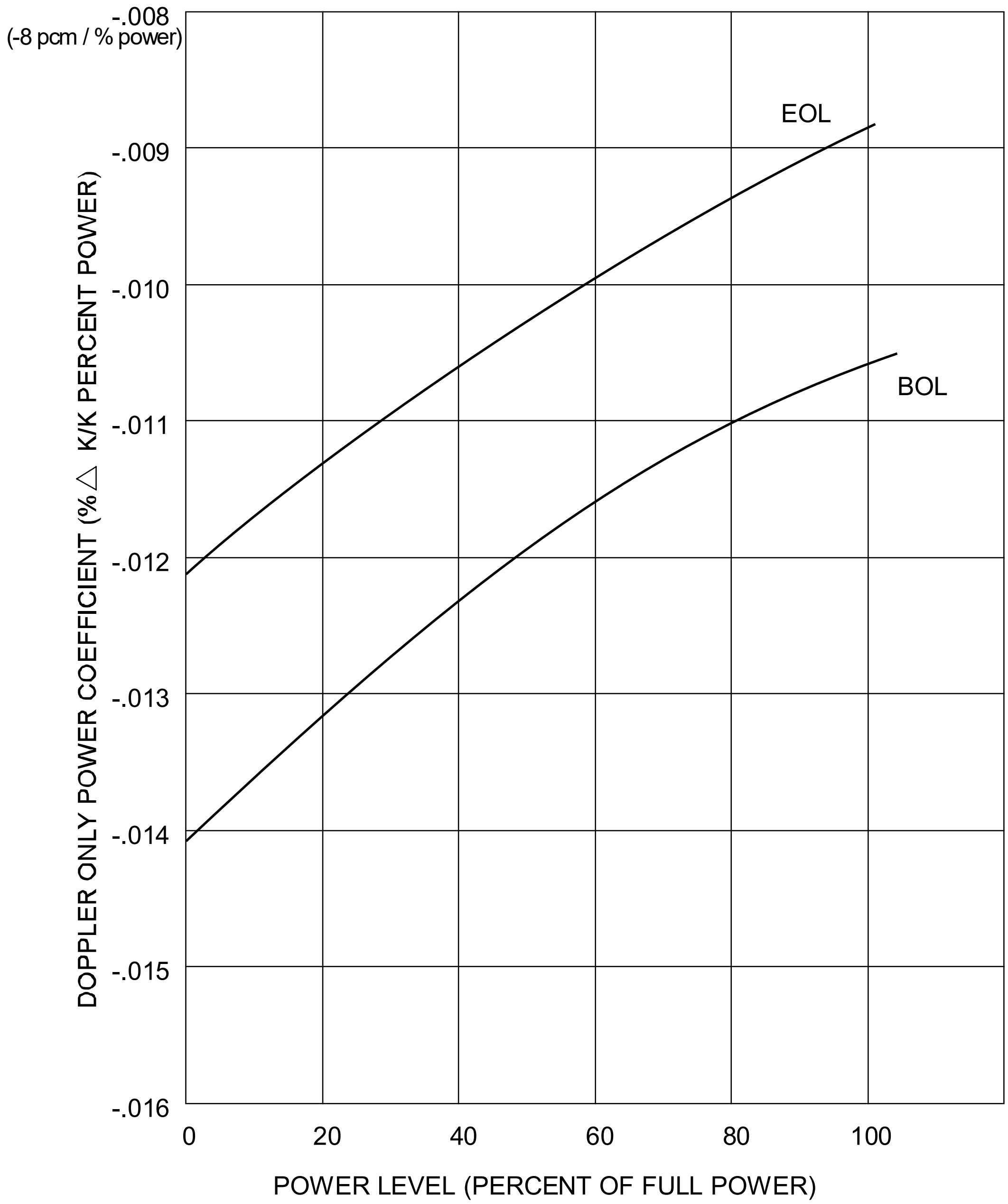


Figure 2.1-6 Doppler Only Power Coefficient, BOL and EOL

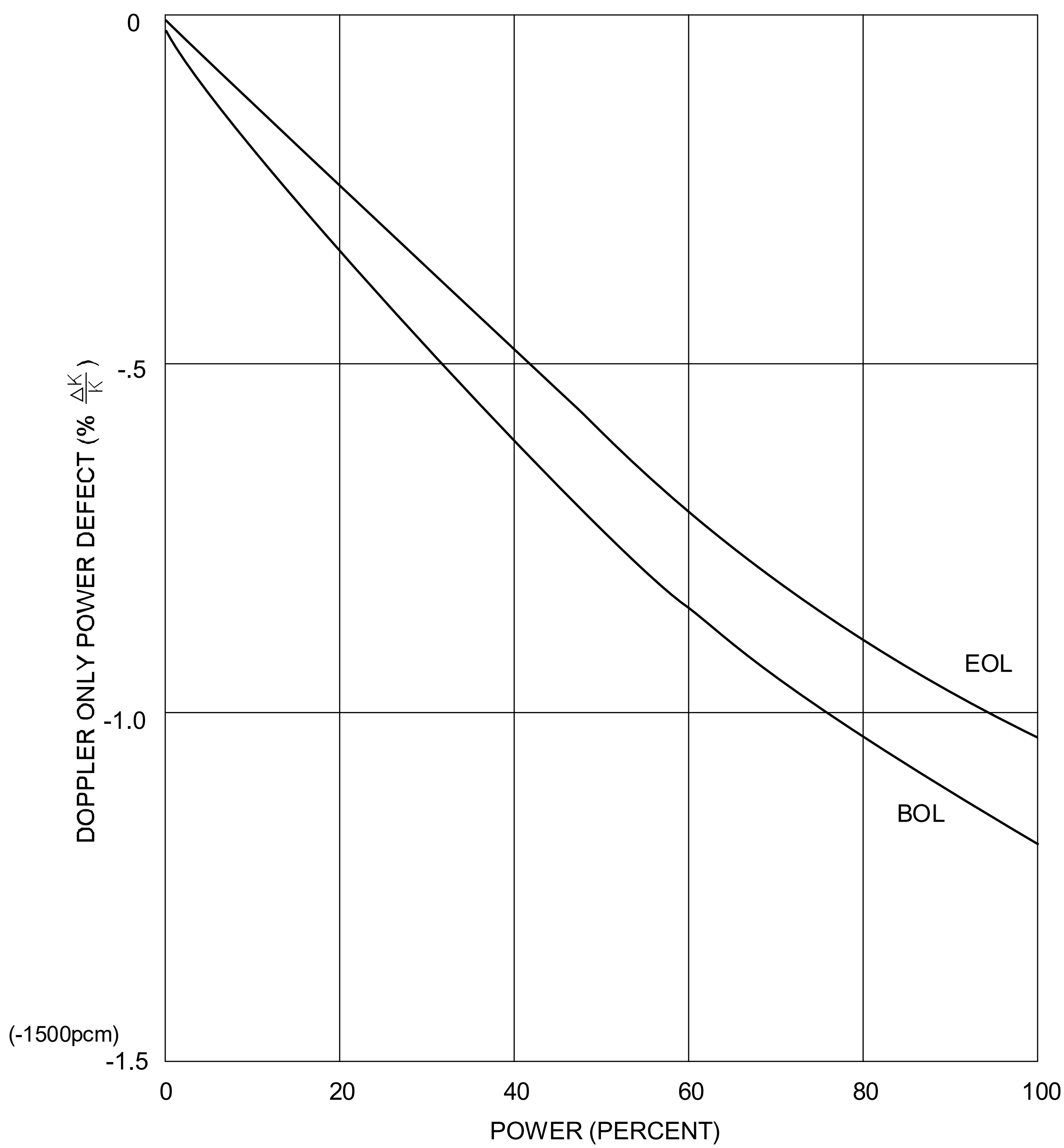


Figure 2.1-7 Doppler Only Power Defect, BOL and EOL

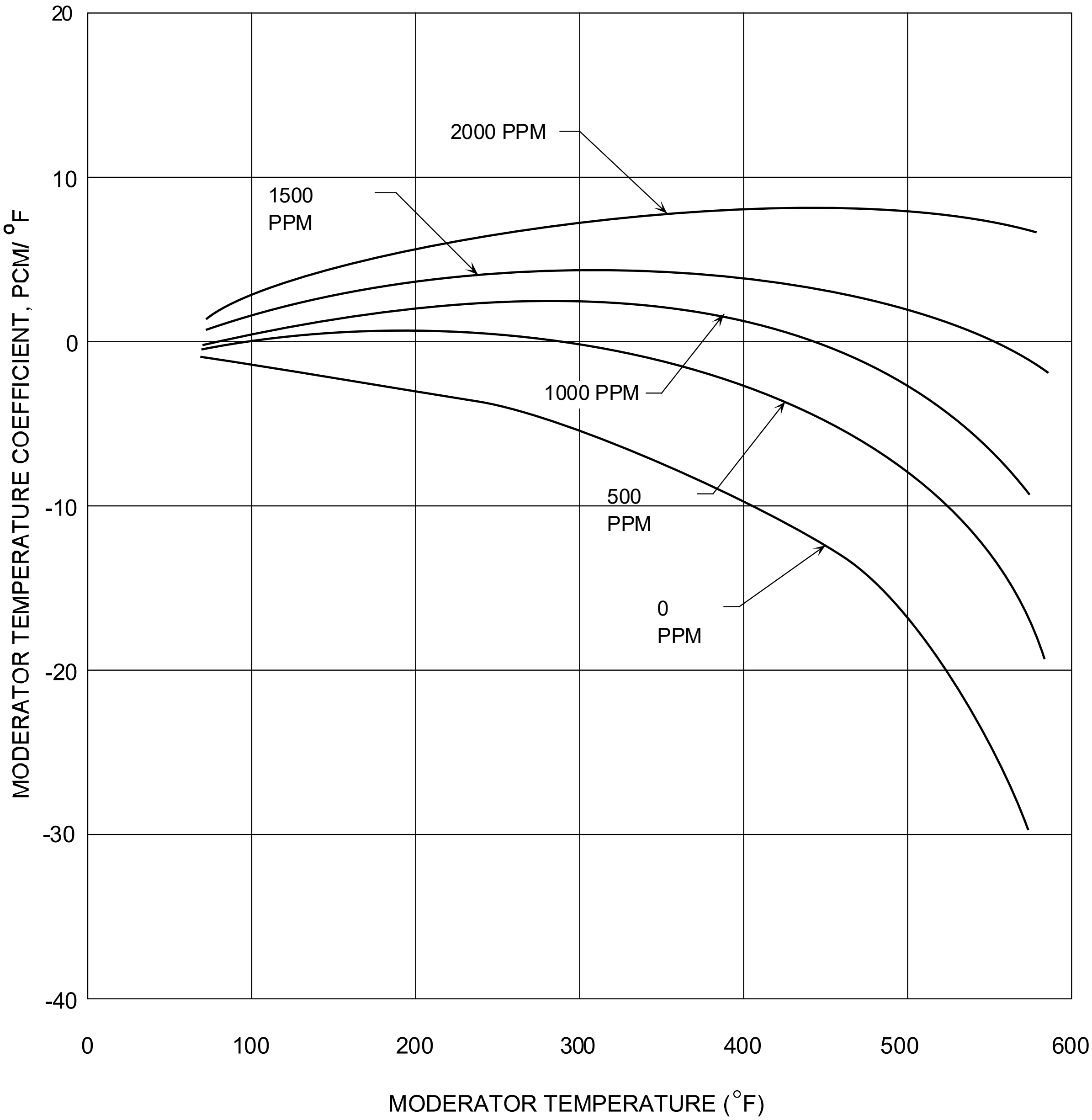


Figure 2.1-8 Moderator Temperature Coefficient

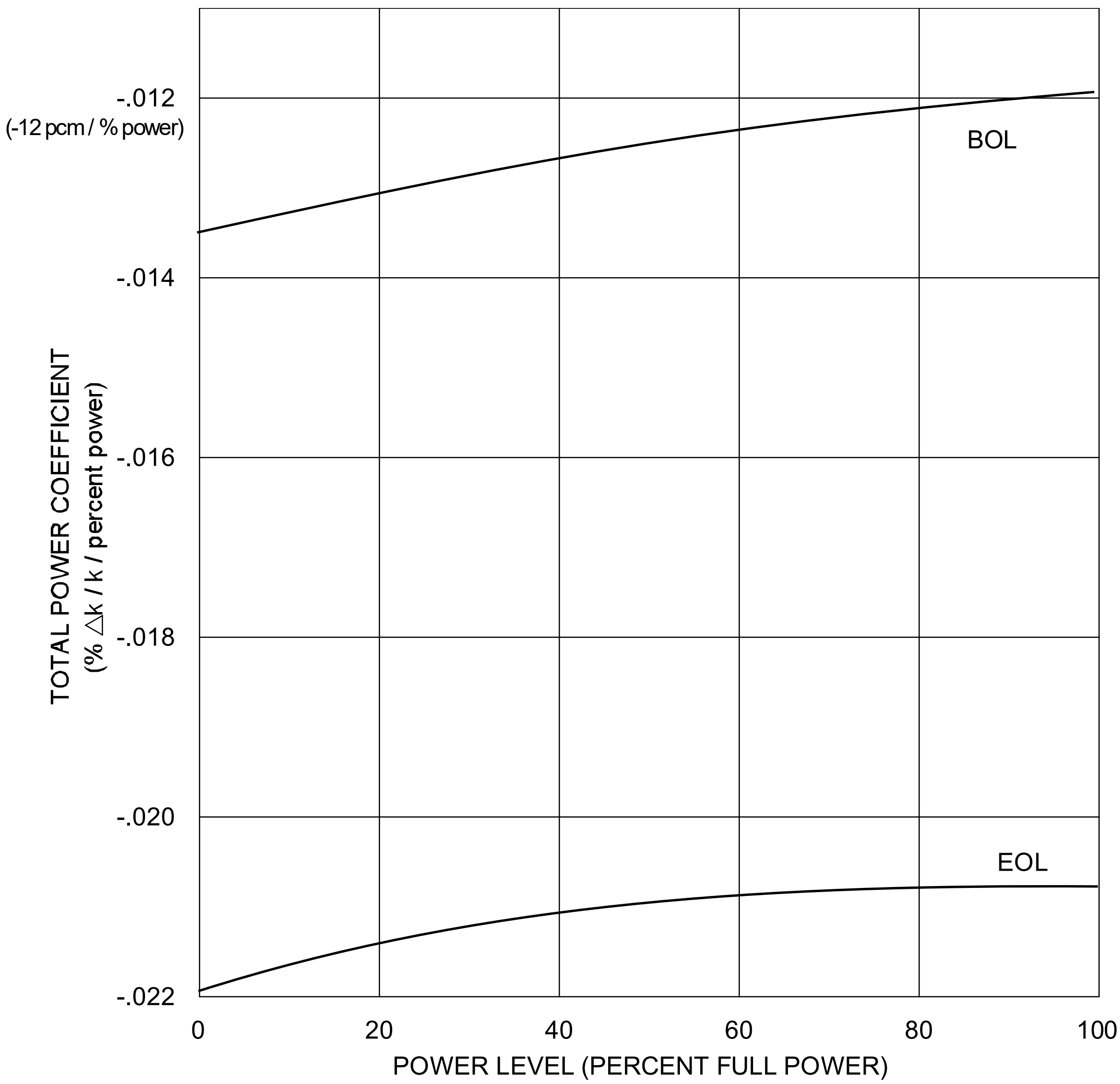


Figure 2.1-9 Total Power Coefficient, BOL and EOL

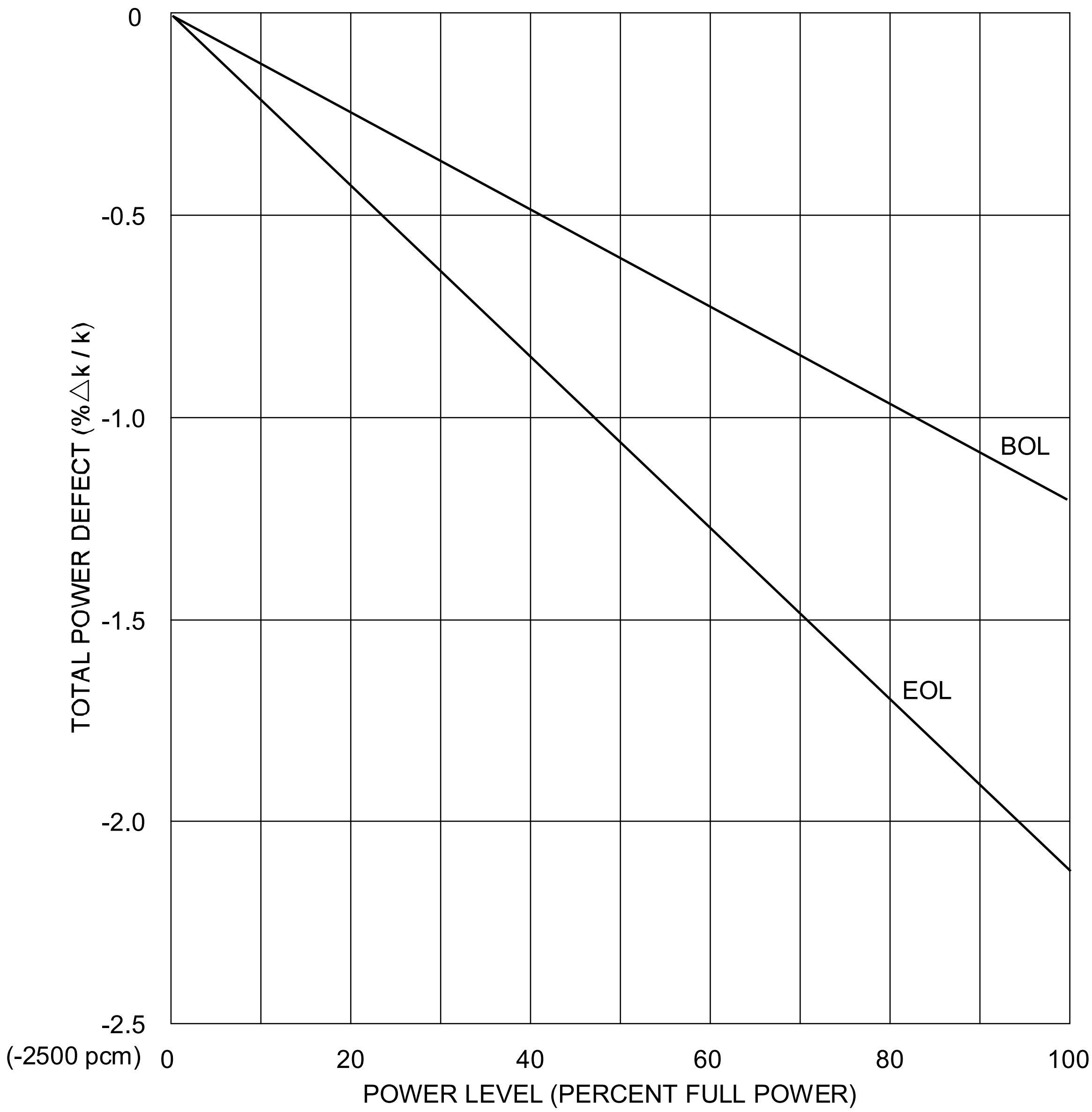


Figure 2.1-10 Total Power Defect, BOL and EOL

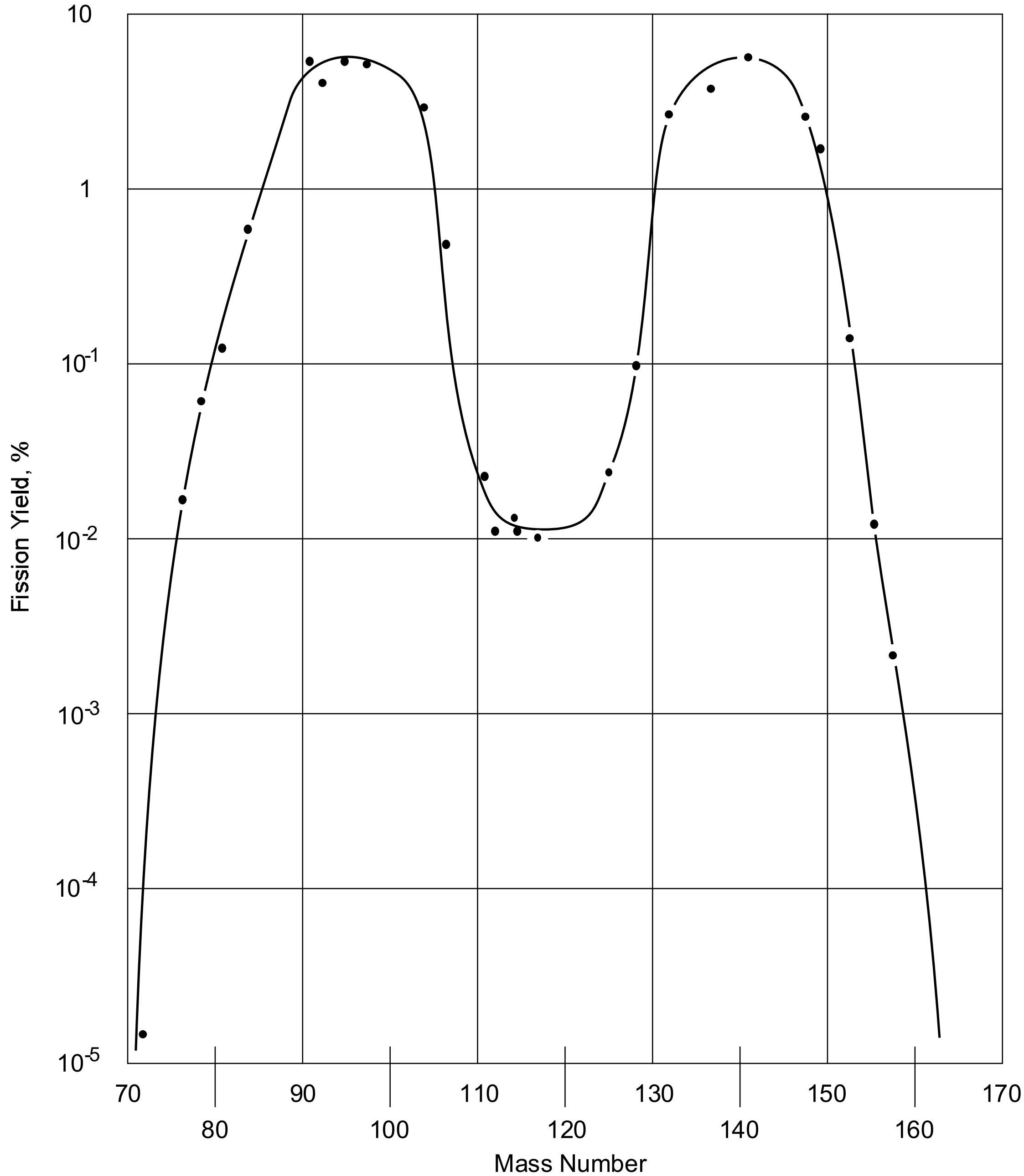


Figure 2.1-11 Fission Yield versus Mass Number

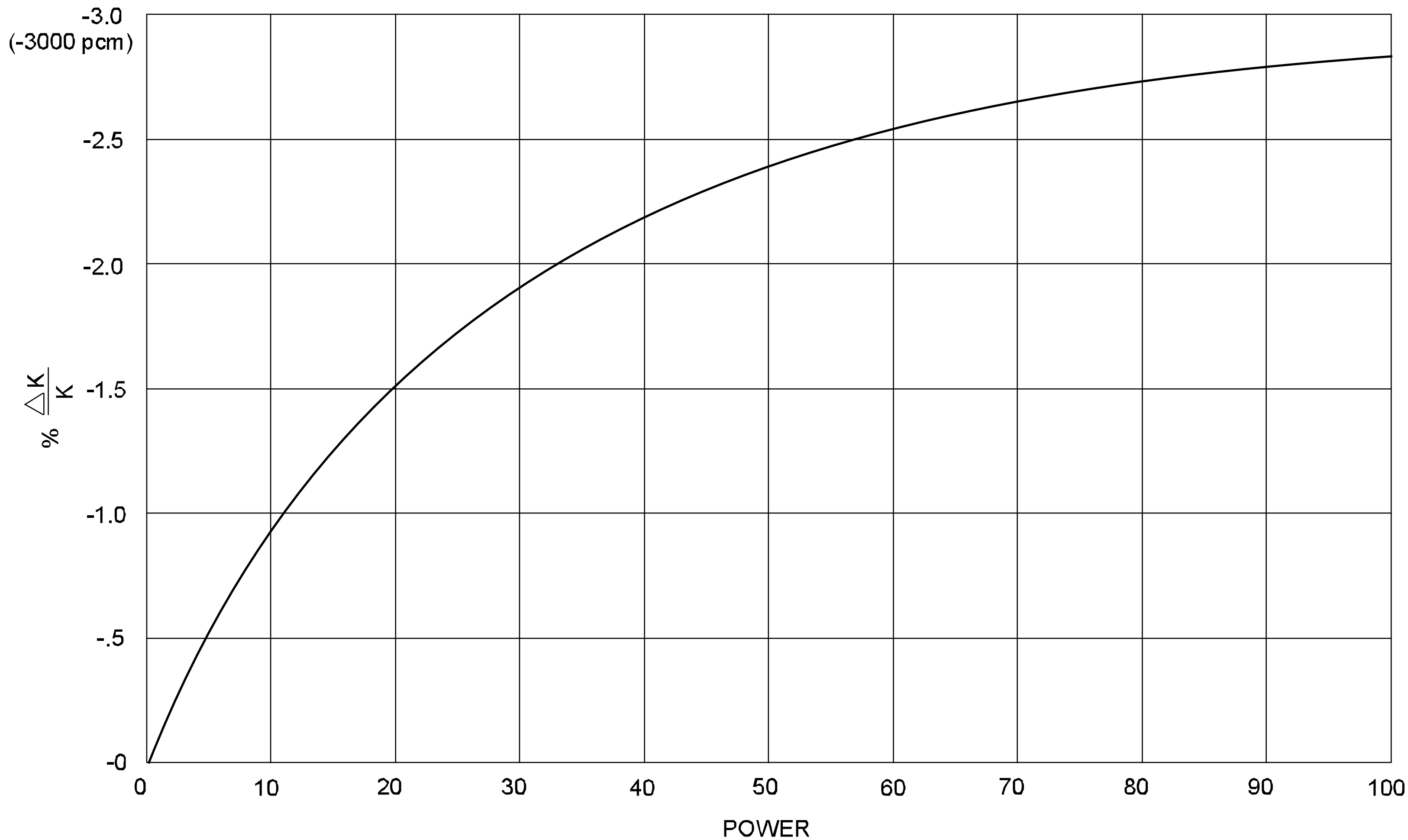


Figure 2.1-12 Equilibrium Xenon Worth vs. Percent of Full Power

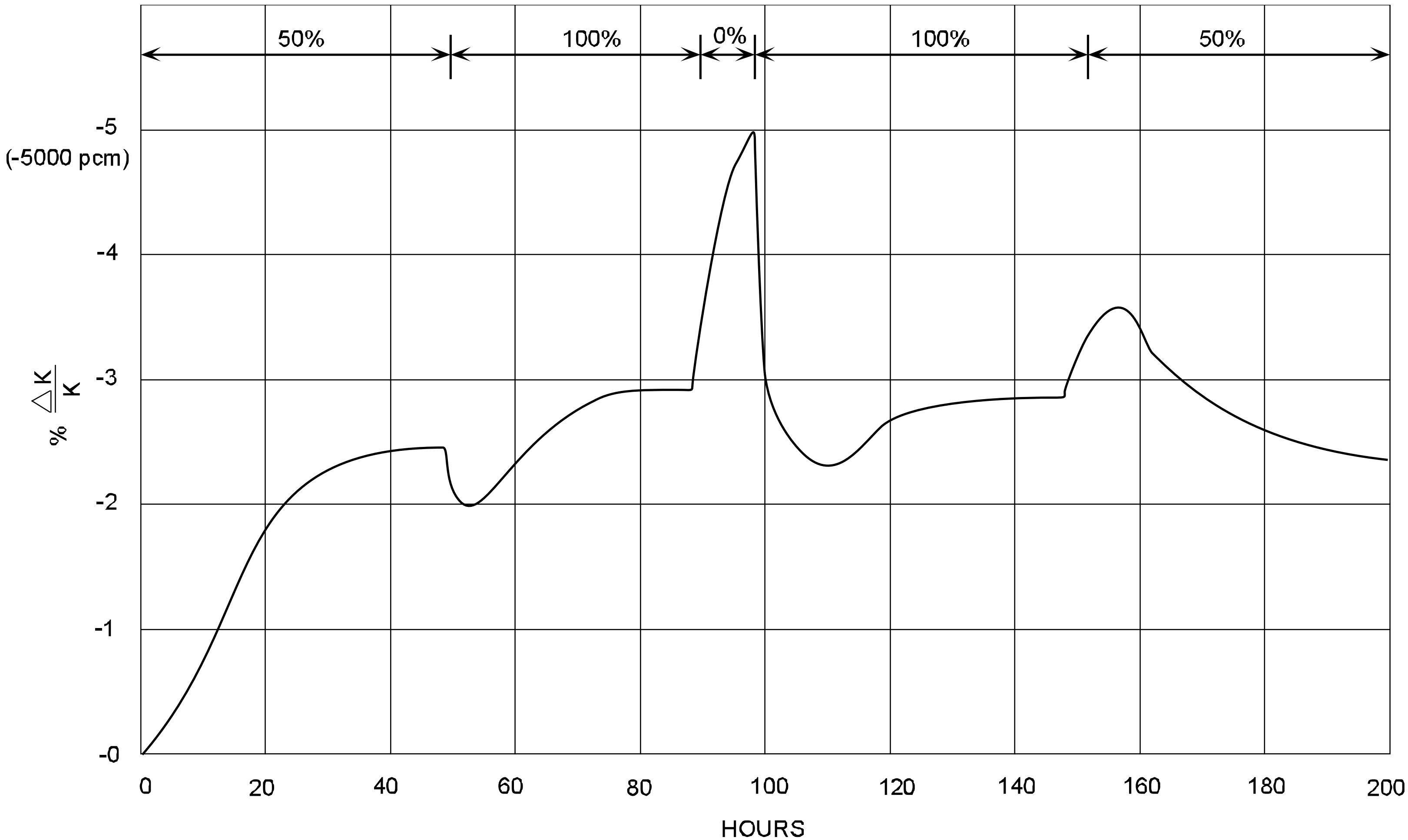


Figure 2.1-13 Xenon Transients

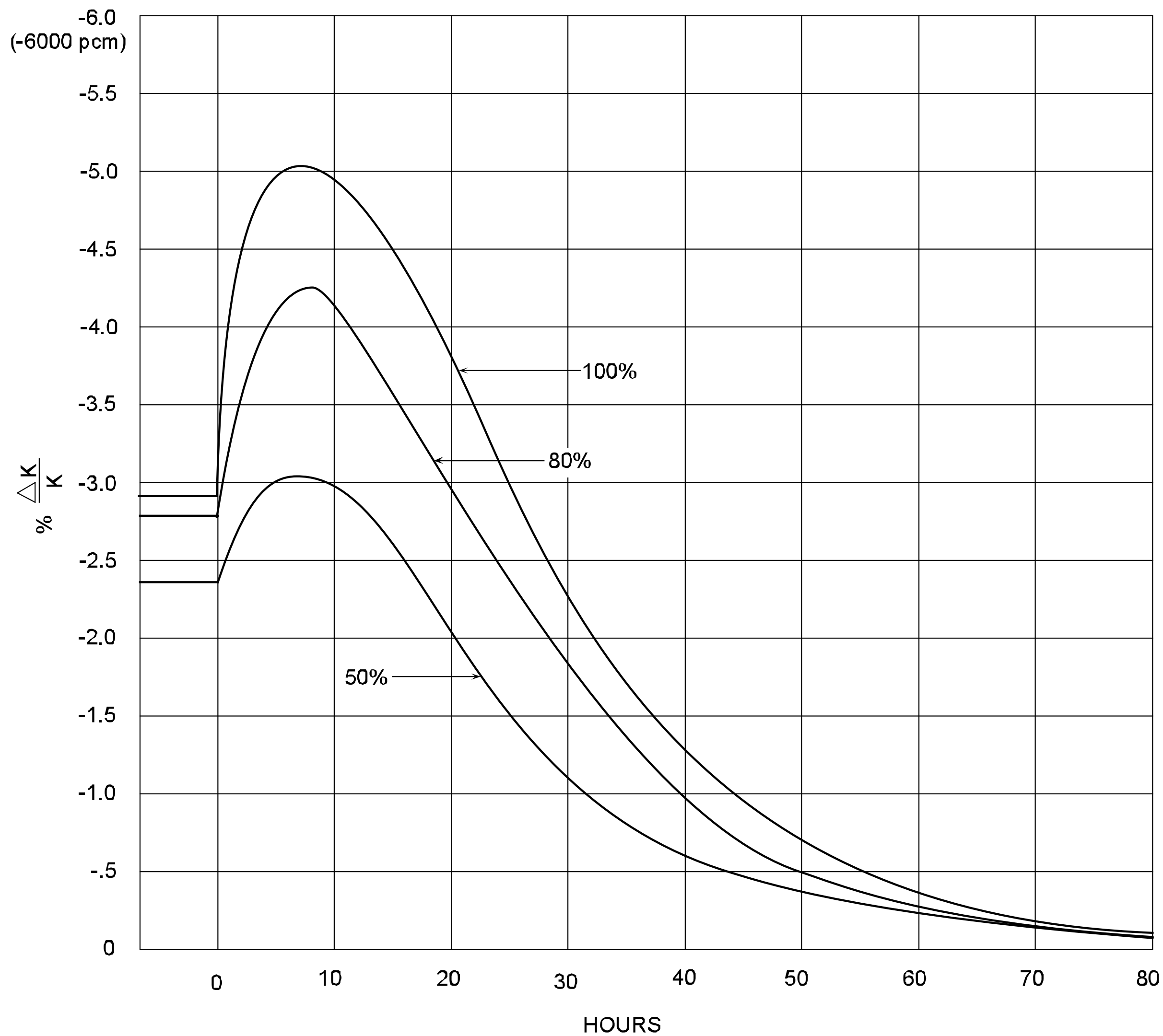


Figure 2.1-14 Xenon Transients Following a Reactor Trip

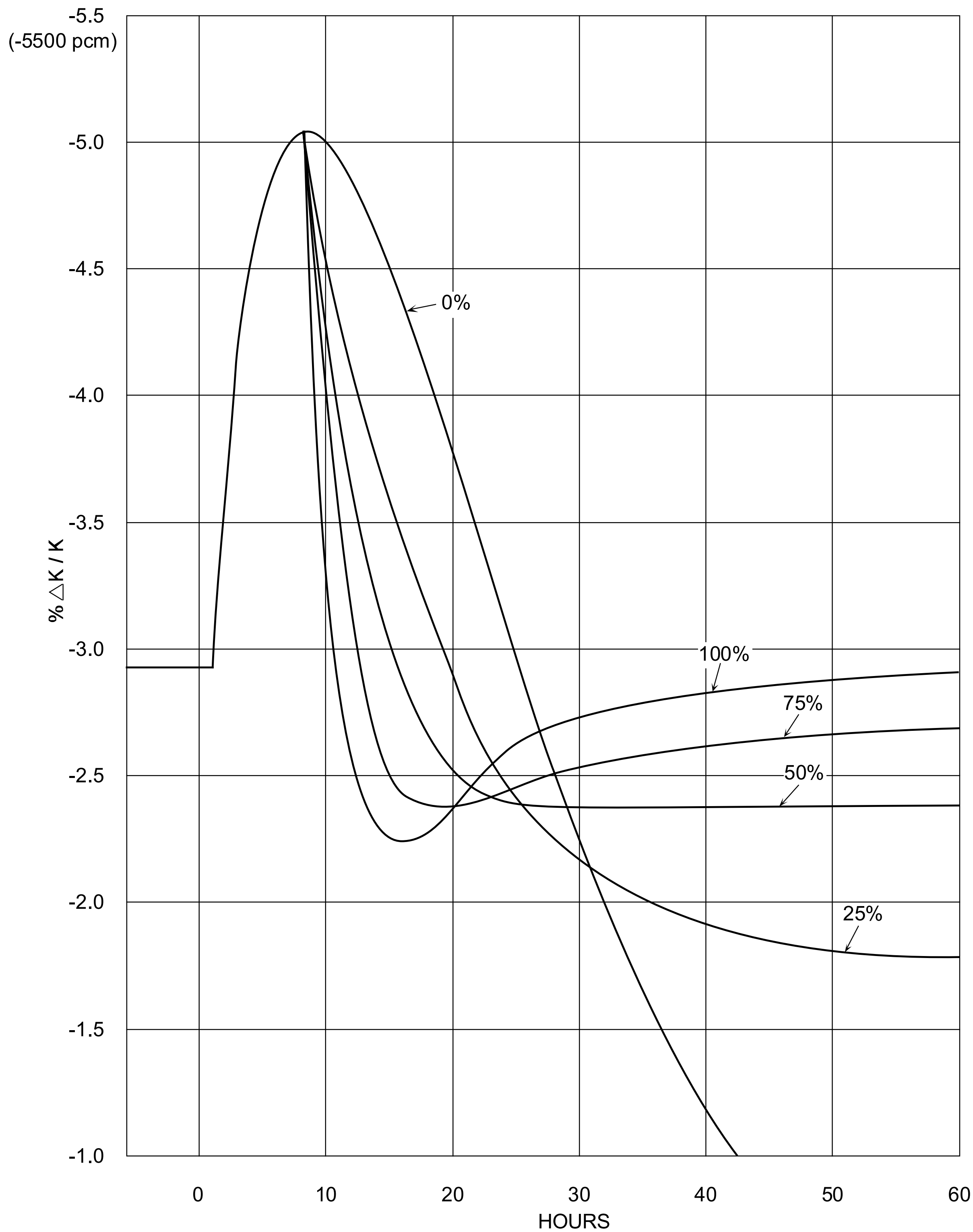


Figure 2.1-15 Xenon Transients Following a Reactor Trip and Return to Power

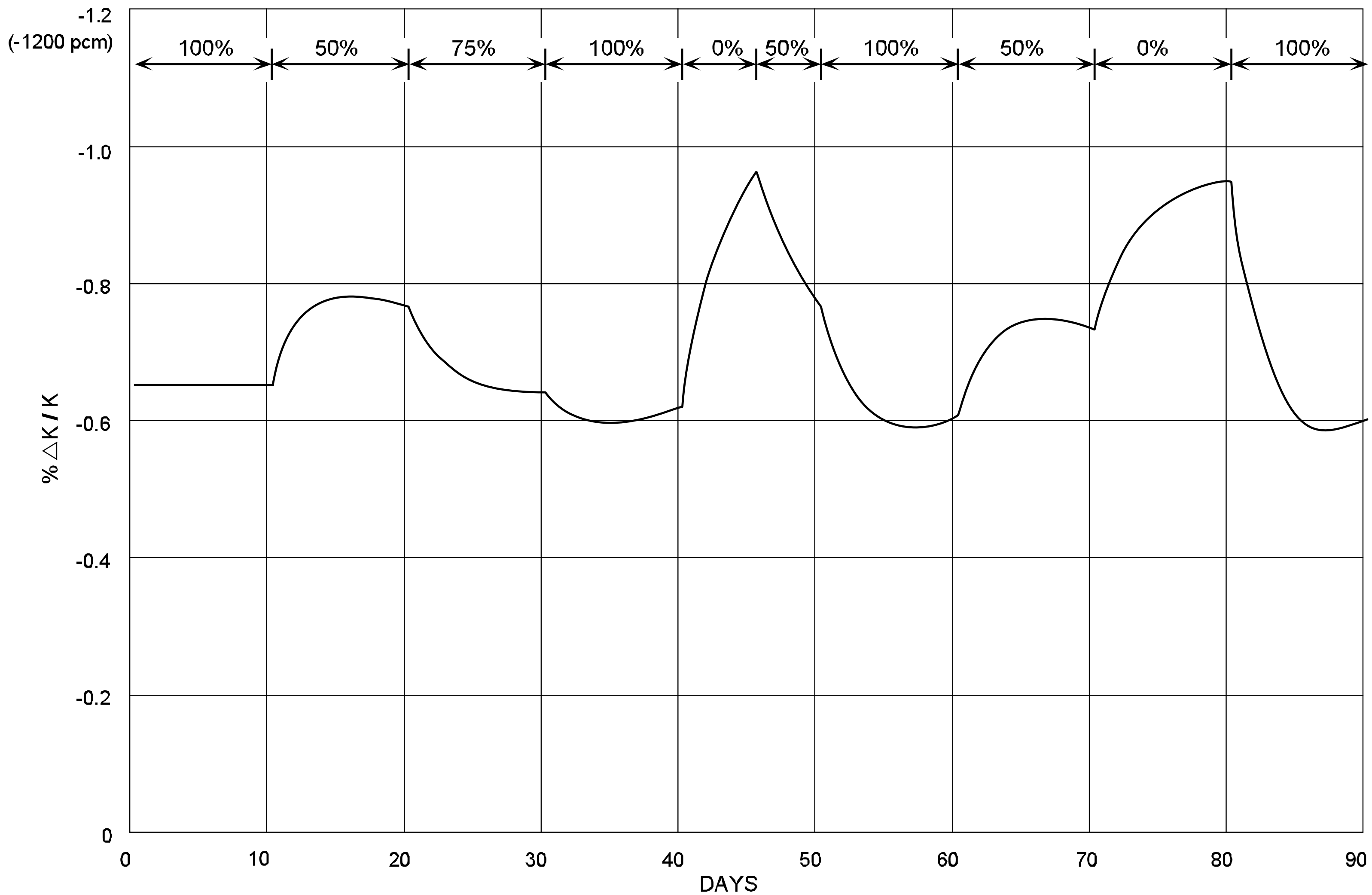


Figure 2.1-16 Samarium Transients

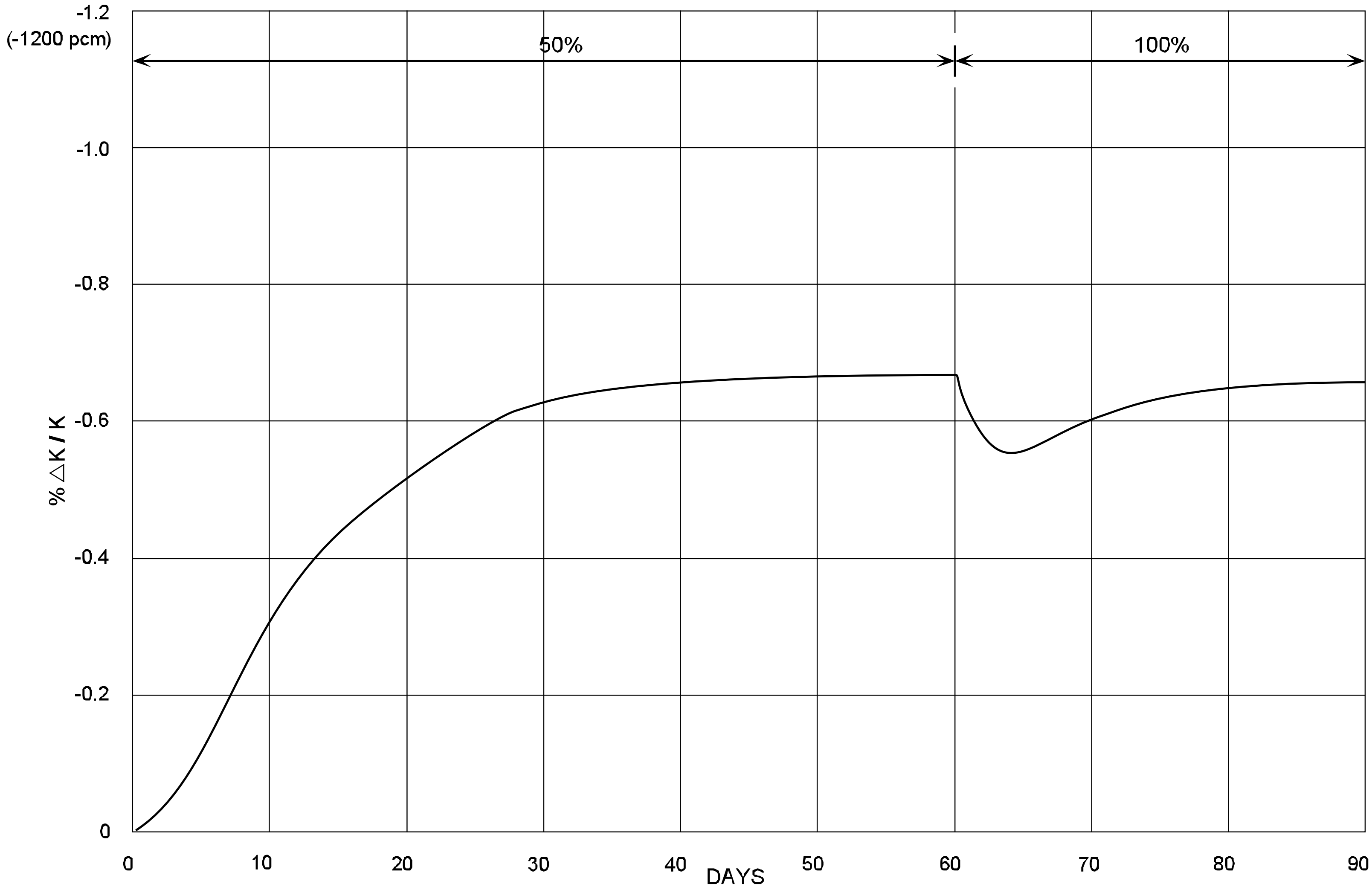


Figure 2.1-17 Samarium Transients Starting with a Clean Core

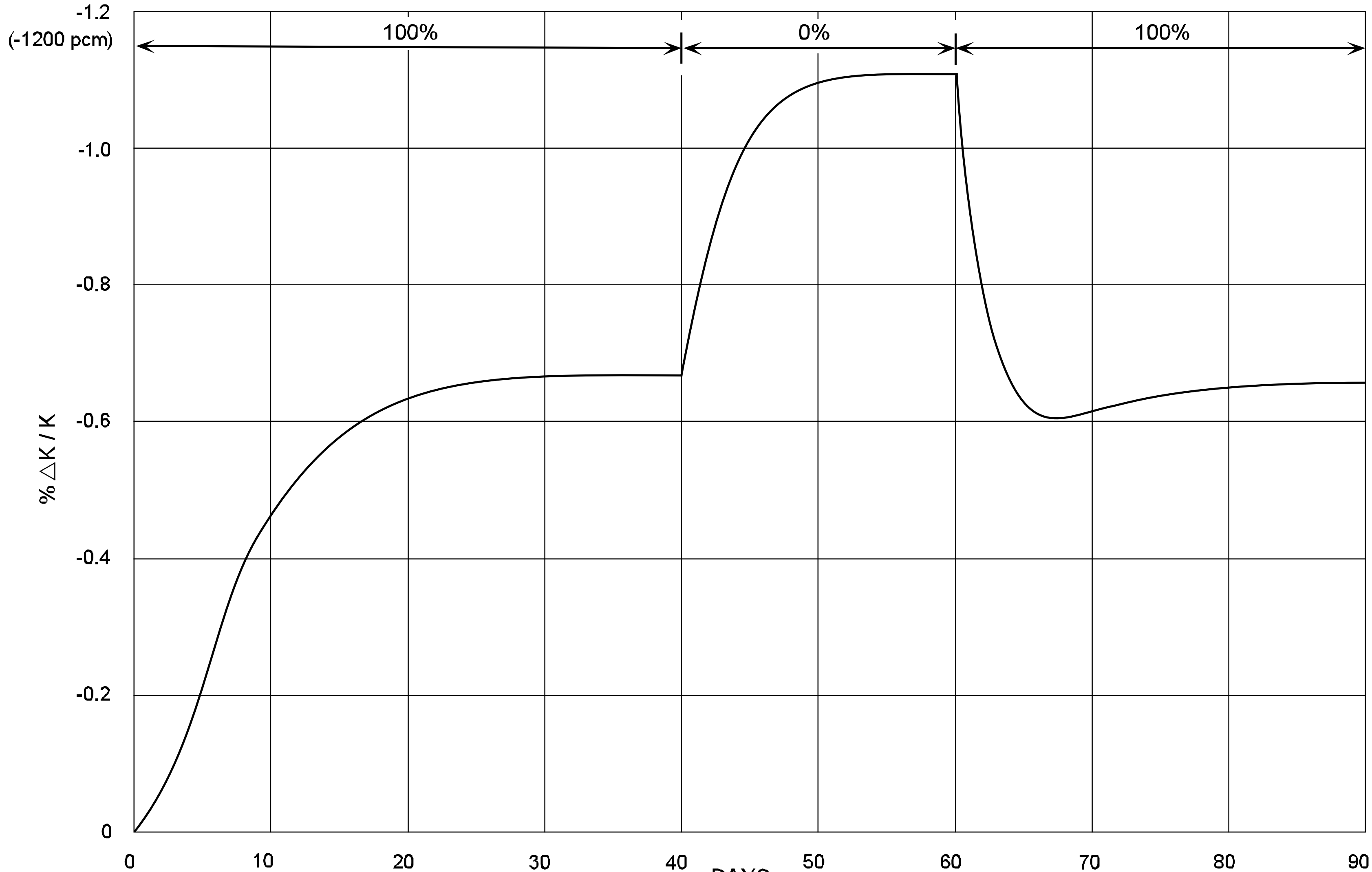


Figure 2.1-18 Samarium Transients Starting with a Clean Core

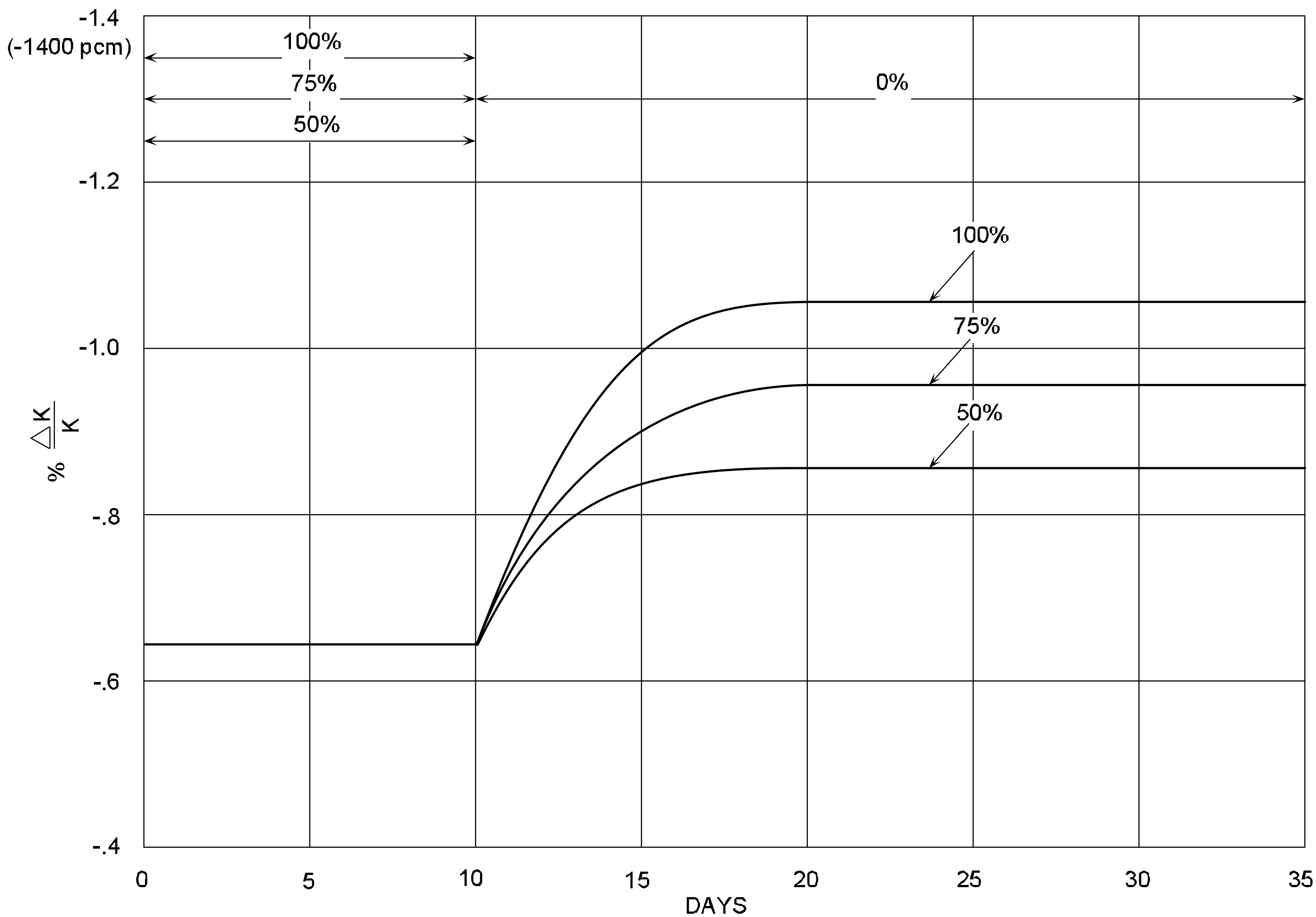
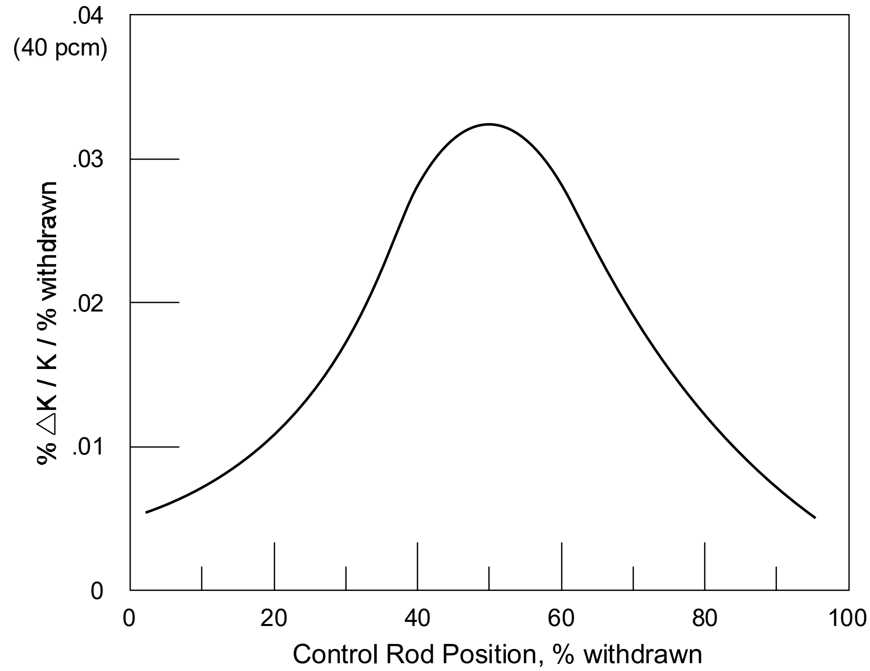
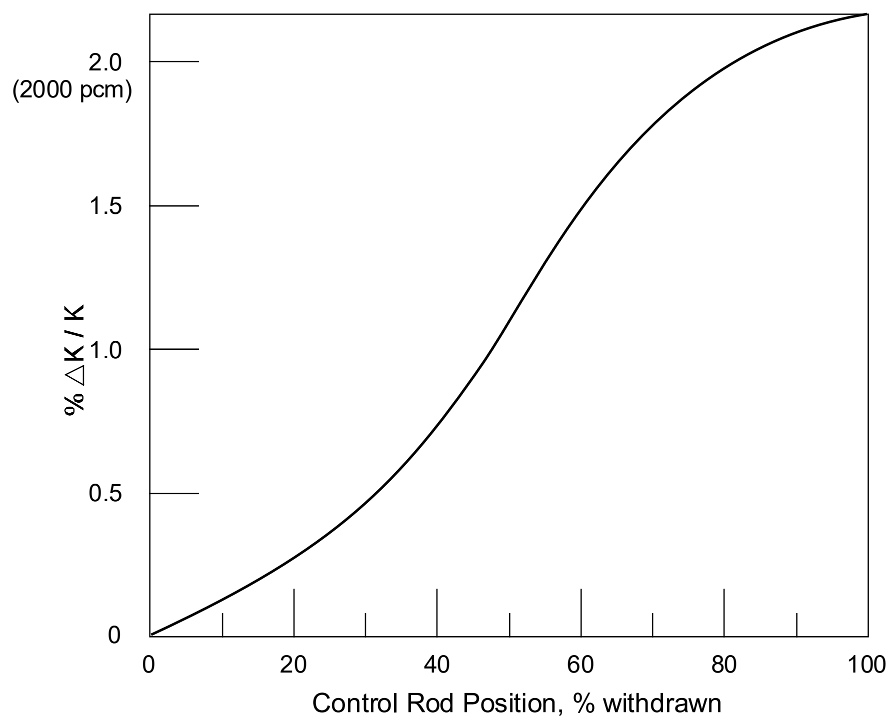


Figure 2.1-19 Samarium Shutdown Transients



(a) DIFFERENTIAL CONTROL ROD WORTH



(b) INTEGRATED CONTROL ROD WORTH

Figure 2.1-20 Integral and Differential Rod Worth

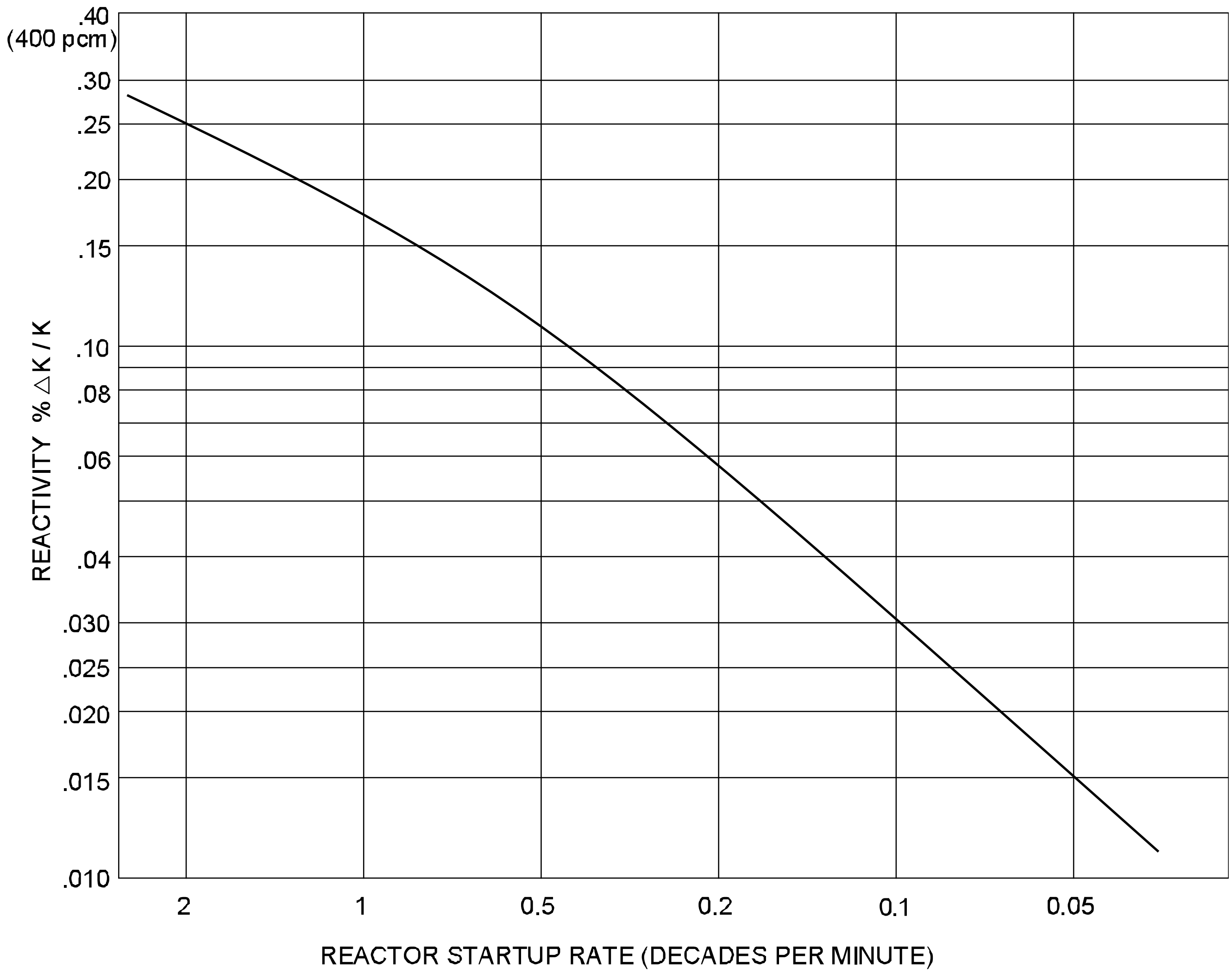


Figure 2.1-21 Reactivity versus Startup Rate

Westinghouse Technology Systems Manual

Section 2.2

Power Distribution Limits

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2.2 POWER DISTRIBUTION LIMITS

Learning Objectives:

1. Define the following terms:

   a. Departure from nucleate boiling (DNB)
   b. Departure from nucleate boiling ratio (DNBR)
   c. Power density (linear heat generation rate)
   d. Heat flux hot channel factor ($F_Q(Z)$)
   e. Axial flux difference (AFD)
   f. Enthalpy rise hot channel factor ($F^N_{\Delta H}$)
   g. Quadrant power tilt ratio (QPTR)

2. Explain why DNBR is required to be greater than a specific limit.

3. Explain why the F_Q limit is varied as a function of core height.

4. Explain why surveillance intervals of 31 effective full power days are adequate to ensure that peaking factor limits are not exceeded.

5. Explain how AFD limits ensure that the F_Q limit is not exceeded.

2.2.1 Introduction

The concept of placing limits on “hot channel factors” or “peaking factors” was introduced to limit the maximum power produced in the fuel to a value consistent with fuel design limitations. These limitations fall into two basic categories:

a. thermal hydraulic design considerations
b. nuclear power distribution considerations

The two are not easily separated but will be discussed separately for ease of clarification. The fuel design limitations provide adequate heat transfer (thermal hydraulic considerations) compatible with heat generation distribution (nuclear or power distribution considerations) in the core. These design limitations ensure adequate heat removal by the reactor coolant system during normal conditions or by appropriate engineered safety features during emergency conditions. The general performance and safety criteria are:

1. Fuel damage is not expected during normal operation and operational transients (Condition I) or any transient conditions arising from faults of moderate frequency (Condition II).
2. The reactor can be brought to a safe state following a Condition III event with only a small fraction of fuel rods damaged. However, sufficient fuel damage might occur to preclude immediate resumption of operation and result in considerable outage time.
3. The reactor can be brought to a safe state and the core configuration can be kept subcritical with acceptable heat transfer characteristics following a transient

arising from Condition IV events.

Since 1970, Westinghouse has been using the classification of plant conditions as described in ANSI Standard 18.2, “Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants,” which amplifies the General Design Criteria of 10 CFR Part 50, Appendix A. This standard divides plant operating conditions into four categories in accordance with the anticipated frequency of occurrence and potential radiological consequences to the public. The four categories are as follows:

- Condition I: Normal Operations
- Condition II: Faults of Moderate Frequency
- Condition III: Infrequent Faults
- Condition IV: Limiting Faults

The basic principle applied in relating design requirements to each of the conditions is that the most frequent occurrences must yield little or no radiological risk to the public and those extreme situations having the potential for the greatest risk to the public shall be those least likely to occur.

Condition I occurrences are those which are expected frequently or regularly in the course of power operation, refueling, maintenance, or maneuvering of the plant. As such, Condition I occurrences are accommodated with margin between any plant parameter and the value of that parameter which would require either automatic or manual protective action.

Condition II faults, at worst, result in a reactor shut down with the plant capable of returning to normal operation. By definition, these faults (or events) do not propagate to cause a more serious fault, i.e., a Condition III or IV category accident. In addition, Condition II events are not expected to result in fuel rod failures.

Condition III occurrences are faults which may occur very infrequently during the life of the plant. They will be accommodated with the failure of only a small fraction of the fuel rods, although sufficient fuel damage might occur to preclude resumption of reactor operation for a considerable outage time. A Condition III fault will not, by itself, generate a Condition IV fault or result in a consequential loss of function of the reactor coolant system or containment barriers.

Condition IV occurrences are faults which are not expected to take place, but are postulated, because their consequences would include the potential for the release of significant amounts of radioactive material. They are the most drastic events which must be designed against and thus represent limiting design bases. Condition IV faults are not to cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of 10 CFR Part 100 limits. Detailed descriptions of and the transients associated with each of these conditions may be found in Chapter 5.0.

2.2.2 Thermal Hydraulic Considerations

The design of the core and its heat transfer system (reactor coolant system) must be compatible. That is, the heat transfer must be equal to or greater than the heat generation rate or overheating and possible damage to the fuel may occur. Both processes (heat generation and heat transfer) should be understood.

2.2.2.1 Heat Generation Process

Of the total heat energy released during reactor operations, 97% is transferred from the fuel to the coolant (energy of all fission fragments, beta particles, some neutrons, and some gammas) and 3% is released directly into the reactor coolant, from the pressure vessel internals, and secondary shield as a result of the heating of these materials by neutrons and gammas. The energy released by the nuclear fission process in a PWR is emitted as heat from the fuel rods. The reactor coolant is circulated through the core and removes the generated heat. The temperature of the coolant increases continuously as it passes through the core. Some local boiling occurs at the fuel rod-coolant interface, although the reactor coolant system is pressurized to prevent bulk boiling during normal operation. The heat energy added to the coolant is measured by the change in its enthalpy, in Btu per pound.

2.2.2.2 Heat Transfer Process

The heat generated in the fuel must be transferred through the fuel pellet, across the pellet-clad gap, and then through the clad to the coolant (Figure 2.2-1). The heated coolant is circulated out of the core and used to boil the water in the secondary side of the steam generators. The thermal conductivity (ability to transfer heat) of the fuel is quite low. The fuel is manufactured in a form that is ceramic or nonmetallic in structure. This results in good fission product retention and a high melting point. Unfortunately, it also results in poor heat transfer characteristics.

Because of this resistance to heat transmission, the temperature gradient within the fuel must be high to achieve a satisfactory rate of heat transfer. Fortunately, the melting point of UO_2 is high enough (5080°F for unirradiated fuel, approximately 4890°F for expended fuel) so that acceptable heat transfer rates can be attained.

Another resistance to heat transfer from the fuel pellet to the coolant is presented by the gap between the pellet and the interior walls of the cladding. The gap conductance is dependent upon the size of the gap, the nature of the gas in the gap, and the extent of direct pellet-to-clad contact. When the fuel is cold, there is clearance between the fuel pellets and the inner walls of the zircaloy rods.

At operating conditions, the highest temperature pellets will be in at least partial contact with the cladding's inner wall. As irradiation progresses, the pellets swell and crack to some extent, increasing the amount of pellet-to-clad contact. Fission product gases mix with the helium gas originally present in the fuel rods. All these factors make the gap conductance variable and difficult to predict. Compared with the other thermal resistances, the cladding presents the least thermal resistance, and the temperature gradient from the inner to outer wall of the cladding is very small.

2.2.2.3 Fluid Heat Transfer

The transfer of heat from the cladding surface to the coolant must also be considered in the heat transfer process. This requires an introduction to thermal hydraulics terminology and concepts.

1. Evaporation is the conversion of a liquid to a vapor.
2. Boiling is the evaporation of a liquid occurring within the body of the liquid by the mechanism of bubble formation.
3. Convection is the transfer of heat from one location to another by fluid motion between regions of unequal density that result from nonuniform heating.
4. Radiation is the transfer of thermal energy by means of electromagnetic waves, with no material medium playing an essential role in the process of transmission.
5. Conduction is the transfer of heat through the conducting medium without perceptible motion of the medium itself.

In a liquid, the types of heat transfer can be broken down into four categories, known as "regimes". These may be best explained by referring to experiments performed with an electrically heated wire submerged in a pool of liquid, a situation similar to the transfer of heat by boiling from any heated surface to a pool.

This experiment relates the heat flux per unit area (or Q/A) to the temperature difference between the surface of the wire and the saturation temperature of the liquid. At low heat transfer rates between the wire surface and the liquid, heat is transferred via natural convection. Natural convection is shown by Regime I on Figure 2.2-2. The heated liquid rises to the surface, where evaporation without the formation of steam bubbles occur. Since temperature, or ΔT, is the "driving force" for transferring heat, the amount of heat transferred increases with the temperature differential while in the natural convection regime.

At a temperature difference of about 10°F, small vapor bubbles start to form at various points along the wire surface. These small bubbles then move into the liquid surrounding the wire and collapse in the cooler water. This agitates the wire/liquid interface promoting better heat transfer. This region of small bubble formation is known as the "nucleate boiling regime" and is designated as Regime II in the figure. In this regime the increase in the amount of heat transferred from the wire surface is due primarily to the increased convective heat transfer due to agitation of the liquid at the heated surface, not due to the heat actually carried away as enthalpy of the vapor in the form of steam bubbles.

When Regime III (partial film boiling regime) is reached, there is a reduction in the amount of heat transfer. This reduction in heat transfer is due to the insulating effect of the formerly mobile nucleate steam bubbles becoming larger and combining to form stationary steam bubbles. Heat removal by radiation through the steam is much less efficient than that of convection or conduction to a liquid. The thermal energy is passed from molecule to molecule in the course of purely thermal motion, with no mass motion of the medium.

When the bubbles become somewhat stagnant, they tend to form an insulating layer between the heated surface and the liquid. In the partial film boiling regime, the film itself is unstable. It spreads over a part of the heated surface and then breaks down. Under these conditions, some areas of the surface exhibit violent nucleate boiling, while film boiling occurs in other areas.

The precise point where the mobile, agitating nucleate boiling ends and where partial film boiling begins is referred to as the “critical heat flux” or “departure from nucleate boiling” (DNB), and is discussed below.

The fourth area, Regime IV, is the film boiling regime. Here, as in the partial film boiling regime, steam blanketing hinders the transfer of heat. With the increasing ΔT, however, the film becomes stable and the heat transfer mechanism is by radiation and conduction, neither of which is very efficient. Heat transfer by radiation requires an extremely large ΔT, which is not attainable in existing commercial reactors without producing considerable fuel damage.

This experiment and its results are not fully applicable to the conditions existing in the reactor coolant system with its forced circulation. Conditions in the reactor coolant system are much more complicated than in the experimental model. It is, however, a close enough approximation that it can be enhanced by computer modeling and actual data input to be used by the designers to predict core conditions with a reasonable certainty.

2.2.2.4 Departure from Nucleate Boiling (DNB)

Pressurized water reactors are designed to operate in the nucleate boiling region at high power levels and are not allowed to operate, at any time, with partial film boiling. Due to the reduction in heat transfer capability that occurs with partial film boiling, excessive fuel rod surface temperatures would actually lower the heat being transferred. This would lead to a larger ΔT between the fuel rods and the coolant, which would lower the heat transfer rate even further. Figure 2.2-2 illustrates this effect. It further illustrates that once the conditions leave the nucleate boiling regime, (point “a”), the ΔT must increase from less than 100°F to slightly more than 1000°F (point “b”) before a net increase in heat flux is realized. This rise of more than 900°F in ΔT occurs as a rise in the temperature of the heated surface.

Once the critical heat flux is reached, the heat flux cannot be increased without a large increase in ΔT in the form of fuel rod surface temperature. This could result in a failure of the fuel. For this reason, the heat flux of the fuel rods must be limited to some value below the critical heat flux.

In an actual core, many things have an influence on the actual point at which DNB or the critical heat flux occurs. Core flow rate, coolant pressure, coolant temperature, coolant channel cross section, and localized variations in the fission rate along the length of the fuel rod can all cause changes in the critical heat flux value. Since many factors vary the point of critical heat flux, it is impossible to predict it with 100% accuracy.

Westinghouse initially used a calculational model known as the “Westinghouse W-3 DNB Correlation” and later used the WRB-1 correlation to assure that core conditions would not result in exceeding the critical heat flux. These correlations employ a computer-assisted program to examine the relationship between the many physical variables and the critical heat flux.

Using variables such as pressure, mass velocity, heated length to point of the critical heat flux, various hydraulic parameters, and grid designs, the WRB-1 correlation predicts the heat flux required to cause DNB. Actual tests were conducted at Columbia University using a range of conditions as described above. Figure 2.2-3 illustrates the difference between the heat flux at DNB predicted by the WRB-1 correlation and the actual heat flux at DNB as determined from the tests. Over 1100 points are plotted on this figure. If the prediction were perfect, all points on this graph would fall on the 45-degree line. However, the prediction of DNB is not exact and, in most cases, either over- or under-predicts the actual point of DNB.

As an example, using Figure 2.2-3, if the predicted heat flux to cause DNB (horizontal axis) for a given set of conditions is 800,000 BTU/hr-ft^2 and the measured value (vertical axis) for the same set of initial conditions was 700,000 BTU/hr-ft^2, a point is placed at the intercept of these two values. In this case DNB occurs at 100,000 BTU/hr-ft^2 less than the predicted value.

Since, in an operating core, the critical heat flux is predicted and never actually attained, a degree of safety margin or conservatism must be applied to the correlation to ensure that the core is operated below the departure from nucleate boiling point. It was concluded, to meet this design criterion, that the limit for DNBR (DNBR is defined as the heat flux required to reach DNB divided by the actual local heat flux) should be set at 1.17 (as predicted by the WRB-1 correlation). This value is displayed as the 0.85-slope line on Figure 2.2-3. This line constitutes the limiting DNBR criterion, and at least 95% of the plotted points must fall above this line.

2.2.2.5 Departure from Nucleate Boiling Ratio (DNBR)

The design criterion established for DNB is that there will be at least a 95 percent probability that departure from nucleate boiling will not occur on “the” limiting fuel rod during normal operation and operational transients and any transient conditions arising from faults of moderate frequency (Condition 1 and 2 events), at a confidence level of 95 percent. For Condition 3 and 4 events (limiting faults), a limited number of fuel rods are allowed to violate the 95/95 DNB criterion. The actual limit depends upon a given plant’s offsite radiation dose release criteria.

The above design criterion ensures safe core operation as discussed below. By preventing departure from nucleate boiling, adequate heat transfer is assured between the fuel cladding and the reactor coolant, which prevents cladding damage as a result of inadequate cooling. The DNBR concept was developed as a measure of the margin of safety existing between the critical heat flux and the actual or existing heat flux. DNBR is defined as:

$$\text{DNBR} = \frac{\text{the heat flux required to reach DNB}}{\text{the actual local heat flux}}$$

Example: If the actual heat flux present at some instant is only half of the heat flux which could produce a departure from the nucleate boiling regime, then:

$$\text{DNBR} = \frac{1.0}{0.5} = 2.0$$

In this instance the DNBR is equal to 2.0.

The minimum allowed DNBR varies depending upon which correlation is used for the calculation. Often the W-3 DNB correlation is used and places the DNBR limit at 1.3. This correlation uses a single tube as the reference point, with correction factors for unheated walls and non-uniform axial heat flux. Further modifications have been made to the W-3 DNB correlation to incorporate L-grid and R-grid fuel assembly designs (Section 3.1), which lower the DNBR limit to 1.24 and 1.28, respectively.

Predicting DNB with greater accuracy was accomplished when Westinghouse developed the WRB-1 (Westinghouse Rod Bundle) correlation. This correlation uses full-length tubes in either 4x4 or 5x5 bundle arrays. The calculations or predictions include both L-grid and R-grid configurations, along with uniform and non-uniform heat flux distributions. Using the WRB-1 correlation, a DNBR limit of 1.17 was shown to meet the 95 x 95 criteria explained earlier.

2.2.3 Nuclear Power Distribution Considerations

As previously discussed, thermal hydraulic considerations place constraints on the design and operation of the core and its support systems. In addition, nuclear power distribution must be held within limits to ensure the integrity of the fuel cladding. The specific design criteria to ensure the integrity of the zircaloy fuel cladding are as follows:

1. DNBR > 1.30, as calculated by the Westinghouse W-3 correlation, or > 1.17 using the WRB-1 correlation. The expected minimum value of DNBR at nominal operating conditions is 2.08.
2. Fuel center line temperature below the melting point of the UO_2 ceramic fuel pellets. This condition is imposed because the change from solid to liquid is accompanied by swelling which could crack the clad. The melting temperature of UO_2 is assumed to be 5080°F minus 58°F for each 10,000 MWD/MTU of burnup. The expected peak value of the centerline temperature at nominal operating conditions is 3275°F.
3. Cladding stress less than the zircaloy yield stress. (Stress is the force applied per unit area.)
4. Cladding strain less than 1%. (Cladding strain is a measure of how much the

cladding has been stretched past its ability to recover elastically. A strain of 1% means that it has been deformed permanently a total of no more that 1% of its original diameter.)

Cladding stress and strain are minimized by limiting the internal fission gas pressure to less than the external reactor coolant system pressure of 2250 psia, and limiting the average cladding temperature to less than 850°F. Above this temperature the minimum ultimate yield strength reduces to the design yield strength.

Some stress and strain occur when the fuel is in contact with the interior wall of the clad. This is due to the fuel having roughly twice the thermal expansion coefficient of the clad. As the power level changes, the temperatures of both the fuel and the clad change. The uneven expansion and contraction of the fuel and clad cause stress and strain. Linear power density, kilowatts of power produced per foot of fuel rod, must also be limited during normal operations (Condition I) so that in the event of a worst-case loss-of-coolant accident (LOCA, a Condition IV event), the criteria of 10 CFR Part 50.46 would be met.

If a LOCA should occur, it is expected to be accompanied by some fuel cladding failure. The idea, then, is to limit the amount of fuel failure that could be expected to occur rather than to prevent cladding failure altogether. In addition to imposing limits on the fuel design, the NRC also imposes minimum design criteria on the Emergency Core Cooling System (ECCS). Each ECCS design must demonstrate the capability to maintain core conditions within five general limits in the event of a worst-case LOCA. These are stipulated in 10 CFR 50.46 and listed below:

a. Peak clad temp. < 2200°F,
b. Clad oxidation < 17% clad thickness,
c. H_2 generation <1% hypothetical maximum,
d. Coolable core geometry maintained, and
e. Long term cooling maintained.

2.2.3.1 Peak Power Limits

Peak power limits are placed on the core to avoid a boiling crisis and to eliminate the conditions which could cause fuel pellet melt. The boiling crisis puts a physical limit on the amount of heat that can be extracted from a fuel rod. The melting point of the fuel material places a limit on the amount of heat that can be generated by the fuel rod. For safety purposes, the license limit on the heat flux is set well below these physical limits.

The most economical way to operate the reactor would be to have the heat flux and power level at all points just equal to the maximum allowable to get the maximum power from each pound of fuel. This cannot be achieved because the neutron flux and the resulting power distribution, is non-uniform. Although attempts are made to “flatten” the radial power distribution with fuel enrichment and burnable poison rods, the flux decreases near the edge of the core. This means that many assemblies around the outer edge of the core operate below license limits. Their power output cannot be increased excessively without violating limits toward the center of the core. Secondly, the heat flux cannot be equal to the maximum allowable at all points along the vertical axis of any channel because the power output at the ends of the channel is lower. If the maximum allowable heat flux is reached near the ends of a channel, it may be exceeded at the middle of the channel.

These and other factors produce differences in power levels throughout the core. In addition, many localized conditions exist to further complicate the situation. These include the location of fuel assembly grid straps, minor manufacturing differences in fuel pellet enrichment and density, gaps between adjacent pellets, a partially inserted control rod, etc.

Since the potential exists for localized “hot spots,” those hot spots must be accounted for. Westinghouse has demonstrated by actual experiments and computational models that the four specific design criteria to ensure the fuel cladding integrity (listed in section 2.2.3) can be met if the maximum power output during normal operations does not exceed 13.6 kW/ft of fuel rod. The value of 13.6 kW/ft then becomes, in effect, the limit to be imposed on peak power output in the fuel.

2.2.3.2 Power Distribution Measurement

Power is proportional to the fission rate, which is in turn proportional to the thermal neutron flux. Thus, local power in the fuel is often taken to be proportional to the thermal neutron flux at the point in question.

If the fuel is to be protected from localized high-power conditions, it is necessary to be able to locate and measure these “hot spots.” If each individual point of each fuel pin could be monitored, then an upper limit of 13.6 kw/ft could be set on local fuel pin power. Monitoring each fuel pin is, however, a physical impossibility.

Since it is impossible to measure each foot of each individual rod, the next best approach is to predict, as accurately as possible, the condition of each location using available information. This consists of the read-out from the incore monitoring system, which is collected by the plant computer. The incore system consists of 6 separate miniature flux detectors that can be driven into the hollow center support thimbles in 58 of the 193 fuel assemblies. As the movable incore detector moves from the bottom to the top of a fuel assembly, and then back down, it provides an electrical output which is transmitted to the plant computer. The computer receives and stores this information once per second. Since the probe travels the full length of the fuel assembly in one minute, the result is a “stack” of points monitored. Instead of a single picture of the core, there are 61 separate pictures collected in each of 58 different fuel assemblies. Having many individual pictures allows a more precisely detailed examination of the core.

Since only 6 detectors are provided, a total of 12 “passes” must be run to monitor all the available assemblies. The small size of the incore movable detectors enables them to “see” highly localized neutron flux conditions. This information is the basis for the computer-assisted calculations to follow. The information generated by the incore system is still in the form of fuel assembly-specific information. It must be extrapolated to include the other, unmonitored, fuel assemblies. The flux level or power detected in any fuel assembly is heavily influenced by the fuel assemblies surrounding the one being monitored. This general diffusion is accounted for in the extrapolation model.

After the information received from the instrumented 58 assemblies has been extrapolated to calculate what is occurring in the other 135 assemblies, a further extrapolation is performed. This involves calculating what each fuel rod is contributing to the power levels, either measured or calculated, for each fuel assembly. With this computer generated information, the fuel design engineer now has an idea about what is occurring in each fuel assembly and in each fuel pin. Not only is the total power known (calculated) for each fuel pin, but also the power level for each elevation of each pin. Remember that the incore detector provided outputs to the plant computer as it traversed the length of the core and provided data at each core slice.

Since the six probes travel together and their locations are known to the computer, the information can be made to reflect relative power levels at any and all core elevations. The information is now in its final form and power distribution throughout the core is known. Every fuel pin has been identified and measured.

The only thing left to do is to make sure that none of the core locations is producing more than the limit of 13.6 kw/ft.

2.2.3.3 Hot Channel (Peaking) Factors

In the early development stages of its core design, Westinghouse found that, in an unrodded core, a relatively constant relationship exists between the peak power in the core and the average power. Since this condition yields a natural flux shape, even during a power level change in which the peak and average values are changing, the ratio remains relatively constant. In other words:

$$\frac{\text{peak}}{\text{average}} = \text{K}, \text{ where K is a constant}$$

The average linear heat generation rate (kw/ft) or power density can be calculated by dividing the total power of the core by the total active rod length. For the plant under discussion, the thermal megawatt rating is 3411 Mwt, 97.4% of which is produced in the fuel. The other 2.6% is contributed by radiation heating of vessel materials. The total number of kw are:

$$3411\text{Mw x } \frac{1000\text{ kw}}{\text{Mw}} \text{ x } 0.974 = 3{,}322{,}314\text{ kw}$$

A similar calculation yields the number of active feet of fuel rods:

$$193\text{ assemblies X } \frac{264\text{ rods}}{\text{assembly}} \text{ X } \frac{11.97\text{ ft}}{\text{rod}} = 609{,}895\text{ ft}$$

The average heat generation rate at full power is:

$$\frac{3{,}322{,}314\,\text{kw}}{609{,}895\,\text{ft}} = 5.45\,\text{kw/ft}$$

This is the average power in one foot of fuel rod during operation at 100% power.

Safety analysis has determined that fuel damage will not result if the peak power does not exceed 13.6 kw/ft. Then at 100% power, the core can be shown to be safe if the ratio of the peak power to average power is 2.5 or less:

$$F_Q\,\text{Limit} = \frac{\text{peak}}{\text{average}} = \frac{13.6\,\text{kw}}{5.45\,\text{kw}} = 2.50$$

In other words, the plant can be safely operated if the peak/avg ratio does not exceed 2.50. In fact, core power distribution limits are placed on this ratio of peak to average. A typical peak power value at 100% power would be 10.9 kw/ft resulting in a ratio of 2.0 (i.e., 10.9 / 5.45), which is well below the limit of 2.50.

2.2.3.4 Peaking Factor Correction Terms

Since calculated values are used instead of actual measurements, and since manufacturing tolerances preclude having perfect, defect-free fuel pellets and pins, the measured values have been conservatively increased. Experiments to match predictive versus actual conditions have demonstrated that the actual peak power is no more than 4.58% greater than the calculated peak power. This was rounded off to 5% and is called the “measurement uncertainty factor.”

In addition to the uncertainty in measuring the magnitude of peak local power density, there is also some uncertainty in precisely locating the peak local power density. This is due to the fact that the measured flux shape produced by the incore detectors and the computer programs is based on the assumption that all fuel rods are identical. Variations from rod to rod in fuel pellet enrichment, density and diameter; in the surface area of the cladding; and in the eccentricity of the pellet-to-clad gap could all make the actual peak power density greater than the measured peak.

Statistical checks indicate that due to the tight quality assurance standards imposed on the fuel rod manufacturing process, it is almost certain that the magnitude of the actual peak local power density is no more than 3% greater than the peak predicted by the incore system and its computational model. This 3% is known as the “engineering uncertainty factor.”

These uncertainty factors are included in the measured value of F_Q. After the measured F_Q is found by the measurement and extrapolation techniques previously described, it is increased by the amount of the uncertainty factors.

F_Q = Total Measured Heat Flux Hot Channel Factor (with correction terms applied)

$$F_Q = \frac{\text{maximum kw/ft}}{\text{average kw/ft}};$$

$$F_Q = F_Q^N \times F_U^N \times F_Q^E$$

where:

F_Q^N = measured and extrapolated nuclear peaking factor, peak nuclear flux to average nuclear flux ratio.

F_U^N = nuclear uncertainty factor, which accounts for possible errors in the measurement techniques involved. This “measurement uncertainty factor” is 1.05.

F_Q^E = engineering uncertainty factor, which accounts for variations in the manufacturing processes and the subsequent deviations in pellet density and diameter, fuel rod eccentricity, and pellet enrichment. This “engineering uncertainty factor” is 1.03.

Example: To illustrate these terms, assume a plant initiated a set of incore data runs. After the data was collected, an off-site computer with the approved math model found, through extrapolation, that the highest measured peak-to-average ratio was 2.0. Using the base formula:

$$F_Q = F_Q^N \times F_U^N \times F_Q^E$$

$$F_Q = 2.0 \times 1.05 \times 1.03 = 2.16$$

The measured F_Q with its correction terms is shown above to be 2.16 and is then compared to the F_Q limit. As shown in this example, the corrected measured value is within the imposed F_Q limit of 2.50.

2.2.3.5 Changes to Peaking Factor Limits

Since the introduction of the peaking factors concept there have been several major changes in the measurement methods, in the math models, and in the basic concept itself. Along with these changes there have been significant changes in the core structure and design. As a result, the peaking factors have undergone several revisions.

As the state of the art has advanced, more accurate and realistic analyses of core behavior under transient and accident conditions have caused several changes in the allowable limits. At one time a maximum of 18.0 kw/ft was considered safe. Using an average of 5.45 kw/ft at 100% power as calculated earlier, this yielded an

F_Q limit of 3.30 (18.0/5.45 = 3.30). Later analysis, however, revealed some errors in the original assumptions. For instance, the early models did not include the possibility that the assumed LOCA could cause fuel swelling and clad burst. This could impede the flow of water from the ECCS which refills the reactor vessel and refloods the core after the initial LOCA blowdown. Delaying or impeding ECCS flow could cause more damage than originally calculated. Since the potential for rod burst could not be eliminated, the only alternative was to reduce the peak allowed kw/ft for normal operation. Therefore, the assumed LOCA would start with a lower peak power.

Similar reductions have occurred due to such diverse conditions as the practice of plugging leaking steam generator tubes (causing an increase in resistance to flow, and heat transfer area reduction), hotter than expected upper head temperatures, math errors found in the zirconium clad/water reaction rates, and fuel densification which causes localized neutron flux peaks.

As a result of the above considerations the F_Q limit at most Westinghouse plants is 2.32. To calculate the equivalent peak power allowed for this value is as follows:

$$F_Q = \frac{\text{Peak Power (kw/ft)}}{\text{Average Power (kw/ft)}}$$; therefore, solving for peak power:

peak power = 2.32 x average power

= 2.32 x 5.45 kw = 12.64 kw/ft

After all the correction terms and factors have been applied, a peak linear power density of only 12.64 kw/ft is allowed for a core originally having been deemed safe operating with a peak of 18.0 kw/ft.

2.2.3.6 Height Dependency Correction Term K(Z)

In addition to modifying the "measured" F_Q as discussed in section 2.2.3.4, it became necessary to modify the F_Q limit to account for another problem. Studies, experiments and computer models revealed that the fuel damage resulting from a LOCA is strongly height dependent. Specifically, the upper areas of the core will experience more damage than the lower areas. This is due to the nature of both the initial blowdown (upper areas uncovered first) and the reflood (upper areas reflooded last).

Additionally, for smaller (3" - 4" diameter) breaks, experiments and computer runs have indicated that reflooding of the top 10" - 12" of the core could be delayed for a significant time. The small break LOCA causes a backpressure which reduces the reflood flow rate.

Rather than reducing the peaking factor limit throughout the core, it was decided to make the limit more restrictive at the higher core elevations. Figure 2.2-4 shows the correction term that must be applied to the F_Q limit. Instead of a single limit that applies from top to bottom, the core now has a specific limit for each core elevation. The new measured peaking factor is $F_Q(Z)$, which is defined as:

$$F_Q(z) = \frac{\text{maximum kw/ft at elevation z}}{\text{average kw/ft in the core}}$$

For instance, the correction term for elevations between 0 and 6 ft is 1.0. This means that the $F_Q(z)$ limit for all locations below 6 ft. is the F_Q limit multiplied by the height correction term K(z), or

$F_Q(z)$ limit = F_Q limit x K(z)

= 2.32 x K(z) =

= 2.32 x 1.0 = 2.32

There is no reduction or penalty imposed on the limit at core elevations less than 6.0 ft. For higher elevations, however, the correction term varies with core height. Between 6.0 feet and 11.0 feet, the correction term reduces linearly to approximately 0.94. This reduction accounts for a large LOCA, which would uncover the upper half of the core first and reflood it last. Imposing a more restrictive limit precludes operating the core with power tilted toward the top. A combination of an upward power tilt and a subsequent LOCA could exceed the fuel design limits. With more restrictive limits, this possibility is reduced. For example:

At 11.0 ft, K(z) = 0.94; therefore, the $F_Q(z)$ limit = 2.32 x 0.94 = 2.18

The highly restrictive values of K(z) above the 11.0-ft elevation are to preclude high power levels in the last 12 inches of the core. In this area, the “small-break LOCA” analysis requires an additional limitation to account for the damage resulting from backpressure increases which could oppose the reflood rate (i.e., reducing the reflood rate to less than 1 in./sec as defined in 10 CFR 50 App. K). This restriction could occur if the break size were large enough to cause a blowdown of the core area but not large enough to allow the displacement of steam out the break when the ECCS starts reflooding the core. This impeding of the reflood water occurs to the extent where additional core damage results in the last 10 – 12 in. of the core. At the 12-ft level the correction term is 0.666:

$F_Q(Z)$ limit = 2.32 x K(z) = 2.32 x 0.66 = 1.53

It should be understood that all of these power distribution limits are operating limits. They ensure an acceptable power distribution at the start of the accident, so that the accident does not cause fuel damage in excess of that stipulated by the ECCS design criteria.

2.2.3.7 Enthalpy Rise Hot Channel Factor

The limits on the heat flux hot channel factor, $F_Q(z)$, ensure that the peak power density does not exceed its limit and that the peak cladding temperature after a LOCA will not exceed 2200°F. However, limiting $F_Q(z)$ does not in itself ensure that DNB will not occur. DNB depends not only on the local power density but also on the local enthalpy and flow rate of the coolant. Consider a case where $F_Q(z)$ is under the limit at each core elevation, but the maximum heat flux at several core elevations occurs in the same coolant channel. In this case, the heat flux is limited at each location, but the coolant enthalpy increases more in that coolant channel than in any other. DNB is more likely to occur in that channel because the heat flux that causes DNB is lower when coolant enthalpy is higher. Therefore, another peaking factor is needed to protect against such cases. This peaking factor is called the enthalpy rise hot channel factor, and is defined as:

$$F^N_{\Delta H} = \frac{\text{maximum integrated rod power}}{\text{average integrated rod power}}$$

A typical technical specification limit for the enthalpy rise hot channel factor is:

$F^N_{\Delta H} \leq 1.49[1 + 0.3(1 - P)]$, where P = fraction of full power

2.2.3.8 Quadrant Power Tilt Ratio

Quadrant power tilt ratio (QPTR) is defined in technical specifications as:

> The ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.

The four upper and lower excore power range detectors are the instruments used to calculate the QPTR. If one of these detectors is inoperable the remaining three detectors will be used for computing the average.

The limit that is placed on the QPTR is 1.02. If the QPTR exceeds the limit and cannot be restored below its limit, thermal power must be reduced to restore calculated safety margins. If the QPTR were to exceed its limit it would most probably be due to a misaligned control rod.

2.2.3.9 Axial Flux Difference and Xenon Transients

One of the few conditions which could cause flux and power levels to be tilted toward the top of the core and exceeding the restrictive $F_Q(z)$ limits in that portion of the core, is a xenon transient. The concentration of xenon at any given location in the core is transient in nature. If the neutron flux levels in the core are allowed to be high at some elevations and low in others, the xenon concentrations will also be of varying magnitudes. The following is an example of how a xenon transient could be initiated:

1. One bank of control rods is inserted into the core to the mid-plane while maintaining full power. This condition exists for 24 hours. While the rods are in the core, they depress the neutron flux in the upper half of the core and force a high flux to exist in the lower half. This initially causes the xenon in the lower half of the core to experience a high burn-up rate, and some hours later a new, higher xenon concentration is reached, consistent with the higher neutron flux and fission rate. The upper half of the core undergoes the opposite change: an initial increase in xenon concentration followed by a lower equilibrium xenon concentration.
2. At the end of the 24-hour period, the rods are withdrawn from the core. Since the two halves of the core now have different xenon levels, the flux will be depressed in the lower half of the core and will increase in the upper half of the core. This effect will eventually reverse itself in a cyclic manner, with each swing of xenon and flux being of a smaller magnitude. Over a period of approximately 48 hours, the transient should dampen itself out.

The problem, however, is in the initial swing of flux levels which displace the flux upward. With the highly restrictive $F_Q(z)$ limits at the higher elevations of the core, the limits would probably be exceeded.

To prevent exceeding these limits, operating conditions have been imposed which will minimize xenon transients. The most important of these are the axial flux difference (AFD) limits. AFD is a measure of the imbalance between the upper and lower halves of the core in terms of power or flux (ϕ). AFD is defined as:

AFD or $\Delta\phi = \phi_{top} - \phi_{bottom}$,

where ϕ is expressed as a fraction of rated thermal power (RTP).

The AFD is determined from the outputs of the upper and lower excore neutron detectors.

For plants operating with “constant axial offset control,” the AFD limit involves a target band, as shown in Figure 2.2-5, and the collection of “penalty minutes” for time operated outside the target band. This target band, +5% and -5% around the target, defines, the allowed variation from the natural flux profile of an unrodded core. As an example, assume the core is operating at 100% power with all rods out, and the delta flux target is -10%. The core would then be able to operate with a delta flux of -15% to -5% without collecting any penalty minutes. The + 5% and - 5% flux difference around the target allows for a small amount of movement of the control rods.

Since the xenon distribution and concentration is time and flux dependent, the longer the core operates outside its target band, the greater the chance of initiating a xenon transient. Therefore, after 60 penalty minutes have accumulated, in a sliding 24-hour period, operation above 50% power is not allowed until the potential for a xenon transient has abated. In addition, if the delta flux exceeds some maximum value, as shown by the maximum AFD limit line, the delta flux must be reduced. The delta flux must be reduced to a value less than this absolute limit within 15 minutes or the power of the core must be reduced to less than 50%. This lower power level provides additional margin to core thermal limits while the xenon transient is dampened.

For some plants an analysis has been completed which allows “relaxed axial offset control.” For these plants, the axial flux difference target band is no longer applicable and the axial flux difference is limited to the area defined by the absolute limits indicated on Figure 2.2-5. However, for plants incorporating the relaxed axial offset, the absolute limit is somewhat modified in size and goes to 100% power.

2.2.3.10 Operational Limits

A problem with the technique described above for measuring the power distribution throughout the core lies in the fact that it is not an on-line system. Typically, incore flux mapping is performed every 31 effective full power days (EFPD). It takes one or two hours to run the incore system through the flux-mapping routine, and the information collected by the on-site computer may have to be transmitted to an off-site computer of sufficient capacity to run the computations and extrapolations. The entire process can take several days to complete. Hence, detailed power distribution data is not available for demonstrating compliance with peaking factor limits on a day-to-day basis. As a result, other methods are employed to ensure safe operation of the core between flux mapping runs.

To ensure that between flux maps the core is operated within the prescribed limits for the heat flux hot channel factor and for the enthalpy rise hot channel factor, technical specifications require compliance with four operational requirements. Such compliance ensures that the peaking factor limits are not exceeded between the required surveillance intervals. These operational requirements are as follows:

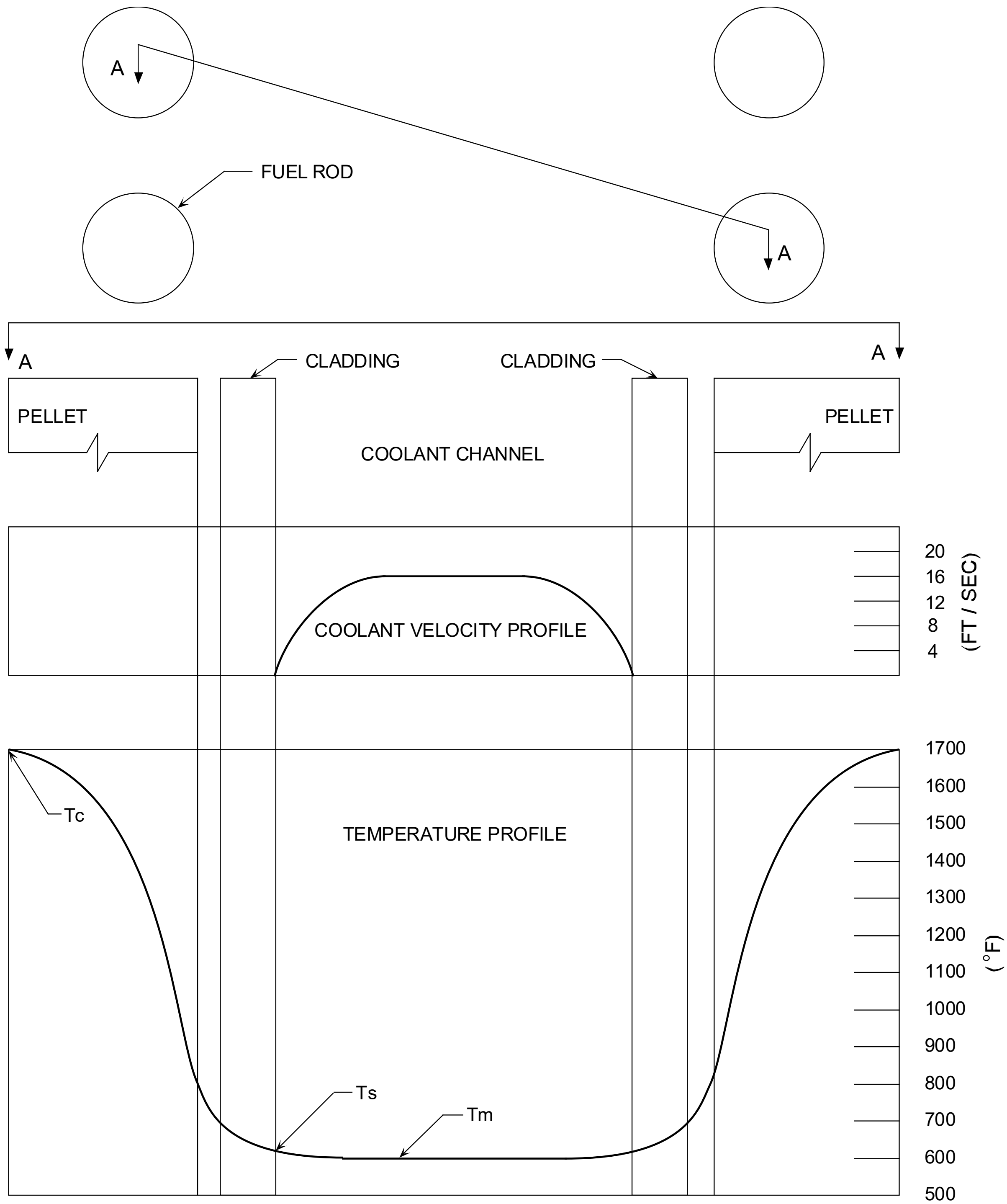
1. Control rod group alignment limits: Individual indicated rod positions are maintained within 12 steps of their group demanded position. A dropped or misaligned control rod may cause excessive power peaking.
2. Control bank insertion limits: Control rod banks are operated within the specified insertion, sequence, and overlap limits. Compliance with the insertion limits preserves an acceptable axial power profile for the core; an excessively inserted bank would likely result in a bottom-skewed power distribution.
3. Axial flux distribution: The AFD is maintained within the specified limits. As described above, compliance with the AFD limits prevents a highly top- or bottom-skewed axial power distribution and minimizes the potential for xenon transients.
4. Quadrant power tilt ratio: The QPTR is maintained within the specified limits. Compliance with the QPTR limit minimizes the potential for excessive power peaking by preventing an undetected change in the gross radial power distribution.

In summary, AFD and QPTR are direct and continuous measures of the core’s “global” power distribution. Staying within their limits and proper operation of the control rods should maintain acceptable peaking factors on a continuous basis. The 31-EFPD frequency for peaking factor verification via flux maps is thus adequate to monitor changes in power distribution with core burnup, because such changes are slow and well controlled with appropriate observance of operational limits.

2.2.4 Summary

The heat generated in the core must be removed by the coolant in order to prevent or to minimize fuel damage. To be reasonably sure that core heat generation does not exceed the heat removal capability of the coolant, limitations have been placed on peak power density and DNBR. In order to meet these limits, certain peaking factors and operational requirements must be maintained.

If the peaking factors are limited and the operational requirements are met, there is a reasonable assurance that the fuel will not be damaged during normal and transient operations and that fuel damage will be limited during accidents. To ensure that the peaking factor limits are not exceeded between surveillences, the operational limits on control rod alignment, control bank insertion, AFD, and QPTR are observed.



Tc - Pellet Centerline Temperature Ts - Rod Surface Temperature

Tm - Moderator Temperature

Figure 2.2-1 Local Radial Temperature and Velocity

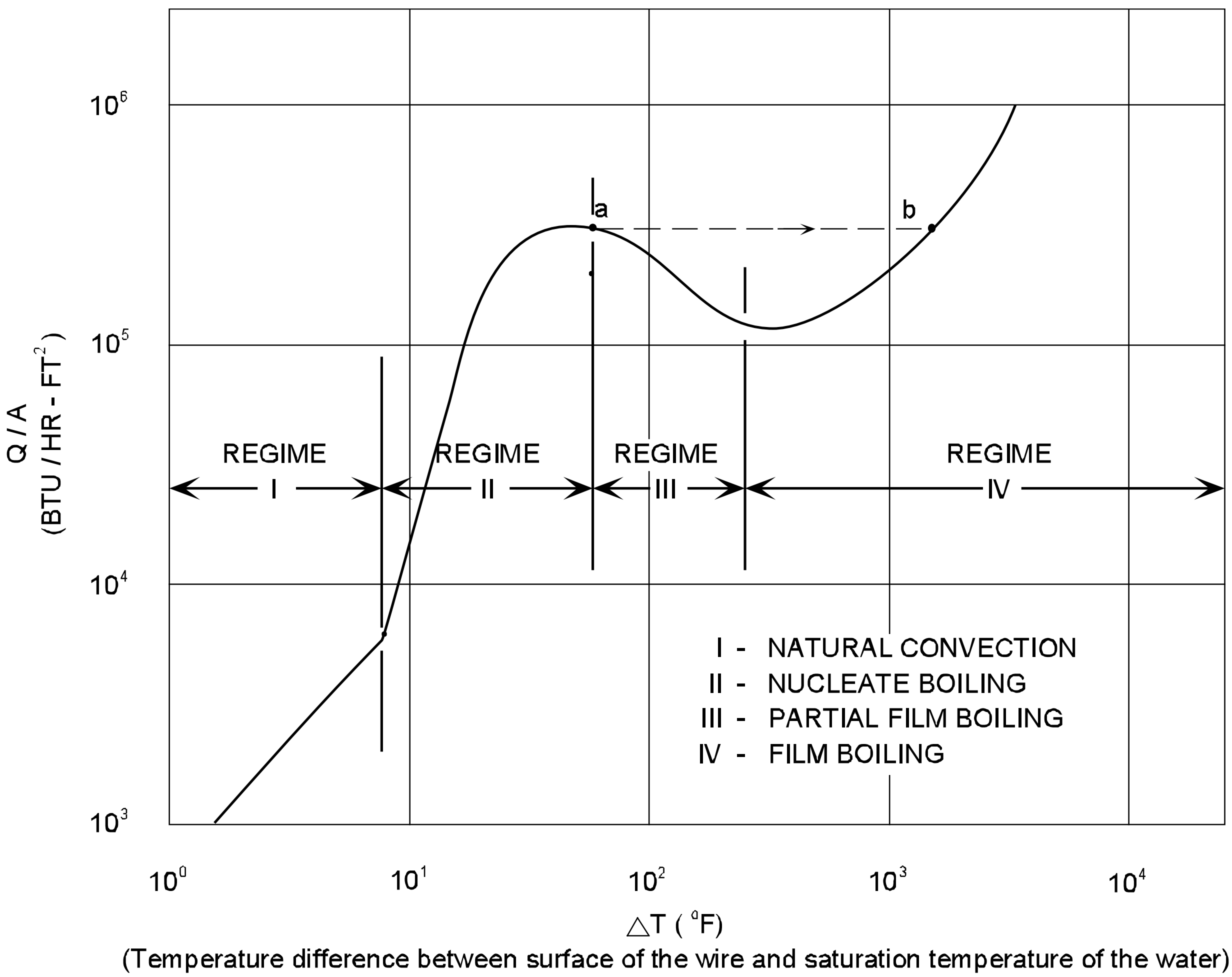


Figure 2.2.2 Heat Rate vs. Temperature Difference

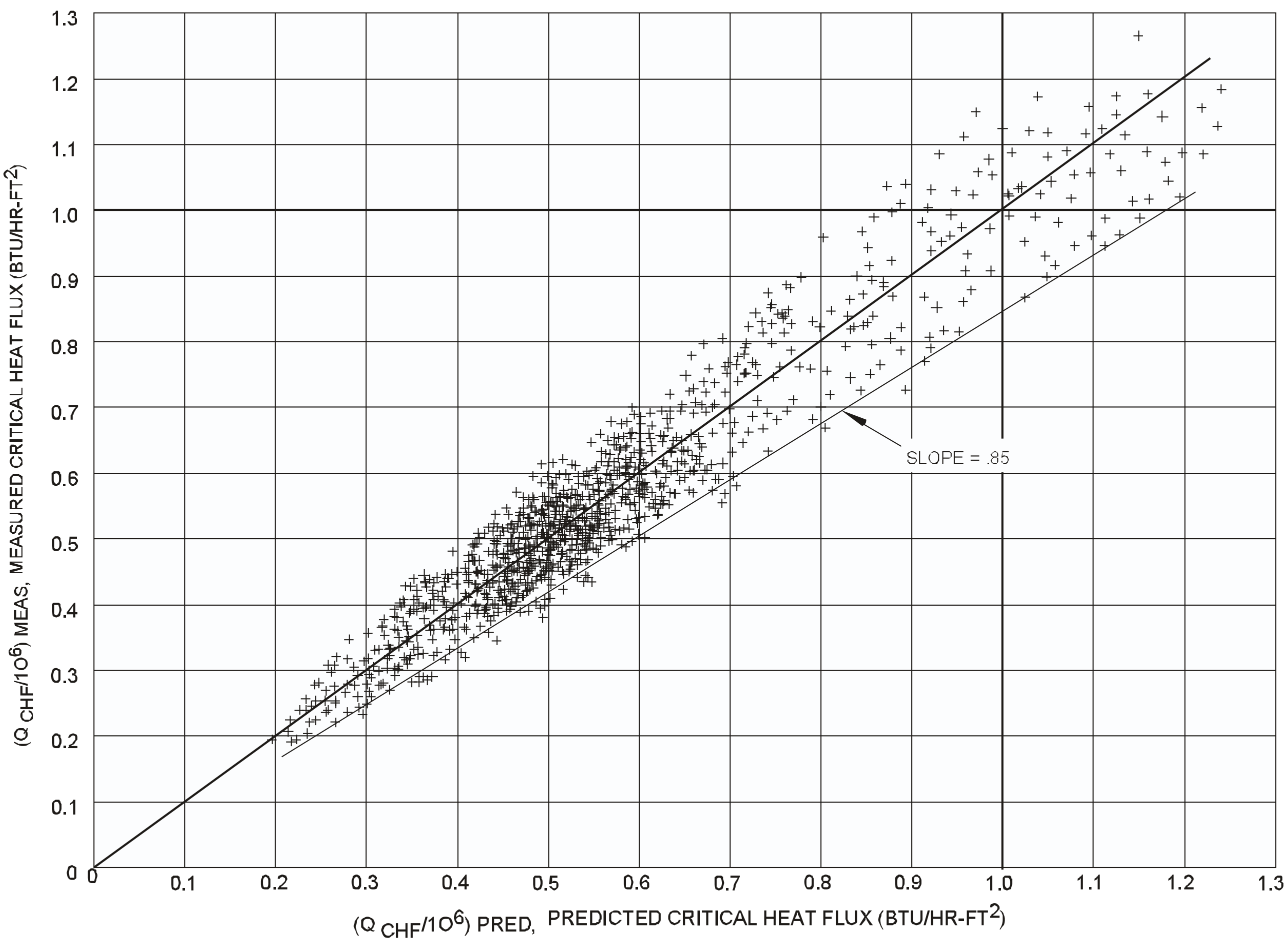


Figure 2.2-3 Measured vs. Predicted Heat Flux

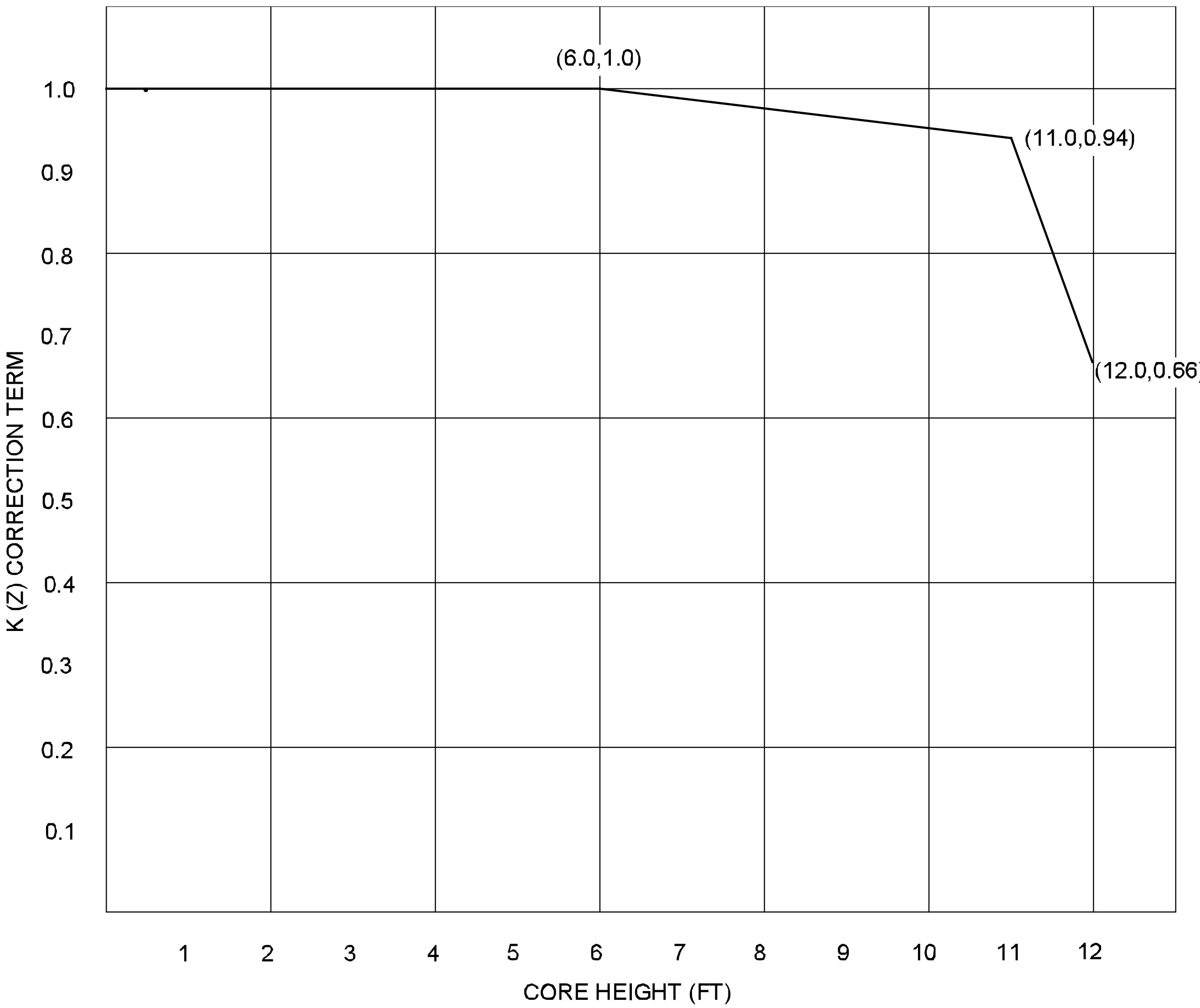


Figure 2.2-4 K(Z) Correction Term

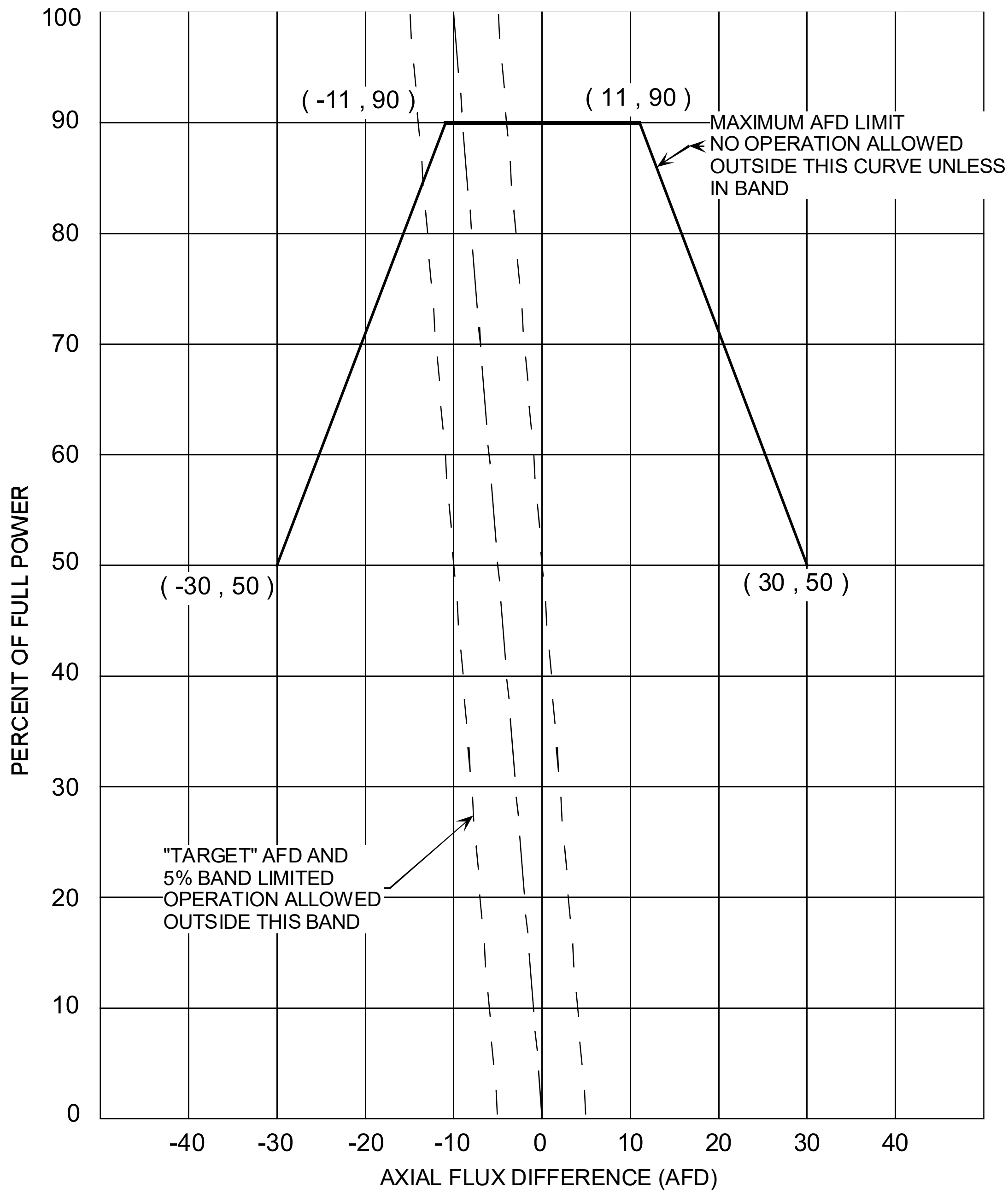


Figure 2.2-5 Axial Flux Difference Limits

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Chapter 3

REACTOR COOLANT SYSTEM

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3.0 REACTOR COOLANT SYSTEM

The Reactor Coolant System (RCS), as shown in Figure 3.0-1, consists of the reactor vessel, which contains the nuclear fuel, and four parallel heat transfer loops. Each loop contains a steam generator, a reactor coolant pump, associated piping and valves, and instrumentation for both control and protection. In addition, the system includes a pressurizer, a pressurizer relief tank, and a number of penetrations for connection of auxiliary systems and components necessary for normal or accident operations of the Reactor Coolant System. All RCS components are located inside the containment building.

The reactor vessel, as discussed in Section 3.1, is part of the Reactor Coolant System pressure boundary and is capable of accommodating the temperatures and pressures associated with operational transients. The reactor vessel supports the reactor core and control rod drive mechanisms.

The Reactor Coolant System, as discussed in Section 3.2, provides sufficient heat transfer capability to transfer the heat produced both during power operations and when the reactor is shutdown. In addition, heat may be transferred to the steam and power conversion system during the first phase of a plant cooldown.

The system heat removal capability under power operations and normal operational transients, including the transition from forced to natural circulation, assures no fuel damage within the operating limits permitted by the reactor control and protection systems.

This system provides the light water used as the neutron moderator and reflector and as a solvent for chemical shim control. The reactor coolant maintains the homogeneity of the soluble neutron poison concentration and controls the rate of change of coolant temperature such that uncontrolled reactivity changes do not occur.

The pressurizer maintains the reactor coolant system pressure during various modes of operation and is designed to limit pressure transients. During an increase or decrease in plant load, the reactor coolant volumetric changes are accommodated via the surge line to the pressurizer.

Reactor coolant pumps provide the reactor core with sufficient coolant flow to remove the heat that is being generated as a result of the fission process. This coolant then flows to the steam generators and transfers this heat to the secondary water, thereby generating steam to be used by the turbine generator.

Steam generators are provided to supply high quality steam to the turbine. The tube and tube sheet boundaries are designed to prevent the transfer of reactor coolant system activity to the secondary system. The layout of the RCS, with the heat sink (steam generators) located above the heat source, assures natural circulation capability following a loss of forced flow.

The RCS serves as a boundary for containing the coolant under operating temperature and pressure conditions and for limiting leakage to the containment atmosphere. The RCS piping contains demineralized light water which is circulated at a flow rate and temperature consistent with achieving the design reactor core thermal and hydraulic performance.

The RCS pressure boundary is defined as those systems and/or components which are subjected to full reactor coolant system pressure and include the following:

1. Reactor vessel including the control rod drive mechanism housings;

2. Reactor coolant side of the steam generators;

3. Reactor coolant pumps;

4. Pressurizer;

5. Pressurizer safety and relief valves;

6. Interconnecting piping, valves and fittings between major components; and

7. Piping, fittings and valves connecting the auxiliary or support systems up to and including the second isolation valve (from the high pressure side) in each line.

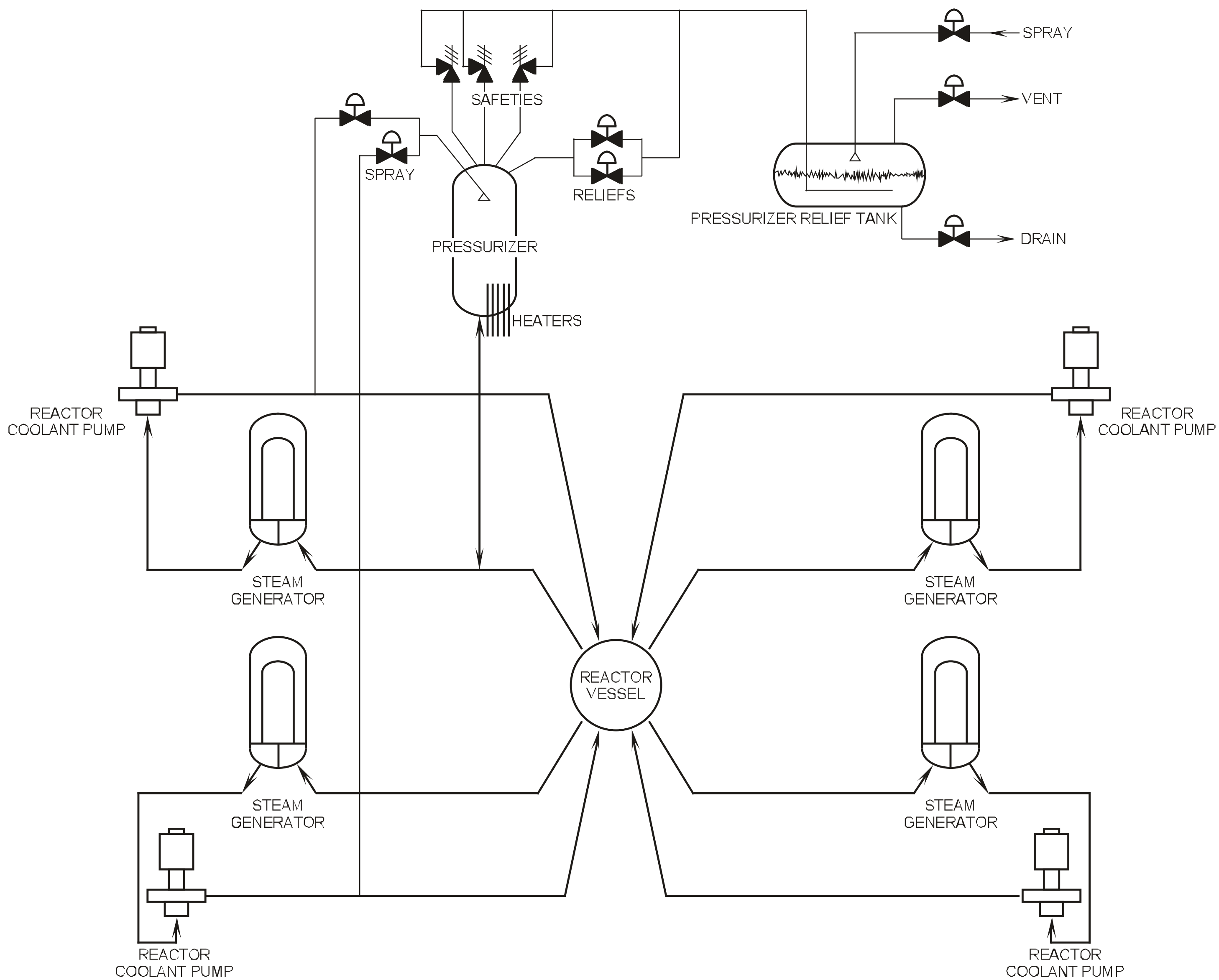

Figure 3.0-1 Reactor Coolant System

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Section 3.1

Reactor Vessel and Internals

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3.1 REACTOR VESSEL AND INTERNALS

Learning Objectives:

1. State the purposes of the following major reactor vessel and core components:

    a. Internals support ledge
    b. Neutron shield pad assembly
    c. Secondary support assembly
    d. Internals packages
    e. Neutron sources
    f. Burnable poisons
    g. Thimble plug assemblies
    h. Irradiation specimens

2. Describe the flow path of reactor coolant from the inlet nozzles to the outlet nozzles of the reactor vessel.

3. List the core bypass flow paths.

4. Describe the physical arrangement of the following assemblies, including the purposes of the component parts listed:

    a. Fuel assembly

    - fuel rods
    - spring clip grid assembly
    - guide thimbles
    - top and bottom nozzles

    b. Control rod assembly

    - rodlets
    - spider
    - hub
    - drive shaft

    c. Rod drive mechanism

    - magnetic coils
    - gripper latches
    - pressure boundary

5. Describe the reactor vessel head seal arrangement.

6. Describe how the reactor vessel is supported.

3.1.1 Introduction

The reactor vessel and its internals contain the heat source for the nuclear steam supply system in the form of the fuel assemblies in the core area. The cladding of the fuel assemblies provides the first barrier to the release of fission products to the environment. The fuel assemblies are supported and held in alignment by the internals packages within the reactor vessel. Additionally, the internals packages provide flow paths for the coolant to remove the heat from the fuel and distribute it to the coolant loops for circulation.

3.1.2 System Description

A simplified diagram of the reactor vessel and internals is shown in Figure 3.1-1. More detailed cutaway and cross-sectional diagrams can be found in Figures 3.1-2, 3.1-3, and 3.1-4, respectively, and are used for the following descriptions.

The reactor vessel is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. The vessel contains the reactor core, core support structures, control rods and other components directly associated with the core.

The vessel inlet and outlet nozzles are located in a horizontal plane just below the reactor vessel flange but above the top of the core. Coolant enters the vessel through the inlet nozzles and flows down the core barrel-vessel wall annulus,

turns at the bottom and flows up through the core to the outlet nozzles.

The reactor internals are comprised of the upper support structure, the lower core support structure, and the incore instrumentation support structure. They are designed to support, align, and guide the core components, direct the coolant flow to and from the core, and to support and guide the incore instrumentation. The fuel assemblies are arranged in a roughly circular cross-sectional pattern.

The fuel is in the form of slightly enriched uranium dioxide ceramic pellets. The pellets are stacked within zircaloy-4 tubular cladding which is plugged, and seal welded at the ends to encapsulate the fuel. The fuel rods are internally pressurized with helium during fabrication. Heat generated by the fuel is removed by demineralized light water which flows upward through the fuel assemblies and acts as both moderator and coolant.

The fuel assembly loading arrangement for an operating cycle is shown in Figure 3.1-5. Refueling is typically accomplished by removing part of the core and replacing it with new fuel. The remaining parts of the core are shuffled. The exact arrangement of the core will depend upon nuclear engineering calculations and vessel embrittlement concerns. For example, to reduce the neutron flux on the vessel, the older fuel can be placed on the outside of the core and the new fuel loaded in the center.

Movable neutron absorbing control rods, designated as Rod Cluster Control Assemblies (RCCAs), are provided to accomplish large rapid reactivity additions for reactor control or shutdown purposes. Each RCCA is identical and consists of a number of individual absorber rods attached to a common spider and hub assembly. These absorber rods fit within hollow guide thimbles in the fuel assemblies.

As shown in Figure 3.1-1 and 3.1-2, the fuel assemblies are positioned and supported vertically in the core between the upper and lower core plates. These plates are manufactured with pins which fit into holes in the fuel assembly top and bottom nozzles to provide lateral support. The pins maintain the fuel assembly alignment, which ensures free movement of the RCCAs in the fuel assembly without binding or restriction between the rods and their guide surfaces.

3.1.3 Component Descriptions

3.1.3.1 Reactor Vessel

The reactor vessel is comprised of (1) a flanged cylinder, made of welded rolled plates or ring forgings, welded to a hemispherical bottom and (2) a removable, flanged and gasketed, hemispherical upper head. The vessel is designed to provide the smallest and most economical volume required to contain the core, core support structures, control rods, and flow directing members of the internals packages. The electromechanical control rod drive mechanisms (CRDMs) and incore temperature instrumentation supports are attached to the reactor vessel head. The bottom of the vessel contains penetrations for the incore nuclear instrumentation. All penetrations are welded to their respective head to minimize coolant leakage.

Inlet and outlet nozzles are located in a horizontal plane below the reactor vessel flange but above the top of the fuel assemblies. Coolant enters the reactor vessel through the inlet nozzles and flows down the annulus between the vessel wall and the core barrel of the core support structure, then turns at the bottom and flows up through the core to the outlet nozzles. All reactor vessel internals are supported from the internals support ledge, which is machined into the reactor vessel flange. Reactor vessel design parameters are listed in Table 3.1-1.

Reactor Vessel Construction

The reactor vessel and head are constructed of manganese-molybdenum alloy steel, with all surfaces in contact with the reactor coolant clad with weld-deposited stainless steel for corrosion resistance. The method of construction is a number of ring forgings and/or rolled plates welded together to form the large reactor vessel, as shown in Figure 3.1-6.

Samples of reactor vessel and weld materials are provided to evaluate the effect of radiation on the fracture toughness of the reactor vessel. The reactor vessel surveillance program uses a number of specimen capsules located in irradiation specimen guides (guide baskets) attached to the outside of the neutron shield pads (Figure 3.1-3). There are two single holders and two double holders. The specimens are positioned at about core midplane height. Dosimeters are also included to evaluate the level of flux experienced by the specimens and vessel wall.

The bottom head of the vessel contains 58 penetration nozzles for connection and entry of the incore nuclear instrumentation. Each nozzle is attached to the inside of the bottom head by a partial penetration weld and extends 12 inches up into the vessel. The nozzles join to the lower internals assembly with a slip fit. Stainless steel conduits are welded to these nozzles below the reactor vessel and are extensions of the Reactor Coolant System (RCS) pressure boundary up to the seal table. At the seal table, a mechanical seal is made to each incore instrument guide thimble, which is inserted inside one of the conduits. The guide thimble is sealed and dry, while the space between the conduit and guide thimble is subjected to reactor vessel pressure. Details of the incore nuclear instrumentation may be found in Section 9.2.

The cylindrical portion of the reactor vessel below the refueling seal ledge and the vessel bottom head are permanently insulated with metallic reflective-type insulation. This insulation consists of inner and outer sheets of stainless steel spaced three (3) inches apart, with the multiple layers of stainless steel and the air between the sheets acting as the insulating agent. Removable panels of this insulation are provided for the reactor vessel flange and head area and also at the vessel inlet and outlet nozzles to facilitate refueling operations and inservice inspections.

Reactor Vessel Flange

The reactor vessel flange is a ring forging that is 32.5 inches wide and contains 54 threaded holes for the studs which hold the vessel head in place. The reactor internals hang from a ledge on the inside surface of the flange. A sealing area is provided on the outside surface of the flange so that a temporary seal may be made between the reactor vessel and the refueling canal liner.

Reactor Vessel Head

The reactor vessel closure head assembly (Figures 3.1-1 and 3.1-2) is a flanged hemispherical component bolted to the vessel by 54 large threaded studs. The head flange is sealed to the vessel flange by two concentric, self-energizing, metallic O-rings which fit into grooves machined in both flanges (Figure 3.1-7). The O-rings are attached to the head by clips to ensure proper alignment during installation. Seal leakage is detected by means of two leak off connections: one between the inner and outer O-rings (normal alignment), and one outside the outer O-ring (must be manually aligned). Leakage is detected by a leak-off line temperature detector, which alarms in the control room. The leakage is directed to the Reactor Coolant Drain Tank (RCDT) via check valves which require two (2) psid to unseat. The RCDT high pressure setpoint of six (6) psig ensures that the level in the leak-off line does not rise to the point where there could be flow out of the vessel flange.

The reactor vessel closure head studs are loosened and retorqued as required using hydraulic stud tensioners. A stud tensioner (normally three [3] are used simultaneously to torque the head evenly) grips the stud, which is threaded into the reactor vessel flange, and stretches it. Then the nut is tightened, and the tension released, producing a correctly torqued stud. The normal procedure is to torque the studs in two stages to eliminate warping. Any time the head is removed, new O-rings are installed to ensure a good seal. Proper alignment of the head during installation is accomplished by the use of long guide studs threaded into several of the holes in the vessel flange. These guides are then aligned with the proper holes in the closure head flange as the head is lowered into place during reactor assembly. When the studs are tightened, the flanges hold the reactor internals in place.

Reactor vessel head penetrations include:

1. CRDM adapters: These penetrations are attached by partial penetration welds to the underside of the closure head. The upper end of each adapter contains threads for attachment of a control rod drive mechanism housing. The housing and penetration are then sealed by a welded flexible canopy seal. A long closed tube called the rod travel housing is attached to the top of the control rod drive mechanism housing to accept the control rod drive shaft as the control rod is withdrawn. The rod travel housing is, therefore, an extension of the reactor vessel pressure boundary and is filled with high pressure reactor coolant during normal operation. A vent valve is installed at the top of each rod travel housing, but it is not normally used due to possible leakage problems.
2. Reactor vessel head vent: This connection is a 3/4-in. outside diameter inconel tube which passes through the upper head and is increased in size to one (1) inch in diameter. The penetration is secured to the interior surface of the head with a partial penetration weld. This penetration is capped but does provide the tap for the reactor vessel head venting system.
3. Reactor Vessel Head Venting System (RVHVS): This system can be used to remove noncondensable gases or steam from the reactor vessel head under certain conditions when these gases could disrupt natural circulation core cooling (Figure 3.1-8). This system was installed as a result of the accident at Three Mile Island. When the RVHVS is operating, flow from either vent line enters the containment atmosphere. An orifice is installed to limit the flow of hydrogen from the reactor coolant system to permit a reasonable venting period without exceeding containment atmosphere combustible limits. In addition, the orifice is designed to limit flow to within the capacity of one centrifugal charging pump in the event of a ruptured vent line or an inadvertent opening of the vent valves. The solenoid valves in each vent line are powered from redundant vital buses. These valves are normally closed and are energized to open. They fail closed on a loss of electrical power. The RVHVS is operated from the main control board. There are no interlocks associated with this system, and all venting operations require manual operator action. In addition to the solenoid valves, there is a manual globe valve in the common piping upstream of each branch vent line. This valve is open during normal plant operations but may be closed during refueling or system maintenance.

Reactor Vessel Supports

Generally, all RCS supports are designed to permit unrestrained thermal growth but to restrain vertical, lateral, and rotational movement resulting from seismic and pipe-break loadings. The reactor vessel is supported by steel pads integral with four of the coolant nozzles, as shown in Figure 3.1-9.

These pads rest upon steel base plates on a support structure mounted to the concrete foundation wall. Thermal expansion and contraction of the vessel are accommodated by sliding surfaces between the support pads and the base plates. Side stops on these plates keep the vessel centered and resist lateral loads, including all pipe loads. The support shoes and support structure are cooled by the reactor cavity cooling system.

3.1.3.2 Reactor Internals

The reactor internals consist of the lower core support structure, the upper core support structure, and the incore instrumentation support structure. The internals are designed to support, align, and guide the core components; direct coolant flow to and from core components; and guide and support the incore instrumentation.

Any operational accident or seismic loads imposed on the fuel assemblies are transmitted to the upper and lower support structures and ultimately to the reactor vessel flange (Figures 3.1-1 and 3.1-2) or to the lower radial support at the bottom of the lower support structure. The internals also provide a form-fitting baffle around the fuel assemblies to direct most of the coolant flow through the fuel assemblies.

During initial assembly and refueling the upper core support structure is removed and installed as a unit. The lower core support structure can also be removed as a unit after all fuel has been removed. The lower core support structure is normally removed only for reactor vessel surveillance.

Lower Core Support Structure

The major support assembly of the reactor internals is the lower core support structure, shown in Figures 3.1-10 and 3.1-11. This support structure consists of the core barrel, the core baffles, the lower core plate and support columns, the neutron shield pads, the specimen holders, and the lower core support plate.

The core barrel supports and contains the fuel assemblies and directs the coolant flow. The core barrel is a cylindrical shell 147.25 inches in diameter and 330.75 inches long. The barrel hangs from a ledge on the reactor vessel flange and is aligned by four flat sided pins which are press fitted into the barrel at 90-degree intervals. Four main coolant outlet nozzles penetrate the shell in the upper region. The lower end of the core barrel is restrained from transverse movement by a radial support system. The radial support system consists of six (6) equally spaced key and keyway joints around the reactor vessel inner wall. At each point an Inconel clevis block is welded to the reactor vessel. An Inconel insert block is bolted to each clevis block, forming the keyway. Welded to the lower end of the core barrel are six (6) keys. These keys engage the keyways when the core barrel is lowered into the reactor vessel. Radial and axial expansions of the core barrel are accommodated, but transverse movement of the core barrel is restricted.

Located on the barrel flange are sixteen reactor vessel head cooling flow nozzles that direct 0.13% of the reactor coolant flow upward to cool the head. The flow passes down minor holes in the control rod guide tubes and into the main outlet flow stream.

An internal hold-down spring is positioned in a groove in the core barrel main flange beneath the upper internals main support flange. The spring separates the upper internals and lower internals flanges and maintains a force to resist any uplift of the lower internals.

There are four (4) neutron shield pads attached to the core barrel. The neutron shield pads attenuate fast neutrons that would otherwise excessively irradiate and embrittle the vessel walls. In addition, gamma radiation is attenuated by the shield pads to alleviate thermal stresses due to uneven gamma heating of the vessel. The four pads are 147 in. high, 48 in. wide and 2.7 to 2.8 in. thick. The pads are made of 304 stainless steel and are attached to the core barrel by spacer blocks. The spacer blocks allow cooling flow between the pads and the reactor vessel.

The reactor vessel specimen holders are attached to the outside surfaces of the neutron shield pads. The specimens are used to evaluate the irradiation effects on the vessel. One sample is evaluated after the first refueling, and subsequent samples are checked at 10-, 20-, and 30-year intervals.

The lower core support plate is 18 in. thick and is welded to the bottom of the core barrel. The support plate carries the weight of the fuel assemblies and distributes the coolant flow to the fuel assemblies. The secondary support structure, tie plates, instrument guide columns, and support columns hang below the lower core support plate (Figure 3.1-11).

The secondary support structure is in place in the event of a postulated downward vertical displacement of the lower internals (or portion thereof) and the reactor core. As the secondary support base falls against the vessel bottom head, the energy absorption features stretch and, by strain energy dissipation, limit the force applied against the vessel head to an acceptable fraction of the yield strength of the pressure vessel. The support structure also ensures that downward displacement of the lower internals is limited, so that the upper core plate remains in engagement with the fuel assemblies. This prevents a misalignment and thus ensures that the controls rods remain capable of inserting.

The secondary core support has four (4) energy absorbing columns that extend up to the lower core support plate and are connected at the bottom by a sole plate. The sole plate is contoured to the shape of the lower head. A 1/2-in. clearance is maintained when the RCS is hot. The energy absorbing devices allow a 3/4-in. displacement, for a total displacement of 1-1/4 in.

The lower core plate is a two (2) in. thick plate located above the lower core support plate through which flow distribution holes for each fuel assembly are machined (four holes per assembly). Additional holes are machined in the plate to allow for passage of the incore instruments and to allow for cooling of the core baffles and formers. Fuel assembly locating pins (two per assembly) are also attached to this plate. The lower core plate is supported by a circumferential ring that is welded to the core barrel. Support columns are also installed between the lower core plate and the lower core support plate of the core barrel in order to provide stiffness and to transmit the load to the lower core support plate.

The boundary of the fuel region of the core is established by the core baffle assembly. This assembly extends from just above the lower core plate to above the fuel assemblies; it guides the coolant flow through the core. Since the fuel assemblies are square and the core barrel is round, without the baffle gaps would exist around the periphery of the core and a large portion of the cooling water flow would bypass the core. This baffle assembly consists of a number of vertical plates (baffles) and horizontal stiffeners (formers). The formers are bolted to circular grooves in the core barrel, and the baffle plates are bolted to the formers to provide alignment and structural rigidity. Small flow holes are drilled in the formers to allow flow mixing to eliminate stagnant areas. This small amount of flow bypasses the fuel region and is considered as a core bypass flow path in the design.

The lower core support structure serves to provide support for the core and guide the flow of reactor coolant. Reactor coolant flow from the vessel inlet nozzles proceeds down the annulus between the core barrel and the vessel wall, flows on both sides of the neutron shield pads, and then flows into a plenum at the bottom of the vessel. It then turns and flows up through the lower core support plate and passes through the lower core plate. The flow holes in the lower core plate are arranged to provide a uniform entrance flow distribution to the core. After passing through the core, the coolant enters the area of the upper support structure and then flows radially to the core barrel outlet nozzles and through the reactor vessel outlet nozzles.

The upper core barrel contains nozzles to direct the outlet flow from the fuel assemblies out of the upper core support structure. These nozzles have a close but noncontacting fit with the reactor vessel outlet nozzles. Since there is no positive seal at this point, a small amount of coolant inlet flow bypasses the core and internals and goes directly to the vessel outlets. This flow is considered a core bypass flow in the design.

Upper Core Support Structure (Upper Internals)

The upper core support structure and its components are shown in Figures 3.1-12, 3.1-13, and 3.1-14. The upper core support structure provides structural support for the fuel assemblies, RCCAs, and incore instrumentation. The structure consists of an upper support assembly, upper support columns, RCCA guide columns, thermocouple columns, and the upper core plate.

The upper core support plate is five (5) in. thick and 172 in. in diameter. The support plate rests on the lower internals hold-down spring and transmits the weight of the upper internals assembly to the hold-down spring, and ultimately to the reactor vessel flange ledge. Holes machined in the upper support plate accommodate the RCCAs, the five (5) thermocouple columns, and some covered spare penetrations.

The 48 upper support columns establish the spacing between the upper support assembly and the upper core plate and are fastened at top and bottom to these plates. These support columns serve to transmit the weight of the upper core plate and the spring force of the fuel assembly top nozzles to the upper core support plate.

The upper core plate is the lowest major component of the upper internals assembly.

The 147.25 in. diameter, three (3) in. thick plate serves to align and locate the fuel assemblies. The plate transmits the uplift forces of core flow and spring forces of fuel assembly top nozzles to the support columns and thus to the upper core support plate. The upper core plate also has machined holes to accommodate the same equipment as the upper support plate.

Control rod guide tube assemblies (Figures 3.1-12 and 3.1-13) shield, guide, and support the RCCAs. They are fastened to the upper support plate and the upper core plate for proper orientation and support. Additional vertical support for the absorber rods is provided by the control rod guide tube extensions which are attached to the upper support plate.

The upper core support structure, which is removed as a unit during refueling operation, is oriented properly with respect to the lower core support structure by the slots in the upper core plate (Figure 3.1-14) which engage flat sided upper core plate alignment pins welded into the core barrel. At an elevation in the core barrel where the upper core plate is positioned, the flat-sided pins are located at angular positions of 90E from each other. As the upper core support structure is lowered into the lower internals, the slots in the plate engage the flat-sided pins. Lateral displacement of the plate and of the upper support assembly is restricted by this design.

As in the lower core plate, fuel assembly locating pins protrude from the bottom of the upper core plate and engage the fuel assemblies as the upper core support structure is lowered into place. Proper alignment of the lower core support structure, the upper core support structure, the fuel assemblies, and control rods are thereby assured by this system of locating pins.

Vertical loads from weight, earthquake acceleration, hydraulic loads and fuel assembly pre-load are transmitted through the upper core plate via the support columns to the upper support plate and then to the reactor vessel flange. Transverse loads from coolant cross flow, earthquake acceleration, and possible vibrations are distributed by the support columns to the upper support and upper core plate. The upper support plate is particularly stiff to minimize deflection.

Incore Instrumentation Support Structure

The incore instrumentation support structure (Figure 3.1-15), consists of an upper system to convey and support incore temperature monitors (thermocouples) penetrating the vessel through the head and a lower system to convey and support incore nuclear instrumentation flux thimbles penetrating the vessel through the bottom.

There are 65 thermocouples attached to the upper core plate at selected fuel assembly outlets. The leads from these thermocouples are enclosed in sealed stainless-steel tubes called thermocouple conduits. The conduits are routed along and supported by the support columns of the upper support structure. The thermocouple conduits are grouped and routed inside five (5) instrumentation port columns which penetrate the reactor vessel head.

A mechanical sealing device is provided at each head penetration to prevent leakage during operation, while allowing disconnection of the thermocouple leads when the head must be removed for refueling. Details of the incore temperature monitoring system are found in Section 9.2.

The lower system is provided to align and support the guide thimbles for the incore nuclear instrumentation system. These guide thimbles are dry, sealed, stainless steel tubes which are inserted into 58 fuel assemblies. A movable miniature fission chamber can be inserted into each dry thimble during reactor power operations for the monitoring of core power distribution.

To each of the 58 penetrations in the reactor vessel bottom head is welded a stainless-steel conduit of larger diameter than the incore guide thimble. These conduits extend from the bottom of the reactor vessel, through a concrete shield area (this opening is also used for access under the reactor vessel when shutdown) to a seal table located above the height of the core.

Each closed, dry guide thimble is then inserted through a conduit and extended into a fuel assembly instrumentation thimble (Figure 3.1-17). The dry guide thimbles are closed at the fuel assembly end and serve as a pressure boundary during operation. Since the conduits welded to the reactor vessel are open to vessel pressure, the spaces between the guide thimbles and conduits are subjected to full reactor vessel pressure. Mechanical seals between the guide thimbles and the conduits are installed at the seal table.

During normal operation, the dry guide thimbles are fixed inside the conduits, and the movable detectors are moved in and out of the core through the dry guide thimbles. For refueling operations, the mechanical seals are broken, and the dry guide thimbles are mechanically withdrawn from the fuel assembly instrumentation thimbles to allow fuel movement. This can produce high radiation levels under the reactor vessel during refueling, since these dry guide thimbles, which have been in the fuel during operation, are now in the conduit outside the reactor vessel. Since these dry guide thimbles are of small diameter and flexible, and have little structural strength, they must be supported and aligned constantly from the penetrations to their entrances into the fuel assemblies.

Figures 3.1-2 and 3.1-10 show components called instrumentation thimble guides. Either a thimble guide or a hollow lower core support column slips over each vessel penetration and encloses the guide thimble to protect it from flow induced vibration. The instrumentation thimble guides are tubes with cross-shaped (cruciform) blades. They are inserted through flow holes in the lower core support and thus provide alignment and support while not restricting flow.

The incore instrumentation support structure is designed for adequate support of instrumentation during reactor operation and is rugged enough to resist damage or distortion under the conditions imposed by handling during the refueling sequence. Additional information is found in Section 9.2.

3.1.3.3 Reactor Core Components

The reactor core components consist of the fuel assemblies and all components which can be inserted into fuel assemblies to affect reactor power, power distribution, or flow distribution.

Fuel Assemblies

All fuel assemblies are mechanically identical, open cage assemblies (Figure 3.1-16). Fuel assembly design parameters are listed in Table 3.1-2. Each fuel assembly consists of 264 fuel rods, 24 guide thimble tubes, and 1 instrumentation guide thimble supported and aligned by grid assemblies and top and bottom nozzles in a 17 x 17 fuel rod array. The instrumentation guide thimble is located in the center position (Figure 3.1-17) and provides a channel for the insertion of an incore neutron detector dry guide thimble if the fuel assembly is located in an instrumented core position. The instrumentation guide sheath is open at the bottom and closed at the top to prevent core bypass flow.

The absorber rod guide thimbles provide channels for insertion of an RCCA, a neutron source assembly, a burnable poison assembly, or a thimble plug assembly, depending on the position of the particular fuel assembly in the core. Figure 3.1-16 shows a fuel assembly with a full length rod fully inserted. The fuel rods are loaded into the fuel assembly structure so that there is clearance between the fuel rod ends and the top and bottom nozzles to allow for expansion without causing bowing of the rods. Fuel rods provide no structural function for the fuel assembly. All structural strength is supplied by the top and bottom nozzles, the grid assemblies, and the absorber rod guide thimbles.

Each fuel assembly is installed vertically in the reactor vessel and stands upright on the lower core plate, which is fitted with alignment pins to locate and orient the assembly. After all fuel assemblies are set in place, the upper support structure is installed. Alignment pins, built into the upper core plate, engage and locate the upper ends of the fuel assemblies. The upper core plate then bears downward against hold-down springs in the fuel assembly top nozzle (Figures 3.1-18 and 3.1-19), to hold the fuel assemblies in place against any flow induced lifting forces while still allowing differential expansion between the internals and the fuel assemblies.

Fuel Rods

Each fuel rod consists of uranium dioxide ceramic pellets which are placed inside a slightly cold worked zircaloy-4 tube. The tube is then plugged, and seal welded at both ends to encapsulate the fuel. Design parameters for the fuel rods are listed in Table 3.1-3.

A schematic of the fuel rod is shown in Figure 3.1-20. The fuel pellets are right circular cylinders consisting of slightly enriched uranium-dioxide powder which has been compacted by cold pressing and then sintered to the required density. (Sintering is high-temperature fusing of metal particles). The ends of each pellet are dished slightly to allow greater axial expansion at the center of the pellets.

To avoid overstressing of the cladding or seal welds, void volume and clearances are provided within the rods to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel density changes during burn-up. Shifting of the fuel within the cladding during handling or shipping prior to core loading is prevented by a stainless-steel helical spring which bears on top of the fuel. At assembly the pellets are stacked in the cladding to the required fuel height. The spring is then inserted into the top end of the fuel tube and the end plugs pressed into the ends of the tube and welded.

All fuel rods are internally pressurized with helium during the welding process in order to minimize compressive clad stresses and to prevent cladding flattening due to coolant operating pressures. The helium pre-pressurization may be different for each fuel region. Fuel rod pressurization is dependent on the planned fuel burn-up as well as other fuel design parameters and fuel characteristics (particularly densification potential). The fuel rods are designed such that the internal gas pressure will not exceed the nominal system coolant pressure even during anticipated transients, and clad flattening will not occur during the core life.

Each fuel rod contains approximately six (6) inches of natural uranium at each end of the rod. This design reduces axial leakage, which is desirable, but increases the heat flux hot channel factor (F_Q).

Bottom Nozzle

The bottom nozzle is a box-like structure which serves as the bottom structural element of the fuel assembly and directs the coolant flow to the assembly. The square nozzle is fabricated of type 304 stainless steel and consists of a perforated plate and four angle legs with bearing plates, as shown in Figures 3.1-16 and 3.1-18. The legs form a plenum for the inlet coolant flow to the fuel assembly. The holes in the plate are smaller than the fuel rod diameters and prevent a downward displacement of the fuel rods from their fuel assembly. The bottom nozzle is fastened to the fuel assembly control rod guide tubes by weld-locked screws which penetrate through the nozzle and mate with threaded plugs in the guide tubes.

Coolant flow through the fuel assembly is directed from the plenum in the bottom nozzle upward through the holes in the plate to the spaces between the fuel rods. The penetrations in the plate are positioned between the rows of the fuel rods.

Axial loads (hold-down forces) imposed on the fuel assembly and the weight of the fuel assembly are transmitted through the bottom nozzle to the lower core plate. Indexing and positioning of the fuel assembly is by alignment holes in two diagonally opposite bearing plates, which mate with locating pins in the lower core plate. Any lateral loads on the fuel assembly are transmitted to the lower core plate through the locating pins.

Top Nozzle

The top nozzle functions as the upper structural element of the fuel assembly. In addition, the top nozzle provides a partial protective housing for a rod cluster control assembly or other insert. It consists of an adapter plate, enclosure, a top plate, hold down springs, clamps, and pads, as shown in Figures 3.1-18 and 3.1-19. The springs and bolts are made of inconel 718, whereas other components are made of type 304 stainless steel.

The square adapter plate is provided with round and oblong penetrations to permit the flow of coolant upward through the top nozzle. Other round holes are provided to accept sleeves which are welded to the adapter plate and mechanically attached to the thimble tubes. The holes in the plate are of smaller diameter than the fuel rods and prevent their upward ejection from the fuel assembly. The enclosure is simply a sheet metal shroud between the adapter plate and the top plate. The top plate has a large square hole in the center to accept a control rod and the control rod spider when the rod is inserted. Hold-down springs are mounted on the top plate and are fastened in place by bolts and clamps located at two diagonally opposite corners. On the other two corners are located the holes which accept the alignment pins of the upper core plate.

A serial number is stamped on the top nozzle of each fuel assembly for quality assurance tracking purposes. The assembly can thus be tracked through construction, shipment, core loading, and shuffling during refueling. These serial numbers are normally scanned by a television camera located on the refueling crane to verify proper core loading.

Absorber Rod Guide and Instrument Thimbles

The guide thimbles are the major structural members of the fuel assembly (Figures 3.1-16 and 3.1-17). They also provide channels for neutron absorber rods, burnable poison rods, neutron sources, or thimble plug assemblies. Each RCCA guide thimble is fabricated from zircaloy-4 tubing of two different diameters. The top of the thimble has a larger diameter to produce little restriction during a reactor trip and to allow short rod insertion times. Toward the bottom of the thimble is a transition to a smaller diameter tube. This produces a dashpot effect and slows the RCCA after a trip. Four small flow holes are located just above the dashpot region to reduce rod drop time, provide a path for water displaced from the dashpot by the RCCA, and allow some flow through the guide thimble to cool the control rod (this coolant is considered a design core bypass flow).

The dashpot is closed at the bottom by means of an end plug, which has a small flow port to avoid fluid stagnation in the dashpot volume during normal operation. The top end of the guide thimble is fastened to a tubular sleeve by three expansion swages. The sleeve fits into and is welded to the top nozzle adapter plate. The lower end of the guide thimble is fitted with an end plug, which is then fastened into the bottom nozzle by a weld-locked hollow screw.

The central instrumentation thimble (also called the instrument guide sheath) of each fuel assembly is not rigidly attached to either the top or the bottom nozzle, but the thimble is constrained by its seating in the counterbore of each nozzle. The thimble internal diameter does not vary. An incore neutron detector guide thimble is installed through the bottom nozzle’s large counterbore into the instrument guide sheath.

Grid Assemblies

The fuel rods are supported laterally at intervals along their length by spring clip grid assemblies (Figures 3.1-21 and 3.1-22), which maintain the lateral spacing between the rods throughout the design life of the assembly. Each fuel rod is afforded lateral support at six contact points within each grid by a combination of support dimples and spring fingers. The magnitude of the grid restraining force on the fuel rod is set high enough to minimize possible fretting, without overstressing the cladding at the points of contact between the grids and fuel rods. The grid assemblies also allow axial thermal expansion of the fuel rods without imposing restraint sufficient to develop buckling or distortion of the fuel rods.

Two types of grid assemblies are used in each fuel assembly. Both types consist of individual slotted straps interlocked in an “egg-crate” arrangement. The straps contain spring fingers, support dimples, and mixing vanes. One type, used in the high flux region of the fuel assemblies, consists of zircaloy straps permanently joined by welding at their points of intersection. This material is chosen primarily for its low neutron absorption properties. The internal straps include mixing vanes which project into the coolant flow and promote mixing of the coolant.

The other grid type, located at the ends of the fuel assemblies, does not include mixing vanes on the internal straps. The material of these grid assemblies is inconel-718, chosen because of its corrosion resistance and high strength. Joining of the individual straps is achieved by brazing at the points of intersection.

The outside straps on all grids contain mixing vanes which, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or during loading and unloading of the core.

Handling of Fuel Assemblies

Due to its method of construction (long, square array supported by the long, small diameter RCCA guide thimbles), the fuel assembly exhibits excellent structural strength in the axial direction but cannot accept large mechanical loads in the radial direction. A fuel assembly is, therefore, handled by grasping the top nozzle with a special tool and moving it while in the vertical position. If a fuel assembly is to be oriented horizontally, it must be supported at the grid locations to prevent bowing.

Other Fuel Designs

The description of the fuel assembly above is of the optimized fuel design. There are some other fuel designs that provide some improvements to the basic optimized fuel assembly.

One change is a debris filter bottom nozzle. The examination of leaking fuel over the years has shown that about 75% of the leakers were due to debris-induced fretting. The debris filter bottom nozzle helps mitigate the effects of debris in the coolant system by trapping it at the entrance of the fuel assembly. The bottom nozzle has a pattern of many small holes which allow reactor coolant to pass through while minimizing the passage of debris large enough to cause wear or fretting. Although the holes are smaller than the earlier design bottom nozzles, the hydraulic performance is the same, and there is no difference in coolant flow or heat transfer.

Another change is the addition of intermediate flow mixing grids. These grids are nonstructural grids located in the three uppermost spans between the zircaloy mixing vane structural grids. They incorporate a similar mixing vane array, with the prime function of mixing in the hottest fuel assembly spans. The increased mixing increases the heat transfer in the upper part of the core. Therefore, the margin to departure from nucleate boiling is increased. The intermediate flow mixing grids are physically shorter than the structural grids, and thus the mixing is accomplished with a minimal pressure drop.

A change has also been made to the material of choice for the guide thimbles, instrument tube, fuel cladding, and some of the grids. This new material is an improved zirconium alloy which contains reduced tin content and now contains niobium. This new material is more resistant to corrosion but has the strength and performance of zircaloy-4.

The top nozzle of the fuel assembly has also undergone some design changes. The material of construction is now a low cobalt stainless steel, which helps reduce radiation levels due to the activation of cobalt. Also, the top nozzle is manufactured to be removable. This allows the removal of leaking fuel rods from a fuel assembly and then replacing them with other fuel rods, stainless steel rods, or water holes. This allows the burnup of fuel rods that are not leaking, which results in fuel savings for the plant.

One of the driving forces behind these and other fuel design changes is longer operating cycles. Burning as much of the fuel as possible is much less expensive than using higher enrichment fuel. However, the longer operating cycle also means that more fission products are produced than with the lower burnup fuel. Therefore, changes must be made to allow the fission product gases to be collected inside the cladding without having excessive stresses. The thickness of the top and bottom nozzles has been reduced. This allows the fuel rods to be slightly longer. However, since the fuel length has not changed, the plenum area of each rod is now longer. The design of the plenum spring has also been changed to allow more space for the gases.

Full Length Rod Cluster Control Assemblies (RCCAs)

The RCCAs (also called control rods) provide a rapid means for reactivity control during both normal operating and accident conditions. RCCA design parameters are listed in Table 3.1-4.

The rod cluster control assemblies are divided operationally into two categories: control banks and shutdown banks. The control banks may be inserted or withdrawn to compensate for various reactivity changes during operation of the reactor and can trip (scram) to provide shutdown capability. The shutdown banks are reserved for shutdown use only and are always fully withdrawn from the core when the reactor is critical. They are inserted only when a reactor trip occurs.

Two criteria are employed for the design of the RCCAs. First, the total reactivity worth must be adequate to meet the nuclear requirements of the reactor. Second, since some of these rods may be partially inserted at power operation, the total power peaking factor should be low enough to ensure that full power capability can be met. The control and shutdown banks provide adequate shutdown margin. Shutdown margin is defined as the amount of reactivity by which the core would be subcritical if all RCCAs are tripped, assuming that the highest worth RCCA remains fully withdrawn.

An RCCA consists of a group of individual neutron absorber rods fastened at the top end to a common spider assembly, as illustrated in Figure 3.1-23. A cutaway of a fuel assembly with an RCCA inserted is shown in Figure 3.1-16.

The absorber material used in the control rods is silver-indium-cadmium alloy (Ag-In-Cd). The silver-indium-cadmium alloy is in the form of extruded rods which are sealed in stainless steel tubes to prevent the poisoning material from coming in direct contact with the coolant. The stainless-steel tubing is sealed at the bottom and the top by welded end plugs. Sufficient clearance is provided to accommodate thermal expansion. The bottom plugs are made bullet-nosed to reduce the hydraulic drag during a reactor trip and to allow smooth insertion into the dashpot sections of the fuel assembly guide thimbles. Each upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

The spider assembly is in the form of a central hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents and detents for connection to the drive rod assembly are machined into the upper end of the hub. A coil spring inside the spider body absorbs the impact energy at the end of a trip insertion. The radial vanes are joined to the hub by welding and brazing, and the fingers are joined to the vanes by brazing. All components of the spider assembly are made from types 304 and 308 stainless steel, except for the spring retainer, which is 17-4 pH stainless steel, and the springs, which are inconel 718 alloy.

The absorber rods, also called rodlets, are fastened securely to the spider to assure trouble free service. The rods are first threaded into the spider fingers and then pinned to maintain joint tightness, after which the pins are welded in place. The end plugs below the pin positions are designed with reduced-diameter sections to permit flexing of the rods to correct for small operating or assembly misalignments. The overall length is such that when the assembly is fully withdrawn, the tips of the absorber rods remain engaged in the guide thimbles, so that alignment between the rods and the thimbles is always maintained. Since the rods are long and slender, they are flexible enough to conform to any small misalignments within the guide thimbles.

A long, hollow, grooved drive shaft (Figure 3.1-24) is attached to the spider hub of each RCCA by a split coupling. The drive shaft extends through the upper core support structure and through a reactor head penetration to the control rod drive mechanism. A disconnect rod, used during core disassembly, is located inside this shaft. When the disconnect rod is inserted into the drive shaft, it expands the split coupling and locks it into place in the hub.

Figure 3.1-25 shows the relative positions of the RCCA and associated equipment in the reactor. Since the poison rods are long and slender, they must be supported and aligned as they are withdrawn from the fuel assembly. The control rod guide tubes of the upper core support structure shown in Figures 3.1-2 and in 3.1-13 perform this function.

Burnable Poisons

Burnable poisons are added to the core to provide fixed discrete poisons when needed due to nuclear considerations, such as controlling power peaking and the moderator temperature coefficient. These discrete poisons may be in the form or burnable poison rod assemblies and/or a poison coating on the fuel pellets.

Figure 3.1-26 shows a burnable poison rod assembly (BPRA). BPRA design parameters are listed in Table 3.1-5.

The poison rods of the burnable poison assemblies are suspended from a flat spider plate and are inserted into the RCCA guide thimbles of selected fuel assemblies at selected unrodded locations. The spider plate fits within a fuel assembly top nozzle and rests on its top adapter plate. A T-bar and spring assembly is attached to the spider. As the upper core support structure is installed, the upper core plate contacts the T-bar and compresses the spring holding the burnable poison assembly in place.

Two designs of the poison rods could be used in the burnable poison assemblies. The poison rods in the older design, Figure 3.1-27, consist of borosilicate glass tubes contained within type 304 stainless steel tubular cladding, which is plugged, and seal welded at the ends to encapsulate the glass. Each glass tube is also supported along the length of its inside diameter by a thin wall 304 stainless steel tubular inner liner. The top end of the liner is open to permit the diffused helium to pass into the void volume and the liner extends beyond the glass. The liner is flanged at the bottom end to maintain the position of the liner with the glass.

The rods are designed in accordance with the standard fuel rod design criteria; that is, the cladding is free standing at reactor operating pressures and temperatures and sufficient cold void volume is provided within the rods to limit internal pressures to less than the reactor operating pressure, assuming the total release of all helium generated in the glass as a result of the B-10 (n,α) reaction. The large void volume required for the helium is obtained through the use of glass in tubular form, which provides central voids along the length of the rods.

Based on available data on properties of borosilicate glass and on nuclear and thermal calculations for the rods, gross swelling or cracking of the glass tubing is not expected during operation. Some minor creep of the glass at the hot spot on the inner surface of the tube is expected to occur, but it continues only until the glass comes into contact with the inner liner.

The inner liner is provided to maintain the central void along the length of the glass and to prevent the glass from slumping or creeping into the void as a result of softening at the hot spot. The wall thickness of the inner liner is sized to provide adequate support in the event of slumping, but to collapse locally before rupture of the exterior cladding if large volume changes due to swelling or cracking should occur. The top end of the inner liner is open to receive the helium which diffuses out of the glass.

The second burnable poison design is called the wet annular burnable absorber, Figure 3.1-28. This design uses aluminum oxide/boron carbide as the absorber. The poison is in the form of a stack of hollow pellets wrapped inside and out with stainless steel cladding and pressurized with helium. Water is allowed to flow in the central passage. This allows for an increase in moderation in the center of the poison rod, which allows for better absorption of neutrons and a more complete burnout of the poison material.

Zirconium boride is used as the poison that is coated on the fuel pellets. Fuel assemblies which have coated fuel pellets are called integral fuel burnable absorbers (IFBAs). One of the advantages of using integral absorbers is that burnable absorbers can be placed in fuel assemblies that also have control rods inserted. The neutron flux shape can be more controlled by the placement of the absorber material and by controlling the number of fuel rods with absorber material, as dictated by individual plant needs.

Neutron Source Assemblies

Prior to initial reactor operation and after long shutdown periods, the core neutron level may be too low to be detected by the installed excore nuclear instrumentation system. To insure adequate indication for the operator during long-term reactor shutdowns and during reactor startups, neutron source assemblies are installed in the core. These sources, in conjunction with subcritical multiplication, produce a neutron level high enough to be monitored by the source range nuclear instrumentation channels (2 cps required). It would be unacceptable for the core to achieve criticality with no indication of reactor power or rate of change of power. The sources are also necessary to provide measurable neutron flux levels during fuel loading. A source is not required to enable the reactor to achieve criticality.

There are two types of source assemblies employed in the Westinghouse design: primary source assemblies (Figure 3.1-29) and secondary source assemblies (Figure 3.1-30).

The primary source spontaneously produces neutrons for indication for the initial reactor startup while the secondary source (which is activated only after being exposed to neutron bombardment) provides neutrons for subsequent startups.

Both types of source assemblies are constructed as burnable poison assemblies, with several of the poison rods replaced by source rods. The primary source rods for the Trojan plant were capsules of californium. Californium fissions spontaneously and thereby produces neutrons directly.

Each of the two (2) secondary sources contains a symmetrical grouping of four (4) secondary source rods and twenty thimble plugs. The secondary sources are constructed of antimony beryllium (SbBe), which is activated only after exposure to neutron flux during reactor operation. The secondary source produces neutrons by the following reactions

$$ {}_{0}n^{1} + {}_{51}Sb^{123} \rightarrow {}_{51}Sb^{124} $$

$$ {}_{51}Sb^{124} \xrightarrow[\text{60 days}]{\beta^{-}} {}_{52}Te^{124} + \gamma $$

$$ {}_{4}Be^{9} + \gamma \rightarrow {}_{4}Be^{8} + {}_{0}n^{1} $$

Neutron source assemblies are located at diametrically opposite sides of the core at locations close to the source range nuclear instrumentation detectors. These assemblies are inserted into the rod cluster control guide thimbles in fuel assemblies at selected unrodded locations.

Thimble Plugging Assemblies (Thimble Plugs)

In order to limit core bypass flow through the absorber rod guide thimbles in the fuel assemblies not containing control rods, source assemblies, or burnable poison rods, the fuel assemblies at these locations are fitted with thimble plugging assemblies (Figure 3.1-31).

A thimble plug consists of a flat spider plate with short rods suspended from the bottom surface, and a spring pack assembly and mixing device attached to the top surface. When installed in the core, the plugging device fits within a fuel assembly top nozzle and rests on its adaptor plate.

The short rods project into the upper ends of the guide thimbles to reduce the bypass flow area. The spring pack is compressed by the upper core plate contacting the T-bar when the upper internals package is lowered into place.

When the core is fully assembled, all fuel assembly absorber rod guide tubes will have control rods, burnable poison rods, source rods, or thimble plugs inserted into them. All components of the plugging device, except for the springs, are constructed of Type 304 stainless steel. The springs (one per plugging device) are wound from an age-hardened nickel base alloy to obtain high strength.

3.1.3.4 Control Rod Drive Mechanisms (CRDMs)

The control rod drive mechanisms are electromechanical devices (magnetic jacks) used to position the rod cluster control assemblies (control rods) in the reactor core. Each CRDM is capable of withdrawing or inserting a control rod in discrete increments (steps) or holding it at a constant position. Tripping (scramming) is accomplished by simply de-energizing the mechanisms and allowing the control rods to fall by gravity into the core. Each RCCA is operated by its own individual CRDM.

The complete drive mechanism, shown in Figures 3.1-32 and 3.1-33, consists of an internal latch assembly, the drive shaft assembly, the pressure vessel (including the rod travel housing), the operating coil stack, and the individual rod position indication coil stack. Reactor coolant at full system pressure fills the pressure housing and rod travel housing. All moving parts are immersed in reactor coolant. This housing forms the RCS pressure boundary.

Each assembly is an independent unit which can be dismantled or assembled separately. The mechanism pressure housing is threaded onto an adaptor atop the reactor pressure vessel head and seal welded. The operating drive assembly is connected to the control rod (directly below) by means of a grooved drive shaft. The upper section of the drive shaft is suspended from the working components of the drive mechanism. The drive shaft and control rod remain connected during reactor operation, including tripping of the rods.

Three magnetic coils, which surround the rod drive pressure housing, induce magnetic flux through the pressure housing wall to operate the working components. They move two sets of latches which lift, lower, or hold the grooved drive shaft. To move the control rod, the three magnets are turned on and off in a fixed sequence by the solid-state full length rod control system (Section 8.1). The sequencing of the magnets produces discrete steps (5/8 in. each) of rod motion over the 144 inches of normal control rod travel.

The mechanism develops a lifting force approximately two times the static lifting load. Therefore, extra lift capacity is available for overcoming mechanical friction between the moving and the stationary parts. Gravity provides the driving force for rod insertion and the weight of the whole rod assembly is available to overcome any resistance.

The mechanisms are designed to operate in water at 650°F and 2485 psig. The temperature at the mechanism head adaptors is much less than 650°F because they are located in regions where there is a limited flow of water from the reactor core, while the pressure is the same as in the reactor pressure vessel.

Latch Assembly

The latch assembly consists of the components which engage and support the grooved drive shaft during insertion, withdrawal, and holding operations. All latch components are located inside the pressure housing.

The primary components are the two latches which engage the drive shaft: the stationary gripper latch and the movable gripper latch. A number of pole pieces, springs, pivot pins, and linkages are provided to support and align the latches during movement or holding operations.

The upper set of latches (movable grippers) is engaged when the movable gripper coil is energized and can move upward 5/8 inch when the lift coil is energized. The lower set of latches (stationary grippers) is engaged when the stationary gripper coil is energized and can move only 1/16 inch axially to allow load transfer between the movable and stationary grippers during rod movement. The stationary gripper latches are normally engaged during periods of no rod motion (holding operations). The insertion and withdrawal sequences are discussed in Section 8.1.

Pressure Vessel

The pressure vessel associated with each CRDM consists of the pressure housing and rod travel housing. The pressure housing is the lower portion of the vessel and contains the latch assembly. The rod travel housing is the upper portion of the vessel. It provides space for the drive shaft during its upward movement as the control rod is withdrawn from the core.

Operating Coil Stack

The operating coil stack is an independent unit which is installed on the drive mechanism by sliding it over the outside of the pressure housing. It rests on a pressure housing flange without any mechanical attachment and can be removed and installed while the reactor is pressurized. Forced air from the CRDM cooling fans flows along the outside of the coil stack to maintain a coil casing temperature of approximately 248°F or lower. These fans must be operating whenever RCS temperature is greater than 350°F.

Drive Shaft Assembly

The main function of the drive shaft, as shown in Figure 3.1-24, is to connect the control rod to the control rod drive mechanism. Grooves for engagement and lifting by the latches are located throughout the 144 in. of control rod travel. The grooves are spaced 5/8 inch apart to coincide with the mechanism step length and have 45° angle sides. The drive shaft is attached to the control rod by a split coupling. The coupling engages the grooves in the spider assembly hub.

A 1/4-in. diameter disconnect rod extends inside the length of the hollow drive shaft. It has a locking button at its lower end to expand and lock the coupling to the control rod hub. At its upper end, there is a disconnect assembly. For remote disconnection of the drive shaft assembly from the control rod, a button at the top of the drive rod actuates the connect/disconnect assembly. The drive shaft assembly can be attached and removed from the control rod only when the reactor vessel head is removed.

During refueling, the drive shafts are uncoupled from the control rod spiders and are removed as the upper internals (upper core support structure) are removed. The control rods themselves remain in the fuel assemblies.

Individual Rod Position Indication (IRPI) Coil Stack

One type of rod position instrumentation, the IRPI coil stack, is installed around the rod travel housing. It detects control rod position by means of a cylindrically wound differential transformer which spans the normal length of rod travel (144 inches). As the drive shaft moves inside the rod travel housing, it changes the coupling between the primary and secondary coils and produces a signal proportional to control rod height.

More detailed descriptions of the individual rod position indication system are found in Sections 8.3 and 8.4.

Materials of Construction

All components exposed to reactor coolant, such as the pressure vessel, latch assembly, and drive rod, are made of or clad with materials which resist the corrosive boric acid. Three types of metals are used exclusively: stainless steels, Inconel, and cobalt-based alloys. Wherever magnetic flux is carried by parts exposed to the main coolant, 400 series stainless steel is used.

Cobalt-based alloys are used for the pins, latch tips, and bearing surfaces. Inconel X is used for the springs of both latch assemblies, and 304 stainless steel is used for all pressure containment. Hard chrome plating provides wear surfaces on the sliding parts and prevents galling between mating parts (such as threads) during assembly. Outside of the pressure vessel, where the metals are exposed only to the reactor plant containment environment and cannot contaminate the reactor coolant, carbon and stainless steels are used. Carbon steel, because of its high permeability, is used for flux return paths around the operating coils. It is zinc plated (0.001 in. thickness) to prevent corrosion.

3.1.4 System Interrelationships

3.1.4.1 Reactivity Control

Reactivity control is accomplished by positioning control rods and by adjusting the concentration of the soluble neutron absorber (boric acid) in the moderator. The boric acid concentration is varied to control long-term reactivity changes such as:

1. Fuel depletion and fission product buildup,
2. The reactivity change associated with the transition from cold shutdown to hot zero power,
3. Reactivity changes produced by intermediate-term fission products such as xenon and samarium, and
4. Burnable poison depletion.

Control rod position is varied to control more rapid reactivity changes due to:

1. Shutdown,
2. Reactivity changes due to coolant temperature changes in the power range,
3. Reactivity changes associated with the power coefficient of reactivity, and
4. Reactivity changes due to void formation.

Due to operating restrictions, some of the reactivity changes designed to be compensated by control rod motion are now accomplished by boron concentration changes. These are associated with planned power changes during operation.

3.1.4.2 Vessel Flowpath

As shown in Figure 3.1-34, reactor coolant enters the reactor vessel through the four inlet nozzles, impinges against the upper core barrel, and flows downward through the annulus between the core barrel and the vessel wall. In passing the neutron shield pads, some flow goes between the neutron shield pads and the vessel. The downward coolant flow continues between the radial support members into the lower vessel head plenum among the tie plates and instrument guide columns, where the flow is directed upward.

The coolant then passes through the lower core plate and into the core to remove the heat generated in the fuel assemblies. Flow continues upward through the fuel assemblies (cross-flow between assemblies is also possible) and exits the core through the upper core plate. The coolant then flows laterally past the support columns and control rod guide tubes of the upper core support structure to the outlet nozzles of the core barrel.

These outlet nozzles have flanges which direct the flow. The flanges maintain small clearances with the vessel outlet nozzles. Ninety-three- and one-half percent (93.5%) of the total coolant flow is available for core heat removal. The remainder (6.5%) bypasses the core. Core bypass flows and their values consist of:

1. Nozzle bypass flow, from the reactor vessel inlet nozzles directly to the outlet nozzles through the small clearances between the core barrel outlet nozzles and the reactor vessel outlet nozzles. This flow accounts for 0.68% of total coolant flow.
2. RCCA guide thimble bypass flow through the small flow holes at the dashpot sections of the guide thimbles. This flow provides cooling for any inserted control rods and burnable poison assemblies and accounts for 3.85% of total coolant flow.
3. Core baffle bypass flow between the core barrel and the core baffle through holes machined in the former plates for cooling. This flow accounts for 1.84% of total coolant flow. Included in this value is 1.51% for actual design flow through the core baffle, 0.23% for outer fuel assembly to baffle gap leakage, and 0.10% for leakage through the plugged barrel flow holes.
4. Head cooling bypass flow through holes drilled in the core barrel flange and corresponding holes in the upper support plate flange, which provides some reactor inlet flow into the head area for cooling. This flow passes through holes in the upper guide tubes to rejoin the rest of the coolant outlet flow. This flow accounts for 0.13% of total coolant flow.

3.1.5 Summary

The reactor vessel and internals support and align the reactor core and its associated components. Additionally, the vessel and internals provide a flowpath to ensure adequate heat removal from the fuel assemblies.

The cylindrical reactor vessel has a removable head with penetrations for the control rod drive mechanisms and incore temperature monitoring instrumentation. Incore nuclear instrumentation enters through penetrations in the bottom of the reactor vessel. The vessel is supported from pads welded to its nozzles.

The lower internals (lower core support structure) hang from the reactor vessel support ledge and align and contain the fuel assemblies. The core barrel is aligned and supported radially by several keys at its bottom, which mate with keyways attached to the reactor vessel wall. Neutron shield pads are attached to the core barrel at core level to reduce radiation damage (primarily neutron embrittlement) to the reactor vessel. Retrievable specimens of reactor vessel materials are attached to the core barrel to monitor radiation-induced changes in the reactor vessel. A core baffle surrounds the core to guide most of the coolant flow through the fuel assemblies.

The upper internals are also supported by a flange at the reactor vessel support ledge. Control rod guide tubes support and align the RCCAs when they are withdrawn from the fuel assemblies. The support columns provide structural strength to transfer normal and accident loads to the reactor vessel support ledge and support the incore temperature detection system.

Each fuel assembly contains 264 fuel rods arranged in a 17x17 array. Each fuel rod is a long, thin zircaloy tube containing slightly enriched uranium dioxide in the form of ceramic pellets. Structural strength for the fuel assemblies is provided by the control rod guide thimbles, grid straps, and top and bottom nozzles. The fuel rods do not provide any structural support for the fuel assembly. The fuel assemblies are aligned by pins in the upper and lower core plate, which mate with holes in the top and bottom nozzles. All control rod guide thimbles are filled with control rods, burnable poison assemblies, source assemblies, or thimble plugging assemblies.

Full length control rod drive mechanisms are magnetic jack assemblies which move control rods in discrete steps. Tripping is accomplished by de-energizing the mechanisms. The control rods are designed to respond to fast reactivity changes, while slow changes such as fuel burnup are compensated by boron concentration changes.

Nearly all reactor coolant flow is available for core cooling, with a small portion bypassing the core at the core barrel to vessel gap, head cooling, control rod guide thimble cooling, and core baffle flowpaths.

Table 3.1-1 Reactor Vessel Design Parameters

Hydrostatic test pressure	3,107 psig
Design pressure	2,485 psig
Design temperature	650°F
Reactor vessel height	525.8"
Number of closure head studs	54
Closure head stud - diameter	7.0"
Vessel flange - width	32.5"
Vessel shell - inside diameter	173"
Inlet Nozzle - inside diameter	27.2"
Outlet Nozzle - inside diameter	28.8"
Closure head - thickness	6.5"
Beltline - thickness	8.5"
Lower hemispherical head - thickness	5.5"
Vessel cladding - thickness	0.156"
Stainless steel insulation - thickness	3.0"

Table 3.1-2 Fuel Assembly Design Parameters

Number of fuel assemblies	193
Number of fuel rods per assembly	264
Number of guide thimbles per assembly	24
Number of grid straps per assembly	8
Rod array	17 x 17
Fuel (UO_2) - weight	222,739 lbs
Cladding (Zr_4)- weight	50,913lbs
Grid straps (Inconel-718) - weight	2,324
Guide thimble - outside diameter	0.482"
Guide thimble - inside diameter	0.450"

Table 3.1-3 Fuel Rod Design Parameters

Number of fuel rods (total)	50,952
Fuel rod - outside diameter	0.374"
Gap - diameter	0.0065"
Fuel rod cladding - thickness	0.0225"
Fuel rod cladding material	Zr_4
Fuel pellet - diameter	0.3225"
Fuel pellet - length	0.530"
Fuel pellet - density	95% theoretical
Fuel pellet material	UO_2

Table 3.1-4 RCCA Design Parameters

Neutron absorber	Ag-In-Cd
Neutron absorber composition	80%-15%-5%
Number of RCCAs	53
Number of rodlets per RCCA	24
RCCA rodlet - cladding material	304 SS
Cladding - thickness	0.0185"
RCCA - weight	157 lbs

Table 3.1-5 BPRA Design Parameters

Number of burnable poison rods	1,440
Burnable poison rod material	Borosilicate glass
BPRA rodlet - outside diameter	0.381"
BPRA rodlet - cladding material	304 SS
BPRA rodlet - boron loading (B_2O_2)	12.5% weight
Reactivity worth - hot	7,630 pcm
Reactivity worth - cold	5,500 pcm

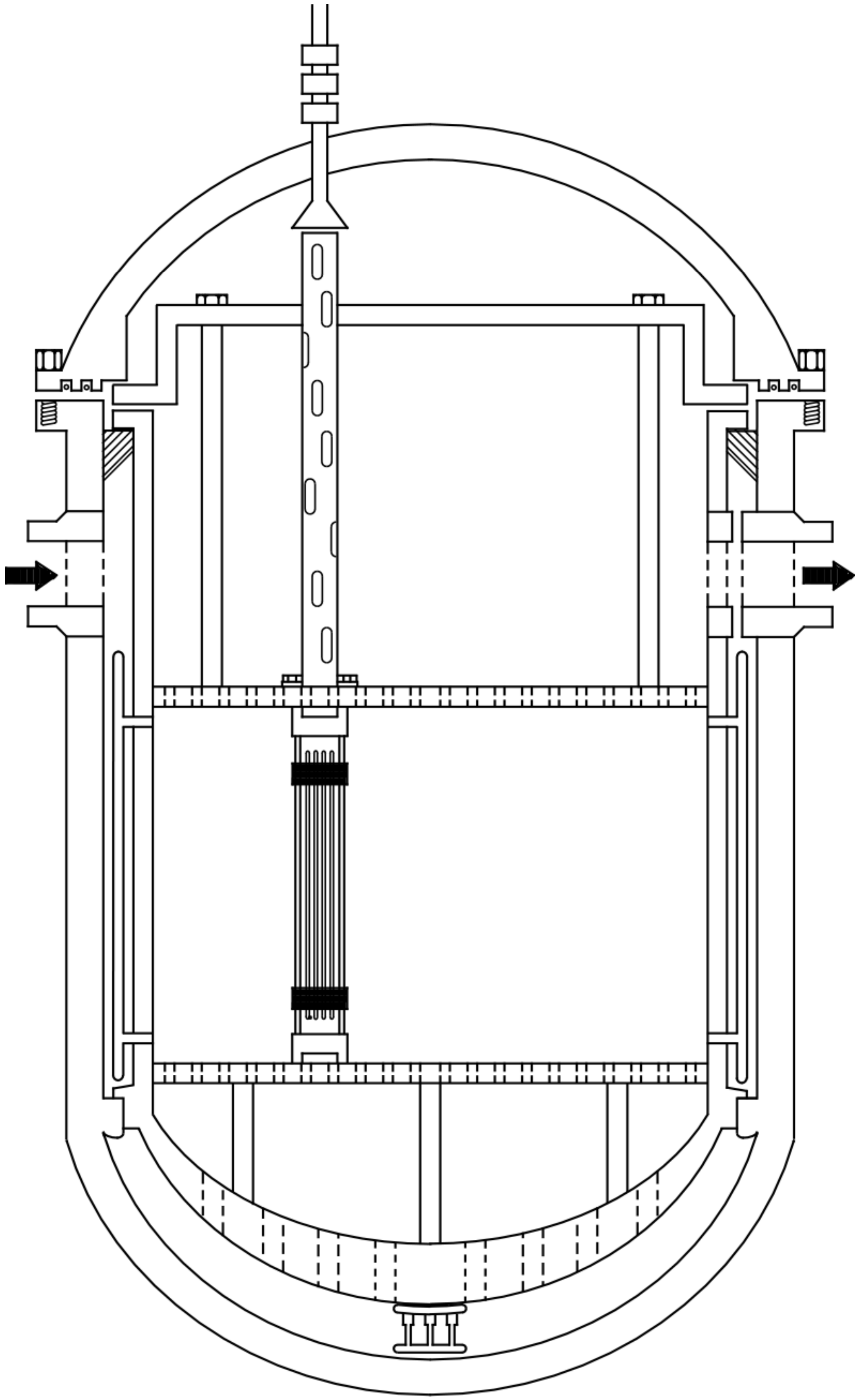


Figure 3.1-1 Reactor Vessel Cutaway

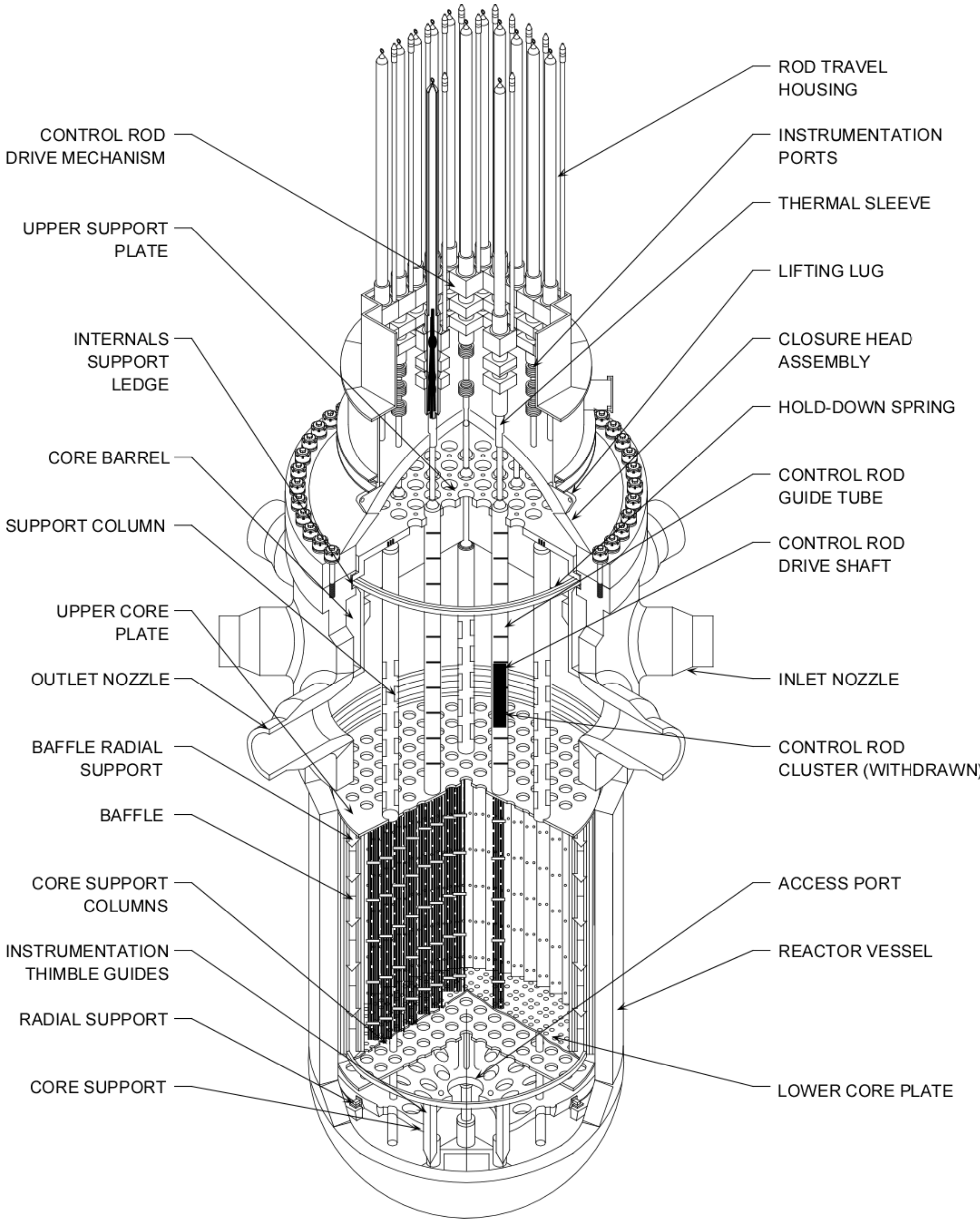


Figure 3.1-2 Reactor Vessel Internals

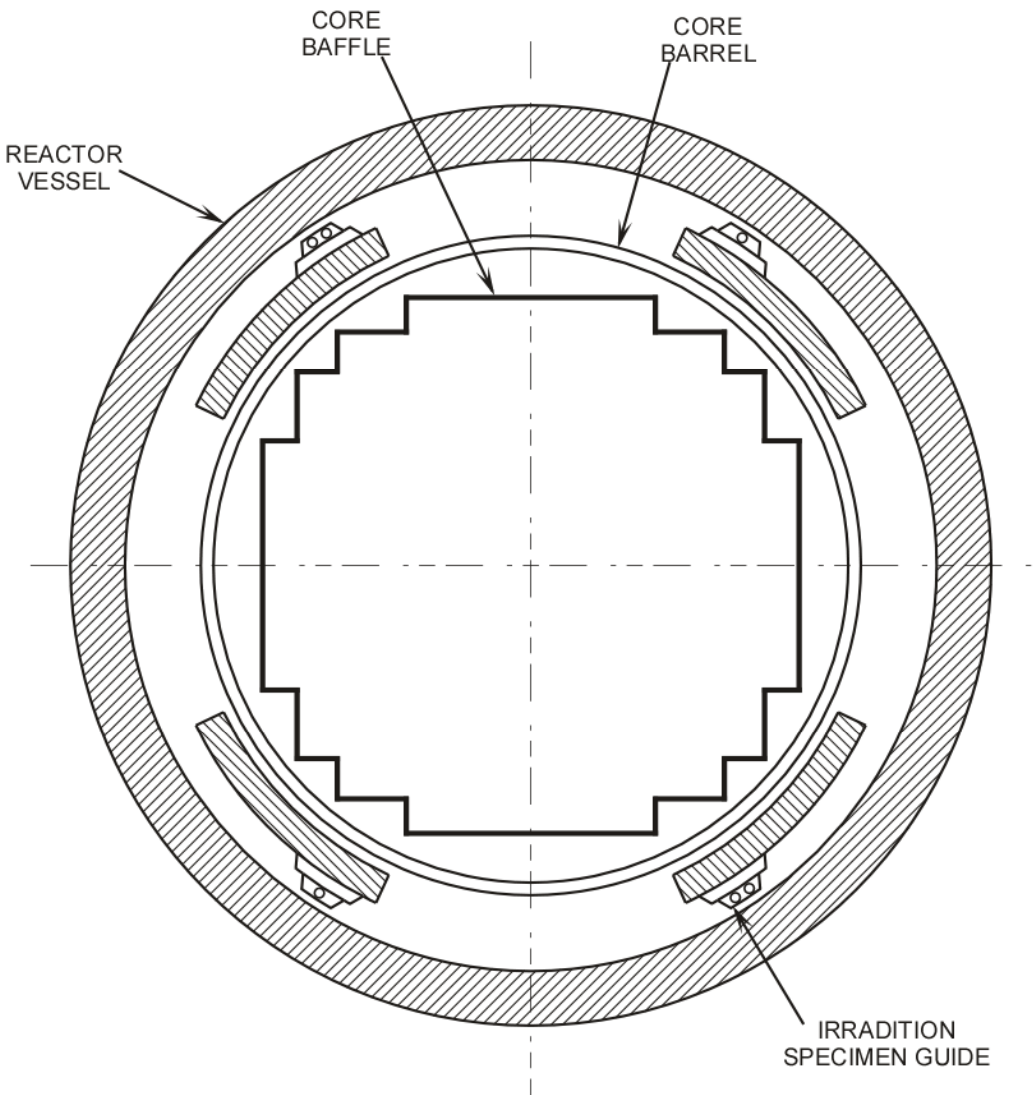


Figure 3.1-3 Reactor Vessel Cross Section

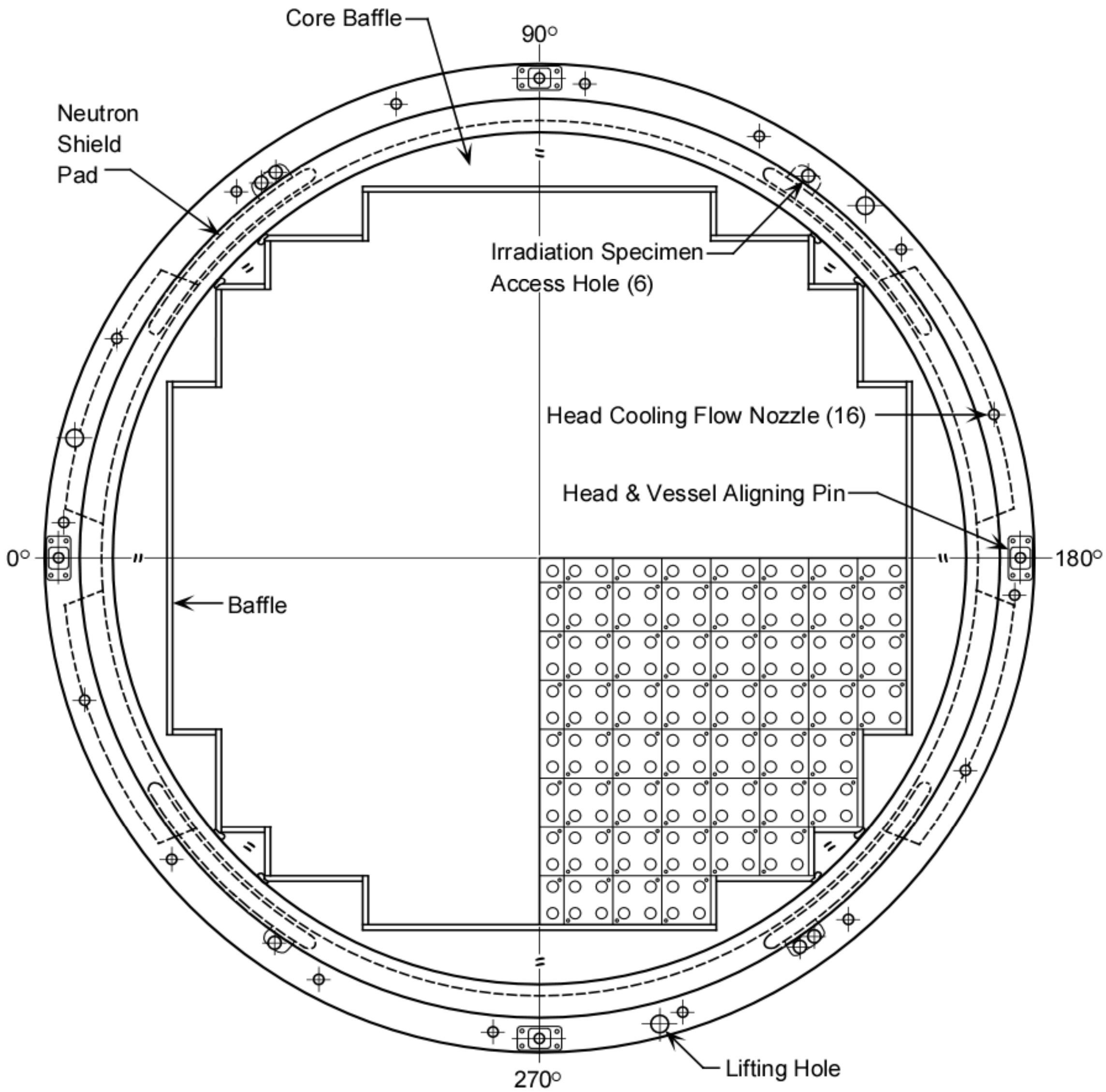


Figure 3.1-4 Core Barrel Flange

	R	P	N	M	L	K	J	H	G	F	E	D	C	B	A
1					N02 K-05	L13 K-15 Cy12	N19 E-04	R33	N23 J-06	N29 K-11	N08 L-04				
2			N14 D-14	R17	R14	R30	R32	N04 J-10	R07	R25	R18	R35	N18 M-14		
3		N06 B-12	D38R K-10	R37	M17 N-05	M45 G-15	L11 A-06 Cy12	P06 G-12	M14 L-03	M48 F-15	M20 K-15	R43	F11 F-10	N13 P-12	
4		R16	R38	P28 J-12	P18 H-12	P17 D-10	Q18 E-02	P38 G-14	Q26 L-02	P34 M-10	P08 J-05	P07 M-07	R41	R10	
5	N12 M-11	R12	M19 A-10	P21 L-09	Q04 N-03	Q17 C-04	P04 G-09	P40 J-14	P19 L-11	Q21 N-04	Q01 C-03	P09 M-08	M07 E-03	R20	N15 E-06
6	N32 E-10	R28	M43 A-06	P27 F-12	Q11 M-13	F04R H-09	Q27 K-14	F07R H-10	Q07 F-14	F56R J-08	Q24 D-13	P11 K-12	M26 R-09	R29	L12 R-06 Cy12
7	N22 K-09	R09	M15 N-11	Q20 P-11	P13 E-11	Q08 B-06	P29 G-05	N34 H-14	P25 E-09	Q15 P-06	P20 J-09	Q23 B-11	L23 F-15 Cy12	R24	N24 D11
8	R04	N25 F-09	P35 D-07	P42 B-07	P41 B-09	F18R F-08	N36 B-08	D12 H-13 Cy 4	N33 P-08	F05R K-08	P37 P-07	P39 P-09	P16 M-09	N21 K-07	R03
9	N11 M-05	R36	L09 K-01 Cy12	Q28 P-05	P03 G-07	Q22 B-10	P33 L-07	N35 H-02	P02 J-11	Q14 P-10	P24 L-05	Q19 B-05	M36 C-05	R21	N26 F-07
10	L20 A-10 Cy12	R01	M47 A-07	P23 F-04	Q09 M-03	F03R G-08	Q13 K-02	F02R H-06	Q06 F-02	F21 H-07	Q10 D-03	P15 K-04	M18 R-10	R27	N27 L-06
11	N20 L-10	R15	M05 L-13	P01 D-08	Q03 N-13	Q05 C-12	P22 E-05	P44 G-02	P05 J-07	Q12 N-12	Q02 C-13	P32 E-07	M38 R-06	R08	N09 D-05
12		R11	R40	P26 D-09	P30 G-11	P36 D-06	Q16 E-14	P43 J-02	Q25 L-14	P12 M-06	P14 H-04	P10 G-04	R39	R19	
13		N10 B-04	F30 F-06	R44	M30 F-01	M32 K-01	M46 E-13	P31 J-04	L30 R-10 Cy12	M04 J-01	M24 C-11	R42	F19R K-06	N05 P-04	
14			N16 D-02	R05	R23	R26	R02	N28 G-06	R22	R13	R31	R06	N07 M-02		
15					N03 E-12	N31 F-05	N30 G-10	R34	N17 L-12	L01 F-01 Cy12	N01 F-11				

XXX	Assembly Identity
XXX	Position in Previous Cycle
XXX	Discharge Cycle of Reinserts

Figure 3.1-5 Core Loading Arrangement

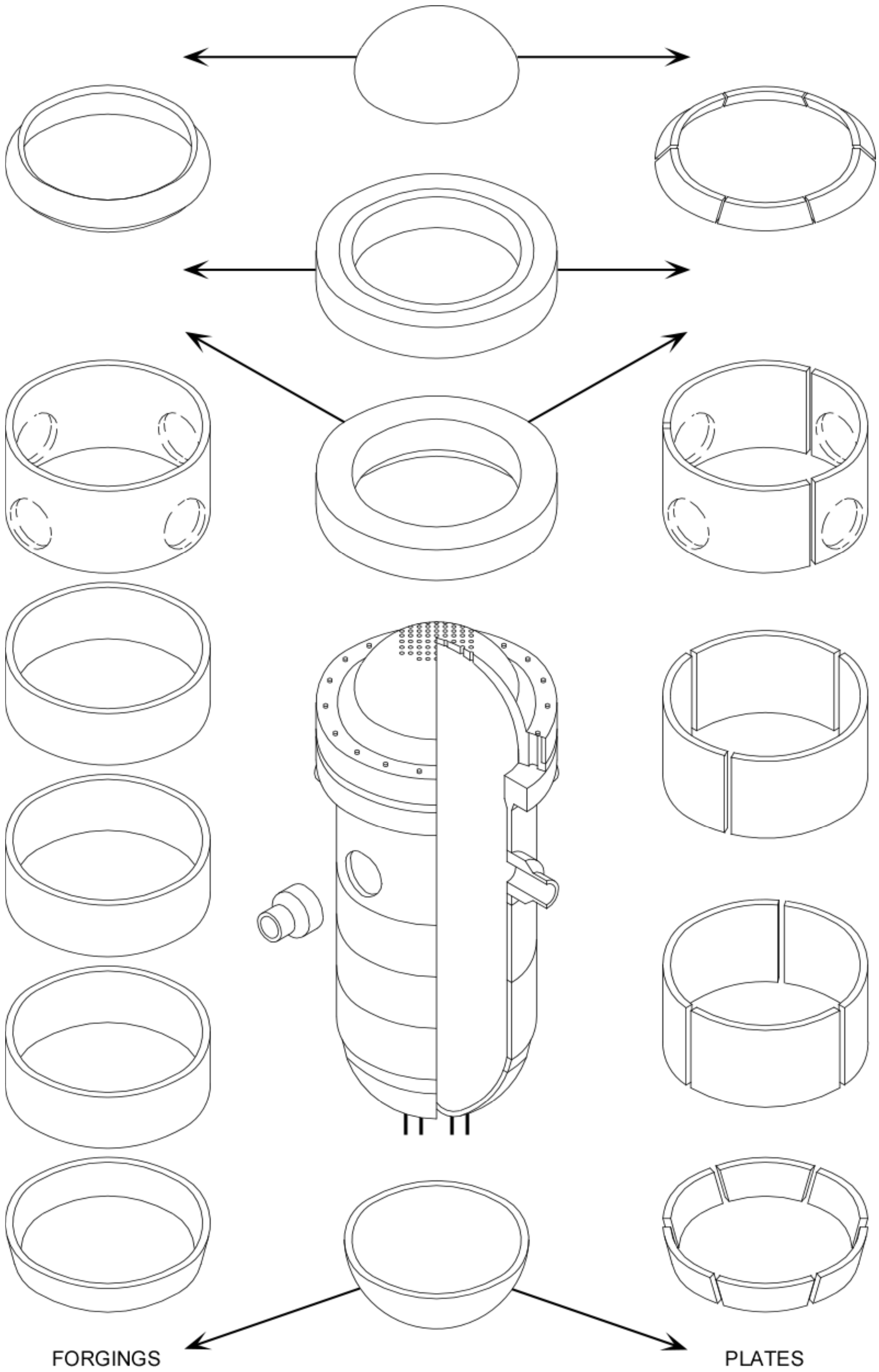


Figure 3.1-6 Reactor Vessel Construction

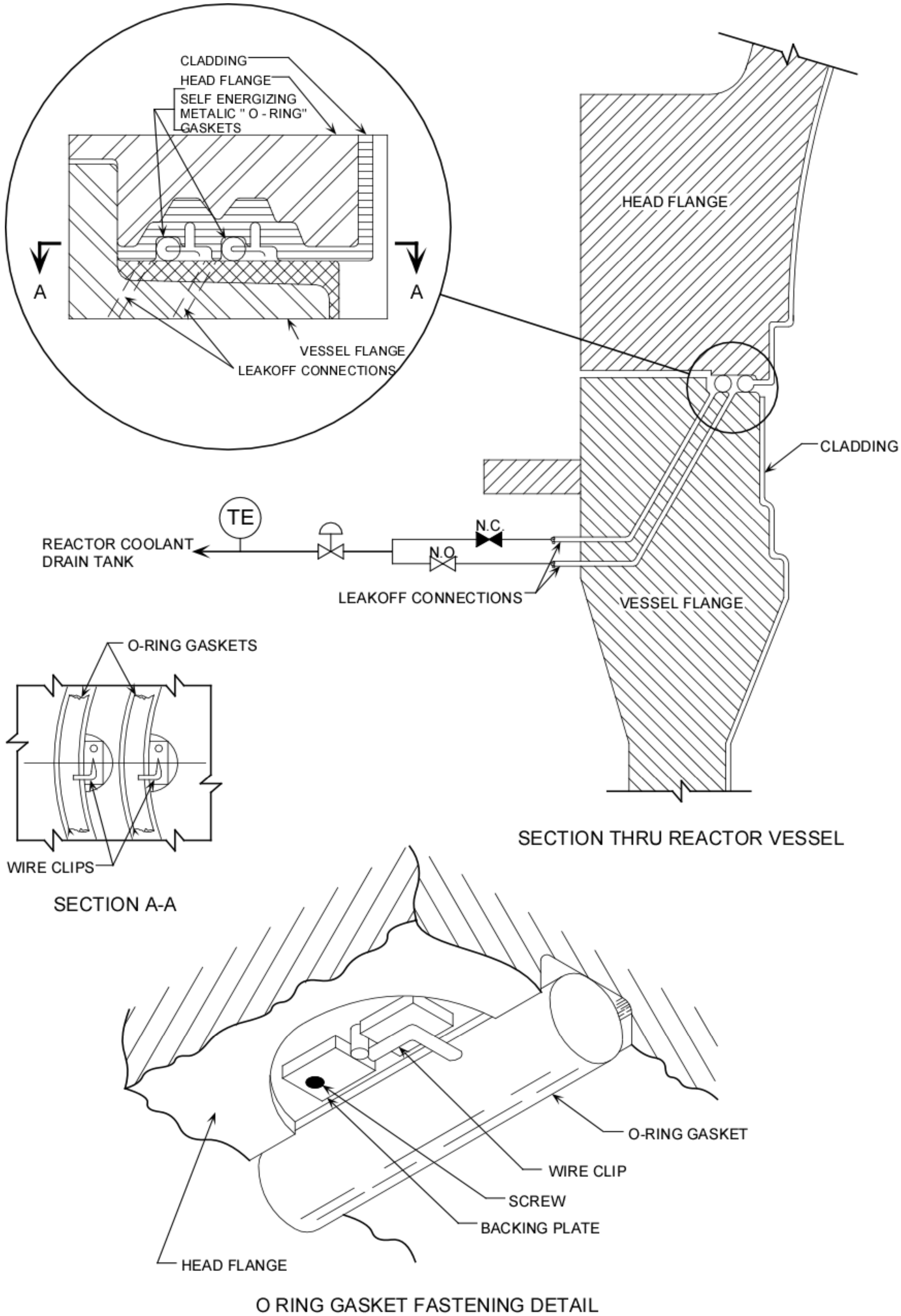


Figure 3.1-7 Reactor Vessel Seal

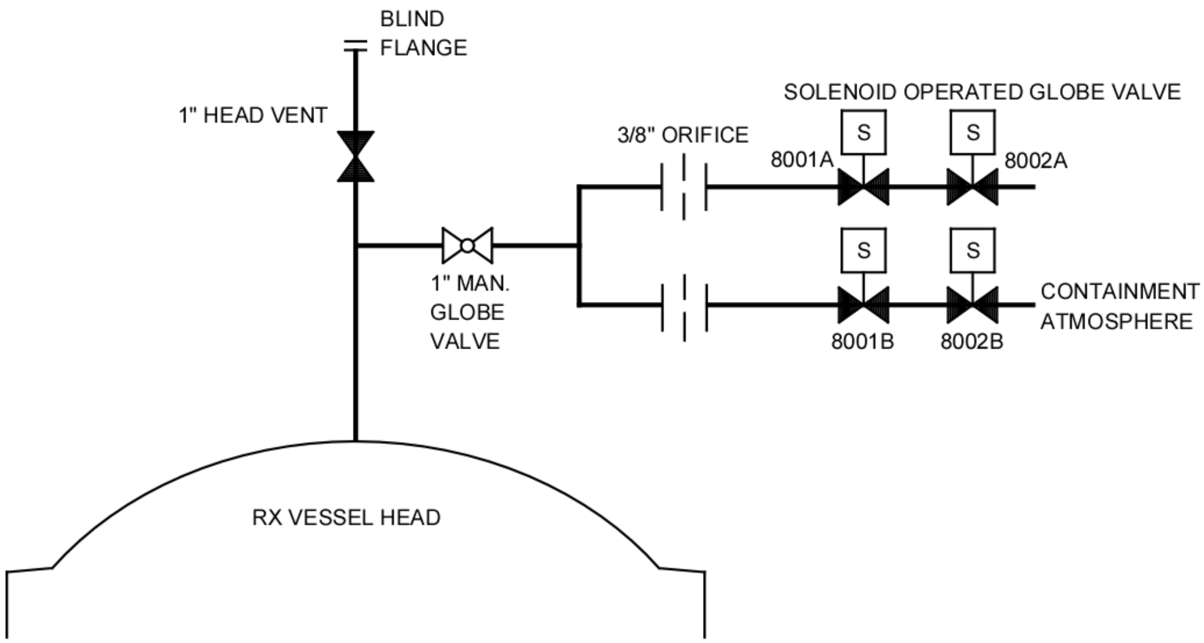


Figure 3.1-8 Reactor Vessel Head Venting System

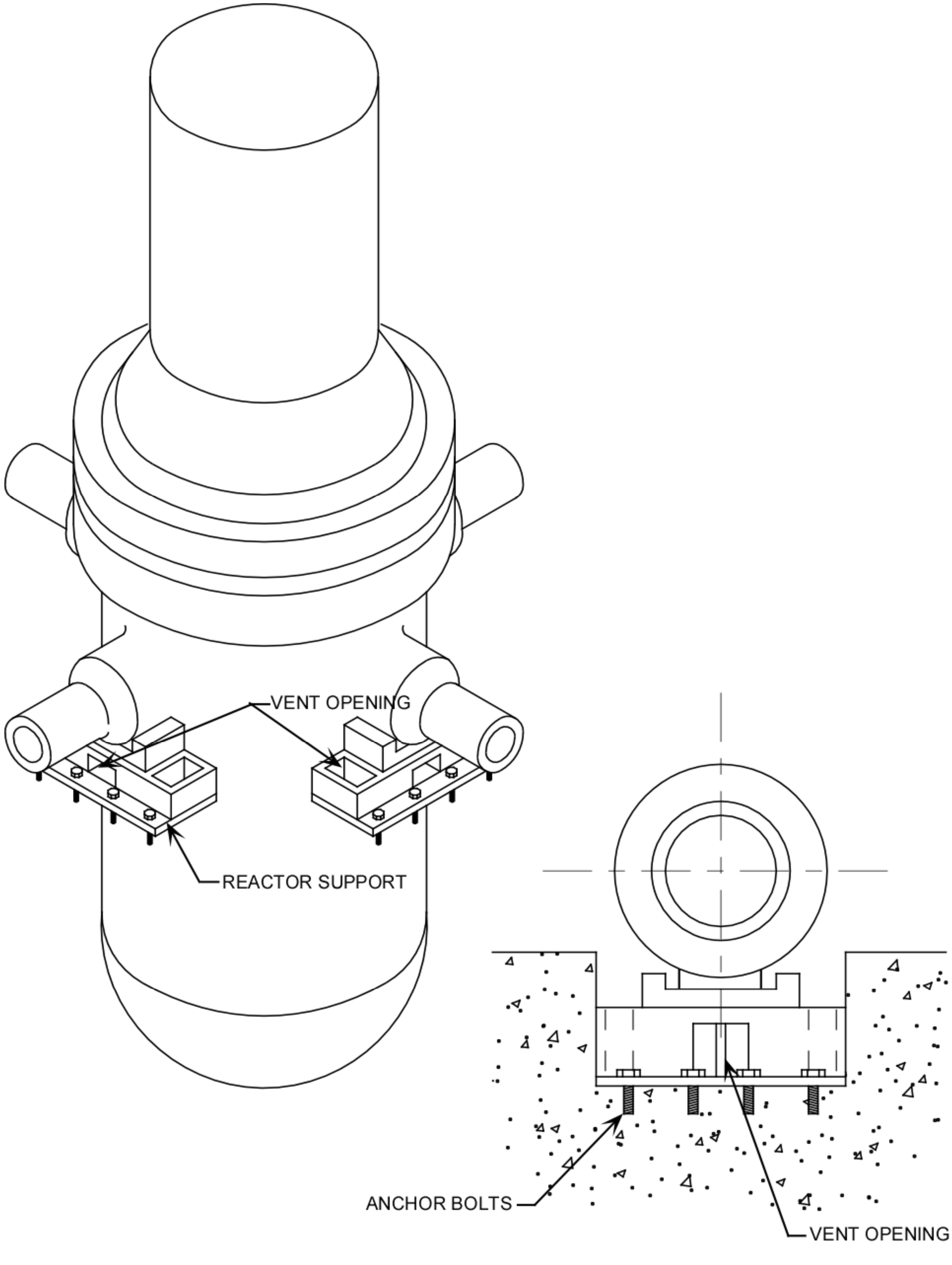


Figure 3.1-9 Reactor Vessel Supports

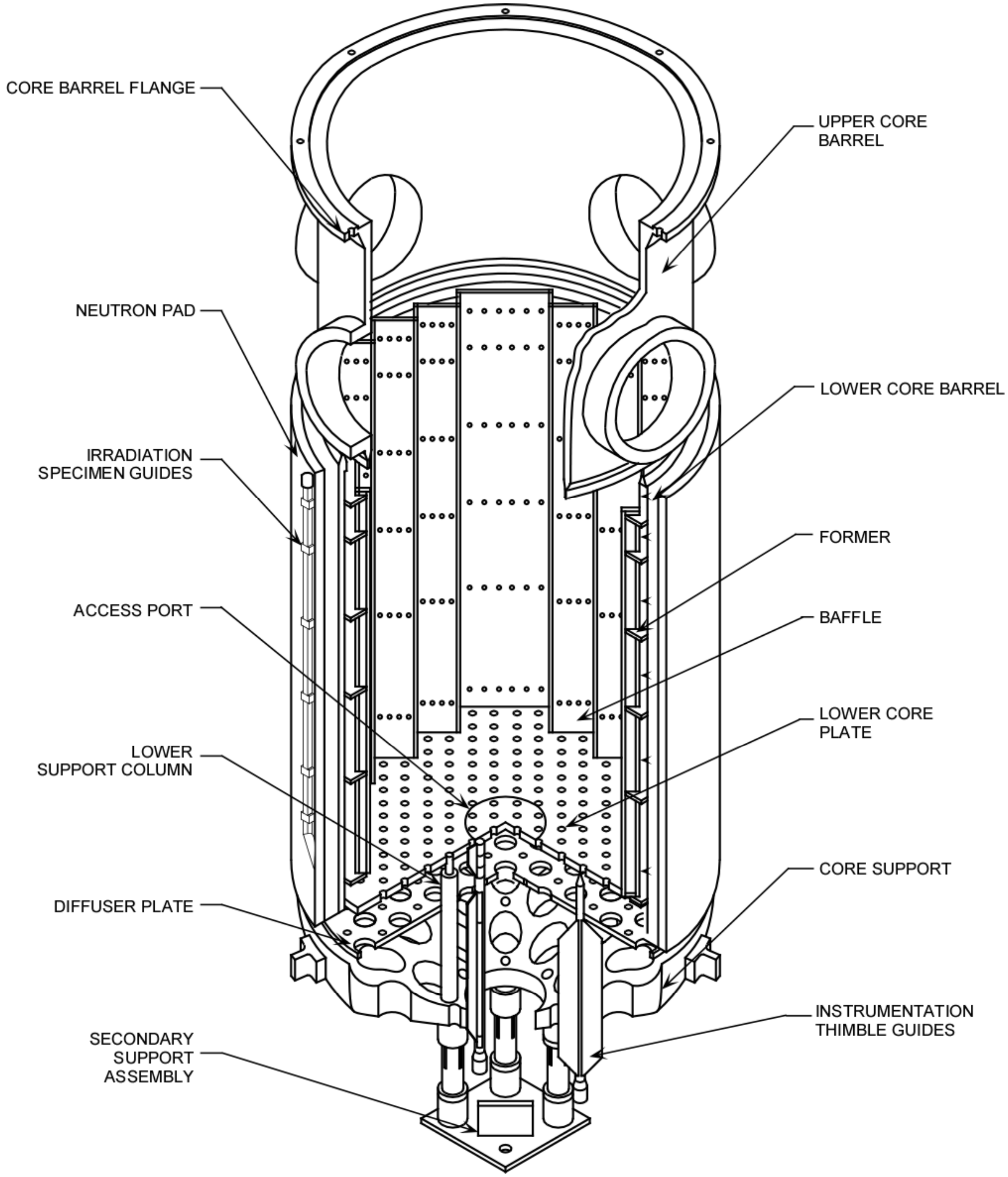


Figure 3.1-10 Lower Core Support Structure

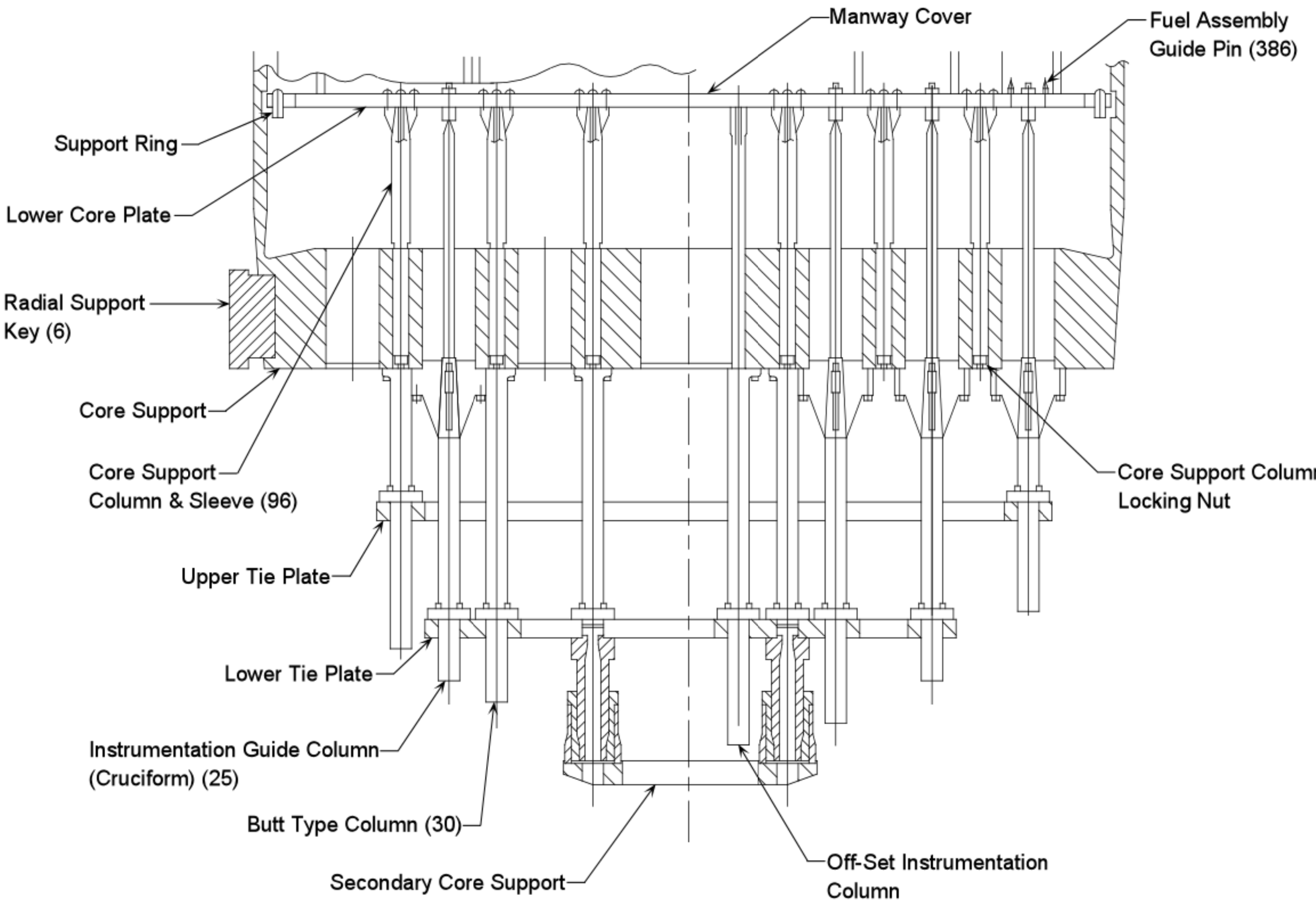


Figure 3.1-11 Instrument Guide and Secondary Core Support Assembly

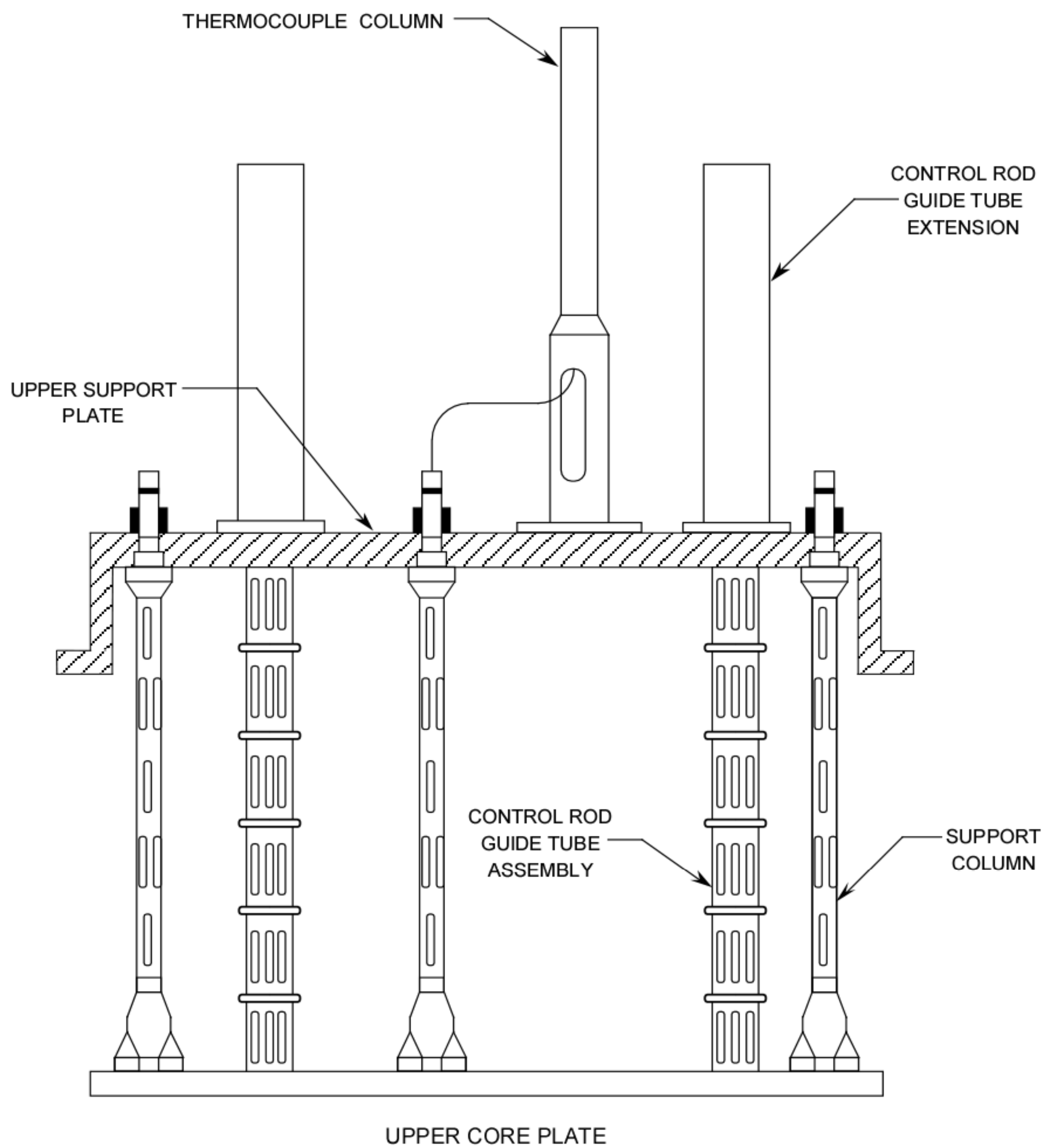


Figure 3.1-12 Upper core Support Structure

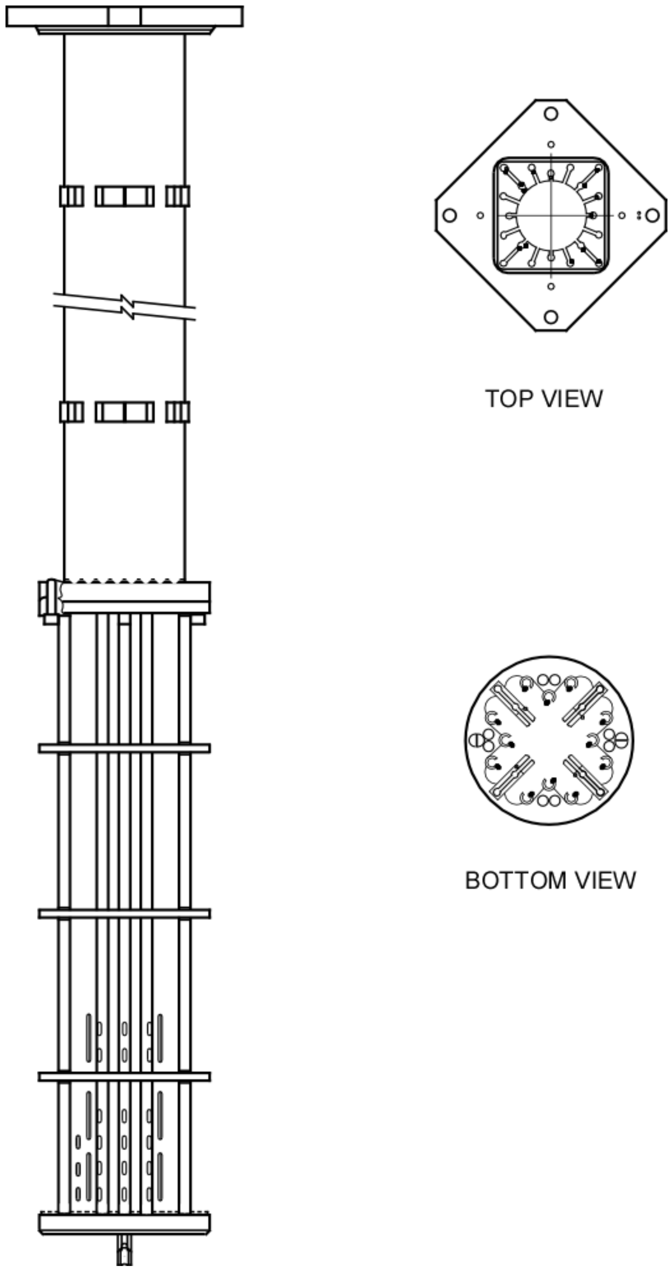


Figure 3.1-13 Control Rod Guide Tube Assembly

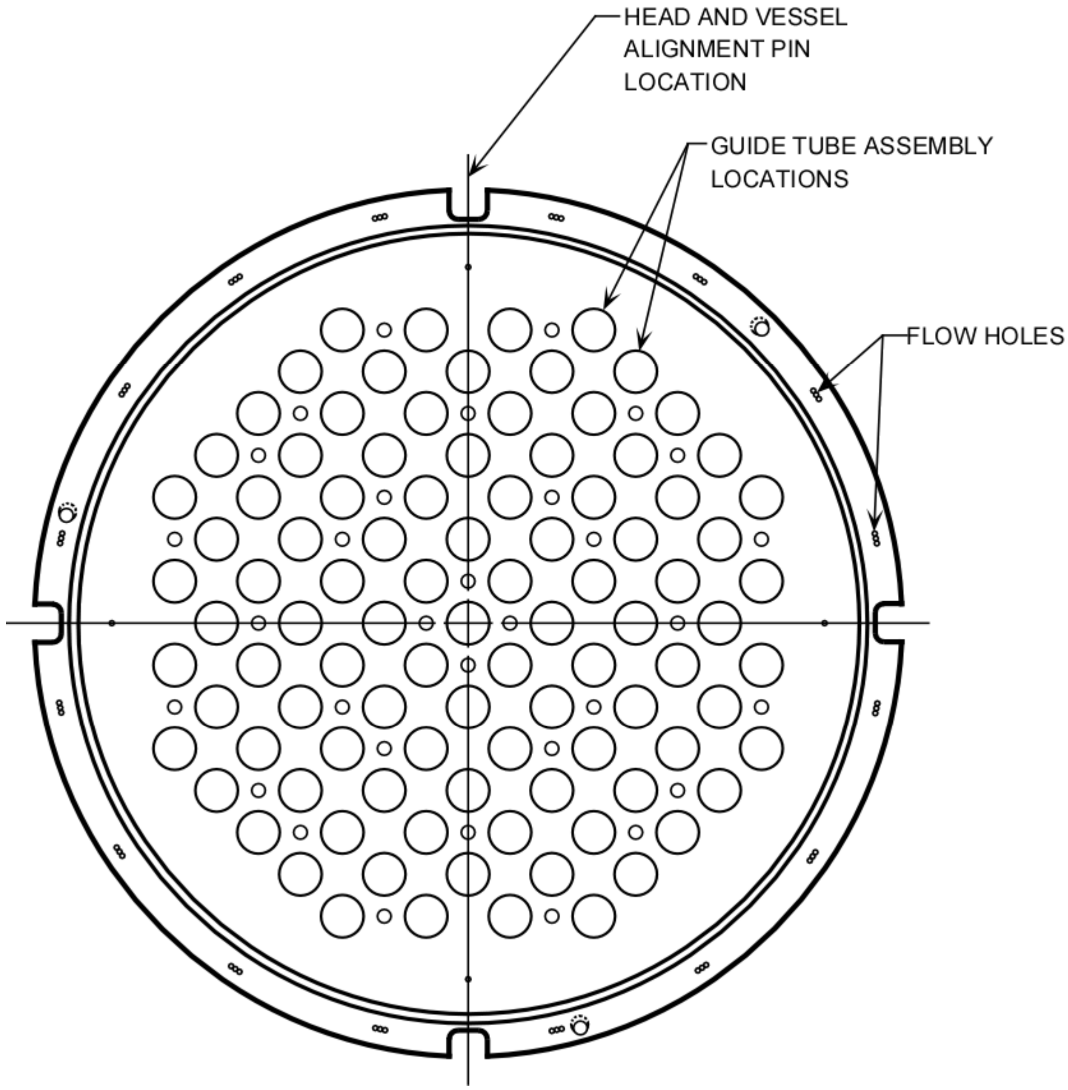


Figure 3.1-14 Upper Core Plate

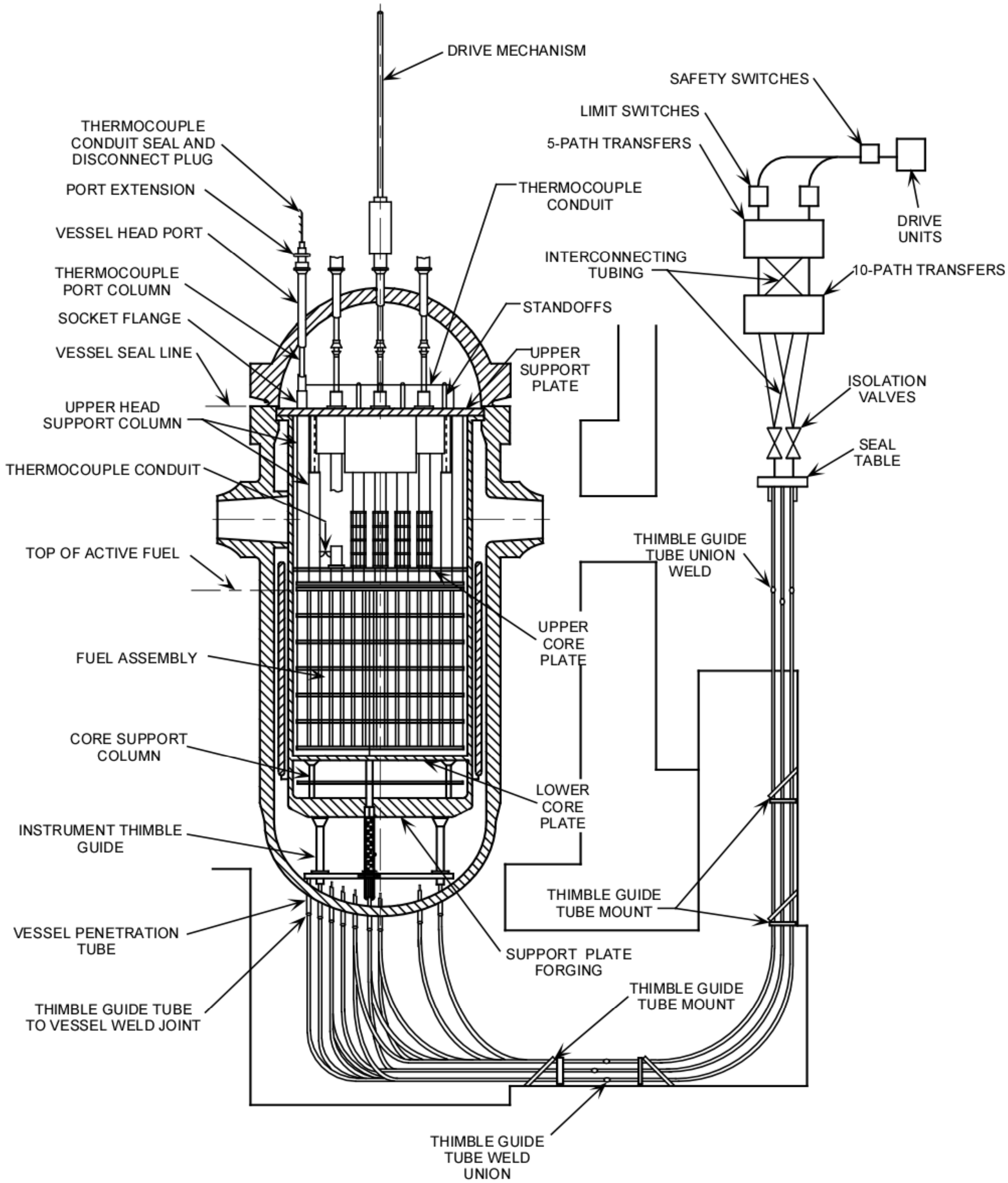


Figure 3.1-15 In-Core Instrumentation

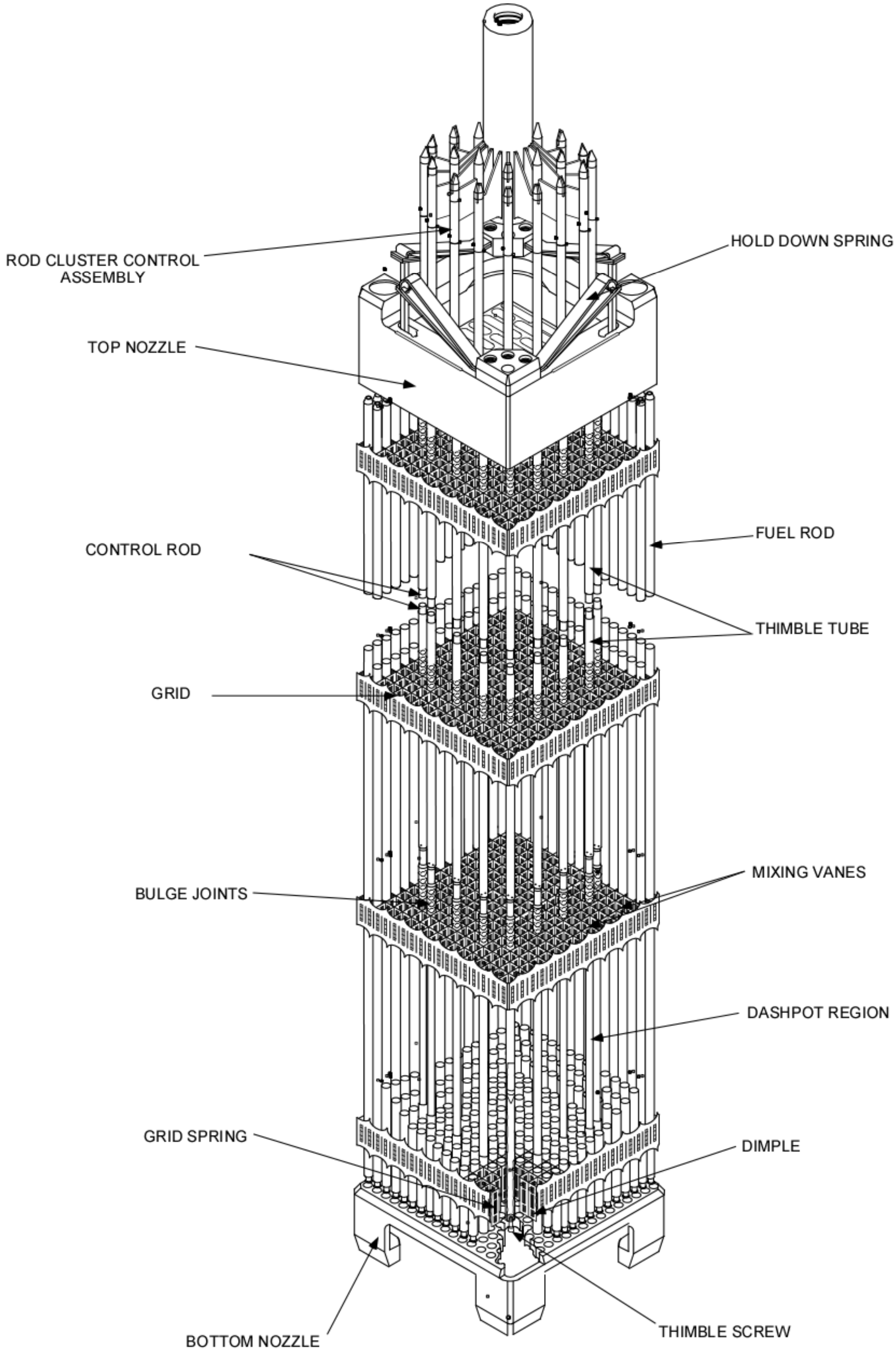


Figure 3.1-16 Fuel Assembly and RCCA Cutaway

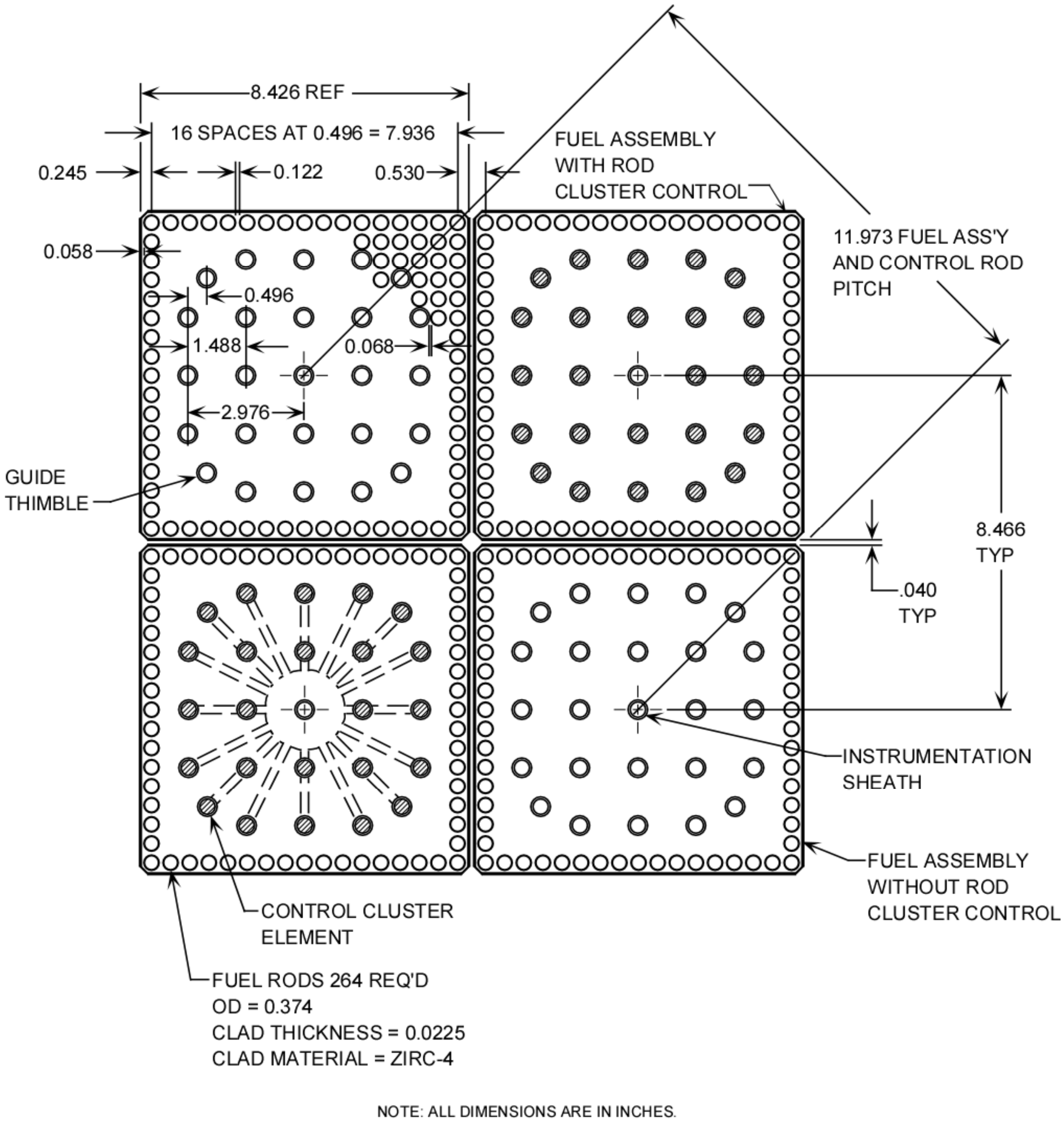


Figure 3.1-17 17 X 17 Fuel Assembly Outline

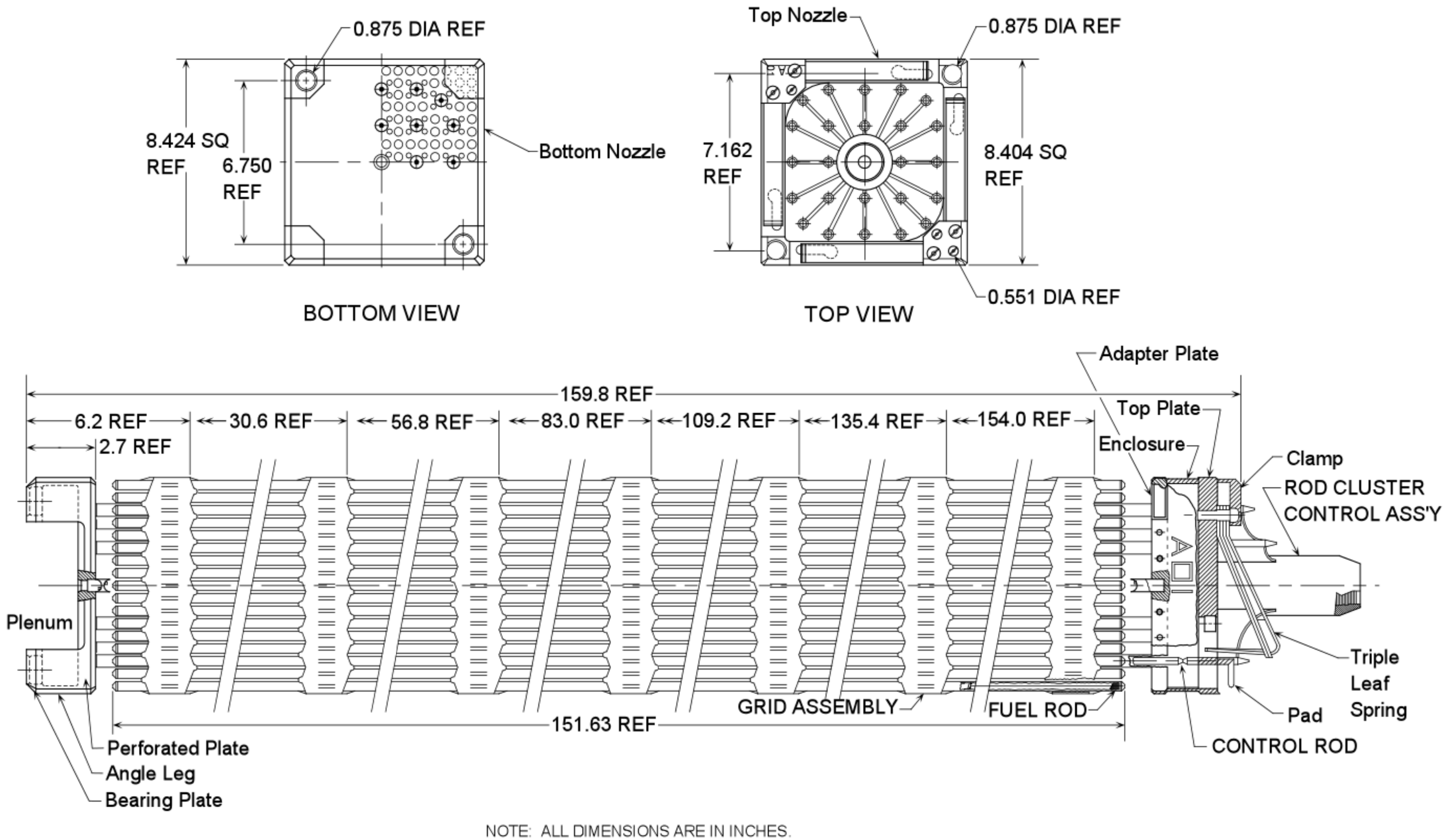


Figure 3.1-18 17 X 17 Fuel Assembly Outline

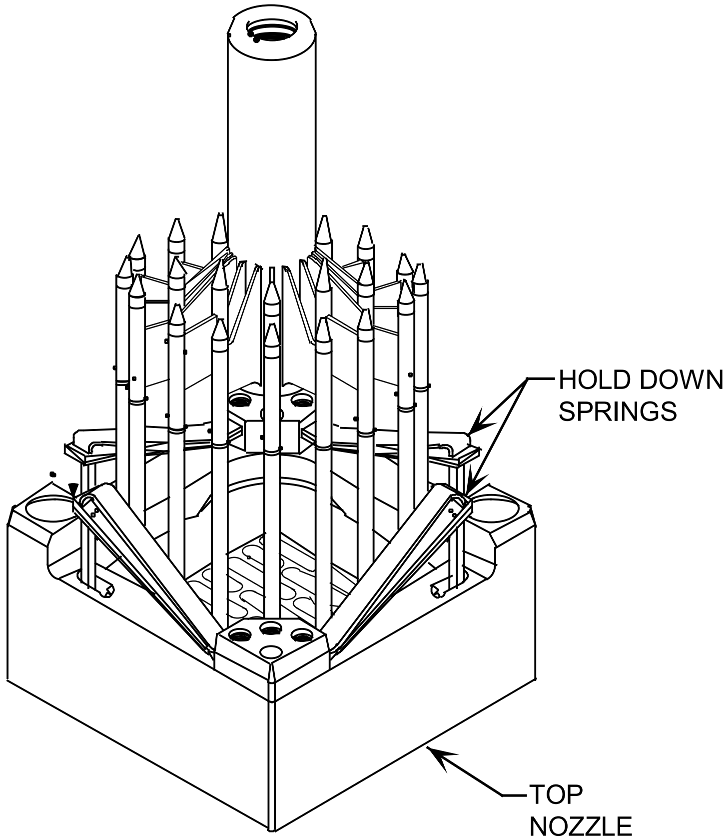
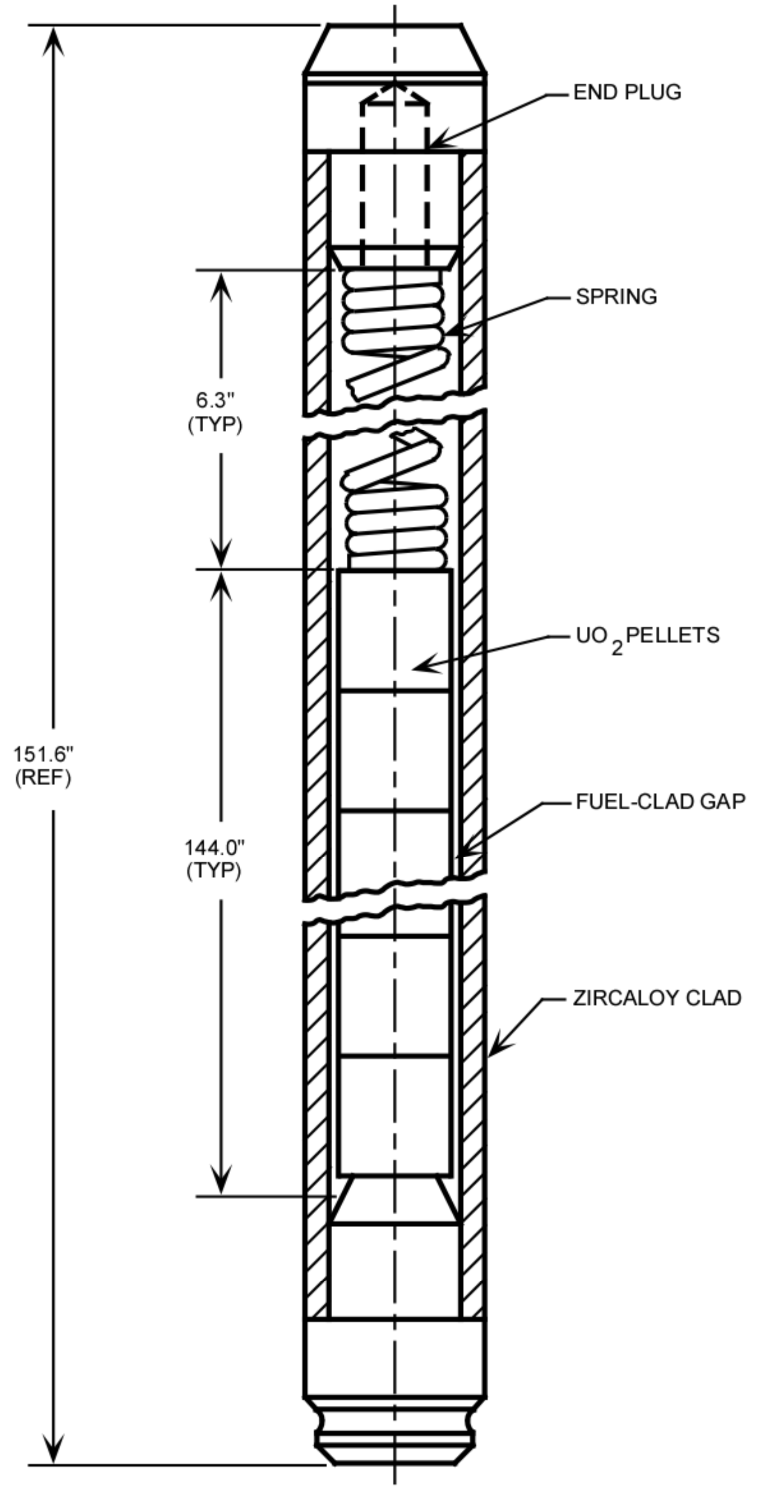


Figure 3.1-19 Upper Fuel Assembly and RCCA Spider



SPECIFIC DIMENSIONS DEPEND ON DESIGN VARIABLES SUCH AS PRE-PRESSURIZATION, POWER HISTORY, AND DISCHARGE BURNUP

Figure 3.1-20 Fuel Rod

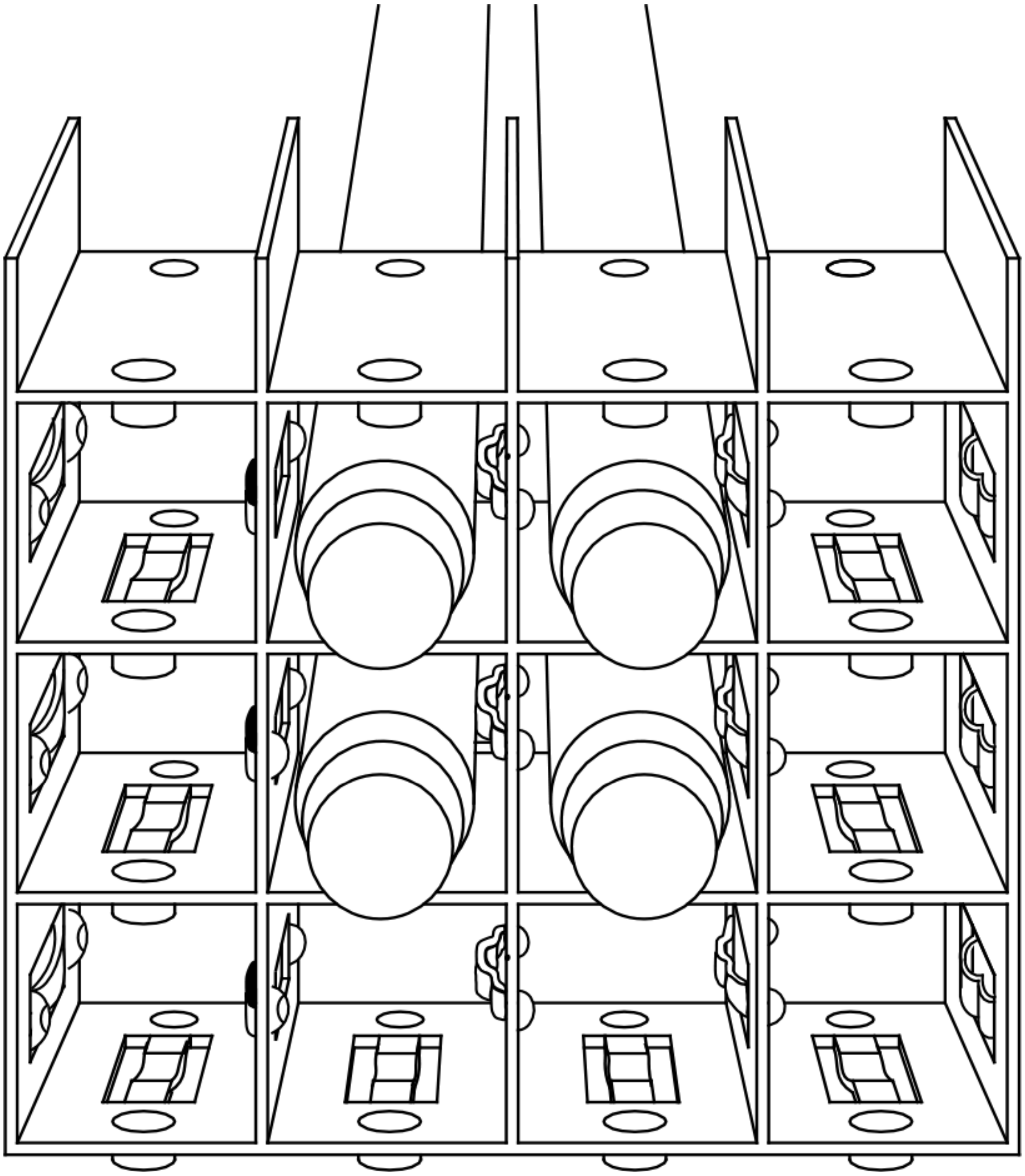


Figure 3.1-21 Spring Grid Clip Assembly

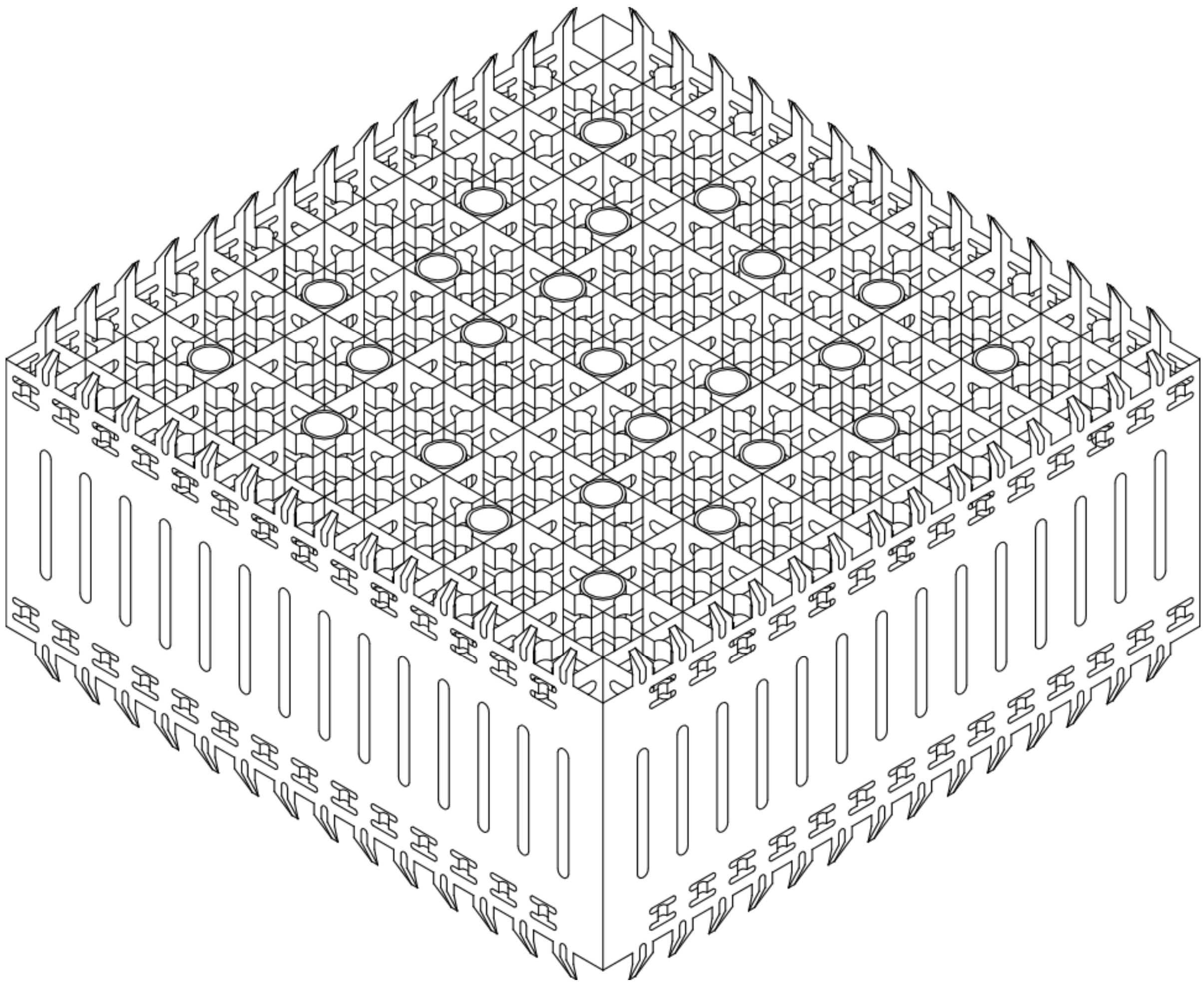
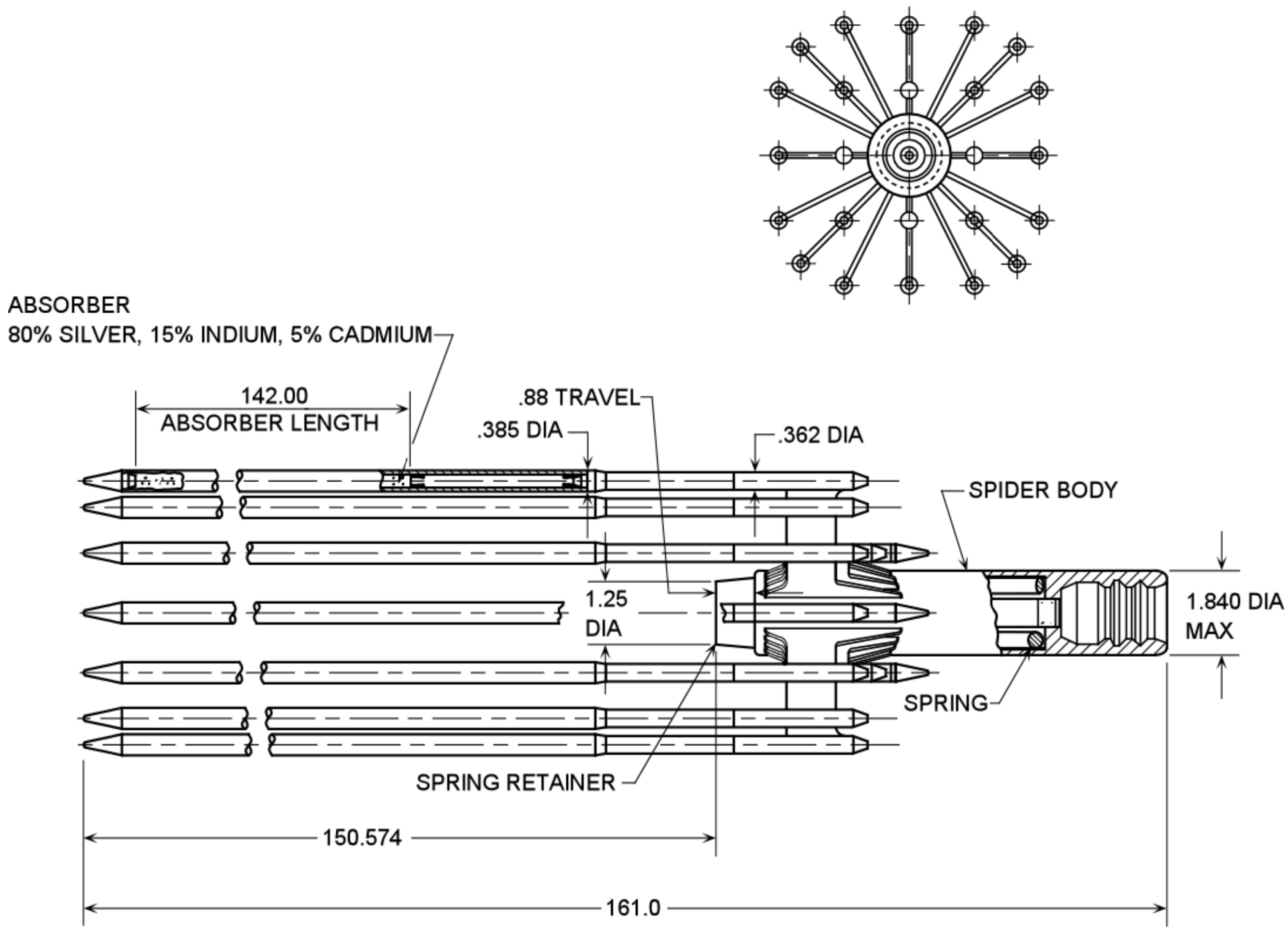


Figure 3.1-22 Spring Grid Assembly



NOTE: ALL DIMENSIONS ARE IN INCHES.

Figure 3.1-23 Rod Cluster Control Assembly

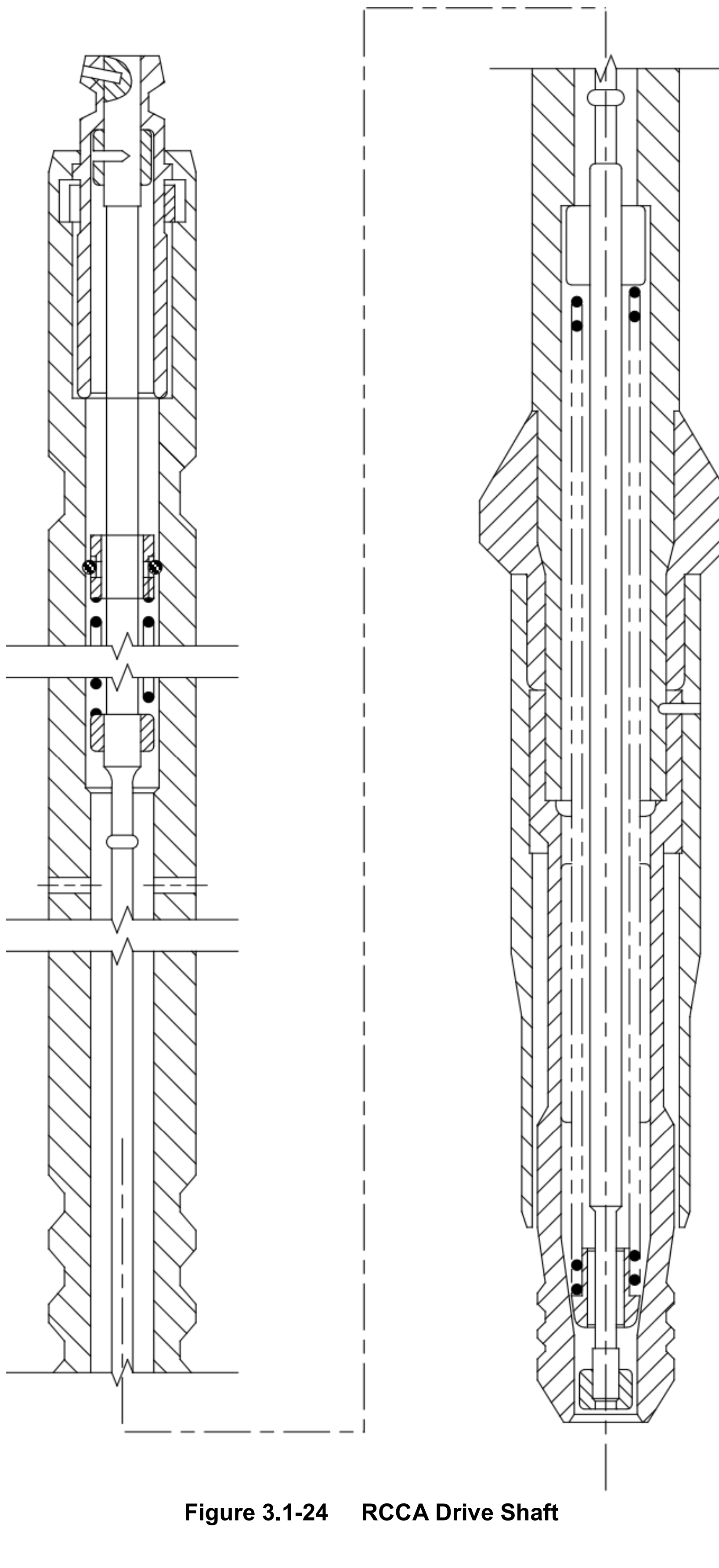


Figure 3.1-24 RCCA Drive Shaft

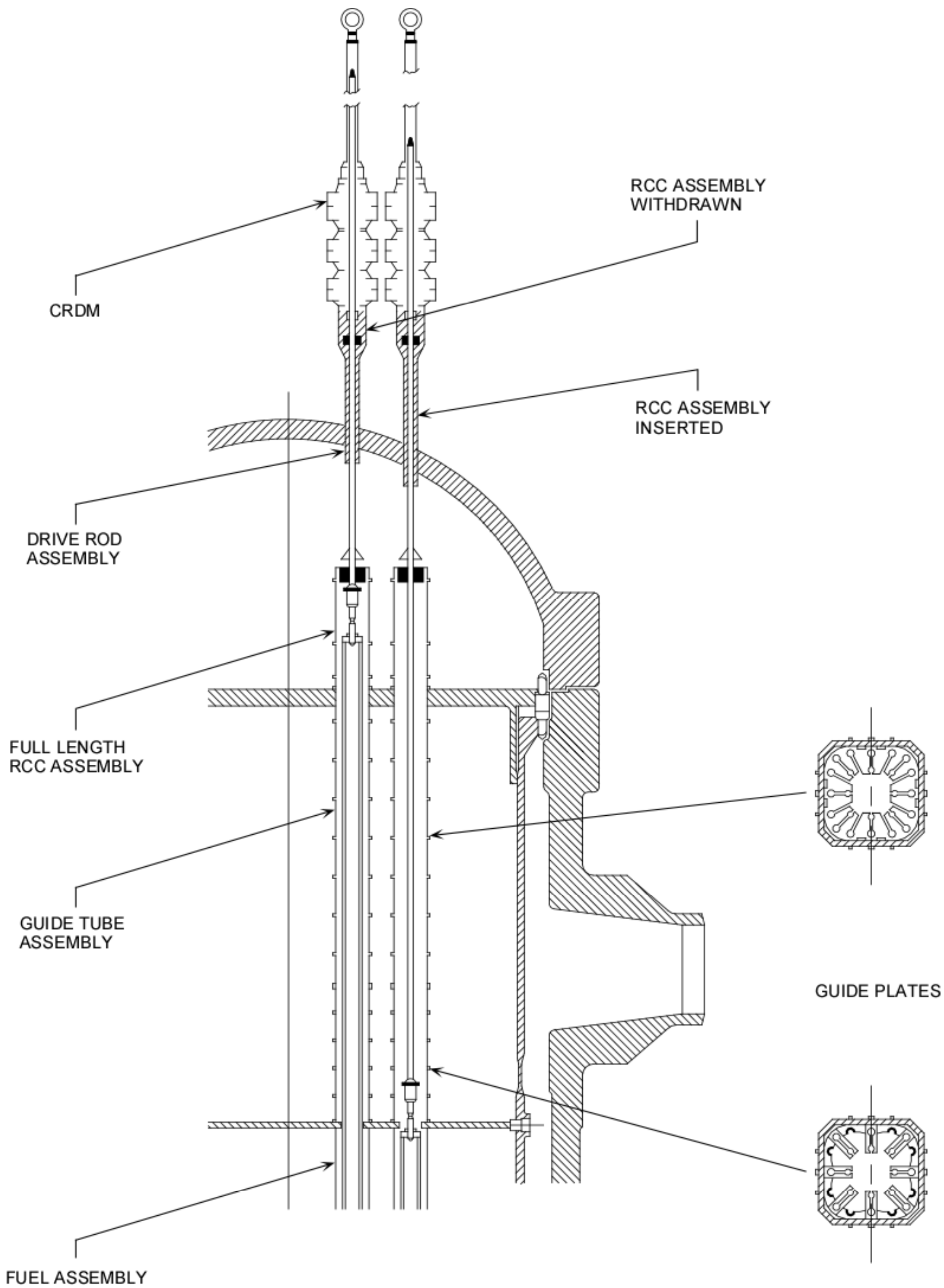
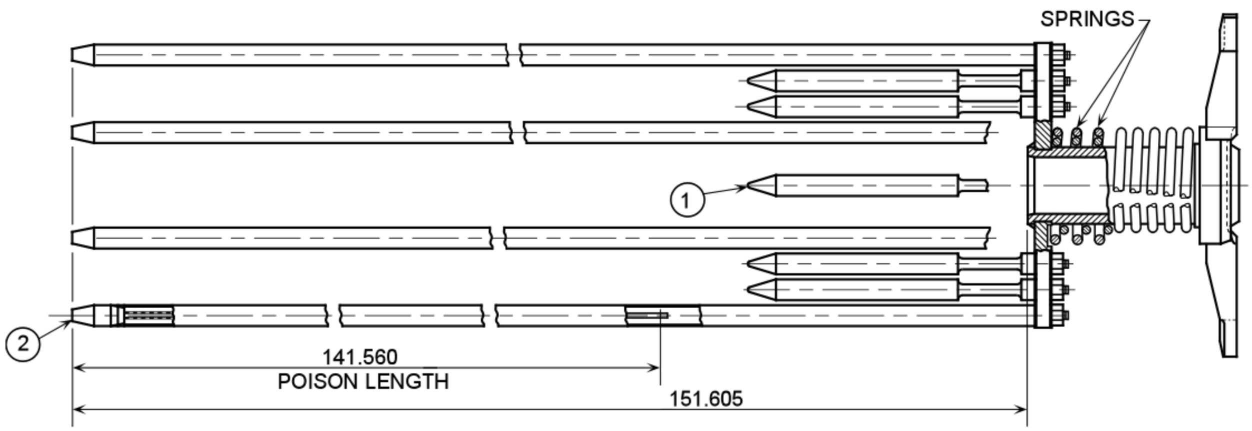


Figure 3.1-25 Full Length Rod with Interfacing Components



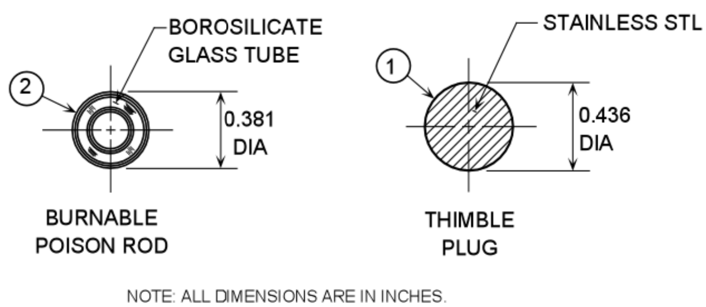


Figure 3.1-26 Burnable Poison Rod Assembly

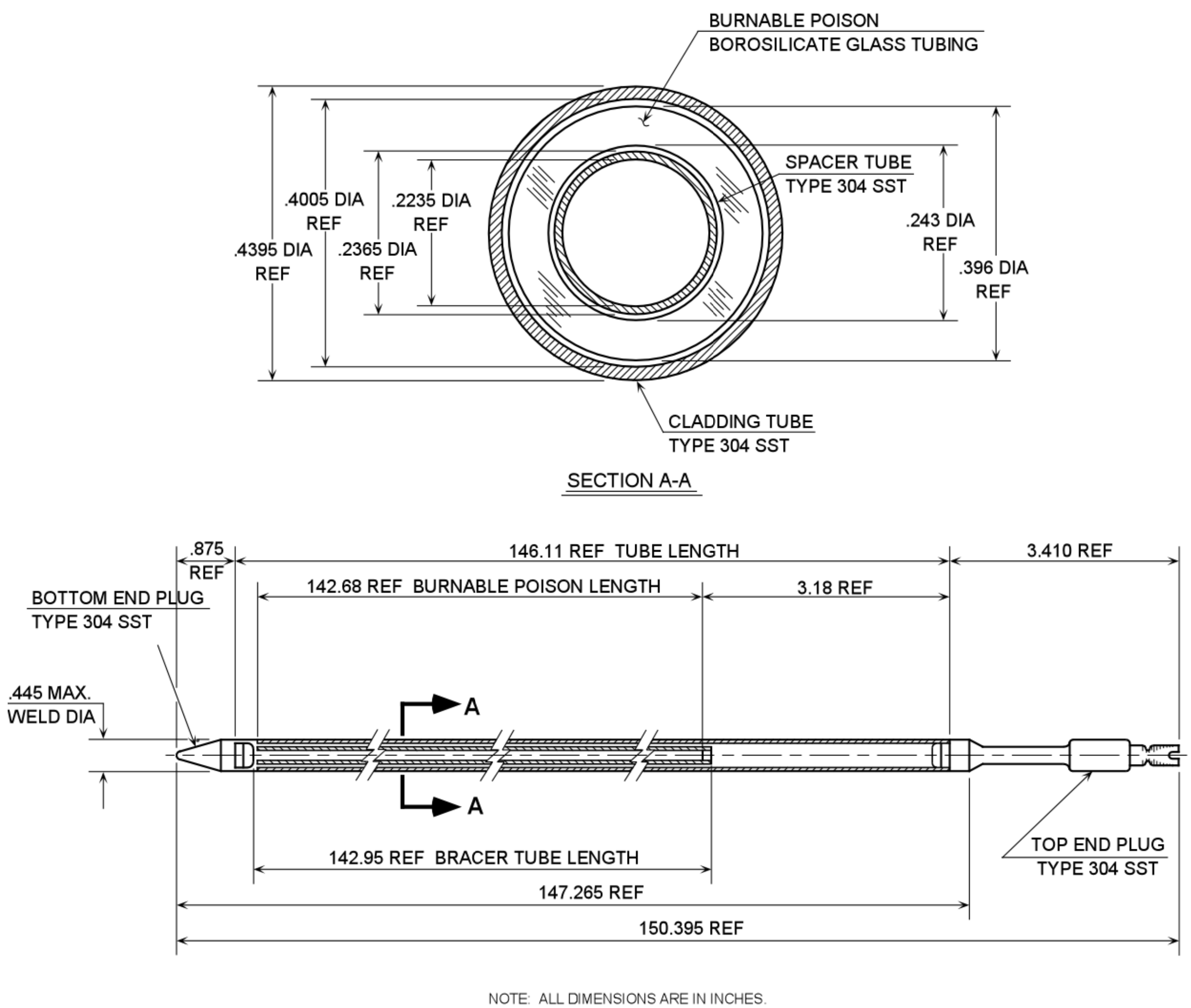


Figure 3.1-27 Burnable Poison Rod

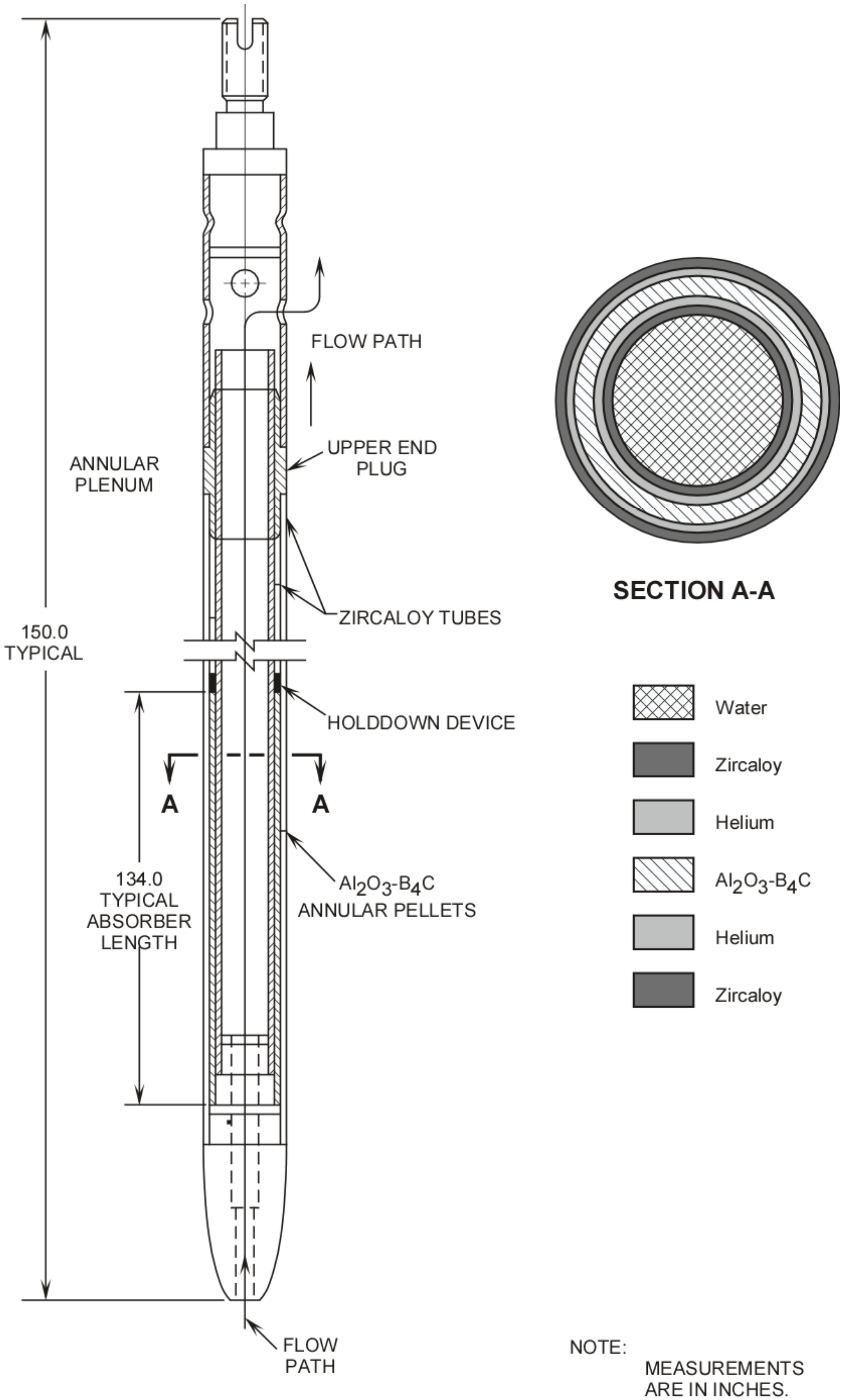


Figure 3.1-28 Wet Annular Burnable Absorber

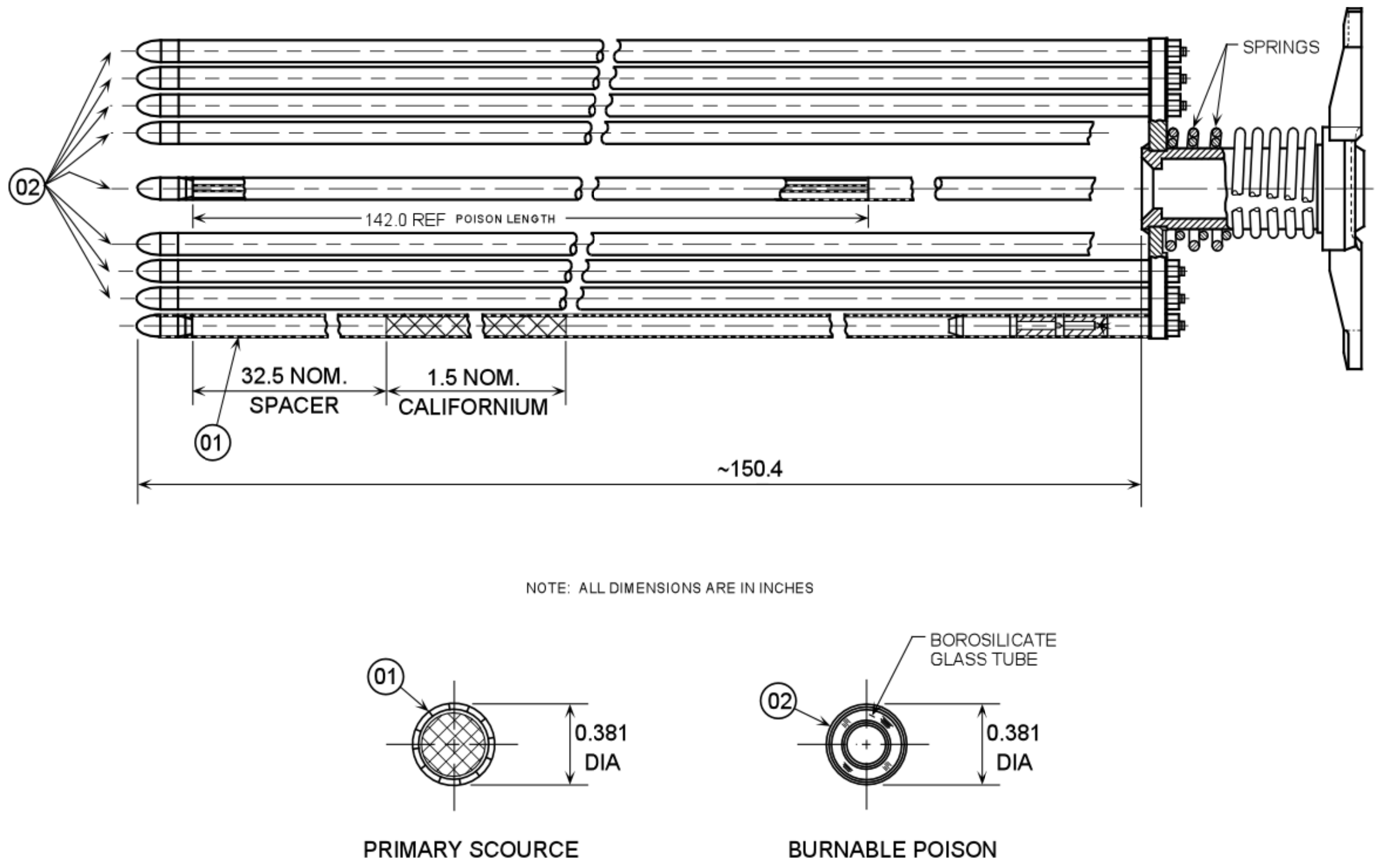


Figure 3.1-29 Primary Source Assembly

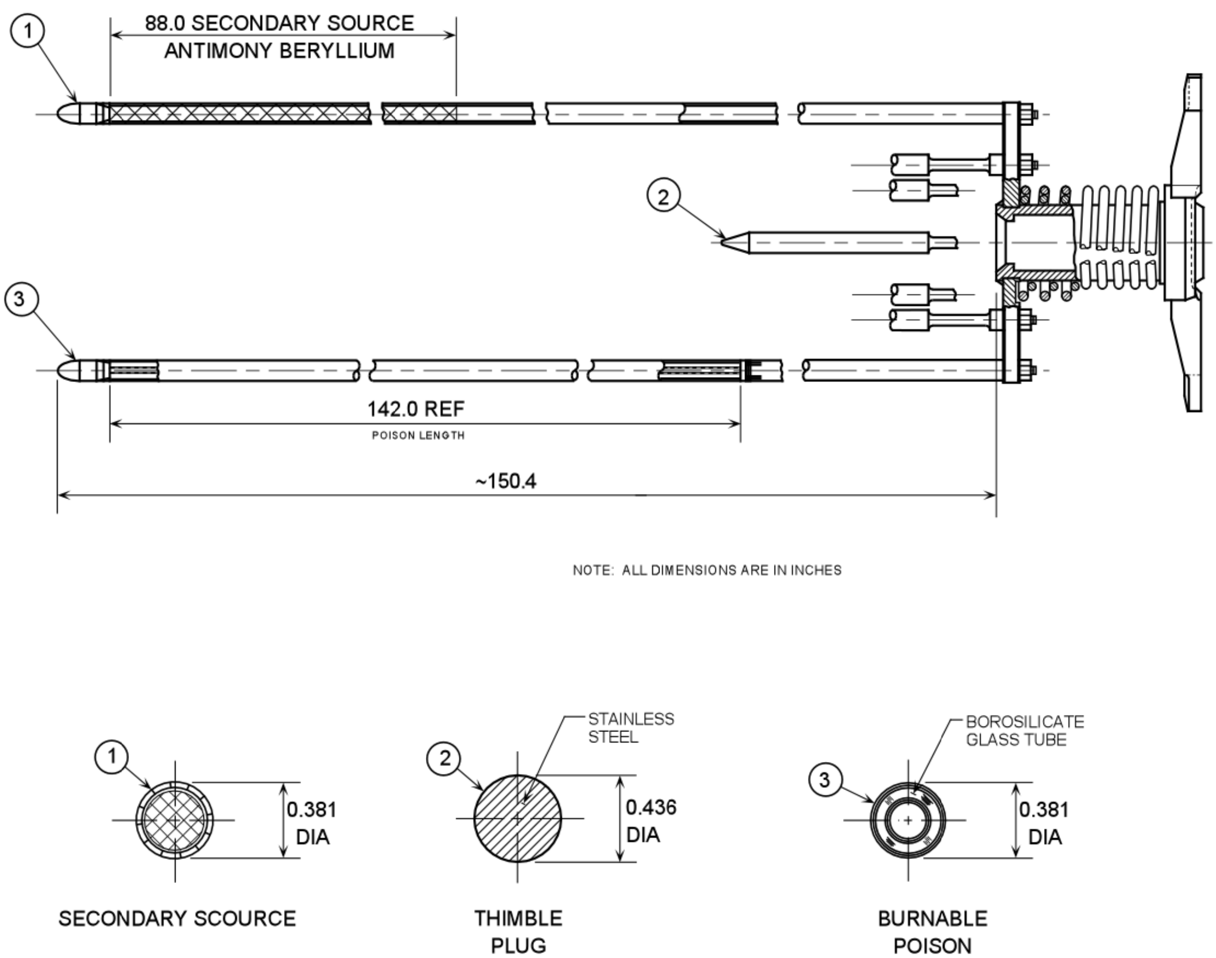
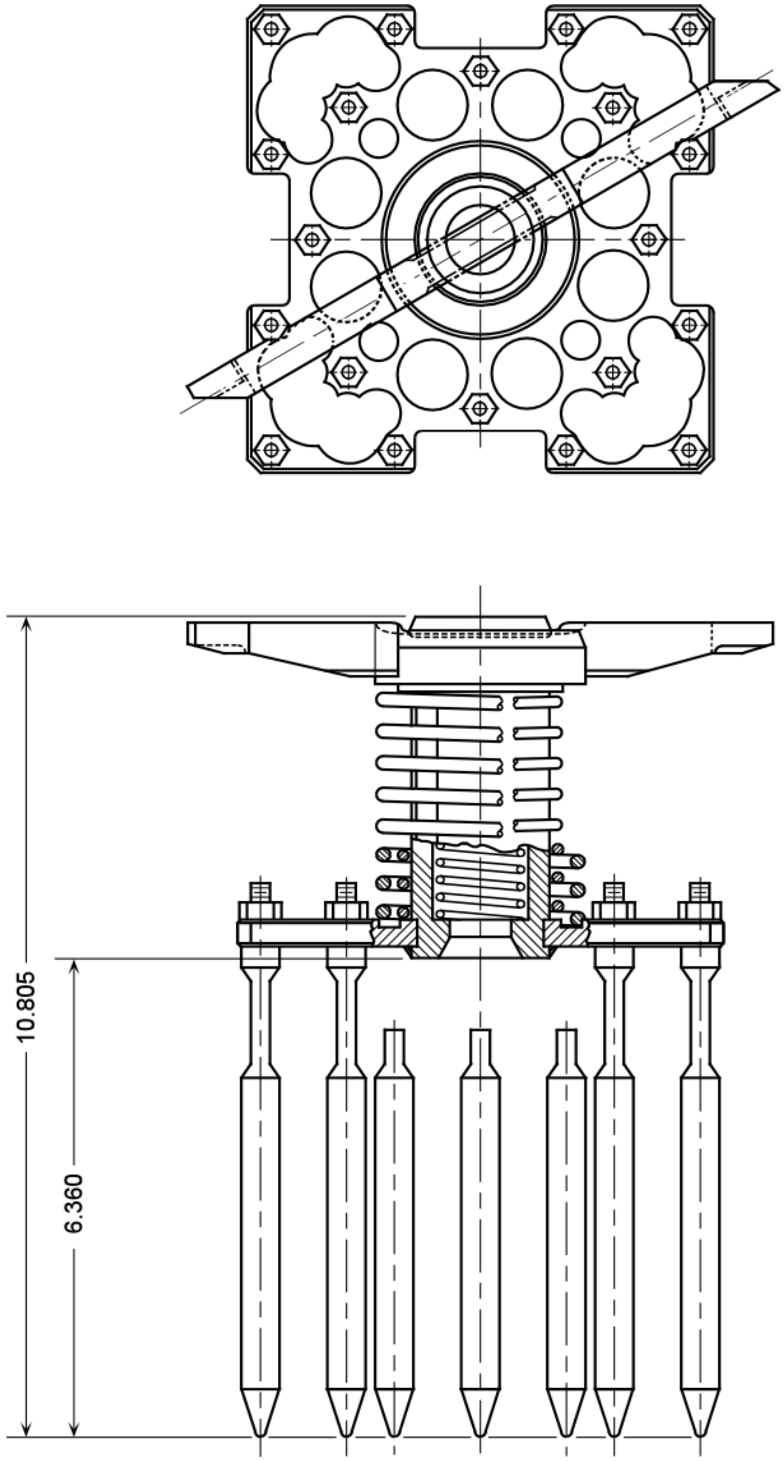


Figure 3.1-30 Secondary Source Assembly



NOTE: ALL DIMENSIONS ARE IN INCHES.

Figure 3.1-31 Thimble Plug Assembly

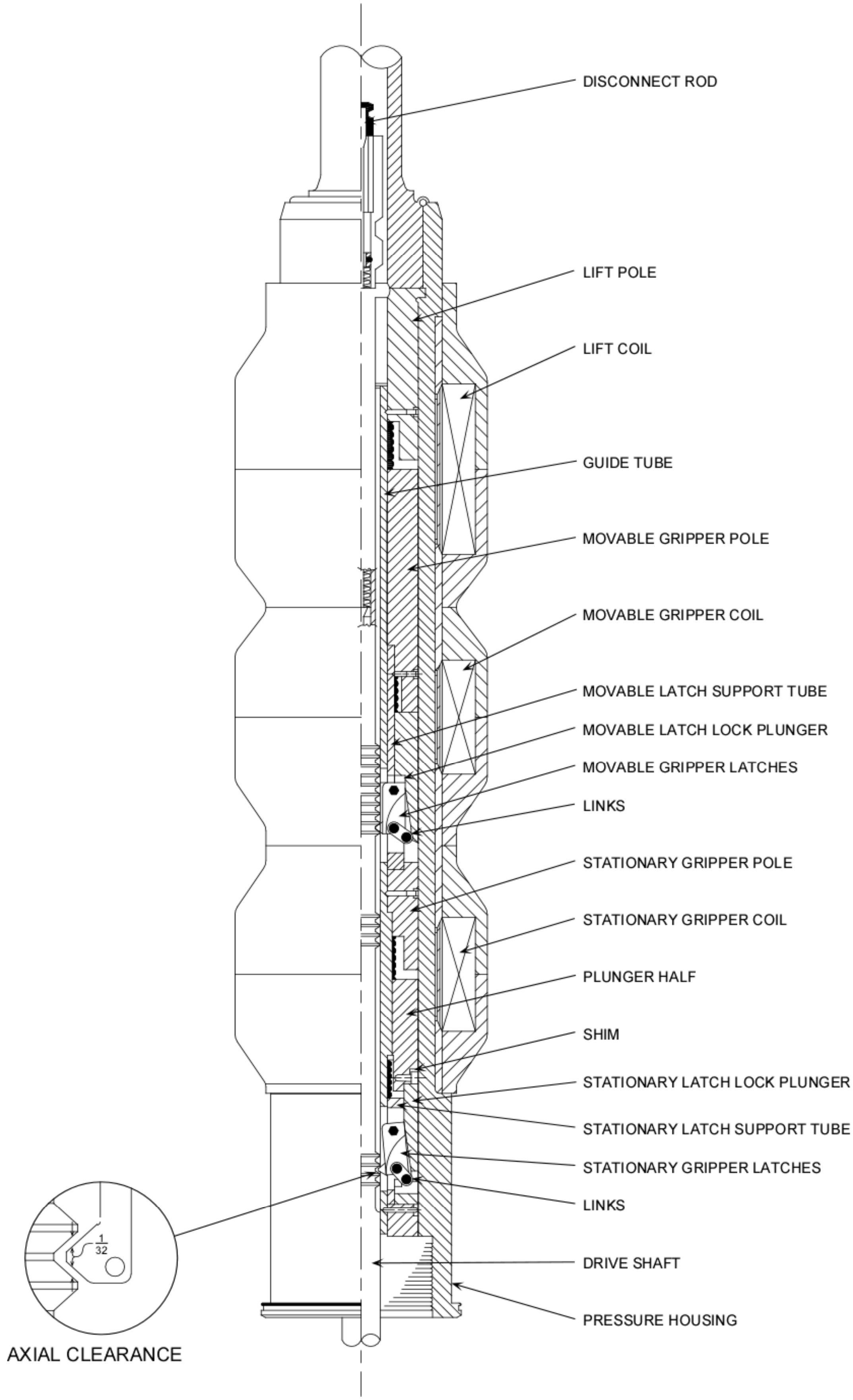
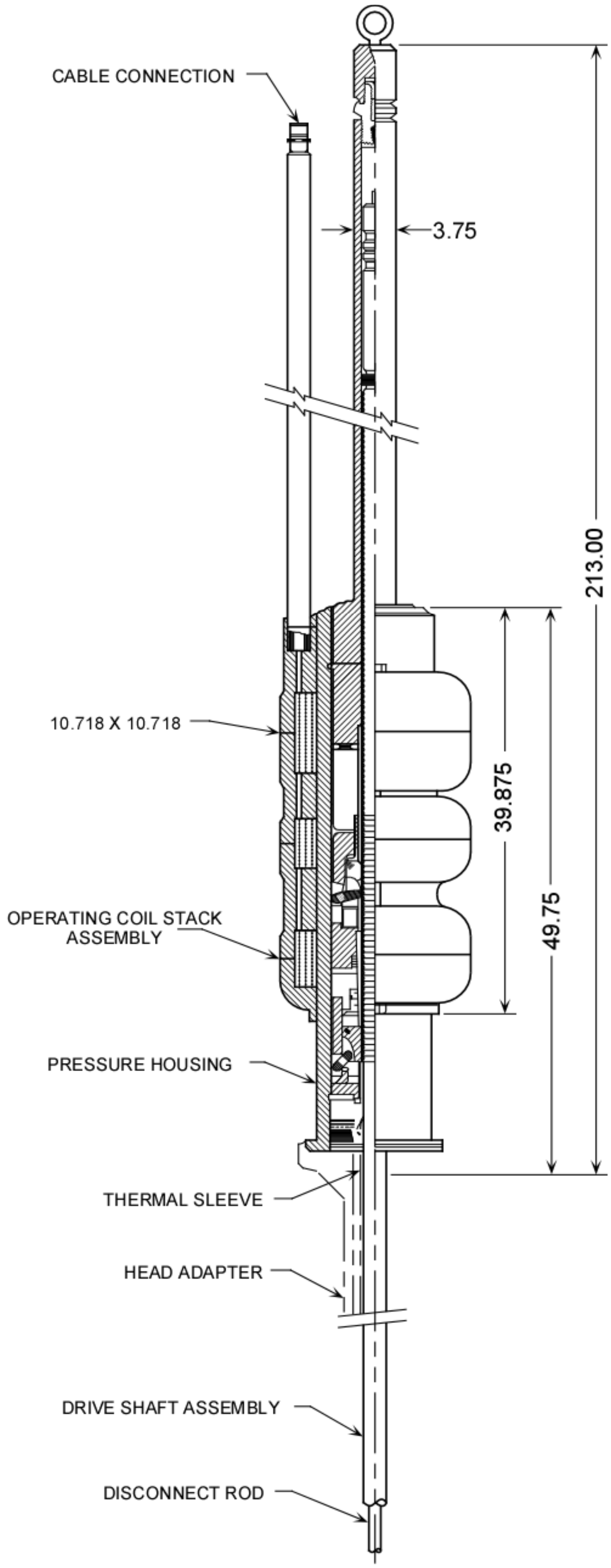


Figure 3.1-32 Control Rod Drive Mechanism



NOTE: ALL DIMENSIONS ARE IN INCHES.

Figure 3.1-33 Control Rod Drive Mechanism Assembly

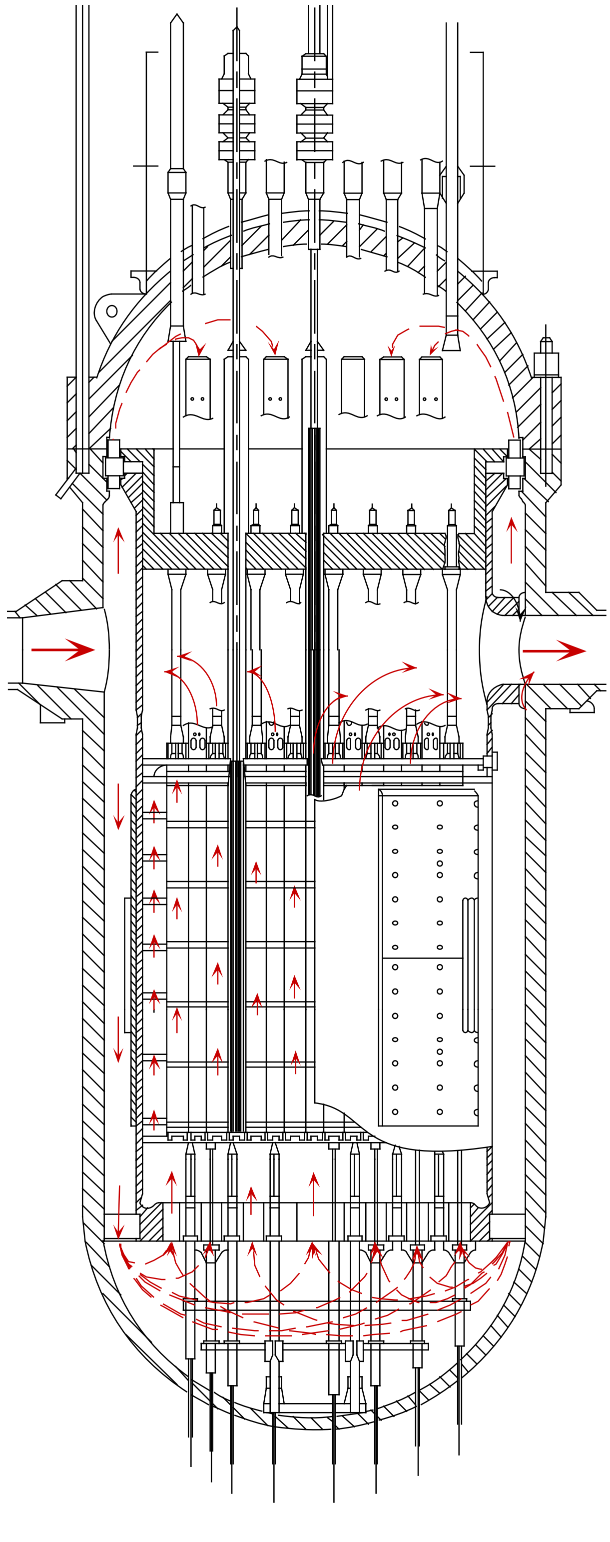


Figure 3.1-34   Core Flow Paths

Westinghouse Technology Systems Manual

Section 3.2

Reactor Coolant System

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3.2 REACTOR COOLANT SYSTEM

Learning Objectives:

1. State the purposes of the Reactor Coolant System (RCS).
2. State the purposes of the following RCS penetrations:
   a. Hot Leg
      - Pressurizer surge line
      - Residual Heat Removal (RHR) suction
      - Sample line
      - RHR/Safety Injection (SI) recirculation

   b. Intermediate Leg
      - Elbow flow taps
      - Chemical and Volume Control System (CVCS) letdown
      - Loop drain

   c. Cold Leg
      - Pressurizer spray line
      - CVCS charging
      - Common injection penetration for RHR, SI, and an accumulator
      - High head injection
      - Excess letdown
3. Describe the primary and secondary flow paths through the steam generator.
4. State the purposes of the following components of the reactor coolant pump.
   a. Thermal barrier heat exchanger
   b. Seal package
   c. Flywheel
   d. Anti-reverse rotation device
   e. Number 1 seal bypass valve
   f. Number 1 seal leak off valve
   g. Seal stand-pipe
5. Explain why seal injection flow is supplied to the reactor coolant pumps.
6. State the purposes of the following:
   a. Pressurizer
   b. Pressurizer safety valves
   c. Power-operated relief valves (PORVs)
   d. PORV block valves

e. Pressurizer relief tank (PRT)
f. Pressurizer spray valves
g. Pressurizer heaters

7. Describe the methods for determining pressurizer relief and safety valve position and/or leakage.
8. Explain the following:
    a. Pressurizer spray driving force
    b. Purpose of pressurizer spray bypass
9. Explain how failure of the following components could lead to core damage.
    a. Reactor coolant pump seals
    b. Power-operated relief valves

3.2.1 Introduction

The purposes of the RCS are:

1. To transfer the heat produced in the reactor to the steam and power conversion systems.
2. To provide a barrier to limit the escape of radioactivity to the containment.

3.2.2 System Description

The reactor coolant piping and components are generally referred to as the reactor coolant system, even though the RCS also includes the reactor vessel and the components directly attached to the reactor vessel. The RCS consists of four similar heat transfer loops connected in parallel to the reactor vessel. Each loop contains a steam generator, a reactor coolant pump, penetrations for connection with auxiliary and emergency systems, and appropriate instrumentation. In addition, a pressurizer is connected by a surge line to one loop for pressure control. A pressurizer relief tank is provided to collect any release from the pressurizer relief and safety valves. All RCS components are located inside the containment. A typical RCS loop is shown on Figure 3.2-1.

During normal operations, the RCS transfers the heat produced in the reactor to the steam generators where steam is produced to supply the turbine generator and other secondary system components. Hot reactor coolant exits the reactor vessel and flows through the hot leg piping to the steam generator where energy is removed to make steam. Coolant exits the steam generator and flows through the intermediate leg piping to the suction of the reactor coolant pump. The pump discharge is directed through the cold leg piping to the reactor vessel inlet nozzles to complete the cycle.

The RCS pressure boundary (described in section 3.0) acts as the second of the three barriers or “lines of defense” against fission product release to the environment. The first and third barriers are the fuel cladding and the reactor containment building respectively. Seismic restraints and supports are provided as required to ensure continued integrity of the RCS during seismic events. All RCS components are designated Seismic Category 1.

3.2.3 Component Descriptions

3.2.3.1. Reactor Coolant Piping

The reactor coolant piping and fittings are austenitic stainless steel. The loop piping is sized to limit the maximum flow velocity for erosion or vibration considerations. The crossover line between the steam generator and reactor coolant pump is larger due to pump suction considerations.

All smaller piping which are part of the RCS boundary, such as the pressurizer surge line, spray and relief line, loop drains and connecting lines to other systems are also austenitic stainless steel. The nitrogen supply line for the pressurizer relief tank is carbon steel. All joints and connections are welded, except for the piping associated with the pressurizer relief and safety valves, where flanged joints are used.

Penetrations (Figures 3.2-1 and 3.2-2) which are common to all reactor coolant loops include the following:

1. Hot leg injection/recirculation from the Emergency Core Cooling Systems (ECCSs),
2. Hot leg wide-range and narrow range, well-mounted, RTDs,
3. Elbow flow detector high and low pressure taps (intermediate leg),
4. Drain connection to the reactor coolant drain tank (RCDT),
5. Cold leg wide-range and narrow range, well-mounted RTDs,
6. Cold leg injection from the ECCS safety injection pumps, residual heat removal pumps and the accumulators,
7. Cold leg injection from ECCS boron injection tank (high head injection), and

Additional penetrations specific to individual loops and their typical locations are as follows:

1. Pressurizer surge line from loop 2 hot leg,
2. Supply to the RHR System from loop 4 hot legs,
3. CVCS letdown from loop 3 crossover leg,
4. CVCS charging to loops 1 and 4 cold legs,
5. Pressurizer spray from loops 2 and 3 cold legs,
6. Excess letdown to CVCS from loop 3 cold leg, and
7. Sample line from loop 1 and 3 hot legs.

Thermal sleeves are installed at points in the system where high thermal stresses could develop due to rapid changes in fluid temperature during normal operational transients. These points include:

1. Charging connections from the CVCS,
2. Pressurizer end of the surge line, and
3. Pressurizer spray line connection to the pressurizer.

Piping connections from process systems are made above the horizontal center line of the reactor coolant piping, with the exception of:

1. RHR suction, which is 45E down from the horizontal centerline. This enables the water level in the RCS to be lower in the reactor coolant pipe while continuing to operate the RHR system, should this be required for maintenance.
2. Loop drain lines and the connection for temporary level measurement of water in the RCS during refueling and maintenance operation.
3. The differential pressure taps for flow measurement, which are downstream of the steam generators on the 90° elbow.

The following penetrations extend into the coolant flowpath:

1. The spray line inlet connections which extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force (Figure 3.2-3).
2. The reactor coolant sample system taps are inserted into the main stream to obtain a representative sample of the reactor coolant (Figure 3.2-4).
3. The RCS narrow range temperature detectors, hot leg RTDs (3 per loop) and cold leg RTDs (1 per loop), are located in RTD wells that extend into the reactor coolant pipes.
4. The wide range temperature detectors are located in RTD wells that extend into the reactor coolant pipes.

All valves in the RCS which are in contact with the coolant are constructed primarily of stainless steel. Other materials in contact with the coolant are manufactured of special materials that are noncorrosive.

All RCS valves which are three inches or larger, and that will normally be operated at a temperature above 212°F, are provided with double-packed stuffing boxes with stem lantern gland leak off connections. All throttling control valves, regardless of size, are provided with double-packed stuffing boxes and stem leak off connections. All leak-off connections are piped to the PRT. Leakage to the containment is essentially zero for these valves.

3.2.3.2. Instrumentation

RCS Temperature

There are two ranges of RCS temperature monitors. Both ranges use RTDs. The temperatures of the hot leg and of the cold leg of each loop are monitored for indication only by wide-range (0-700°F) detectors. These detectors are mounted in wells which penetrate the coolant piping and are part of the pressure boundary. These RTDs do not come in contact with the reactor coolant.

The narrow-range T_h and T_c temperature detectors are used for reactor control and protection and are mounted in RTD wells which extend into the RCS piping. The narrow-range (530°F-650°F) T_h RTDs obtain a representative sample of the hot leg temperature by using three RTDs which are mounted in wells that extend into the flow stream 120 degrees apart. The narrow-range (510°F – 630°F) T_c RTDs are also mounted in wells and have one tap directly downstream of each reactor coolant pump. Only one connection per cold leg is required to get a representative temperature indication due to the mixing of the reactor coolant caused by the reactor coolant pump.

The information derived from these hot and cold leg RTDs (T_{avg} and ΔT), from all four loops, is indicated in the control room. Additional information about these temperature indicators may be found in Chapter 10.0, Primary Systems Control and Instrumentation.

RCS Flow

Elbow taps are used in the RCS to indicate the status of the reactor coolant flow (Figure 3.2-6). The function of this device is to provide information as to whether or not a reduction in flow has occurred. An advantage of this type of flow detection system is that no components need to be inserted into the coolant flowpath. Components in the flowpath produce pressure drops and either reduce flow or require increased pumping power. The elbow flow instrument measures the differential pressure between the inner and outer radius of the intermediate leg piping elbow. The outer radius will experience a slightly higher pressure due to the dynamic effects of coolant flow.

The correlation between changes in flow and elbow tap indication has been well established and is described by the following equation:

$$\frac{\Delta P}{\Delta P_0} = \frac{\omega^2}{\omega_0^2}$$

where:

ΔP is the differential pressure corresponding to present measured flow rate ω.

ΔP_0 is the differential pressure corresponding to initial reference flow rate ω_0.

The full-flow reference point ΔP_0 is established during initial plant startup. The low-flow reactor trip setpoint is then established by extrapolating data from a curve which correlates ΔP_0 to flow. This technique has been well established in providing core protection against low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within $\pm$10% and field results have shown the repeatability of the trip point to be within $\pm$1%. The accident analysis for a loss-of-flow transient assumes an instrumentation error of $\pm$3%.

Pressurizer Pressure

Redundant pressure detectors are provided to monitor the pressure in the steam space of the pressurizer. Information from these detectors is used for indication, control, and protection. For additional information see Chapter 10.0, Primary Systems Control and Instrumentation.

Pressurizer Level

Redundant level instrumentation is provided to monitor the water level in the pressurizer. Differential pressure detectors monitor the difference between the height of a known column of water (reference leg) and the height of the water in the pressurizer.

This instrumentation is used for indication, control, and protection. A separate channel calibrated for cold plant conditions is provided for shutdown, startup and refueling operations. Additional information may be found in Chapter 10.0, Primary Systems Control and Instrumentation.

Safety and Relief Valve Monitors

The safety valves and power-operated relief valves (PORVs) are monitored for open or leaking conditions. Leakage or opening of these valves is indicated by increasing discharge piping temperature and (if installed) via acoustic monitors. Each power-operated relief valve (PORV) also has a stem-mounted valve position indicating switch which provides positive Control Room indication of actual valve position (as opposed to "demanded" position). These switches were required to be added as modifications as a result of the confusing indications observed during the Three Mile Island event.

Loop Pressure

Three pressure detectors are installed at the hot leg suction of the residual heat removal system. These instruments are wide range transmitters (0-3000 psig) which provide pressure indication over the full operating range.

One of the three pressure transmitters provides indication to the remote shutdown station only. The remaining two pressure transmitters provide indication in the main control room, a PORV actuation signal in conjunction with the low temperature over pressure mitigation system, the permissive signals for the RHR loop isolation valves interlock circuits to protect the low pressure piping of the RHR system and input to the subcooled margin monitor.

Two local pressure indicators are also provided for operator reference during shutdown conditions. One taps into the loop 3 sample line, and the other senses the pressure in the loop-4-to-RHR suction line.

3.2.3.3. Pressurizer

The pressurizer is a vertical, cylindrical vessel with hemispherical top and bottom heads, constructed of manganese-molybdenum alloy steel, and clad with austenitic stainless steel on all surfaces exposed to reactor coolant water. Electrical heaters

(78) are installed through the bottom head of the vessel, while the spray nozzle, relief, and safety valve connections are located in the top of the vessel.

The pressurizer has four basic functions:

1. Pressurizing the RCS during plant heatup,
2. Maintaining normal RCS pressure during steady state operations,
3. Limiting pressure changes during RCS transients to within allowable values and,
4. Preventing the reactor coolant system pressure from exceeding its design pressure value of 2500 psig.

During normal operations, the pressurizer is maintained at saturation conditions by electrical heaters (Figure 3.2-7). Under saturation conditions, each temperature has a corresponding saturation pressure. At nominal full power conditions, approximately 60 percent of the pressurizer volume is saturated water, with the remaining 40 percent saturated steam.

The pressurizer is connected to a loop hot leg by the surge line. Since the RCS (except for the pressurizer) is a hydraulically solid system, the pressure in the pressurizer will be maintained throughout the system. Design parameters for the pressurizer are listed in Table 3.2-2.

If the RCS were operated completely full of water any change in temperature of the reactor coolant would produce unacceptably large changes in pressure due to the density change of the coolant. Therefore, the pressurizer is attached to the reactor coolant system to provide a surge and makeup volume to accommodate these density changes.

To understand how the pressurizer maintains RCS pressure, consider the volumetric difference between water and steam. At normal system operating temperatures, water is approximately six times as dense as steam. Therefore, as the water is heated by the pressurizer electrical heaters to produce steam, a factor of six volume change occurs. For example, boiling one cubic foot of water would produce six cubic feet of steam. Since the volume in the pressurizer which is available for steam is fixed by the pressurizer level control system, the density of steam must increase. This increase in density produces a pressure increase in the RCS. Conversely if steam is condensed, a factor of six density reduction occurs, which results in a reduction in pressure. The steam inside the pressurizer responds in a manner similar to an ideal gas (pressure is proportional to density).

During steady-state operations a small number of heaters are energized to make up for ambient heat losses. The small amount of subcooled liquid which is continuously circulated from the RCS via the spray line bypass valves promotes mixing and aids in chemistry control.

Many transients affecting pressure are caused by changes in the reactor coolant temperature. Temperature changes produces changes in coolant density, which force water into (insurge) or out of (outsurge) the pressurizer.

In the case of an increase in RCS temperature, the expansion of the coolant produces an insurge into the pressurizer. This insurge compresses the steam “bubble,” resulting in an increase in steam density and a corresponding increase in pressure. If the pressure increases by a predetermined amount, the pressurizer pressure control system modulates the spray valves to admit relatively cool water to the steam space to condense some steam. This reduces the density of the steam and limits the pressure increase.

If the RCS temperature decreases, the contraction of the coolant produces an outsurge from the pressurizer. This is accommodated by an expansion of the steam bubble and a corresponding decrease in steam density and pressure. As the pressure decreases, some of the saturated water in the pressurizer will flash to steam to help maintain system pressure. If pressure decreases to a predetermined value, the pressurizer pressure control system will energize additional electrical heaters to boil more water and return pressure to normal.

If the RCS pressure increases towards the design limit, power-operated relief and safety valves open. These valves release steam from the steam space of the pressurizer and thereby limit the overpressure condition.

The volume of the pressurizer (1800 ft^3) is greater than, or equal to, the minimum volume of steam and water combination which satisfies all of the following requirements:

1. The combined saturated water volume and steam expansion volume is sufficient to provide the desired pressure response to programmed system volume changes.
2. The water volume is sufficient to prevent the heaters from being uncovered during a step load increase of ten percent of full power.
3. The steam volume is large enough to accommodate the insurge resulting from a 50 percent reduction of full load with automatic rod control and full steam dump capacity without the water level reaching the high level reactor trip set point.
4. The pressurizer does not empty following a reactor trip with a turbine trip.
5. The steam volume is large enough to prevent water relief through the safety valves following a loss of load with the high pressurizer water level initiating a reactor trip.
6. A safety injection signal will not be activated following a reactor trip and turbine trip.

Pressurizer Heaters

The electrical heaters installed in the pressurizer are replaceable, direct-immersion, tubular-sheath type heaters with hermetically sealed terminals. They are located in the lower portion of the pressurizer vessel and maintain the steam and water contents at equilibrium conditions. There are 78 heaters installed for a total capacity of 1794 kW. The heaters are broken down into two groups, the proportional heater group consists of 18 heaters for an output of 414 kW and the backup heater group consists of 60 heaters for an output of 1380 kW. The heaters are capable of raising the temperature of the pressurizer and its contents at approximately 55EF/hr.

The hermetically sealed terminals connected to the external pressurizer vessel wall are capable of retaining full system pressure should the immersed tubular heater sheath fail. Ventilation of the heater connections is accomplished through holes drilled in the pressurizer support skirt.

Pressurizer Spray

Spray water is injected into the steam volume of the pressurizer through a spray nozzle located in the top of the vessel (Figure 3.2-8). Automatically controlled, air-operated valves with remote manual overrides are used to control pressurizer spray from two loop cold legs. In parallel with each spray valve is a manual throttle valve which permits a small continuous flow to bypass the spray valves. This small flow (one gpm) is provided to reduce the thermal stresses and/or thermal shock to the pressurizer spray penetration and spray nozzle inside the pressurizer when the spray valves open. In addition, this flow helps maintain uniform water chemistry in the pressurizer to that of the reactor coolant system. Design parameters for the spray valves are listed in Table 3.2-3.

Temperature sensors with low temperature alarms are provided in each spray line to alert the operator of insufficient bypass flow. The layout of the spray line piping to the pressurizer forms a water seal which prevents steam buildup back to the spray valves. The maximum spray flow rate (840 gpm) is selected to prevent the pressure in the pressurizer from reaching the operating set point of the PORVs, following a 10 percent step decrease in power.

The pressurizer spray lines and valves are sized and located to provide adequate spray using the differential pressure between the surge line connection in the hot leg and the spray line connection in the cold leg as the driving force. The spray line inlet connections (Figure 3.2-3) extend into the cold leg piping in the form of a scoop so that the velocity head of the reactor coolant loop flow adds to the spray driving force. The spray valves and spray line connections are redundant so that the spray flow can be admitted to the steam space of the pressurizer even when one of the associated RCP's is not operating. In addition to their pressure control function, the sprays may be manually operated to circulate coolant from the loop to the pressurizer for boron concentration equalization.

A flow path from the CVCS to the pressurizer spray line is also provided. This connection provides auxiliary spray to the vapor space of the pressurizer during cool down if the reactor coolant pumps are not operating. The thermal sleeve on the pressurizer spray connection is designed to withstand the thermal stresses resulting from the introduction of this relatively cold auxiliary spray water.

Surge Line

The surge line connects the bottom of the pressurizer to one of the reactor coolant system hot legs. It is sized to limit the pressure drop between the pressurizer and the RCS during the maximum anticipated insurge. It is designed in this fashion to ensure that the highest pressure point in the RCS does not exceed the design pressure with the safety valves discharging at their maximum allowable accumulation. The surge line also contains a thermal sleeve at the pressurizer end which is designed to withstand the thermal stresses resulting from surges of relatively hotter or colder water which will occur when the temperature of the RCS changes.

A temperature sensor with remote indication and a low temperature alarm is provided on the surge line. This indication along with the spray line temperature indication monitors performance of the continuous spray bypass flow.

Safety Valves

The three pressurizer safety valves are totally enclosed pop-open-type valves. The valves are spring loaded, self-actuating, and they have backpressure compensation designed to prevent the reactor coolant system pressure from exceeding the design pressure by more than 10 percent. This meets the requirements of the ASME Boiler and Pressure Code, Section III. The set pressure of the safety valves is 2485 psig. Design parameters for the pressurizer safety valves are listed in Table 3.2-4.

A water seal is maintained below each safety valve seat to minimize leakage. The 6-in. pipes connecting the pressurizer nozzles to their respective safety valves are shaped in the form of a loop seal. Condensate, as a result of normal heat losses to ambient, accumulates in the loop and floods the valve seat. This water seal prevents leakage of steam or hydrogen gas to pass by the safety valve seats. If the pressure inside the pressurizer exceeds the set point of the safety valves, they will lift and the water from the loop seal will discharge during the accumulation period.

Due to the high pipe and pipe support loads caused by these “water slugs,” catch pots were designed and placed immediately downstream of the relief and safety valves. A total of four of these slug diversion devices (SDDs) are installed (one for each of the safeties and one for the PORV combined discharge). The SDDs are located at the change in pipe direction so that the water slugs flow into the devices and are trapped. These devices are totally passive and ensure that the piping system is not subjected to stresses or loads beyond code allowable.

A temperature indicator in the safety valve discharge manifold alerts the operator to the passage of steam due to leakage or valves lifting. Acoustic monitors are also provided for each valve to provide a positive indication of leakage or safety valve operation.

Power-Operated Relief Valves

The pressurizer is normally equipped with two PORVs, which limit pressure in the reactor coolant system and minimize the probability of actuation of the high-pressure reactor trip. The operation of the PORVs also limits the operation of the fixed high-pressure safety valves. The PORVs are air operated and can be opened or closed automatically or by remote manual control. Should the air supply to the PORVs fail, a backup air supply system is provided to maintain the PORVs operable for 10 minutes following a loss of instrument air. Remotely operated block valves are provided to isolate the PORVs if excessive leakage occurs. Design parameters for the power-operated relief valves are listed in Table 3.2-5.

The PORVs are designed to limit the pressure in the pressurizer to a value below the high pressure reactor trip setpoint for design transients up to and including a 50-percent step load decrease with full steam dump actuation. An acoustic monitor can be installed at the outlet of each PORV to detect leakage and/or valve opening. Note that the use of an added acoustic monitor is a plant-specific variation. Acoustic monitors on the PORVs are not installed on the Westinghouse reference simulator.

The PORVs, with additional actuation logic, are also utilized to mitigate potential RCS cold over pressurization transients during cold shutdown conditions.

Pressurizer Relief Tank

The PRT collects, condenses and cools the steam discharged from the pressurizer safety and power-operated relief valves. The tank is maintained approximately three quarters full of water with a nitrogen cover gas. Steam is discharged through a sparger at the bottom of the tank below the water level. This condenses and cools the steam by mixing it with water that is near containment ambient temperature. Discharge from a number of smaller relief valves located in systems inside or outside of the containment are also piped to the pressurizer relief tank.

The design of the PRT is based on the requirement to condense and cool a discharge of pressurizer steam equal to 110 percent of the volume above the zero power pressurizer water level set point (25%). This tank is not designed to accept a continuous discharge from the pressurizer. The volume of water in the PRT is capable of absorbing the heat from the assumed discharge from the pressurizer safety valves, with an initial water temperature of 120°F and increasing to a final temperature of 200°F. If the temperature inside the PRT rises above 114°F during plant operation, the tank is cooled by spraying in cool primary makeup water and draining the warm mixture to the reactor coolant drain tank. Design parameters for the pressurizer relief tank are listed in Table 3.2-6. The spray rate inside the PRT is designed to cool the tank from 200°F to 120°F in approximately one hour following the design discharge of pressurizer steam. The nitrogen gas overpressure inside this tank is selected to limit the maximum pressure following a design discharge to 50 psig.

The PRT is constructed of austenitic stainless steel. A flanged nozzle is provided for connection of the pressurizer relief and safety valve discharge line. The discharge piping and the sparger are constructed of austenitic stainless steel. A vacuum breaker hole is located on the discharge line inside the PRT which will allow the PRT and the discharge line pressure to equalize, preventing water in the PRT from being forced up into the discharge line. Two rupture discs are provided to prevent exceeding the design pressure of the PRT. The rupture discs have a relief capacity equal to the combined capacity of all three pressurizer safety valves. The design pressure of the PRT (and the rupture discs setting) is twice the calculated pressure produced by the design relief volume described above. This margin is provided to prevent deformation of the rupture disc.

The PRT and its connections are designed to operate under a vacuum to prevent the collapse of the tank if the contents are cooled following a discharge without adding additional cover gas. Piping penetrations are provided so that the cover gas may be sampled and analyzed for hydrogen and oxygen. A vent to the gaseous waste disposal system allows venting of excess pressure or removal of any non-condensable or fission product gases which might be transferred from the pressurizer to the relief tank. A nitrogen supply connection allows initial supply and makeup of the cover gas.

3.2.3.4. Steam Generators

The steam generators are vertical shell-and-U-tube heat exchangers in which energy from the hot pressurized reactor coolant is transferred to the secondary coolant to produce dry, saturated steam. The steam generator provides the boundary between the radioactive primary system and the non-radioactive secondary system.

Each steam generator is fitted with a ring on the inside of the hot and cold leg nozzles for the fitting of a nozzle dam. These nozzle dams are fitted robotically and allow RCS level to be raised to refueling levels while the steam generator primary side is drained. This allows more flexibility in scheduling the time consuming steam generator tube inspections. In addition, it reduces the time where the RCS must be operated in a reduced inventory status with RCS water level at the loop mid-point.

A cutaway diagram showing the construction of a Westinghouse model 51 steam generator may be found on Figure 3.2-9 and will be used for explanation purposes. The design data for the steam generators are listed in Table 3.2-7.

The steam generator is designed to produce saturated steam with less than 0.25% percent moisture by weight under the following conditions:

1. Steady-state operation at up to 100% of full load steam flow, assuming that the water level in the steam generator is at program,
2. Ramp load changes at a maximum rate of 5% per minute in the range from 15 to 100% full power steam flow, and
3. Step load changes of 10% of full power between 15 and 100% full power steam flow.

The steam generator is constructed of carbon steel, with all surfaces in contact with reactor coolant made from or clad with appropriate corrosion resistant material. Construction and operation of both the primary (reactor coolant) and secondary (steam) sides of the steam generator are described in the following paragraphs. Primary and secondary flow paths are shown on Figure 3.2-10.

Primary (Reactor Coolant) Side

Reactor coolant enters and leaves the steam generator through nozzles in the bottom hemispherical head. The head is divided into inlet and outlet chambers by a vertical partition (divider) plate which extends from the bottom of the tubesheet to the bottom hemispherical head. Bolted, gasketed manways are provided for access to both the inlet and outlet sides of the bottom hemispherical head.

The tubesheet and the heat transfer tubes form the boundary between the primary and secondary systems. The tubes and the divider plate are manufactured of Inconel. The primary side of the tubesheet is clad with Inconel while the interior surfaces of the hemispherical head and the nozzles are clad with austenitic stainless steel. After the tube ends are seal welded to the tube sheet, they are roller expanded for the full depth of the tubesheet cladding. This is done to prevent the leakage of the high pressure reactor coolant from the primary side to the lower pressure secondary side.

Secondary (Steam) Side

The secondary side of the steam generator consists of the feed and steam nozzles, the tube bundle and supports, the tube bundle wrapper, primary and secondary moisture separators, appropriate instrumentation and blow down penetrations. The steam generator shell and its internals are constructed of carbon steel.

At 100% thermal power feedwater at a temperature of approximately 430°F enters the steam generator through the feedwater inlet nozzle. As the feedwater leaves the feed ring it is distributed to the annulus between the tube bundle wrapper and the steam generator shell where it mixes with the hot recirculation water from the moisture separation equipment. This annulus is called the downcomer and is where steam generator level is measured for indication, control and protection. The feed water is distributed through an upper feed ring (Figure 3.2-11) into the annulus.

The feedwater-recirculation flow mixture then flows between the bottom of the tube wrapper (shroud) and the tubesheet into the tube bundle region. In the tube bundle region, heat is transferred to the secondary coolant producing a steam-water mixture. This mixture flows upward to the primary or swirl-vane moisture separators (Figure 3.2-12). These separators consist of a number of stationary vanes which impart a swirling motion to the steam water mixture. The steam, being less dense than the water can change direction easily and passes through the swirl vanes. The water is slung to the outside and flows to the downcomer where it mixes with incoming feedwater. The water in the downcomer is maintained at a level that is equal to a height in the boiling section of the steam generator that is approximately at the bottom of the swirl vanes.

Although the swirl vanes remove most of the moisture from the steam, a second stage of moisture separation is necessary to meet design requirements. The steam passes through chevron separators (Figure 3.2-13) and then leaves the generator through the outlet nozzle. These chevron separators force the steam to take a torturous path. Again, the steam can change directions easily as it passes through while the denser water cannot. The separated moisture is collected and drained to the downcomer. Steam exiting the steam generator has a minimum quality of 99.75% (less than 0.25% moisture).

The steam generator operates as a natural circulation boiler. The flow from the downcomer to the tube bundle is caused by the difference in density between the slightly subcooled liquid in the downcomer and the steam-water mixture in the tube bundle. At full power, the flow in the downcomer is three (3) to five (5) times that of the incoming feedwater. This is caused by the recirculation flow from the moisture separators and is necessary to ensure proper thermal-hydraulic performance of the steam generator. The higher flow velocities also help prevent the collection of impurities at the tube to tube sheet area of the steam generator.

In order to support and align the steam generator tubes and prevent flow induced movement, tube support plates are provided (See Figure 3.2-14). Some steam generators have support plates with drilled holes; each tube passes through a hole which is slightly larger than the diameter of the tube. Additional flow holes are drilled to provide passage for steam flow. During cold plant conditions, the gap between the tube and support plate increases due to differential expansion. Corrosion products deposit in the holes in the support plate. When the steam generator is heated, differential expansion closes the gaps. Since the holes are now smaller due to the corrosion products, tubes can actually be dented, and tube integrity can be affected. This phenomenon is known as tube denting.

To help maintain the steam generator relatively free of dissolved solids and remove corrosion products which tend to concentrate at the tubesheet, a penetration is provided to drain a portion of the steam generator water for processing. This drain is called steam generator blowdown. It removes water from just above the tubesheet and diverts it to the steam generator blow down system. This path is monitored for radiation which would indicate a steam generator primary to secondary leak. Steam generator blowdown is in service continuously during plant operations.

Steam Generator Level Instrumentation

There are two types of steam generator level indication: wide range and narrow range. Both indicators measure the water level in the downcomer. The wide-range level instrument (one per steam generator) provides indication only and monitors the level from the top of the tube sheet to a height of approximately 48 feet.

The narrow-range level instruments monitor the upper 12 feet of the wide-range span. Therefore, if the water level is at the bottom of the narrow-range span, the narrow-range instrument indicates 0% level, and the wide-range instrument should indicate approximately 75% level. The narrow-range indicators are used for indication, control, and protection.

There are three narrow-range channels; each provides indication in the control room. The steam generator water level control system utilizes a median select circuit for the automatic feed water control system. A median signal circuit automatically discriminates against a high or low instrument failure. It does this by throwing out both the high and low inputs and selecting a middle or “median” value as the output. For protection, a two-out-of-three logic provides a low-low steam generator level reactor trip for loss of heat sink protection, and a high-high steam generator level turbine trip to protect the turbine against excessive moisture carryover.

Steam Generator Operational Characteristics

It is a characteristic of U-tube steam generators that steam pressure decreases with increasing load or steam flow. The rate of heat transfer across the tubes is approximated by the following equation:

$$\dot{Q} = UA\Delta T$$

where:

$\dot{Q}$ = Rate of heat transfer (typically expressed in BTU/hr)

U = Heat transfer coefficient

A = Total heat transfer area

ΔT = Temperature difference across the tubes, which is approximately equal to the average temperature of the reactor coolant (T_{avg}) minus the saturation temperature of the steam (T_{sat}) inside the steam generator

The rate of heat transfer ($\dot{Q}$) is determined by the plant load. The heat transfer coefficient (U) can be assumed to be constant, since it is a function of the materials of construction. The heat transfer surface (A) is also a constant, given that the tubes remain covered at all power levels. Therefore, in order to transfer more energy across the tubes, the ΔT must increase. It would be desirable to accomplish this increase in ΔT by raising T_{avg}, but reactor thermal limits preclude raising T_{avg} to the extent necessary. Therefore, T_{avg} is increased by the rod control system to gain part of the required ΔT increase, but the additional increase in ΔT must come from a reduction in T_{sat}. As T_{sat} decreases, steam pressure also decreases because the steam generator operates as a saturated system. Steam pressure decreases approximately 150 psi from no load to full load.

As the secondary load is increased, the number and size of the steam bubbles in the steam generator increase. This reduces the density and increases the specific volume of the mass in the steam generator. If mass were held constant, steam generator level would increase unacceptably. The steam generator water level control system maintains a programmed level during power operation (see Chapter 11.1).

In order to maintain level constant with increasing load, the mass in the generator must decrease. Due to this reduction in mass at high power, a plant trip produces a large reduction in level as the steam bubbles collapse and the specific volume of the steam generator secondary fluid decreases. As described above, it should be understood that there is more mass of secondary coolant in the steam generator at no load than at full power. Therefore, no load is the worst case for steam line break analyses.

Shrink and Swell

Characteristic of a U-tube steam generator are the phenomena of “shrink” and “swell.” Referring to Figure 3.2-15, at time 0_1 steam flow is decreased. This results in a rapid increase in steam pressure. This causes the steam bubbles in the tube bundle region to collapse and the saturation conditions to change. The boiling rate in this region decreases because of the pressure increase. Both effects result in the inability of the mass in the tube bundle region to hold up the level in the downcomer, and a drop in the measured level occurs. The continued heat input from the primary and the drop in heat removal from the generator combine to raise the temperature in the generator to a new saturation condition and boiling increases. The increase in bubble formation results in the ability of the mass in the tube bundle region to hold up the level in the downcomer and level starts to return to setpoint. The response of the feed water system causes level to oscillate, but eventually returns to setpoint.

With an increase in steam flow at time 0_2, and the resultant decrease in steam pressure, the opposite effect, swell, will occur. Again, the saturation conditions in the generator are affected. The more rapid the change in steam flow, the more pronounced will be the effect of shrink or swell on generator level.

At low power levels, a similar effect is produced by rapid changes in feed flow. The heat input rate from the primary is low compared to that at high power levels. This limits the ability of the steam generator to compensate for rapid changes on the secondary side. For example, a rapid increase in feed water flow will put more relatively cold water in the steam generator than the primary can heat up in a short time period. This results in a drop in the temperature of the steam generator and a reduction of the boiling rate in the tube bundle region. Again, the ability of the mass in the tube bundle region to hold up the level in the downcomer is affected and measured level drops.

As the water is heated and boiling begins to occur, there is an expansion of the additional mass in the steam generator, and the water level in the downcomer will rise to some higher value.

3.2.3.5. Reactor Coolant Pump

The reactor coolant pumps provide forced-circulation flow through the core sufficient to ensure adequate heat transfer to maintain a departure from nucleate boiling ratio (DNBR) of greater than 1.3. The required net positive suction head (NPSH) for the reactor coolant pumps is always less than that available by system design and operating limits. Design parameters for the reactor coolant pumps are listed in Table 3.2-8.

To ensure adequate core cooling after a loss of electrical power to the RCPs, each pump is designed with a flywheel that is attached to the top of the pump motor. If the reactor trips on a loss of flow due to a loss of power to the reactor coolant pumps, the flywheels will extend the coast-down time to maintain adequate heat transfer capability and help establish natural circulation flow. Power to the reactor coolant pump motors is from the nonvital station service power and cannot be supplied from the emergency diesel generators. The RCPs are capable of operation without mechanical damage at speeds of up to 125% of normal speed. Periodic surveillances are performed on the flywheel to ensure its integrity.

The reactor coolant pump is a vertical, single-stage, centrifugal pump designed to pump large volumes of reactor coolant at high temperatures and pressures. A cutaway of a typical reactor coolant pump is shown on Figure 3.2-16. The pump consists of three sections from bottom to top:

1. The hydraulic section consists of the inlet and outlet nozzles, casing, flange, impeller, diffuser, pump shaft, pump bearing, thermal barrier and thermal barrier heat exchanger.
2. The shaft seal section consists of the number one controlled leakage seal and the numbers two and three rubbing face seals. These seals are located within the main flange and seal housing.
3. The motor section consists of a vertical, squirrel cage, induction motor with an oil lubricated double Kingsbury thrust bearing, two oil-lubricated radial bearings, and a flywheel with an anti-reverse rotation device and appropriate support equipment.

Hydraulic Section

Casing - The pump casing contains and supports the hydraulic section of the pump and is part of the reactor coolant pressure boundary. The casing is a 304 stainless steel casting whose nozzles are welded to the RCS piping. The entire weight of the pump and motor is supported by pads attached to the casing. This support system is designed to allow for thermal expansion of the RCS.

Impeller - The impeller is designed to impart energy to the reactor coolant. This energy is added in the form of kinetic energy (velocity head). The impeller is a stainless-steel casting which is shrunk and keyed to the lower end of the pump shaft. An impeller nut is then threaded and locked to the shaft. The impeller is designed for counter clockwise rotation as viewed from the top of the pump.

Diffuser and Turning Vanes - The diffuser, which is located above the impeller, converts the velocity head generated by the impeller to a static head by reducing the fluid velocity in the expanding flow channels between the diffuser vanes. The flow is then directed to the outlet nozzle by the turning vanes. The diffuser and turning vanes are constructed of stainless steel.

Radial Bearing Assembly - The pump bearing is a self-aligning, spherical, graphitar-coated, journal bearing. The bearing provides radial support and alignment for the pump shaft and is water cooled and lubricated. It is essential that the water circulating through the bearing be kept cool. High temperatures will damage the graphitar coating and cause bearing failure. This cool water is normally supplied by seal injection from the CVCS as described in Chapter 4.0.

Thermal Barrier and Heat Exchanger - The thermal barrier assembly consists of the thermal barrier and thermal barrier heat exchanger. The thermal barrier is designed to reduce the rate of heat transfer from the hot reactor coolant to the pump radial bearing and thermal barrier heat exchanger. It consists of a number of concentric stainless-steel cylinders extending vertically from the top of the impeller to the thermal barrier flange, and a number of stacked horizontal plates at the flange. The barrier to heat transfer is provided by the gap between the cylinders and plates. The thermal barrier heat exchanger is located at the bottom of the thermal barrier assembly below the pump radial bearing. The function of this heat exchanger is to cool any reactor coolant leaking up the shaft to protect the radial bearing and shaft seals.

Seal injection water is normally supplied to the reactor coolant pump from the CVCS (Figure 3.2-17). This water is injected into the pump at a point between the radial bearing and the thermal barrier heat exchanger. Of the eight (8) gallons per minute total injection flow to each RCP, three (3) gpm flow upward through the radial bearing and pump seals and five (5) gpm flow downward through the heat exchanger and into the RCS. This downward flow acts as a buffer to prevent the hot reactor coolant from entering the bearing and seal area.

The reactor coolant pump is designed to operate with either seal injection or thermal barrier heat exchanger cooling. However, it is desirable to maintain bearing and seal cooling from the purified and filtered seal injection water rather than the contaminated unfiltered reactor coolant leaking up the shaft from the RCS. The thermal barrier heat exchanger is used as a backup if a loss of seal injection flow were to occur. Under this condition approximately three (3) gpm (the normal shaft seal leakage) flows from the RCS through the heat exchanger to the pump radial bearing and the controlled leakage seal package. Operation of the reactor coolant pump under these conditions is permitted only for a short period of time due to the fact that the unfiltered coolant flowing through the seal package could damage the seals. Labyrinth seals between the shaft and heat exchanger force most of this water through the heat exchanger. Component cooling water is the cooling medium for the thermal barrier heat exchanger.

Coupling/Spool Piece - A spool piece connects the pump and motor shafts. The spool piece can be removed to make the shaft seals accessible for maintenance without removing the motor.

Shaft Seal Section - The function of the shaft seal assembly is to provide essentially zero leakage from the RCS along the pump shaft to the containment atmosphere during normal operating conditions. The assembly consists of three seals, two of which are full design pressure seals and a third which is simply a leakage diversion seal. Figure 3.2-18 shows the relative position of the three seals. The seal assembly is located concentric to the pump shaft as it passes through the main flange. The seals are contained in a seal housing which is bolted to the top side of the main flange.

The number one seal (Figure 3.2-18) is the main seal of the pump. It is a controlled-leakage, film-riding seal whose sealing surfaces do not contact each other. Its primary components are a runner which rotates with the shaft and a nonrotating seal ring. The seal ring and runner are faced with aluminum oxide coatings. If the two surfaces come in contact during operation, the seal will be damaged and excessive leakage will result. The number one seal produces a 2200 psi pressure drop.

During normal operation, cool injection water, at a pressure greater than RCS pressure, enters the pump through a connection on the thermal barrier flange at a rate of about eight gpm (Figure 3.2-19). About five gpm of this injection water flows downward through the thermal barrier/heat exchanger and into the RCS.

This downward flow of water prevents the primary coolant from entering the seal area of the pump. The remaining 3 gpm of the injected water pass through the pump radial bearing and number one seal. The seal is termed a "controlled-leakage" seal because the leakage through the seal is controlled to a design value and is maintained by floating the seal ring so that the gap between the non-rotating seal ring and the rotating seal runner is always held to a constant value (Figure 3.2-20).

To understand the concept of why the gap between the seal ring and the runner stays constant, it is necessary to examine the hydrostatic forces on the seal ring by dividing them into "closing forces" (those forces tending to close the gap) and "opening forces" (those forces tending to open the gap). A constant closing force proportional to the pressure differential across the seal is imposed on the upper surface of the ring. This is shown on Figure 3.2-20, as a rectangle on the force balance curve.

At equilibrium conditions, an equal and opposite opening force acts on the bottom of the ring. The nonuniform shape of the opening force distribution is due to the taper on the underside of the ring. The taper causes the rate of change of the pressure drop, and thus the associated force, to be different from those in the parallel section of the ring. If the gap closes, the seal ring moves downward and the percentage reduction of flow area in the parallel section is greater than that in the tapered section. This causes the resistance to flow in the parallel section to increase more rapidly than it does in the tapered section. This, in turn, distorts the force diagram and results in a slight increase in the opening force. The increased opening force pushes the seal ring up, which causes the gap to widen until equilibrium conditions are again established. Similarly, if the gap increases, the opening force decreases. The closing force (being greater) will then push the seal ring down and close the gap. Again, the seal ring will be restored to its equilibrium position.

If the pressure in the primary system is decreased, the shape of the force-balance diagram does not change. However, the actual values of the forces decrease. If the pressure in the RCS continues to decrease, the weight of the seal ring becomes a large part of the “closing” force.

At pressure differentials below about 200 psid, the hydrostatic lifting forces become insufficient to float the seal ring and contact between the seal ring and its runner may occur causing damage to both rings. Therefore, to prevent damage to the number one seal, it is not permitted to operate the pump with the number one seal differential pressures less than 275 psid. The minimum required differential pressure of 275 psid should be obtained when the RCS pressure is 400 psig.

The flow rate through the seals at lower RCS pressures decreases to a value less than that required to cool the pump radial bearing. A penetration is provided to bypass some flow around the number one seal when the pressure in the RCS is less than 1500 psig (Figure 3.2-19). This ensures adequate radial bearing cooling flow.

The number two seal is a rubbing-face seal, with a graphitar-faced seal ring which rubs on an aluminum-oxide-coated stainless-steel runner. During normal operation, the number two seal directs the leakage from the number one seal to the CVCS (Figures 3.2-18 and 3.2-19).

The function of the number two seal is to act as a backup in case of number one seal failure. The number two seal has full operating pressure capability. If the number one seal fails, it will pass greater amounts of water. This is sensed by leak-off flow detectors which are indicated and alarmed in the control room. The operator should then shut the number one seal leak-off flow control valve. This directs all number one seal leakage through the number two seal placing it into service as the primary seal. The plant should then be shut down using normal procedures to replace the failed seal. Normal leakage through the number two seal (number one seal not failed) is three gph.

The number three seal is a rubbing face seal similar to the number two seal, except that it is not designed for full RCS pressure. It is provided to divert the leakage from the number two seal to the RCDT. The number two seal leak off is directed to a standpipe which maintains sufficient back pressure to ensure flow through the number three seal for cooling purposes. The leak off from the number two seal is then piped from the top of the standpipe to the reactor coolant drain tank. High and low level alarms on the standpipe alert the operator to malfunctions of the number two and three seals. Number three seal leak off is also routed to the RCDT. The normal leakage rate through the number three seal is 100 cc/hr.

The primary components of the number three seal are a 304 stainless steel rotating runner with a chrome-carbide-coated rubbing face and a Graphitar 114 stationary ring which is fit to a 304 stainless steel holding ring. The operation of the seal package ensures nearly zero leakage from the RCS at the reactor coolant pump shaft.

Instrumentation - Temperature detectors are provided to monitor the seal water inlet temperature to the pump bearing and the number one seal outlet temperature. These are indicated and annunciated in the control room.

Differential pressure across the number one seal is also indicated and annunciated in the control room to ensure minimum ΔP for pump operation (Figure 3.2-19). This ensures sufficient gap between the number one seal ring and its runner. Each RCP seal supply has a flow transmitter and flow indicator followed by a seal injection throttle valve, all are located outside containment.

The number one seal leak-off flow is monitored, recorded and annunciated in the control room. A high leak-off flow indicates a failed number one seal and alerts the operator to close the number one seal leak-off flow control valve to place the number two seal in service. A low flow is usually produced by low RCS pressure and indicates that insufficient seal leak off exists to ensure proper cooling for the pump bearing. The operator should then open the number one seal bypass valve (a common valve for all pumps) to increase the leak off and provide sufficient cooling.

Motor Section - The motor (Figure 3.2-16) is a vertical, six-pole, squirrel-cage induction motor of drip-proof construction. It is equipped with upper and lower radial bearings, a double Kingsbury type thrust bearing, flywheel, anti-reverse rotation device, oil coolers, and appropriate instrumentation and support equipment. The power supply for reactor coolant pump motors is from the non-vital plant electrical distribution system. Design parameters for the RCP motors are listed in Table 3.2-9.

Flywheel - In the case of loss of power to the reactor coolant pumps, it is necessary to maintain a relatively high flow through the reactor core for a short while after reactor shutdown. Each reactor coolant pump has a 13,200-lb flywheel keyed to the top of its shaft above the motor upper bearings. The stored energy in the flywheel increases the total inertia extending the pump coast down period by 22 to 30 seconds. This, in conjunction with the reactor protection system, assures adequate heat removal during a plant trip and loss of power to the RCPs. The flow coastdown provided by the flywheel also assists in initiating natural circulation flow. The flywheel is shown on Figures 3.2-16 and 3.2-21.

Anti-reverse Rotation Device - If one reactor coolant pump is de-energized while the remaining pumps continue to operate, reverse flow will occur in the idle loop (the loop with the RCP that is off). This reverse flow is not available for core cooling because it bypasses the core. The reverse flow also would cause the pump to turn backwards. Although this would produce no mechanical damage, an attempt to start the pump would produce excessively high starting currents which could overheat or otherwise damage the motor.

To prevent the pump from turning backwards, an anti-reverse rotation device is provided (Figure 3.2-21). The anti-reverse mechanism consists of eleven ratchet pawls mounted in the bottom of the flywheel at its outside diameter, a serrated ratchet plate that is mounted to the motor frame and return springs and two shock absorbers for the ratchet plate which are also mounted to the motor frame. After the pump has stopped, one pawl will engage the ratchet plate. As the motor begins to rotate in the reverse direction, the ratchet plate will also rotate slightly until stopped by the shock absorbers. When the motor is started, the return springs return the ratchet plate to its original position.

As the motor speed increases, the pawls drag over the ratchet plate until the motor speed reaches approximately 80 rpm. At this time, centrifugal force and friction keep the pawls in an elevated position.

Thrust Bearing, Upper Radial Bearing, and Oil Lift System - The upper bearing is a combination double-Kingsbury-type thrust bearing (suitable for up or down thrust) and a radial guide bearing (Figure 3.2-16). The babbitt-on-steel thrust bearing shoes are mounted on equalizing pads, which distribute the thrust load to all shoes equally.

The radial bearing is of conventional, babbitt-on-steel design. Both the thrust and radial bearings are located in the upper oil pot and are submerged in oil. During operation, the bearings are self-lubricating and require no external oil pump. Oil is circulated from the bearings to an external oil cooler by means of drilled passages in the thrust runner which act as a centrifugal pump. Component cooling water provides the heat sink for the bearing cooler.

The thrust bearing oil lift system is provided for pump starts to reduce starting currents and to prevent damage to the thrust bearing (the thrust bearing is only self-lubricating at relatively high pump speeds). A small, high pressure pump provides an oil film to lift the thrust shoes away from the thrust runner. An interlock prevents starting the pump unless proper oil lift pressure has been present for a preset time. The oil lift pump is secured after the pump has been running for about a minute and is not required for pump shutdown.

During operation, the thrust is carried by the upper thrust bearing. This load is due to both RCS pressure and pump dynamic forces. The only time the lower thrust shoes carry load is when the RCS pressure is at a pressure less than the minimum allowable for pump operation or when the motor is run uncoupled from the pump.

Motor Lower Radial Bearing - The motor lower radial bearing is also a conventional, babbitt-on-steel design. It is immersed in oil in the lower oil pot. A cooling coil supplied by component cooling water is provided in the oil pot.

Motor Air Cooling - The motor windings are air cooled. Integral vanes on each end of the rotor force air through cooling slots in the motor frame. It is then discharged to the containment atmosphere. Some designs are supplied with air/water heat exchangers for additional cooling capacity.

Instrumentation - The motor is provided with various instruments which may provide indication in the control room and in most cases will provide annunciation. These instruments include:

1. Temperature detectors for stator and bearing temperatures,
2. Oil level switches for both the upper and lower oil pots, which alarm in the control room on low level,
3. Vibration monitors to detect pump misalignment or mechanical problems, and

4. Ammeters to monitor motor starting and running currents.

Cooling Water - It is essential that cooling water be supplied to the motor bearing coolers and thermal barrier heat exchanger during pump operation. Although it is possible to operate the pump without damage with no cooling flow to the thermal barrier heat exchanger, operation under these conditions should be minimized. If seal injection were lost while thermal barrier cooling was not available, hot reactor coolant would leak up the shaft into the bearing and seal area and damage these components.

The component cooling water system supplies the reactor coolant pump heat exchangers. The piping to the thermal barrier heat exchanger is designed to withstand full system pressure in case of a leak in the heat exchanger. The remainder of the system is low pressure piping.

In the event of a leak from the RCS into the thermal barrier heat exchanger, a high flow is sensed in the component cooling return line. This initiates an alarm and automatically isolates the return. Isolation of the return stops the leak flow and the high pressure piping of the component cooling system becomes part of the RCS pressure boundary. Component cooling water to the reactor coolant pumps is automatically isolated by a containment isolation phase B signal.

If component cooling water is unavailable to the RCP oil coolers and motor coolers, the reactor coolant pumps must be secured within approximately two minutes. Additional information concerning the component cooling water system may be found in Chapter 14.0, Cooling Water Systems.

3.2.4 Leakage Detection

Detection of leakage from the RCS is accomplished by a number of diverse systems and methods. Several of these are described below.

1. The most sensitive indication of reactor coolant system leakage is the containment air monitoring system. Experience has shown that the particulate activity in the containment atmosphere responds very rapidly to increased leakage. Systems are provided to monitor particulate and gaseous activity from the areas enclosing the reactor coolant system components so that any leakage from them will be easily detected.
2. Any leakage will cause an increase in the amount of makeup water required to maintain a normal level in the pressurizer. The makeup rate is monitored, and any unexplained increase indicates a leak. The magnitude of the leak can be calculated by measuring the increased makeup requirements.
3. Leakage through the head to vessel closure joint will result in flow to the leak-off between the double gaskets of the closure and produce a high temperature alarm.
4. Other methods of detecting leakage in the containment are containment pressure, temperature, humidity, containment condensate measurement, visual inspection, ultrasonic inspection and the containment sump water level. Primary-to-secondary system leakage is detected by the air ejector and steam generator blow down monitors as well as by chemical analysis of secondary water samples.

3.2.5 Vibration and Loose Parts Monitoring

The purpose of the vibration and loose parts monitoring system (VLPMS) is to detect the presence of unexpected impacts within the boundary of the RCS and to actuate alarms to warn plant operators of the abnormal condition. The VLPMS equipment is installed to guard against inadvertent operation of the RCS with inadequately secured parts or drifting metallic parts within the coolant system.

The major components of the VLPMS are accelerometer sensors, preamplifiers, indicator assembly, audio monitor, FM cassette tape recorder, X-Y plotter and a chart recorder with selector switches.

Accelerometer sensors - There are 12 sensors installed at various locations (Figure 3.2-22) on the external surfaces of RCS components and piping. The purpose of these sensors is to monitor the sonic outputs of the components and piping (Figures 3.2-23, 24, 25).

Preamplifiers - A preamplifier is installed in the circuitry from each accelerometer sensor to boost the sensor output signal before its transmission to signal processing and alarm instrumentation in the control room.

Indicator assembly - The indicator assembly receives amplified signals from the preamplifiers. The amplification and signal conditioning assure that only valid metallic impact signals will provide alarm indications.

Audio monitor - The audio monitor is an amplifier and speaker assembly that provides an audible means of detecting vibration or loose parts at each of the 12 sensor locations.

Cassette tape recorder - The FM tape recorder provides on-line recording of signals from any of the 12 sensors.

Spectrum analyzer - The spectral analyzer operates in the low frequency or audio range and measures the amplitude and frequencies of the spectral components of an input signal which allows a more detailed analysis of sensor signals.

X-Y plotter - The plotter may be used to produce graphic tracings showing the relationship between two variable functions.

Chart recorder - The recorder is a dual pen recorder capable of recording an appropriate voltage that represents any type of variable data.

3.2.6 System Interrelationships

3.2.6.1. Materials of Construction

Each of the materials used in the RCS is selected for the expected environment and service conditions. All RCS materials which are exposed to the coolant are corrosion resistant. These materials are stainless steels and Inconel, and they are chosen for specific purposes at various locations within the system for their compatibility with the reactor coolant.

The phenomena of stress corrosion cracking and corrosion fatigue are not generally encountered unless a specific combination of conditions is present. The necessary conditions are a susceptible alloy, an aggressive environment, stress, and time. Therefore, to minimize or prevent stress corrosion of the RCS components, strict chemistry specifications must be maintained to control the aggressive environment of the reactor coolant.

3.2.6.2. Heatup and Cooldown Limits

The maximum rates of heatup and cooldown are based upon the total stress and temperature of the reactor vessel. There is a temperature below which the metal of the reactor vessel may experience brittle fracture. Brittle fracture is the catastrophic failure (cracking) of a material with little or no plastic deformation. Conditions necessary to produce brittle fracture are a susceptible material, an existing flaw (stress riser), low temperature, and stress.

The nil-ductility transition (NDT) temperature of the reactor vessel material opposite the core is established at a Charpy V-notch test value of 30 ft-lb or greater. The material is tested to verify conformity to specified requirements and to determine the actual NDT temperature value. In addition, this material is 100 percent volumetrically inspected by ultrasonic test using both straight beam and angle beam methods. The transition temperature is increased by exposure to radiation, and this must be accounted for in setting operating limits.

Stresses on the reactor vessel wall are produced by reactor coolant system pressure and the differential temperature between the inner and outer walls which exists during heatup or cooldown. The pressure stresses upon the reactor vessel are tensile stresses. The stresses due to heatup are compressive on the inner wall and tensile on the outer wall. Therefore, the heatup-induced stresses subtract from the pressure stresses on the inner wall of the vessel. This results in a lower overall stress on the inner wall.

The stresses due to cooldown are tensile on the inner wall and compressive on the outer wall. Therefore, the cooldown-induced stresses add to the pressure stresses on the inner wall of the vessel. This results in an overall stress which is larger than the pressure-only stress on the inner wall.

To limit the maximum stress on the vessel to within allowable limits, reactor coolant pressure and temperature must be appropriately regulated. Typical pressure and temperature limit curves are shown in Figures 3.2-26 and 3.2-27. The curves are plots of allowable pressure vs. temperature for various heatup and cooldown rates. Permissible operation is below and to the right of the heatup and cooldown limit curves. The criticality limit on Figure 3.2-26 defines a minimum temperature at which criticality may be achieved in order to limit pressure excursions which could occur with a critical reactor.

In actual operation, other limits prevent the reactor from being made critical until operating temperatures are achieved. Typical design thermal and loading cycles for the RCS are shown in Table 3.2-10.

3.2.6.3. Natural Circulation

It is essential to ensure sufficient flow to remove reactor decay heat even when reactor coolant pumps are not operating. The higher elevation of the steam generators relative to the reactor vessel produces a thermal driving head to establish and maintain flow in the RCS when heat is removed from the steam generators by dumping steam. Natural circulation flow is sufficient only for decay heat removal of a shutdown reactor, not for power operation.

3.2.7 PRA Insights

3.2.7.1. Reactor Coolant Pump Seals

The purpose of the reactor coolant pump seals is to ensure nearly zero leakage from the reactor coolant pumps to the containment. A failure of the reactor coolant pump seals is a small break loss of coolant accident, which requires the high head injection system to be operable to supply core cooling, and later the recirculation system to provide the long-term core cooling.

For PRA accident sequences the failure of the reactor coolant pump seals is a result of the loss of component cooling water initiator and the loss of all ac power initiator. Both of these initiators result in a loss of the pump seals, followed within a certain amount of time by core damage due to the unavailability of the high-head injection and/or recirculation system. The time to core damage is very dependent upon the assumed size of the seal LOCA, and the time between the seal LOCA occurring and the time of recovery of the high pressure injection flow. The causes of a loss of ac power and the loss of component cooling water are discussed in the appropriate chapters.

Westinghouse has developed a high temperature Shutdown Seal (SDS) which allows licensees who have the seal installed to use a new seal failure model that greatly reduces leakage of reactor coolant following a loss of seal cooling. See Figure 3.2-28 Westinghouse High Temperature Shutdown Seal (SDS).

The RCP SDS is located between the No. 1 and No. 2 seals, just upstream of the No. 1 seal leak-off line in the housing of the No. 1 insert, encircling the shaft. The No. 1 seal insert is modified by machining out a portion of the inner diameter at the top flange. Until activated, the SDS is completely contained within the space once taken by the No. 1 insert prior to modification. Thus, the annulus between the No.1 insert and the shaft is unaltered. The leak-off through the No. 1 seal is expected to be unimpeded on its way to the No. 1 seal leak-off line and should not be affected during normal operation of the rotating equipment.

The SDS is composed of an actuating device and a sandwich composed of a wave spring, a piston ring, a polymer ring, and a retaining ring. The actuating device holds the piston ring "open" permitting No. 1 seal leak-off to flow up the shaft to the No. 1

seal leak-off line. The polymer ring is sandwiched between the piston ring and the retaining ring. The retaining ring is shrink-fitted and retains all of the SDS components. When assembled in the pump, the retaining ring is further retained in place by the RCP seal housing located directly above it. The wave spring is designed to maintain contact between the three rings.

The activating portion of the seal is made up of a retractable spacer holding the ends of a piston ring open. The retractable spacer is activated by a thermally responsive piston device. When the fluid coming through the No.1 seal increases to the temperature that causes the actuator to retract the spacer from the piston ring, the piston ring snaps closed against the shaft, providing a significant flow restriction and causing the pressure to build on the back side of the polymer ring. With the flow severely restricted, the pressure at the piston ring approaches the RCS pressure which forces the polymer ring against the shaft, creating a leak-tight seal. While the piston ring provides a substantial flow restriction, the primary sealing ring is a polymer material that, when acted upon by the very high pressure drop induced by the piston ring interrupting the flow through the annulus, is constricted around the shaft and upwards against a retaining ring. As the primary sealing ring constricts, it creates greater pressure drop which in turn further constricts the ring tighter around the shaft and upwards. This pressure drop also forces the piston ring and retaining ring upwards, ensuring a tight seal between all the sealing surfaces.

The polymer ring design is expected to conform to pump shaft out-of-roundness, scratches, dents, debris, roughness, and other surface anomalies. Westinghouse maintains that an advantage of the polymer is its ability to slip along the shaft axially and shift with it radially and still maintain a tight seal. This is because it is a continuous ring with a low coefficient of friction. The piston ring, once it initiates sealing, is no longer required for the polymer ring to seal. The piston ring provides a secondary method to reduce No. 1 leak-off flow in the event of a polymer ring failure caused by a poorly sealing polymer ring or an inadvertent actuation. If the SDS actuates on a stationary sealing surface and the polymer ring fails to seal, the piston ring restricts flow to 1.7 gpm. If the polymer ring is removed, i.e. RCP is allowed to continue to operate and the polymer ring is completely worn away, analysis states that the piston ring will wear a gouge into the sealing surface until the ring’s two ends meet. The leak-off flow through the RCP shaft/retaining ring annulus will be restricted to 19 gpm. Installation of the SDS is projected to reduce RCS inventory losses through the RCP seals, following a loss of seal cooling, to a negligible amount requiring no additional RCS makeup to achieve a stable state with the reactor core being cooled. The design basis for the SDS is contained in Section 3.1.2 of TR WCAP-17100-P/NP, Revision 1.

3.2.7.2. Pressurizer Power-Operated Relief Valves

The pressurizer power-operated relief valves are used to limit the primary pressure on transients in order to avoid a reactor trip on high RCS pressure and lifting of the safety valves. The pressurizer PORVs are also used to remove the heat from the core if no other methods of heat removal are available.

The failure of the pressurizer power-operated relief valves is present in several accident sequences which lead to core damage. There are two general failure modes for the relief valves. First, the failure of the power-operated relief valve(s) to shut when required leads to the need for recirculation cooling of the reactor, and the subsequent failure of the recirculation mode of the emergency core cooling system results in core damage. The second failure is the failure to open when required for the purpose of initiating bleed and feed cooling for the reactor. This failure of heat removal results in core damage. At Surry, the failure of the PORVs to shut and, therefore, requiring recirculation cooling, are present in the accident sequences which are 21.2% of the core damage frequency. The failure of the PORVs to open which limits the bleed and feed capability are 4.4% at Surry and 3.2% at Sequoyah. The values for bleed and feed capability will be affected by whether the plant requires one or two relief valves to open to provide sufficient flow for bleed and feed.

Probable causes of a loss of the power-operated relief valves are:

1. Failure of the PORVs to open on demand,
2. Failure of the block valve to shut to isolate a stuck open relief valve, or
3. Failure of the power supply to the PORVs.

NUREG-1150 studies on importance measures have shown that the power-operated relief valves are not a major contributor to risk achievement or risk reduction.

3.2.8 Summary

The reactor coolant piping and components circulate the reactor coolant to transfer the energy produced in the reactor to the steam system to produce electrical output from the turbine generator. The reactor coolant piping is part of the primary pressure boundary and is considered the second line of defense to the release of fission products to the environment. The first line of defense is the fuel cladding and the third is the reactor containment building. Appropriate supports and seismic restraints are provided to ensure the integrity of the RCS pressure boundary during normal and accident operations, including the effects of the design basis earthquake.

The pressurizer, with heaters, sprays, and relief and safety valves, is used to pressurize the RCS during plant startup, to maintain normal RCS pressure during steady-state operation, to limit pressure changes during RCS transients, and to prevent RCS pressure from exceeding design values. Pressurizer pressure, level, and temperature instrumentation is provided for indication, control, and protection.

The steam generators are vertical, shell-and-U-tube heat exchangers which transfer energy from the radioactive reactor coolant to the nonradioactive steam system. The dry, saturated steam produced is used to operate the main turbine and auxiliaries to produce electricity. The steam generator U-tubes provide the boundary between the primary and secondary systems. Steam generator level, steam flow, feed flow and steam pressure instrumentation are provided for indication, control, and protection.

The reactor coolant pumps provide sufficient flow to ensure adequate heat transfer from the RCS to the steam generators. A flywheel extends flow coastdown after a loss of power to maintain flow through the core and help establish natural circulation.

An anti-reverse rotation device prevents the pump from turning backwards which would increase core bypass flow and pump starting current. Shaft sealing is accomplished by a film-riding, controlled-leakage seal with a backup, rubbing-face seal. Seal injection from the CVCS, or flow from the RCS through the thermal barrier heat exchangers, cools and lubricates the seals and pump bearings. Cooling for the motor bearings and thermal barrier heat exchangers is from the component cooling water system. Electrical power to the pump motors is from a non-vital supply.

Reactor coolant piping is constructed of stainless steel and is sized to limit maximum flow velocities and provide proper pump suction characteristics. Penetrations which could experience large thermal stresses have thermal sleeves.

Reactor coolant system temperature instrumentation consists of well-mounted and direct-immersion RTDs. The direct-immersion detectors are located in the RTD bypass manifolds. These instruments are used to supply indication of T_{avg} and ΔT.

Reactor coolant flow is measured by elbow flow monitors which do not introduce a pressure drop in the reactor coolant flow. This flow signal is used for indication and protection.

Leakage detection is accomplished by containment activity monitors; observation of RCS makeup requirements; containment sump level, pressure, temperature and humidity monitors; and steam generator activity monitors.

Heatup and cooldown limits maintain the reactor vessel total stresses to within limits, especially during low temperature operation, when the vessel might be susceptible to brittle fracture. The transition temperature from brittle to ductile fracture increases with exposure of the vessel to radiation, so the limits become more restrictive as the plant ages.

The orientation of the major components in the RCS is designed so that a thermal driving head will exist to produce natural circulation flow if the RCPs are not operating. Natural circulation flow is sufficient for removal of reactor decay heat.

Table 3.2-1 Reactor Coolant Piping Design Parameters

Inlet piping - inside diameter	27.5"
Inlet piping - nominal thickness	2.69"
Outlet piping - inside diameter	29.0"
Outlet piping - nominal thickness	2.84"
RCP suction piping - inside diameter	31.0"
RCP suction piping - nominal thickness	2.99"
Design pressure	2,485 psig
Design temperature	650°F

Table 3.2-2 Pressurizer Design Parameters

Design pressure	2,485 psig
Hydrostatic test pressure	3,107 psig
Design Temperature	680°F
Volume	1,800 ft^3
Full power water volume	1,080 ft^3
Full power steam volume	720 ft^3
Shell - inside diameter	84.0"
Surge line - inside diameter	14.0"
Surge line - wall thickness	1.40"
Surge line design temperature	680°F
Heater capacity	1,794 kW

Table 3.2-3 Spray Control Valve Design Parameters

Number of spray valves	2
Design pressure	2,485 psig
Design temperature	650°F
Design flow rate per valve	420 gpm

Table 3.2-4 Safety Valve Design Parameters

Number of safety valves	3
Set pressure	2,485 psig
Design temperature	680°F
Relieving capacity per safety valve	420,000 lb/hr
Normal backpressure	3 psig
Maximum backpressure during discharge	500 psig
Accumulation	3%
Blowdown	5%

Table 3.2-5 Pressurizer Power Operated Relief Valve Design Parameters

Number of power operated relief valves	2
Design pressure	2,485 psig
Design temperature	680°F
Relieving capacity per relief valve	210,000 lb/hr

Table 3.2-6 Pressurizer Relief Tank Design Parameters

Volume	1,800 ft^3
Design pressure	100 psig
Design temperature	340°F
Rupture disc release pressure	100 psig
Rupture disc relieving capacity	$1.6x10^6$ lb/hr

Table 3.2-7 Steam Generator Design Parameters

Number of steam generators	4
Design pressure RCS side	2,485 psig
Design pressure steam side	1,185 psig
Design temperature RCS side	650°F
Design temperature steam side	600°F
Height	67.75'
Shell - outside diameter	175.75"
U-Tubes - number	3,388
U-Tubes - number	0.875"
U-Tubes - number	0.050"
Steam generator conditions at full load	
Steam flow	$3.77x10^6$ lb/hr
Steam pressure	895 psig
Steam temperature	533.3°F
Moisture carryover - weight	0.25%

Table 3.2-8 Reactor Coolant Pump Design Parameters

Number of reactor coolant pumps	4
Design pressure	2,485 psig
Design temperature	650°F
RCP capacity per pump	88,500 gpm
Speed rating	1,200 rpm
Discharge head	277 ft
Minimum required NPSH	170 ft
Overall height	28.5 ft
Overall weight	188,900 lb
Suction nozzle - inside diameter	31.0"
Discharge nozzle -inside diameter	27.5"

Table 3.2-9 Reactor Coolant Pump Motor Design Parameters

Horsepower rating	6,000
Voltage	12,500Vac
Phase	3
Frequency	60 hz
Power (cold RCS)	5,997 kW
Power (hot RCS)	4,540 kW
Starting current	3,000 amps
AC induction motor, single speed, air cooled. Insulation class B, thermoplastic epoxy	

Table 3.2-10 Thermal and Loading Cycle Design Parameters

	Design Cycles
Heatup at <100°F/hr	200
Cooldown at <100°F/hr	200
Loss of load without an immediate reactor trip	80
Loss of offsite power	40
Loss of RCS flow (one pump only)	80
Reactor trip from 100% power	400
Auxiliary spray >320°F differential	10
Main RCS pipe break	1
Safe shutdown earthquake	1
Leak test at >2335 psig	50
RCS hydrostatic test >3107	5
Steam line break >6" in diameter	1
Steam generator hydrostatic test >1485 psig	5
Turbine rolls on pump heat with >100°F/hr cooldown	10

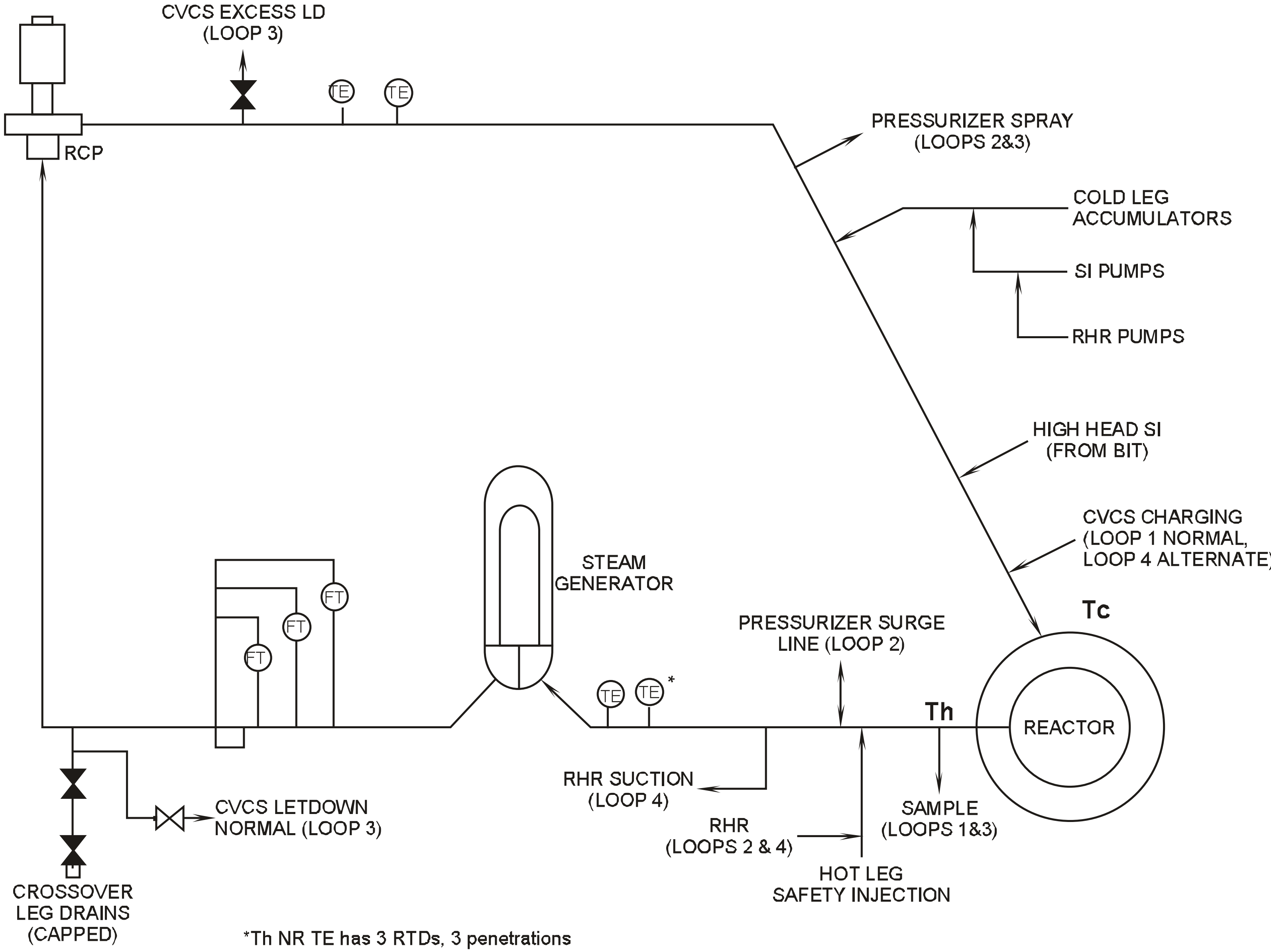
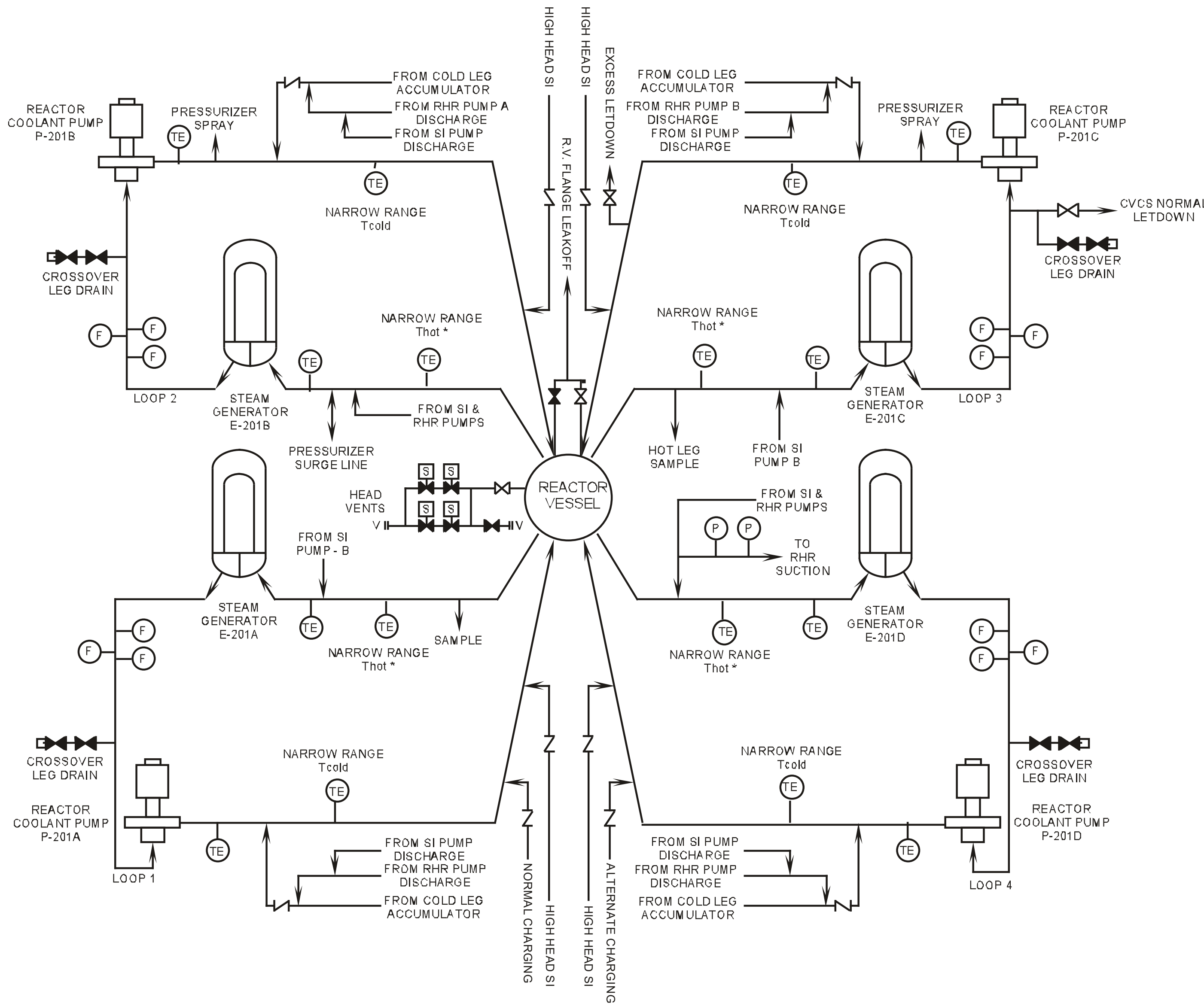


Figure 3.2-1 Reactor Coolant Loop Penetrations



*Th NR TEs have 3 RTDs, 3 penetrations

Figure 3.2-2 Reactor Coolant System

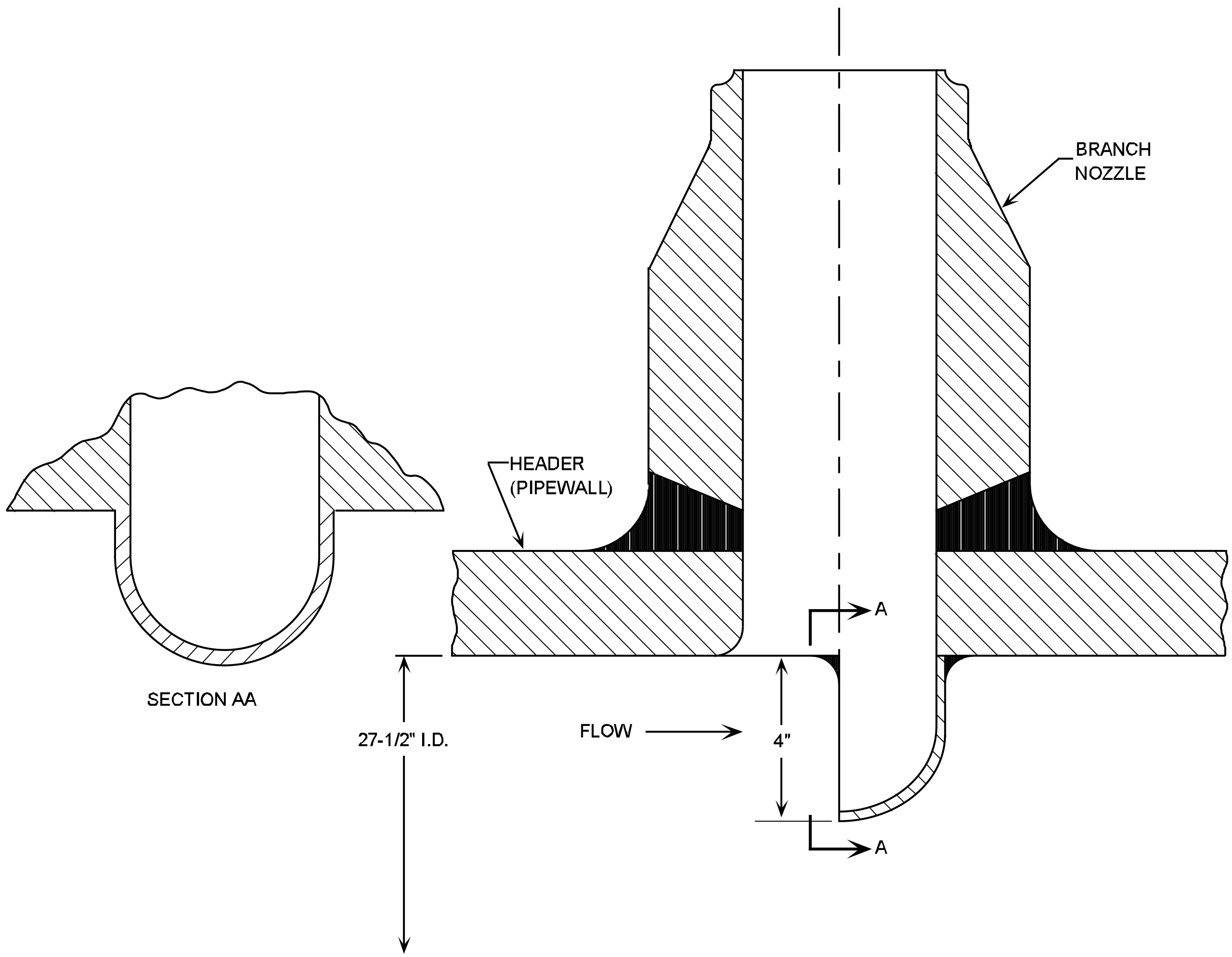


Figure 3.2-3 Pressurizer Spray Scoop

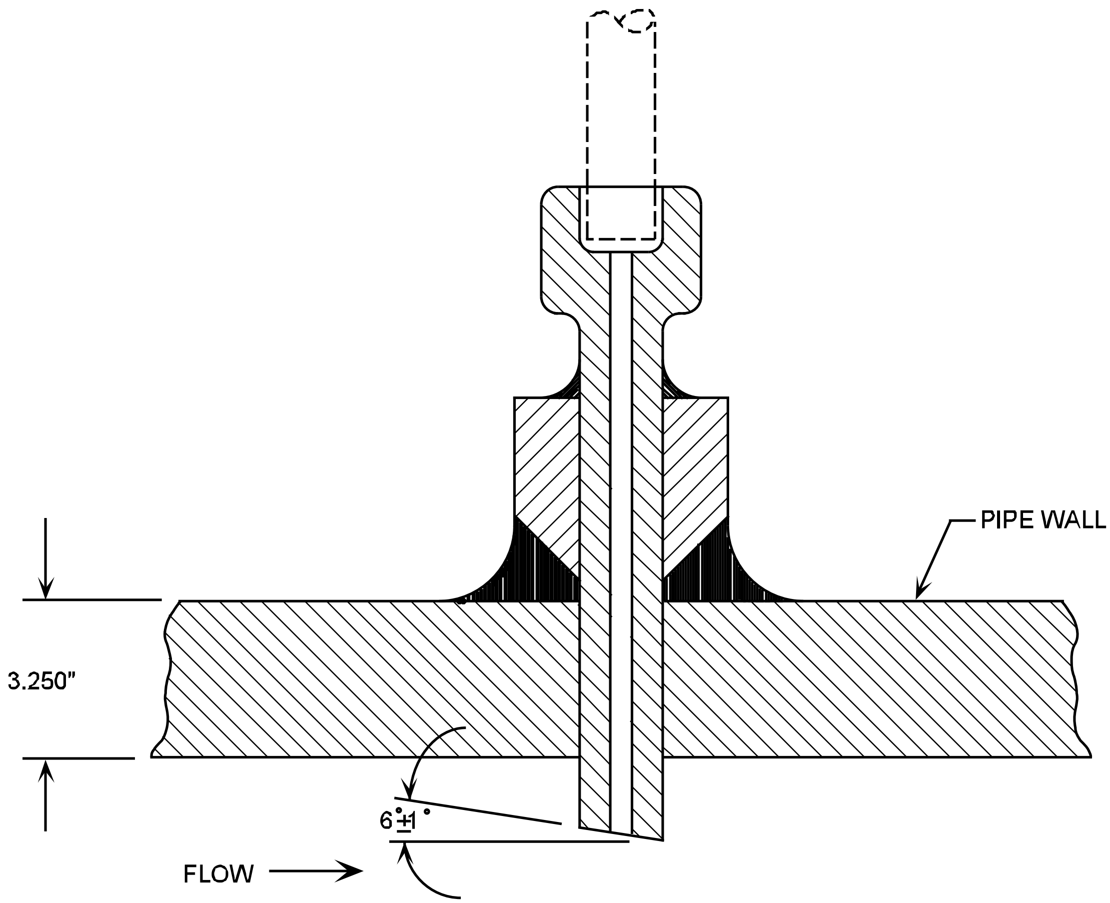


Figure 3.2-4 Sample Connection Scoop

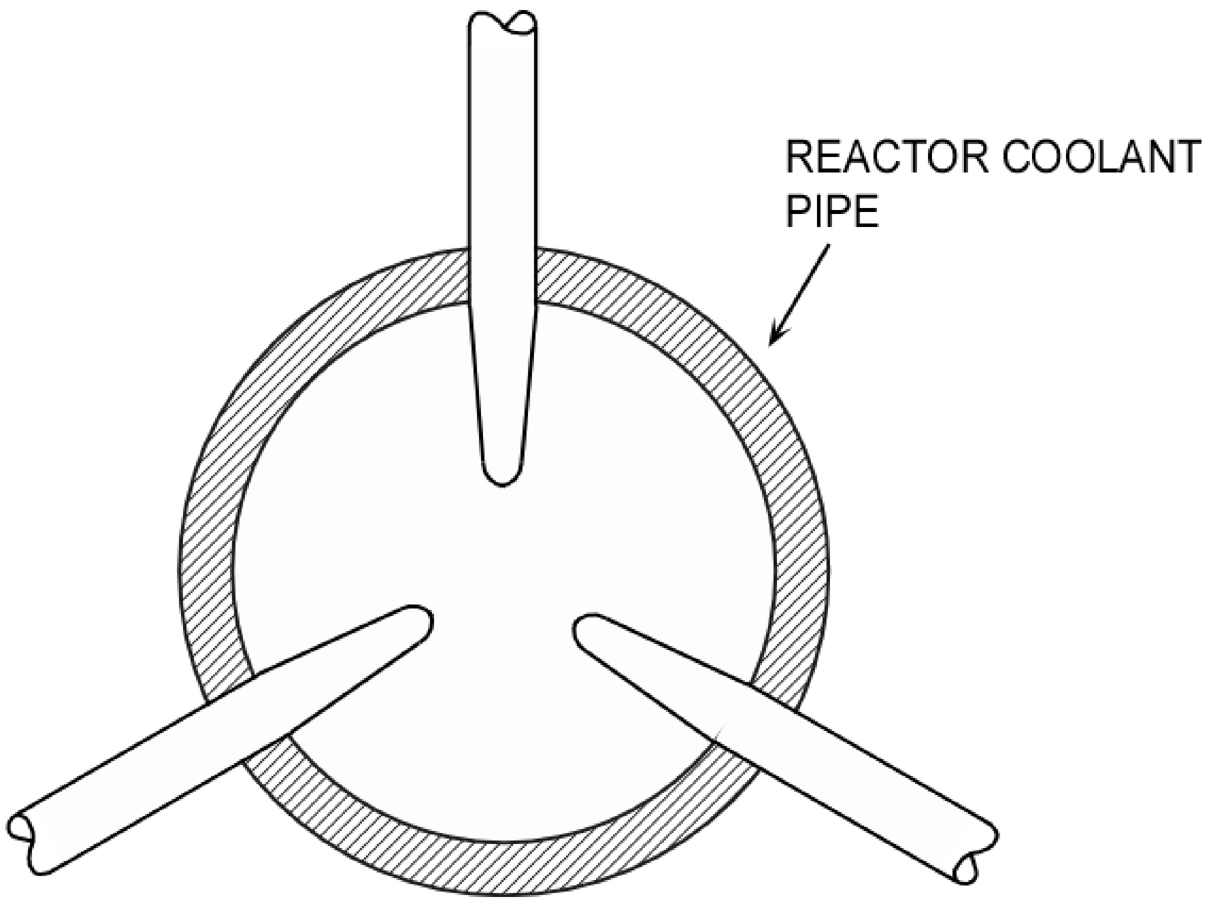
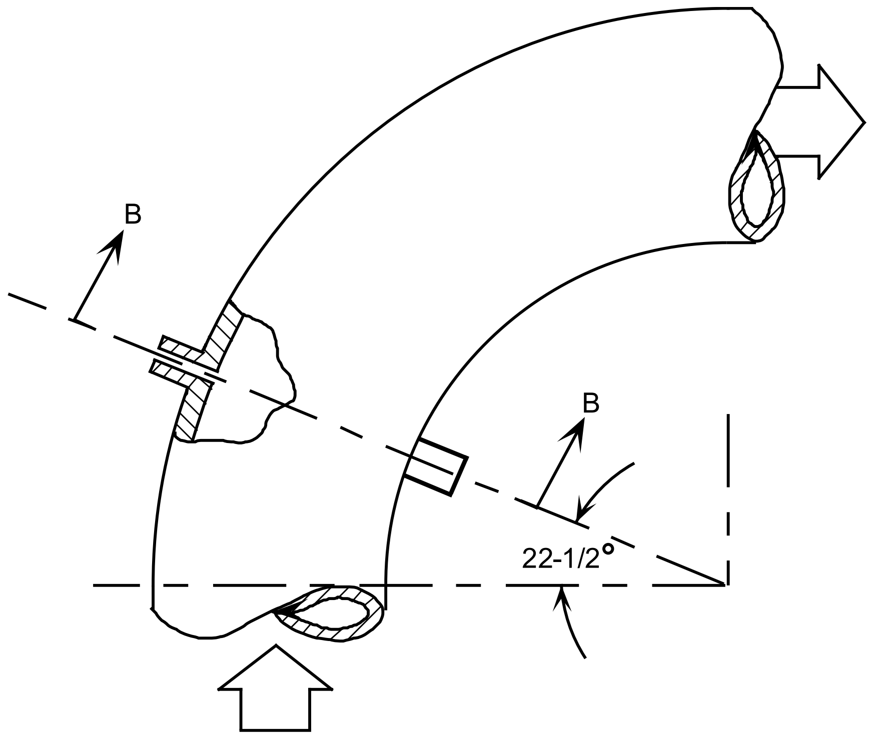


Figure 3.2-5 Hot Leg RTD Configuration



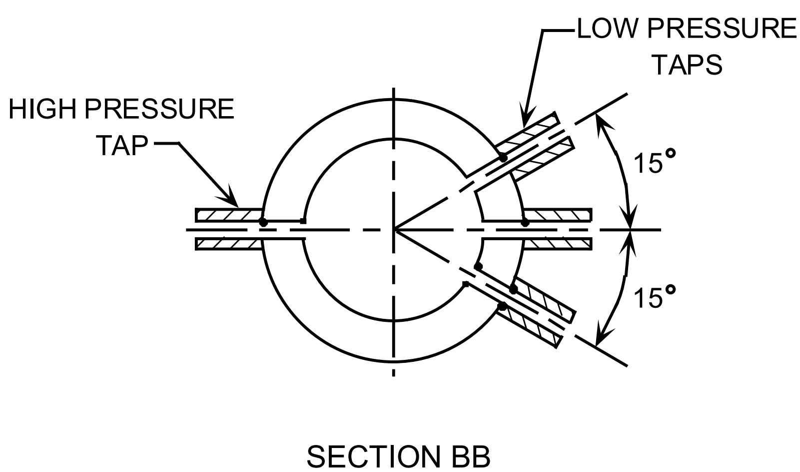


Figure 3.2-6 Reactor Coolant Flow Taps

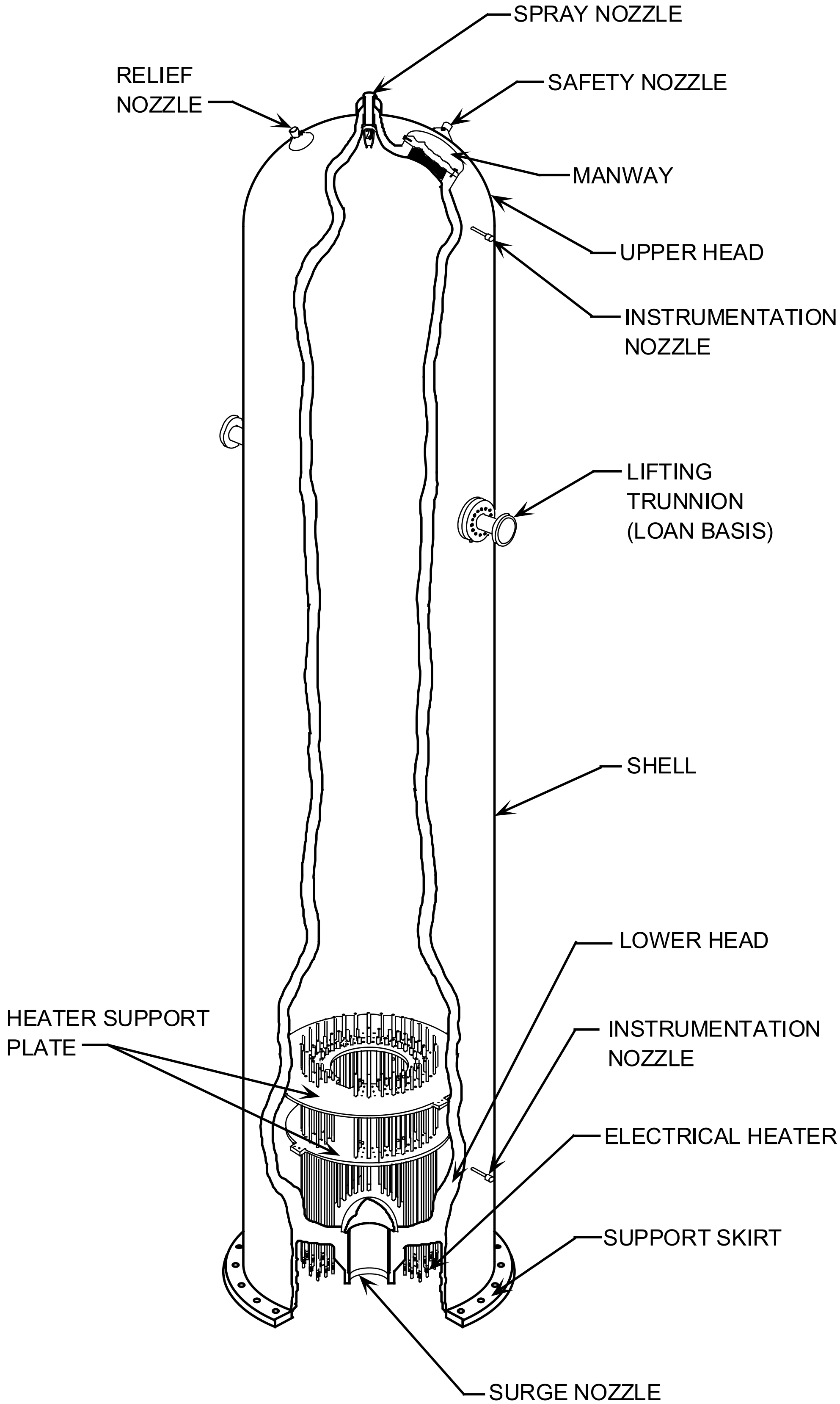
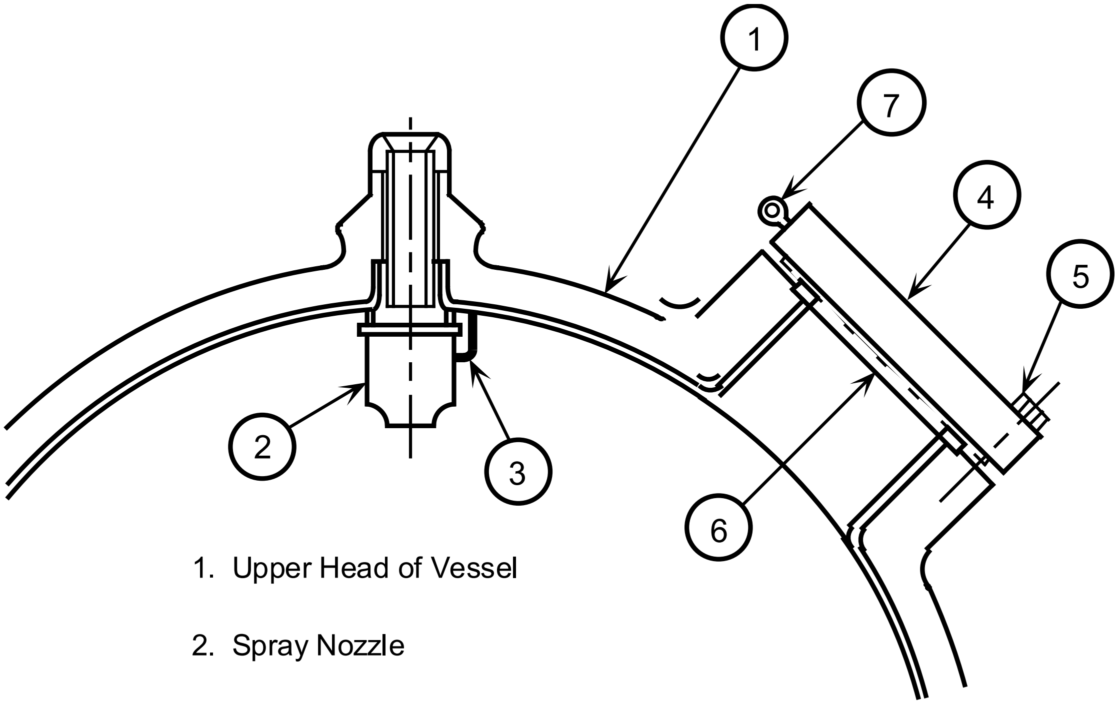
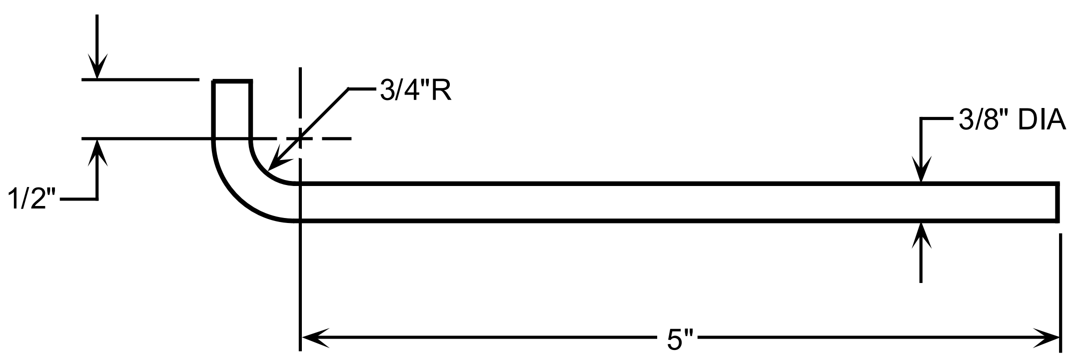


Figure 3.2-7 Pressurizer



1. Upper Head of Vessel
2. Spray Nozzle
3. Spray Nozzle Locking Bar
4. Manway Cover
5. Manway Cover Bolt
6. Manway Cover Insert Assembly
7. Lifting Eye Bolt Location



Matl to Stainless Steel, 18-8 Type 304

Spray Nozzle Locking Bar Detail

Figure 3.2-8 Pressurizer Manway Cover and Spray Nozzle

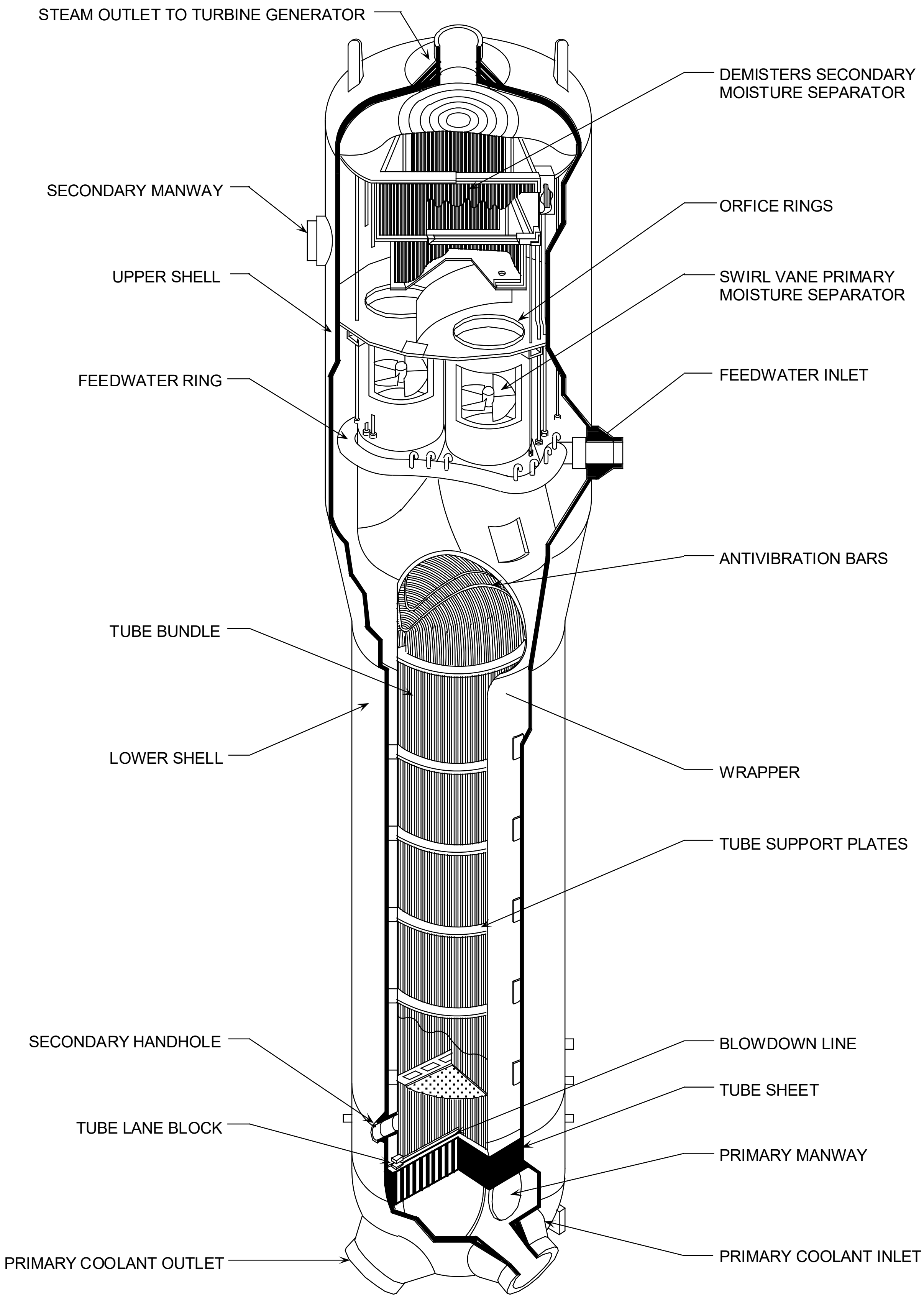


Figure 3.2-9 Model 51 Steam Generator

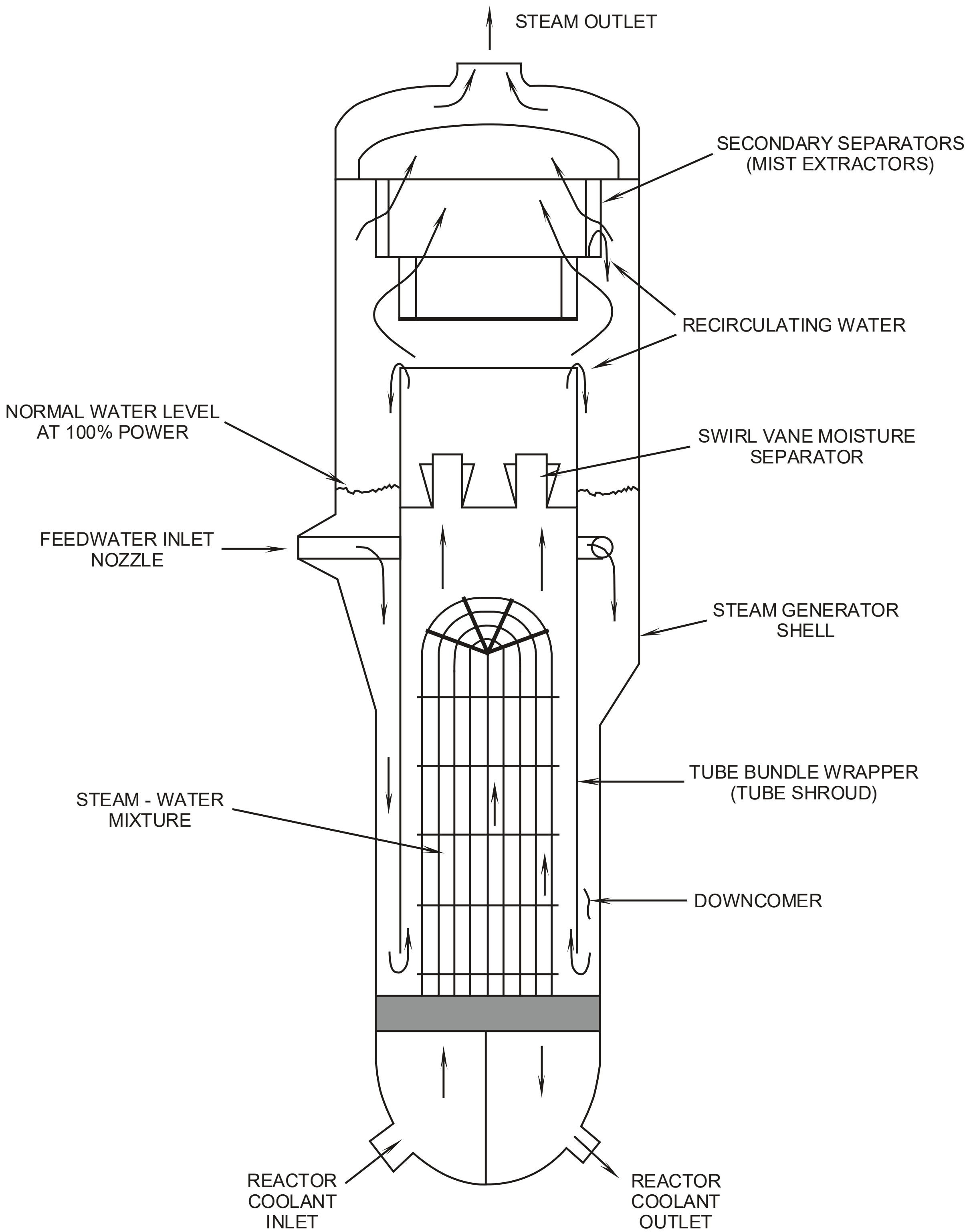
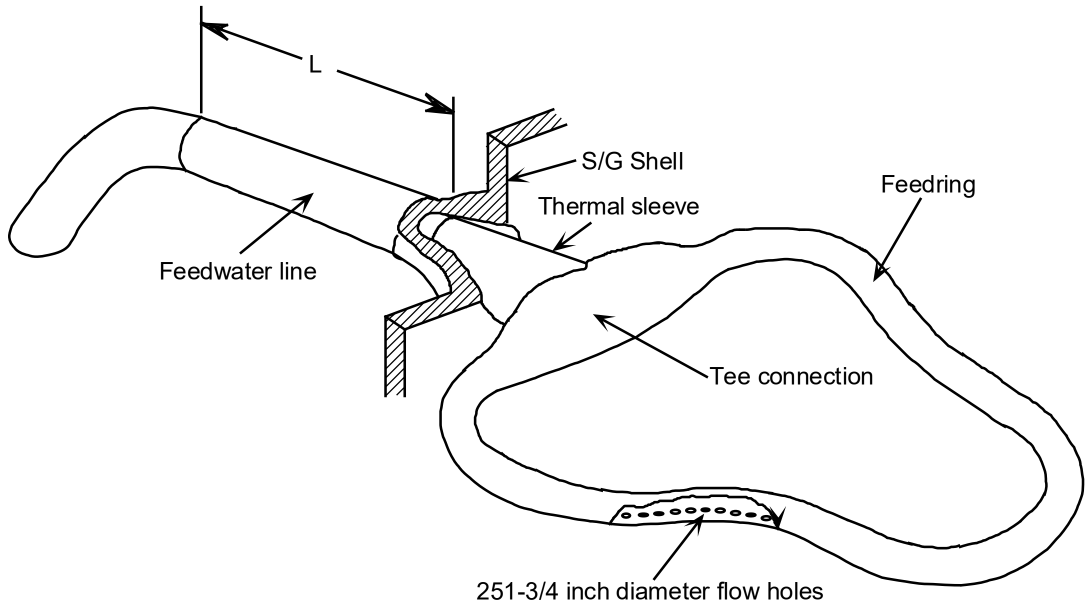


Figure 3.2-10 Steam Generator Flow Paths

FEEDRING ASSEMBLY
FEEDRING TYPE STEAM GENERATOR



J-TUBE CONFIGURATION
FEEDRING STEAM GENERATOR

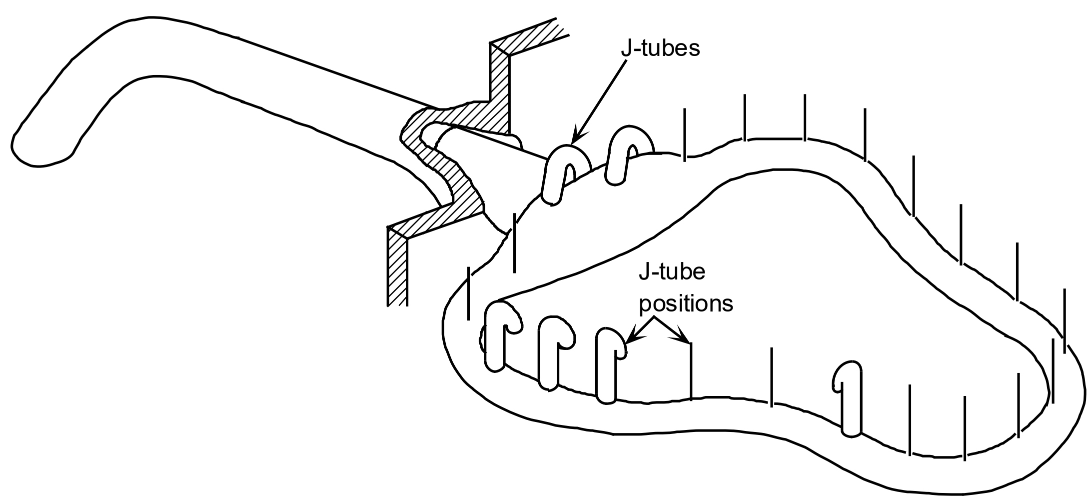


Figure 3.2-11 Feed Ring Assemblies

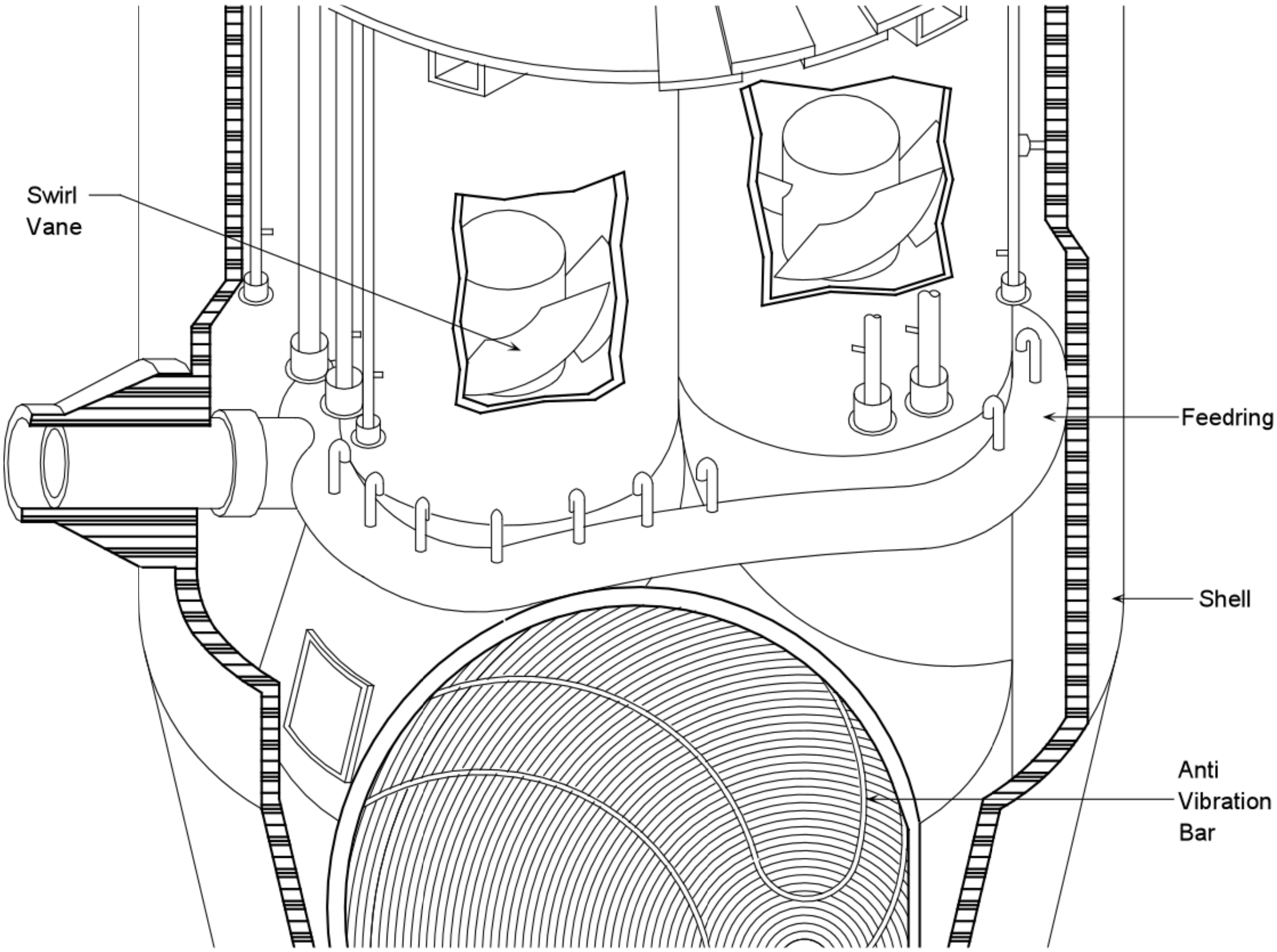


Figure 3.2-12 Feedring and Moisture Separators

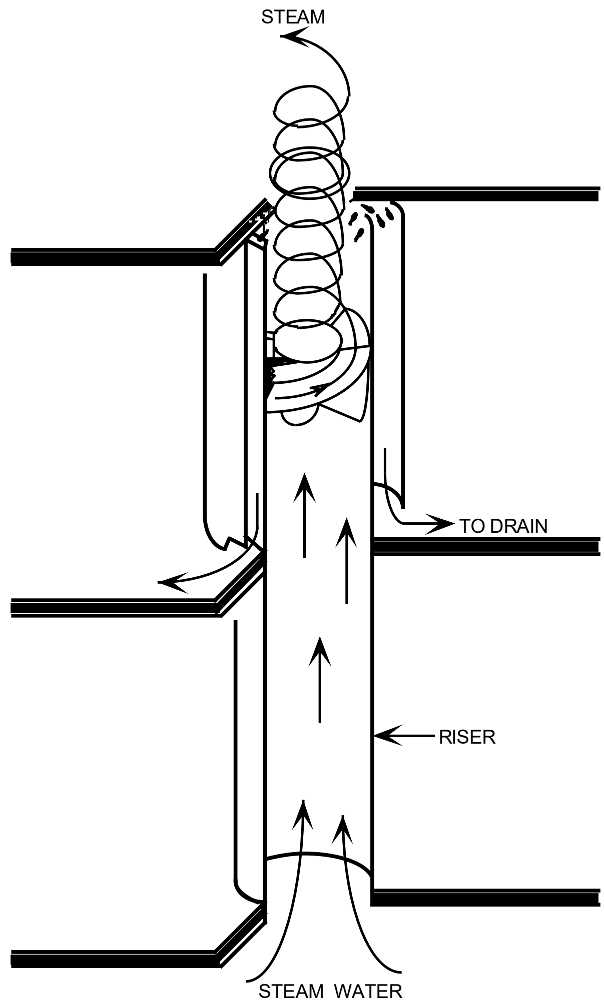
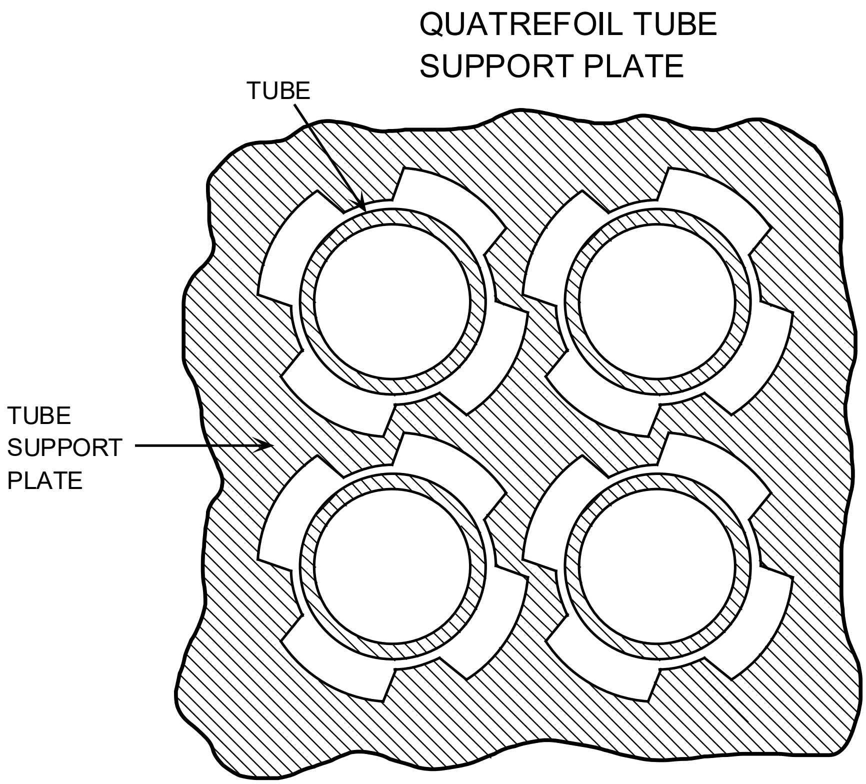


Figure 3.2-13 Steam Generator Moisture Separators



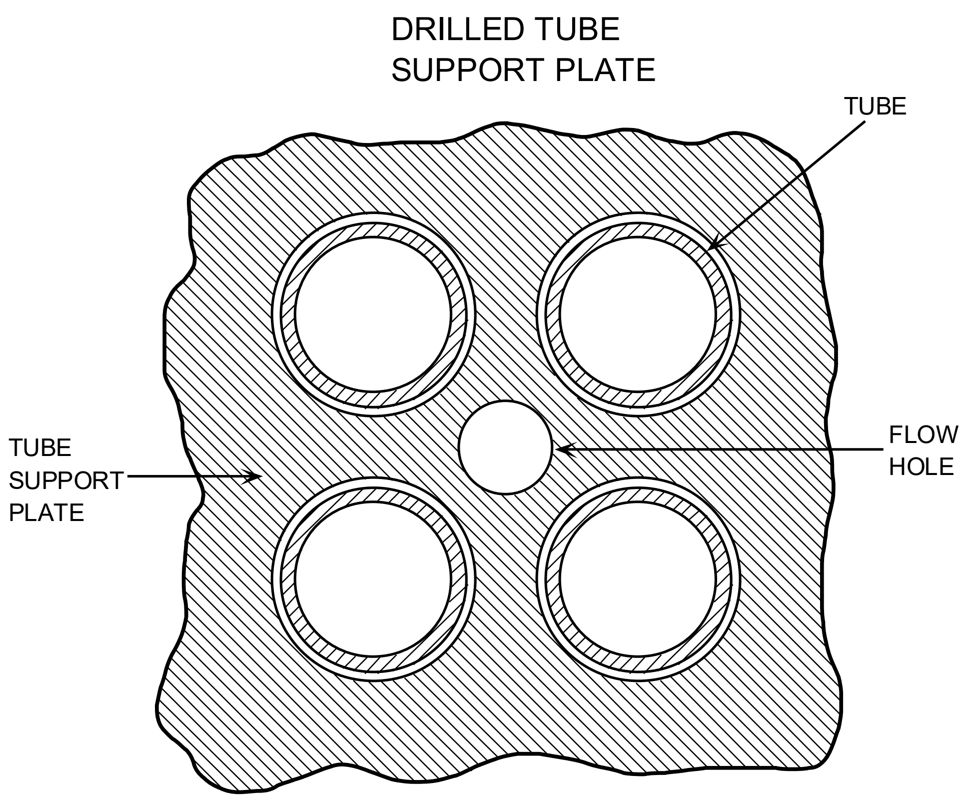


Figure 3.2-14 Tube Support Plate

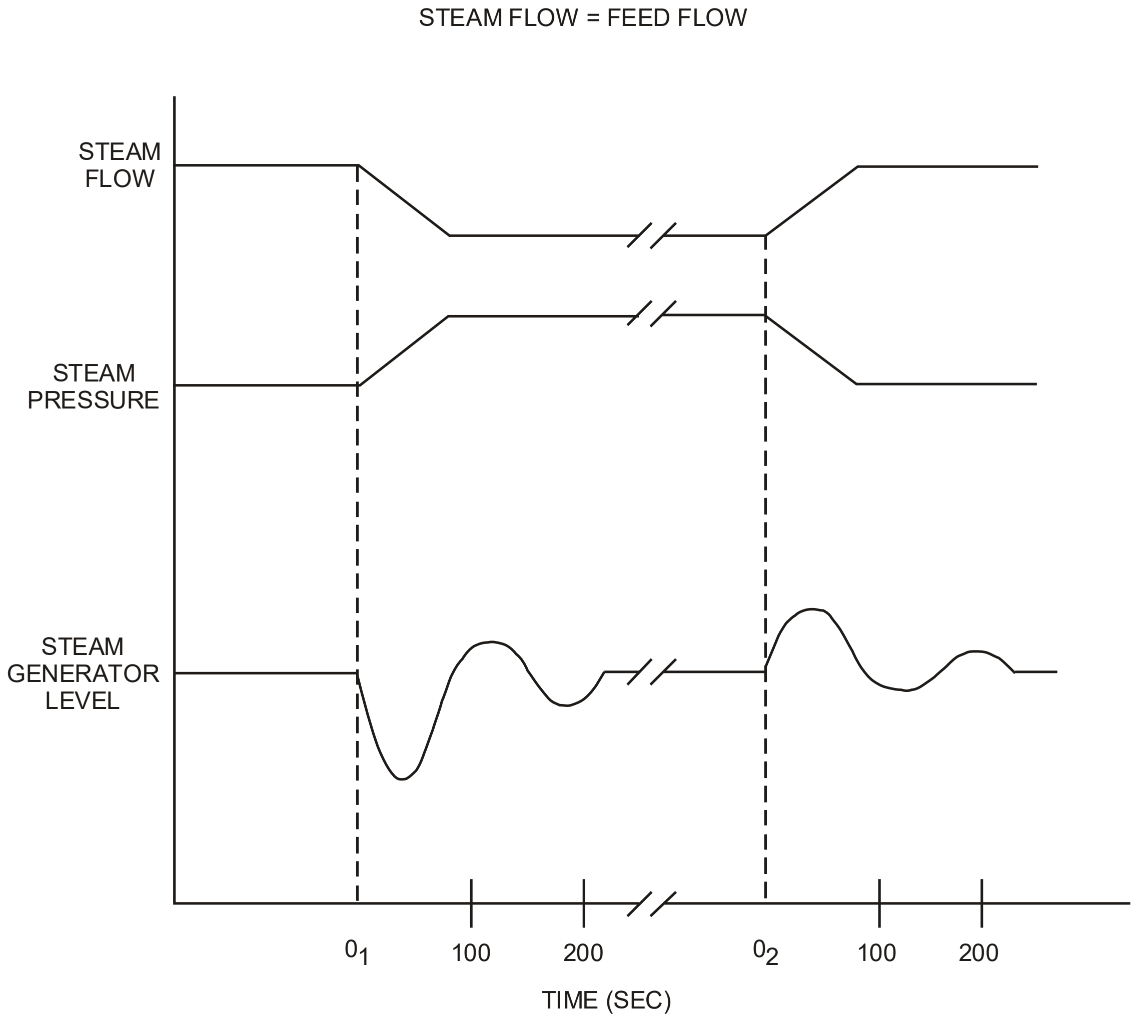


Figure 3.2-15 Steam Generator Shrink and Swell

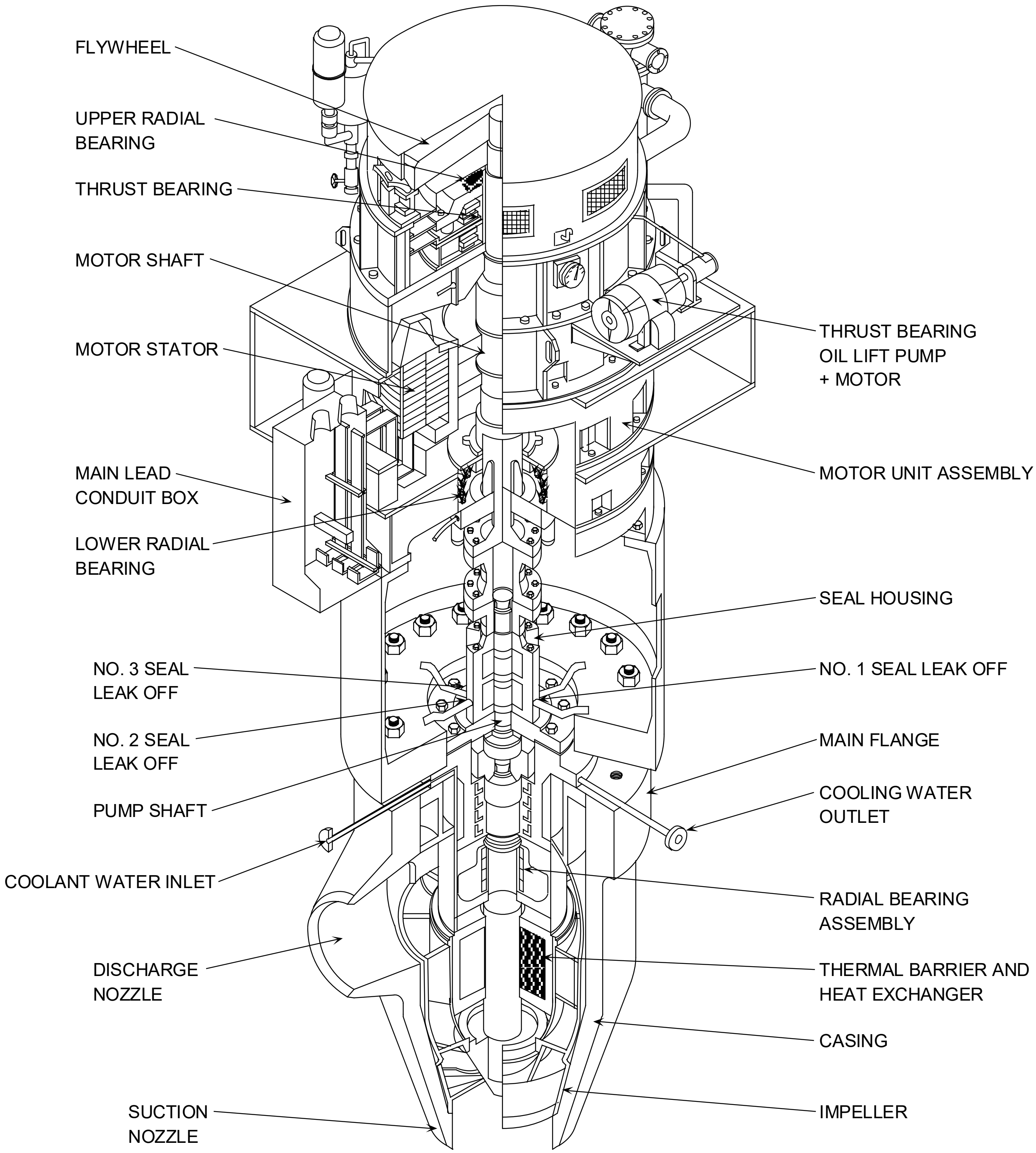


Figure 3.2-16 Reactor Coolant Pump

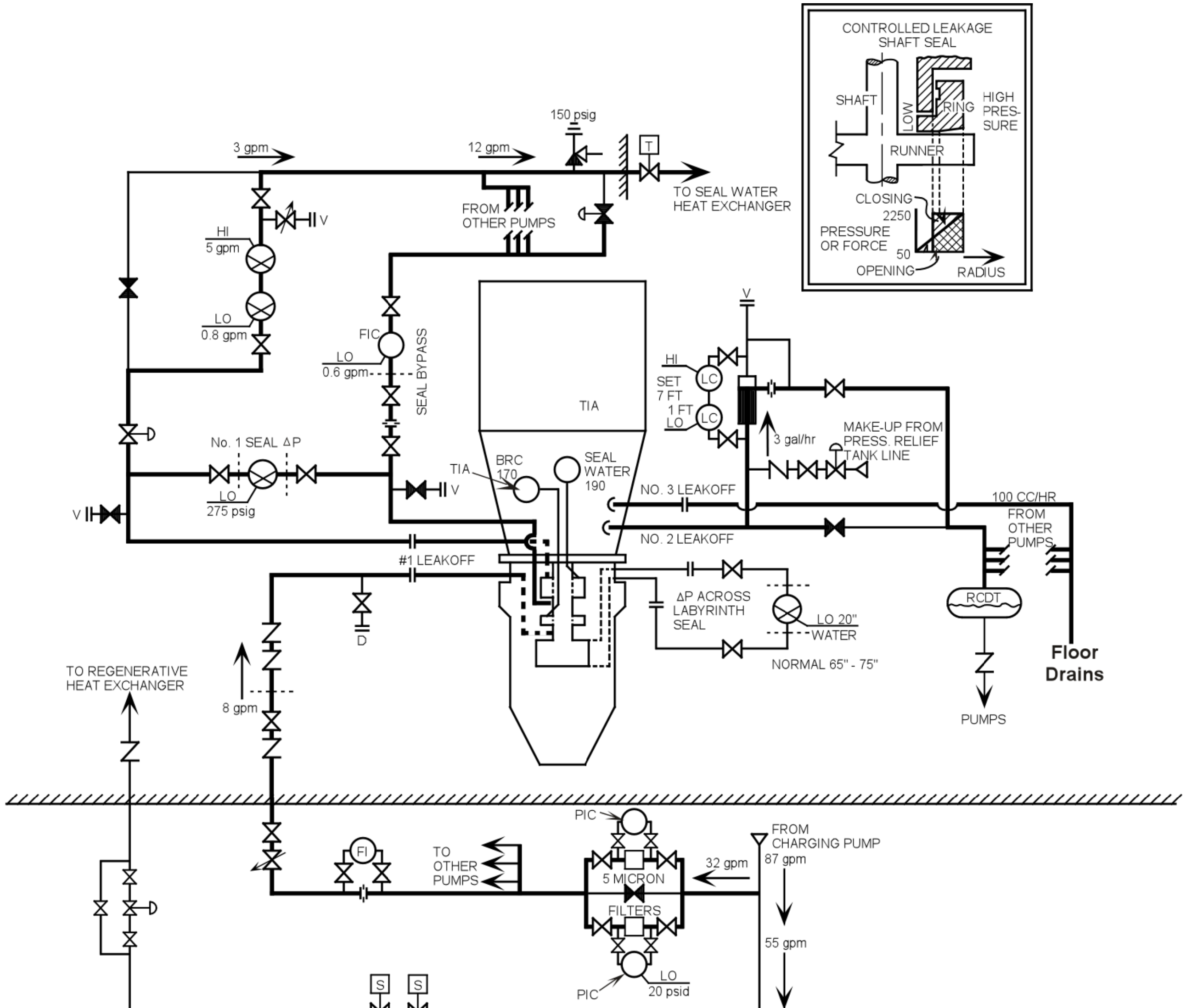


Figure 3.2-17 Seal Water Injection and Leakoff

PRELIMINARY OPERATING PARAMETERS		
SEAL	INLET PRESSURE	FLOW RATE
NO. 1	2250	3 GPM
NO. 2	50	3 GPH
NO. 3	6	100 CC/HR

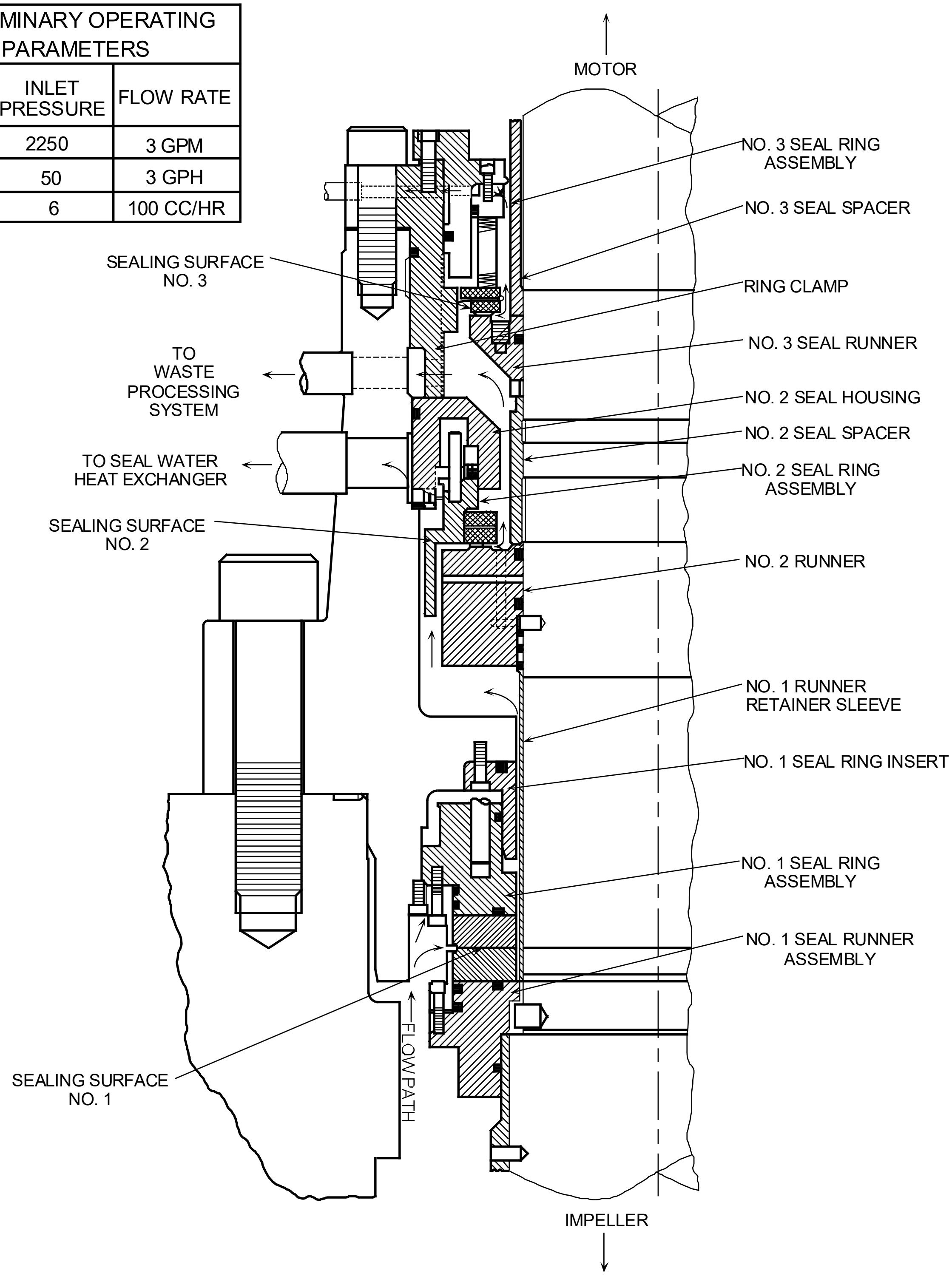


Figure 3.2-18 Shaft Seal Arrangement

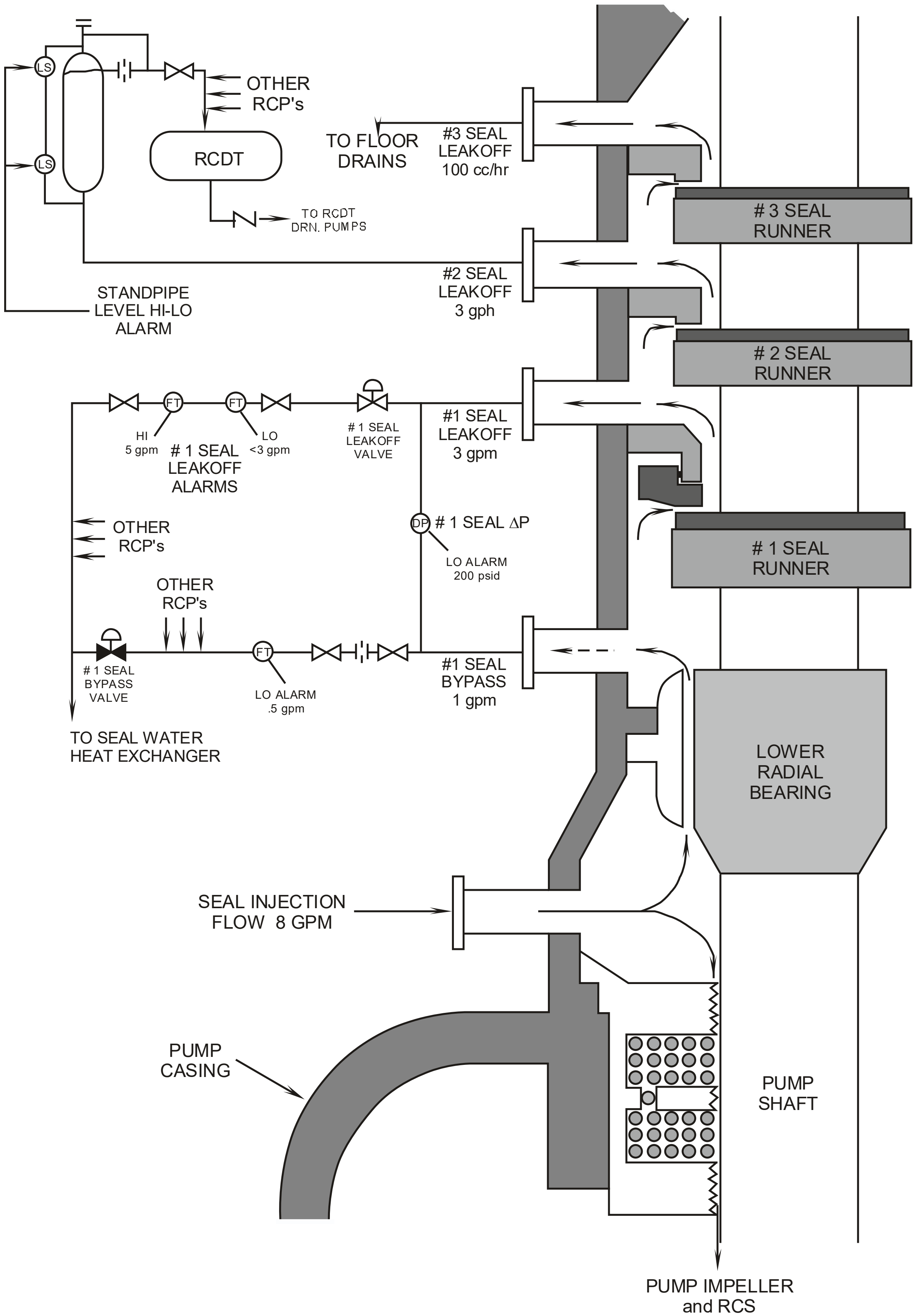


Figure 3.2-19 Seal Flow Diagram

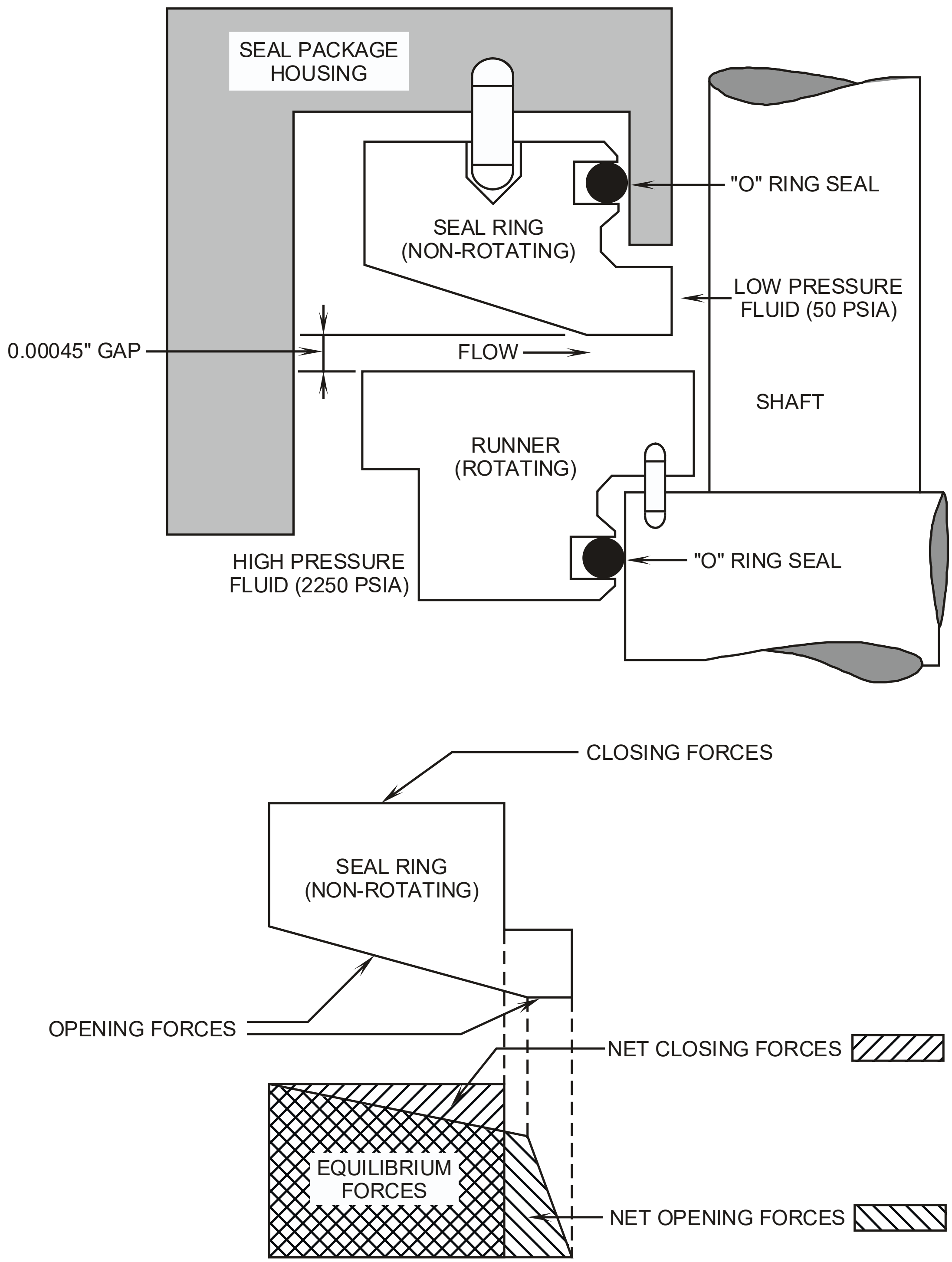


Figure 3.2-20 Controlled Leakage Shaft Seal

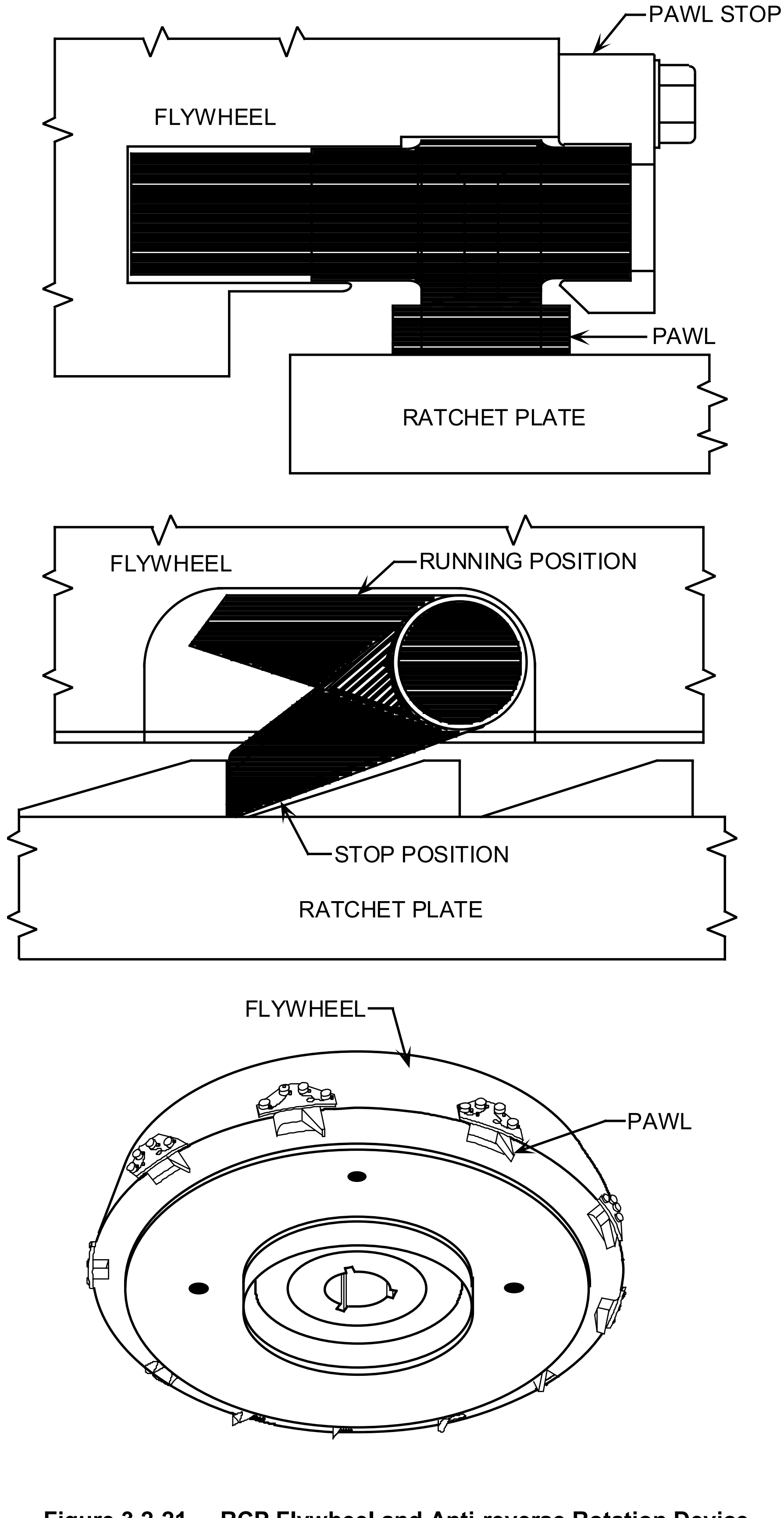
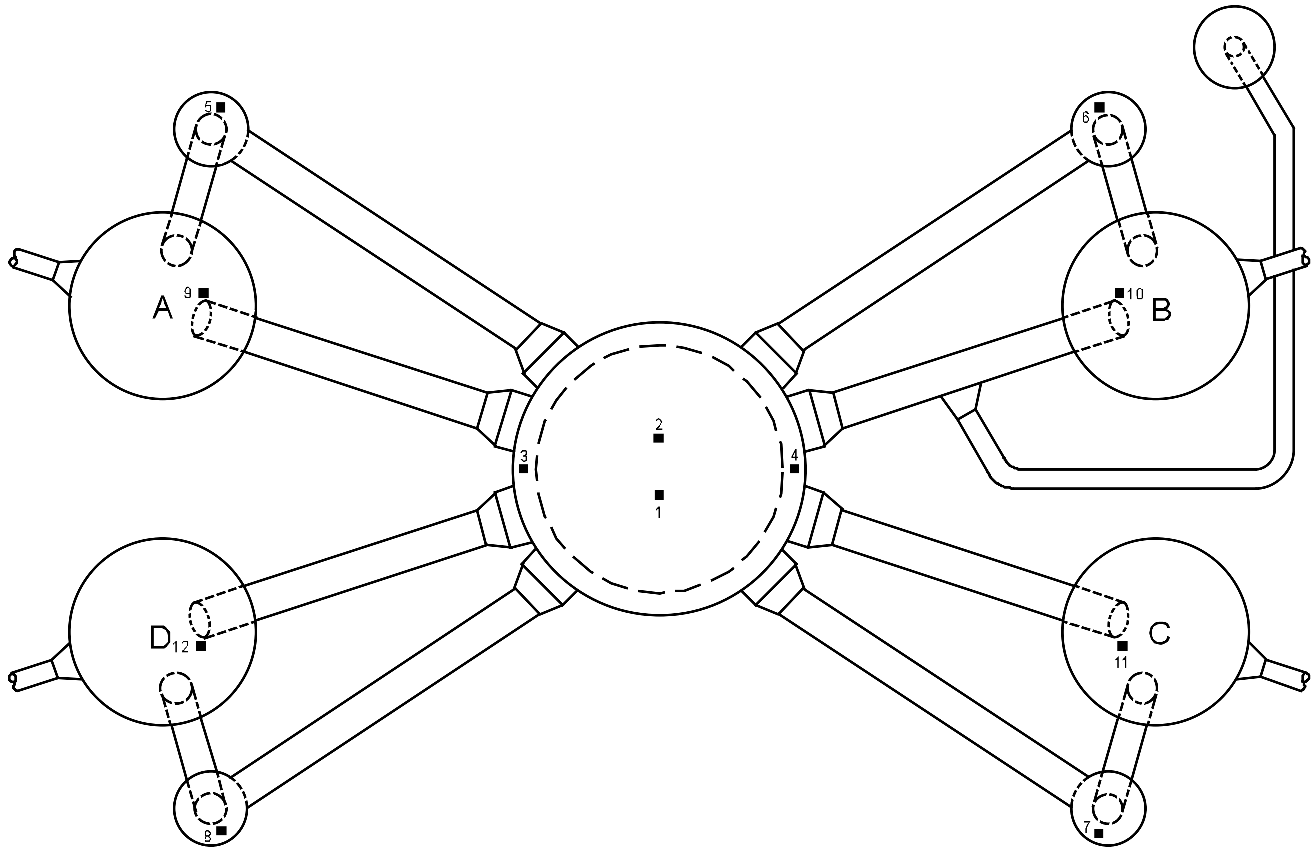


Figure 3.2-21 RCP Flywheel and Anti-reverse Rotation Device



CHANNEL	LOCATION	CHANNEL	LOCATION
1	LOWER VESSEL (WEST)	7	RC PUMP C
2	LOWER VESSEL (EAST)	8	RC PUMP D
3	UPPER VESSEL (NORTH)	9	STEAM GENERATOR A
4	UPPER VESSEL (SOUTH)	10	STEAM GENERATOR B
5	RC PUMP A	11	STEAM GENERATOR C
6	RC PUMP B	12	STEAM GENERATOR D

Figure 3.2-22 Vibration and Loose Parts Monitoring Transducer Locations

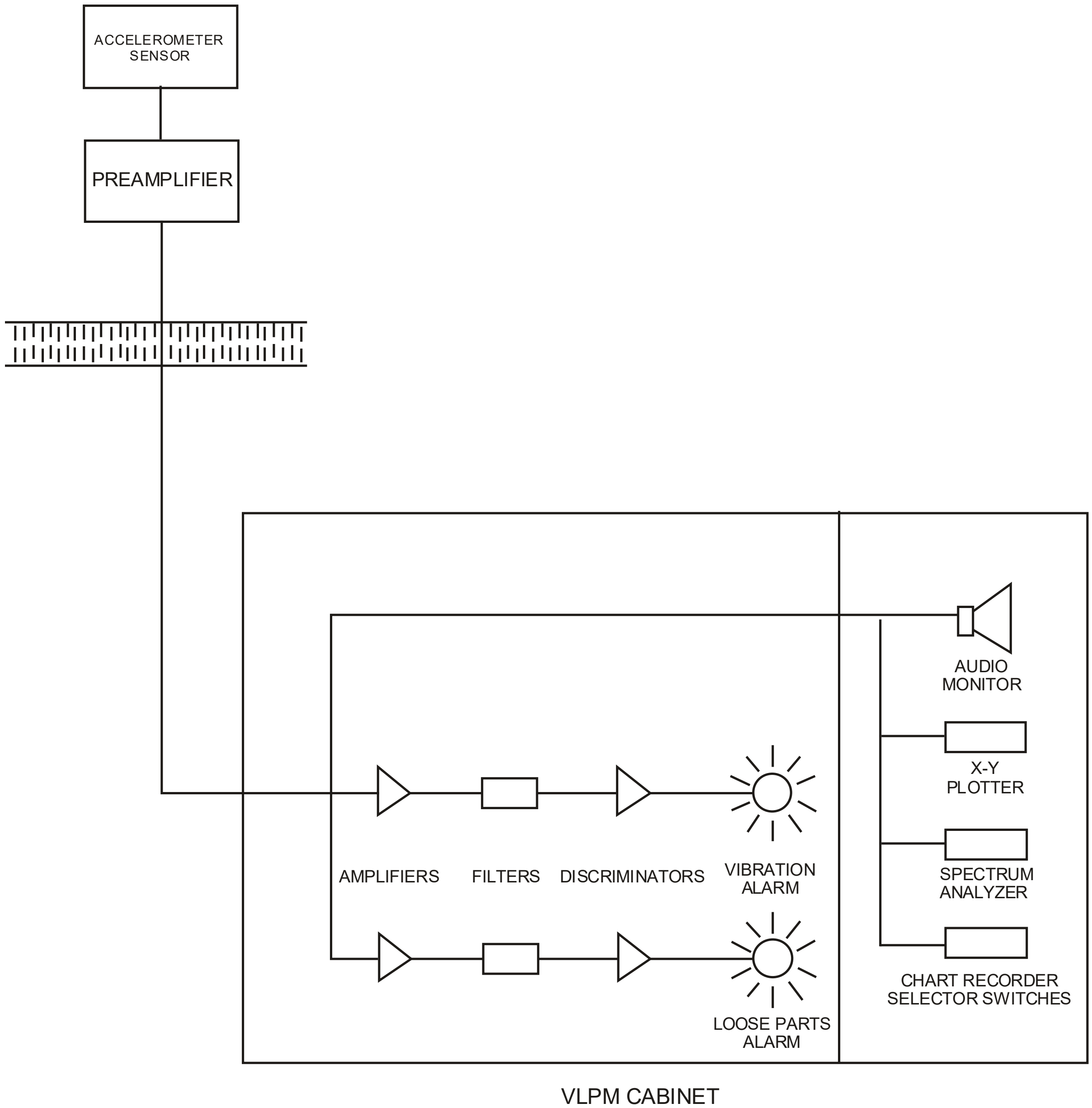


Figure 3.2-23 Vibration and Loose Parts Monitoring System

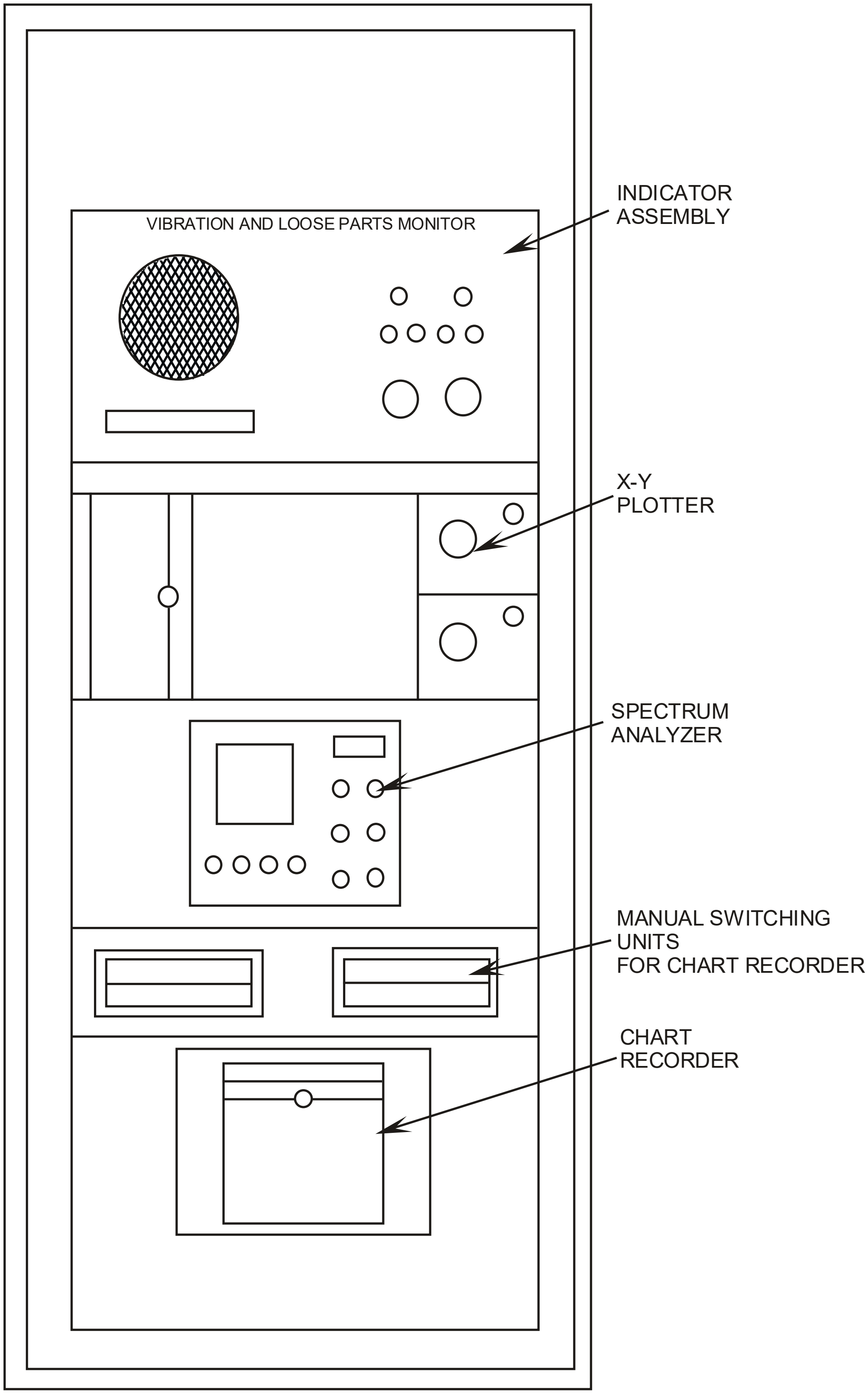


Figure 3.2-24 Vibration and Loose Parts Monitoring Cabinet Arrangement

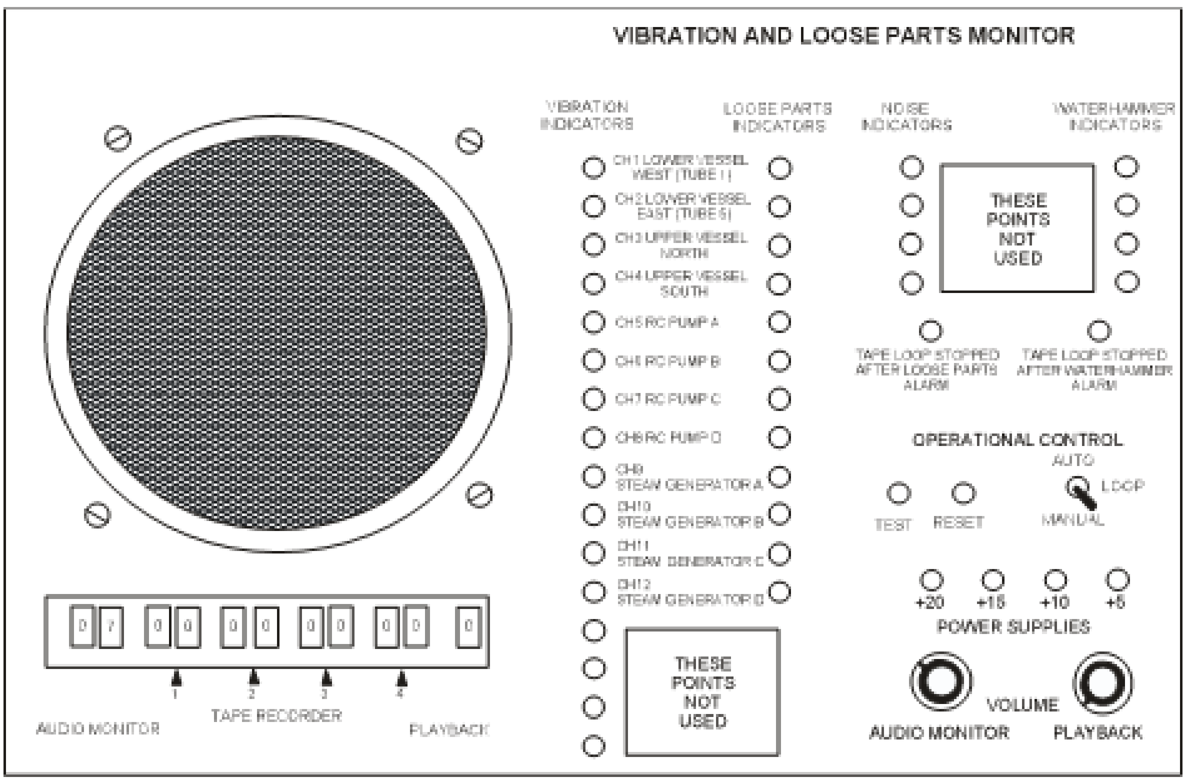


Figure 3.2-25   Vibration and Loose Parts Monitoring Indicator Assembly

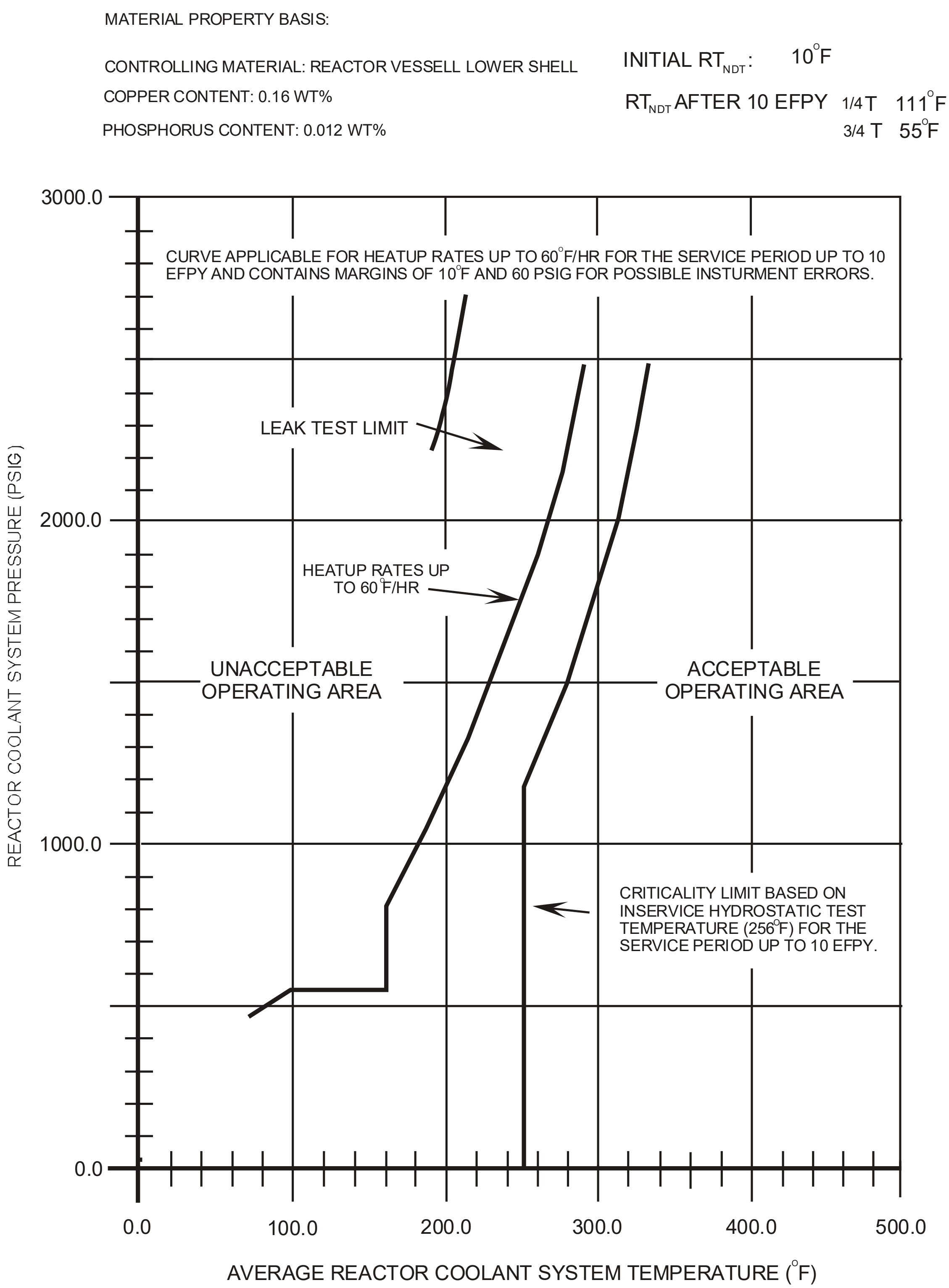


Figure 3.2-26 RCS Pressure-Temperature Limits (Heatup)

Material Property Basis:

Controlling Material: Reactor Vessel Lower Shell
Copper Content: 0.16 WT%
Phosphorus Content: 0.012 WT%

Initial RT_{NDT}: 10°F
RT_{NDT} after 10 EFPY 1/4 T 111°F
3/4 T 55°F

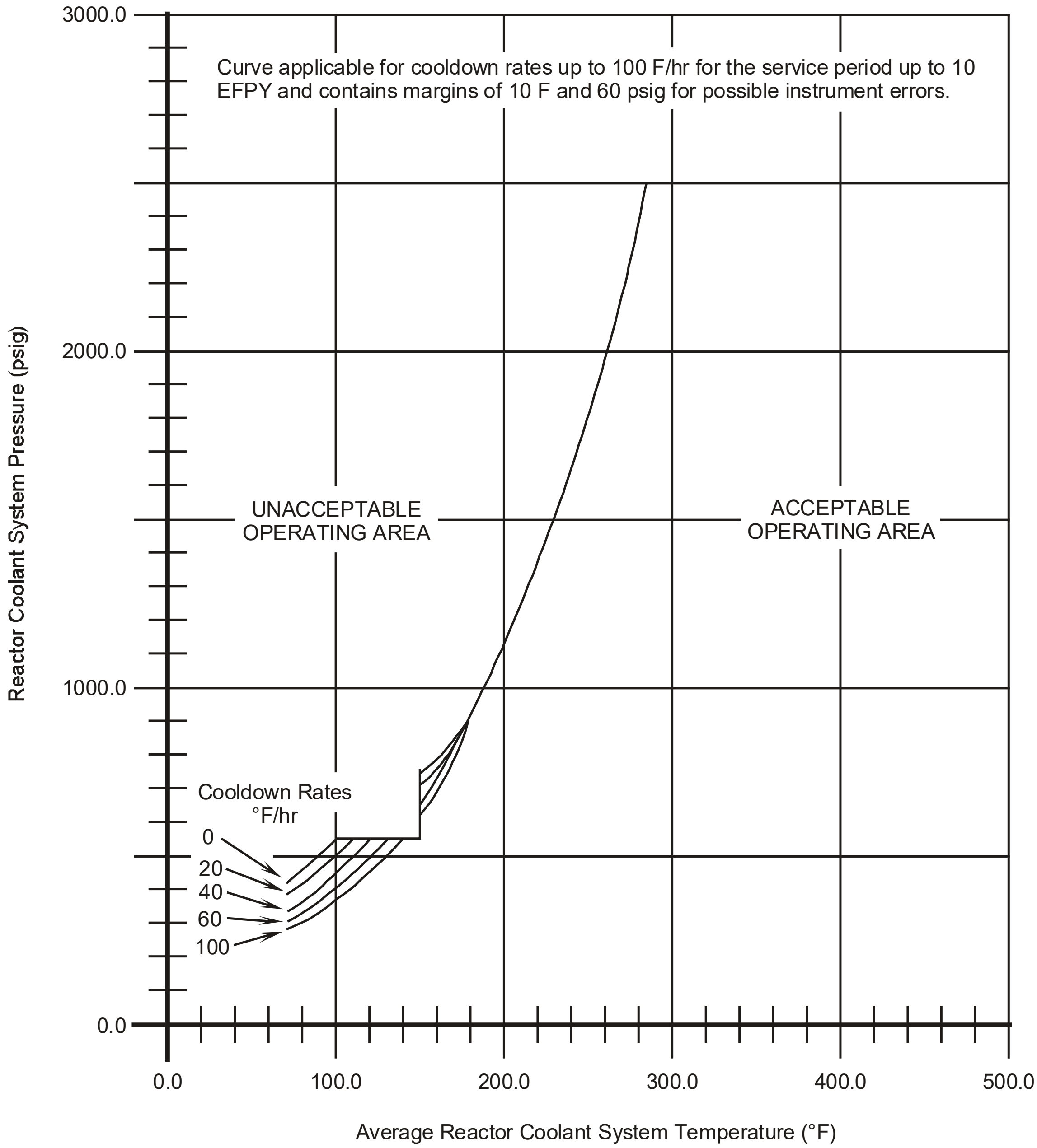


Figure 3.2-27 RCS Pressure-Temperature Limits (Cooldown)

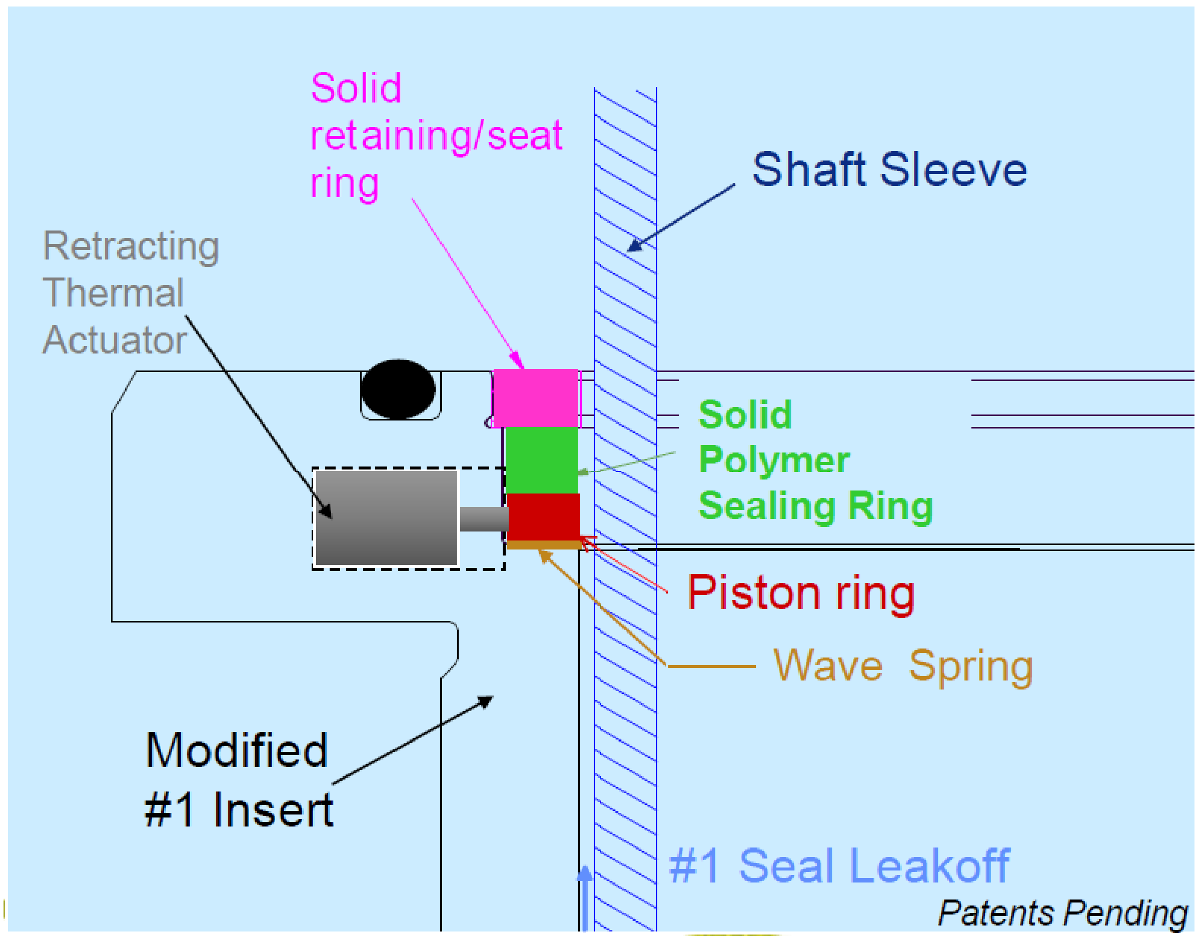


Figure 3.2-28 Westinghouse High Temperature Shutdown Seals (SDS)

Westinghouse Technology Systems Manual

Chapter 4

CHEMICAL AND VOLUME CONTROL

Section

Westinghouse Technology Systems Manual

Section 4.1

Chemical and Volume Control System (CVCS)

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LIST OF FIGURES

4.1 CHEMICAL AND VOLUME CONTROL SYSTEM (CVCS)

Learning Objectives:

1. List the purposes of the Chemical and Volume Control System (CVCS).

2. List in flowpath order and state the purposes of the following major components of the CVCS:

   a. Regenerative heat exchanger
   b. Letdown orifice
   c. Letdown heat exchanger
   d. Demineralizers (ion exchangers)
   e. Letdown filter
   f. Volume control tank (VCT)
   g. Charging pump

3. Identify the components in the CVCS that are used to purify the reactor coolant and the types of contaminants each is designed to remove.

4. Describe how the makeup system is used to borate, dilute, and make up a blended flow of boric acid and primary water to, the reactor coolant system (RCS).

5. Explain why and for what plant conditions the following chemicals are added to the RCS:

   a. Lithium hydroxide
   b. Hydrogen
   c. Hydrazine

6. Describe the emergency boration flow path, and identify the plant conditions which would require its use.

7. State the purpose of the connection between the Residual Heat Removal (RHR) System and CVCS letdown.

8. List the plant operations that result in large amounts of influent into the Boron Recovery System (BRS).

9. Identify the changes in the CVCS that occur upon receipt of engineered safety features actuation signals.

10. Explain how the CVCS is designed to prevent the following:

    a. Flashing and pressure transients in the regenerative and nonregenerative heat exchangers,
    b. Loss of suction to the charging pumps,
    c. High temperature in the letdown ion exchangers (demineralizers), and
    d. Overpressurization of the volume control tank.

11. State when and why excess letdown would be used.

12. List the automatic actions initiated by VCT level instrumentation.

4.1.1 Introduction

The purposes of the Seismic Category I Chemical and Volume Control System are to:

1. CVCS provides means to control the Reactor Coolant System (RCS) soluble chemical neutron absorber concentration (Boric Acid).

The CVCS regulates the concentration of chemical neutron absorber in the reactor coolant to control reactivity changes resulting from the change in reactor coolant temperature between cold shutdown and hot full power operation, burnup of fuel and burnable poisons, and xenon transients. Makeup to the RCS can be supplied at a boron concentration ranging from 0-7000 ppm boron to achieve a desired reactivity change.

(1) The CVCS is capable of borating the RCS through either one of two flow paths and from either one of two boric acid sources. Each source can feed either flow path.

(2) The amount of boric acid stored in the CVCS always exceeds that amount required to borate the RCS to cold shutdown concentration assuming that the rod control cluster assembly (RCCA) with the highest reactivity worth is stuck in its fully withdrawn position. This amount of boric acid also exceeds the amount required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

(3) The CVCS is capable of counteracting inadvertent positive reactivity insertion caused by the maximum boron dilution accident.

2. CVCS maintains the required water inventory in the RCS at programmed level in conjunction with the pressurizer water level control system

The CVCS maintains the coolant inventory in the RCS within the allowable pressurizer level range for all normal modes of operation including startup from cold shutdown, full power operation and Plant cooldown. This system also has sufficient makeup capacity to maintain the minimum required inventory in the event of minor RCS leaks. The eves flow rate is based on the requirement that it permit the RCS to be heated to or cooled from hot standby condition at a rate of 50° F/hr and maintain pressurizer level within the limits of the operating band.

3. CVCS can provide seal-water injection flow to the Reactor Coolant Pump (RCP) shaft seals

The CVCS is able to continuously supply filtered water to each RCP seal, as required by the RCP design.

4. CVCS can add corrosion inhibiting chemicals to the reactor coolant system.

5. CVCS can purify the reactor coolant in order to maintain it within its design activity limits

The CVCS removes fission products and corrosion products from the reactor coolant during operation of the reactor. The CVCS can also remove excess lithium ions from the reactor coolant, keeping the lithium ion concentration within the desired limits for pH control.

The CVCS is capable of removing fission and activation products, in ionic form or as particulates, from the reactor coolant in order to provide access to those process lines carrying reactor coolant during operation and to reduce activity releases due to leaks.

The CVCS provides a means for adding chemicals to the RCS to control the pH of the coolant during initial startup and subsequent operation, scavenge oxygen from the coolant during startup, and control the oxygen level of the reactor coolant due to radiolysis during all operations subsequent to startup. The CVCS is capable of maintaining the oxygen content and pH of the reactor coolant within limits.

6. CVCS provides borated water for emergency core cooling

The centrifugal charging pumps (CCPs) in the CVCS also serve as the high-head safety injection pumps in the ECCS. Other than the CCPs and associated piping and valves, the CVCS is not required to function during a Loss-of-Coolant Accident (LOCA). During a LOCA, the CVCS is isolated except for the CCPs and the piping in the safety injection path.

7. CVCS provides a means of emergency boration of the reactor coolant system.

8. PCVCS can process reactor coolant for the reuse of boric acid and reactor makeup water in the Boron Recovery System (BRS).

9. CVCS can degasify the reactor coolant using the Volume Control Tank (VCT) and Gaseous radwaste or nitrogen purge.

The CVCS system is shown in Figures 4.1-1 through 7. The CVCS consists of several subsystems: the charging, letdown and seal-water system, the chemical control, purification and makeup system, and the boron recovery system. Discussions of these purposes, a system description, and individual component descriptions are contained in subsequent paragraphs of this section.

4.1.2 System Description

The CVCS consists of several subsystems: the charging, letdown and seal-water system, the chemical control, purification and makeup system, and the boron recovery system. The charging and letdown functions of the CVCS are employed to maintain a programmed water level in the RCS pressurizer, thus maintaining proper reactor coolant inventory during all phases of plant operation. This is achieved by means of a continuous feed and bleed process during which the feed rate is automatically controlled based on pressurizer water level. The bleed rate can be chosen to suit various plant operational requirements by selecting the proper combination of letdown orifices in the letdown flow path.

4.1.2.1 Letdown

Reactor coolant is discharged to the CVCS from the reactor coolant loop piping at a point upstream of the Reactor Coolant Pump “C” the intermediate section of the loop 3 cold leg piping. The CVCS letdown path, as shown in Figure 4.1-1, travels through two series letdown isolation valves (LCV 459, 460). The reactor coolant, now referred to as letdown fluid, then flows through a delay pipe to the shell side of the regenerative heat exchanger. The regenerative heat exchanger provides the initial cooling of the letdown fluid while preheating the returning charging flowing inside the tubes of the heat exchanger. From the regenerative heat exchanger, the letdown fluid passes through one or more letdown orifices. The letdown orifice(s) controls the amount of reactor coolant that is let down (removed) from the RCS and provides the initial large pressure reduction. After passing through the regenerative heat exchanger the letdown exits the containment and flows through a containment isolation valve (CV-8152) to the tube side of the letdown heat exchanger where the final cooling of this liquid occurs.

The shell side of the letdown heat exchanger is cooled by the Component Cooling Water (CCW) system. This heat exchanger reduces the letdown fluid temperature to a value that is compatible with the ion exchanger (mixed bed demineralizer) resin. From the letdown heat exchanger, the fluid is delivered to the second pressure reduction performed by the letdown low-pressure control valve (PCV-131). This valve is sometimes referred to as the back-pressure regulator or low-pressure letdown valve. The letdown low-pressure control valve automatically maintains a constant upstream pressure of 340 psig in the section of letdown piping from the orifice outlet to the back-pressure regulating valve to prevent flashing to steam downstream of the letdown orifice valves. The cooled and depressurized letdown is then directed to the mixed-bed demineralizers.

The two mixed-bed demineralizers (ion exchangers) are designed to remove ionic impurities from the reactor coolant. The ion exchangers are called mixed-bed demineralizers because they contain a mixture of anion and cation resins. In addition to the mixed-bed demineralizers, a special-purpose ion exchanger, the cation demineralizer, is used when a reduction in the RCS lithium or cesium concentration is desired. All of the ion exchanger resins are temperature sensitive; therefore, a temperature divert valve (TCV-129) bypasses letdown flow around the ion exchangers if the letdown heat exchanger outlet temperature rises to 137°F.

The next component in the letdown stream is the letdown filter. The reactor coolant filter is located between the demineralizers and the VCT. The filter collects resin fines (broken resin beads) and particulates from the letdown stream. The nominal flow capacity of the filter is equal to the maximum purification flow rate. Two local pressure indicators are provided to show the pressures upstream and downstream of the reactor coolant filter and thus provide filter differential pressure for indication of filter clogging.

The purified, filtered letdown then flows to the volume control tank through a three-way valve. This three-way valve (LCV-112A) diverts the letdown to the Boron Recovery System (BRS) on a high level in the Volume Control Tank (VCT). The VCT completes the portion of the CVCS known as the letdown path.

4.1.2.2 Volume Control Tank

The volume control tank collects the coolant letdown and provides a suction reservoir and head for the charging pumps. The tank is pressurized with hydrogen gas. The letdown flows through the reactor coolant filter and into the VCT through a spray nozzle in the top of the tank. The gas space in the VCT is filled with hydrogen. The partial pressure of hydrogen in the VCT determines the concentration of hydrogen dissolved in the reactor coolant. The partial pressure of hydrogen in the VCT determines the concentration of hydrogen dissolved into the tank contents and later the RCS, so that it can ultimately scavenge oxygen from the coolant in the reactor core at power.

4.1.2.3 Reactor Makeup and Chemical Addition

The Reactor Makeup System (RMS) provides a method of supplying concentrated boric acid, demineralized reactor makeup water, or a mixture of both, to the volume control tank or the charging pump suction header. Chemicals such as zinc, lithium hydroxide and hydrazine may be added to the charging pump suction header via the chemical addition mixing tank (section 4.1.3.2).

4.1.2.4 Charging

The charging portion of the system contains three pumps: two redundant Centrifugal Charging Pumps (CCP) and a Positive Displacement Pump (PDP). When the PDP is selected as the charging pump the flow is controlled by changing the speed of the Positive Displacement Pump. If the CCPs are selected as the charging pump, then the flow is controlled by a discharge valve downstream of the CCPs that is automatically controlled by the Pressurizer Level Control System to maintain pressurizer level (discussed in chapter10.3). Any of the pumps may be used to supply charging; however, a centrifugal charging pump is normally used. In addition to the charging function, the centrifugal charging pumps also serve as the high head safety injection pumps following Emergency Core Cooling System (ECCS) actuation (discussed in chapter 5.2). During normal operation, the charging pumps supply both Reactor Coolant Pump (RCP) seal injection and normal charging requirements.

The seal injection portion of the system consists of seal injection filters and individual flow control valves to supply the required amount of seal injection flow to each Reactor Coolant Pump (RCP). Discussed in Chapter 3.2 RCS, figures 3.2-17 through 3.2-20.

The normal charging header contains a manually set flow control valve (HCV-182) that divides flow between the seal injection header and the charging header. The charging header contains isolation valves to isolate the charging header during accident conditions. Downstream of the charging header isolation valves (MO-8105 and MO-8106) is the tube side of the regenerative heat exchanger, and the three charging paths. The charging paths allow the preheated charging flow to be directed to loop 1 (normal charging), to loop 4 (alternate charging), or to the pressurizer spray line (auxiliary spray).

During normal steady-state operations, letdown is in service through one letdown orifice and a mixed-bed demineralizer, and then to the VCT. This flowpath allows continuous purification of the RCS. From the VCT, reactor coolant is returned to the RCS via the seal injection piping and the normal charging path by one of the charging pumps. Reactor coolant pump seal return flow is routed to the charging pump suction via the seal water heat exchanger.

A flow balance diagram of the CVCS is provided in Figure 4.1-2. Normally operators establish a letdown flow of 75 gpm. The pressurizer level control system (Chapter 10.3) balances this rate of coolant removal from the RCS by maintaining a charging pump discharge flow of 87 gpm, of which 55 gpm returns to the RCS via the normal charging line and 32 gpm flows to the reactor coolant pump (RCP) seals. This division of flow is determined by the position of valve HCV-182. Five gpm per RCP are returned to the RCS via the hydraulic chambers of the RCPs, for an RCS total of 20 gpm. This flow, plus the 55 gpm normal charging, results in a total of 75 gpm returning to the RCS, matching the letdown flow.

A flow balance is maintained on the VCT by the 75 gpm letdown and 12 gpm seal return into the VCT, and the 87 gpm output to the charging pump suctions. In reality, since 3 gph per RCP of the seal injection goes to the liquid waste system, slightly less than the 3 gpm per pump is returned to the VCT. Therefore, the VCT has a normal flow imbalance; that is, less entering the tank than leaving. As a result of this flow imbalance over a time period of several operating shifts, the automatic makeup system to the VCT or manual operator action makes up for this inventory loss.

4.1.2.5 Excess Letdown

Certain plant evolutions, such as RCS heatup or the inoperability of the normal letdown path, may require the use of the excess letdown. At low RCS pressures, when the letdown orifices do not pass their design flows, the excess letdown may be placed in service. Placing excess letdown in service assists the normal letdown system in removing the expansion volume due to the RCS heatup. The amount of water removed via the 1-in. excess letdown line at low pressures is small; it is designed to pass the nominal RCP seal injection flow (20 gpm) at normal RCS pressure. If plant conditions dictate the removal of the normal letdown flow path from service, then excess letdown can be placed in service to balance RCP injection flow.

The excess letdown line consists of a penetration to the loop 3 cold leg piping, an excess letdown heat exchanger with associated inlet and outlet valves, and an excess letdown divert valve. To place excess letdown in service, CCW is supplied to the heat exchanger, and excess letdown flow is established by opening the heat exchanger inlet and outlet valves.

Normally the excess letdown is directed to the CVCS through the reactor coolant pump seal return line. However, the excess letdown divert valve may be positioned to divert flow to the Reactor Coolant Drain Tank (RCDT).

4.1.2.6 Boron Recovery (Recycle) System

The BRS (sometimes called the boron recycle system), as shown in Figure 4.1-3, collects excess borated water resulting from certain plant operations. In each of these operations, the excess reactor coolant is diverted from the CVCS letdown line to the recycle holdup tanks as a result of a high level in the volume control tank. The following operations result in borated water being diverted to the BRS:

1. Dilution of reactor coolant to compensate for core burnup,
2. Load follow operations,
3. Heatup of the RCS from cold shutdown to hot standby, and
4. Refueling operations.

HUT: Three holdup tanks are provided to contain radioactive liquid which is diverted from the letdown line. The liquid is released from the RCS during startup, shutdowns, load changes and from boron dilution to compensate for burnup. The contents of one tank are normally being processed by the evaporator train while another tank is being filled. The third tank is normally kept empty to provide additional storage capacity when needed. Each tank is provided with level instrumentation. Both high- and low-level alarms are indicated.

Excess liquid effluents containing boric acid flow from the RCS through the letdown line are collected in the austenitic stainless steel Hold Up Tanks (HUT). The three holdup tanks have a design pressure of 15 psig, a design temperature of 200°F and a capacity of 64000 gallons each. Normal operating pressure in the holdup tanks is 0.5-3 psig.   Each tank has its own pressure transmitter. The transmitters provide an alarm and pump interlock function to prevent pumping the tanks down to a low-pressure condition which could cause their collapse.

The tanks are provided with gas-sample points, relief valves to prevent over pressurization and drain connections and connections which provide suction to the gas stripper feed pumps and the recirculation pump. The vapor spaces are interconnected to the suction of the waste gas compressors.

As this liquid enters the holdup tanks and the level rises, nitrogen cover gas is displaced to the waste gas decay tanks in the gaseous waste disposal system. The concentration of boric acid in the holdup tanks varies throughout core life from the just-after-refueling concentration of 2000 ppm to essentially zero ppm at the end of the core cycle. A holdup tank recirculation pump is provided to transfer liquid between the holdup tanks. After a certain amount of fluid has been collected, the liquid effluent in the holdup tanks will be processed in a batch operation.

GAS STRIPPER FEED PUMPS: Two centrifugal austenitic stainless-steel gas stripper feed pumps supply feed from the holdup tanks, through the evaporator feed ion exchangers or demineralizers, to the gas stripper boric acid evaporator packages. The non-operating pump is a standby and is available for operation in the event the operating pump malfunctions.

EVAPORATOR FEED ION EXCHANGERS: Three flushable demineralizers remove anions and cations (primarily cesium and molybdenum) from the holdup tank effluent. Two of the demineralizers are operated in series with the third serving as a standby. The first demineralizer and its standby contain a mixed-bed resin of hydrogen-type cation resin and hydroxyl-type anion resin. The resin in the second demineralizer is a hydrogen-form cation resin.

Series operation is recommended to ensure prevention of breakthrough of cesium in the event of operation with I-percent defects. If fuel defects are small, one demineralizer can be employed. The design flow rate is equal to the rated flow of both evaporator and gas stripper packages; however, this flow can be increased by implementation of a manual bypass (miniflow line) located downstream of the demineralizers which recycles to the holdup tanks.

GAS STRIPPER BORIC ACID EVAPORATOR PACKAGE: Two gas stripper-boric acid evaporator packages are provided. Each package will process 15 gprn of dilute radioactive boric acid and produce distillate and approximately 4 wt% of concentrated boric acid stripped of hydrogen. nitrogen. and radioactive gases. Each package consists of a feed preheater, stripping column, vent condenser. evaporator, absorption tower, evaporator condenser, distillate cooler. distillate pumps. boric acid concentrates pumps and associated piping. valves and instrumentation. Radioactive gas stripping is achieved by passing heated feed through packed towers employing stripping steam which removes nitrogen, hydrogen and fission gases from the feed.

GAS STRIPPER COLUMN: After passing through a preheater, the fluid enters the stripper column of the evaporator (Figure 4.1-4), where dissolved gasses are removed from the liquid. These gases are vented through the vent condenser to the waste gas disposal system. The liquid effluent from the stripper column enters the evaporator section, where the evaporator separates the fluid into water vapor and a concentrated boric acid solution. The water vapor rises through the absorption tower, where any boric acid or gas carryover is absorbed by the recirculated condensate (reflux) flow and returned to the evaporator section.

After stripping. the feed enters the evaporator where it is evaporated by a submerged steam tube bundle. The vapors leaving the boiling pool are stripped of entrained liquid and volatile boron by passing through an absorption tower. Pure vapors are then condensed in the condenser section and pumped from the system. The evaporator bottoms are continuously recirculated by one of the boric acid concentrates pumps. When the desired concentration is reached in the boiling pool, the concentrates are pumped from the system. All evaporator equipment is constructed of austenitic stainless steel.

Each gas stripper boric acid evaporator package has a design feed (RCS) flow of 15 gpm, a design condensate (PMW) flow of 15 gpm, and a design concentrates (4% boric acid solution) of 40 gpm, The concentrates filter is a disposable synthetic cartridge type with a design pressure of 200 psig, a design temperature of 250°F, a design flow of 35 gpm and a design maximum pressure drop of 70 psig through the austenitic stainless steel vessel.

The remaining water vapor is condensed in the evaporator condenser and pumped through an evaporator condensate demineralizer (Figure 4.1-3) and a condensate filter to one of two monitor tanks. The evaporator condenser is serviced by component cooling water on the tube side and the component cooling water flow is controlled by the distillate flow. The evaporator is tube side steam heated and steam flow *is* controlled by evaporator pressure.

The two flushable anion evaporator condensate demineralizers can be used to remove any boric acid contained in the evaporator condensate. Their capacity is based on a maximum design carryover of 10-ppm boron in the distillate. Each demineralizer is sized for the throughput of both evaporators and will be employed only when carryover is unacceptably high. The evaporator condensate demineralizer has a design pressure of 200 psig, a design temperature of 250°F, a design flow of 72 gpm, and the austenitic stainless-steel vessel can hold 30 ft^3 of resin. The normal flow through the evaporator condensate demineralizer 20 ft^3 anion bed is 30 gpm at 130°F at -50 psig.

The condensate filter collects resin fines and particulates from the boric acid evaporator condensate streams. Local pressure indicators indicate the pressure upstream and downstream of the filter and thus provide filter differential pressure.

The condensate is accumulated in the monitor tanks and sampled before it is moved. Two monitor tanks permit continuous operation of the evaporator trains. When one tank is filled, the contents are analyzed and either reprocessed, discharged to the waste disposal system, or pumped to the primary makeup water storage tank.

The two austenitic stainless-steel diaphragm monitor tanks have a capacity of 21,600 gallons each normally at 130°F. Each tank is provided with level instrumentation, with both high- and low-level alarms indicated.

The two monitor tank squirrel cage induction drip proof centrifugal pumps are made of austenitic stainless-steel and have a design pressure of 150 psig, a design temperature of 200°F, and a flow of 150 gpm. Normally one pump is in service and one pump is in standby. Primary makeup water discharge from the monitor tanks may be pumped to any one of the following places.

1. Primary water storage tank,
2. Lake discharge tank,
3. Holdup tanks,
4. Evaporator condensate demineralizers, or
5. Liquid waste system.

The concentrated boric acid solution originally in the evaporator section remains as the bottoms of the distillation process and is concentrated to approximately four weight percent boric acid. Boric acid evaporator bottoms are sampled and, if analysis indicates that the solution meets specifications for use as boric acid makeup, the solution is sent to the boric acid tanks via the concentrates filter and concentrates holding tank. The concentrates filter removes particulates from the boric acid evaporator concentrates. The design flow rate is compatible with the rated flow of the boric acid evaporator concentrates pump. Local pressure indicators indicate the pressure upstream and downstream of the filter and thus provide filter differential pressure.

The concentrates holding tank is sized to hold the production of concentrates from one batch of evaporator operation. The concentrates holding tank holds up to 1000 gallons of 4% boric acid solution normally at 150°F. The tank is supplied with an electrical heater which prevents boric acid precipitation and is constructed of austenitic stainless-steel. Temperature instrumentation provides both high and low temperature alarms at the Auxiliary Building control board. Water level is also indicated with high- and low-level alarms provided.

The centrifugal holdup tank recirculation pump has a design pressure of 150 psig, a design temperature of 200°F, and a design flow of 500 gpm reactor coolant.

Otherwise, the concentrates are returned to the holdup tanks for reprocessing or are pumped to the liquid waste system. The two canned centrifugal concentrates holding tank transfer pumps have a design flow of 40 gpm, a design temperature of 250°F, a design pressure of 100 psig, and are austenitic stainless steel to pump 4% boric acid solution. The pumps are sixed to empty the tank in about 30 minutes.

4.1.3 Component Descriptions

4.1.3.1 Letdown Components

Letdown Isolation Valves

The letdown isolation valves (LCV-459 and LCV-460) automatically isolate the letdown flow when pressurizer level decreases to the low level (17%) setpoint. An interlock prevents opening or closing these valves unless all three letdown orifice isolation valves are closed. This feature prevents depressurization of the letdown piping which contains the regenerative heat exchanger.

Letdown Delay Pipe

A long section of larger diameter pipe results in a coolant transport time sufficient to allow most of the highly radioactive nitrogen-16 to decay before the letdown flow exits the containment.

Regenerative Heat Exchanger

The regenerative heat exchanger is designed to recover heat from the letdown flow by reheating the charging flow, which reduces thermal shock on the charging penetrations into the reactor coolant loop piping. The regenerative heat exchanger is an austenitic stainless-steel, tube-and-shell heat exchanger with RCS letdown flow on the shell side and CVCS charging flow through the tubes.

The letdown stream flows through the shell of the regenerative heat exchanger and the charging stream flows through the tubes. The unit is constructed of austenitic stainless-steel and is of all welded construction.

The regenerative heat exchanger has a tube side design pressure of 2735 psig and design temperature of 650°F with a design heat duty of 10.35×10^6 Btu/hr. The tube side has a design operating inlet temperature of 130°F with a design operating outlet temperature of 495°F and a design operating flow of 21,170 lb/hr. The shell side has a design operating inlet temperature of 545°F with a design operating outlet temperature of 290°F and a design operating flow of 37,050 lb/hr. The design shell side pressure is 2485 psig.

The first stage of letdown cooling is performed by the charging flow. The removal of heat from the letdown drops its temperature from 550°F to 290°F and preheats the charging stream from 130°F to 500°F. This helps conserve energy and minimizes thermal stresses to the charging nozzles.

The temperatures of both outlet streams from the heat exchanger are monitored with indication given in the control room. High alarm is given on the main control board if the temperature of the letdown stream exceeds desired limits.

Letdown Orifices and Letdown Orifice Isolation Valves

The three letdown orifices are arranged in parallel and serve to reduce the pressure of the letdown stream to a value compatible with the letdown heat exchanger design. Two of the three are sized such that either can pass normal letdown flow; the third can pass less than the normal letdown flow. One or both standby orifices may be used with the normally operating orifice in order to increase letdown flow such as during reactor heatup operations. This arrangement also provides a full standby capacity for control of letdown flow. Orifices are placed in and taken out of service by remote manual operation of their respective isolation valves. A flow monitor provides indication in the control room of the letdown flow rate and high alarm to indicate unusually high flow. A low-pressure letdown controller controls the pressure downstream of the letdown heat exchanger to prevent flashing of the letdown liquid. Pressure indication and high-pressure alarm are provided on the main control board.

The three orifices provided to control letdown flow are austenitic stainless-steel designed for 2485 psig and 650°F. Design pressure drop for all three is 1900 $\pm$100 psi. Two of these orifices pass 75 gpm each at an RCS pressure of 2235 psig. The third orifice is rated at 45 gpm. Normally one of the two 75-gpm orifices is in service. If extra purification flow is desired, or additional letdown flow for boron concentration changes is required, the 45-gpm orifice may be placed in service. Ion exchanger flow limitations (127 gpm maximum), which are administratively maintained, preclude placing both 75 gpm orifices in service at normal system pressure.

Remotely operated letdown orifice isolation valves are located downstream of the letdown orifices. These valves are interlocked as follows:

1. The letdown orifice isolation valves automatically close on low pressurizer level. These valves and the letdown isolation valves redundantly isolate letdown.

2. At least one charging pump must be running in order to open any letdown orifice isolation valve. If the running charging pump(s) is lost, then the letdown orifice isolation valves close. This interlock ensures that cooling water (charging) is available to the regenerative heat exchanger prior to the establishment of letdown flow.
3. The letdown isolation valves (LCV-459 and LCV-460) must be open prior to opening the letdown orifice isolation valves. This interlock prevents depressurization of the letdown line.
4. The letdown orifice isolation valves automatically close on receipt of a containment isolation phase A signal.

The interlocks associated with the letdown isolation valves and the letdown orifice isolation valves mandate a specific order of operation when placing the CVCS in service. First, a charging pump is started. Next, the letdown isolation valves are opened. Finally, a letdown orifice isolation valve is opened.

Containment Isolation Valve

The containment isolation valve (CV-8152) is a remotely operated isolation valve that provides redundant isolation of letdown flow, along with the orifice isolation valves, on receipt of a Containment Isolation Signal Phase A (CISA).

Letdown Heat Exchanger

The letdown heat exchanger cools the letdown stream to the operating temperature of the mixed-bed demineralizers. This heat exchanger is of the tube-and-shell design, with reactor coolant letdown flowing through its austenitic stainless-steel tubes and Component Cooling Water (CCW) flowing through its carbon steel shell.

With a design heat duty of 4.61 x 10^6 Btu/hr the letdown heat exchanger has a tube side (RCS) design pressure of 2485 psig and a design temperature of 650°F. The tube side design operating flow is 12,380 lb/hr with a design operating inlet temperature of 545°F and a design operating outlet temperature of 195°F. The letdown heat exchanger shell side (CCW) has a design pressure of 150 psig and a design temperature of 250°F. The shell side has a design operating flow of 492,00 lb/hr with a design operating inlet temperature of 95°F and a design operating outlet temperature of 125°F.

The component cooling water outlet valve is a modulating valve; its position is controlled by the letdown outlet temperature control. The normal controller setpoint is 120°F. If the controller is in automatic and the letdown outlet temperature increases, then the letdown heat exchanger component cooling water outlet valve opens to increase cooling flow. Conversely, if temperature decreases, component cooling water flow through the letdown heat exchanger decreases.

The letdown temperature control indicates and controls the temperature of the letdown flow exiting from the letdown heat exchanger. The temperature sensor, which is part of the CVCS, provides input to the controller in the CCW system. The exit temperature is controlled by regulating the component cooling water flow through the letdown heat exchanger by using the control valve located in the component cooling water discharge line. Temperature indication is provided on the main control board. If the temperature of the letdown stream exceeds ~137.5°F, the flow is diverted to the VCT in order to avoid damaging the resin in the mixed-bed or cation demineralizers.

Letdown Low-Pressure Control Valve (Back Pressure Regulating Valve)

The pressure relief valve downstream of the letdown orifices protects the low-pressure piping and the letdown heat exchanger from overpressure when the low-pressure piping is isolated. The capacity of the relief valve exceeds the maximum flow rate through all letdown orifices. The valve set pressure is equal to the design pressure of the letdown heat exchanger tube side.

In order to prevent the letdown fluid from flashing to steam upstream of the letdown heat exchanger, a high pressure must be maintained until the letdown temperature is reduced. The required pressure is maintained by the letdown low-pressure control valve (PCV-131). A PID controller receives an input from a pressure transmitter downstream of the letdown heat exchanger and compares this pressure with an adjustable setpoint (normally 340 psig). The controller modulates the pressure control valve to maintain letdown system pressure between the outlet of the orifice and the inlet of the back pressure regulating vale at a setpoint above flashing.

The pressure relief valve downstream of the low-pressure letdown valve protects the low-pressure piping. demineralizers. and filter from overpressure when this section of the system is isolated. The overpressure may result from leakage through the low-pressure letdown valve. The capacity of the relief valve exceeds the maximum flow rate through all letdown orifices. The valve set pressure is equal to the design pressure of the demineralizers.

Temperature Divert Valve

The temperature divert valve (TCV-129) is a three-way valve. In the normal position, the temperature divert valve directs letdown flow to the mixed-bed demineralizers; in the bypass position, letdown flow is diverted around the demineralizers. Demineralizer efficiency is reduced and resin-bed lifetime is shortened by high temperatures. The position of the temperature divert valve is determined by the letdown temperature at the outlet of the letdown heat exchanger. The temperature divert valve directs flow to the demineralizers when the temperature is less than 137°F. When the letdown heat exchanger outlet temperature reaches 137°F, the temperature divert valve automatically bypasses letdown flow around the demineralizers. The valve can also be manually operated from the main control board. The operator can select either the normal or the divert position. Once the divert valve has been automatically shifted to the divert position, operator action is required to return the valve to its normal position.

Letdown Line Overpressure Protection

Two relief valves are installed to prevent overpressurization of the letdown piping. The first relief valve is located downstream of the letdown orifices; it prevents overpressurization of the piping between the orifices and the letdown pressure control valve. The valve has a setpoint of 600 psig, and has a capacity equal to the flow through all three letdown orifices (195 gpm). The valve discharges to the pressurizer relief tank (PRT). The second relief valve is located downstream of the letdown pressure control valve and protects the ion exchangers, letdown filter, and low pressure letdown piping from overpressurization. This valve is set at 285 psig, and also has a capacity equal to the flow through all three letdown orifices. This valve discharges to the VCT.

Mixed-Bed Demineralizers

Two mixed-bed demineralizers are installed to remove ionic impurities from the coolant letdown from the RCS. The demineralizers are called "mixed bed" because both anion resins (remove negatively charged ions) and cation resins (remove positively charged ions) are contained in the same vessel.

Each of the stainless-steel demineralizer vessels has a capacity of 30 ft^3 of resin with a design flow of 109 gpm, a design pressure of 200 psig, and a design temperature of 250°F. During normal operations, one mixed-bed demineralizer will be in service with flow of 75 gpm at about 127°F and <150 psig while the other bed is in standby. The minimum design decontamination factor (input activity/output activity) for the resin beds is ten. Since each cubic foot of resin contains millions of beads, the ion exchangers are also very effective mechanical filters. Either Li-OH or H-OH resin may be used in the mixed-bed demineralizers.

Two flushable mixed-bed demineralizers assist in maintaining reactor coolant purity. A lithium-form cation resin and hydroxyl-form anion resin are charged into the demineralizers. Both forms of resin remove fission and corrosion products. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream except for cesium, yttrium and molybdenum by a minimum factor of 10.

The design life of the resin in the mixed bed demineralizers is one core cycle. One deminera1izer serves as a standby unit for use if the operating demineralizer becomes exhausted during operation. The vessels, constructed entirely from austenitic stainless-steel, are provided with connections for resin addition, replacement, flushing, and draining. The resin fill tank is used to charge fresh resin to the demineralizers. The tank has a conical bottom connecting to a line with a dump valve. This line may be connected to the fill line of each demineralizer. Demineralized water is added to the tank to produce a resin slurry which can then be sluiced from the tank into a demineralizer by opening the dump valve.

A temperature sensor measures temperature of the letdown flow downstream of the letdown heat exchanger and controls the letdown flow to the mixed-bed demineralizers by means of a three-way valve. If the letdown temperature equals or exceeds 137°F, the flow is automatically bypassed around the demineralizers to the VCT in order to protect the resin from a high temperature condition which would destroy the effectiveness of the resin. Temperature indication and high alarm are provided on the main control board. The air-operated three-way valve failure mode directs flow to the VCT.

Cation Demineralizer

During power operations, lithium is formed from the boron-neutron reaction. This extra lithium could result in excessively high pH values in the RCS. One of the purposes of the cation demineralizer is to remove excess lithium. This demineralizer is placed in service as needed to maintain the coolant lithium concentration within limits. In the event of fuel clad failure, the cation demineralizer can also remove fission-product ions, especially cesium, from the letdown stream.

As its name implies, the cation ion exchanger contains only cation-type resin. The cation demineralizer has a capacity of 30 ft^3 of resin with a design pressure of 200 psig, a design temperature of 250°F, and a design flow of 72 gpm. Normal flow is 75 gpm at 127°F and <150 psig through the austenitic stainless-steel vessel.

A flushable cation resin bed in the hydrogen form is located downstream of the mixed-bed demineralizers and is used intermittently to control the concentration of Li-7 which builds up in the coolant from the B-10 (n, α)-Li-7 reaction. The demineralizer also has sufficient capacity to maintain the Cs-137 concentration in the coolant below 1.0 ~Ci/cc with l-percent defective fuel. The resin bed is designed to reduce the concentration of ionic isotopes, particularly cesium, yttrium, and molybdenum by a minimum factor of 10.

Ion Exchanger Filter

The ion exchanger filter is the disposable synthetic cartridge type inside an austenitic stainless-steel vessel with a design pressure of 200 psig and a design temperature of 250°F. The filter design flow is 35 gpm with a maximum pressure drop of 70 psig.

VCT Level Divert Valve

Surges in RCS inventory due to load changes are accommodated for the most part in the pressurizer. The VCT provides surge capacity for reactor coolant expansion not accommodated by the pressurizer. When the level in the tank reaches the high-level setpoint, the remainder of the expansion volume is accommodated by diversion of the letdown stream to the holdup tanks.

If the VCT level rises above the normal operating range, one channel provides an analog signal to a proportional controller which modulates the three-way valve downstream of the reactor coolant filter to divert a portion of the letdown to the holdup tanks in the boron recovery system to maintain the VCT level within the normal operating band. The three-way valve can split letdown flow so that a portion goes to the holdup tanks and a portion to the VCT. The controller would operate in this fashion during a dilution operation when primary makeup water is being fed to the VCT from the reactor makeup control system.

If the modulating function of the channel fails and the VCT level continues to rise, then the high-level alarm in the control room will alert the operator to the malfunction and the letdown flow can be manually diverted to the holdup tanks. If no action is taken by the operator and the tank level continues to rise, the letdown flow will be automatically diverted to protect the tank from an overpressure condition.

The level divert valve (LCV-112A) is a three-way valve controlled by volume control tank level. An operator-adjusted VCT level setpoint is compared with actual VCT level. If actual tank level exceeds the setpoint, then LCV-112A begins to divert a portion of the letdown flow to the BRS holdup tanks. As the level error increases, an increased amount of letdown is diverted. With decreased flow into the VCT (due to partial diversion of letdown flow) and normal charging outflow, the VCT level drops. As VCT level drops, the amount of letdown diverted to the holdup tanks decreases. This action continues until the level setpoint is again reached. At or below the begin-divert setpoint, LCV-112A is automatically positioned to direct all letdown flow to the VCT.

Backup level control from a redundant VCT level transmitter is provided in the case of normal controller failure. In the backup control mode, if VCT level reaches the high level alarm setpoint, LCV-112A diverts all letdown flow to the BRS. The level divert valve can also be operated from the main control board. The operator can select either the normal or the divert position. If the divert position is selected the valve will go to full divert, with no flow being supplied to the VCT.

Volume Control Tank (VCT)

The VCT provides surge capacity for part of the reactor coolant expansion volume not accommodated by the pressurizer. If the level in the pressurizer is above its setpoint, then CVCS charging flow is reduced. Reduced charging flow and constant letdown flow restore pressurizer level to normal. The mass removed from the RCS to lower pressurizer level results in an increased VCT level. Conversely, if the level in the pressurizer is below its setpoint, then the charging flow is increased. Increased charging flow and constant letdown flow raise pressurizer level to its normal setpoint. The water required to raise the pressurizer level comes from the VCT. Pressurizer level control is discussed in Section 10.3.

If the level in the pressurizer is above its setpoint, then CVCS charging flow is reduced. Reduced charging flow and constant letdown flow restore pressurizer level to normal. The mass removed from the RCS to lower pressurizer level results in an increased VCT level. Conversely, if the level in the pressurizer is below its setpoint, then the charging flow is increased. Increased charging flow and constant letdown flow raise pressurizer level to its normal setpoint. The water required to raise the pressurizer level comes from the VCT resulting in a low VCT level.

Low level in the VCT initiates makeup from the reactor makeup control system. If the reactor makeup control system does not supply sufficient makeup to keep the VCT level from falling to a lower level, an emergency low-level signal causes the suction of the charging pumps to be transferred to the Refueling Water Storage Tank (RWST).

DEGAS: It *also* provides a means of introducing hydrogen into the coolant to maintain the required equilibrium concentration of 25 to 35 cc hydrogen/kg of water and is used for degassing the reactor coolant and serves as a head tank for the charging pumps. A spray nozzle located inside the tank on the letdown line nozzle provides liquid-to-gas contact between the incoming fluid and the hydrogen atmosphere in the tank. A hydrogen overpressure is maintained in the volume control tank. The letdown flow enters the VCT through a spray nozzle and absorbs the hydrogen gas. When this fluid reaches the reactor core, radiation causes the combination of the excess hydrogen with any free oxygen to form water.

For degassing, the tank is provided with a remotely operated solenoid valve backed up by a pressure control valve which ensures that the tank pressure does not fall below minimum operating pressure 15 pounds per square inch gauge (psig) during degassing to the waste disposal system. Relief protection, gas space sampling, and nitrogen purge connections are also provided. The tank also accepts the seal-water return flow from the RCPs. This flow may alternately go directly to the suction of the charging pumps. Relief discharges from the letdown line and the seal-water return line go to this tank.

The following list contains additional penetrations into the VCT:

1. Nitrogen supply - This tap shares a VCT penetration with the plant hydrogen system. Nitrogen may be used to purge hydrogen and fission gasses from the VCT during periods of shutdown or maintenance. Nitrogen is not added during power operations because of possible nitric acid formation in the RCS.
2. VCT vent - This connection is used to vent fission gasses and hydrogen from the VCT gas space to the waste gas system. The vent line contains a remotely operated solenoid valve and a pressure regulating valve. The pressure regulating valve senses VCT pressure and closes if pressure drops to 15 psig, to ensure an adequate net positive suction head (NPSH) for the charging pumps.
3. VCT relief valve - The VCT relief valve line shares a penetration with the VCT vent. The relief valve provides overpressure protection for the tank. The valve relieves at 75 psig and discharges to the recycle holdup tanks.
4. RCP seal return line – This penetration allows the seal return from the reactor coolant pumps to be directed to the VCT. However, the seal return is normally aligned directly to the charging pump suction.

The VCT is made of austenitic stainless steel with a normal operating pressure of 15-60 psig and 127°F. The VCT has a capacity of 2992 gallons with a design pressure of 75 psig and 250°F. The VCT assists the pressurizer with RCS volume changes, provides an interface with the RMS (Section 4.1.3.2), provides a means of hydrogen addition to the RCS, and allows for RCS degasification.

The VCT pressure and temperature are monitored with indication provided in the control room. Alarms for high- and low-pressure conditions and for high temperature are located in the control room. Two level channels govern the water inventory in the VCT. These channels provide local and remote level indication, level alarms, level control, makeup control, and emergency makeup control.

The relief valve on the VCT permits the tank to be designed for a lower pressure than the upstream equipment. This valve has a capacity greater than the summation of the following items: maximum letdown flow, excess letdown flow, RCP normal seal water return flow from three RCPs, maximum leakage from one RCP floating ring seal and makeup water system flow, plus margin. The valve set pressure equals the design pressure of the VCT.

VENTING: As the letdown is depressurized through the spray nozzle in the VCT, dissolved fission-product gases come out of solution and collect in the VCT. Degasification of the RCS is accomplished by opening the VCT vent to the waste gas system and dropping the VCT pressure. When pressure reaches 15 psig, the vent is closed. VCT level is increased to compress the gasses, and again the VCT vent is opened until the pressure drops to 15 psig. During venting operations, letdown flow is manually diverted to the holdup tanks until the automatic makeup point is reached. This decrease in VCT level allows a volume for the accumulation of hydrogen and fission gasses from the reactor coolant. When the automatic makeup setpoint is reached, letdown flow is manually returned to the VCT. The level oscillations and venting operations are continued until the desired gas concentration is reached.

4.1.3.2 Reactor Makeup System Components

As stated in section 4.1.2.3, the RMS provides a method of supplying concentrated boric acid, demineralized reactor makeup water, or a mixture of both to the VCT or to the charging pump suction. The reactor makeup system can also supply borated water to the refueling water storage tank (RWST), the spent fuel pool, and the waste holdup tanks. The system consists of storage tanks, transfer pumps, and associated pipes and valves. The reactor makeup system is illustrated in Figure 4.1-5.

Primary Water Storage Tank

The primary water storage tank provides a source of demineralized water for the RMS. This 203,000-gal tank may be filled with water from the plant secondary makeup system or with distillate from the boric acid evaporators. Demineralized water is transferred from the primary water storage tank by one of the two primary water transfer pumps.

Boric Acid Tanks

Two 4% boric acid tanks are located in the auxiliary building normally operating at 0-7 psig and a minimum temperature of 65°F. Each boric acid tank is constructed of austenitic stainless steel and has a capacity of 24,228 gallons with a design pressure of 15 psig and a design temperature of 250°F. The concentration of the stored boric acid is between 4 and 4.4 weight percent (7000 ppm). The boric acid is maintained in solution by maintaining the room temperature above 65°F. A major advantage of this system over the 12 weight percent systems found at some plants is that special heat tracing is not required for the 4-weight percent solution.

A temperature sensor provides a temperature measurement of each tank's contents. Local temperature indication is provided as well as high and low temperature alarms which are indicated on the main control board. Two level detectors indicate the level in each boric acid tank. Level indication with high-; low-, and low-low level alarms is provided on the main control board. The low alarm is set to indicate the minimum level of boric acid in the tank to ensure sufficient boric acid to provide for a cold shutdown with one stuck rod.

The Technical Requirements Manual for the plant requires a minimum volume of 15,900 gal of 7,000-ppm borated water from the boric acid tanks to ensure a shutdown margin from all operating conditions of 1.0 %ΔK/K after xenon decay and cooldown to cold shutdown (< 200°F). The limiting operating conditions for this requirement occur with the plant at full power with an equilibrium xenon concentration and at the end of its fuel cycle.

A boric acid tank may be filled with a solution from the boric acid batch tank or with boric acid evaporator concentrates. As shown in Figure 4.1-5, the RMS is normally aligned so that the contents of one boric acid tank are supplied by its associated boric acid transfer pump to the charging pump suction during RMS operation. The contents of the other tank are recirculated by its associated pump to minimize boric acid stratification in that tank.

Boric Acid Batch Tank

The batch tank is made of austenitic stainless steel with a capacity of 400 gallons. The batch tank is used for mixing the makeup supply of boric acid solution for the boric acid tanks. A local sampling point is provided for verifying the solution concentration prior to transferring it out of the tank. The tank is provided with an agitator to improve mixing during batching operations. The tank is provided with a steam-heated jacket, whose area is sufficient to heat the tank from ambient temperature to 165°F within 3 hours when employing process saturated steam at 50 psig. The tank is provided with drain connections, a fill line for demineralized water, and a screen-protected filling nozzle for introduction of boric acid crystal.

The mixing evolution consists of heating the required volume of demineralized water to a temperature above the saturation temperature for the boric acid concentration to be mixed, adding the correct amount of boric acid crystals, and agitating the mixture with an electric-driven agitator. The concentrated boric acid mixture is transferred to one of the boric acid tanks by one of the boric acid transfer pumps.

Boric Acid Transfer Pumps

The two horizontal, centrifugal, single-speed electric-driven pumps are made of austenitic stainless steel with a design flowrate of 75 gpm and a design pressure of 150 psig. Boric Acid transfer pumps transfer boric acid from the boric acid tanks to the charging pump suctions and from the boric acid batch tank to the boric acid tanks. Each pump can also be used to recirculate the contents of a boric acid tank.

One pump is normally aligned to supply boric acid to the boric acid blender. while the second serves as a standby. Manual or automatic initiation of the reactor coolant makeup system will start the pumps to provide normal makeup of boric acid solution

through the boric acid blender. The transfer pumps also function to transfer boric acid solution from the batching tank to the boric acid tanks. The design discharge pressure is sufficient to overcome any pressures which may exist in the suction manifold of the charging pumps (VCT relief valve setting). In addition to the automatic actuation by the makeup control system, and manual actuation from the main control board, these pumps may also be controlled at a *local* control center.

Emergency boration. supplying 4 wt% boric acid solution directly to the suction of the charging pumps can be accomplished by the operator manually starting either pump and manually open the emergency boration valve (MO-8104).

Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution being pumped from the boric acid tanks. The filter is designed to pass the design flow of two boric acid transfer pumps operating simultaneously. Local pressure indicators indicate the pressure upstream and downstream of the boric acid filter and thus provide filter differential pressure. The boric acid filter collects particulates from the (4%) boric acid solution being pumped to the CVCS. The filter is designed to pass the design flow of two boric acid transfer pumps operating simultaneously. The boric acid filter is the disposable synthetic cartridge type inside an austenitic stainless steel vessel with a design pressure of 200 psig and a design temperature of 250°F. The filter design flow is 150 gpm with a maximum pressure drop of 70 psig.

Reactor Makeup Control

Components involved in reactor makeup operations include the boric acid flow transmitter, boric acid batch integrator, boric acid flow control valve, total flow transmitter, total flow batch integrator, primary water flow control valve, a blender, blender supply valves to the VCT and to the charging pump suction, a mode selector switch, and a makeup permissive switch. These components are used to add boric acid or demineralized water to the RCS and other plant destinations via five modes of operation. These modes are borate, dilute, alternate dilute, automatic, and manual. The operator controls RMS operation from the reactor makeup control station in the control room by selecting a particular mode with the mode selector switch and then selecting “start” with the makeup permissive switch. Changing the position of the mode selector switch automatically turns off the makeup system. Therefore, after selection of a new mode, the system must be re-initiated by placing the makeup permissive switch in “start.”

1. **BORATE** - The borate mode is used to increase the boron concentration in the RCS. The mode selector switch is selected to the “borate” position. The desired amount of boric acid to be added is set into the boric acid batch integrator, and the desired boric acid flow rate is selected with the boric acid flow controller. The makeup permissive switch is selected to “start.” The boric acid transfer pumps are automatically started, and boric acid is added from a boric acid tank to the charging pump suction via the boric acid flow control valve (FCV-110A), the blender, and the blender supply valve to the charging pumps (FCV-110B). The flow controller automatically positions the boric acid flow control valve so that the flow measured by the boric acid flow transmitter matches the selected flow rate. The output of the flow transmitter is also supplied to the boric acid batch integrator. When the batch integrator has determined that the desired amount of boric acid has been added, valves FCV-110A and FCV-110B are automatically closed, the boric acid transfer pumps are automatically stopped, and “stop” is automatically selected at the makeup permissive switch.

After the boration ends, the operator must either (1) select a new mode and energize the system by selecting “start” with the makeup permissive switch, or (2) initiate another boration by leaving the mode selector switch in “borate” and again selecting “start” with the makeup permissive switch.

2. **DILUTE** - The dilute mode is used to reduce the boron concentration in the RCS. The mode selector switch is selected to the “dilute” position. The desired amount of water to be added is set into the total flow batch integrator, and the desired primary water flow rate is selected with the total flow controller. The makeup permissive switch is selected to “start.” One primary water transfer pump is automatically started, and water is added from the primary water storage tank to the VCT via the total flow control valve (FCV-111A), the blender, and the blender supply valve to the VCT (FCV-111B). The flow controller automatically positions the total flow control valve so that the flow measured by the total flow transmitter matches the selected flow rate. The output of the flow transmitter is also supplied to the total flow batch integrator. When the batch integrator has determined that the desired amount of water has been added, valves FCV-111A and FCV-111B are automatically closed, the primary water transfer pump is automatically stopped, and “stop” is automatically selected at the makeup permissive switch.
3. **ALTERNATE DILUTE** - Operation of the RMS in the alternate dilute mode is the same as in the dilute mode, except that the flowpath for primary water is different. With the mode selector switch selected to the “alternate dilute” position, both FCV-110B and FCV-111B are opened. As a result, a portion of the primary water flows directly to the charging pump suction, and a portion flows through the normal dilution path to the VCT. Use of the alternate dilute mode reduces the time for the dilution to take effect in the reactor coolant, because some of the dilution water does not have to drain from the top of the VCT to the charging pump suction before it is pumped into the RCS. Since some of the primary water bypasses the VCT, it does not absorb hydrogen. Excessive use of the alternate dilute mode could result in high RCS oxygen concentrations.
4. **AUTOMATIC** - With the automatic makeup mode selected, the reactor makeup control system, upon demand, provides a predetermined blend of boric acid and primary water to the charging pump suction. With the system controls preset properly by the operator, the boron concentration of the blended makeup flow should match that of the reactor coolant. The automatic makeup compensates for normal leakage of reactor coolant, which is reflected in a decreasing VCT level, without causing changes in the reactor coolant boron concentration.

   Under normal plant operating conditions, the mode selector switch is selected to “auto,” RMS valves and pumps are set in their automatic positions, and the makeup permissive switch is set to “start.” The operator sets the boric acid flow controller to a desired flow rate that results in the desired final boron concentration; this setting is provided by a table or chart readily available to the operator. A preset low level signal from the volume control tank level controller (see Figure 4.1-7) initiates automatic makeup: both boric acid transfer pumps and one primary water transfer pump start, the blender supply valve to the charging pump suction (FCV-110B) opens, the boric acid flow control valve (FCV-110A) automatically positions to provide the boric acid flow rate selected by the operator, and the total flow control valve (FCV-111A) automatically positions to provide a total flow rate of 80 gpm. (The primary water flow rate is thus the difference between 80 gpm and the boric acid flow rate.)

The addition of the blended flow to the charging pump suction header causes the water level in the volume control tank to rise. At a preset level in the VCT, the boric acid and primary water transfer pumps stop, and valves FCV-110A, FCV-111A, and FCV-110B close. The RMS is now ready for another automatic makeup demand.

5. **MANUAL** - The manual mode of operation permits the addition of operator-selected quantities and blends of boric acid and primary water to the CVCS, the refueling water storage tank, the holdup tanks in the boron recovery system, and other locations via temporary connections. With the RMS in the manual mode of operation, automatic makeup to the RCS is prevented. The operator manually aligns the RMS flow paths.

   The operator sets the mode selector switch to “manual,” sets the boric acid and total flow controllers to the desired flow rates, sets the boric acid and total flow batch integrators to the desired quantities, and positions the makeup permissive switch to “start.” Both boric acid transfer pumps and one primary water transfer pump start, the boric acid and total flow control valves position to provide the selected flow rates, and the blended flow goes to the selected destination. When the preset quantities of boric acid and primary water have been added, the boric acid and primary water transfer pumps stop, and the boric acid and total flow control valves close. This operation may be stopped manually by placing the makeup permissive switch in the “stop” position, and by manually closing any valves the operator had previously opened.

   If either batch integrator is satisfied before the other has reached its selected total, the pump(s) and flow control valve associated with the satisfied integrator terminate that portion of the total flow. The flow controlled by the other integrator continues until that integrator is also satisfied.

Boric Acid Blender

The boric acid blender (Figure 4.1-6) ensures thorough mixing of boric acid and primary water for the RMS. The blender decreases the pipe length required to homogenize the mixture for taking a representative local sample. A sample point is provided in the piping just downstream of the blender.

The boric acid blender has a design pressure of 150 psig, a design temperature of 250°F, a design flow of 35 gpm 4% boric acid, and a design flow of 85 gpm primary makeup water. The austenitic stainless steel blender consists of a conventional pipe tee fitted with a perforated tube insert. The boric acid enters through the perforated tube, and primary water enters at the bottom. A blended concentration exits the tee. The blender and boric acid flow control valve limit boric acid flow to a maximum of 10 gpm in plants with a 12-weight percent boric acid concentration in the boric acid tanks.

Emergency Boration Path

Certain operational events require the rapid addition of large quantities of boric acid into the RCS. This is accomplished through the emergency boration flowpath. Events that would require emergency boration are shutdown margin related, and include anticipated transients without scram (ATWSs), reactor trips with more than one rod stuck out of the core, and the development of inadequate boron concentrations during shutdown or refueling conditions. Boric acid addition is a diverse alternative to control rod insertion as a method of negative reactivity addition to assure that the reactor can be shut down.

The emergency boration flow path, as shown in Figure 4.1-5, consists of the motor-operated emergency boration valve (MO-8104) and a flow transmitter. Emergency (immediate) boration is accomplished by starting a boric acid transfer pump and throttling the emergency boration valve to achieve the desired flow rate. In the event that both the normal (blender) and emergency boration flow paths are unavailable, an alternate emergency boration path is provided. For this path, FCV-110A and a normally locked-closed local manual valve (8439) must be opened. Regardless of the emergency boration path chosen, the delivery of emergency boration to the RCS is governed by the charging pump flow rate.

Electric Heat Tracing (Only for RMSs with 7 or 12 weight percent boric acid)

Electric heat tracing is installed under the insulation on all piping, valves, line-mounted instrumentation, and components normally containing the concentrated boric acid solution. The heat tracing is designed to prevent boric acid precipitation due to cooling. Redundant heat tracing in applicable locations provides protection against single failure. Power for the electric heat tracing is supplied from 480-Vac vital busses. Heat tracing is addressed by Technical Specifications.

Chemical Addition

The chemical addition portion of the CVCS, as shown in Figure 4.1-5, consists of an austenitic stainless-steel chemical mixing tank and the piping which connects the tank to the charging pump suction. The chemical mixing tank has a design pressure of 150 psig with a capacity of 5 gallons and a design temperature of 200°F. Not normally in use, the chemical mix tank will be between 15-60 psig when adding chemicals. Added chemicals include lithium hydroxide for pH control of the reactor coolant, zinc for corrosion protection supplement (enhancing a tight film barrier and reducing crud burst), and hydrazine for oxygen scavenging when the plant is in cold shutdown. Chemicals are added to the mixing tank through a funnel and flushed to the charging pump suction with primary water.

4.1.3.3 Charging Components

VCT Outlet Valves

Two series motor-operated valves (LCV-112B and LCV-112C) are located in the VCT outlet line. These valves provide redundant isolation of the charging pump suction path from the VCT on low VCT level or on receipt of a safety injection actuation signal.

RWST Suction Supply

Two parallel motor-operated valves (LCV-112D and LCV-112E) supply the charging pump suction header with borated water from the refueling water storage tank (RWST). The valves are normally closed; they open to supply the suctions of the charging pumps on low VCT level or on receipt of a safety injection actuation signal.

RHR Suction Supply

A suction supply to the centrifugal charging pumps is supplied by the residual heat removal (RHR) pump discharge. This line is used to supply the high head injection pumps during the recirculation phase of ECCS operation in response to a loss-of-coolant accident.

Charging Pumps

A relief valve on the charging pump suction header relieves pressure that may build up if the suction line isolation valves are closed or if the system is over pressurized. The valve set pressure is equal to the design pressure of the associated piping and equipment.

Three squirrel cag induction open drip-proof charging pumps are installed in the system to provide charging flow to the RCS. All parts in contact with the reactor coolant are fabricated of austenitic stainless steel or other materials of adequate corrosion resistance. The reciprocating or Positive Displacement Pump (PDP) is equipped with a variable speed drive and is powered from a non-vital ac source with a design flow rate of 98 gpm and a design pressure of 3200 psig. The reciprocating or PDP has a suction stabilizer and a discharge pulsation dampener installed to reduce pressure pulsations in the adjoining piping. The reciprocating pump has a recirculation line with a relief valve (relieves to the VCT) for overpressure protection.

Two of the charging pumps are single-speed, horizontal Centrifugal Charging Pumps (CCP) powered from vital (Class 1E) ac power. The centrifugal charging pumps have a design flow rate of 150 gpm, a design temperature of 300°F, a design pressure of 2800 psig, and a maximum operating flow of 550 gpm. Flow through the minimum flow recirculation line for the centrifugal charging pumps protects them from a low flow condition. The centrifugal pump seals and the reciprocating pump stuffing box are provided with leak-offs to collect reactor coolant leakage before it can escape to the atmosphere.

The charging flow rate is determined by the pressurizer level control system. Control of the flow rate from the reciprocating pump is accomplished by varying the speed of the pump. With a centrifugal charging pump operating, the charging flow rate is controlled by varying the position of an automatic modulating valve (FCV-121) on the discharge of the centrifugal pumps. The charging flow measured downstream of FCV-121 (by FT-121) is an input to the controller which positions the valve (see Section 10.3).

The centrifugal charging pumps also serve as the high head safety injection pumps of the Emergency Core Cooling Systems (ECCS).

RCP Seal Flow Control Valve

The reactor coolant pump seal flow control valve (HCV-182), located in the charging header, determines the division of flow between the RCP seal injection path and the charging path. This valve is remotely adjusted by the control room operator. RCP seal flow is increased by throttling closed HCV-182. If seal flow is increased, then the charging flow is decreased. Conversely, if HCV-182 is throttled open, the seal flow decreases and the charging flow increases.

Charging Isolation Valves

Two series motor-operated isolation valves (MO-8105 and MO-8106) isolate the charging header on receipt of a safety injection actuation signal.

Two charging paths to the RCS are provided. The normal path is into loop 1 through an air operated isolation valve (CV-8146). A spring-loaded check valve set to open at 200 psid is in parallel with the isolation valve. The purpose of the check valve is to relieve the volumetric expansion of coolant if charging were to be isolated and letdown continued. The alternate charging connection (CV-8147) taps into loop 4, and can be used if the normal charging line is inoperable.

Pressurizer Auxiliary Spray

The charging header can supply spray to the pressurizer when the reactor coolant pumps are not running. Depressurization of the RCS during RHR system operation is a normal evolution requiring the use of the auxiliary spray valve.

The auxiliary spray line is routed from the outlet of the regenerative heat exchanger to the pressurizer spray line downstream of the normal pressurizer spray valves. Auxiliary spray flow is remotely controlled with an air-operated valve (CV-8145).

4.1.3.4 Seal Injection and Seal Return

Seal Injection Header

The reactor coolant pump seal injection header connects to the CVCS at the discharge of the charging pumps and directs flow to the seal injection filter(s). The seal injection filters are 5-micron filters installed to collect particulate matter that could damage the reactor coolant pump seal faces. The seal injection filters are the disposable synthetic cartridge type inside an austenitic stainless steel vessel with a design pressure of 2735 psig and a design temperature of 200°F. The filter design flow is 80 gpm with a maximum pressure drop of 70 psig.

The filtered seal injection water is directed to each reactor coolant pump through an individual injection line. Two seal-water injection filters are located in parallel in a common line to the Rep seals; they collect particulate matter that could be harmful to the seal faces. Each filter is sized to accept flow in excess of the normal seal-water flow requirements. A differential pressure indicator monitors the pressure drop across each seal-water injection filter and gives local indication with high differential pressure alarm on the main control board.

A total seal injection flow of 32 gpm, determined by the position of the seal injection flow control valve (HCV-182), is divided equally among the four reactor coolant pumps. Each seal injection line contains a manual throttle valve, locked in a throttled position, for balancing pump seal injection flow rates, and a manually operated isolation valve.

Seal Return Header

A seal return flow of 3 gpm/RCP is returned to the CVCS. The individual pump seal return lines join together and exit the containment through one penetration. Motor operated isolation valves (MO-8112 and MO-8100), located on opposite sides of the containment building penetration, provide redundant isolation of the seal return line on receipt of a containment isolation phase A signal. A relief valve, located in the containment, routes seal return flow to the pressurizer relief tank (PRT) if the seal return motor-operated isolation valves are closed. The relief valve lifts at 150 psig.

A filter is installed in the seal return piping to collect particulates from the seal return and excess letdown lines. The seal-water return filter collects particulates from the RCP seal-water return and from the excess letdown flow. The filter is designed to pass flow in excess of the sum of the excess letdown flow and the maximum design leakage from the RCP seals. The seal return filter is the disposable synthetic cartridge type inside an austenitic stainless steel vessel with a design pressure of 200 psig and a design temperature of 250°F. Th filter design flow is 35 gpm with a maximum pressure drop of 70 psig. Two local pressure indicators are provided to show the pressures upstream and downstream of the filter and thus provide differential pressure across the filter. The filtered seal return water passes through the seal water heat exchanger to the charging pump suction header.

Seal-Water Heat Exchanger

The seal-water heat exchanger is designed to cool fluid from three sources: RCP seal water returning to the CVCS, reactor coolant discharged from the excess letdown heat exchanger, and CCP recirculation flow. The seal water heat exchanger is a carbon steel shell with austenitic stainless-steel tubes and tubesheets. Reactor coolant flows through the tube side of the heat exchanger and Component Cooling Water (CCW) is circulated through the shell.

The seal water heat exchanger has a design heat duty of 2.95 x 10^6 Btu/hr. The shell side (CCW) has a design pressure of 150 psig, a design temperature of 250°F, a design operating flow of 99,500 lb/hr, a design operating inlet temperature of 95°F, and a design operating outlet temperature of 120°F. The tube side (RCS) has a design pressure of 150 psig, a design temperature of 250°F, a design operating flow of 160,600 lb/hr, a design operating inlet temperature of 143°F, and a design operating outlet temperature of 127°F.

The design flow rate is equal to the sum of the excess letdown flow, the maximum design RCP seal leakage, and bypass flow from one CCP. The unit is designed to cool the above flow to the temperature normally maintained in the VCT. All surfaces in contact with the reactor coolant are austenitic stainless steel and the shell is carbon steel. The seal water return line with charging pump bypass flow (RECIRC) has a relief valve that protects the seal-water heat exchanger and its associated piping from over pressurization. If either of the isolation valves for the heat exchanger are closed and if the bypass line is closed, the piping may be over pressurized by the bypass flow from the CCPs. It is assumed that all CCPs are running with full bypass flow. The valve is set to relieve at the design pressure of the heat exchanger.

4.1.3.5 Excess Letdown

Excess letdown (Figure 4.1-1) is supplied from the loop 3 cold leg through the excess letdown heat exchanger and isolation valves to the CVCS. An alternate letdown path from the RCS is provided in the event that the normal letdown path is inoperable. Reactor coolant can be discharged from the cold leg through the tube side of the excess letdown heat exchanger. Downstream of the heat exchanger, a remote manual control valve controls the excess letdown flow. The flow normally joins the Number 1 seal discharge manifold and passes through the seal-water return filter and heat exchanger to the VCT. The excess letdown flow can also be directed to the RCDT. When the normal letdown line is not available, the normal purification path is also not in operation. Therefore, this alternate condition would allow continued power operation for limited periods of time dependent on RCS chemistry and activity. The excess letdown flow path is also used to provide additional letdown capability during the final stages of Plant heatup. This path removes some of the excess reactor coolant due to expansion of the system as a result of the RCS temperature increase. In this case, the excess letdown is diverted to the RCDT.

Excess Letdown Valves

Four remotely operated valves are associated with the excess letdown line. Two isolation valves (CV-8153 and CV-8154) are located at the excess letdown heat exchanger inlet. A control valve (HCV-123) at the excess letdown heat exchanger outlet is positioned with a manual controller in the control room to throttle excess letdown flow. A three-way valve (CV-8143) is used to direct excess letdown flow to the CVCS or to the reactor coolant drain tank (RCDT). Excess letdown flow is normally routed to the CVCS.

Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown flow which is equivalent to the nominal seal injection flow which enters into the RCS through the reactor coolant pump labyrinth seals (normally about 20 gpm total).

The excess letdown heat exchanger has a design heat duty of 4.61 x 10^6 Btu/hr with austenitic stainless-steel tubes and tubesheets. The design tube side (RCS) pressure is 2485 psig with a design temperature of 650°F. The tube side design operating inlet temperature is 545°F with a design operating outlet temperature of 195°F and a design operating flow of 12,380 lb/hr. The shell side (CCW) design pressure is 150 psig and a design temperature of 250°F. The shell side design operating inlet temperature is 95°F with a design operating outlet temperature of 135°F and a design operating flow of 115,000 lb/hr.

The excess letdown heat exchanger can be employed either when normal letdown is temporarily out of service to maintain the reactor in operation or it can be used to supplement maximum letdown during the final stages of heatup. The letdown flows through the tube side of the unit and component cooling water is circulated through the shell. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded.

A temperature detector measures temperature of excess letdown downstream of the excess letdown heat exchanger. High temperature alarm and indication are provided on the main control board. A pressure sensor indicates the pressure of the excess letdown flow downstream of the excess letdown heat exchanger control valve. Pressure indication is provided on the main control board.

4.1.4 System Features and Interrelations

4.1.4.1 Deborating Ion Exchangers

Some Westinghouse plants are equipped with deborating ion exchangers. Late in core life, the necessary boron concentration of the RCS approaches zero. At low boron concentrations, the volume of dilution required to further decrease the boron concentration is extremely large. The large dilution volume required must be processed as liquid radioactive waste because boron recovery becomes impractical at low boron concentrations.

The deborating ion exchangers provide a means of reducing RCS boron concentration without generating a large volume of liquid radioactive waste. The ion exchangers contain anion-type resin and remove boric acid from the RCS by ion exchange.

4.1.4.2 Boron Thermal Regeneration System

To allow maximum load following while minimizing the amount of processing in the boron recovery system, some plants are equipped with a boron thermal regeneration system (BTRS). The BTRS takes the letdown flow at the outlet of the ion exchangers, adds or removes boron, and returns the flow to the inlet of the letdown filter. The BTRS is discussed in detail in Section 4.2.

4.1.4.3 Boron Concentration Monitoring System

Boron concentration can be determined from lab analysis of a reactor coolant sample. In addition, some plants have an on-line boron concentration monitoring system (BCMS) that continuously measures the boron concentration with a remote readout in the control room.

The BCMS consists of a neutron radiation source and a sample chamber in a tank full of water. The water moderates neutrons and shields against neutron leakage. A BF_3 proportional neutron detector is located in the center of the sample chamber to detect neutrons that get through the sample boron solution. The neutrons come from an Am-Be source located just outside the chamber. The time required to detect a given number of neutrons is proportional to the boron concentration.

Sample flow to the BCMS is from downstream of the ion exchangers (or upstream of the letdown filter). The return flow is via the relief line to the VCT.

4.1.4.4 Pressurizer Level Control

The CVCS maintains the proper water inventory in the RCS by adjusting the changing flow rate as pressurizer level deviates from its program. The error signal from the pressurizer level control system (Section 10.3) increases or decreases the charging system flow. The charging flow may be controlled by varying the speed of the positive displacement (PD) charging pump, or by varying the position of the charging flow control valve (FCV-121) if a centrifugal charging pump is in service. If the level in the pressurizer is below its setpoint, the PD pump speed is increased, or FCV-121 is opened to increase charging flow. If the level in the pressurizer is above its setpoint, then the PD pump speed is decreased, or FCV-121 is closed to decrease charging flow.

4.1.4.5 Purification during Residual Heat Removal Operation

A connection from the RHR system, located between the letdown line containment isolation valve (CV-8152) and the letdown heat exchanger, allows purification of the RCS while the plant is in cold shutdown. Purification is accomplished by directing a portion of the RHR flow to the CVCS. Flow from the RHR system to the CVCS letdown line is controlled by HCV-128. The mixed-bed ion exchanger and letdown filter purify the coolant prior to its entry into the VCT. The purified coolant is then returned to the RCS by the normal charging flow path.

4.1.4.6 CVCS Alignment during ECCS Operation

The following valves close in response to engineered safety features actuation signals:

1. Letdown orifice isolation valves (CV-8149A, CV-8149B, and CV-8149C) - closed by a containment isolation phase A signal,
2. Containment isolation valve (CV-8152) - closed by a containment isolation phase A signal,
3. Seal return isolation valves (MO-8112 and MO-8100) - closed by a containment isolation phase A signal,
4. VCT outlet valves (LCV-112B and LCV-112C) - closed by a safety injection actuation signal, and
5. Charging isolation valves (MO-8105 and MO-8106) - closed by a safety injection actuation signal.

Closing the above valves isolates letdown, normal charging, seal return, and charging pump suction from the VCT.

The following valves open in response to a safety injection actuation signal:

1. RWST suction supply valves to the charging pumps (LCV-112D and LCV-112E), and

2. Boron injection tank (BIT) inlet and outlet valves. (These are not CVCS valves, but are included here for completeness. See Section 5.2.)

Opening the above valves supplies borated water to the RCS from the RWST via the BIT by the centrifugal charging pumps, which automatically start in response to a safety injection actuation signal.

4.1.4.7 Volume Control Tank Level Functions

The level in the VCT controls the position of the level divert valve (LCV-112A), the VCT outlet valves (LCV-112B and LCV-112C), and the RWST suction supply valves (LCV-112D and LCV-112E), and starts and stops the reactor makeup system when the mode selector switch is in automatic. Figure 4.1-7 summarizes the VCT level control functions.

4.1.5 Plant and System Operations

4.1.5.1 Reactor Startup

Reactor startup is defined as the operations which bring the reactor from cold shutdown to normal operating temperature and pressure. It is assumed that:

1) Normal RHR is in progress.
2) RCS boron concentration is at the cold shutdown concentration.
3) Reactor makeup control system is set to provide makeup at the cold shutdown concentration.
4) RCS is either water solid or drained to minimum level for the purpose of refueling or maintenance. If the RCS is water solid, system pressure is controlled by letdown through the RHR System and through the low-pressure letdown valve in the letdown line.
5) The charging and letdown lines of the CVCS are filled with coolant at the cold shutdown boron concentration. The letdown orifice isolation valves are closed.

If the RCS -requires filling and venting, the procedure is as follows:

1) One charging pump is started, which provides blended flow from the reactor makeup control system at the cold shutdown boron concentration.
2) The vents on the head of the reactor vessel and pressurizer are opened.
3) The RCS is filled and the vents are closed.

The charging pump and the low-pressure letdown valve continue to pressurize the system. When the system pressure is adequate for operation of the RCPs, seal-water flow to the pumps is established and the pumps are operated and vented sequentially until all gases are cleared from the system. Final venting takes place at the pressurizer.

After the filling and venting operations are completed, charging and letdown flows are established. All pressurizer heaters are energized, and the RCPs are employed to heat up the system. After the RCPs are started, the RHR pumps are stopped but pressure control via the RHR System and the low-pressure letdown line is continued as the pressurizer steam bubble is formed. At this point, steam formation in the pressurizer is accomplished by manual control of the charging flow and automatic pressure control of the letdown flow. When the pressurizer water level reaches the no-load programmed setpoint, the pressurizer level control is shifted to control the charging flow to maintain programmed level. The RHR System is then isolated from the RCS.

The reactor coolant boron concentration is now reduced by operating the reactor makeup control system in the "dilute" mode. The reactor coolant boron concentration is corrected to the point where the control rods may be withdrawn, and criticality achieved. Nuclear heatup may then proceed with corresponding manual adjustment of the reactor coolant boron concentration to balance the temperature coefficient effects and maintain the control rods within their operating range. During heatup, the appropriate combination of letdown orifices is used to provide necessary letdown flow.

Prior to or during the heating process, the CVCS is employed to obtain the correct chemical properties in the RCS. The reactor makeup control is operated on a continuing basis to ensure correct control rod position. Chemicals are added through the chemical mixing tank as required to control reactor coolant chemistry such as pH and dissolved oxygen content. Hydrogen overpressure is established in the VCT to ensure the appropriate hydrogen concentration in the reactor coolant.

4.1.5.2 Power Generation and Hot Standby Operation

At constant power level, the rates of charging and letdown are dictated by the requirements for seal-water to the RCPs and the normal purification of the RCS. One charging pump is employed and charging flow is controlled automatically from pressurizer level. The only adjustments in boron concentration necessary are those to compensate for core burnup. These adjustments are made at infrequent intervals to maintain the control groups within their allowable limits. Rapid variations in power demand are accommodated automatically by control rod movement. If variations in power level occur, and the new power level is sustained for long periods, some adjustment in boron concentration may be necessary to maintain the control groups within their maneuvering band.

During normal operation, normal letdown flow is maintained, and one mixed-bed demineralizer is in service. Reactor coolant samples are taken periodically to check boron concentration, water quality, pH and activity level. The charging pump flow to the RCS is controlled automatically by the pressurizer level control signal through the discharge header flow control valve. A power reduction will initially cause a xenon buildup followed by xenon decay to a new lower equilibrium value. The reverse occurs if the power level increases; initially, the xenon level decreases and then it increases to a new and higher equilibrium value associated with the amount of the power level change.

The reactor makeup control system is used to vary the reactor coolant boron concentration to compensate for xenon transients occurring when the reactor power level is changed.

The most important intelligence available to the Plant operator, enabling him to determine whether dilution or boration of the RCS is necessary, is the position of the control rods within the maneuvering band. If, for example, the control rods are moving down into the core, and are approaching the bottom of the maneuvering band, the operator must borate the reactor coolant to bring the rods outward. If not, the control rods may move into the core beyond the shutdown limit. If, on the other hand, the rods are moving out of the core, the operator dilutes the reactor coolant to keep the rods from moving above the top of the maneuvering band. Keeping the control rods at the top of the maneuvering band ensures the capability of immediate return to full power. However, violation of the upper limit of the maneuvering band is not safety related and is allowed. With the c9ntrol rods above the top of the maneuvering band the reactor cannot return to full power immediately; it can return to some intermediate power level immediately and then reach full power at some rate determined by the xenon burnout transient.

During periods of Plant loading, the reactor coolant expands as its temperature rises. The pressurizer absorbs most of this expansion as the level controller raises the level setpoint to the increased level associated with the new power level. The remainder of the excess coolant is let down and stored in the VCT. During this period, the flow through the letdown orifice remains constant and the charging flow is reduced by the pressurizer level control signal, resulting in an increased temperature at the regenerative heat exchanger outlet. The temperature controller downstream from the letdown heat exchanger increases the component cooling water flow to maintain the desired letdown temperature.

During periods of Plant unloading, the charging flow is increased to make up for the coolant contraction not accommodated by the programmed reduction in pressurizer level.

If required for periods of maintenance, or following spurious reactor trips, the reactor can be held subcritical, but with the capability to return to full power within the period of time it takes to withdraw the control rods. During this hot shutdown period, temperature is maintained at no-load Tavg by initially dumping steam to remove core residual heat, or at later stages, by running RCPs to maintain system temperature.

Following shutdown, xenon buildup occurs and increases the degree of shutdown. If hot shutdown is maintained, a point may be reached where xenon decay results in a decrease in the degree of shutdown. Boration of the reactor coolant may be necessary to counteract the xenon decay and maintain shutdown.

If rapid recovery is required, dilution of the system may be performed

to counteract this xenon buildup.

4.1.5.3 Reactor Shutdown

Reactor shutdown is defined as the operations which bring the reactor to cold shutdown for maintenance or refueling.

Before initiating a cold shutdown, the RCS hydrogen concentration is reduced by reduction of the VCT overpressure and venting the gases to the waste gas vent header.

Before cooldown and depressurization of the reactor Plant is initiated, the reactor coolant boron concentration is increased to the cold shutdown value. The operator sets the reactor makeup control to "borate", selects the volume of concentrated boric acid solution necessary to perform the boration, selects the desired flow rate and actuates makeup start. After the boration is completed and reactor coolant samples verify that the concentration is correct, the operator resets the reactor makeup control system for leakage makeup and system contraction at the shutdown reactor coolant boron concentration.

Contraction of the coolant during cooldown of the RCS results in actuation of the pressurizer level control to maintain normal pressurizer water level. The charging flow is increased, relative to letdown flow, and results in a decreasing VCT level. The VCT level controller automatically initiates makeup to maintain the inventory.

After the RHR System is placed in service and the RCPs are shut down, further cooling of the pressurizer liquid is accomplished by charging through the auxiliary spray line. Coincident with Plant cooldown, a portion of the reactor coolant flow may be diverted from the RHR System to the CVCS for cleanup demineralization of ionic radioactive impurities and stripping of fission gases reduce the reactor coolant activity level sufficiently to permit personnel access for refueling or maintenance operations.

4.1.6 Summary

The CVCS is a major process system that controls RCS inventory, maintains RCS chemistry, provides the reactor coolant pumps with seal water, and controls the soluble poison concentration of the RCS. In addition, the centrifugal charging pumps supply borated water from the RWST to the RCS in the event of an accident.

The CVCS interfaces with the following systems:

- Pressurizer level control system
- Reactor makeup system
- Emergency core cooling system
- Boron recovery system

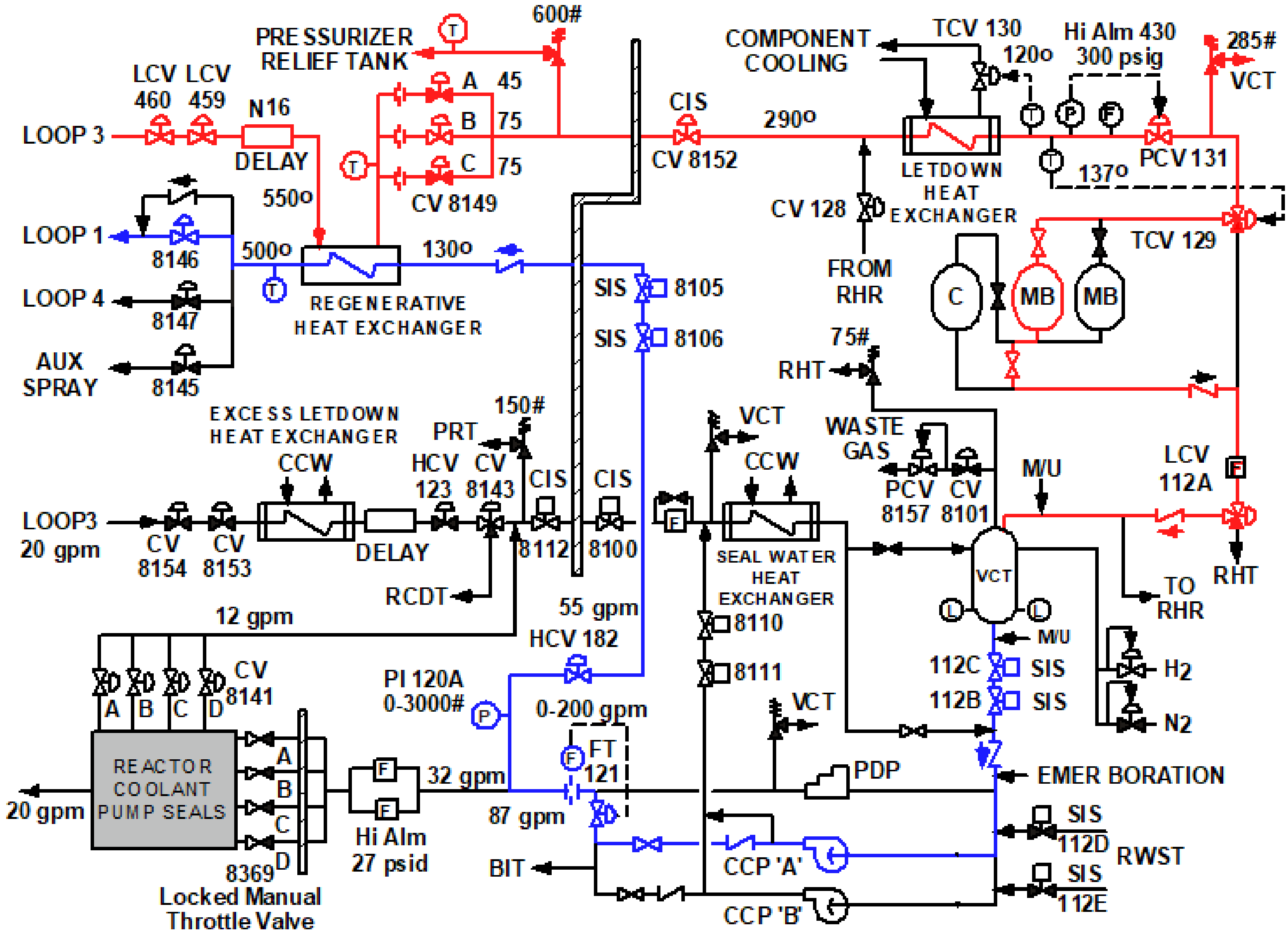

Figure 4.1.1 Charging and Volume Control System

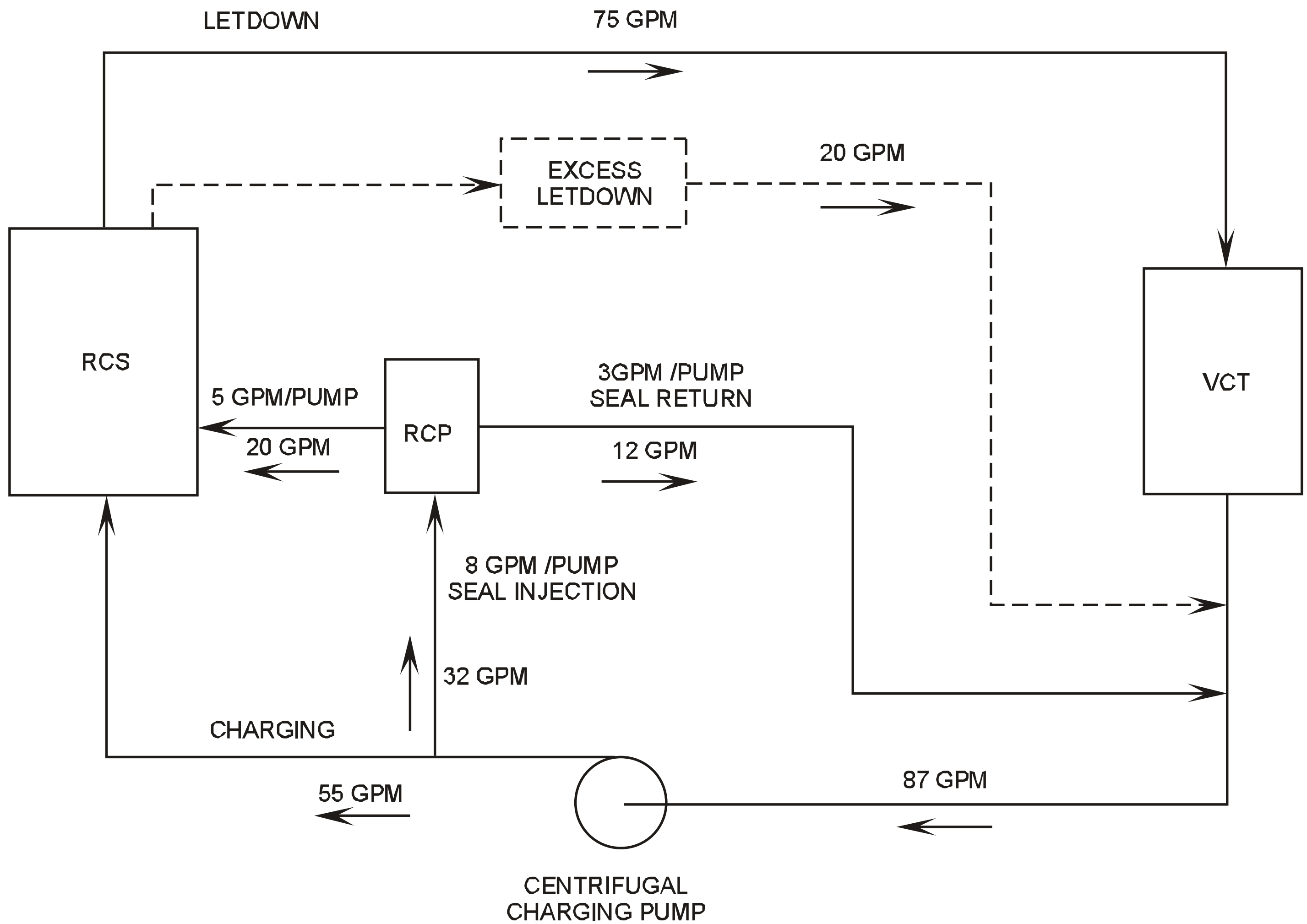

Figure 4.1.2 CVCS Flow Balance

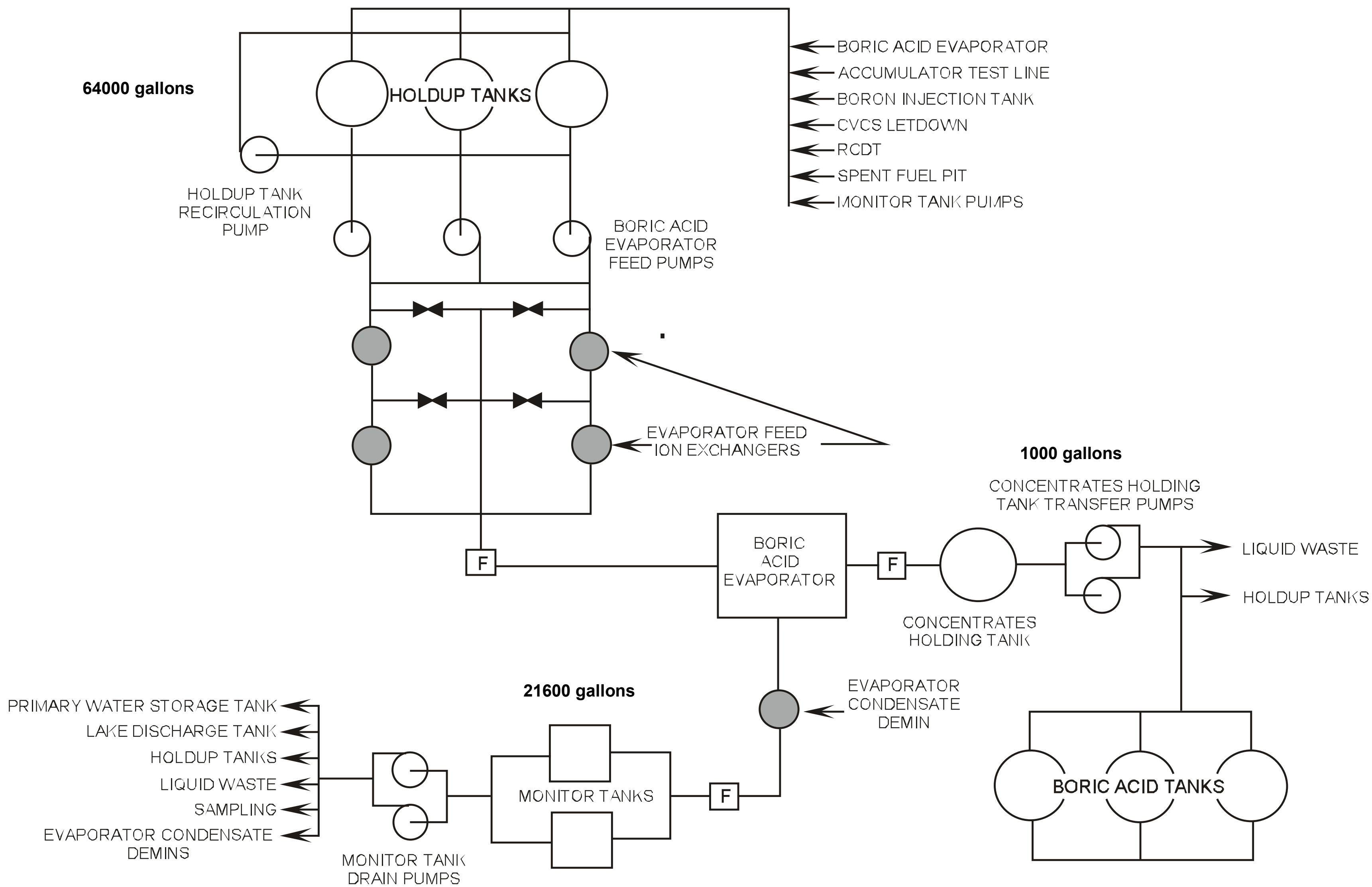

Figure 4.1.3 Boron Recycle System

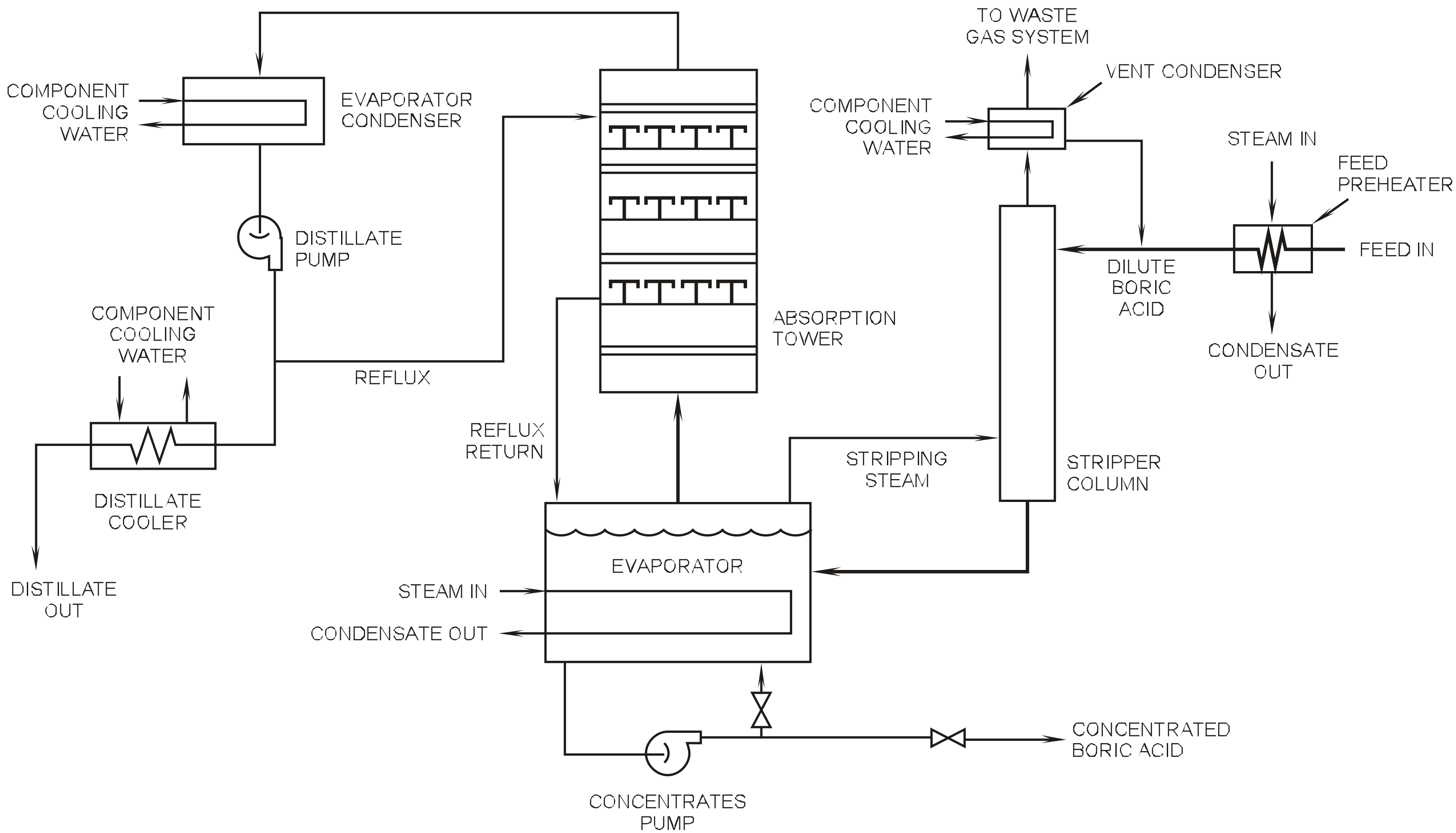

Figure 4.1.4 Boric Acid Evaporator

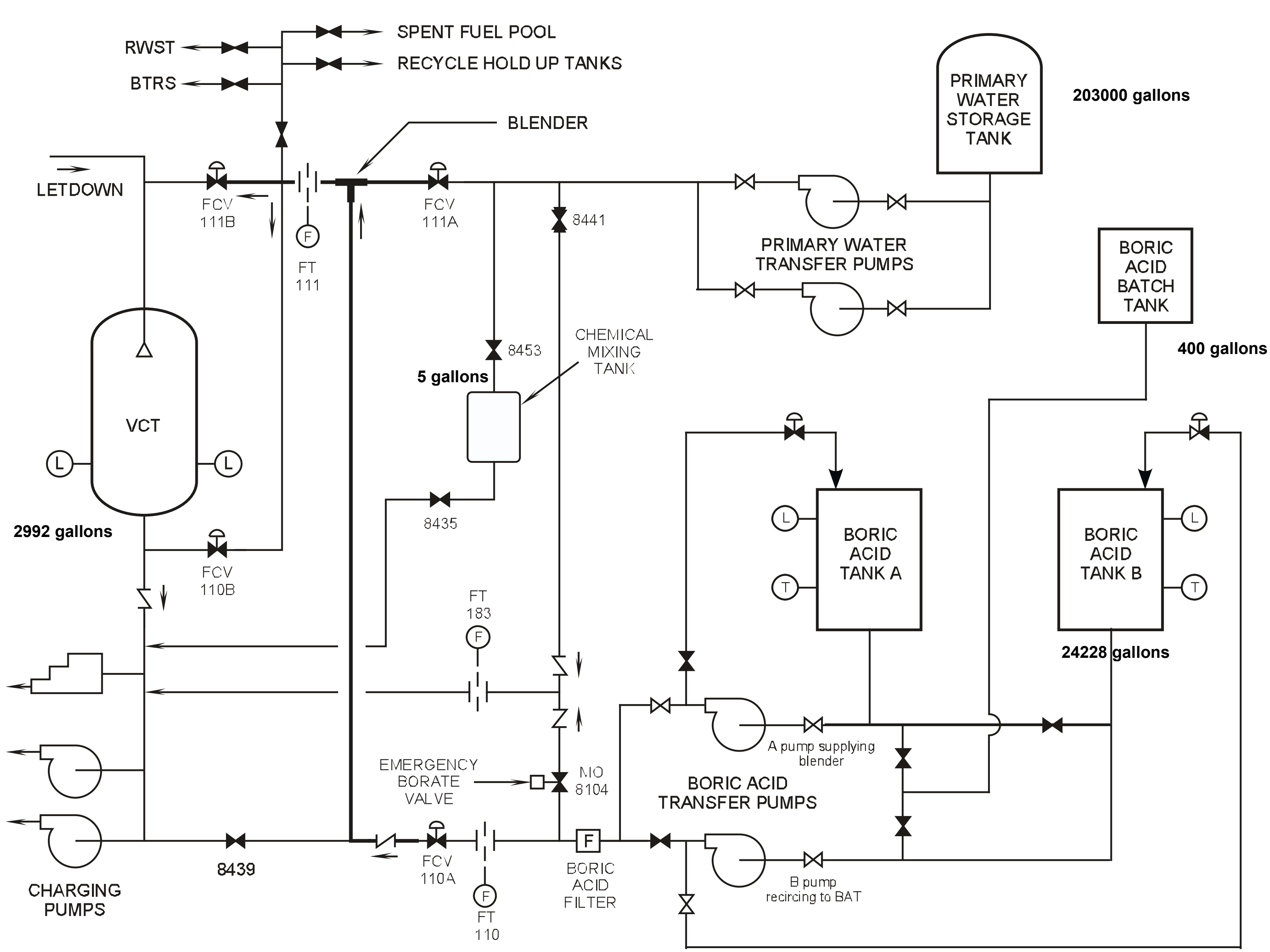

Figure 4.1.5 Reactor Makeup System

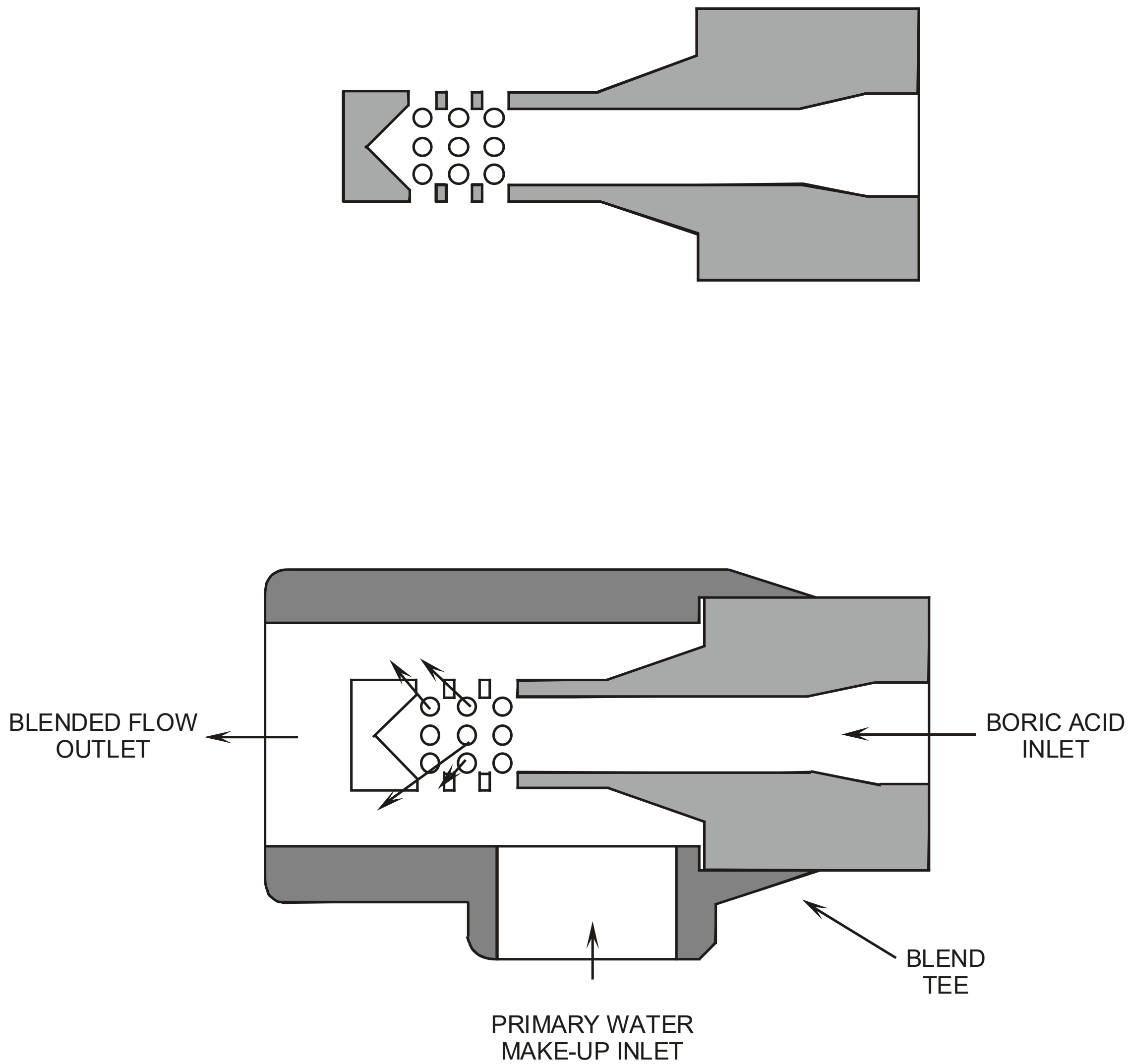

Figure 4.1.6 Boric Acid Blender

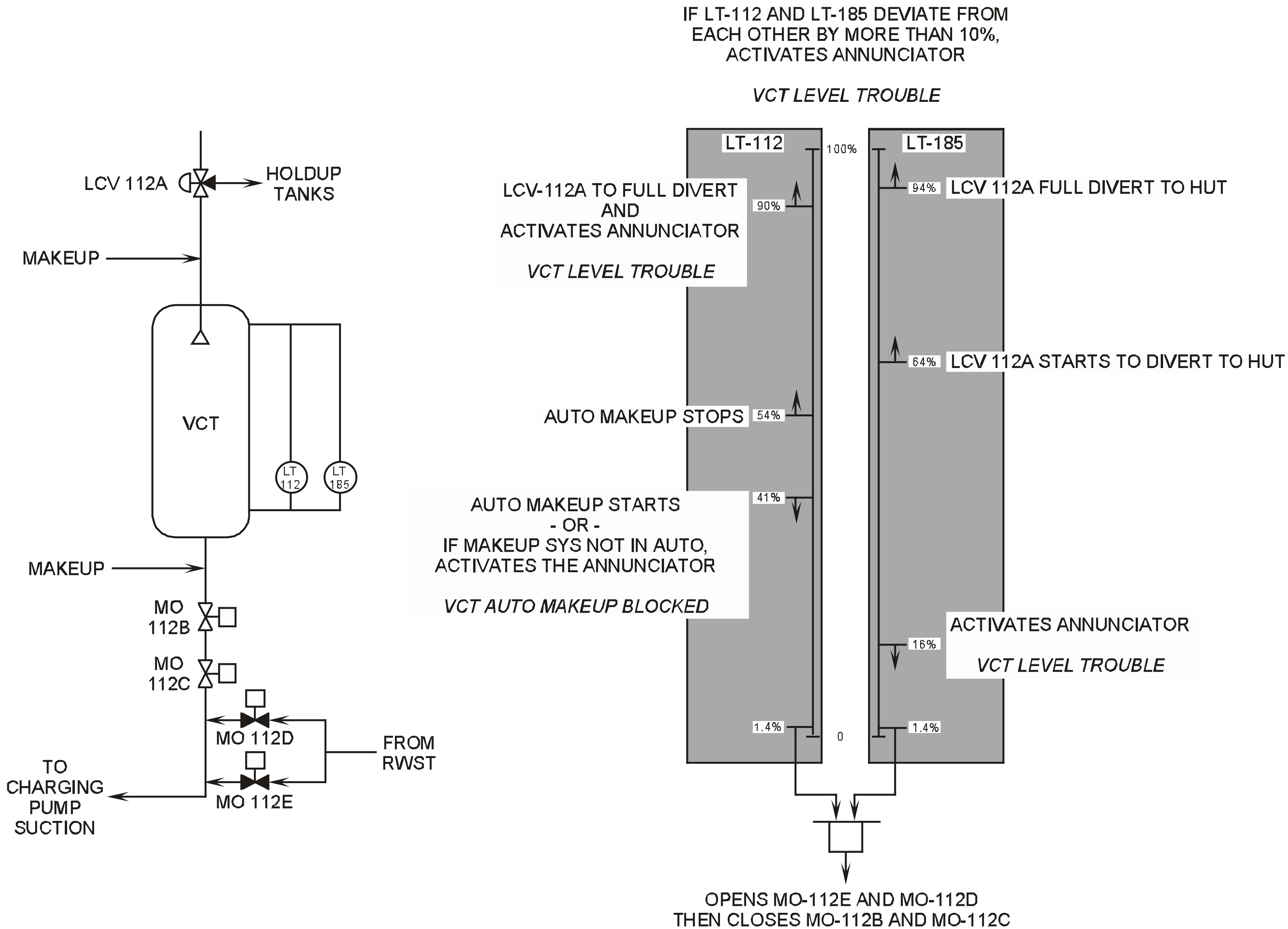

Figure 4.1.7 VCT Level Functions

WATER CHEMISTRY AND CHEMICAL ADDITIVES

Primary Makeup Water

Electrical Conductivity	≤2.0 μmhos/cm at 25°C
pH	6.0 to 8.0
Oxygen	≤0.1 ppm
Chloride	≤0.15 ppm
Fluoride	≤0.15 ppm
Suspended solids	≤0.1 ppm
Particulates	Filtered to <25 microns

Boric Acid

H_3BO_3, min %	99.90
Sodium, max %	0.003
Chloride, max %	0.00004
Sulfate, max %	0.0006
Phosphate, max %	0.003
Iron, max %	0.0002
Calcium, max %	0.005
Water insolubles	0.005
Fluoride (F), max %	0.0002
Arsenic (As), max %	0.0002

NOTE: The boric acid shall be in the granular form and shall be undepleted in boron-10.

Lithium Hydroxide

LiOH, %	48-58
Water (monohydrate)	42-52
Li-7, min %	99.9 of elemental lithium
Lead, max %	0.001
Zinc, max %	0.0005
Mercury, max %	0.00005
Chloride, max %	0.5

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Section 4.2

Boron Thermal Regeneration System (BTRS)

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4.2 BORON THERMAL REGENERATION SYSTEM

4.2.1 Introduction

The Boron Thermal Regeneration System (BTRS) varies the reactor coolant system (RCS) boron concentration to compensate for xenon transients and other reactivity changes which occur when power is changed. The BTRS is installed to allow for maximum load following while minimizing the liquid radioactive effluents from boron concentration changes. The design load follow capability for the BTRS is 12 hours at 100% power, 3 hour ramp to 50% power, 6 hours at 50% power, and a 3 hour ramp to 100% power. The operation of the BTRS is described below.

4.2.2 System Operation

Downstream of the mixed bed demineralizers in the chemical and volume control system (CVCS), the letdown flow can be diverted to the BTRS. The letdown flow, all or in part, may be treated when boron concentration changes are desired for load follow operations. After processing, this fluid is returned to a point upstream of the reactor coolant filter in the CVCS letdown line. Storage and release of boron during load follow operations are determined by the temperature of the fluid entering the thermal regeneration demineralizers. A chiller, which is cooled by a separate refrigeration system, and a group of heat exchangers are employed to provide the desired fluid temperatures to the demineralizers for either storage or release operation of the system.

4.2.2.1 Dilution Mode

The flow path through the BTRS is different for the boron storage and release operations. During boron storage (dilution - Figure 4.2-1), the letdown stream enters the moderating heat exchanger tube side and from there it passes through the letdown chiller heat exchanger tube side.

These two heat exchangers cool the letdown stream prior to entering the BTRS demineralizers. The letdown reheat heat exchanger is valved out on the tube side and performs no function during boron storage operations. The temperature of the letdown stream at the point of entry to the demineralizers is maintained automatically by the temperature control valve which regulates the shell side flow to the letdown chiller heat exchanger. After passing through the BTRS demineralizers, the letdown enters the moderating heat exchanger shell side, where it is heated by the incoming letdown stream.

The letdown flow then enters the normal letdown flowpath upstream of the RCS filter before going to the volume control tank. Therefore, for boron storage, a decrease in the boric acid concentration in the reactor coolant is accomplished by sending the letdown flow at relatively low temperatures to the thermal regeneration demineralizers. The resin, which was depleted of boron at high temperature during a prior boron release operation (borate), is capable of storing boron from the low temperature letdown stream. Letdown flow with a decreased concentration of boric acid leaves the demineralizers and is directed to the RCS via the CVCS normal charging flowpath.

4.2.2.2 Boration Mode

During the boron release operation (boration - Figure 4.2-2), the letdown stream enters the moderating heat exchanger tube side, bypasses the letdown chiller heat exchanger, and passes through the shell side of the letdown reheat heat exchanger. The moderating and letdown reheat heat exchangers heat the letdown stream prior to its entering the resin beds. The temperature of the letdown at the point of entry to the demineralizers is maintained automatically by the temperature control valve which regulates the flow rate on the tube side of the letdown reheat heat exchanger. After passing through the demineralizers, the letdown stream enters the shell side of the moderating heat exchanger, passes through the tube side of the letdown chiller heat exchanger.

An increase in the boric acid concentration in the reactor coolant is accomplished by sending the letdown flow at relatively high temperatures through the thermal regeneration demineralizers. The higher temperature water flowing through the demineralizers releases boron which was stored by the resin at low temperature during a previous boron storage (dilution) operation. The boron enriched letdown is returned to the RCS via the CVCS normal charging flowpath.

Although the BTRS is primarily designed to compensate for xenon transients occurring during load follow operations, it can also be used to handle boron swings far in excess of the design capacity of the demineralizers.

For dilution during a reactor start-up and power escalation for example, the resin beds are first saturated with boron, then washed off to the boron recovery system, then again saturated and washed off. This operation continues until the desired dilution in the RCS is obtained.

As an additional function, a thermal regeneration demineralizer can be used as a deborating demineralizer, which would be used to dilute the reactor coolant when it has very low boron concentrations at the end of the core cycle. To make such an operation effective, the boron concentration of the effluent from the resin bed must be kept very low, close to zero ppm. This low effluent concentration can be achieved by using fresh resin. The use of fresh resin can be coupled with the normal replacement cycle of the resin; one resin bed being replaced during each core cycle.

4.2.3 Summary

The BTRS provides a means of varying the boron concentration of the reactor coolant. This system reduces the operational demands on the boron recovery system thereby generating less liquid radioactive waste. The BTRS makes use of a temperature dependent ion exchange process in order to both remove boron from (dilute) and release boron to (borate) the CVCS letdown stream.

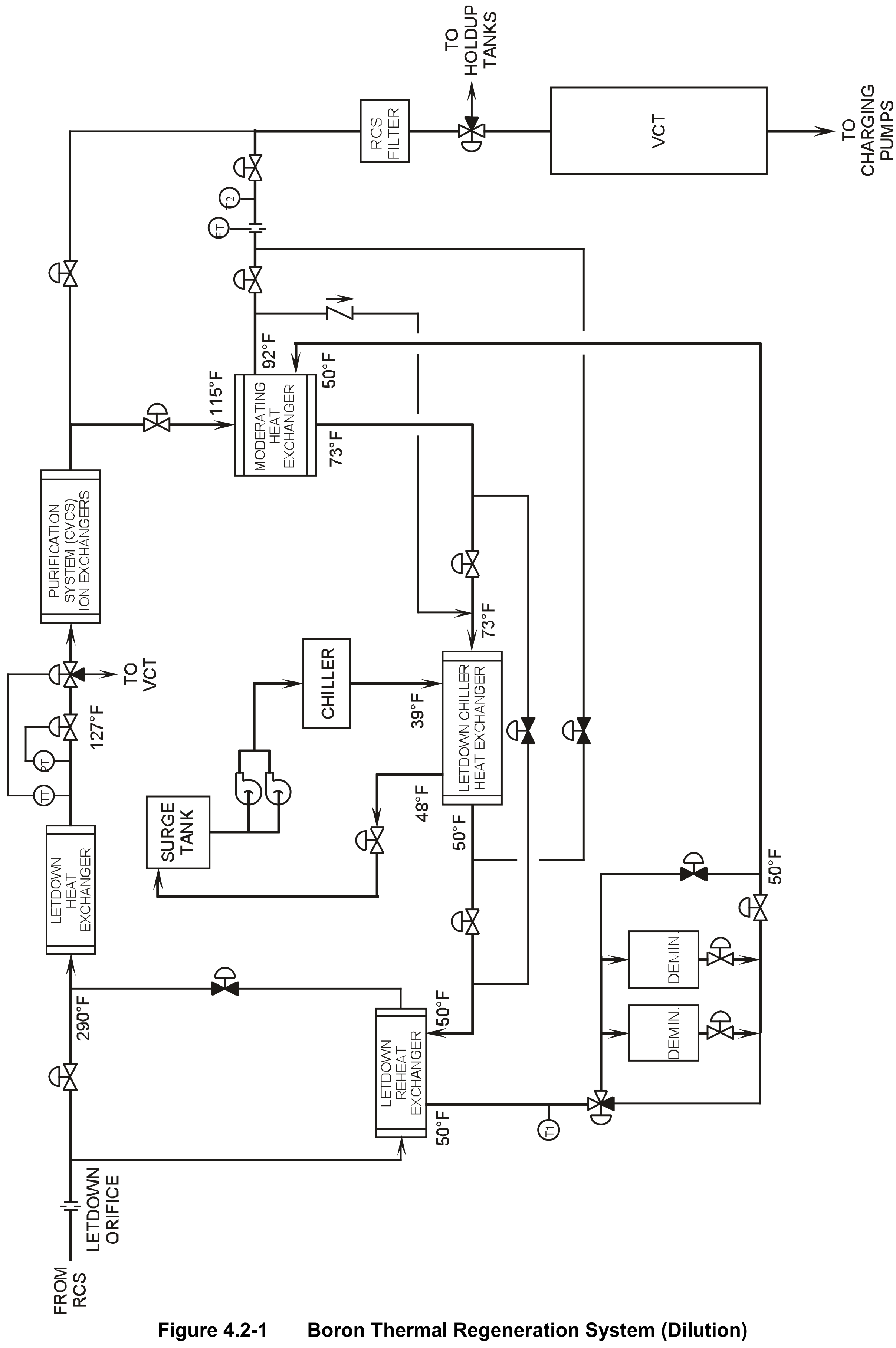

Figure 4.2-1 Boron Thermal Regeneration System (Dilution)

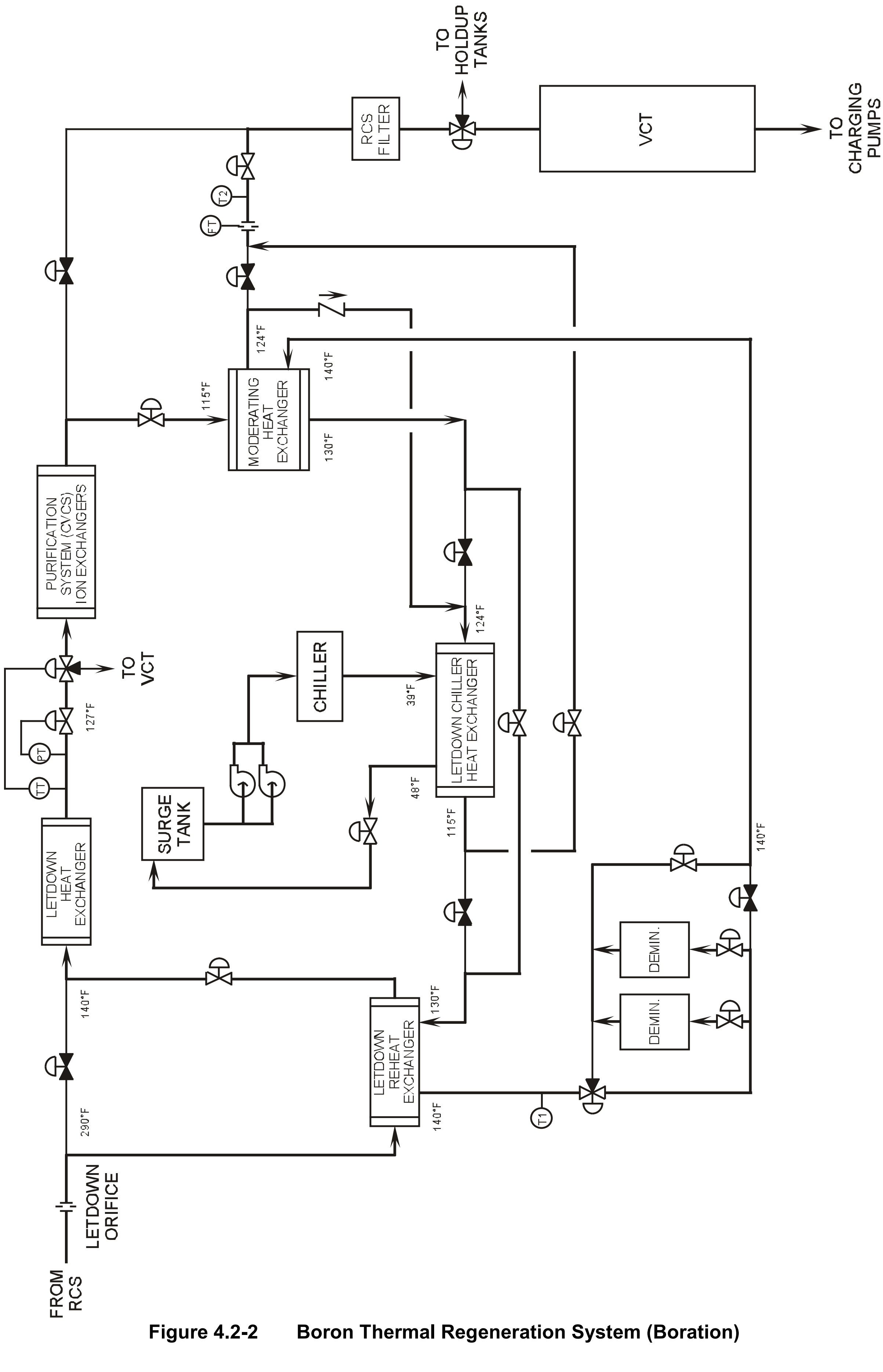

Figure 4.2-2 Boron Thermal Regeneration System (Boration)

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Chapter 5

ESF, RHR, ECCS, CTMT, AFW Systems

Section

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Section 5.0

Introduction to Engineered Safety Features

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5.0 INTRODUCTION TO ENGINEERED SAFETY FEATURES

Learning Objectives:

1. State the purposes of the Engineered Safety Feature (ESF) Systems.

2. Identify the three barriers designed to limit the escape of fission products to the environment.

3. Explain the following terms:

    a. Redundancy
    b. Physical and electrical separation
    c. Regulatory terms associated with safety:
        - Important to safety
        - Safety related
        - Safety grade

    d. Seismic Category I
    e. Diversity
    f. Single failure
    g. Active failure
    h. Passive failure
    i. ESF train

4. List the four design categories or conditions of operation and give an example of each.

5. List the five acceptance criteria for the Emergency Core Cooling Systems (ECCSs).

5.0.1 Introduction

In a large nuclear generating station with a core output rated at over 3,000 MW thermal, about 6 pounds of fission products are produced each day the unit is operated at full power. To protect the public from these fission products, a multiple barrier concept is incorporated into the design of the plant.

The first barrier consists of an enclosed cylindrical cladding that surrounds the fuel pellets and is designed to contain the fission products.

The second barrier is the reactor coolant system (RCS) pressure boundary. This barrier is designed to withstand high pressures and temperatures. The thickness of this barrier varies from a few inches for the reactor coolant loop piping, about 8 inches for the reactor vessel walls, and about one-tenth of an inch for the steam generator U-tubes. Since the RCS pressure boundary surrounds the first barrier, it will contain any fission products that escape from the cladding.

The final barrier of protection is the containment (reactor building). Many approved designs are used, but all contain the reactor coolant system and provide a third barrier to the release of radioactivity to the public.

The three barriers and the protection against the loss of each barrier is required by the Code of Federal Regulations. The reactor trips based on avoiding departure from nucleate boiling (DNB) and excessive local power densities (kw/ft.) are installed to protect the first barrier (fuel cladding) from damage. The high-pressure reactor trip and the pressurizer code safety valves provide protection for the second barrier (RCS) by limiting the pressure in the RCS to less than its design pressure. Finally, the design of the containment, its support systems, and allowable leakage specifications help to insure the integrity of the containment.

5.0.1.1 **LOCA Description**

Consider the effect on the fuel cladding and the containment if a gross failure of the reactor coolant system occurs without the benefit of the engineered safety features. When a loss-of-coolant accident (LOCA) occurs, hot pressurized reactor coolant is forced out of the reactor coolant system, and pressure in the RCS rapidly decreases. An automatic reactor shutdown occurs because of this decrease in pressure and the control rods drop into the core. The fission process in the core is all but stopped and heat production drops to the decay heat value. As the coolant rapidly escapes via the break, containment temperature and pressure begin to increase. In a short time, the reactor coolant system has flashed to steam, and the pressure has equalized with the pressure inside the containment. At this time the blowdown phase of the loss of coolant accident has ended.

The fuel cladding begins to heat up following the blowdown phase of the accident. When the cladding temperatures exceed 2200°F, a zirconium-water reaction starts to occur. The hydrogen produced from this chemical reaction escapes into the containment, and the exothermic reaction causes an extra heat input into the cladding. The extreme pellet temperatures cause increased fuel rod pressures and the weakened cladding begins to bow. As the zirconium-water reaction continues, the zircalloy cladding begins to undergo metallurgical changes and becomes brittle, adding to its destruction.

As a result of the cladding degradation, fission products are released from the reactor coolant system to the containment through the RCS break. Two of the three barriers have now failed, and the third barrier is threatened. The containment pressure has increased due to the blowdown phase and will cause the escape of fission products to the environment through minute leakage paths. For some plant designs, the potential for a gross failure of the containment due to a hydrogen explosion is of great concern. For others the continuous heat input into the containment can cause the pressure and temperature to increase to the point where the containment could rupture.

However, the engineered safety feature systems are installed in nuclear units to mitigate the consequences of the loss of the reactor coolant system pressure boundary. Among these systems are the emergency core cooling systems, which are actuated automatically during accident situations.

When a safety injection actuation signal is generated, borated water is pumped from the refueling water storage tank to the reactor coolant system, and the reactor vessel is refilled. This reflooding of the core from the refueling water storage tank is called the injection phase of the LOCA. With a flow of water into the core, decay heat is removed and the fission product release due to cladding failure is minimized. Consider the following major issues concerning the ECCSs.

First, if only one pump is installed and it fails, the consequences of a LOCA are the same as those previously discussed. But if a redundant pump that is also capable of supplying 100% of the required core cooling is installed, then the public can be protected. General Design Criterion (GDC) 35 of 10 CFR 50, Appendix A, requires redundant emergency core cooling systems.

Next, if only one sensor is used to actuate the ECCS, and it fails in a nonconservative direction, the core will not be reflooded, regardless of the number of ECCS pumps installed. If the sensor fails in the conservative direction, then an unnecessary actuation of ECCS equipment would occur. Therefore, IEEE-279 requires that redundant sensors, as well as redundant instrument strings, logic devices, and actuating devices, be installed.

After providing protection for the first two contingencies as stated above, a loss of power to the emergency core cooling system pumps must be considered. The normal power supplies to the pump motors come from the electrical grid by way of transformers, breakers, and buswork. Because this distribution system is vulnerable to thunderstorms, tornadoes, hurricanes, icing, and other acts of nature; a standby (emergency) power system is provided to ensure a power supply to the ECCS pump motors.

Redundant diesel generators are normally used as the standby power supply. GDC 17 of 10 CFR 50, Appendix A, outlines the requirements for electrical power distribution.

Finally, the emergency equipment must be designed to remain operational during a postulated seismic event. Paraphrasing 10 CFR 100, nuclear plant components designated to prevent or mitigate the consequences of accidents must be designed and built to remain functional during the design basis earthquake. Components satisfying this requirement are designated Seismic Category I.

In summary, the emergency core cooling systems must be redundant, actuated by redundant sensors, powered from redundant electrical power sources, and designed to be operational during seismic events.

5.0.1.2 **Emergency Core Cooling Systems**

Certain systems are installed to provide emergency cooling to the core in the event of a LOCA. These systems include the high, intermediate, and low-pressure injection systems, and the cold leg accumulators.

The high-pressure injection system, consisting of two redundant trains, provides protection for small-break LOCAs (SBLOCAs). This system pumps water from the refueling water storage tank (RWST) into the RCS cold legs during the injection phase. The high-pressure system can also be used during the recirculation phase by connecting its suction to the residual heat removal system. In addition, this system injects boric acid from the RWST into the RCS during steam break accidents to offset the positive reactivity added by the rapid cooldown of the RCS.

The intermediate pressure injection system (safety injection system), provides protection for small to intermediate sized loss of coolant accidents. It has a greater capacity than the high-pressure injection system but less than the low-pressure injection system. Both safety injection system trains take suction from the RWST during the injection phase of the accident. Like the high-pressure injection system, it can also be used during the recirculation phase by connecting its suction to the residual heat removal system.

The low-pressure injection system (residual heat removal system) provides protection for a large loss of coolant accident. This system consists of two trains which can pump at a high rate of flow and at a low pressure from the RWST to the reactor coolant system. These pumps are also supplied with suction from the containment emergency core cooling recirculation sump. This suction source will be used during the recirculation phase of the accident. In addition to supplying cooling water to the reactor vessel, these pumps can also supply the suctions of the intermediate and high-pressure injection systems.

The cold leg accumulators consist of four tanks filled with borated water and pressurized with nitrogen. When the RCS is pressurized and the reactor is at power, check valves, held closed by the higher reactor coolant system pressure, prevent the entry of water from the accumulators into the reactor coolant system. However, if a loss of coolant accident results in a reactor coolant system pressure lower than the pressure in the accumulators, then borated water will flow from the accumulators to the reactor vessel, via the cold legs. This system, unlike the high, intermediate, and low-pressure injection systems, requires no actuation signal.

In addition to emergency core cooling systems, the engineered safety features design includes provisions to protect the containment barrier and to remove the core decay heat (auxiliary feedwater system).

5.0.1.3 **Containment Barrier Protection**

The containment spray system is installed to reduce the pressure inside the containment following a loss of coolant accident or a steam line break within the confines of the containment. The containment spray system satisfies the same design requirements as the emergency core cooling system. In addition to the containment spray system, other methods of controlling the containment pressure include containment fan coolers and hydrogen recombiners.

5.0.1.4 **Decay Heat Removal**

When the reactor trips, the rapid insertion of the control rods stops the heat production from the fission process. However, the heat production from fission product decay continues. This decay heat is normally removed by converting feedwater to steam in the steam generators. The main feedwater system does not meet safety system design criteria and if it is lost, the steam generators will boil dry. When the secondary inventory is lost, the decay heat will not be removed from the core. As the fission product decay continues, the resultant heat production causes an increase in reactor coolant temperature and a corresponding increase in RCS pressure. If left unchecked, the temperature and pressure increases will result in a challenge to the reactor coolant system pressure boundary.

The auxiliary feedwater system is designed to provide feedwater to the steam generators to remove decay heat in the event of a loss of main feedwater. The auxiliary feedwater system meets the same design criteria as the emergency core cooling system.

The emergency systems installed to mitigate the consequences of accidents are among the most important systems in the nuclear plant. Normally these systems are aligned for the injection phase. However, if the safety system is in use performing one of its non-safety functions, it will be automatically re-aligned to perform its safety function upon receipt of an engineered safety features actuation signal.

5.0.2 Terms

5.0.2.1 **Redundancy**

If a component such as a pump is installed to provide a safety function, a second 100% backup pump must also be installed. This convention is known as redundancy. Redundant instrument sensors, instrument strings, and logic devices are required to ensure that no single failure will prevent at least one of these components from performing their intended function.

5.0.2.2 **Physical and Electrical Separation**

All engineered safety feature systems must be physically separated so that a catastrophic failure of one system will not prevent another engineered safety feature system from performing its intended function. Electrical power to the engineered safety features comes from the transmission grid via transformers, breakers and bus work. Because this distribution system is vulnerable to thunderstorms, hurricanes, icing, and other acts of nature, a standby power system is provided to insure a reliable source of power. Redundant diesel generators are normally used for this standby power supply. These standby power supplies are normally arranged into redundant trains (typically Train A and Train B), which provide power to separate trains of redundant safety features.

5.0.2.3 **Regulatory Terms Associated With Safety**

1. Important to safety - Those structures, systems, and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. This encompasses the broad class of plant features that contribute in an important way to the safe operation and protection of the public in all phases and aspects of facility operations. This includes “safety grade” or “safety related” as a subset.

2. Safety related - Those structures, systems, or components designed to remain functional during a safe shutdown earthquake (SSE) and are necessary to assure:
   a. The integrity of the reactor coolant system pressure boundary,
   b. The capability to shut down the reactor and maintain it in a safe shutdown condition, or
   c. The capability to prevent or mitigate the consequences of accidents which could result in potential off-site exposures comparable to the guidelines in 10CFR 100, Appendix A.

3. Safety grade - This term is not explicitly used in regulations. It is equivalent to “safety related,” and is a subset of “important to safety.”

5.0.2.4 **Seismic Category I**

Those structures, systems, and components, including their foundations and supports, designed to remain functional if the safe shutdown earthquake occurs have been designated as Seismic Category I.

The following constitutes the systems and components designated as Seismic Category I.

1. The reactor coolant pressure boundary,
2. The reactor core and vessel internals, and
3. Systems or portions of systems that are required for emergency core cooling, post-accident containment heat removal, and post-accident containment atmosphere cleanup.

Seismic Category I design requirements extend to the first seismic restraint beyond the identified boundaries.

5.0.2.5 **Diversity**

Diversity refers to different methods of providing the same safety protection or function. An example of this is the containment fan cooler system and the containment spray system. Both of these systems are designed to lower the pressure inside the containment following a steam break or a loss of coolant accident inside the containment.

5.0.2.6 **Single Failure (Active/Passive)**

A “single failure” is an occurrence which results in the loss of capability of a component to perform its intended safety function when called upon. Multiple failures resulting from a single occurrence are to be considered as a single failure. Fluid process systems are considered to be designed to withstand an assumed single failure if neither a single active nor a single passive failure results in a loss of the safety function to the nuclear unit.

An “active failure” is a malfunction, excluding passive failures, of a component which relies on mechanical movement to complete its intended function on demand.

Examples of active failures include the failure of a powered valve or a check valve to move to its correct position, or the failure of a pump, fan, or diesel generator to start.

Spurious action of a powered component originating within its actuation system shall be regarded as an active failure unless specific design features or operating restrictions preclude such spurious actions.

A “passive failure” is a breach of a fluid pressure boundary or blockage of a process flow path.

The design flow limit for a passive failure (i.e., flow from a pressure boundary breech or flow through the blockage of a process flow path) is analyzed by the utility. This is done by performing an analysis of passive failures in the system, considering conditions of operation and possible failure or leakage modes as appropriate. For example, a review of a system that contains piping, heat exchangers, valves, flanged joints, and system interface barriers might result in the definition of a design leak rate for passive failure in that system based on the maximum flow through a failed packing or mechanical seal rather than complete severance of the piping.

In lieu of this analysis, the designer must consider complete severance of the piping and an independently complete blockage of the process path as a passive failure.

5.0.3 General Design Requirements

The engineered safety feature systems are provided in nuclear power plants to mitigate the consequences of reactor plant accidents. Sections of the General Design Criteria (refer to Chapter 1.1) require the installation of specific ESF systems. Containment systems, the residual heat removal (RHR) system, emergency core cooling systems, containment heat removal systems, containment atmospheric cleanup systems and certain cooling water systems are typical of the systems required to be provided as ESF systems. Each of the ESF systems is designed to withstand a single failure without loss of its protective function capabilities during or following an accident condition.

5.0.3.1 **Failure Criteria**

The ESF systems are designed to withstand any single failure without loss of core and containment protection. However, this single failure is limited to either an active failure during the injection phase (a short period of time until the RWST empties) following an accident, or an active or a passive failure during the recirculation phase (a long period of time when water is taken from the containment recirculation sump, cooled by the RHR heat exchangers and pumped back into the RCS).

Most accidents are analyzed assuming a loss of off-site power conditions. This loss of off-site power is considered in addition the “single active failure.”

5.0.3.2 **ESF Train**

The engineered safety features which contain active components are designed with two independent trains. This convention is illustrated by the ECCSs, of which either train can satisfy all the requirements to safely shut down the plant or meet the final acceptance criteria following an accident.

The Technical Specifications state that one ECCS train consists of:

1. One centrifugal charging pump,
2. One safety injection pump,
3. One RHR pump,
4. An operable flow path from the RWST to the RCS and from the containment sump back to the RCS, and
5. Power supplies and instrumentation for the above items.

To guarantee that at least one train of the ECCS is available if an accident occurs, both trains must meet the operability requirements in the Technical Specifications whenever the temperature of the RCS is above 350°F. This will allow for the single active failure of the emergency power source (diesel generator), and still retain one train of ECCS for accident mitigation.

5.0.3.3 **Typical Engineered Safety Feature Systems**

The typical ESF systems that may be found at a Westinghouse nuclear power plant are listed below.

1. Containment - This Seismic Category I building provides a virtually leak-tight barrier to prevent the release of fission products to the environment.
2. Containment heat removal systems - These systems, containment spray and containment fan coolers, reduce the pressure and temperature inside the containment and remove fission products from the containment atmosphere.
3. Containment isolation system – This system provides isolation capability for the various lines penetrating the containment.
4. Containment combustible gas control system - The hydrogen recombiners control the concentration of hydrogen gas which may be released to the containment following an accident to assure containment integrity.
5. Emergency core cooling systems – These systems deliver the borated water from the RWST to the core following various postulated accidents.
6. Habitability systems – These systems provide the control room with adequate shielding, air purification, and climatic control.
7. Auxiliary feedwater system – This system provides makeup to the steam generators whenever the main feedwater system is not available and thus maintains the primary-to-secondary heat removal capability of the steam generators.
8. Class 1E electrical system - This vital electrical distribution system, including the emergency diesel generators, provides a reliable source of power to the active components of the ESF.
9. Essential support systems – These include any system or subsystem (component cooling water, essential raw cooling water, etc.) which would be required to operate in support of the above systems.

5.0.3.4 Design Categories or Conditions of Operation

Each facility shall, as a condition of licensing, include in its Final Safety Analysis Report (FSAR) a section titled "Accident Analysis." The requirements for the information contained in this section are outlined in 10 CFR 50.34 and are detailed in Regulatory Guide 1.70, Standard Format and Content of Safety Analysis Reports. This regulatory guide sets up a standard approach to ensure the license applicant has analyzed both expected and unexpected transients and accidents, that conservative values are applied in the analysis, and that the plant design has incorporated an adequate margin of safety.

The accident analysis section of the FSAR shall include the analysis of several transients and accidents. These analyzed incidents are placed in four (4) categories or conditions of operation.

Condition I - Normal Operations

Condition I events are those occurrences which are expected to happen frequently or regularly in the course of power operation, refueling, maintenance, or changing power in the plant. Therefore, Condition I occurrences are accommodated with a margin between any plant parameter and the value of that parameter which would require either automatic or manual protective actions. Since Condition I events occur frequently or regularly, they must be considered from the point of view of affecting the consequences of fault conditions (Conditions II, III and IV). In this regard, analysis of each fault condition described is generally based on a conservative set of initial conditions corresponding to adverse conditions which can occur during Condition I operation. Below is a typical list of Condition I events:

1. Steady state and shutdown operations.

   a. Power operation (15-100% of full power)
   b. Start up (or standby) (critical, 0-15% of full power)
   c. Hot shutdown (subcritical, residual heat removal system in operation)
   d. Refueling

2. Operation with permissible deviations - Various deviations which may occur during continued operation as permitted by the plant Technical Specifications must be considered in conjunction with other operational modes. These include:

   a. Operation with components or systems out of service (such as power operation with a reactor coolant pump out of service)
   b. Leakage from fuel with clad defects
   c. Radioactivity in the reactor coolant

      - Fission Products
      - Corrosion Products
      - Tritium

   d. Operation with steam generator leaks up to the maximum allowed by the Technical Specifications

   e. Testing as allowed by the Technical Specifications

3. Operational testing

   a. Plant heatup and cooldown (up to 100°F/hour for the RCS; 200°F/hour for the pressurizer cooldown only)
   b. Step load changes (up to 10%/minute)
   c. Ramp load changes (up to 5%/minute)
   d. Load rejection up to and including a full load rejection transient

Condition II - Faults of Moderate Frequency

These faults, which are expected to happen on a once-per-year basis and at worst, result in a reactor trip with the plant being capable of returning to operations. By definition, these faults (or events) do not propagate to cause a more serious fault, i.e., a Condition III or IV event. In addition, Condition II events are not expected to result in fuel rod failures or the over pressurization of the RCS. The operational events that meet the above assumptions have been grouped below:

1. Uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition
2. Uncontrolled rod cluster control assembly bank withdrawal at power
3. Rod cluster control assembly misalignment
4. Uncontrolled boron dilution
5. Partial loss of forced reactor coolant flow
6. Start-up of an inactive reactor coolant loop
7. Loss of external electrical load and/or turbine trip
8. Loss of normal feedwater
9. Loss of offsite power to the station auxiliaries.
10. Excessive heat removal due to feedwater system malfunctions
11. Excessive load increase incident
12. Accidental depressurization of the RCS
13. Accidental depressurization of the main steam system
14. Inadvertent operation of emergency core cooling system during power operation

Condition III - Infrequent Faults

Condition III occurrences are faults which are expected to happen once in the 40-year life of the plant. Such an event would result in the failure of only a small fraction of the fuel rods, although sufficient fuel damage might occur to preclude resumption of power operations for a considerable outage time. The release of radioactivity will not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius. A Condition III fault will not, by itself, generate a Condition IV fault or result in a consequential loss of function of the reactor coolant system or containment barriers. The following faults have been grouped into this category:

1. Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates the emergency core cooling system
2. Minor secondary pipe breaks

3. Inadvertent loading of a fuel assembly into an improper position
4. Complete loss of forced reactor coolant flow
5. Single rod cluster control assembly withdrawal at full power

Condition IV - Limiting Faults

Condition IV occurrences are faults which are never expected to take place but are postulated because the events are so severe that the consequences would include the potential for the release of significant amounts of radioactive material. These accidents are the most drastic and therefore represent the limiting design cases. Condition IV faults shall not cause a fission product release to the environment resulting in an undue risk to public health and safety in excess of the guideline values of 10 CFR Part 100. A single Condition IV fault shall not cause a consequential loss of required functions of systems needed to cope with the fault, including those of the emergency core cooling system and the containment. The following faults have been classified in this category:

1. Major ruptures of pipes containing reactor coolant up to and including the double-ended rupture of the largest pipe in the reactor coolant system (LOCAs)
2. Major secondary system pipe ruptures
3. Steam generator tube rupture
4. Single reactor coolant pump locked rotor
5. Fuel handling accident
6. Rupture of a control rod drive mechanism housing (rod cluster control assembly ejection)

5.0.3.5 **Acceptance Criteria for the Emergency Core Cooling Systems (10CFR 50.46**

In 1974, the final acceptance criteria for emergency core cooling systems for light water reactors were established. These criteria require the ECCS to be designed and built so that the calculated cooling performance following a full spectrum of postulated LOCA's would meet the following limits during or following the accident.

1. Peak Cladding Temperature (PCT) shall remain less than 2200°F.
2. Maximum cladding oxidation shall not exceed 17% of the total cladding thickness.
3. Maximum hydrogen generated by the reaction of water or steam with the cladding shall not exceed 1% of the amount that would be generated if all the cladding reacted chemically with water or steam.
4. Coolable geometry - Any changes in core geometry shall be such that the core remains in a coolable configuration.
5. Long-term cooling - Core temperature, after the injection phase, shall be maintained at an acceptably low value. Decay heat shall be removed for the extended period of time required.

5.0.3.6 **Engineered Safety Features Actuation Signals**

Many of the engineered safety feature systems of a facility are actuated by any of the safety injection actuation signals, listed below:

1. High steam line flow coincident with low steam line pressure or low-low T_{avg}.
2. High steam line differential pressure - One steam line lower in pressure than at least two of the remaining three by 100 psid/or more.
3. Low pressurizer pressure – At least two of four measured pressurizer pressures less than setpoint.
4. High containment pressure – At least two of three measured containment pressures greater than setpoint.
5. Manual – Operation of one of two control board switches.

It should be noted that, with a few exceptions, each safety injection actuation signal achieves identical results. That is, regardless of the protection signal being generated, each signal causes the same equipment to be operated.

An additional ESF actuation signal is the containment spray actuation signal, which actuates the containment spray system when containment pressure reaches approximately half of design pressure.

5.0.4 Typical Analysis Limits and Assumptions

For conservatism, each accident that is analyzed assumes the most conservative conditions, setpoints, equipment operability, and other factors which could conceivably affect the severity of the event. Listed below are some of the assumptions used in the accident analysis.

1. Maximum time delays for reactor trip, safety injection actuation, steam line isolation valve closure, etc., are assumed.
2. Starting values for the various plant parameters will be assumed to be at their worst-case conditions.
3. Plant history, reactivity coefficients and other variables affecting the accident are chosen to produce the most severe transient.

5.0.4.1 **Steam Line Break Accident Analysis**

The steam break accident is outlined here as an example of the goals and concerns that are assumed in performing accident analysis.

The analysis is performed to demonstrate that:

1. There is no consequential damage to the primary system and the core remains intact.
2. Energy release for the worst-case break does not cause failure of the containment.
3. There is no return to criticality after the reactor trip for a break equivalent to a stuck-open steam bypass, relief, or safety valve.

5.0.4.2 **Assumptions for Steam Line Break Analysis**

The assumptions used for the steam line break accident are listed as follows:

1. The design end-of-life shut down margin at no-load, equilibrium xenon conditions, and with the most reactive rod stuck in its fully withdrawn position.
2. The negative moderator temperature coefficient corresponding to the end-of-life rodded core with the most reactive rod in the fully withdrawn position. The variation of the coefficient with temperature and pressure has been included.
3. The minimum capability for injection of concentrated boric acid solution corresponding to the most restrictive single active failure in the safety injection system. This corresponds to the flow delivered by one centrifugal charging pump delivering its full contents to the cold legs.
4. The design value of the steam generator heat transfer coefficient, including an allowance for tube fouling.
5. Hot channel factors corresponding to the worst-case stuck rod at end of core life.
6. Several combinations of break sizes and initial plant conditions have been considered in determining the core power transient which can result from large area pipe breaks:

    a. Complete severance of a pipe downstream of the steam flow restrictor with the plant initially at no-load conditions and all reactor coolant pumps running. (Figure 5.0-1).
    b. Complete severance of a pipe inside the containment at the outlet of the steam generator with the same plant conditions as above (Figure 5.0-2).
    c. Case (a) above with loss of outside power simultaneous with the generation of the safety injection signal (loss of ac power results in coolant pump coastdown).
    d. Case (b) above with the loss of offsite power simultaneous with the safety injection signal. A fifth case was analyzed consistent with the criterion stated earlier that there should be no return to criticality after reactor trip in the event of the spurious opening of a steam bypass or relief valve.
    e. A break equivalent to a steam flow of 247 lb/sec at 1100 psi from one steam generator with offsite power available.
7. Initial hot shutdown conditions were considered for all of the above cases since this represents the most pessimistic initial condition for the accident.
8. The containment pressure response was evaluated for case 6.b above, since this results in the most severe steam break containment transient. In addition to the full contents of the faulty steam generating unit being delivered to the containment, it was also assumed that break flow was delivered from the other three steam generators through a failed nonreturn valve in the broken steam line. The latter flow continues until the main steam isolation valves close in the intact steam lines.
9. Perfect moisture separation in the steam generator is assumed. This assumption leads to conservative results since, in fact, considerable water would be discharged. Water carryover would reduce the magnitude of the temperature decrease in the core and the pressure increase in the containment.

5.0.4.3 **Systems Which Provide Protection Against Steam Line Break Accidents**

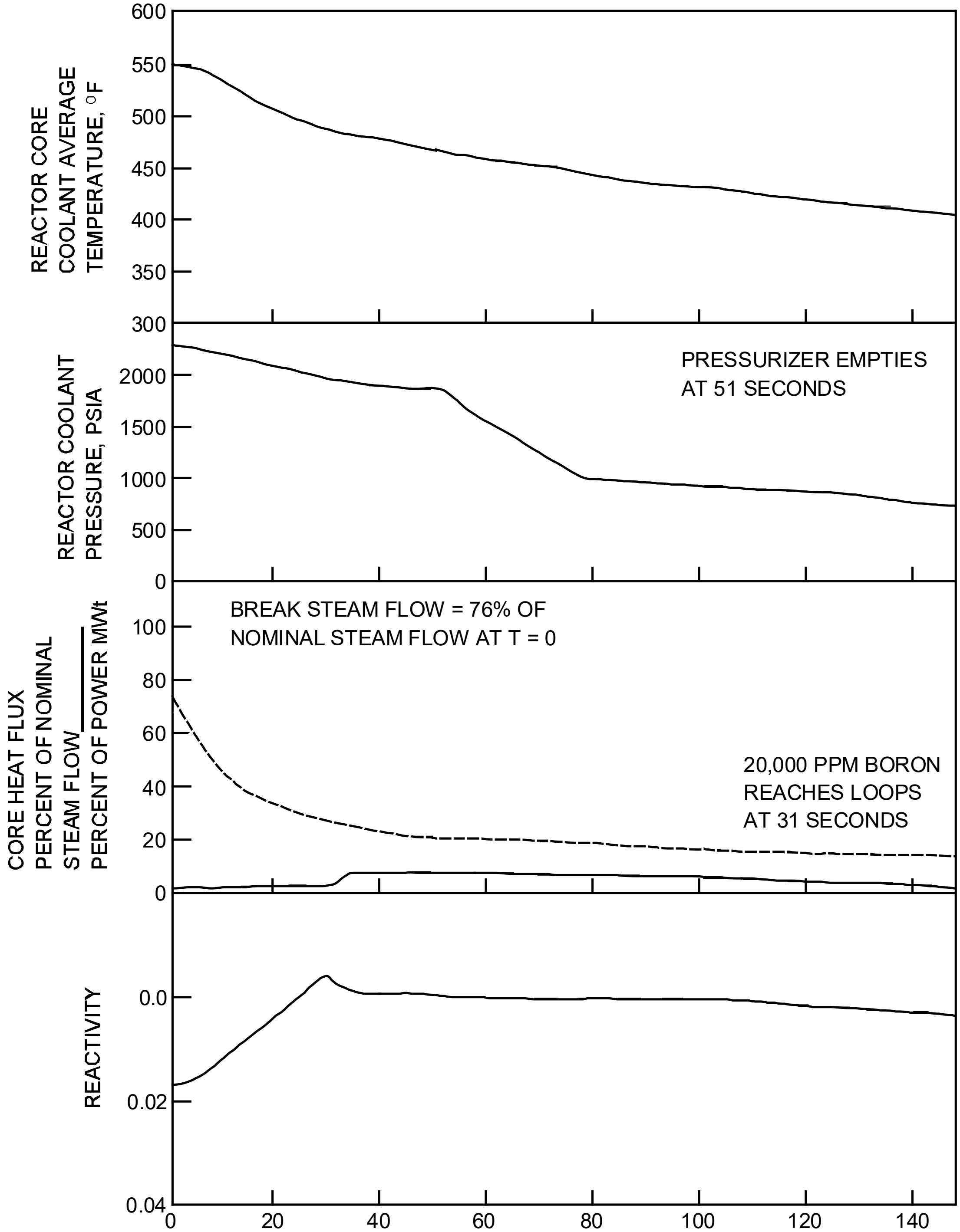
The following protection signals and plant features mitigate the consequences of a main steam line rupture.

1. Safety injection actuation signal (any of the following):
   a. High steam line flow
   b. High steam line differential pressure
   c. Low pressurizer pressure
   d. High containment pressure
2. Reactor trip (any of the following):
   a. High neutron flux
   b. Overpower ΔT
   c. Safety injection reactor trip
3. Main feedwater isolation signal, generating the following responses:
   a. Close feedwater isolation valves
   b. Close feedwater control valves
   c. Close feedwater control bypass valves
   d. Trip main feedwater pumps
4. The shutting of the main steam isolation valves and/or the affected generator's main steam check valve prevents the blowdown of more than one steam generator for any break location.
5. The steam line flow venturi of the affected steam generator limits break flow.

5.0.5 Summary

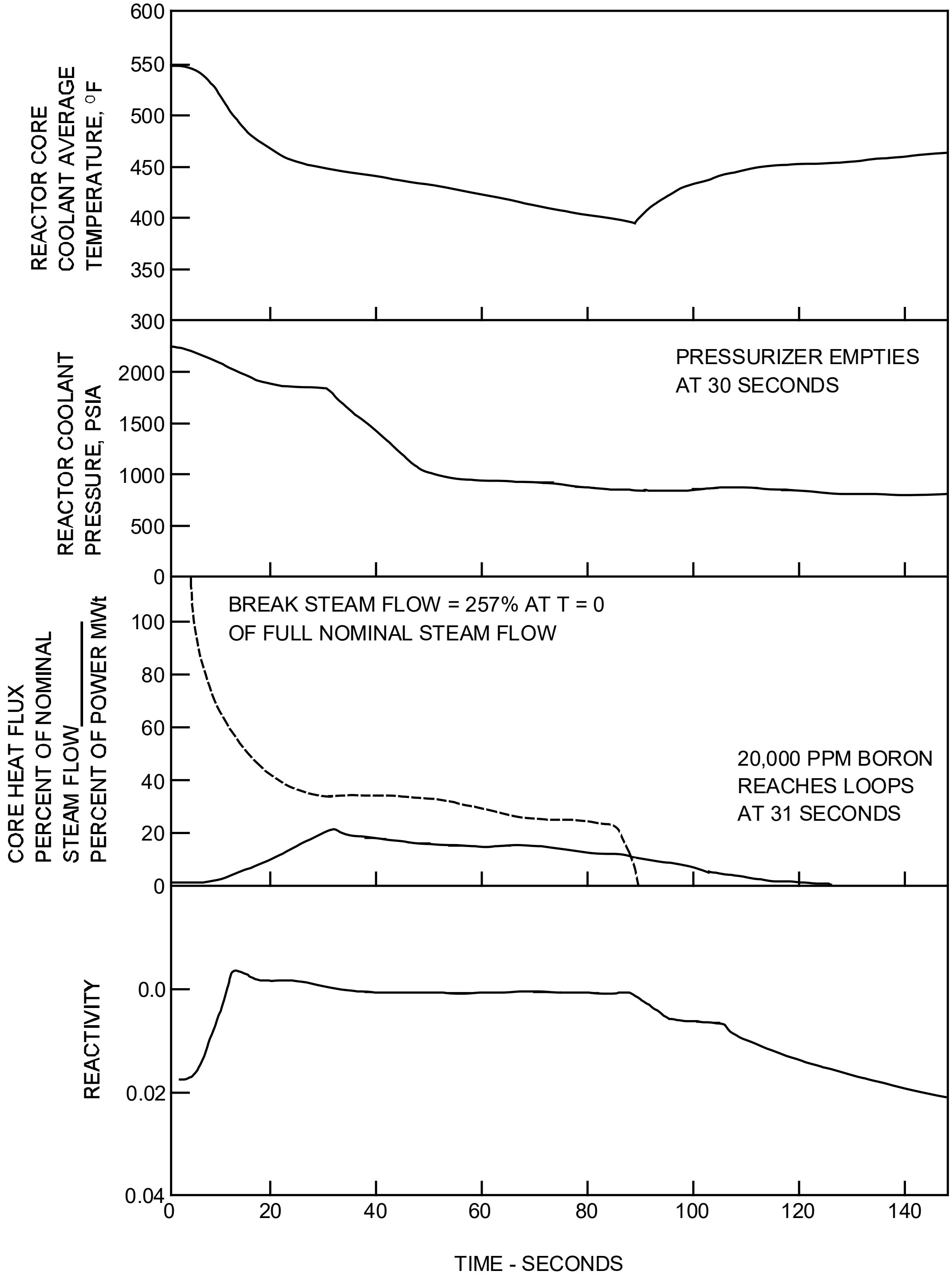
To protect the public from fission products, multiple barriers of protection are incorporated into the design of a commercial pressurized water reactor plant.

If the reactor enters unsafe regions of operation, the reactor protection system will generate a reactor trip to protect the cladding and reactor coolant system pressure boundary (first two barriers of protection). If an accident has occurred, such as a loss-of-coolant accident (LOCA), the reactor protection system actuates the engineered safety feature systems to mitigate the consequences of the accident and to protect the containment (third and final barrier of protection). The engineered safety feature systems must be redundant, actuated by redundant sensors and instrument strings, physically separated, powered from redundant electrical power supplies, and designed to remain operational during seismic events.



Safety Injection with Offsite Power

Figure 5.0-1 Steam Line Break Downstream of Flow Measuring Nozzle



Safety Injection with Offsite Power

Figure 5.0-2 Steam Line Break at Exit of Steam Generator

Westinghouse Technology Systems Manual

Section 5.1

Residual Heat Removal System (RHR)

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5.1 RESIDUAL HEAT REMOVAL SYSTEM (RHR)

Learning Objectives:

1. State the purposes of the Residual Heat Removal (RHR) System.

2. Describe the RHR system flow path including suction supplies, discharge points and major components during decay heat removal.

3. Describe the normal, at-power lineup of the RHR system.

4. Explain why Reactor Coolant System (RCS) pressure and temperature limits are placed on the initiation of RHR cooldown.

5. Explain how the RHR system is protected against over pressurization.

6. Explain how an intersystem LOCA is initiated in the residual heat removal system and what effect it can have on long-term core cooling.

5.1.1 Introduction

The purposes of the residual heat removal system are as follows:

1. Removes decay heat from the core and reduces the temperature of the RCS during the second phase of plant cooldown,
2. Serves as the low-pressure injection portion of the Emergency Core Cooling System (ECCS), following a loss of coolant accident, and
3. Transfers refueling water between the refueling water storage tank and the refueling cavity before and after refueling.

The RHR system transfers heat from the reactor coolant system to the component cooling water system. During shut down plant operations, the RHR system is used to remove the decay heat from the core and reduce the temperature of the reactor coolant to the cold shutdown temperature (< 200°F). The cooldown performed by the RHR system (from 350°F to < 200°F) is referred to as the second phase of cooldown. The first phase of cooldown is accomplished by the auxiliary feedwater (AFW) system (Chapter 5.8), steam dump control system (Chapter 11.2), and the steam generators.

Once the plant is in cold shutdown, the RHR system will maintain RCS temperature until the plant is started up again. The residual heat removal system also serves as part of the emergency core cooling system during the injection and recirculation phases of a loss of coolant accident. The residual heat removal system is used to transfer refueling water between the refueling water storage tank and the refueling cavity before and after the refueling operations.

5.1.2 System Description

The residual heat removal system, as shown in Figure 5.1-1, consists of two heat exchangers, two residual heat removal pumps, and the associated piping, valves, and instrumentation necessary for operational control. The inlet lines to the residual heat removal system for the second phase of cooldown are connected to the hot leg of reactor coolant loop 4, and the return lines are connected to each cold leg of the reactor coolant system. These return lines also function as the emergency core cooling system low pressure injection lines.

The RHR System is normally used to remove the decay and sensible heat from the RCS during plant heatup, cooldown, and refueling when RCS pressure is ≤ 450 PSIG and temperature is ≤ 350°F. The 350°F restriction is based on the RHR pump seal limitations. The 450 PSIG limitation is based on not exceeding RHR System design pressure. The 450 PSIG system limitation plus the RHR pump head of about 150 PSID equals the system design pressure of 600 PSIG.

The RHR pump suction line from the reactor coolant system is normally isolated by two series motor-operated valves (8701&8702). The suction line has a relief valve located downstream of the isolation valves, all of which are located inside the containment. Each RHR pump discharge line is isolated from the reactor coolant system by two check valves located inside the containment and by two normally open motor-operated valves (8809A and 8809B) located outside the containment. These motor operated valves are part of the emergency core cooling system and receive confirmatory open signals from the engineered safety features actuation system. During the second phase of cooldown, reactor coolant flows from the RCS to the residual heat removal pumps, through the tube side of the RHR heat exchangers, and back to the RCS. The heat from the reactor coolant is transferred to the component cooling water which is circulating through the shell side of the RHR heat exchangers.

If one of the two pumps or one of the two heat exchangers is not operable, the ability to safely cooldown the plant is not compromised; however, the time required for the cooldown is extended. When the residual heat removal system is in operation, the water chemistry requirements are the same as that of the reactor coolant system. Provisions are made for extracting samples from the flow of reactor coolant downstream of the RHR heat exchangers for analysis. A local sampling point is also provided on each residual heat removal train between the pump and its associated heat exchanger.

To insure the reliability of the RHR system, the two residual heat removal pumps are powered from separate vital electrical power supplies. If a loss of offsite power occurs, each vital bus is automatically transferred to a separate emergency diesel power supply. A prolonged loss of offsite power would not adversely affect the operation of the residual heat removal system.

The residual heat removal system is normally aligned to perform its safety function. Therefore, no valves are required to change position. For the RHR system to perform its safety function, the RHR pumps must start when the engineered safety features actuation signal is received, and the pressure in the reactor coolant system must drop below the discharge pressure of the RHR pumps.

The materials used to fabricate the RHR system components are in accordance with the applicable ASME code requirements. All parts or components in contact with borated water are fabricated of or clad with austenitic stainless steel or an equivalent corrosion resistant material.

5.1.3 Component Descriptions

5.1.3.1 Residual Heat Removal Pumps

Two pumps are installed in the residual heat removal system. The pumps are vertical, centrifugal units with mechanical seals on the shafts. These seals can be cooled by either component cooling water or service water depending on the plant design. All pump surfaces in contact with reactor coolant are manufactured from austenitic stainless steel or an equivalent corrosion resistant material. The pumps are sized to deliver reactor coolant flow through the residual heat exchangers to meet the plant cooldown requirements.

The residual heat removal pumps are protected from overheating and loss of suction flow by minimum flow bypass lines that assure flow to the pump suction for pump cooling. A control valve located in each minimum flow line (MO-610, 611) is regulated by a signal from the flow transmitters located in each pump discharge header. These control valves open when the RHR pump discharge flow is less than 500 gpm and the pump is running and closed when the flow exceeds 1000 gpm or the pump is not running. A pressure sensor in each pump header provides a signal for an indicator on the main control board. A high-pressure annunciator alarm is also actuated by the pressure sensor.

5.1.3.2 Residual Heat Removal Heat Exchangers

Two heat exchangers are installed in the system. The heat exchanger design is based on the heat load and temperature differences between reactor coolant and component cooling water twenty hours after the reactor has been shut down. The temperature difference between these two systems at that time is at its minimum, thus creating the minimum heat transfer capability.

The heat exchangers are of the shell and U-tube type. Reactor coolant circulates through the tubes while component cooling water circulates through the shell. The tubes are welded to the tube sheet to prevent leakage of reactor coolant.

5.1.3.3 Residual Heat Removal System Valves

Each valve that performs a modulating function is equipped with two stem packing glands and an intermediate leak-off connection that discharges to the drain header.

Manual and motor-operated valves have backseats to facilitate repacking and to limit stem leakage when the valves are open. Leakage connections are provided where required by valve size and fluid conditions. The suction line from the reactor coolant system is equipped with a pressure relief valve sized to relieve the combined flow of all the charging pumps at the relief valve set pressure. This relief valve is installed to provide overpressure protection for the reactor coolant system under solid plant operations.

Each discharge line to the reactor coolant system is equipped with a pressure relief valve to relieve the maximum possible backleakage through the check valves which separate the residual heat removal system from the reactor coolant system. The design of the residual heat removal system includes two isolation valves (8701 and 8702) in series on the inlet line between the high-pressure reactor coolant system and the lower pressure RHR system.

Each isolation valve is interlocked with one of two independent reactor coolant system pressure transmitters. These interlocks prevent the valves from being opened unless the reactor coolant system pressure is less than 425 psig to ensure that the RHR system is not over pressurized. After the valves are open, another set of interlocks will cause the valves to automatically close when the reactor coolant system pressure increases to approximately 585 psig.

5.1.4 System Features and Interrelationships

5.1.4.1 Plant Cooldown

The initial phase of reactor cooldown is accomplished by transferring heat from the RCS to the steam and power conversion system across the steam generator tubes. The second phase of cooldown starts with the RHR system being placed in operation. The RHR system is placed in operation approximately four hours after reactor shutdown, when the temperature and pressure of the RCS are approximately 350°F and 425 psig, respectively.

Assuming that two heat exchangers and two RHR pumps are in service, and that each heat exchanger is being supplied with component cooling water at its design flow rate and temperature, the RHR system is designed to reduce the temperature of the reactor coolant from 350°F to 140°F within 16 hours. The heat load handled by the residual heat removal system during the cooldown includes residual and decay heat from the core, and reactor coolant pump heat. The design heat load is based on the decay heat fraction that exists at 20 hours following reactor shutdown from extended operations at full power. Coincident with operation of the residual heat removal system, a portion of the reactor coolant flow may be diverted from downstream of the residual heat removal heat exchangers to the chemical and volume control system (CVCS) low pressure letdown line for cleanup and/or pressure control.

Startup of the residual heat removal system includes a warmup period during which time reactor coolant flow through the heat exchangers is limited to minimize thermal shock to the heat exchangers. The rate of heat removal from the reactor coolant is manually controlled by regulating the coolant flow through the RHR heat exchangers.

Component cooling water is supplied at a constant flow rate to the RHR heat exchangers. The temperature of the return flow can be controlled by manually adjusting the control valves (606, 607) downstream of the RHR heat exchangers. In coincident with the manual adjustment of the heat exchanger outlet valves, a heat exchanger bypass valve (HCV-618) is manually adjusted to maintain a constant flow through each train of the RHR system.

The reactor coolant system cooldown rate is limited by equipment cooldown rates based on allowable stress limits. The available cooldown rate can be affected by the operating temperature limits of the component cooling water system. As the reactor coolant temperature decreases, the reactor coolant flow through the RHR heat exchangers is gradually increased by adjusting the control valve in each heat exchanger outlet line. The normal plant cooldown function of the residual heat removal system is independent of any engineered safety features function.

The normal cooldown return lines are arranged in parallel redundant flow paths and are also utilized as the low-pressure emergency core cooling injection lines to the reactor coolant system. Utilization of the same return lines for emergency core cooling as well as for normal cooldown lends assurance to the proper functioning of these lines for engineered safety features purposes.

5.1.4.2 Solid Plant Operations

The residual heat removal system is used in conjunction with the chemical and volume control system (Figure 5.1-2) during cold shutdown operations (< 200°F) to maintain reactor coolant chemistry and pressure control. Solid plant operation (i.e., no steam bubble in the pressurizer) is one method of operating the plant during the cold shutdown period. This mode of operation is generally limited to system refill and venting operations. Solid plant operation receives its name from the fact that the reactor coolant system is completely filled to the top of the pressurizer with liquid coolant.

The RHR system circulates reactor coolant from the loop 4 hot leg to the cold leg connections on each loop. The RHR system is essentially operating as an extension of the reactor coolant system and is completely filled with reactor coolant. Pressure in the system can be changed by either changing the temperature of the reactor coolant or by varying the mass of the reactor coolant within the system. Varying the temperature of the reactor coolant is not an effective method of RCS pressure control due to the time required to heat the coolant and the large pressure changes that are experienced for a small temperature change. Volume control of the reactor coolant is preferred because it is fast responding, and any desired pressure change can be obtained within controllable limits. Since it is preferred to control the mass in the RCS for pressure control, a portion of the RHR flow is diverted to the chemical and volume control system through valve HCV-128.

The volume of water diverted to the CVCS is controlled by the position of the backpressure regulating valve PCV-131, which is located downstream of the letdown heat exchanger. During solid plant operations the volume of water returned to the reactor coolant system is determined by the charging rate, which is controlled by manually positioning the charging flow control valve HCV-182. The chemical and volume control system is also a water solid system, with the exception of the volume control tank, which acts as a buffer or surge volume for the purpose of pressure control. Pressure is controlled by maintaining a constant charging rate and varying the flow rate of the water into the chemical and volume control system (PCV-131). To maintain a constant pressure in the RCS, both flow rates (charging and letdown), must be equal. If the charging rate exceeds the letdown rate, then the pressure in the RCS will increase. Conversely pressure in the RCS will decrease if the letdown flow rate exceeds the charging flow rate.

Normally the backpressure regulating valve, PCV-131, is maintained in the automatic mode of operation and set to control the reactor coolant pressure at a desired setpoint. The volume control tank absorbs any mismatches in flow rates between charging and letdown. Pressure regulation is necessary to maintain the pressure in the RCS to a pre-selected range dictated by the fracture prevention criteria requirements of the reactor vessel.

5.1.4.3 Refueling

Both residual heat removal pumps are utilized during refueling to pump borated water from the refueling water storage tank to the refueling cavity. During this operation, the isolation valves in the inlet line from the reactor coolant system (8701, 8702) are closed, and the isolation valve from the refueling water storage tank (8812) is opened. The reactor vessel head is lifted slightly, refueling water is pumped into the reactor vessel through the normal RHR system return lines, into the refueling cavity through the open reactor vessel. The reactor vessel head is gradually raised as the water level in the refueling cavity increases. After the water level reaches the normal refueling level, the reactor coolant system inlet isolation valves are opened and the refueling water storage tank supply valves are closed.

During refueling, the residual heat removal system is maintained in service with the number of pumps and heat exchangers in operation as required by the heat load and Technical Specification minimum flow requirements.

After completion of the refueling, the RHR system is used to return the water from the refueling cavity to the refueling water storage tank via a manual isolation valve. The water level is brought down to the flange of the reactor vessel. The remainder of the water in the refueling cavity is removed through drains located in the bottom of the refueling canal.

5.1.4.4 Emergency Core Cooling

The residual heat removal system functions in conjunction with the higher pressure portions of the emergency core cooling systems to inject borated water from the refueling water storage tank into the RCS cold legs during the injection phase following a loss of coolant accident. The residual heat removal system is aligned as shown in Figure 5.1-1. After the injection phase, the RHR system provides long-term recirculation capability for core cooling. This function is accomplished by aligning the residual heat removal system to take water from the containment sump (opening valves 8811A&B and closing valves 8700A&B and 8812), to cool it by circulating it through the residual heat removal heat exchangers, and to pump it back to the core through the cold leg penetrations. If pressure in the RCS is greater than the discharge pressure of the RHR pumps, water may be returned to the core by the centrifugal charging pumps (8804A) and the safety injection pumps (8804B), with the RHR pump discharge serving as the suction source from those pumps.

In the event of a loss of coolant accident, fission products may be circulated through parts of the residual heat removal system that are exterior to the containment. If a residual heat removal pump seal should fail, the water would spill out on the floor in a shielded compartment. Each pump is located in a separate, shielded room. If one of the rooms floods, it would have no effect on the other train since there are no interconnections between trains during the recirculation phase.

Provisions are made for draining spillage into a sump which is provided with dual pumps and suitable level instrumentation so that this spillage can be pumped to the waste disposal system.

5.1.5 PRA Insights

A type of LOCA which has become a safety concern is the intersystem loss of coolant accident, sometimes called “Event V.” An intersystem LOCA is of concern because the coolant is lost outside the containment, and therefore would not be available for recirculation from the containment sump.

The intersystem LOCA is a small contributor to core damage frequency (4% at Surry, 0.1% at Zion, and 0.4% at Sequoyah). The failure that leads to an intersystem LOCA is the failure of the check valves in the low-pressure injection system (RHR). This would lead to a loss of coolant outside the containment building. The water would not be available for recirculation from the containment sump.

Probable causes of an intersystem LOCA include:

1. Transfer open of one check valve followed by the rupture of the second interface valve,
2. Failure of one valve to close on re-pressurization followed by the rupture of the second valve,
3. Rupture of the interface valve, and
4. Operator failure to isolate the interfacing valve.

NUREG-1150 studies on importance measures have shown that Event V is a contributor to risk achievement, but a very minor contributor to risk reduction. Specifically, a large increase in the probability of the check valve rupture event involved in the intersystem LOCA would increase the core damage frequency (a factor of 30 at Sequoyah and a factor of 270 at Surry). Reducing the probability of the Event V initiators did not have a significant effect on the risk reduction factors.

5.1.6 Summary

The residual heat removal system performs both normal plant functions and accident functions. The normal plant function is the transfer of heat from the reactor coolant system to the component cooling water system during shutdown operations. This is referred to as the second phase of plant cooldown, which starts when RCS T_{avg} is at 350°F. The RHR System is designed to remove the decay heat associated with the shutdown reactor until the plant is restarted. During the shutdown, if solid plant operations are desired, the RHR system is used in conjunction with the chemical and volume control system for solid plant pressure control.

The RHR system is normally aligned to perform its accident function. During the injection phase following a loss of coolant accident, water is supplied from the refueling water storage tank to the reactor coolant system cold legs. For long-term cooling and recirculation, the containment sump as the source of water to the RHR system, and the RHR heat exchangers to cool the water as it is returned to the reactor coolant system.

The RHR system is also used during refueling to remove decay heat and to transfer water between the refueling water storage tank and the refueling cavity.

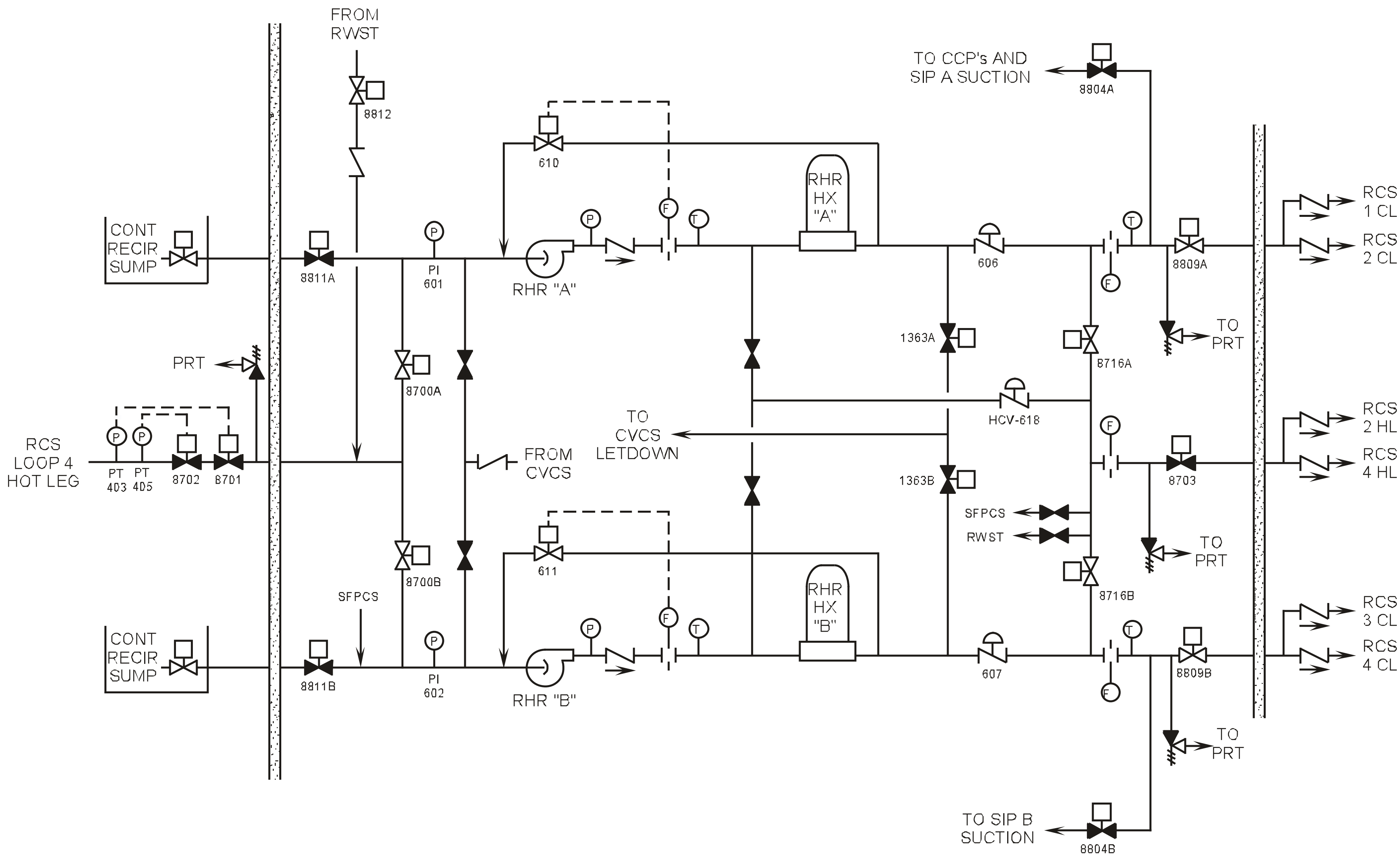

Figure 5.1-1 Residual Heat Removal System

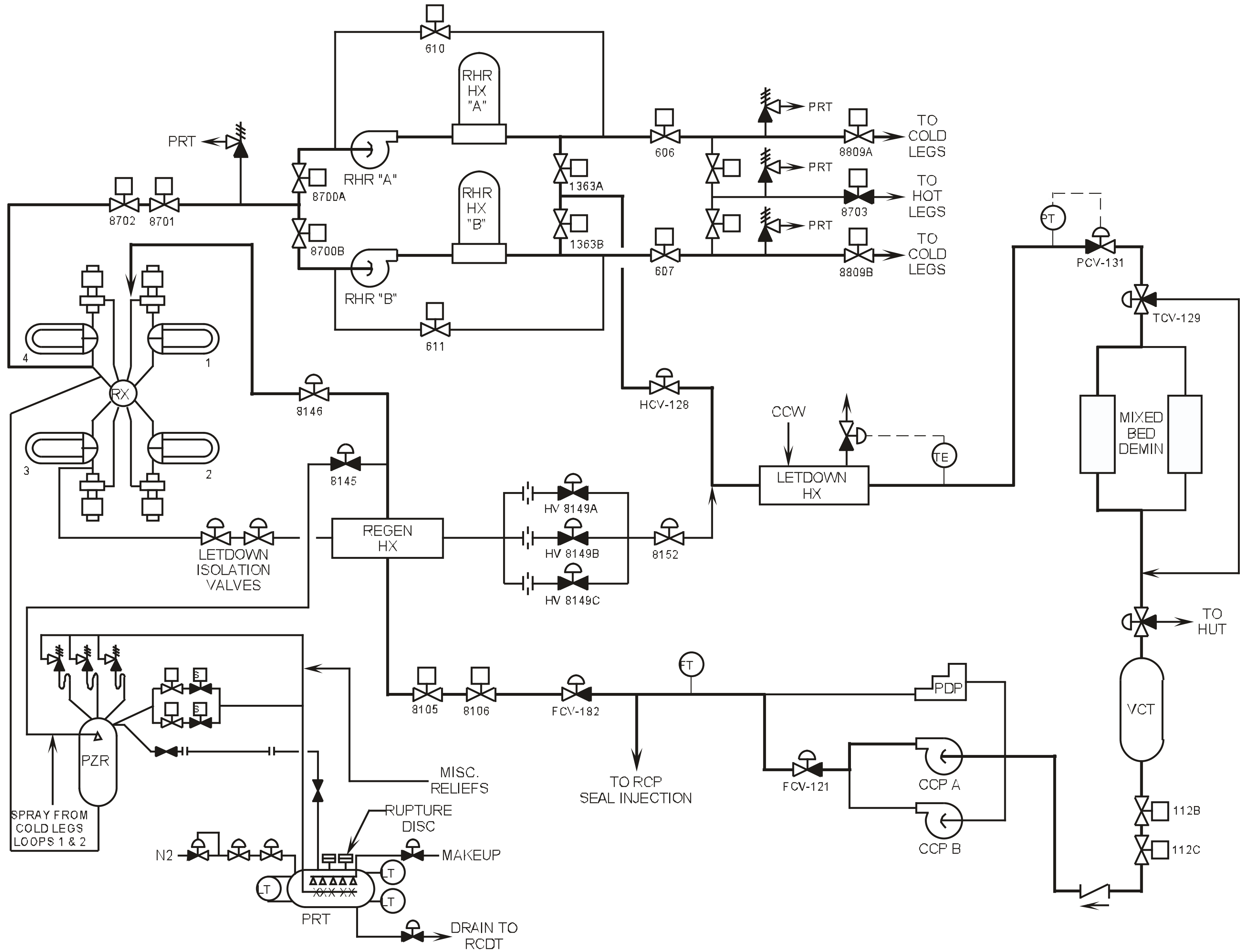

Figure 5.1-2 Solid Plant Control

Westinghouse Technology Systems Manual

Section 5.2

<u>Emergency Core Cooling Systems (ECCS)</u>

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5.2 EMERGENCY CORE COOLING SYSTEMS (ECCS)

Learning Objectives:

1. Explain why emergency core cooling systems (ECCSs) are incorporated into plant design.

2. State the purposes of the following systems:

   a. Accumulator injection system,
   b. High head injection system,
   c. Intermediate head injection (safety injection) system, and
   d. Low head injection system.

3. State the purposes of the following major components:

   a. Refueling Water Storage Tank (RWST), and
   b. Containment recirculation sump.

4. List the order of ECCS injection during the following abnormal conditions:

   a. Small (slow depressurization) Loss-Of-Coolant Accident (LOCA), and
   b. Large Loss-Of-Coolant Accident (LOCA).

5. Describe the ECCS flow paths during the following modes of operation:

   a. Cold-leg injection,
   b. Cold-leg recirculation, and
   c. Hot-leg recirculation.

5.2.1 Introduction

The purposes of the emergency core cooling systems are as follows:

1. Emergency core cooling systems:

   - Provide core cooling to minimize fuel damage following a LOCA, and
   - Provide additional shutdown margin following a steam line break accident.

2. Cold-leg accumulators (passive system - section 5.2.4.1):

   - Rapidly refill the reactor vessel downcomer and bottom plenum and begin to reflood the core following a large LOCA.

3. High head injection system (active system - section 5.2.4.2):

   - Provides high pressure, low volume safety injection for small to intermediate sized LOCAs, and

- Adds negative reactivity and makes up for reactor coolant contraction by injecting borated water into the Reactor Coolant System (RCS) following a steam line break.

4. Intermediate head injection (safety injection) system (active system - section 5.2.4.4):
   - Provides intermediate pressure, low volume safety injection for small to intermediate sized LOCAs.
5. Low head injection system (active system - section 5.2.4.5):

   - Provides low pressure, high volume safety injection to complete the reflooding of the core following a LOCA, and
   - Provides a flow path and heat sink for long-term core cooling following a LOCA.

As listed above, the emergency core cooling systems consist of one passive system and three active systems.

The passive system (accumulators) consists of large volume tanks of borated water pressurized with nitrogen. The pressure in the passive system is less than that of the RCS. Following an accident, when RCS pressure decreases below tank pressure, the borated water is injected.

The active systems (high, intermediate, and low-pressure injection systems) consist of several pumping systems capable of varying discharge pressures and flow rates. Each of these systems does not start until it receives an accident initiation signal (a safety injection actuation). Once started, these systems inject borated water into the RCS as the RCS pressure decreases below the discharge pressures of the system pumps.

The ECCSs are designed to cool the reactor core and provide additional shutdown capability following initiation of the following accident conditions:

1. Loss of coolant from the RCS in excess of the normal makeup capability,
2. Steam generator tube rupture, and
3. Pipe break in the main steam system.

The emergency core cooling systems provide reactor shutdown capability for the accidents listed above by means of chemical poison (boron) injection.

5.2.2 **Regulatory Requirements**

5.2.2.1 General Design Criteria

The Emergency Core Cooling Systems (ECCS) are designed in accordance with 10 CFR 50, Appendix A, General Design Criteria 35, 36, and 37. Criteria 36 and 37 address system inspection and testing. Criterion 35 states:

> A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.
>
> Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

5.2.2.2 ECCS Acceptance Criteria

The emergency core cooling systems must also meet the requirements of 10 CFR 50.46, the acceptance criteria for ECCSs for light-water nuclear power reactors. 10 CFR 50.46, in part, states:

> Each ... pressurized light-water nuclear power reactor fueled with uranium oxide pellets within cylindrical zircaloy or ZIRLO cladding must be provided with an emergency core cooling system that must be designed so that its calculated cooling performance following postulated loss-of-coolant accidents conforms to the [following] criteria:
>
> 1. *Peak Cladding Temperature*. The calculated maximum fuel element cladding temperature shall not exceed 2200°F.
> 2. *Maximum Cladding Oxidation*. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.
> 3. *Maximum hydrogen generation*. The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.
> 4. *Coolable Geometry*. Calculated changes in core geometry shall be such that the core remains amenable to cooling.
> 5. *Long-term cooling*. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

5.2.3 **General Description**

The emergency core cooling systems are comprised of the accumulators, the Centrifugal Charging Pumps (CCPs), the Safety Injection Pumps (SIPs), the Residual Heat Removal (RHR) pumps, the RHR heat exchangers, the Refueling Water Storage Tank (RWST), the containment recirculation sump, and the associated valves and piping. Table 5.2-1 lists normal parameter values associated with these systems; Figure 5.2-1 provides a composite diagram of the systems. The order of system injection into the RCS is dependent on the nature and severity of the accident.

For large reactor coolant pipe ruptures, the RCS would be depressurized and voided of coolant rapidly; a high flow rate of emergency coolant is required to quickly recover the exposed fuel rods and to limit core damage. This high flow is provided almost immediately by the passive cold-leg accumulators and then subsequently by the active CCPs, safety injection pumps, and RHR pumps discharging into the cold legs of the RCS. The suction source for all active systems is the RWST.

Emergency cooling is provided for smaller reactor coolant pipe ruptures primarily by the high head and intermediate head injection pumps. A small-break LOCA (SBLOCA) has an equivalent diameter of 6 inches or less and does not immediately depressurize the reactor coolant system below the accumulator discharge pressure. As the RCS depressurizes during an SBLOCA, the centrifugal charging (high head injection) pumps and possibly the safety injection (intermediate head injection) pumps deliver borated water at the prevailing RCS pressure to the cold legs of the RCS. During the injection, the pumps take suction from the RWST.

In response to a steam pipe break, injection by the CCPs makes up for the reactor coolant contraction (reduction in coolant volume) associated with the break-induced cooldown of the reactor coolant. The borated water from the RWST also adds negative reactivity, which counters the positive reactivity addition from the cooldown.

5.2.4 **System Descriptions**

5.2.4.1 Cold-Leg Injection Accumulators

The accumulators (Figure 5.2-2) are pressure vessels containing borated water and pressurized with nitrogen. During normal operation each accumulator is isolated from the RCS by two seated check valves in series. Should the RCS pressure fall below the accumulator pressure, the check valves unseat, and borated water is immediately forced into the RCS by the expansion of the nitrogen volume. One accumulator is attached to each of the cold legs of the reactor coolant system. The accumulator discharge penetration into each cold leg and the downstream check valve in each accumulator discharge pipe are shared with the intermediate and low head injection systems (see Figure 5.2-1). The accumulators are passive components, since mechanical operation of the swing disc check valves is the only action required to open the injection path from each accumulator to the core via the cold leg.

The accumulator tank volume is approximately two thirds full of borated water; the remaining volume is filled with nitrogen at a pressure greater than 600 psig. The boron concentration (approximately 2000 ppm) is about the same as that of the RWST contents. The technical specification limits on accumulator water volume and nitrogen cover pressure ensure that the discharge from three accumulators is sufficient to rapidly refill the reactor vessel downcomer (the annular space between the vessel and the core barrel) and vessel bottom plenum and to begin reflooding the core so that core damage is limited following a design-basis LOCA. The entire contents of the fourth accumulator are assumed to be completely lost via the RCS pipe break during the blowdown phase of the LOCA and are thus unavailable for core cooling. The boron concentration limits ensure that sufficient negative reactivity is added to maintain post-LOCA subcriticality and ensure acceptable post-LOCA containment recirculation sump pH values.

The accumulator design basis summarized in the preceding paragraph indicates that <u>all</u> four accumulators must be operable (filled to the appropriate level, pressurized to the appropriate value, and borated to the appropriate concentration) when the plant is operating at power. To ensure that no accumulator is inadvertently isolated and to maintain the passive nature of the system, the isolation valve in each accumulator's discharge piping (valve 8808A [B,C,D] in Figure 5.2-2) is maintained open with power removed from its motor operator. During a deliberate plant depressurization, power to the valve motor operators is temporarily restored so that the valves can be closed before plant pressure is less than the accumulator cover pressure. The valves are then maintained shut with power removed during low pressure maintenance and refueling activities.

Each accumulator's nitrogen pressure can be adjusted as required during normal plant operation by supplying nitrogen from the plant's nitrogen supply header or by venting nitrogen to the containment atmosphere. The accumulators are isolated from the nitrogen supply when pressure adjustment is not in progress. A relief valve on each accumulator protects it from pressures in excess of design pressure. Each accumulator has redundant pressure instruments.

The accumulators are located within the containment but outside of the secondary shield wall, which protects them from internally generated missiles. Since the accumulators are located within the containment, a release of nitrogen would cause a small increase in containment pressure. Releases of accumulator gas are detected by accumulator pressure indicators and alarms; the operator would take action promptly as necessary to restore accumulator parameters to within the limits of the technical specification covering accumulator operability.

An accumulator's water level may be adjusted either by draining accumulator contents to the reactor coolant drain tank or by pumping water from the RWST to the accumulator. The RWST water is transferred by a safety injection pump. Each accumulator has redundant level instruments.

Cold leg accumulator design parameters are listed in Table 5.2-2.

Accumulator Check Valves

Each accumulator check valve is designed with a low pressure drop configuration with all operating parts contained within the body. The disc is permitted to rotate, providing a new seating surface after each valve opening. Each valve has a test connection on its upstream side to permit leakage testing. Design considerations and analysis which assure that leakage through both check valves in an accumulator injection line does not impair accumulator availability are as follows:

1. During normal operation each downstream check valve is seated with an approximate differential pressure of 1650 psid across the disc. Since the valve remains in this position except for testing or when called upon to function, and is not, therefore, subject to the abuses of flow operation or impact loads caused by sudden flow reversal and seating, it does not experience significant wear of the moving parts, and hence it is expected to function with minimal leakage.
2. When the reactor coolant system is being pressurized during the normal plant heatup operation, each check valve is tested for leakage as soon as there is a stable differential pressure of about 100 psi or more across the valve. This test confirms the seating of the disc and whether there has been an increase in leakage since the last test. When the leakage testing is completed, the discharge line motor-operated isolation valves are opened, and the RCS pressure increase is continued. There should be no increase in leakage with further RCS pressurization, since increasing the reactor coolant pressure increases the seating forces on the valve discs and decreases the probability of leakage.
3. The accumulators can accept some in-leakage from the RCS without an effect on availability. In-leakage would require, however, that the accumulator water volume be adjusted according to technical specification requirements. An accumulator level alarm is provided as an added safeguard against excessive accumulator in-leakages.

5.2.4.2 High Head Injection System

The high head injection system (Figure 5.2-3) includes the CCPs, the Boron Injection Tank (BIT), and the associated valves and piping in the flow path from the RWST to the RCS cold legs. During normal plant operations the CCPs supply charging flow as part of the Chemical and Volume Control System (CVCS - Chapter 4.1). Under accident conditions these pumps deliver water to the RCS at the prevailing RCS pressure. To provide initial core cooling in response to smaller LOCAs, the high head injection system provides high pressure, low volume injection from the RWST (see section 5.2.4.3). In addition, the system can be aligned for high pressure coolant recirculation to provide long-term core cooling. In response to a steam line break, the injection of borated water from the RWST adds negative reactivity and makes up for reactor coolant contraction.

Each CCP is of the multistage, diffuser design, with a barrel-type casing and vertical suction and discharge nozzles. Each pump has a self-contained lubrication system with a shaft-driven lubricating oil pump and an oil cooler. The lubricating oil is cooled by service water. The pump's integral mechanical shaft seals are cooled by ambient heat loss. Pump design parameters are listed in Table 5.2-3.

A minimum flow bypass line is provided at each pump's discharge to circulate flow to the Volume Control Tank (VCT) via the seal water heat exchanger to ensure sufficient flow for pump cooling at or near the shutoff head. The charging pumps may be tested during normal operation through the use of the minimum flow bypass lines.

A safety injection actuation signal initiates the following actions in the high head injection system:

1. Both CCPs receive start signals. An already running pump continues to run.
2. The motor-operated suction isolation valves from the RWST (112D, 112E) open, and the suction isolation valves from the VCT (112B, 112C) subsequently shut. The charging pump suctions are thus aligned to the RWST.
3. The motor-operated BIT outlet valves (8801A, 8801B) open to align the pump discharge to the cold-leg injection paths. The BIT inlet valves (8803A, 8803B) are already open with power removed. The high head injection penetrations into the cold legs are separate from those of the other ECCSs.

(The normal charging, letdown, and seal return flow paths in the CVCS isolate as well.) The high head injection system operates in this configuration until the lineup is changed by the reactor operator. The discharge pressure of the CCPs is sufficient to provide flow to the RCS for any postulated size break. The pumps can deliver flow under all pressure conditions up to and including the pressurizer safety valve lift pressure. At very low RCS pressures, the two high head injection trains deliver a combined flow rate of up to several hundred gpm.

As shown in Figure 5.2-1, the discharge of the RHR pumps is manually aligned to the CCP suctions in order to circulate water from the containment recirculation sump to the RCS cold legs at high pressures (see section 5.2.5). The discharge from the A train RHR pump is provided directly to the CCP suctions; the discharge from the B train RHR pump is available to the CCP suctions via the cross-connection to the safety injection pump suction piping.

In addition to providing core cooling flow during accident conditions, operation of the high head injection system is part of a last-resort method of cooling the core known as bleed and feed, which is used when heat transfer from the reactor coolant to the steam generators is unavailable. For this cooling method, flow through the core is delivered by the CCPs and displaced out the intentionally opened power-operated pressurizer relief valves.

Boron Injection Tank (BIT)

The BIT is a 900-gal tank in the CCP discharge piping that was originally intended to contain highly borated (20,000- to 22,500-ppm) water that would be immediately injected into the RCS upon actuation of the high head injection system. The original design basis of the BIT and its contents was to provide sufficient negative reactivity to maintain core subcriticality during a worst-case RCS cooldown accident (main steam line break). A reanalysis of the cooldown accident without the highly borated BIT contents revealed that, although the core could regain criticality, core damage would be avoided. As a result, most Westinghouse reactor plants have eliminated the requirement for the high boron concentration in the BIT. (The boron concentration in the high head injection piping is the same as that in the RWST up to the normally closed BIT outlet valves.) At some plants the BIT has been removed or bypassed; at others, including the course reference plant, the tank physically remains in the high head injection flow path.

The former high boron concentration of the BIT contents necessitated several auxiliary components. To prevent cold spots and stratification within the tank during normal operation, the contents of the BIT were continuously recirculated by BIT recirculation pumps. The BIT inlet pipe incorporated a sparger to keep the boric acid solution well mixed. Redundant tank heaters and line heat tracing were provided to ensure that the solution was stored at a temperature high enough (normally greater than 135EF) to keep the boric acid in solution. The BIT and the recirculation piping were isolated from the rest of the high head injection system during normal operation by normally closed BIT inlet and outlet valves; both sets of valves were opened by a safety injection actuation. In the course reference plant, the very high boron concentration in the BIT is no longer maintained, and all BIT auxiliary equipment except the sparger has been removed. Because isolation of BIT recirculation piping is no longer necessary, the motor-operated BIT inlet valves are maintained de-energized in the open position.

Boron injection tank design parameters are listed in Table 5.2-4.

5.2.4.3 Refueling Water Storage Tank

The RWST is a very large (438,000-gal capacity) seismically qualified tank containing borated (greater than 2000-ppm) water. The tank contents are used to fill the refueling cavity for refueling operations and to provide water for ECCS and containment spray system operation. During normal operation, the RWST is always aligned through open isolation valves to the suctions of the safety injection, RHR, and containment spray pumps. As indicated in the previous section, the CCP suctions switch from the VCT to the RWST with a safety injection actuation signal.

The minimum water volume (428,000 gal) and boron concentration required by the RWST technical specification ensure:

1. Sufficient coolant to support ECCS operation during the injection phase (see section 5.2.5),
2. Sufficient water volume in the containment recirculation sump to support continued ECCS and containment spray system operation during the recirculation phase (see section 5.2.5), and
3. Maintaining core subcriticality following a LOCA.

Electric heaters in the tank keep the water temperature above the boron solubility limit. RWST design parameters are listed in Table 5.2-5.

The RWST has four redundant level transmitters which provide indication in the control room, alarms, and control actions. At the low-level (48%) setpoint (119,000 remaining usable gallons), the RHR pumps automatically trip, and the operators align the ECCSs for cold-leg recirculation of coolant from the recirculation sump.

Realigning for recirculation at the low-level setpoint ensures that vortexing does not occur in the RWST, and that there is sufficient water in the recirculation sump to provide adequate suction head for the RHR pumps. At the low-low-level (17%) setpoint (78,000 remaining usable gallons), the containment spray pumps automatically trip, and the operators then manually complete the recirculation alignment of the engineered safety features (ESF) equipment by shifting the containment spray pump suctions to the recirculation sump. The additional water sprayed into containment by the containment spray system as the RWST empties between the low-level and low-low-level setpoints ensures a sufficiently basic pH in the sump water.

During normal operating conditions backflow from the RCS into the RWST is prevented by seated check valves in the unisolated discharge paths. When the RHR system is placed into operation during an RCS cooldown, the RHR pump suctions are isolated from the RWST by a motor-operated valve (8812) in addition to a check valve (see Figure 5.2-5).

5.2.4.4 Intermediate Head Injection (Safety Injection) System

The intermediate head injection system (Figure 5.2-4), also referred to as the safety injection system, includes two safety injection pumps and the associated valves and piping in the flow paths from the RWST to the RCS cold and hot legs. The system is designed to provide water from the RWST to the RCS in the case of a relatively small break in which the RCS pressure remains high (above the accumulator pressure and the RHR pump shutoff head) for a relatively long period. In addition, the system is aligned for coolant recirculation to both the hot and cold legs to provide long-term core cooling at intermediate coolant pressures.

Each safety injection pump is a multistage centrifugal pump, driven directly by an induction motor. Each pump has a self-contained lubrication system and a mechanical seal cooling system. The lubricating oil cooler is cooled by service water, and the seals are cooled by component cooling water. Safety injection pump design parameters are listed in Table 5.2-6.

The system is aligned during normal operation with unisolated suction and discharge paths. Upon receipt of a safety injection actuation signal, the pumps start and recirculate water to the RWST until the RCS pressure decreases below the pump shutoff head. Once the RCS pressure is below the pump shutoff head, the pumps inject at a flow rate of up to several hundred gpm per pump (increasing as the RCS pressure decreases) through a common discharge header that branches to all four cold legs of the RCS. The intermediate head injection discharge penetration into each cold leg and the downstream check valve in each cold leg injection path are shared with the accumulator discharge piping and the low head injection system (see Figure 5.2-1).

A minimum flow bypass line is provided at each pump's discharge to circulate flow to the RWST during low pump flow conditions. These lines also permit pump testing during normal operation. Two normally open motor-operated valves (8813, 8814) are provided in the recirculation path to the RWST. These valves are closed by the operator during the recirculation mode to prevent the diversion of radioactive fluid to the vented RWST.

As shown in Figure 5.2-1, the discharge of the RHR pumps can be manually aligned to the safety injection pump suctions in order to recirculate water from the containment recirculation sump to the RCS cold legs at pressures above the RHR pump shutoff head (see section 5.2.5). The discharge from the B train RHR pump is provided directly to the safety injection pump suctions; the discharge from the A train RHR pump is available to the safety injection pump suctions via the cross-connection to the CCP suction piping. After many hours of cold-leg recirculation, the safety injection system is manually realigned for hot-leg recirculation by opening the hot-leg injection isolation valves (8802A, 8802B) and closing the cold-leg injection isolation valves (8821A, 8821B, 8835). The suction source for hot-leg recirculation remains the discharge of the RHR pumps.

While the system is in its standby alignment, backflow from the RCS into the safety injection system is prevented by two check valves in series in each injection flow path. A piping connection on the upstream side of each valve permits leakage testing during outages.

A safety injection pump is aligned for accumulator fill operations when necessary via a piping branch upstream of the A train hot-leg injection isolation valve. Accumulator filling is the only non-accident function of the system.

5.2.4.5 Low Head Injection System

The low head injection system (Figure 5.2-5) is designed to provide low pressure, high volume injection from the RWST to the four RCS cold legs for large RCS pipe breaks up to and including the design-basis LOCA, in which the RCS pressure decreases to containment pressure in a relatively short period of time. In addition, the system provides long-term core cooling following a LOCA via the recirculation and cooling of water collected in the containment recirculation sump.

The low head injection system utilizes the RHR pumps to deliver water from the RWST or the containment recirculation sump to the RCS. Each RHR pump is a single-stage, vertical centrifugal pump. It has an integral shaft driven by an induction motor. The unit has a self-contained mechanical seal, which is cooled by component cooling water. The RHR pumps and the nonaccident functions of the RHR system are discussed in Chapter 5.1.

The system is aligned during normal operation with unisolated suction and discharge paths. Upon receipt of a safety injection actuation signal, the RHR pumps start and recirculate water through the uncooled RHR heat exchangers (via valves 610 and 611) until the RCS pressure decreases below the pump shutoff head. Once the RCS pressure is below the pump shutoff head (approximately 200 psid), the pumps inject at a flow rate of up to several thousand gpm (increasing as the RCS pressure decreases) through discharge headers to all four cold legs of the RCS. Each of the two discharge headers provides flow to two cold legs; the headers are cross-connected to ensure that each low head injection train can provide flow to all cold legs. The low head injection discharge penetration into each cold leg and the downstream check valve in each cold leg injection path are shared with the accumulator discharge piping and the intermediate head injection system (see Figure 5.2-1).

When the RWST has emptied to the low-level setpoint (48%), the suctions of the RHR pumps are manually realigned to the containment recirculation sump for recirculation of the sump water to the RCS. The cold-leg recirculation lineup is completed by opening the component cooling water supplies to the RHR heat exchangers and by opening the RHR pump discharge paths to the suctions of the CCPs and safety injection pumps (via valves 8804A, 8804B). After many hours of cold-leg recirculation, the low head injection system is manually aligned for hot-leg recirculation by realigning the injection flow paths from the cold legs to two of the four hot legs (see Figure 5.2-5). The low head injection discharge penetrations into the hot legs are shared with the intermediate head injection system (see Figure 5.2-1). During hot-leg recirculation, the RHR pumps remain the suction source for the higher headed ECCSs.

While the system is in its standby alignment, backflow from the RCS into the low head injection system is prevented by two check valves in series in each injection flow path. A piping connection on the upstream side of each valve permits leakage testing during outages.

5.2.4.6 Containment Recirculation Sump

The containment recirculation sump (Figures 5.2-6 and 5.2-7) is a large collection reservoir designed to provide an adequate water supply to the ECCSs and containment spray system during recirculation modes of operation. The water collected in the sump is reactor coolant lost through an RCS pipe break as well as water that has been injected from the RWST into the RCS and then through the pipe break. Sump design features limit the size of debris that can enter the recirculation flow paths and ensure an adequate net positive suction head (NPSH) for the containment spray and RHR pumps. It should be noted that the course reference recirculation sump described in this section can differ significantly from the sumps at other Westinghouse plants.

The sump is located at a low level in containment outside the biological shield. The sump is covered by a sheet metal roof and is surrounded on the sides by bars and screens; the fine screen mesh size of 3/16 in. limits the size of floating debris that can become entrained in the suction piping from the sump. The bar and screen arrangement can withstand clogging of 50% of the incoming flow area without significantly degrading the NPSH for the RHR and containment spray pumps. The sump has an 18-in.-high baffle along its floor which is located between the suction pipes for the two trains of ESF equipment. Two level switches supply indicating lights in the control room. When the RWST level has reached the low-low-level setpoint following an accident, the fluid elevation in containment should be 13 ft above the sump floor.

Two suction pipes penetrate the recirculation sump walls; each pipe supplies one train of low head injection and one train of containment spray. The suction piping is oriented horizontally through the sump and is sufficiently submerged to limit vortexing. Each suction pipe contains a normally open motor-operated isolation valve that is also within the sump confines; each valve's motor operator is mounted atop the sump's roof and remains above the water level following collection of the RWST contents. The suction piping branches to the RHR and containment spray pumps outside containment; four normally closed suction isolation valves (one for each RHR and containment spray pump) isolate the recirculation sump from the ECCSs and containment spray system when the systems are in their standby alignments. The suction isolation valves are manually opened as part of the realignment of the systems to the cold-leg recirculation mode.

The sump dimensions, the materials used in the fabrication of the sump, the suction piping, and the isolation valves are designed to provide assurance that the sump will remain functional for long-term coolant recirculation during the existence of the post-accident environment.

The course reference plant ceased operations in the early 1990s; significantly revised containment recirculation sump strainer designs have been implemented at operating plants since then. A major concern has been the potential blockage of recirculation sump strainers by post-accident debris. Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at Pressurized-Water Reactors," required licensees to perform, in part, an evaluation of the potential for sump strainer blockage to impede or prevent recirculation of sump contents by safety systems. In accordance with their responses to the generic letter, almost all PWR licensees have adopted sump screen modifications which have greatly increased the effective surface areas for post-accident recirculation flows. A large strainer surface area ensures that, even with extensive strainer blockage, the remaining unblocked suction flow area is sufficient to support recirculation safety functions.

Two such modifications are illustrated in Figures 5-8 and 5-9. Figure 5-8 shows the pocket-screen technology of Control Components Incorporated, which involves banks of cheese-grater-shaped cartridges at the inlets to pump suction piping. The large strainer surface area is provided by the dimensions and contours of the cartridges. Figure 5-9 illustrates the "Sure-Flow Strainer" of Performance Contracting Incorporated. That design also involves banks of strainer elements in the suction piping inlets. Each element provides a large surface area for flow via a collection of thin perforated plates which feed a central core tube.

5.2.5 Emergency Core Cooling Systems Integrated Operations

The operation of the emergency core cooling systems following a LOCA can be divided into three distinct modes of operation, summarized as follows:

1. The injection mode, in which borated water is injected into the RCS from the accumulators and from the RWST by the high, intermediate, and low head injection systems, provided that the RCS pressure is low enough for the lower headed systems to inject. The injected water provides initial core cooling by refilling the reactor vessel and reflooding the core. The injected boron adds to the post-accident shutdown margin.

2. The cold-leg recirculation mode, in which the suction of the low head injection system is aligned to the containment recirculation sump, from which the collected water is recirculated to the core via the RCS cold legs. The recirculated water is cooled in the RHR heat exchangers. The discharge of the low head injection (RHR) pumps is also directed to the suctions of the higher headed ECCS pumps; the discharge from those pumps completes the recirculation path for high prevailing RCS pressures. The recirculated, cooled water from the containment recirculation sump maintains post-accident core cooling.
3. The hot-leg recirculation mode, in which the discharge of the intermediate and low head injection pumps is realigned to the RCS hot legs to reverse the direction of flow through the core and to continue long-term cooling. The ECCS suction source during hot-leg recirculation remains the containment recirculation sump.

Injection Mode

The injection mode of emergency core cooling is initiated by a safety injection actuation signal. This signal is actuated in response to any of the following:

- Low pressurizer pressure,
- High containment pressure,
- High steam flow, coincident with either low-low T_{avg} or low steam pressure,
- High steam line differential pressure, or
- Manual actuation.

These signals are discussed in detail in Chapter 12.3.

Operation of the emergency core cooling systems during the injection mode is completely automatic. The safety injection actuation signal starts the ECCS pumps (usually via a sequencer which starts the pumps at different times), realigns the CCP suction and discharge paths for high head injection, and realigns auxiliary cooling systems as necessary to support post-accident operation of the ECCS equipment. Realignment of the intermediate and low head injection systems is unnecessary. Actuations and realignments of other ESF equipment by the safety injection actuation are discussed in Chapter 12.3.

Following a large RCS pipe rupture, the RCS is depressurized and voided of coolant rapidly. A high flow rate of emergency coolant is required to quickly cover the exposed fuel rods and to limit possible core damage. This high flow is provided initially by the discharge from the passive cold-leg accumulators, which rapidly refill the reactor vessel downcomer and vessel bottom plenum and begin to reflood the core. Reflooding of the core is subsequently completed by injection from the centrifugal charging (high head injection) pumps, safety injection (intermediate head injection) pumps, and RHR (low head injection) pumps. These pumps inject to the RCS cold legs as soon as they start and begin to develop sufficient discharge pressure. The pumps are started in order from highest to lowest discharge head. The suction source for all of the active systems is the RWST.

The order of ECCS injection is different for smaller RCS pipe ruptures. An SBLOCA results in a gradual depressurization of the reactor coolant. In response, each

ECCS pump begins to deliver water from the RWST to the cold legs once the reactor coolant pressure has decreased to below the pump's shutoff head, and the accumulators begin to discharge to the cold legs once the coolant pressure is less than the nitrogen cover pressure. Hence, the ECCSs begin to inject in order of decreasing discharge capability: the high head injection system first, the intermediate head injection system second, the accumulators third, and the low head injection system last.

If the size of the rupture is small enough, the coolant depressurization stops when the rate of inventory addition by the ECCSs equals the rate of inventory loss or saturation conditions are reached at the core exit. An equilibrium coolant pressure can be reached with just the high head injection system injecting, or with just the high and intermediate head injection systems injecting. In such a case further coolant depressurization requires operator action.

The injection mode continues until the RWST level reaches the low-level setpoint, at which time the operator changes the ECCS alignment for operation in the cold-leg recirculation mode.

Cold-Leg Recirculation Mode

The details of transfer from the injection mode to the recirculation mode of operation are plant specific. At plants where a portion of the transfer is automatic, the suction supply to the low head injection pumps is automatically switched from the RWST to the containment recirculation sump. For the course reference plant, the change in suction supplies is a manual operation directed by the emergency operating procedures. In any case, the transfer from the injection mode to the recirculation mode takes place well before the RWST is empty, so that until the transfer is complete, the remaining RWST contents provide adequate net positive suction head to running ECCS pumps.

For the course reference plant, the RHR pumps automatically stop when the RWST reaches the low-level setpoint (48%). Operators are then directed by procedure to establish component cooling water flow to the RHR heat exchangers, to isolate the RHR suctions from the RWST, to open the RHR suctions from the containment recirculation sump, and to then restart the RHR pumps. At this point, the water collected in the recirculation sump is available for cooling and recirculation to the RCS for long-term core cooling. If the reactor coolant pressure is below the shutoff head of the low head injection pumps, they will provide cooled water directly to the RCS cold legs via the low head injection discharge piping.

In the event of a smaller RCS rupture, in which the coolant depressurization proceeds slowly, the reactor coolant pressure may still exceed the shutoff head of the low head injection pumps at the onset of recirculation. In this case, the low head injection pump discharge (cooled water from the recirculation sump) must be aligned to the suction piping of the centrifugal charging pumps and the safety injection pumps so that those pumps can inject it into the RCS at higher pressure and thus maintain core cooling (see Figure 5.2-1). This alignment is referred to as high pressure recirculation or as "piggyback" operation. The completion of the piggyback realignment includes manually shutting the high and intermediate head pump recirculation valves and isolating the RWST suctions to those pumps. A manually unisolated cross connection between the centrifugal charging pump and safety injection pump suctions ensures that either low head injection train can supply flow to both of the higher headed systems. The ECCS piggyback alignment is typically directed by procedure at the initiation of cold-leg recirculation regardless of reactor coolant pressure.

Hot-Leg Recirculation Mode

Approximately 24 hours (course reference plant value) after the switchover to cold-leg recirculation, hot-leg recirculation is initiated. In this manually initiated mode of operation, the low head injection paths to the RCS cold legs are isolated, and the injection paths to two of the four hot legs are opened. Also, the intermediate head injection paths to the cold legs are isolated, and the injection paths to all four hot legs are opened. The suction sources for all ECCS pumps are unchanged from the cold-leg recirculation alignment, and the high head injection system continues to discharge to the cold legs. Hot-leg recirculation thus reverses the direction of much of the coolant flow delivered to the core.

Hot-leg recirculation is implemented to terminate boiling in the core and to prevent boron precipitation in the core following a large cold-leg break. For such a break, core decay heat boils off much of the injected water while the nonvolatile injected boron concentrates in the vicinity of the fuel assemblies. Cold-leg injection is not effective in countering core boil-off because the vessel downcomer level is low, injection flow primarily fills the downcomer and not the core region, and “flushing” of the core does not occur. With the direction of coolant flow reversed, hot-leg recirculation terminates boil-off and dilutes the concentrated boric acid solution in the vessel with the less concentrated solution recirculated from the containment sump. The switchover to hot-leg recirculation is initiated before the boron solubility limit of the reactor vessel water is exceeded, so that boron does not plate out on fuel cladding and interfere with decay heat removal. An additional benefit of hot-leg recirculation is the quenching of any steam bubble that remains in the vessel.

Transferring to hot-leg recirculation is not necessary for all types of LOCAs. For a hot-leg break, cold-leg recirculation flow passes through the core and spills through the break with little resistance. The core is thus flushed without boron buildup. However, hot-leg recirculation would be implemented whenever the initiation conditions are reached so that the implementing procedure is not event specific.

5.2.6 **PRA Insights**

For the purposes of a typical PRA, the high-pressure portion of the ECCSs includes both the centrifugal charging pumps and the safety injection pumps. The low-pressure portion involves only the RHR pumps.

NUREG-1150 indicates that the LOCA initiator is a major contributor to core damage frequency (59% for Sequoyah, 28% for Surry, and 18% for Zion). The major failures in the LOCA sequences that lead to core damage include either the failure of the high pressure ECCSs in the recirculation mode or the failure of the low pressure ECCS in the recirculation mode. The loss of the recirculation capability allows the core to continue to heat up and any remaining coolant to boil off, resulting in core damage.

Probable causes of failure of an ECCS function include:

1. Failure to shift the high-pressure systems from the injection to the recirculation mode.
2. Failure of the high-pressure injection discharge isolation valves to open.
3. Failure of room cooling for the high-pressure injection pumps.
4. Failure to shift from cold-leg to hot-leg recirculation.
5. Failure to shift the low-pressure system from the injection to the recirculation mode.
6. Failure of the low-pressure recirculation sump suction isolation valves to open.
7. Failure of the RWST suction isolation valves for the low-pressure injection system to close.
8. Failure of the operators to properly realign an ECCS after testing.
9. Failure of the low-pressure injection pumps to start.

NUREG-1150 studies on importance measures have shown that the ECCSs can be major contributors to both risk reduction and risk achievement. Specifically, the core damage frequency is most sensitive to increases in the probabilities of component faults and of operator errors associated with establishing recirculation from the containment sump. The greatest reductions in core damage frequencies are achieved by reducing the frequencies of initiating events and the probabilities of operator errors and valve failures.

In current risk-informed notebooks for operating plants, safety functions provided by the ECCSs appear in many core damage sequences. Failures of the high-pressure injection, low pressure injection, accumulator injection, low pressure recirculation, and high-pressure recirculation safety functions are involved in core damage sequences associated with the LOCA initiators. Because of their roles in the bleed and feed method of core cooling, the failures of the high-pressure injection and high-pressure recirculation safety functions appear in core damage sequences in which all decay heat removal options are lost (i.e., auxiliary feedwater, main feedwater, and bleed and feed cooling have all failed).

5.2.7 **Summary**

The emergency core cooling systems are designed to provide post-accident core cooling. The ECCSs are designed in accordance with the General Design Criteria of 10 CFR 50, Appendix A, and they must meet the acceptance requirements of 10 CFR 50.46. They are designed to withstand a single failure by providing 100% redundancy in components and system flow paths.

The ECCSs include both passive and active systems. The passive system is comprised of the cold-leg injection accumulators. The active systems include the high head injection (centrifugal charging pumps), intermediate head injection (safety injection pumps), and the low head injection (RHR pumps) systems.

All active components are actuated by a safety injection actuation signal, which originates from the reactor protection system (see Chapter 12.3).

The order of ECCS injection into the reactor coolant system following a LOCA is dependent on the size of the rupture. Following a large rupture, the passive accumulators inject first, followed by the active pumping systems. A small rupture is characterized by a slow rate of coolant pressure reduction, during which the ECCSs inject in order from highest to lowest discharge pressure capability: high head injection, intermediate head injection, accumulators, and low head injection.

The RWST is the suction source for all active systems following actuation. A low level in the RWST signals the end of the injection mode of operation. Cold-leg recirculation is then initiated manually or with partial automation. Cold-leg recirculation initiates long-term core cooling. Hot-leg recirculation is initiated many hours after the onset of a LOCA to alleviate concerns with the potential buildup of boron in the core.

Table 5.2-1 Normal Operating Status of Emergency Core Cooling System Components

Number of charging pumps operable	2
Number of safety injection pumps operable	2
Number of residual heat removal pumps operable	2
Number of residual heat removal heat exchangers operable	2
Minimum refueling water storage tank volume, gal.	428,000
Boron concentration in refueling water storage tank, ppm	2,000 - 2,500
Number of cold leg accumulators	4
Cold leg accumulator water volume, ft^3	870 - 930
Cold leg accumulator pressure, psig	600 - 650
Minimum boron concentration in cold leg accumulators, ppm	1,900

Table 5.2-2 Accumulator Design Parameters

Number 4	
Design pressure, psig	700
Design temperature, °F	300
Operating temperature, °F	100-150
Normal operating pressure, psig	650
Minimum operating pressure, psig	600
Total volume, gal	10,100 ea.
Minimum water volume, gal	6,500 ea.
Boric acid concentration, minimum ppm	1,900

Table 5.2-3 Centrifugal Charging Pump Design Parameters

Number	2
Design pressure, psig	2,800
Design temperature, °F	300
Design flow rate, gpm	150
Developed head at maximum flow rate, psig	1,400
Shutoff head, psig	2,670

Table 5.2-4 Boron Injection Tank Design Parameters

Number	1
Total volume, gal	900
Boric acid concentration, ppm	1,900-2,000
Design pressure, psig	2,735
Design temperature, °F	300
Operating temperature, °F	150-180

Table 5.2-5 Refueling Water Storage Tank Design Parameters

Number	1
Total volume, gal	438,000
Minimum volume, gal	428,000
Boric acid concentration, ppm	2,000 - 2,500
Normal pressure	Atmospheric
Operating temperature, °F	37 - 90
Design temperature (Tank),°F	200

Table 5.2-6 Safety Injection Pump Design Parameters

Number	2
Design pressure, psig	1,700
Design temperature, °F	300
Design flow rate, gpm	425
Developed head at maximum flow rate, psig	650
Shutoff head, psig	1,520

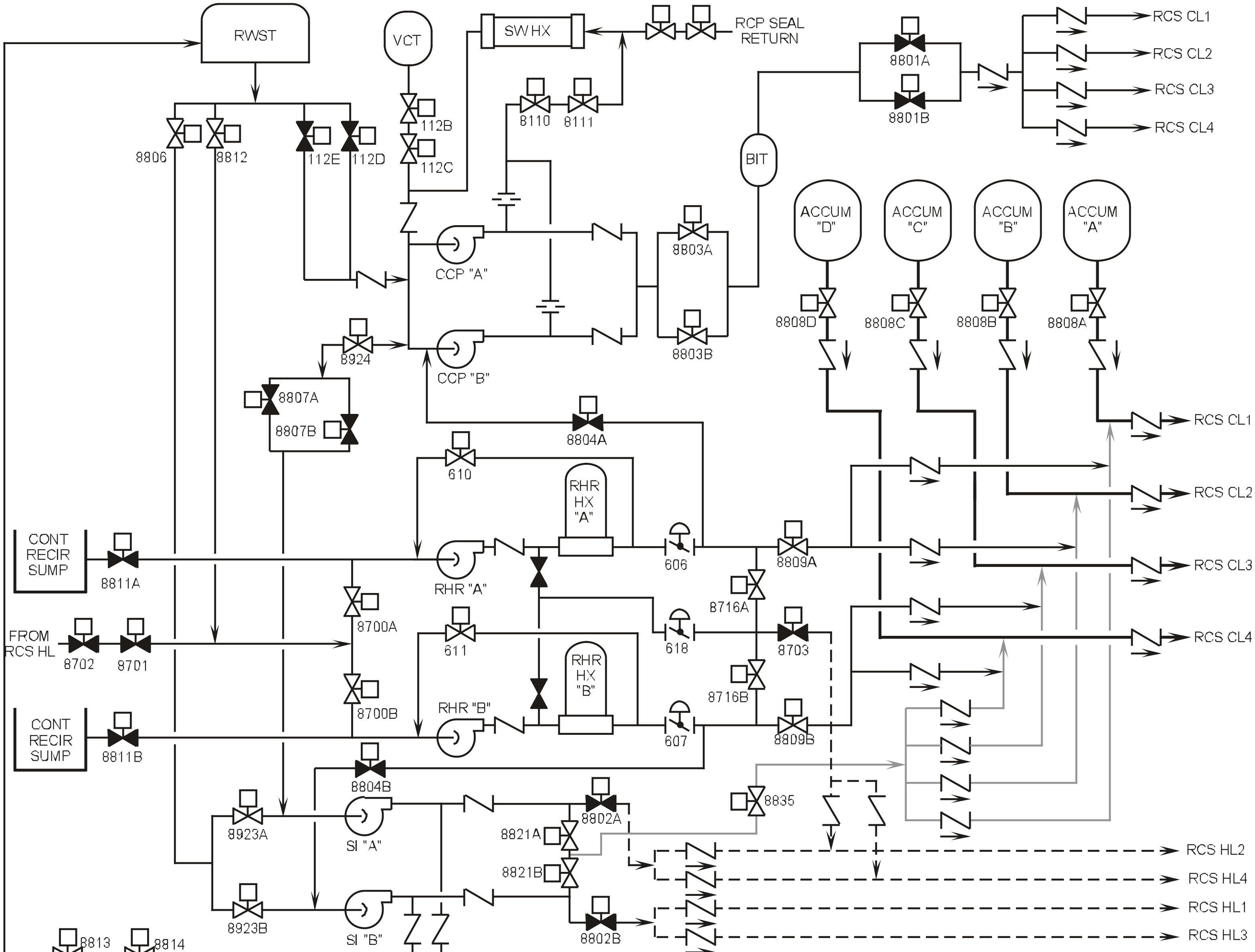


Figure 5.2-1 ECCS Composite

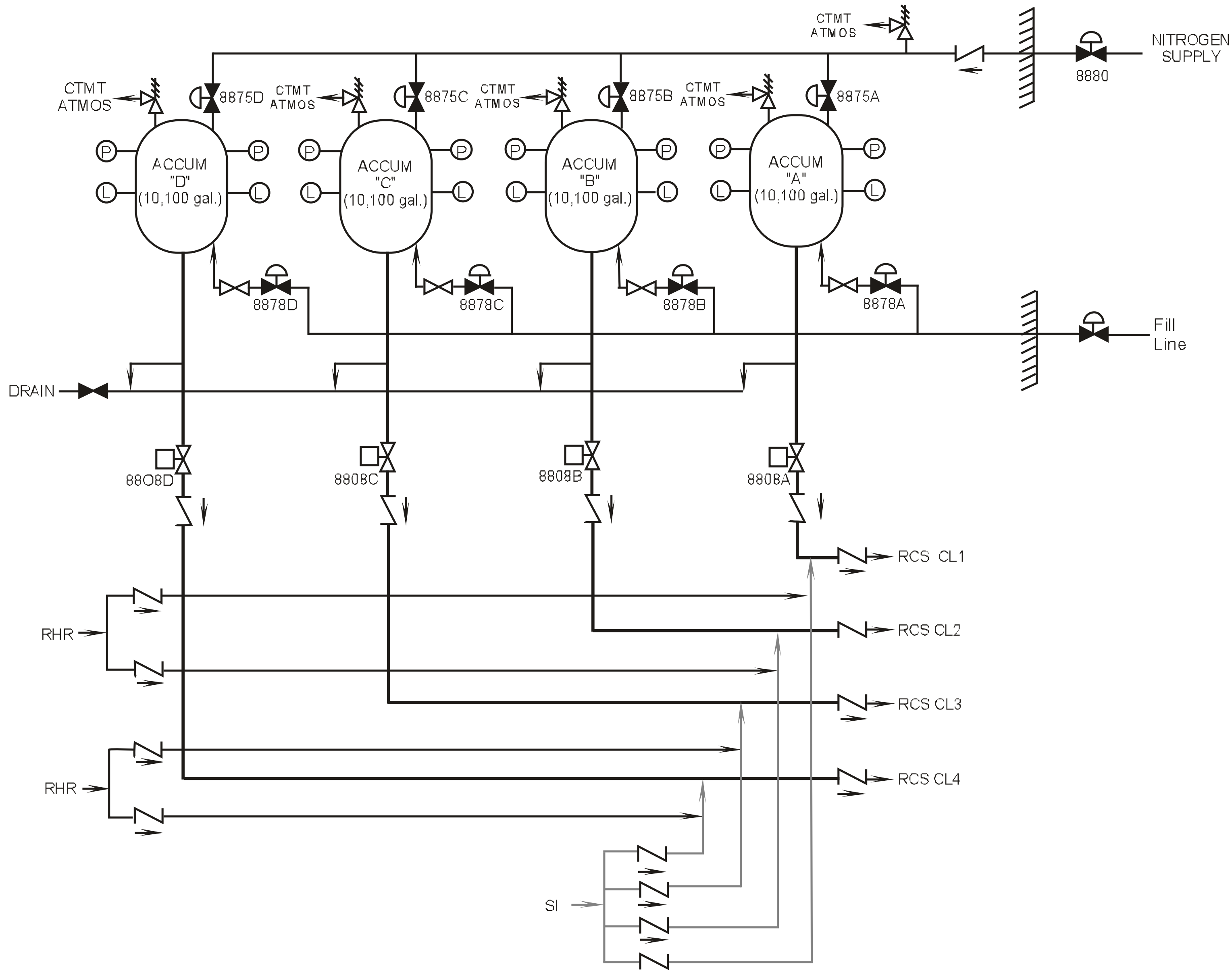


Figure 5.2-2 Cold Leg Accumulator System

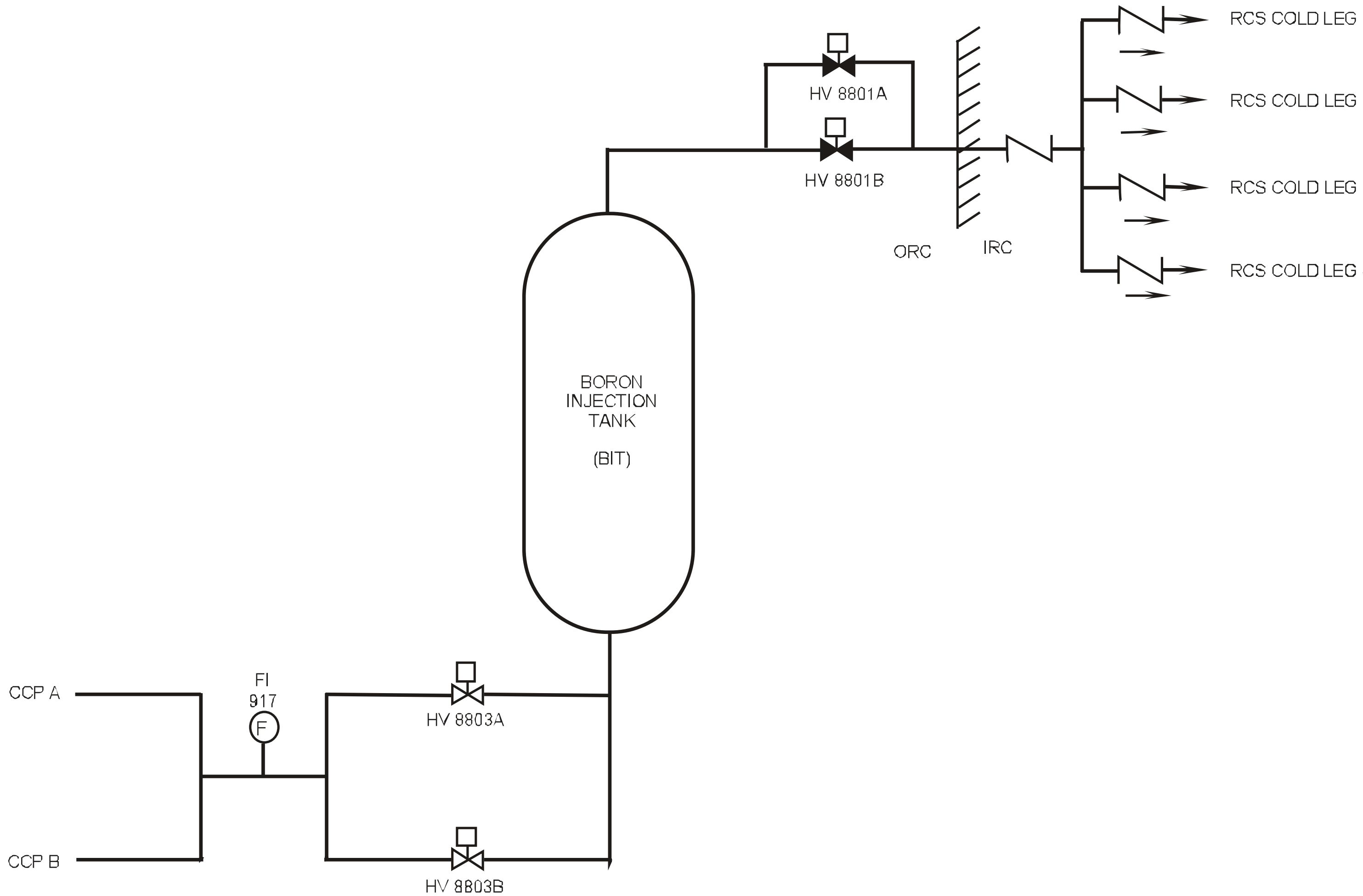


Figure 5.2-3 High Head Injection System

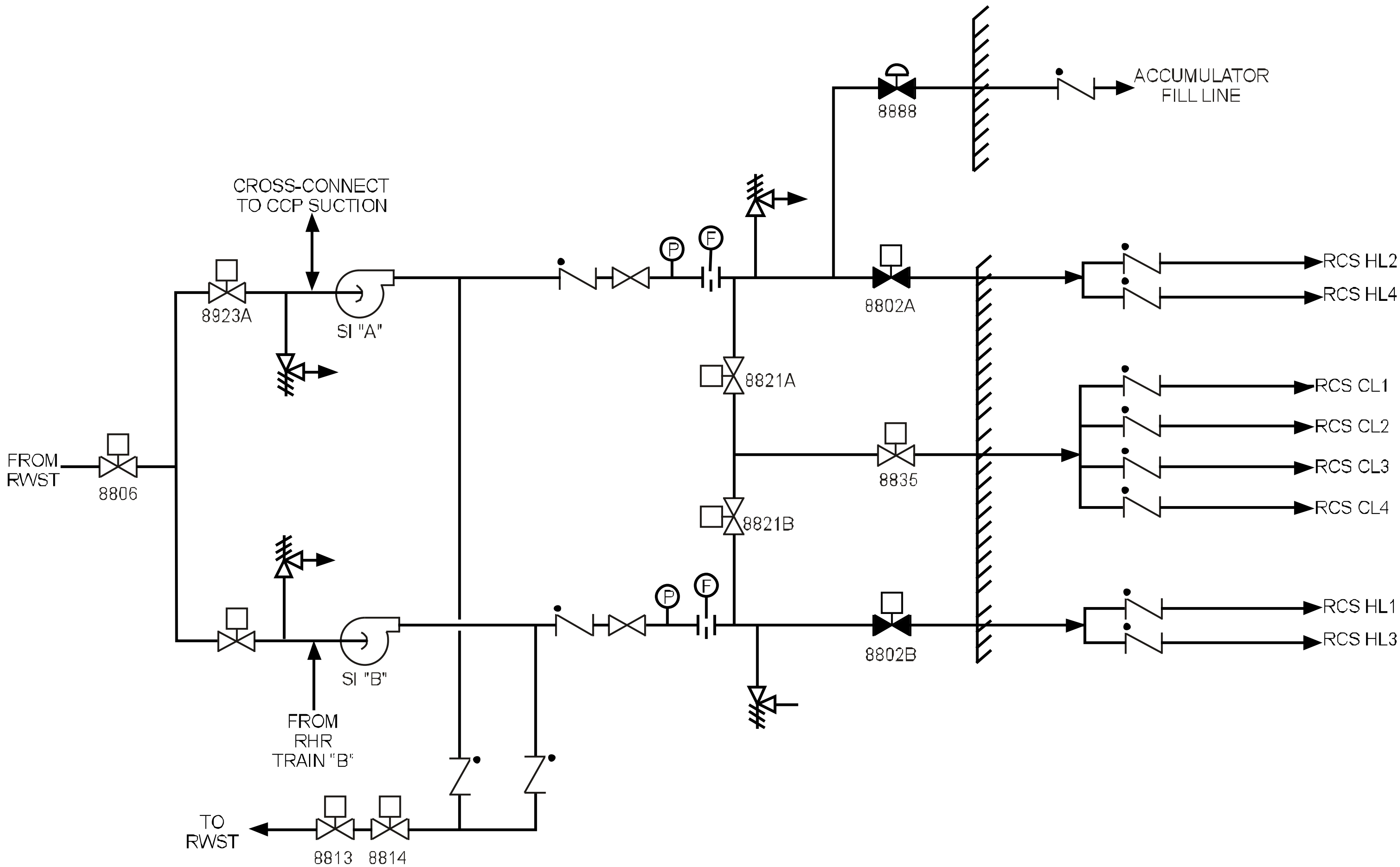


Figure 5.2-4 Safety Injection System

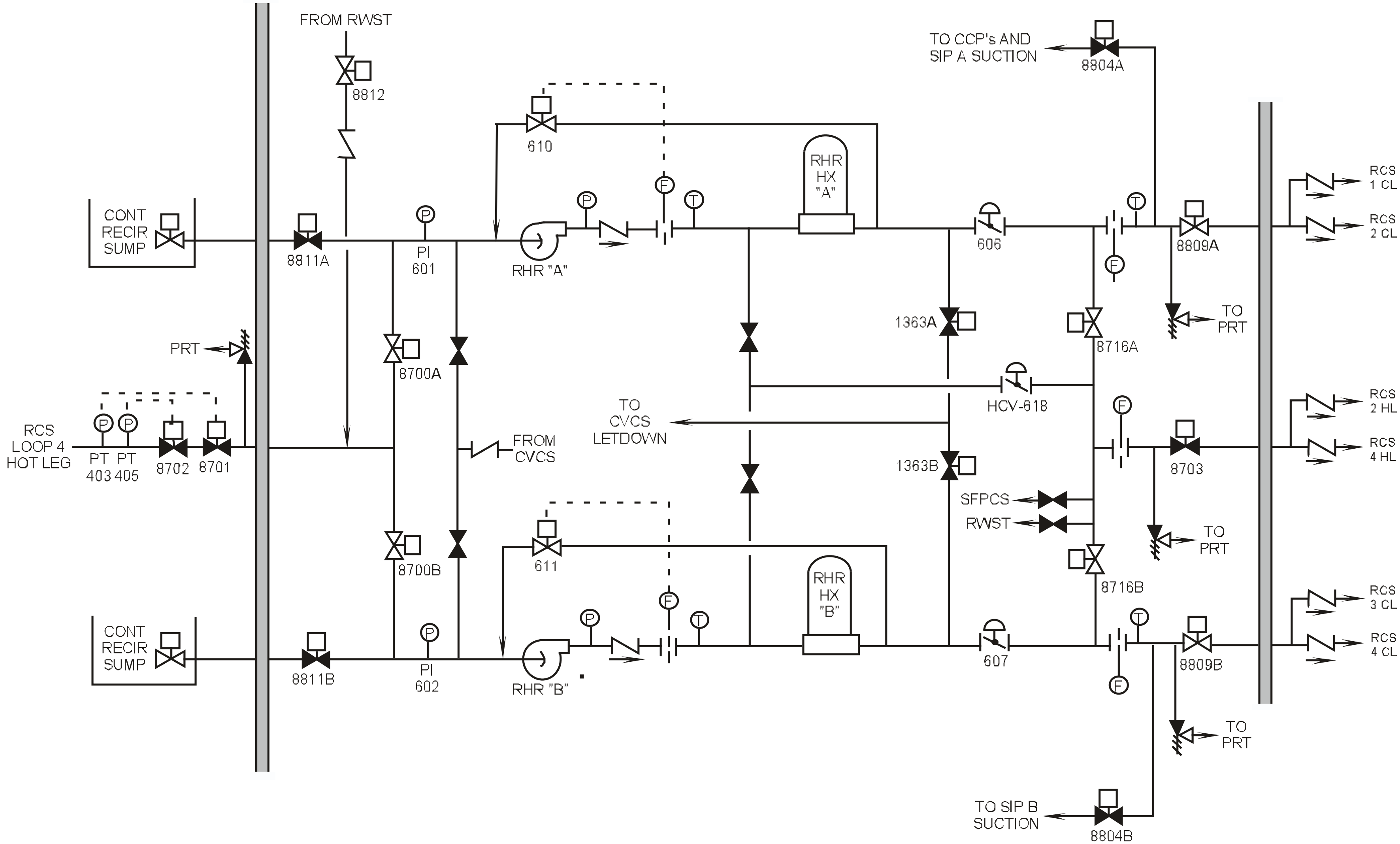


Figure 5.2-5 Residual Heat Removal System

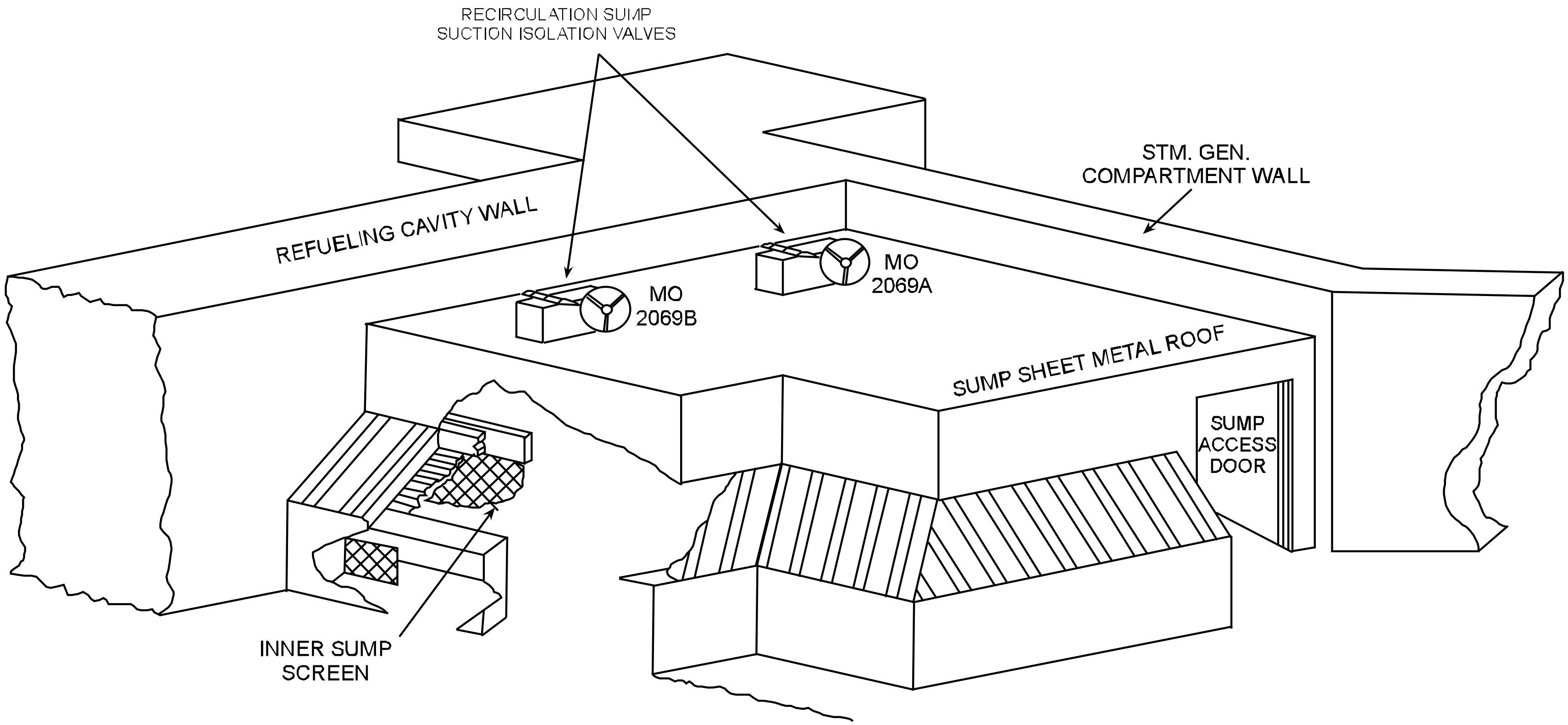


Figure 5.2-6 Containment Recirculation Sump

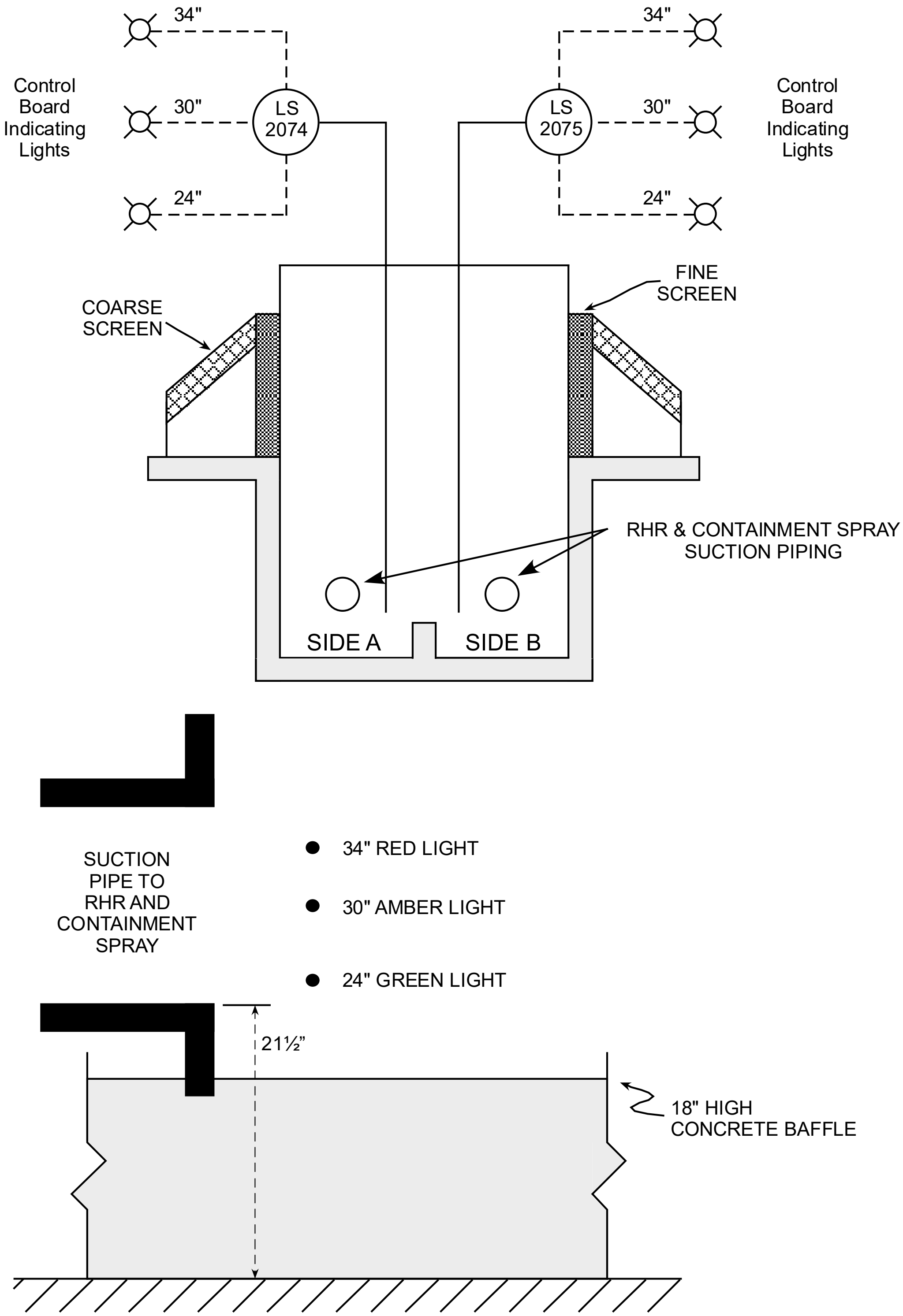


Figure 5.2-7 Recirculation Sump Features

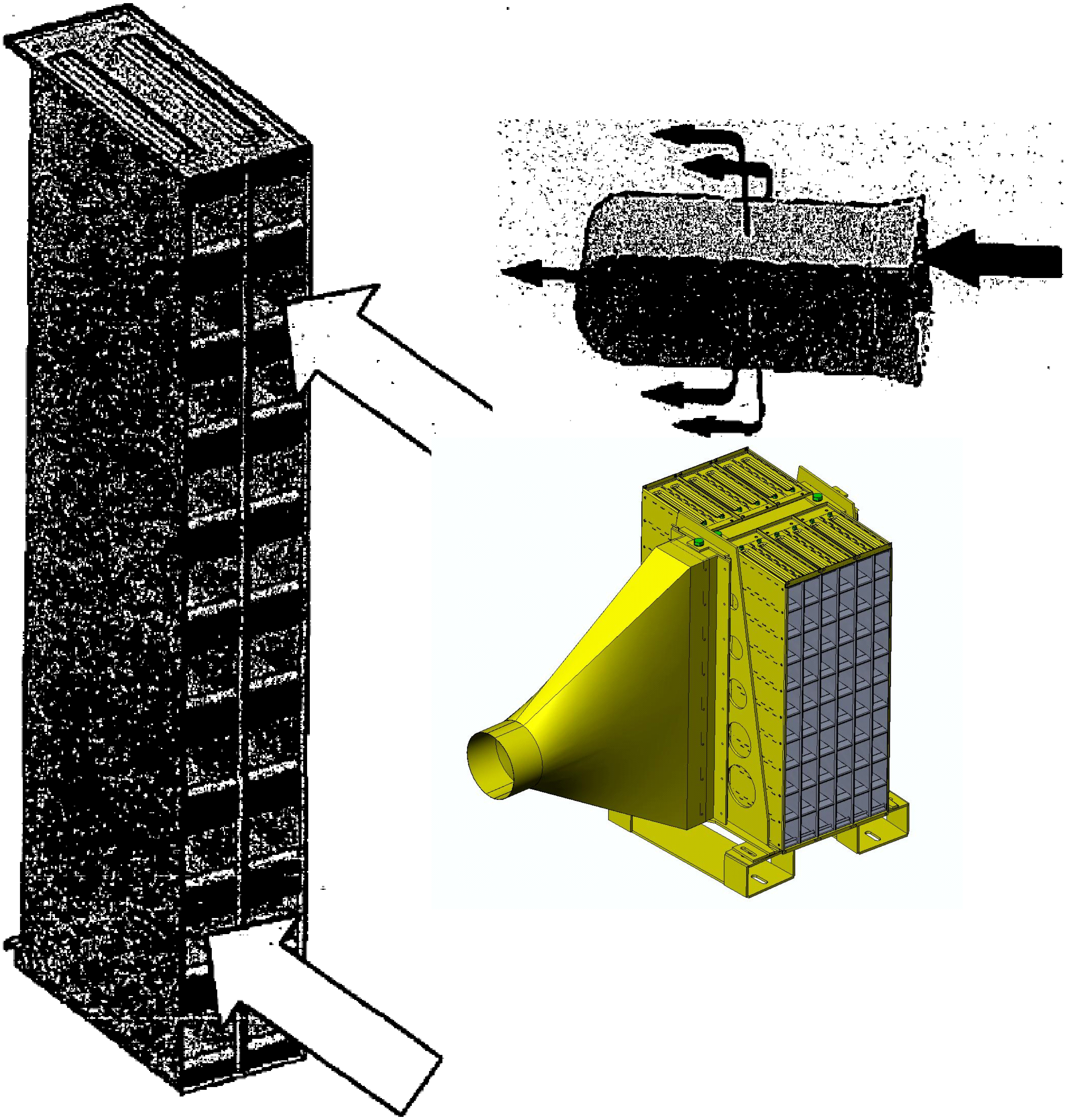
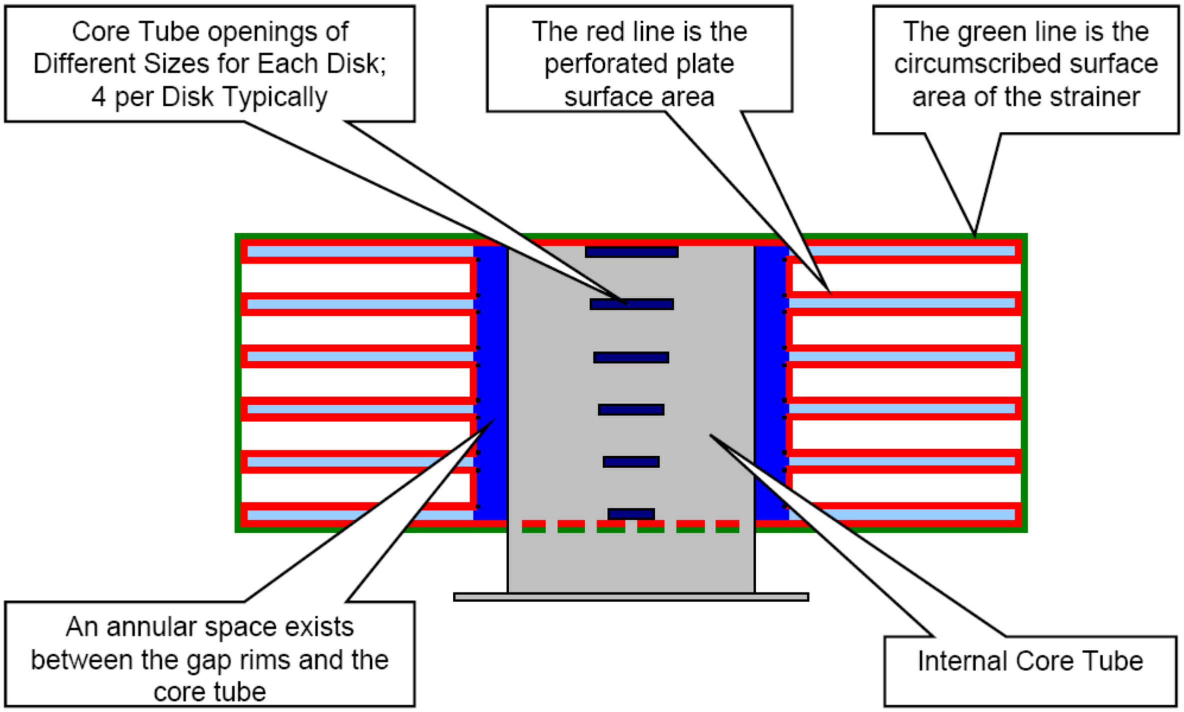


Figure 5.2-8 Recirculation Sump Cartridge Pocket Screens



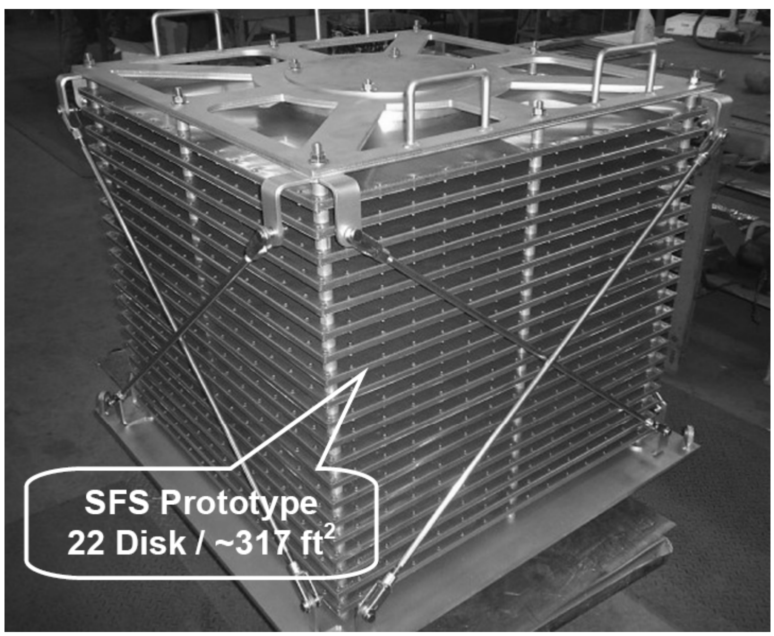


Figure 5.2-9 Recirculation Sump Sure-Flow Strainer

Westinghouse Technology Systems Manual

Section 5.3

Containment

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5.3 CONTAINMENT

Learning Objectives:

1. State the purposes of the containment.

2. Briefly describe the functions of the following:

   a. Containment liner
   b. Primary shield wall
   c. Secondary shield wall
   d. Refueling canal
   e. Containment sumps
   f. Containment recirculation sump
   g. Containment hydrogen analyzer

3. Briefly describe the methods of monitoring the containment environmental conditions.

5.3.1 Introduction

The purposes of the containment are as follows:

1. Provides a barrier to prevent the escape of radioactivity during normal and accident conditions,
2. Provides protection against internally and/or externally generated missiles,
3. Provides biological shielding during normal and accident conditions, and
4. Provides Seismic Category I supports for the Reactor Coolant System (RCS) and its associated support systems.

The containment completely encloses the reactor and the RCS and serves to prevent the inadvertent release of radioactive fission products to the atmosphere. The containment also provides biological shielding during normal operations and during the unlikely event of a Loss-Of-Coolant Accident (LOCA).

Several different types of containments have been developed for Pressurized Water Reactor (PWR) applications, and almost all are premised on the use of the containment structure to contain the large volume of high pressure, high temperature steam-water mixture that would result from a LOCA or a Steam Line Break (SLB) inside the containment. After a LOCA or a SLB, the pressure and temperature inside the containment will increase to a peak level, and then decrease as the containment support systems are activated.

The containment structure must be shown to be functionally available for the life of the plant. From the viewpoint of design, the containment design must consider the following loadings:

1. Pressure and temperature transients that occur as the result of a Design-Basis Accident (DBA).

2. Thermal loads, such as the temperature gradient through the containment wall, during normal and transient conditions.
3. Dead loads consisting of the weight of the concrete wall, dome, base slab, internal concrete, and machinery, and other permanent load-contributing stresses.
4. Live loads, which consist of snow loading, movable equipment loads, and other loads which vary with intensity and occurrence.
5. Earthquake loads, such as those associated with the Operating Basis Earthquake (OBE) and the Safe Shutdown Earthquake (SSE).
6. Wind and tornado loads, with consideration given to missile impingement.
7. Hydrostatic loads based on the worst-case flood conditions with a water level significantly above mean sea level.
8. External pressure loads based on a maximum differential pressure, inside to outside, on the containment.
9. Prestressing loads, considered in all loading combinations.
10. Pressure test loads up to 1.15 times the design pressure.

The loading conditions caused by the DBA, resulting from gross failure of the RCS, and those caused by earthquake, are considered to be the critical loading conditions.

5.3.2 System Description

The large dry primary containment utilizing a three dimensional (3-D) post-tensioned, prestressed, reinforced concrete cylinder with a steel liner was first used in 1966 and is deployed in the majority of the PWRs in the United States.

Because of the inherent weakness of concrete in tension and its strength in compression, prestressing systems were developed to superimpose compressive loads onto concrete structures so that when these structures are loaded by exterior force systems (such as a LOCA) the net stresses in the concrete are still generally compressive. Therefore, prestressing keeps the concrete in compression under all postulated loading conditions, and the concrete will be available to carry seismic shear forces without any need for additional reinforcement. The prestressed containment's single greatest disadvantage is the active nature of the structural system which requires monitoring during the life of the plant. This monitoring is accomplished in the form of periodic lift-off tests of a sample of tendons, to insure no prestress loss, and added in-service inspection requirements of the tendon strands.

5.3.3 Component Descriptions

5.3.3.1 Containment Shell

The containment shell (Figure 5.3-1) is a Seismic Category I prestressed, post-tensioned concrete cylinder with a hemispherical dome and a flat foundation slab. The reactor cavity and instrumentation tunnel are located below the foundation slab. A continuous access gallery for the installation, tensioning and inspection of the vertical U-tendons is also provided below the foundation slab. A 19-ft diameter equipment hatch and two personnel airlocks approximately 10 ft in diameter are provided in the shell (Figure 5.3-2). Table 5.3-1 lists the design parameters of the containment shell.

The foundation slab is conventionally reinforced with high-strength reinforcing steel. Three (3) buttresses equally spaced at 120° intervals around the outside of the containment are provided as anchor points for the horizontal tendons.

A transfer tube penetration (Figure 5.3-4) is provided for fuel movement between the refueling canal in the containment building and the fuel handling building. Numerous smaller penetrations for electrical conduits, piping and other systems are also provided.

5.3.3.2 Internal Structures

The major internal structures (Figure 5.3-3) are:

1. Primary shield wall,
2. Secondary shield wall,
3. Operating floor,
4. Refueling canal,
5. Intermediate floor, platforms, and hatches,
6. Removable shield slabs,
7. Pipe supports and restraints, and
8. Nuclear Steam Supply System (NSSS) equipment supports and restraints.

The primary shield wall is a reinforced concrete wall which completely surrounds the reactor vessel and provides biological shielding. The shield wall is located in the center of the containment and extends from the foundation slab to the operating floor. The primary shield wall also gives support to the reactor.

The secondary shield wall is a reinforced concrete structure which provides radiation shielding and protection to the RCS. The RCS is completely enclosed by the secondary shield wall, which extends from the foundation slab to above the operating floor. The wall also provides lateral support to the steam generators, reactor coolant pumps, pressurizer and associated piping.

The operating floor is constructed of reinforced concrete and structural steel framing. The floor is supported by the refueling canal walls, secondary shield walls and the containment shell. Separation is provided in the supports and between the floor and shell to allow for differential horizontal movement. Floor hatches are provided for equipment and tank removal. A refueling canal, of reinforced concrete with a stainless steel liner, is provided for transportation of new and used fuel between the reactor vessel and the fuel transfer penetration. During periods of maintenance or refueling the canal is used for temporary storage of vessel internals or fuel.

The intermediate floor is constructed of reinforced concrete with steel grating platforms and walkways supported by structural steel framing. Hatches are provided for equipment removal. The floor is also used as a laydown area during maintenance activities or refueling.

Removable shield slabs, of precast concrete, are supported above the reactor vessel by the secondary shield walls. These shield slabs protect the steel liner from damage by missile impingement.

5.3.3.3 Steel Liner

To ensure a high degree of leak tightness, the inside face of the containment shell is lined with one-quarter (1/4) inch of carbon steel plate, which is thickened in the regions adjacent to all penetrations. The carbon steel has a minimum yield strength of 30,000 psi and an elongation, in an eight (8) inch section, of 21 percent.

The liner is designed to function as a leak-tight seal only. Any tensile stresses due to a DBA are transferred from the liner to the concrete wall. Table 5.3-2 shows the liner design parameters.

5.3.4 System Features and Interrelationships

5.3.4.1 Prestressing

Prestressing is a method by which internal compressive stresses are induced in concrete, so that when a load is applied the tensile stresses in the concrete are minimized.

In prestressed containment shells, compressive stresses are produced in both directions in the cylinder and the dome. The level of prestressing is adjusted such that when tensile forces are acting on the shell, most load combinations do not produce tensile stresses in the concrete.

The concrete compression is achieved by installing high strength steel tendons in ducts in the concrete and tensioning them. To minimize the adverse affects of corrosion, the ducts are filled with corrosion-inhibiting grease. The number and placement of the tendons is determined by the containment design such that the minimum force required is provided to all sections of the containment shell in both the horizontal and vertical directions. Consideration is also given for stress losses in the tendons which result from friction forces during tensioning, elastic shortening of concrete, concrete creep under long term loads and tendon steel relaxation.

5.3.4.2 Tendons

Each tendon is composed of 170 stress relieved, high strength one-quarter (1/4) inch diameter wires. Each tendon has an ultimate yield strength in excess of 1000 tons. Button heads are employed at the ends of the tendons to transfer tensile forces to the anchor plates (Figures 5.3-5, 5.3-6 and 5.3-8). There are 70 vertical tendons arranged in two (2) families that are perpendicular to each other in the upper region of the dome (Figure 5.3-7). See Table 5.3-3 for tendon design data.

Each vertical tendon is continuous and stretches from one anchor point in the tendon gallery, up through the wall, through the roof, and back down the opposite wall to another anchor point in the tendon gallery.

There are three (3) buttresses equally spaced around the outside of containment. The buttresses serve as anchor points for the hoop tendons, each of which extends from one buttress, past the next, and to the third buttress. The 132 horizontal tendons continue in this manner up the wall and onto the roof, with each successive tendon anchored to a different buttress.

Sufficient prestressing is provided in the cylindrical and dome portions of the containment to eliminate any tensile stress across the interior wall thickness under design loads. There is a loss of approximately 12 percent of prestress, due to elastic and creep losses, which reduces the prestress to design levels.

Each tendon is pretested at the time of initial tensioning. The stress in the tendons during accident loading is approximately 80 percent of the stress induced at tensioning. This ensures that the possibility of tendon failure under DBA loading is remote. The coincident failure of two (2) or three (3) side by side tendons during

DBA conditions will have no significant affect on containment integrity. This is ensured by designing the walls sufficiently thick to transmit the force to adjoining tendons without resulting in any serious local stress. The tendons are inspected periodically and lift-off readings made to ensure adequate performance of the prestressing system during the life of the plant.

5.3.4.3 Penetrations

There are four types of penetrations through the containment. All are welded assemblies, except the equipment hatch, which is manufactured in two (2) bolted halves and seal welded after installation. All penetrations are pressure resistant and leak tight. The steel liner is thickened in the region near each penetration.

The four types of penetrations are:

1. Electrical,
2. Piping,
3. Equipment hatch and personnel airlocks, and
4. Special purpose.

The containment penetrations are discussed in more detail in Section 5.6 of this manual.

5.3.4.4 Cranes

The containment is equipped with two (2) cranes and a hoist for installation of equipment and for plant maintenance. The reactor area polar bridge crane is supported by brackets embedded in the containment shell concrete. The polar crane is equipped with two (2) 15-hp bridge motors, a 10-hp trolley motor, an auxiliary hoist, and a main hoist. The auxiliary hoist has a capacity of 25 tons and is driven by a 60-hp motor. The main hoist has a capacity of 125 tons and is driven by a 60-hp motor.

The containment jib crane is a one-ton capacity, 14-ft crane installed on the steam generator shield wall near the refueling cavity. The crane can pivot over the refueling cavity, and against the wall for storage.

The stairwell hoist crane provides lifting capability for the stairwell.

5.3.4.5 Containment Recirculation Sump

The containment recirculation sump serves a vital safety-related function as a large collection reservoir designed to provide an adequate water supply to both the Containment Spray (CS) and Residual Heat Removal (RHR) systems. A detailed discussion of the recirculation sump is provided in Section 5.2 of this manual.

5.3.4.6 Containment Building Sumps

Two containment building sumps provide low points for leakage collection within the containment building. Each sump has a dedicated sump pump which is utilized to pump water to the dirty waste drain tank when necessary (Figure 5.3-9).

Technical Specifications require that the containment building sumps and their associated sump pumps be operable for so that RCS leakage can be monitored. The frequency with which the sump pumps operate is an indication of leakage.

5.3.4.7 System Isolation and Integrity

The containment isolation systems provide the means for isolating fluid, air, and gas systems that penetrate containment. This confines any radioactivity that may be released during and after a design-basis LOCA to the containment volume. Containment isolation is achieved by applying common design criteria to penetrations in the many different fluid systems and by use of a Containment Isolation Signal (CIS) to actuate appropriate valves. A detailed discussion of containment isolation is provided in Section 5.6 of this manual.

5.3.5 System Instrumentation

Containment instrumentation is provided for the detection of radioactive and nonradioactive leakage in the containment. Continuous monitoring of the environmental conditions within the containment also provides a background level of overall normal leakage from primary systems and components. Detection of deviations from the normal containment environmental conditions provides indication in the control room of increases in leakage rates.

The instrumentation provided for containment monitoring consists of pressure transmitters, Resistance Temperature Detectors (RTDs), sump level transmitters, area and process radiation monitors, a humidity monitor, and the Containment Hydrogen Analysis System (CHAS).

5.3.5.1 Containment Pressure Instrumentation

Four pressure transmitters (Figure 5.3-10) and seven pressure switches provide indication in the main control room and actuation signals to Engineered Safety Features (ESF) systems. Employing a two-out-of-three logic, pressure switches provide a “Containment Pressure High” alarm in the main control room at 3.5 psig. Additionally, safety injection actuation and containment isolation signals are generated. Using a two-out-of-four logic, pressure switches provide a “Containment Pressure High-High” alarm in the main control room at 30 psig. Containment spray actuation and steam line isolation signals are also generated. To prevent an inadvertent spraydown of the containment, the Hi-Hi pressure switches energize to cause actuation. A loss of power to the switches thus does not cause actuation of the containment spray system.

5.3.5.2 Containment Temperature Instrumentation

Containment ambient temperature is monitored by eight (8) RTDs located above the 205-ft elevation. In addition, local temperatures are monitored in the steam generator cubicles, in the pressurizer cubicle, in the reactor vessel cavity, alongside the containment wall and bio-shield wall, and in the incore instrumentation switching room. Main control room indication for the containment temperatures is provided on a scanning temperature recorder.

5.3.5.3 Containment Sump Level Instrumentation

Level indications and alarms are provided for the containment recirculation sump (Figure 5.3-11) and for the containment building sumps (Figure 5.3-9).

The containment recirculation sump is designed to operate in the post-DBA environment to provide water for the CS pumps and to provide water for long-term core cooling by low head recirculation. The recirculation sump is provided with dual level alarm and indication circuitry. Each channel has three (3) indicating lights for levels of 24 inches, 30 inches and 34 inches above the sump floor. There are also high level alarms at 30 inches and 34 inches. All indications are in the main control room.

Containment sump level indication and alarms are provided on the radioactive waste control panel. The low level alarm setpoint is set at three (3) inches above the bottom of the sump, and the high level alarm setpoint is 42 inches above the bottom of the sump. Level indication for each sump is provided by a series of six (6) lights which indicate at eight-in. intervals from three (3) inches to 42 inches. Additional narrow-range and wide-range level indication is provided in the main control room for the containment sumps.

5.3.5.4 Containment Radiation Monitors

The containment Process and Effluent Radiation Monitors (collectively, PERM-1) continuously monitor gaseous, iodine, and air particulate activity levels in the containment atmosphere during normal operation. PERM-1 detectors also monitor the gaseous, iodine and air particulate activity levels of the containment purge exhaust flow during containment purge operations. Increasing airborne radiation levels are one indication of potential RCS leakage. By comparing the activity in the coolant to the activity in the containment atmosphere, a magnitude of leakage can be determined.

There are five (5) area radiation monitors (ARMS) in containment. Two (2) of them are high-range post-accident detectors used to determine the effectiveness of accident mitigation efforts. The other three (3) detectors monitor containment radiation levels in areas likely to experience high levels. A detailed presentation of the radiation monitoring system is provided in Chapter 16 of this manual.

5.3.5.5 Containment Humidity Instrumentation

The containment humidity detection system (HDS) provides a means of measuring the overall leakage within the containment. The psychrometric detector measures wet and dry bulb temperature and displays percent humidity in the main control room on both a meter and a chart recorder. By comparing these values for specific humidity within the containment over a period of time, a means of measuring the overall leakage within the containment is achieved.

5.3.5.6 Containment Hydrogen Analysis System (CHAS)

The CHAS (Figures 5.3-12, 5.3-13) is a standby system that is only used when directed by procedure. The system is used to determine the need for operation of hydrogen recombiners and hydrogen mixing fans in containment. In addition, since the amount of hydrogen in containment is proportional to the amount of core damage, a rough approximation of damage can be made using the CHAS.

In the event of a LOCA, the CHAS is designed to operate for up to 30 days without servicing while providing accurate hydrogen measurement at containment pressures up to 50 psig and containment temperatures up to 445°F. Remote readouts of hydrogen concentration are available in the main control room.

The CHAS consists of two (2) large analysis panels and two (2) smaller control panels with appropriate indication and control capability. The control units are located in an area that would be accessible during an accident and will normally be operated by chemistry personnel to obtain the sample. The system uses redundant sample paths, with CHAS A using the normal PERM 1 sample path and CHAS B using a separate penetration.

The CHAS has a selectable span for the indication. In LOW, the indication reads out from zero (0) to ten (10) percent. In HIGH, the indication reads out from zero (0) to thirty (30) percent. The system is normally selected to the LOW span, and the control room must be notified if the span is changed to the HIGH position.

To initiate sampling of the containment atmosphere for hydrogen, containment isolation signals must be cleared, a sample flow path must be established, and the CHAS must be turned on. The CHAS A and CHAS B inlet and outlet valves are controlled from the main control room. The system takes about 20 minutes to warm up and be operational. During the warmup, the alarms from the system are disabled.

5.3.6 Containment Evacuation Alarm

A containment evacuation alarm circuit is provided to alert personnel that may be in containment of the need to evacuate. The alarm is of particular significance during maintenance and outage activities when there may be many people in containment.

The alarm consists of an audible siren and a portion of the normal containment lighting that is made to flash during actuation. The alarm is actuated by the high-flux-at-shutdown bistables in the excore nuclear instrumentation source range indication circuit and manually from the main control room.

5.3.7 Summary

The containment is a cylindrical, fully reinforced concrete Seismic Category I structure with a hemispherical roof and a flat foundation slab. The cylindrical portion is prestressed by a post-tensioning system consisting of horizontal and vertical tendons. The dome is prestressed by a two-way post-tensioning system consisting of horizontal and vertical tendons.

The containment structure provides biological shielding for both normal and accident conditions. By completely enclosing the reactor and the RCS, the containment system ensures that an acceptable upper limit for leakage of radioactive materials to the environment is not exceeded even with gross failure of the RCS.

The containment is designed for all credible conditions of loading, including normal loads, LOCA loads, test loads and loads due to adverse environmental conditions. The loading conditions caused by a DBA, resulting from gross failure of the RCS, and those caused by earthquake are considered to be the critical loading conditions.

Table 5.3-1 Containment Shell Design Parameters

Inside diameter, ft	124
Inside height, ft	203
Wall thickness, ft	3.5
Dome thickness, ft	2.5
Internal free volume, ft^3	2×10^6
Design pressure, psig	60
Design temperature, °F	120 normal 288 DBA
OBE, g	0.15
SSE, g	0.25
DBA, break area, ft^2 (double-ended pump suction shear)	10.48
Buttresses	3
Material	Prestressed reinforced concrete

Table 5.3-2 Containment Liner Design Parameters

Material	ASTM-442, Grade 55 welded steel plate
Thickness, in.	0.25
Yield strength, psi	> 30,000
Elongation (8-in. specimen), %	21

Table 5.3-3 Tendon Design Parameters

Number of vertical	70
Number of horizontal	150
Wires per tendon	170
Wire diameter, in.	0.25
Ultimate strength, tons	> 1000
Material	High strength, stress-relieved steel in accordance with ASTM A-421

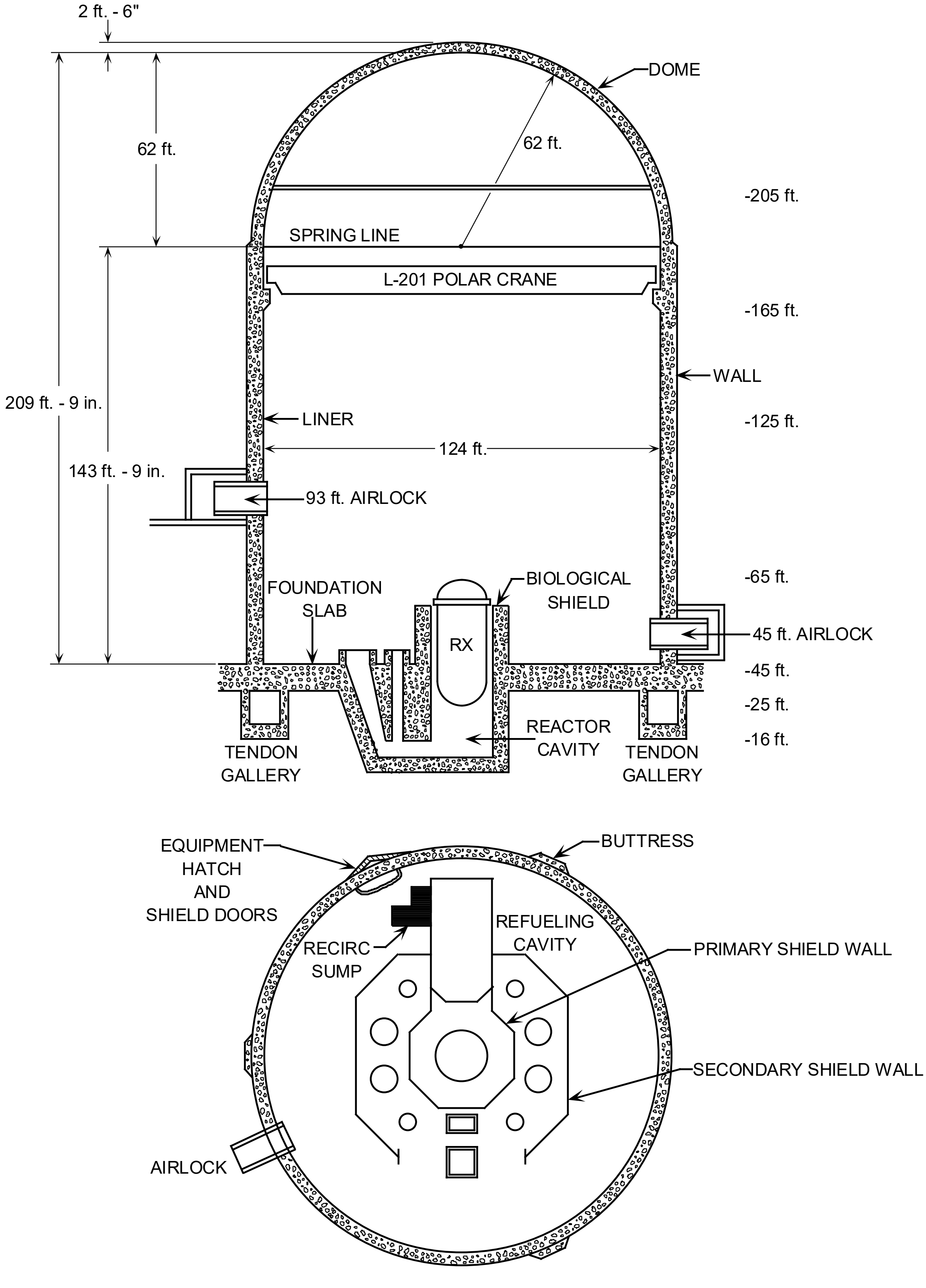


Figure 5.3-1 Containment and Internals

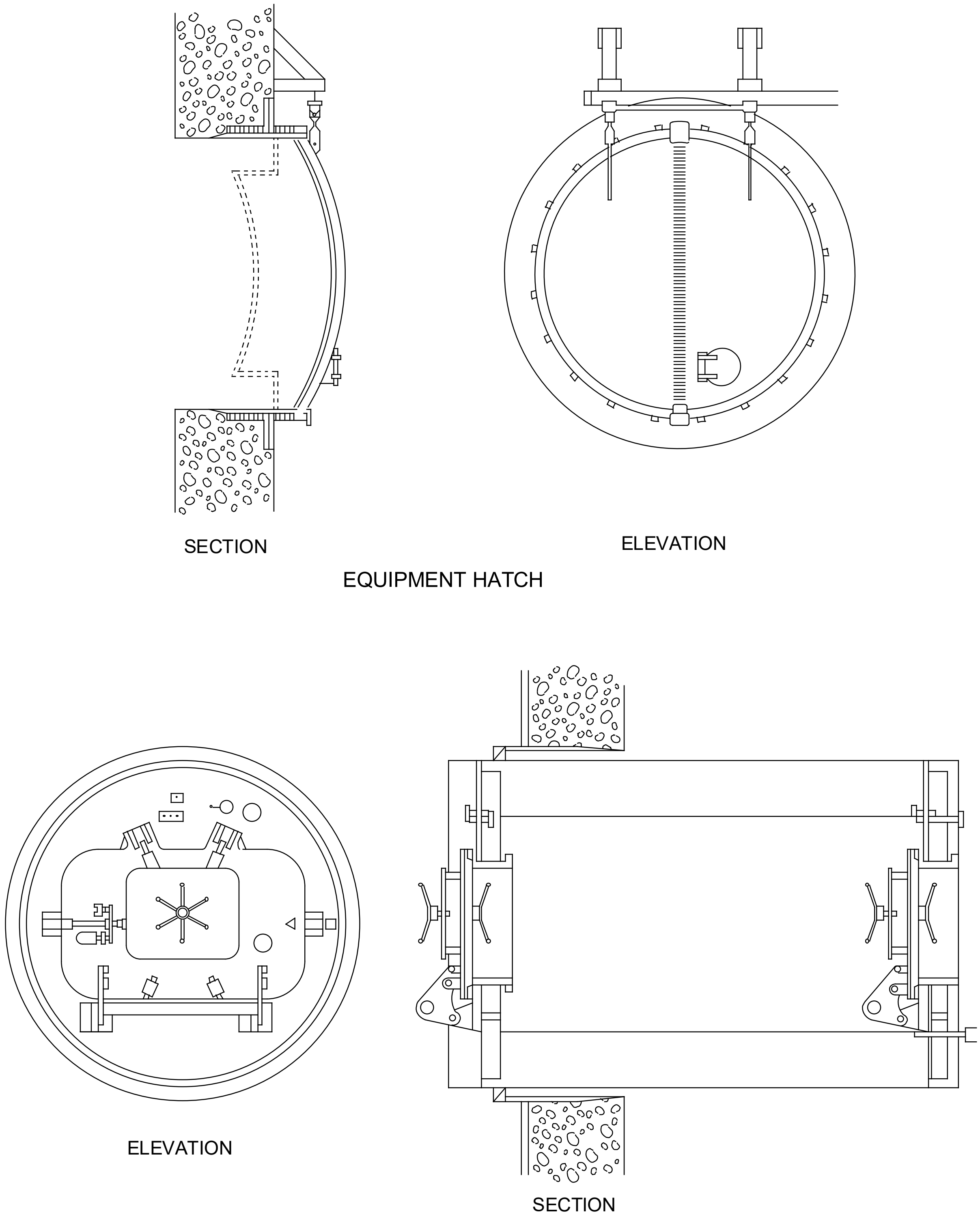


Figure 5.3-2 Equipment Hatch and Personnel Lock

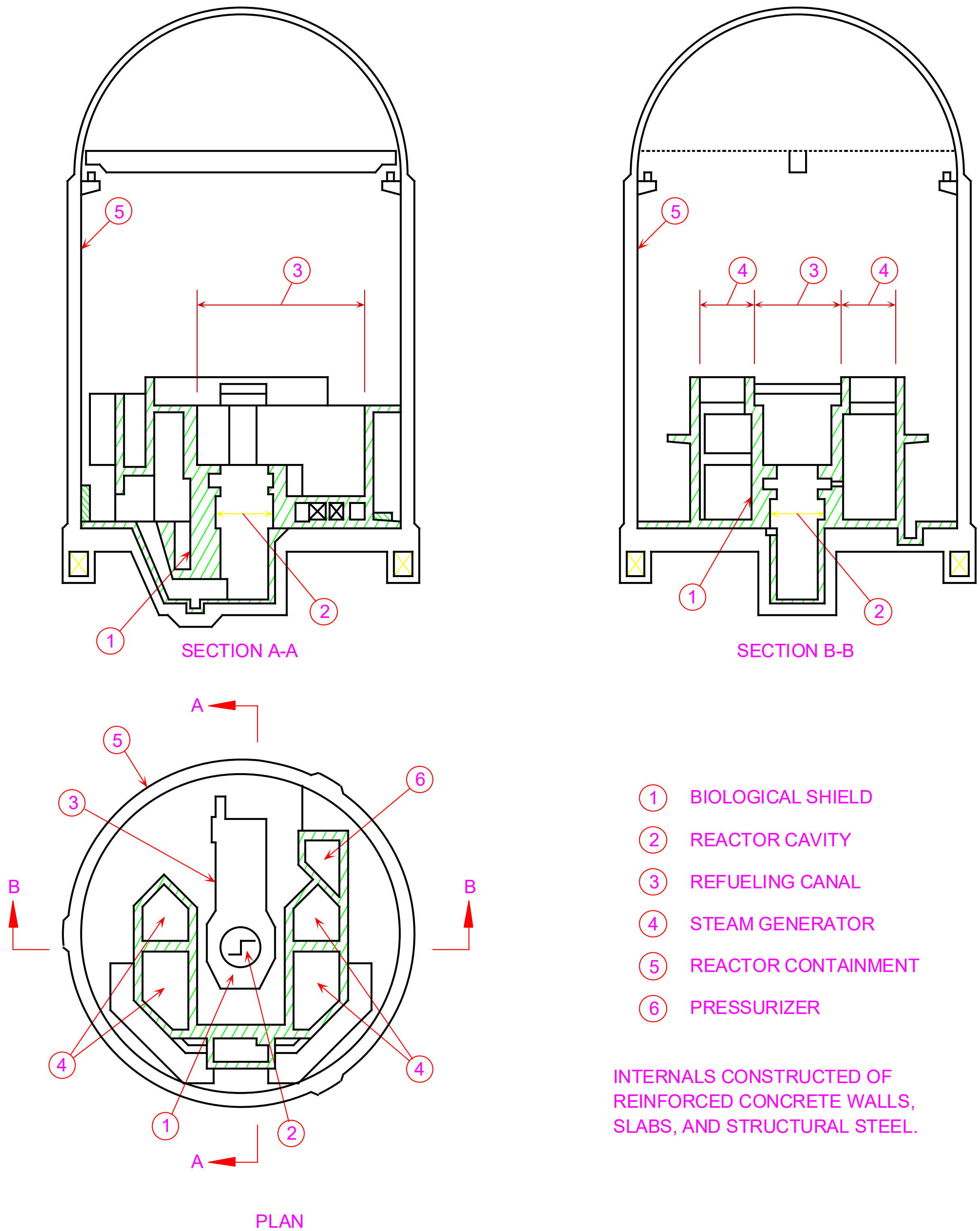


Figure 5.3-3 Containment Internals (Simplified)

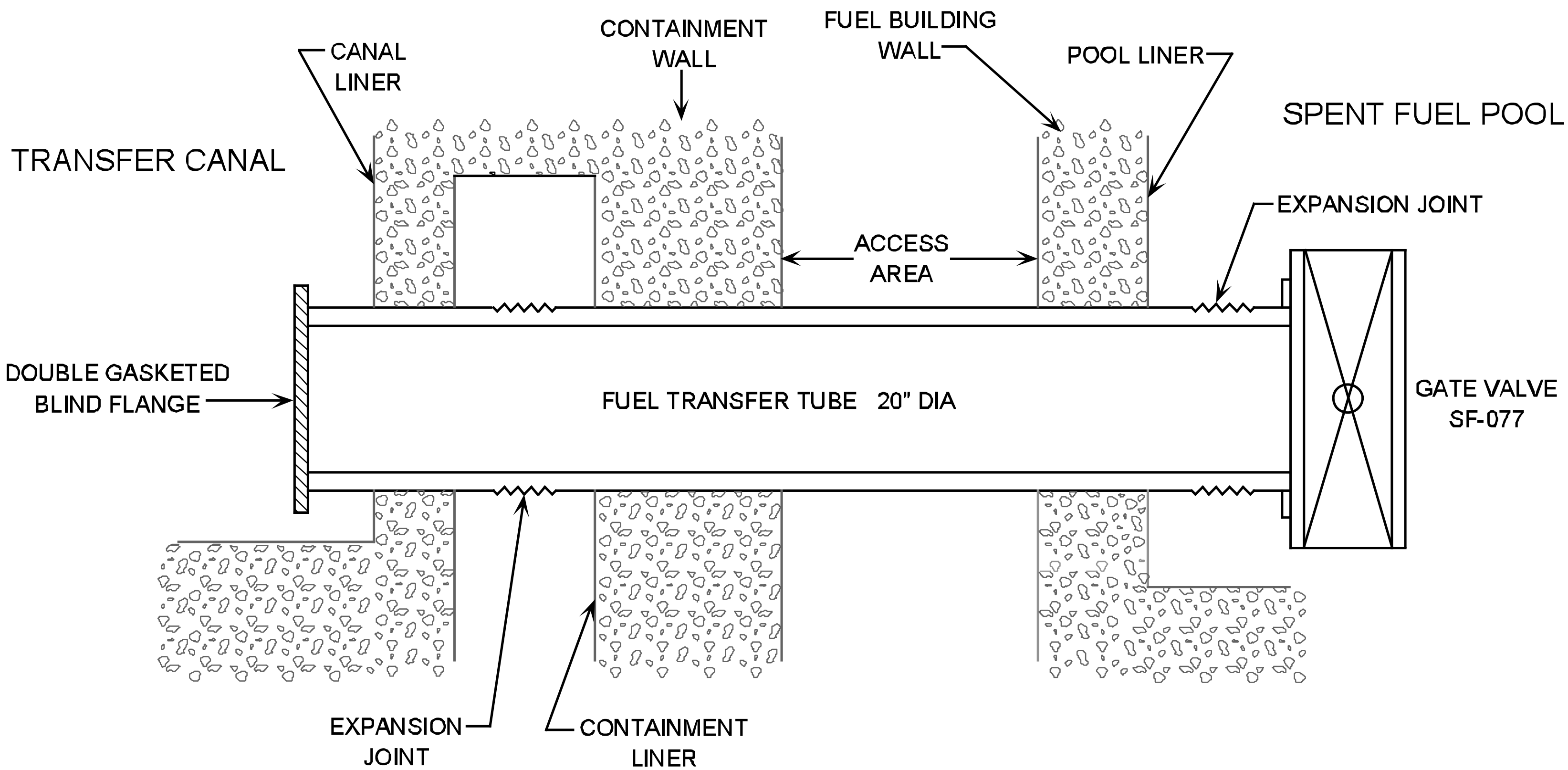


Figure 5.3-4 Fuel Transfer Tube Penetration

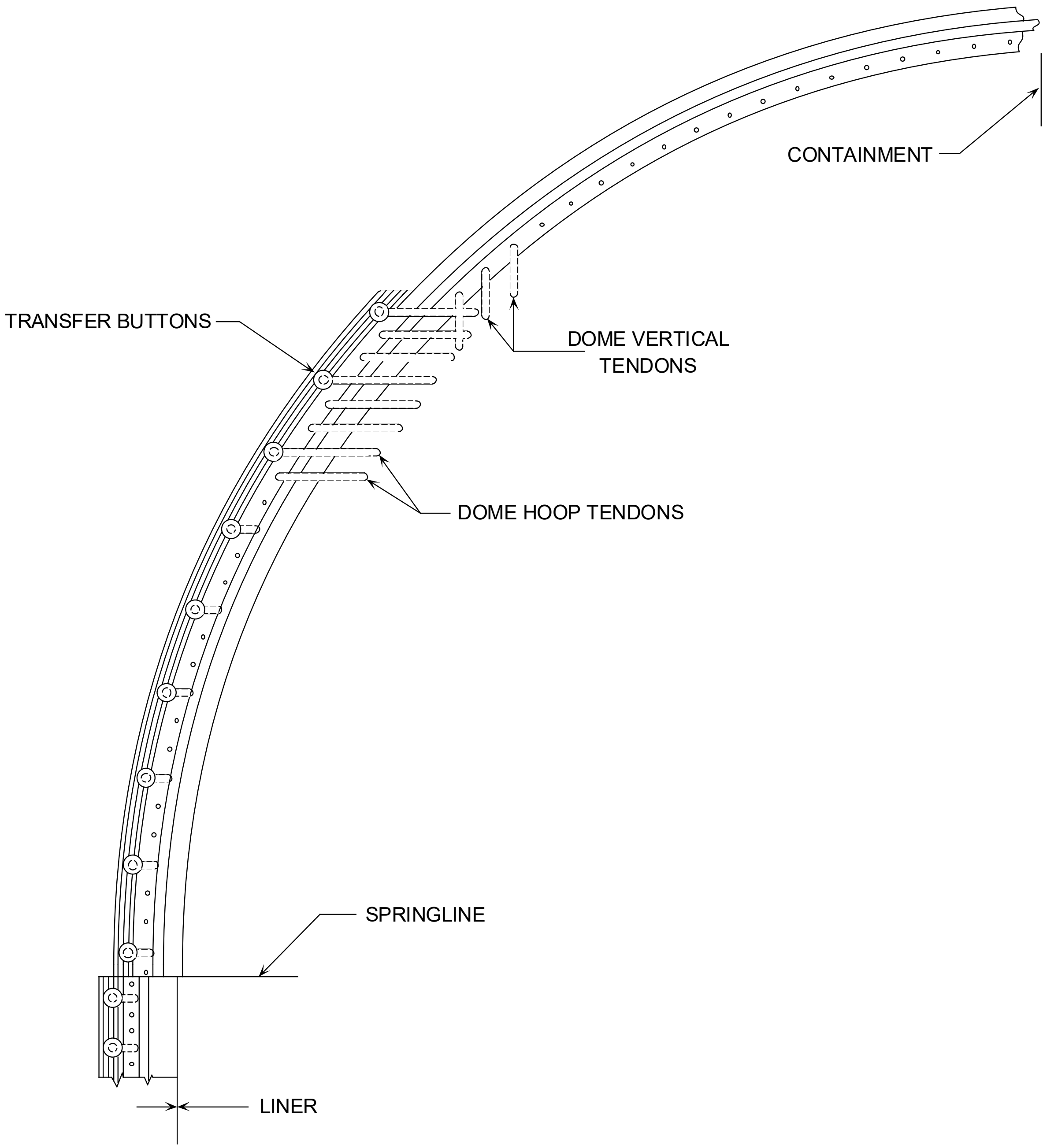


Figure 5.3-5 Transfer Buttons

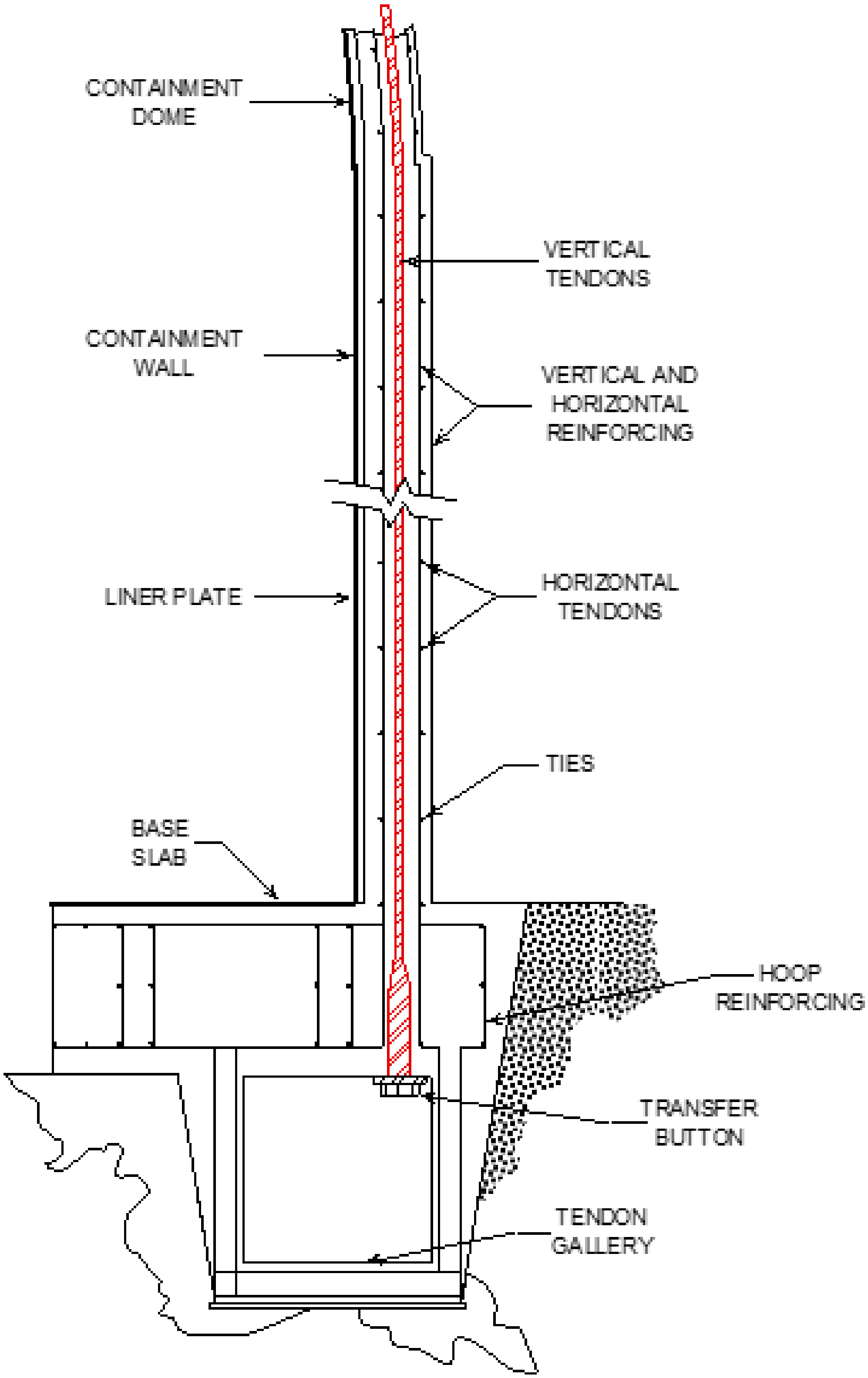


Figure 5.3-6 Section View of Wall and Vertical Tendons

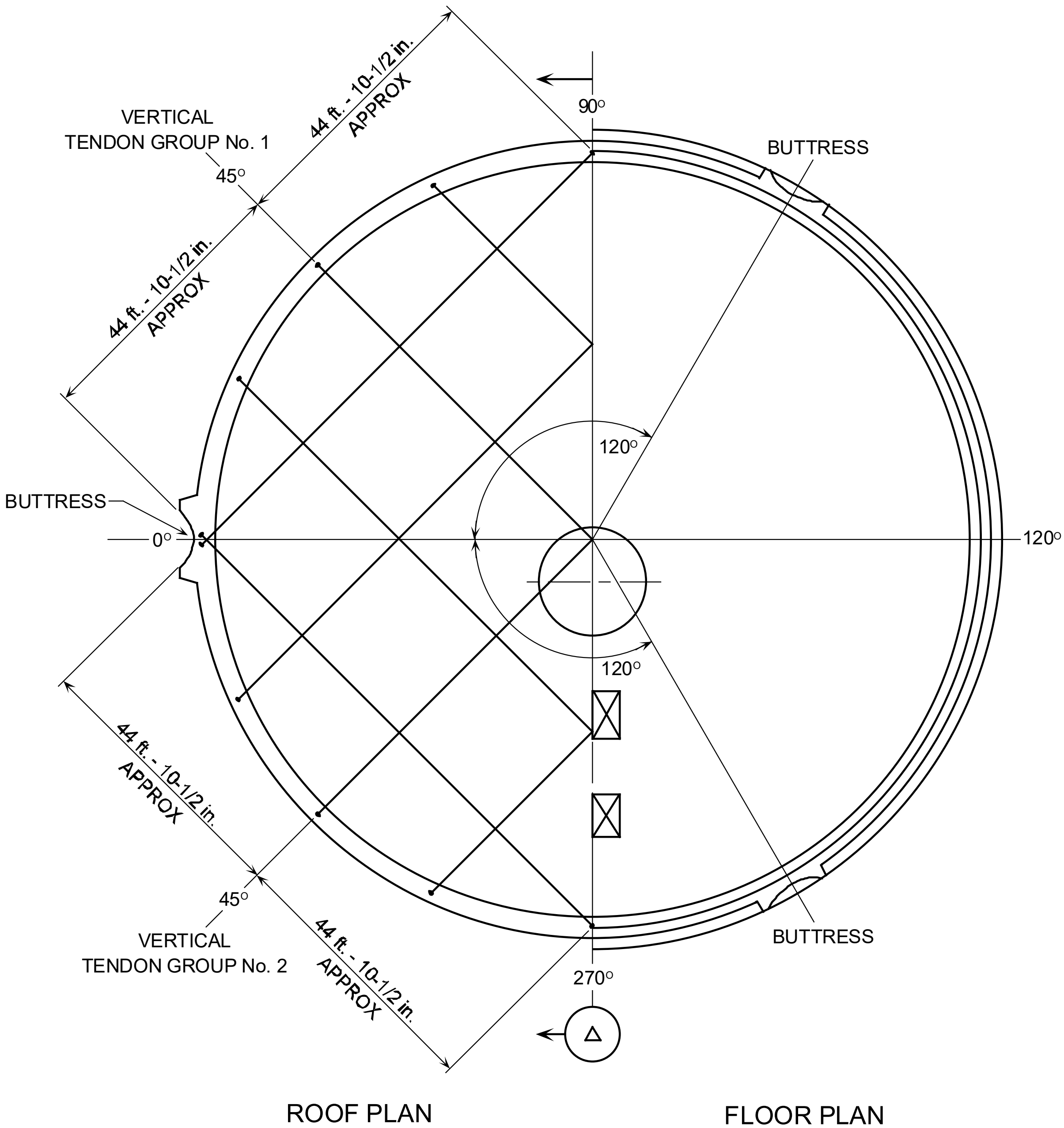
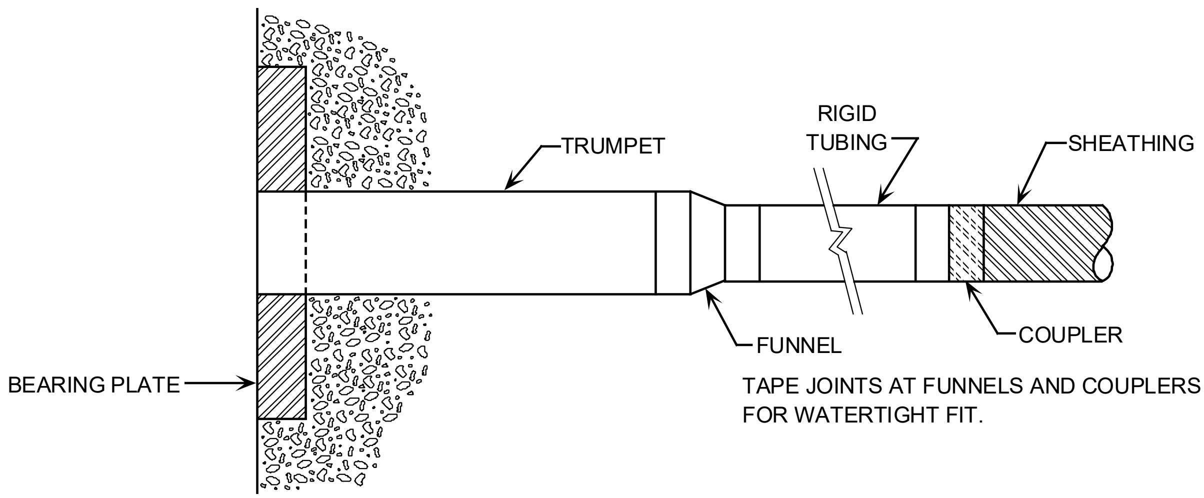
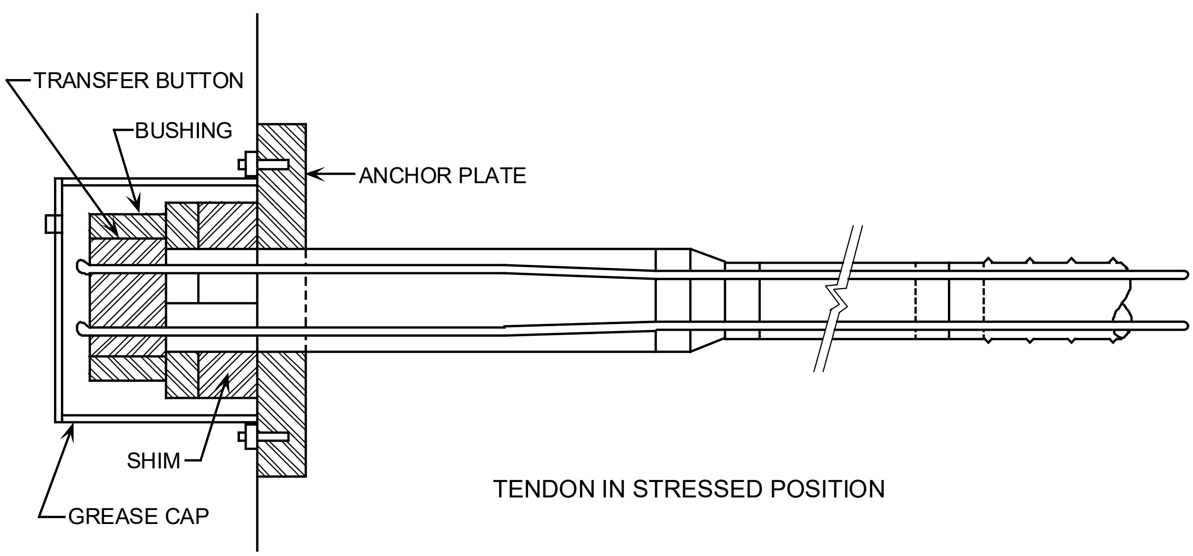


Figure 5.3-7 Dome Tendon Families



TRUMPLATE AND SHEATHING AS PLACED



TENDON IN STRESSED POSITION

Figure 5.3-8 Tendon Anchor Assembly

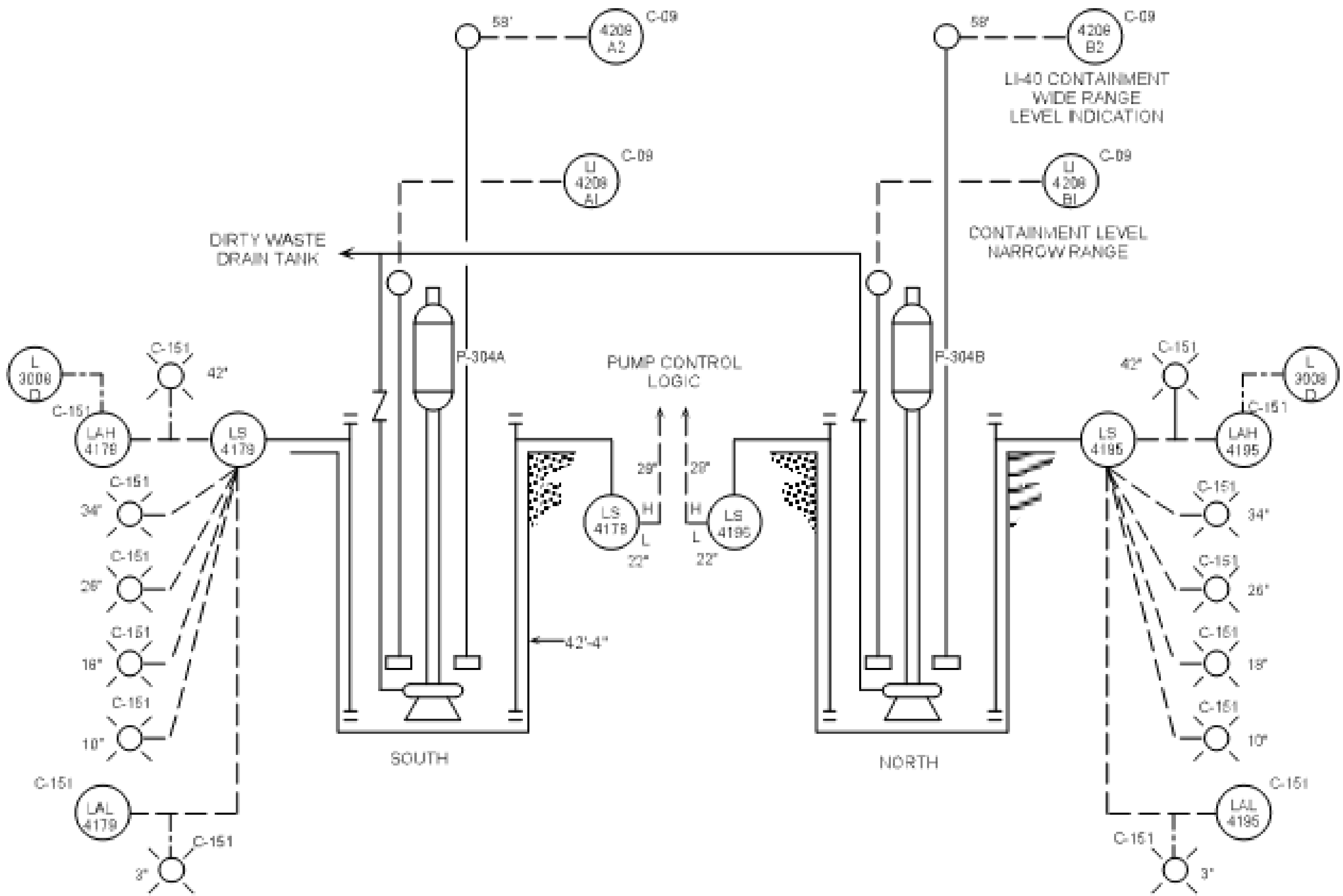


Figure 5.3-9 Containment Building Sump Level Indication

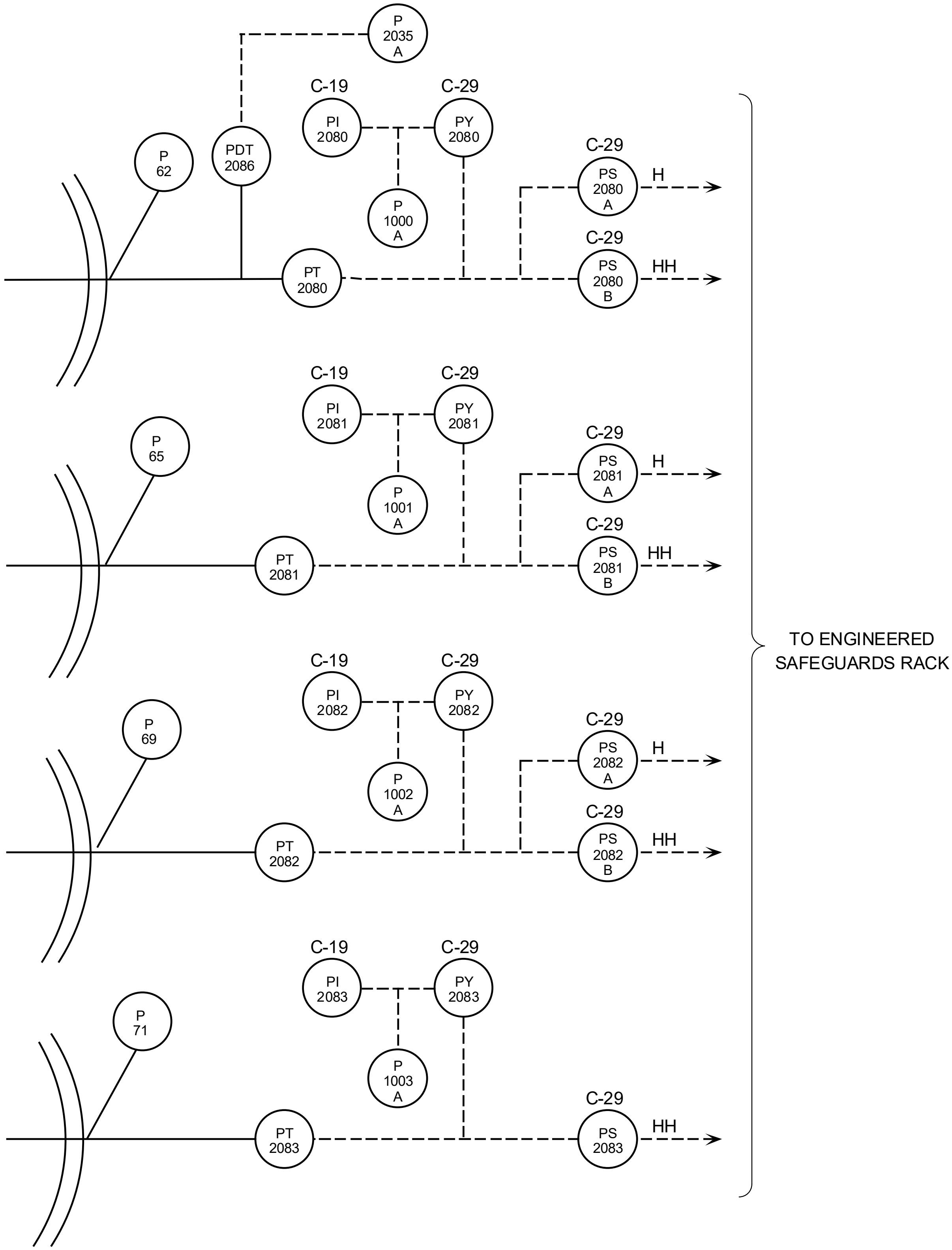


Figure 5.3-10 Containment Atmosphere Pressure

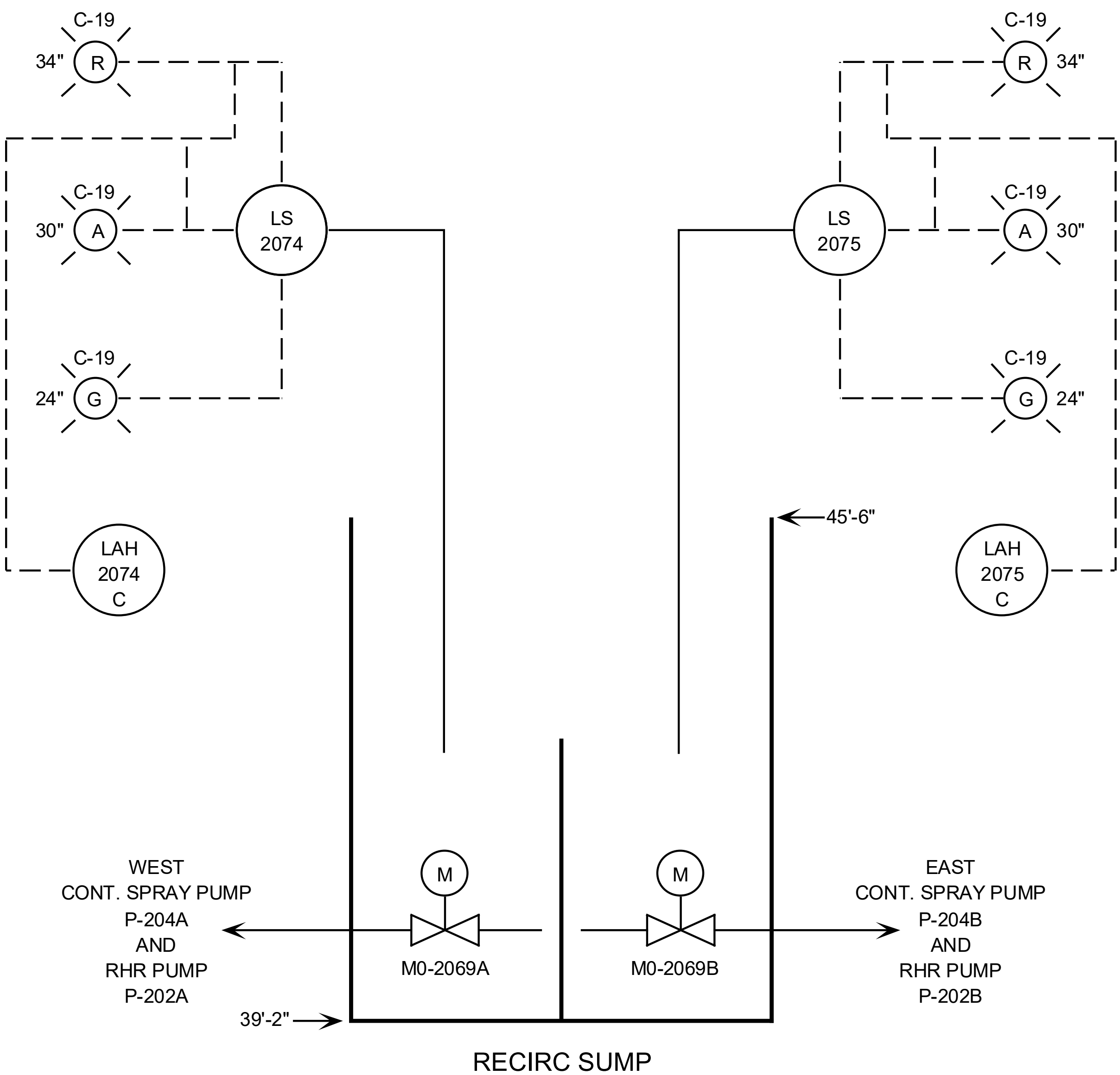


Figure 5.3-11 Recirculation Sump Level

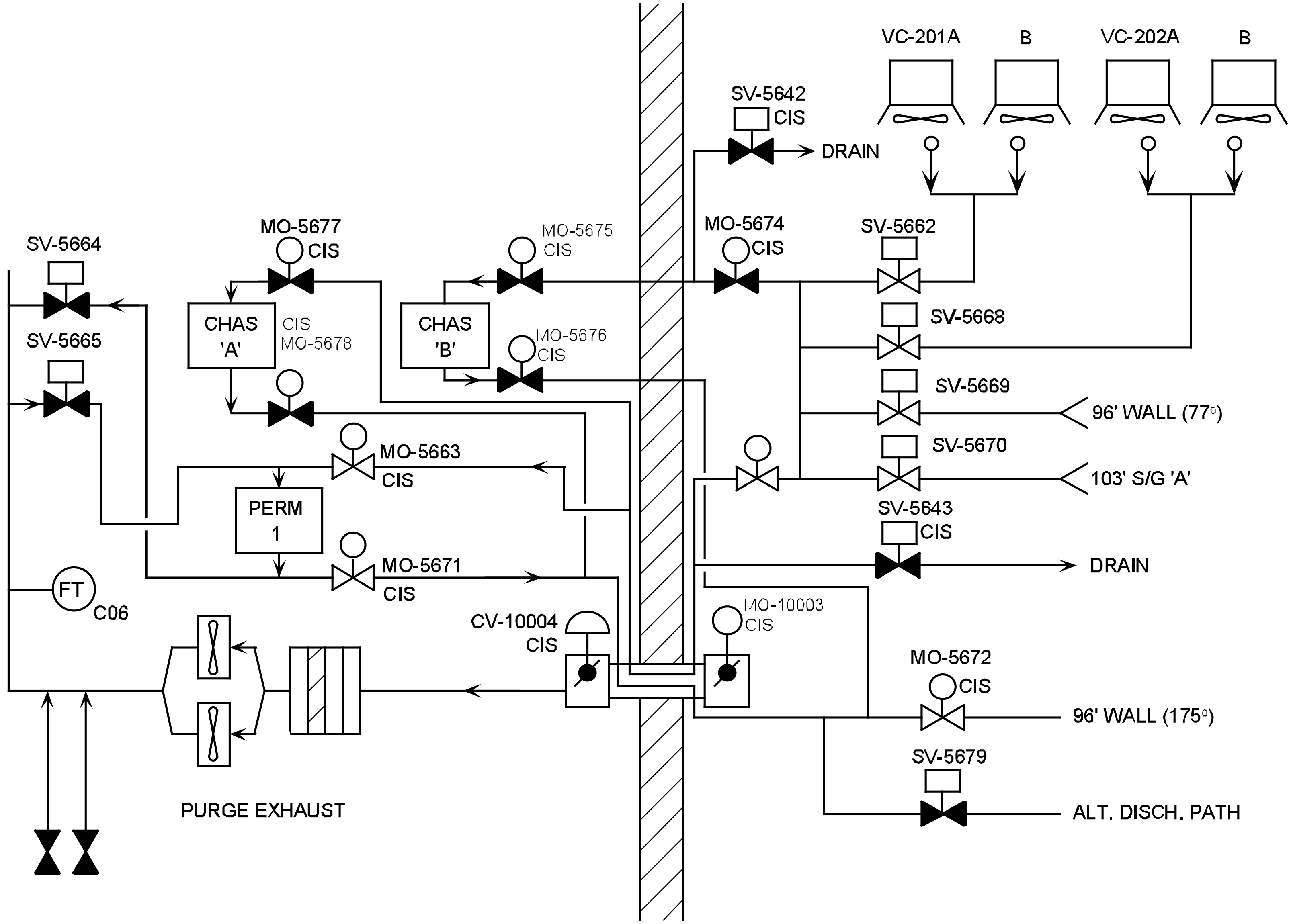


Figure 5.3-12 Containment Sampling Valves and Paths

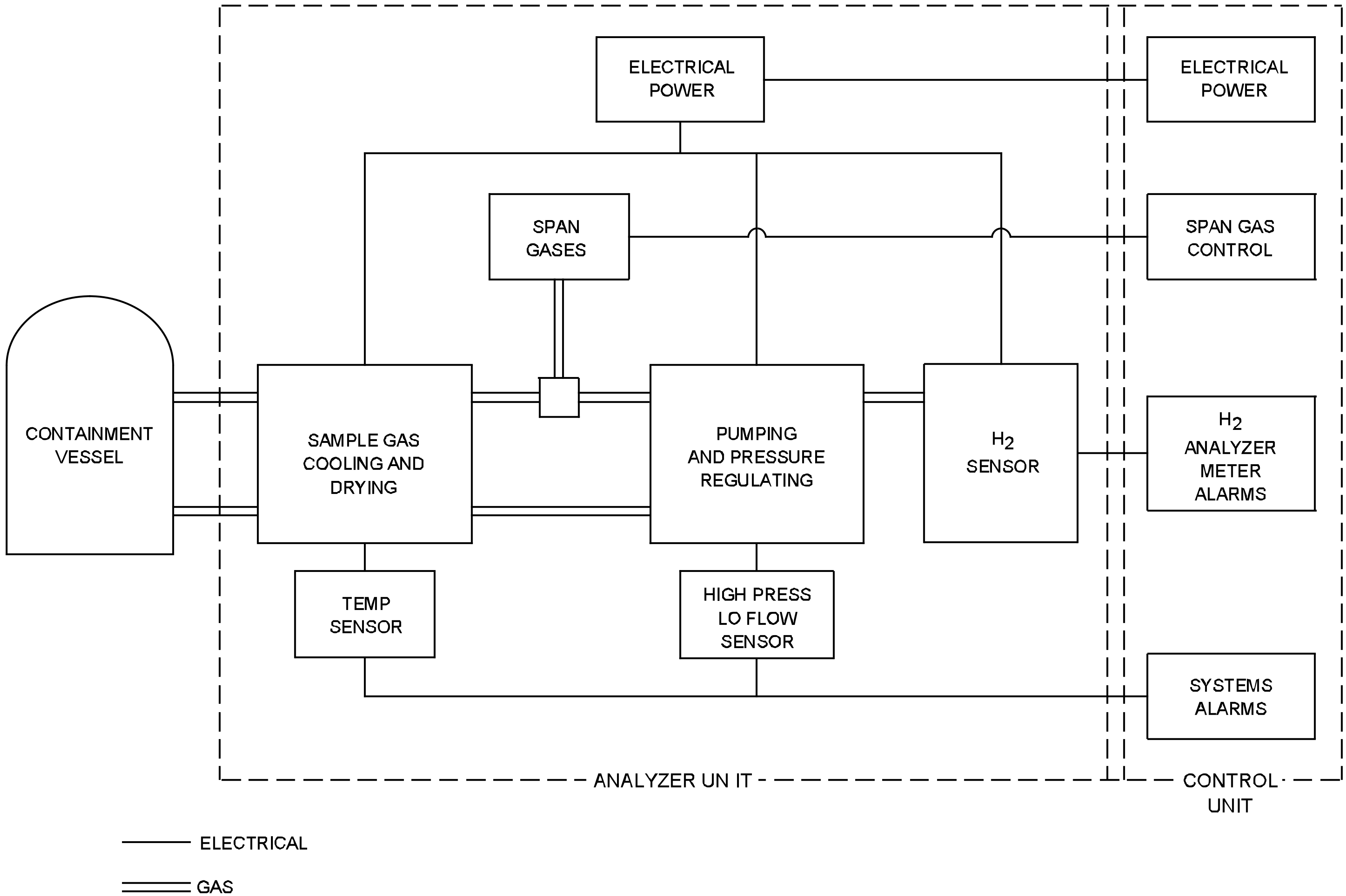


Figure 5.3-13 Hydrogen Sampling System

Westinghouse Technology Systems Manual

Section 5.4

Containment Temperature, Pressure, and Combustible Gas Control Systems

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5.4 CONTAINMENT TEMPERATURE, PRESSURE AND COMBUSTIBLE GAS CONTROL SYSTEMS

Learning Objectives:

1. State the purposes of the containment ventilation systems.

2. List the signals that automatically initiate isolation of the purge supply and exhaust systems.

3. State the purposes of the containment spray system.

4. List the signals that automatically initiate the containment spray system.

5. State the purposes of the containment combustible gas control systems.

5.4.1 Introduction

The purposes of the containment temperature, pressure, and combustible gas control systems are as follows:

1. To control the temperature and pressure of the containment during normal operations,
2. To protect the containment barrier and to minimize the leakage of radioactivity to the environment following an accident by reducing the containment temperature and pressure,
3. To remove hydrogen from the containment atmosphere and to limit localized hydrogen concentrations to prevent explosive mixtures, and
4. To remove radioactive iodine from the containment atmosphere after a Loss-Of-Coolant Accident (LOCA).

The central safety objective in reactor plant design and operation is limiting the release of radioactive fission products. To ensure that this objective is met, the containment must be designed and maintained so that the fission products are retained after operational and accidental releases inside the containment.

The containment temperature, pressure, and combustible gas control systems are those systems which are necessary for reducing the release of airborne radioactivity and for ensuring continued containment integrity. These containment systems function as necessary during normal operation and during the period following a postulated accident.

To minimize the leakage from the containment and any subsequent release of fission products after an accident, it is necessary to reduce the pressure and temperature inside the containment. Also, the capability to remove the additional energy produced by reactor decay heat must be provided, so that the containment design pressure is not exceeded. Since it is not permissible to cool the containment by means of once-through ventilation (due to the increased radioactive release to the environment) the containment ventilation systems and the Containment Spray (CS) system provide the required heat removal.

To further limit the release of radioactive species, the CS system includes a chemical additive (sodium hydroxide) to scrub any iodine from the containment atmosphere and keep it in solution in the containment sump water.

It is also necessary to control the buildup of hydrogen gas resulting from metal-water reactions in the core, from evolution of dissolved hydrogen from the reactor coolant, and from other sources to prevent reaching flammable levels. This is necessary to protect the integrity of the containment and the equipment within containment. The hydrogen recombiners and hydrogen vent system are used to remove hydrogen from the containment atmosphere, and the hydrogen mixing system is operated to prevent high localized hydrogen concentrations.

5.4.2 Containment Ventilation Systems

The purposes of the containment ventilation systems are as follows:

1. To control the temperature and pressure of the containment during normal operations to maintain operability of the containment and associated equipment,
2. To provide localized area ventilation for equipment inside containment, and
3. To provide cleanup of the containment atmosphere for limited personnel access while at power, and for continuous access while shutdown.

To satisfy these purposes, the containment ventilation systems are designed to accomplish the following:

1. Maintain the average containment temperature within 50 - 120°F during normal operation.
2. Provide 70,000 CFM of air to the control rod drive mechanisms with a maximum inlet air temperature of 120°F.
3. Supply air to maintain the Reactor Coolant Pump (RCP) air temperature below 120°F.
4. Provide cooling air for the primary concrete shield and the enclosed nuclear instrumentation wells.
5. Provide air to cool the reactor vessel supports.
6. Control containment airborne fission product gases, halogens and particulates in order to allow containment access without exceeding the occupational exposure dose limits of 10 CFR Part 20.
7. Control the releases of fission product halogens, particulates, and noble gases during containment purge such that the requirements of 10 CFR Part 50, Appendix A, may be met for overall plant radioactivity releases.

Nine systems, operating together, meet the diverse design requirements for containment ventilation. These systems are as follows:

- Purge supply system
- Purge exhaust and refueling cavity supply and exhaust system
- Control Rod Drive Mechanism (CRDM) cooling system
- Pressurizer compartment and incore instrumentation switching room cooling system
- RCP cooling system

- Reactor cavity cooling system
- Containment air cooler system
- Unit heater system
- Cleanup recirculation units

5.4.2.1 Purge Supply System

The purge supply system (Figure 5.4-1), operating in conjunction with the purge exhaust system (section 5.4.2.2), is designed to ensure safe, continuous access to the containment after a planned or unplanned reactor shutdown by reducing the airborne particulates of the containment atmosphere. The system performs no function with respect to reactor safety.

The containment is normally isolated from the environment during power operations. Prior to unisolating and activating the purge supply and exhaust systems, the radioactive particulate and gaseous activity levels inside the containment are monitored to ensure that releases from the containment are permitted. The activity of the purge exhaust flow is then monitored during purging operations.

The purge supply system consists of an outside air intake, an automatic roll filter, a bank of High Efficiency Particulate Air (HEPA) filters, two 100-percent supply fans arranged in parallel, backdraft dampers, an outboard air-operated isolation damper, a containment penetration, an inboard motor-operated isolation damper, and associated ductwork.

The ductwork out to and including the containment outboard isolation valve is designed to Seismic Category I specifications. The quick closing isolation dampers are capable of closing within five seconds for the motor-operated damper and within three seconds for the air-operated damper upon receipt of a Containment Ventilation Isolation Signal (CVIS).

The purge supply fans are 480-Vac, 3-phase, 125-hp vane axial fans. Each is capable of providing 100 percent of the required 50,000-CFM air flow. The fans are controlled from the main control room and are interlocked such that only one fan runs at a time. To start a fan, both isolation valves must be open, and the other fan must be stopped. A pressure switch that senses pressure in the common discharge ductwork will start the standby fan on low pressure if the running fan stops. When starting a fan, the control switch for the redundant fan must be placed in pull-to-lock until the running fan has increased the duct pressure above the pressure switch setpoint. The supply fans have undervoltage and overcurrent protection.

The automatic roll filter is an 80-percent efficient filter designed to reduce the particulates and dust in the supply air and to serve as a prefilter for the HEPA filter. The filter drive motor is interlocked with the supply fans such that it will run when either fan is running, and it is de-energized by a filter runout interlock.

The inboard and outboard dampers are controlled from the main control room. With their control switches in their normal positions (not in lockout), they will automatically close on a CVIS. A CVIS is generated by a safety injection signal (SIS), a high containment radiation signal, manual containment spray actuation, or manual initiation of phase A containment isolation. The open/closed status of each damper is sensed by limit switches and is indicated at the control switch and also on one of the containment isolation system status panels in the main control room.

5.4.2.2 Purge Exhaust and Refueling Cavity Supply and Exhaust System

The purge exhaust and refueling cavity supply and exhaust system (Figure 5.4-2) is operated in conjunction with the containment purge supply system to exchange 150% of the containment air volume per hour. The purge exhaust system is operated in modes 5 and 6 when continuous containment occupancy is desired.

The purge exhaust system consists of an inboard motor-operated isolation damper, a containment penetration, an outboard air-operated isolation damper, an automatic roll filter, a bank of HEPA filters, two 100-percent exhaust fans arranged in parallel, backdraft dampers, and associated ductwork. These components meet the same requirements as noted for the purge supply system. The isolation dampers automatically close upon receipt of a CVIS.

The purge exhaust system exhausts to the containment purge vent at the top of the containment building. The exhausted air is monitored for gaseous, particulate and iodine activity.

The supply portion of the refueling cavity supply and exhaust system consists of two fans drawing air from the containment atmosphere and discharging it horizontally across the refueling cavity. The exhaust portion of the system consists of two fans drawing air from the inlets at the surface of the refueling cavity and discharging it to the purge exhaust system. The refueling cavity supply and exhaust system's design objective is to rapidly remove and exhaust water vapor and fission products escaping from the fuel pool surface, to reduce the burden in the containment atmosphere during refueling.

5.4.2.3 Control Rod Drive Mechanism (CRDM) Cooling System

The CRDM cooling system (Figure 5.4-3) is designed to remove heat from the CRDMs and release it to the containment atmosphere. The system flow rate and static pressure drop requirements are based on maintaining the CRDM temperatures < 300°F with normal operation of two of the four fans and a containment air temperature of 120°F. The system is operating any time the reactor coolant temperature is $\geq$ 350°F. The system draws a minimum of 70,000 CFM of air through the shroud enclosing the CRDMs and discharges it upward, where it rises by convection to the containment air coolers. The four fans are mounted on the CRDM missile shield. The system is designated Seismic Category II.

5.4.2.4 Chill Water System

The chill water system (Figure 5.4-4) is not a safety-related system; however, it performs the important function of removing heat generated in the digital rod position indication and control cabinets, the pressurizer compartment, the incore instrumentation switching room, the reactor cavity, and the process sample system. The majority of the cooled equipment and spaces are located in the containment, where ambient temperatures range from 90°F to 110°F. Any equipment cooled by chill water may overheat if chill water flow is interrupted.

5.4.2.5 Pressurizer Compartment and Incore Instrumentation Switching Room Cooling System

The pressurizer compartment and incore instrumentation switching room cooling system (Figure 5.4-5) is designed to circulate containment air to these areas during normal operation and to supply 80°F air when personnel must access these areas. The system consists of two independent subsystems, one for the pressurizer compartment and the other for the incore instrumentation switching room.

Each subsystem consists of a dust filter, a chill water cooling coil, a supply fan, and distribution ductwork. Each subsystem cools its area sufficiently for personnel entry with the fan running and chill water supplied to the cooling coil, and maintains a suitable compartment temperature for normal equipment operation with only the fan running. The cooling coils can be served by either of two chillers, each of which can provide 100 percent of the required design cooling capacity. The system is designed as a Seismic Category II system.

5.4.2.6 Reactor Coolant Pump (RCP) Cooling System

The RCP cooling system (Figure 5.4-6) distributes cooling air to each of the RCP motors. The system consists of four independent subsystems, one for each RCP. Each subsystem consists of two 100-percent capacity fans arranged in parallel, backdraft dampers, and associated ductwork. One fan is normally running in each subsystem with the other in standby. The RCP cooling system is a Seismic Category II system.

5.4.2.7 Reactor Cavity Cooling System

The reactor cavity cooling system (Figure 5.4-7) circulates chilled air through the incore instrumentation tunnel and then up through the reactor cavity around the reactor vessel and its supports. The system is designed to handle the portion of the vessel cooling load below the cavity seal. The 110°F upper limit on the system's exit air temperature is based on the fact that the air exiting the reactor cavity subsequently enters the CRDM cooling system. The system is a Seismic Category II system.

5.4.2.8 Containment Air Cooler System

The containment air cooler system (Figure 5.4-8), when operating under normal conditions, and in conjunction with other normally running containment ventilation systems, removes heat from normally operating equipment and from radiation and convective transfer from the primary and secondary coolant systems.

The system provides the heat removal capacity to maintain containment temperature below 120°F during normal plant operation. The system also has the capacity to remove significant heat from the containment following a LOCA. The containment air cooler system is an engineered safety features (ESF) system and is designated Seismic Category I.

The system consists of eight individual air cooler units of equal capacity mounted above the containment spray header. Each unit contains a fan enclosed by an airtight roof and floor and surrounded on four sides by 12 cooling coils. The fans draw air horizontally across the cooling coils and discharge the cooled air downward into the containment. The cooling coils are supplied with cooling water from the Component Cooling Water (CCW) system. The eight air coolers are divided into two groups of four units, designated as trains A and B. The cooling coils of each of the train A air coolers are supplied with cooling water from train A of the CCW system. Each of the four train A cooler fans is powered by a train A 480-Vac ESF electrical bus. The fans and cooling coils of the train B air coolers are similarly supplied by train B of the Class IE electrical distribution system and train B of the CCW system. Physical separation and barriers are provided between all train A and train B components.

The containment air cooler system is designed to maintain containment air temperature below 120°F during normal operation with six of the eight cooler units in operation and with the CCW system operating with design flows and temperatures. The containment air cooler system also removes heat from the containment atmosphere in the event of a LOCA in order to suppress any resultant increase in containment pressure and temperature. The system is designed such that a single failure of any active component during the injection phase, or any active or passive failure during the recirculation phase, will not degrade the system's ability to meet the design objectives.

The air cooler fans are 480-Vac, three-phase, 125-hp, down-blast discharge, vane axial fans. Each fan has a design capacity of 100,000 CFM. The fan motors are designed to ensure that the required air and steam mixture flow is achieved under design-basis-event conditions. Fan motor output horsepower requirements are greater under accident conditions because of the greater density of the containment atmosphere.

The containment air cooler fans are normally controlled from the main control room. The control switches have STOP, NORMAL, and START positions, with PULL-TO-LOCK (PTL) and spring return to NORMAL features. With the control switches in NORMAL, the air coolers are automatically started by the Design Basis Accident (DBA) load sequencer.

During normal operation the CCW system supplies both containment air cooler trains. The CCW supply to each air cooler train contains a normally closed motor-operated valve and an orificed bypass line which supplies 1950 gpm of CCW flow. The air cooler fans are started as necessary to maintain containment temperature between 50 and 120°F. Not more than three air coolers in each train are run simultaneously, except for periodic testing. Normal air cooler operation has six of the eight coolers in operation.

Humidity in the containment air condenses on the cooling coils. The condensation from each cooler collects in a drip pan below the cooler. The drip pans are connected to a common collection header, and the drains are directed to a condensate collection pot. When the level in the pot reaches a setpoint, a motor-operated valve opens, and the pot drains to the containment sump. The number of times that the motor-operated valve opens is recorded in the control room. Condensate pot drain cycles are proportional to the condensation rate. The condensation rate is proportional to humidity and CCW temperature. Humidity is proportional to the leak rate of liquid systems inside the containment.

An SIS causes the start of any standby CCW train and the separation of the two CCW trains (if the trains are not already separated). The motor-operated valve in each CCW supply to the containment air coolers opens and provides a minimum flow of 6000 gpm flow to its associated cooler train. The DBA load sequencer automatically starts all previously idle air cooler fans when their control switches are in the NORMAL positions.

5.4.2.9 Unit Heater System

The unit heater system consists of ten unit heaters located throughout the containment building. The unit heaters are designed to provide heating to allow for personnel comfort during periods of personnel access. The electrical heating coils and blower units are locally controlled and have a variable temperature control.

5.4.2.10 Cleanup Recirculating Units

During normal operation, two Seismic Category II recirculating filter units are available for intermittent or continuous operation to control the buildup of airborne halogens and particulates which result from small RCS leaks within the containment. The cleanup filters (in conjunction with the containment purge supply and exhaust systems) have two objectives. The first is to maintain airborne fission product levels below the 10 CFR Part 20 limits for occupational exposures to allow safe access to the containment. The second is to reduce fission product releases to the environment to levels as low as reasonably achievable when containment purging is required. The cleanup recirculation system performs no function with respect to reactor safety.

The cleanup recirculation system (Figure 5.4-9) consists of two separate units. Each unit draws a containment air flow of 4000 CFM through a prefilter, a HEPA filter, and a carbon adsorber. With both units in operation, approximately one equivalent containment air volume is recirculated every four hours.

5.4.3 Containment Combustible Gas Control Systems

Three systems are provided to control hydrogen in the containment building. These systems are the hydrogen control system, the hydrogen mixing system, and the hydrogen vent system.

Following a LOCA, hydrogen gas may accumulate within the containment as a result of:

1. The metal/water reaction involving the zirconium fuel cladding and the reactor coolant,
2. Radiolytic decomposition of the post-accident emergency cooling solutions, and
3. Corrosion of metals caused by the solutions used for emergency cooling or containment spray.

If a sufficient amount of hydrogen is generated, it may react with the oxygen present in the containment atmosphere or with the oxygen generated following the accident. In this event, the reaction could take place at rates rapid enough to lead to high temperatures and significant pressures in the containment. This could conceivably result in the loss of containment integrity and/or damage to systems and components essential to the control of the post-LOCA conditions.

5.4.3.1 Hydrogen Control System

The hydrogen control system consists of two in-containment hydrogen recombiner units. The recombination units draw in containment air by natural convection and heat it to a temperature of 1150 - 1400°F. At a temperature of approximately 1135°F, hydrogen and oxygen recombine and thereby reduce the containment hydrogen concentration. The units are completely enclosed, and the internals are protected against impingement by containment spray. The units are designed as Seismic Category I components and are capable of functioning during a LOCA.

Each recombination unit (Figure 5.4-10) consists of an inlet preheater section, a recombination section, and a mixing chamber. Containment air is drawn into the unit by natural convection via inlet louvers and passes through the preheater section. The preheater section is outside a shroud placed around the central heaters; it takes advantage of heat conduction through internal unit walls. Preheating the air accomplishes the dual function of increasing the system efficiency and evaporating any moisture which is entrained in the air. The warmed air then passes through a specifically sized flow orifice and flows vertically upward through the recombination section, where its temperature is raised, and the hydrogen and oxygen recombine.

The recombination section contains five banks of vertically stacked electric heaters. Each heater bank contains 60 U-type heating elements. After heating and recombination, the air rises to the mixing chamber. In the mixing chamber the hot air is mixed with the cooler containment air that enters the mixing chamber through the lower parts of the louvers located on three sides of the mixing chamber; the mixture is then discharged to the containment atmosphere.

In the event of a LOCA, plant personnel use the containment hydrogen analysis system to determine the hydrogen concentration in containment. The recombination units are started as required (normally with the hydrogen concentration between 0.5 percent and 4.0 percent). The units are started from the main control room.

5.4.3.2 Hydrogen Mixing System

The hydrogen mixing system (Figure 5.4-11) consists of two fans which take suction from the high point of the containment dome, where any generated hydrogen is expected to collect. The exhaust from the fans is directed downward into the lower containment air space, where rapid mixing by turbulence created by the containment air coolers occurs. Operating the hydrogen mixing fans helps to prevent a localized hydrogen concentration in the containment dome area which exceeds the flammability limit. The hydrogen mixing system is an ESF system which meets Seismic Category I requirements.

5.4.3.3 Hydrogen Vent System

The hydrogen vent system (Figure 5.4-12) consists of two redundant subsystems which permit controlled purging of the containment. Each subsystem includes a fan which exhausts air from the containment through motor-operated isolation dampers and a filter assembly containing a roughing filter, a HEPA filter, a carbon adsorber, and a HEPA after filter. The filter assembly reduces the activity of the halogens and particulates in the vent flow. Each fan exhausts air through a motor-operated damper to the purge exhaust system.

Filtered air from the purge supply system is supplied by the hydrogen vent system to replace the air that is removed and to maintain containment pressure within normal limits. The intake path is through a manual valve and remotely controlled motor-operated dampers.

The eight motor-operated containment isolation dampers are operated from the main control room. A phase A containment isolation signal (CIS - channel A for inboard dampers and channel B for outboard dampers) or a CVIS will cause the dampers to automatically close. Damper open and closed indication is provided in the main control room.

Following an accident, the hydrogen vent system provides the capability to lower the containment hydrogen concentration by venting hydrogen to the environment. Analyses show that hydrogen venting should not be required until a few weeks after the accident; that time should be sufficient for containment air activity to reach a level which can be vented to the environment without exceeding exposure guidelines. During normal plant operation, the system is periodically operated to vent containment air to maintain the containment pressure below the upper limit. (Containment pressure increases mainly due to leakage from the instrument air system.) The hydrogen vent system is the preferred vent path because of the extensive filtering of the exhausted air.

5.4.4 Containment Spray (CS) System

The Containment Spray (CS) system is designed to accomplish three (3) main objectives:

1. Limit the peak containment pressure below its design pressure of 60 psig following a worst case LOCA, and then subsequently reduce the post-accident containment pressure;
2. Reduce the concentration of fission product iodine in the containment atmosphere following a LOCA; and
3. Keep spray-entrained iodine in the containment recirculation sump while maintaining the sump water at a basic pH.

The CS system is an Essential Safety Feature (ESF) system which functions to reduce the containment pressure and airborne fission products in the containment atmosphere following a steam break or a LOCA. The pressure reduction is accomplished by spraying cool, borated water from the refueling water storage tank into the containment atmosphere. Sodium hydroxide is added to the containment spray water to enhance absorption of the airborne fission product iodine and to retain the radioactive iodine in solution.

5.4.4.1 System Description

The containment spray system (Figure 5.4-13) is comprised of two 100-percent, independent, and identical trains, with the exception of a common spray additive tank and a common containment spray pump recirculation test line to the Refueling Water Storage Tank (RWST). Otherwise, train separation extends from the pump suctions to the containment spray headers. Redundancy of equipment in the containment spray trains satisfies the single failure design criterion.

The containment spray system consists of two pumps, two spray ring headers, a spray additive tank, a number of motor-operated isolation valves, and all necessary piping, instrumentation, and accessories to make the system operable.

During the injection phase of system operation, the containment spray pumps start and take suction from the RWST upon receipt of a Containment Spray Actuation Signal (CSAS). The pumped fluid pumped is borated water mixed with a sodium hydroxide (NaOH) solution from the spray additive tank. The NaOH is added to the spray water to enhance removal of elemental iodine from the containment atmosphere. The spray water pH value is maintained within the range of 9.0 - 10.5 during injection. This pH range helps ensure iodine removal from the containment atmosphere by the spray droplets, retaining iodine in solution, and compatibility between the spray fluid and the materials with which it comes in contact.

The NaOH solution is piped to two liquid jet eductors, each of which is located in a bypass line around one of the spray pumps. Motor-operated isolation valves in the NaOH supply path to the eductors open upon receipt of the CSAS. The bypassed spray water from each pump’s discharge passes through an eductor and draws the NaOH solution into the eductor, where it mixes with the spray water and is piped back to the suction of the pump.

The discharge from each CS pump is piped to a ring header located on the inside of the containment dome. A motor-operated isolation valve in each header supply line opens upon receipt of the CSAS. Each ring header contains spray nozzles aimed in various predetermined directions to ensure maximum spray coverage of the containment. The ring headers are piped to provide complete coverage of the containment even if one spray pump fails to start on demand.

During the recirculation phase of system operation, the spray pump suctions are manually realigned from the RWST to the containment recirculation sump. The pump discharge paths to the ring headers and the eductors are unchanged. This evolution permits continued delivery of spray flow to the containment environment after the RWST has largely emptied.

Recirculation lines from the pumps to the RWST allow testing of the pumps without initiating containment spray. A locked-closed, manually operated globe valve in each pump recirculation line and one in the downstream common line allow test flow alignment and throttling.

5.4.4.2 Component Descriptions

Containment Spray Pumps

The spray pumps are vertical, single-stage centrifugal pumps. Each pump is rated for 2800 gpm at approximately 200 psig. The pumps are made of a material compatible with the NaOH additive and the boric acid solution of the RWST. Each spray pump delivers a design flow equal to 100 percent of the heat removal capability necessary to maintain the pressure in the containment below its design maximum. The design discharge pressure of each pump is sufficient to continue at rated flow with the RWST almost empty, against a head equivalent to the sum of design containment pressure, the elevation head of the uppermost nozzle, and the line and nozzle pressure losses.

As a component of an ESF system, each pump is supplied electrical power from an independent ESF 4.16-kv bus. The CS pumps can be individually controlled from two separate locations. A selector switch, mounted on the local switchgear panel, determines which station, LOCAL or REMOTE, has control. In LOCAL, START or STOP may be selected at the switchgear panel. In REMOTE, control is shifted to the main control room. With the pump control selected to REMOTE and the main control room switch selected to AUTO, the CS pumps are started by a CSAS coincident with an SIS.

Spray Additive Tank

The spray additive tank is constructed of carbon steel and lined with a special coating on its interior surface to protect the tank from the highly corrosive caustic contained within. The tank capacity is 4000 gal of 30 weight percent NaOH solution. To prevent degradation of the NaOH solution due to introduction of air into the tank, a nitrogen blanket is maintained above the solution surface. The normal nitrogen pressure is two psig.

The NaOH concentration of the spray additive tank and the addition rate of NaOH to the spray flow provided by the eductors are selected so that, after the tank solution mixes with the water from the reactor coolant system, the RWST, and the safety injection accumulators, the resulting basic pH of the containment recirculation sump solution ensures effective iodine retention and limited corrosion of containment materials.

Spray Additive Eductors

The liquid jet eductors provide the means of adding NaOH to the spray water. An eductor uses the kinetic energy of a pressurized liquid to entrain another liquid, mix the two, and discharge the mixture against a counter pressure. For the spray additive eductors, the pressurized liquid is the spray pump discharge, which entrains the NaOH solution and discharges the mixture into the suctions of the spray pumps. During the initial injection phase of CS system operation, the RWST supplies water to each spray pump. Ninety-five percent of a pump's discharge is directed to its respective spray ring, and the remaining five percent bypasses the spray ring to supply motive force for that train's additive eductor. From each eductor, the mixture of NaOH and borated water enters the suction of its associated CS pump.

Spray Headers and Nozzles

The CS pumps discharge to two concentric spray rings in the dome of the containment. The rings are redundant, with half being supplied from each spray pump through a normally shut motor-operated isolation valve. Each ring provides a full 360° coverage of the containment. Protruding from each spray ring are hollow core nozzles. Train A has 176 spray nozzles and Train B has 178 spray nozzles. Each nozzle is capable of delivering approximately 15 gpm of atomized spray water. The spray nozzles are not subject to clogging by particles less than 1/4 in. in maximum dimension.

The spray rings are a critical portion of the CS system. The pumps provide the proper flow of spray water, and the eductors supply the proper addition rate of NaOH solution. The spray nozzles deliver this mixture in a fine mist to the containment atmosphere. Atomization increases the effective surface area of the water spray. The greater surface area allows a given volume of water to absorb more internal energy from the atmosphere, thereby increasing the rate at which the containment pressure and temperature decrease. Secondly, the greater surface area exposes a given water volume to more iodine and therefore increases its iodine-removal efficiency.

The positioning of the spray nozzles is such that both spray ring headers develop a blanket of mist covering over 90 percent of the containment building volume. The remaining 10 percent consists of completely flooded lower regions as well as the volume above the spray rings. A portion of the spray pattern intentionally strikes the containment inner walls to create a liquid layer that acts as an additional barrier to fission product leakage.

5.4.4.3 Containment Spray Actuation Signals (CSAS)

Containment Spray Actuation Signals (CSAS) are developed by two completely redundant channels (A and B). Either of the following conditions will cause both a train A and a train B CSAS:

1. High-high containment pressure (30 psig), as sensed by two out of four containment building pressure detectors, or
2. Manual operator initiation from the main control room.

Containment spray initiation involves several unique features in comparison to initiation of other ESF functions. First, for manual initiation from the control room, two actuation switches are provided; both must be simultaneously positioned to the ACTUATE position to initiate containment spray. The simultaneous positioning of these switches is also required to generate a phase B containment isolation signal

(CCW flows to the reactor coolant pumps will be isolated). Second, a CSAS, either from manual or automatic initiation, is insufficient, by itself, to start the CS pumps. An SIS must also be present to energize each ESF train's DBA load sequencer, allowing it to start that train's CS pump. An SIS is not required to open the spray header isolation valves or NaOH tank outlet valves; the CSAS alone is sufficient to cause valve opening. Third, the containment pressure bistables for spray actuation are energized to actuate, whereas other protection bistables are de-energized to actuate. The status of the four individual high-high containment pressure channels is monitored by trip status lamps on the ESF trip status panel in the main control room. These design features make an inadvertent and unnecessary spraydown of the containment building unlikely.

Each CSAS (high-high containment pressure, manual initiation) can be manually reset from the control room. The reset logic for the high-high containment pressure CSAS involves a retentive memory with an actuation block. The presence of the retentive memory means that, once an actuation signal has initiated (assuming no reset action by the operator), it remains present even if the containment building pressure returns to normal (below the actuation setpoint). The operator must manually reset the automatic actuation in accordance with plant emergency operating procedures to stop spraying into the containment atmosphere. If the operator resets the CSAS prior to the containment pressure returning below the high-high actuation setpoint, automatic reinitiation does not occur because of the actuation block feature. When the containment building pressure decreases below the actuation setpoint, the block feature automatically clears, and automatic reinitiation would then occur if containment pressure again exceeds the actuation setpoint.

5.4.5 Summary

Containment ventilation systems are provided to maintain the containment's temperature, pressure, humidity, and activity within appropriate limits for equipment operation and personnel access.

The purge supply and exhaust systems maintain proper environmental quality for unlimited access during periods of reactor shutdown. This function is accomplished by continuously circulating outside air through the containment.

The containment air coolers provide general containment atmosphere cooling by removing heat generated by plant components and heat losses to ambient from reactor coolant system piping. Other ventilation systems force cooled air directly past components requiring additional cooling. The cleanup recirculating units, with HEPA filters and carbon adsorbers, are used to reduce containment activity.

The refueling cavity supply and exhaust system minimizes exposure of refueling personnel to airborne activity during refueling operations.

Three combustible gas control systems (the hydrogen control system, hydrogen mixing system, and the hydrogen vent system) are provided to remove hydrogen from the containment atmosphere and to limit localized hydrogen concentrations to prevent explosive mixtures.

A containment spray system is designed to limit the peak containment pressure following a LOCA, to subsequently reduce the post-accident containment pressure, and to reduce the concentration of iodine in the containment building. Additionally, the system keeps spray-entrained iodine in the containment recirculation sump while maintaining the sump water at a basic pH. The containment air coolers supplement the containment spray system in cooling the post-accident containment environment.

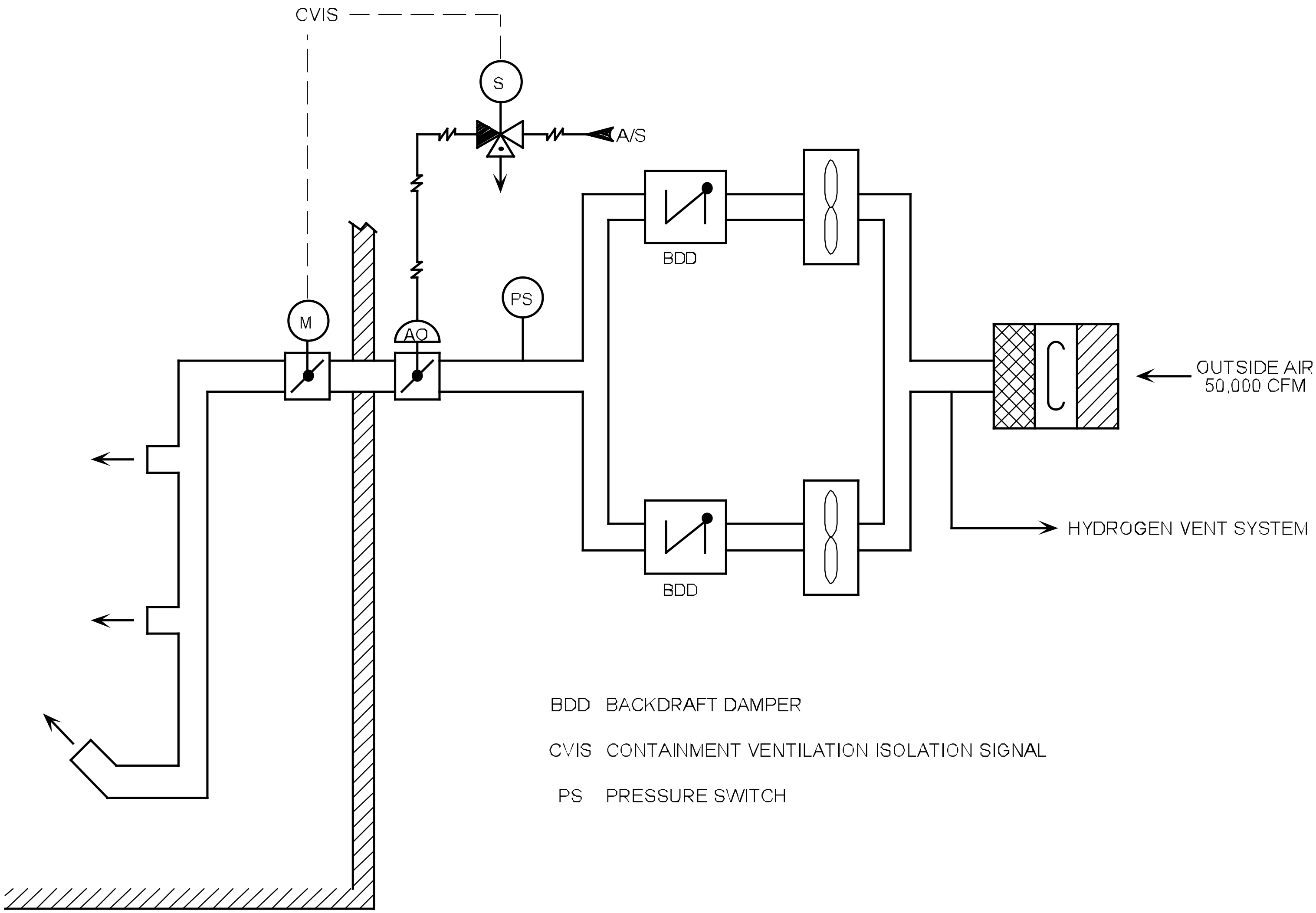

Figure 5.4-1 Purge Supply System

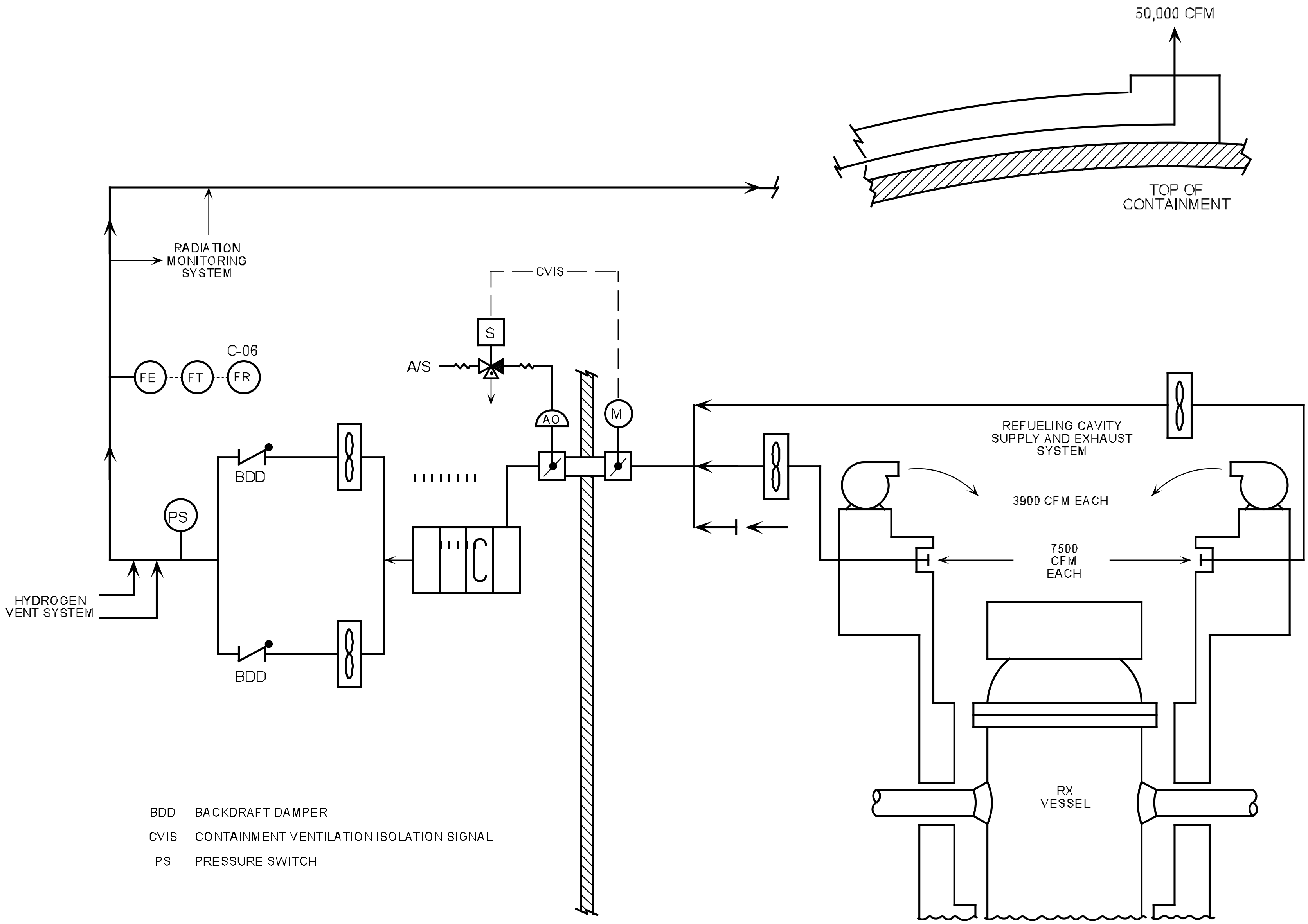

Figure 5.4-2 Purge Exhaust and Refueling Cavity Supply and Exhaust System

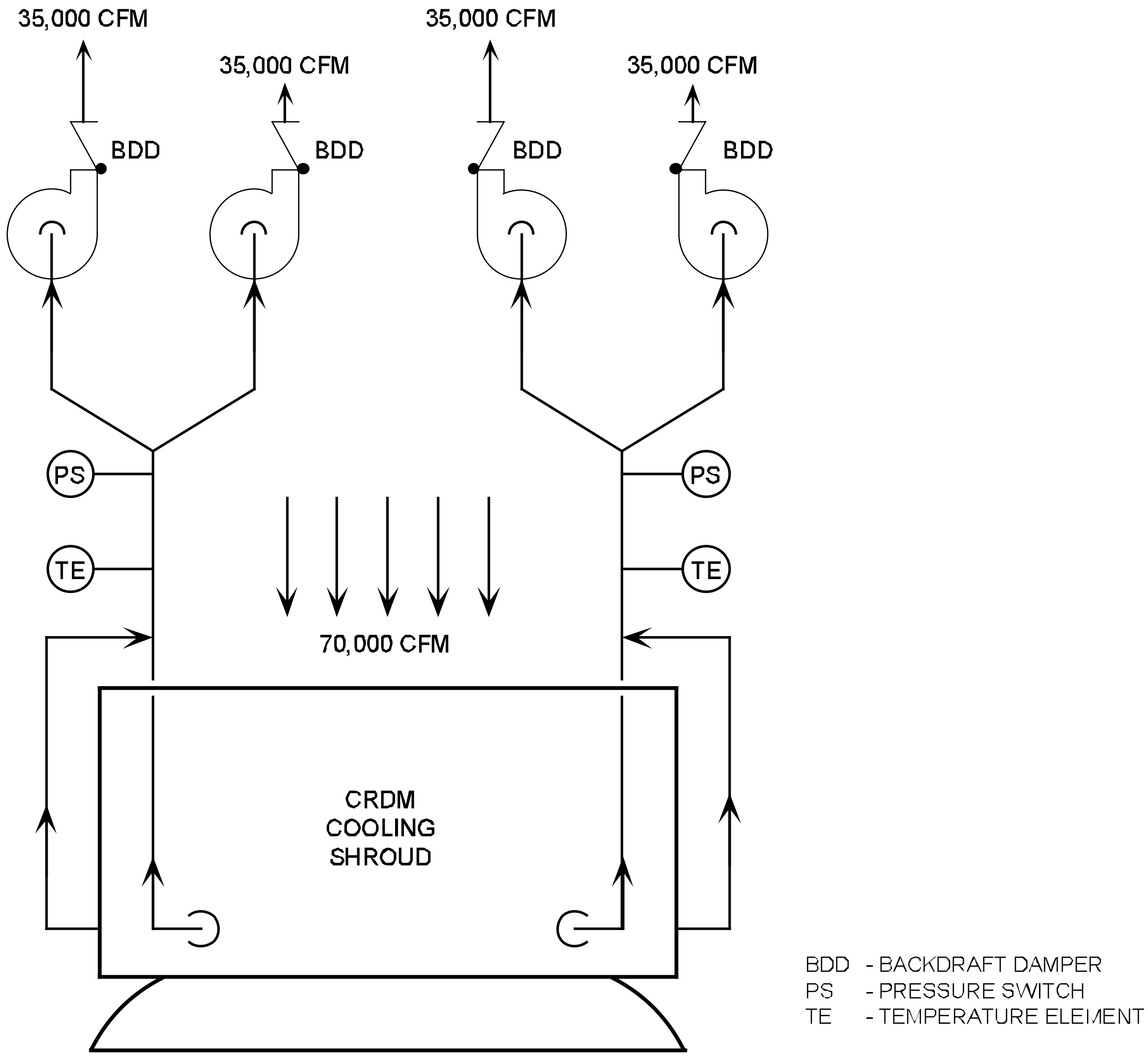

Figure 5.4-3 CRDM Cooling System

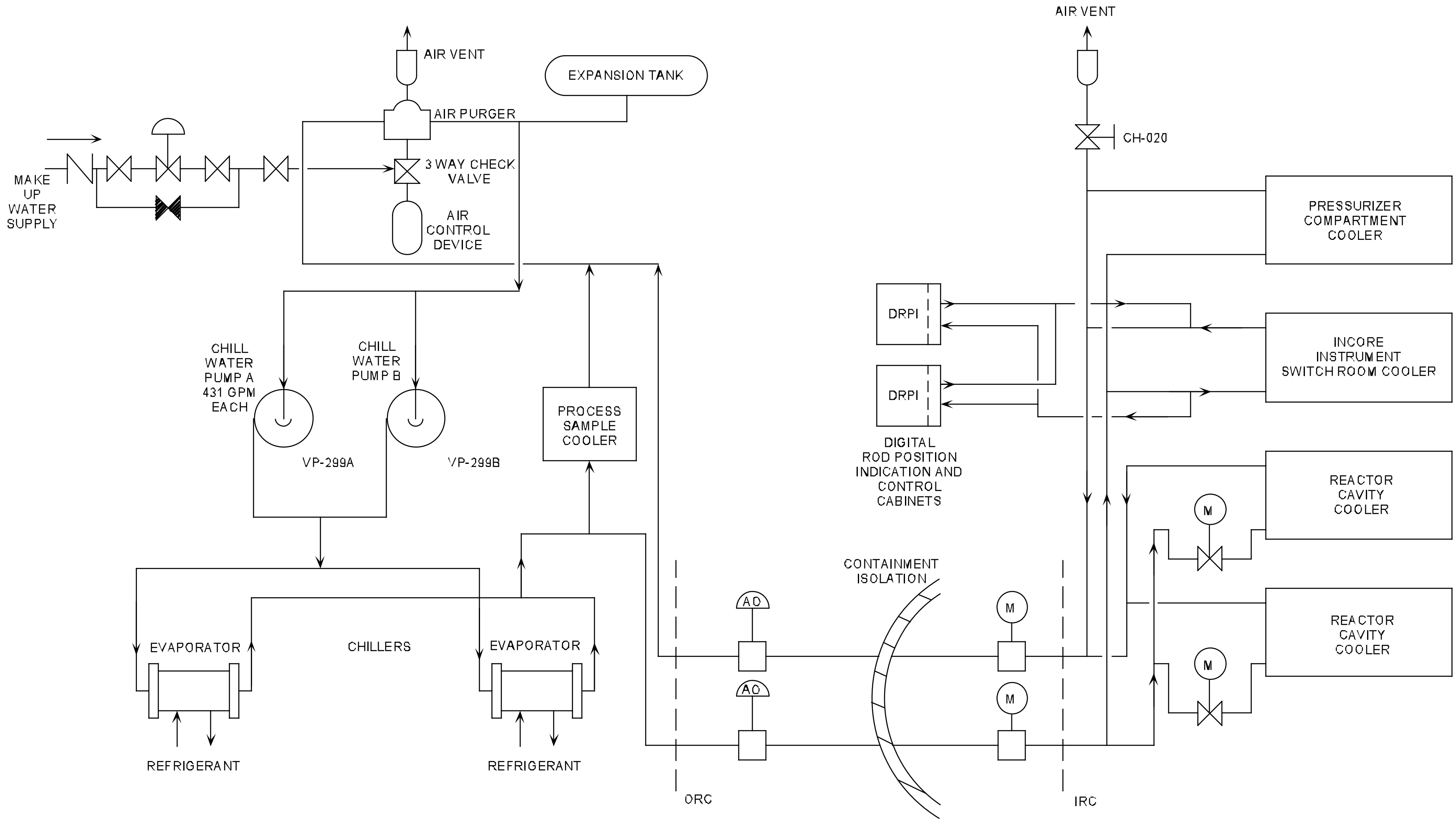

Figure 5.4-4 Chill Water System

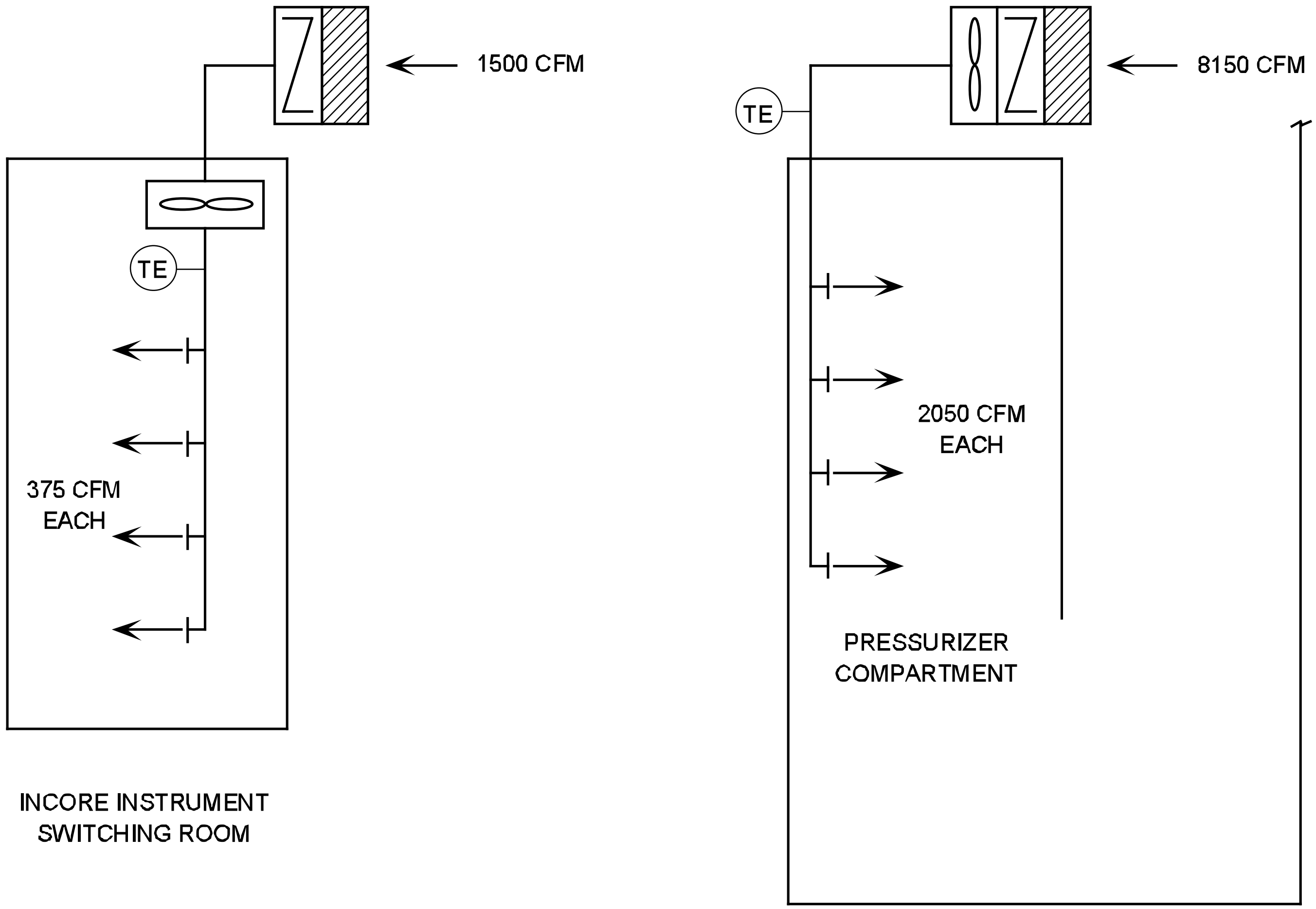

Figure 5.4-5 Pressurizer Compartment and Incore Instrument Switching Room Cooling

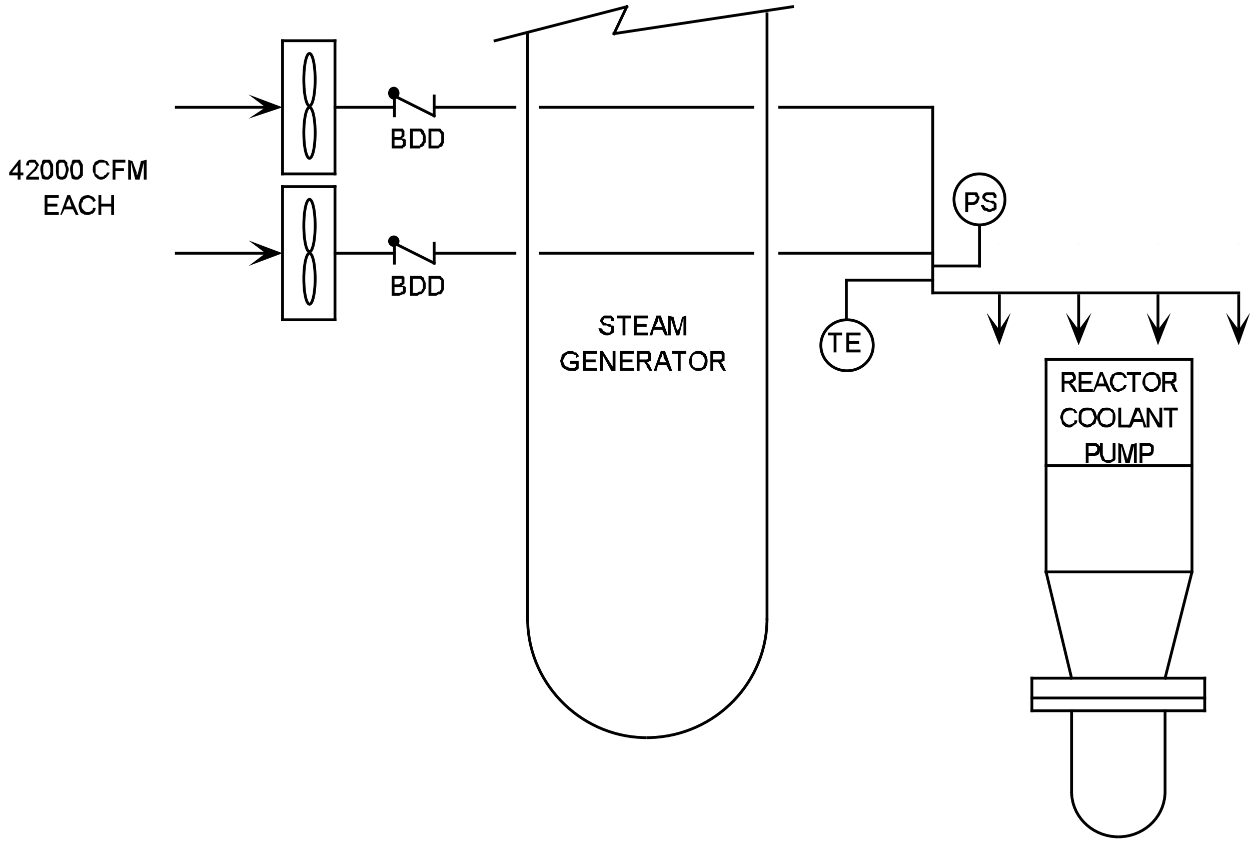

Figure 5.4-6 Reactor Coolant Pump Cooling System

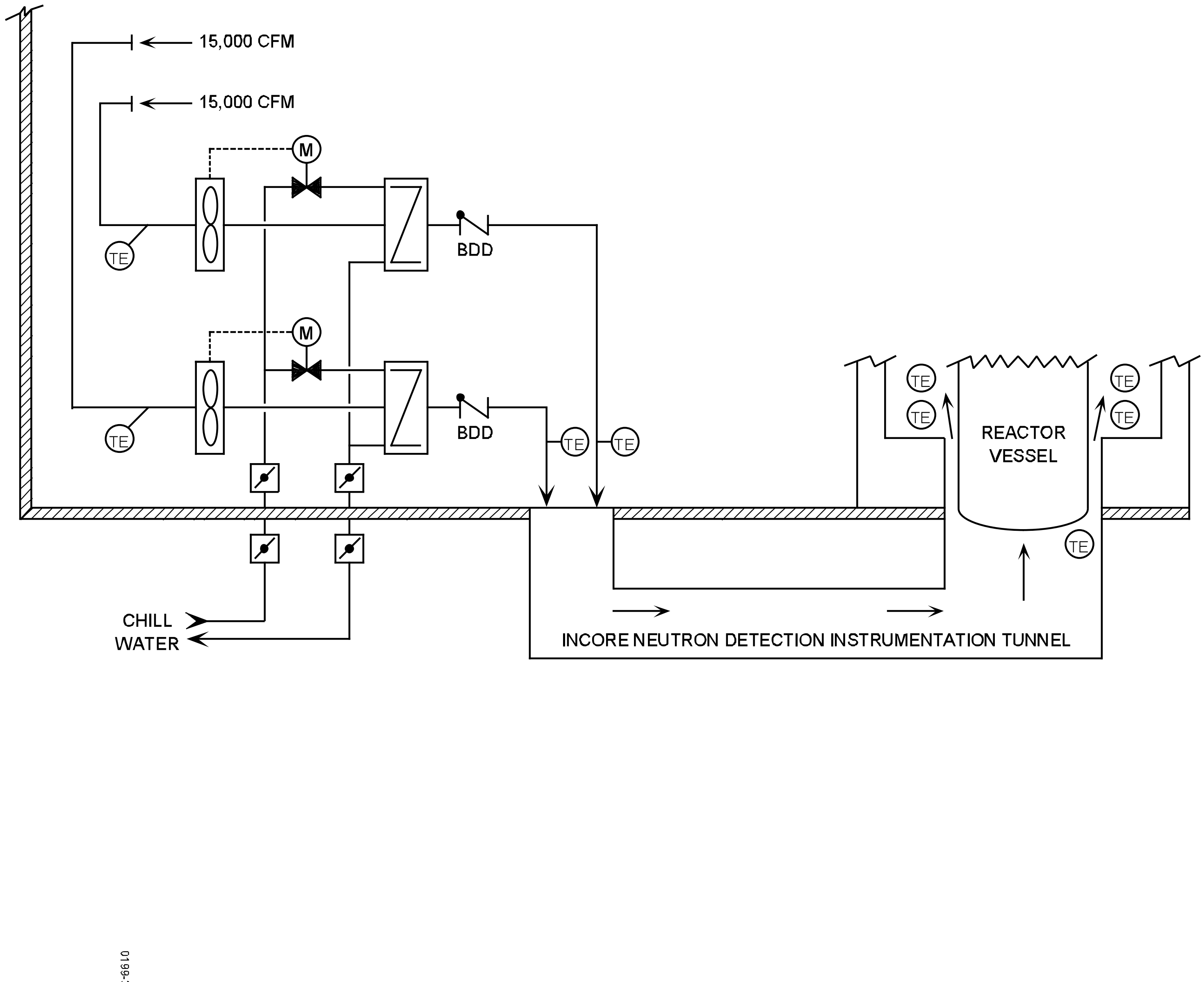

Figure 5.4-7 Reactor Cavity Cooling System

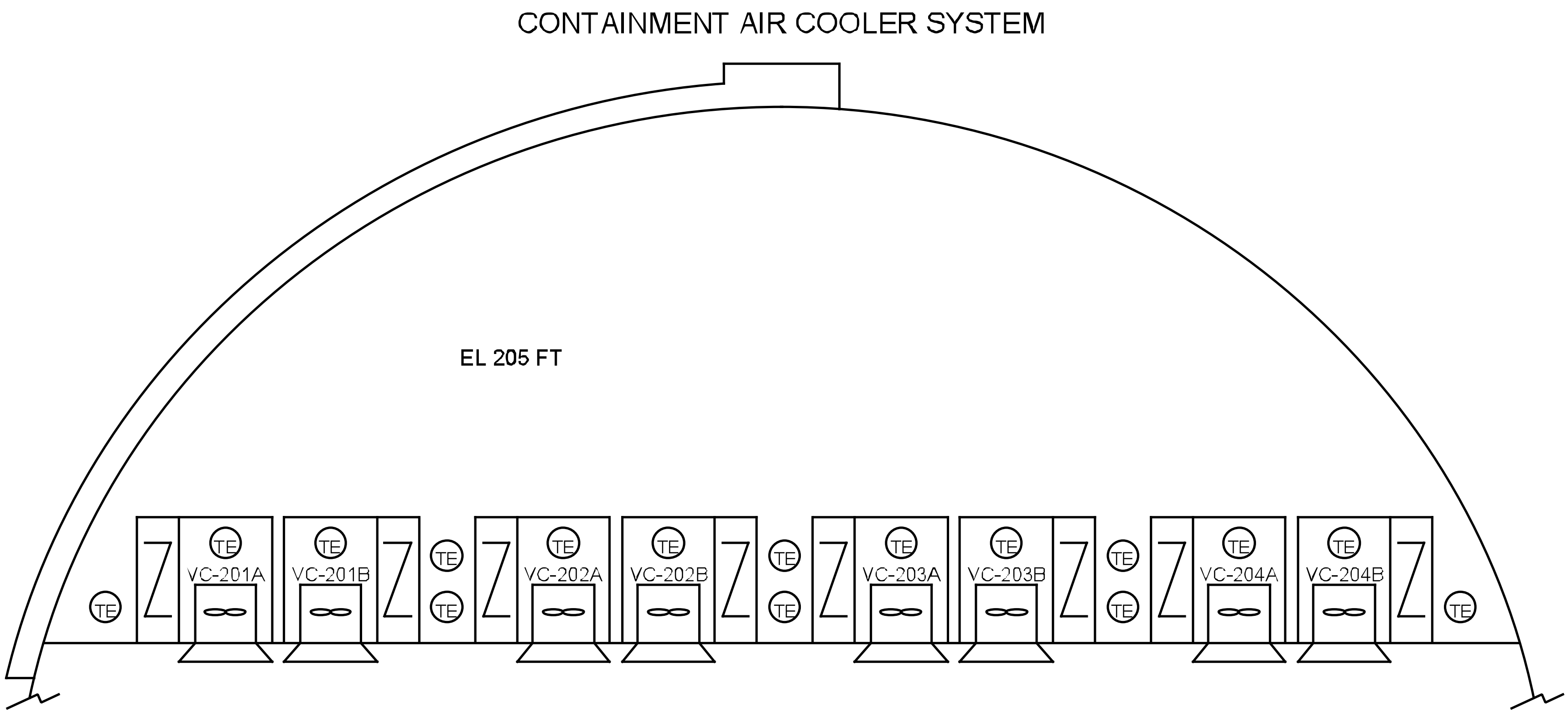

Figure 5.4-8 Containment Air Cooler System

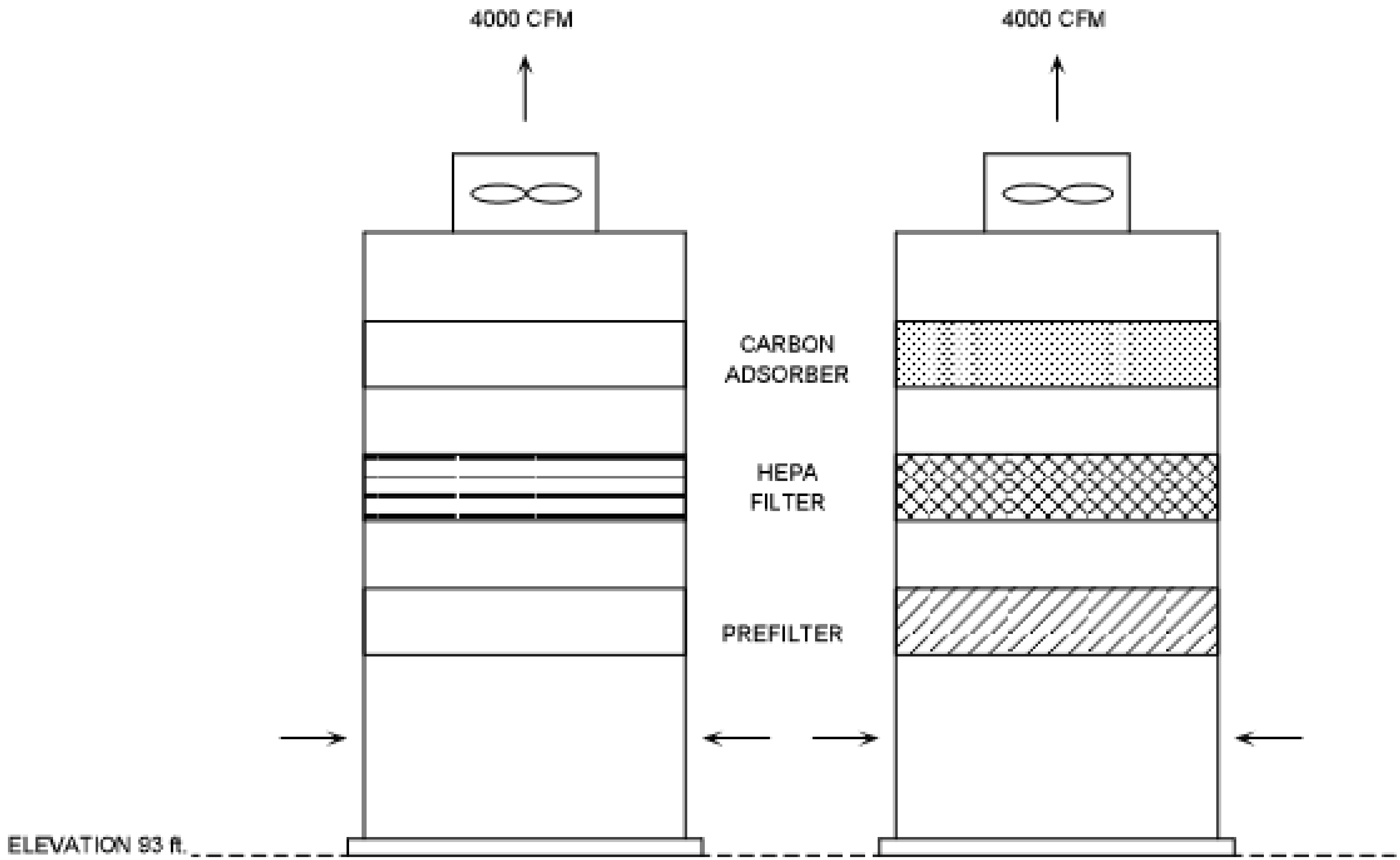

Figure 5.4-9 Cleanup Recirculation Units

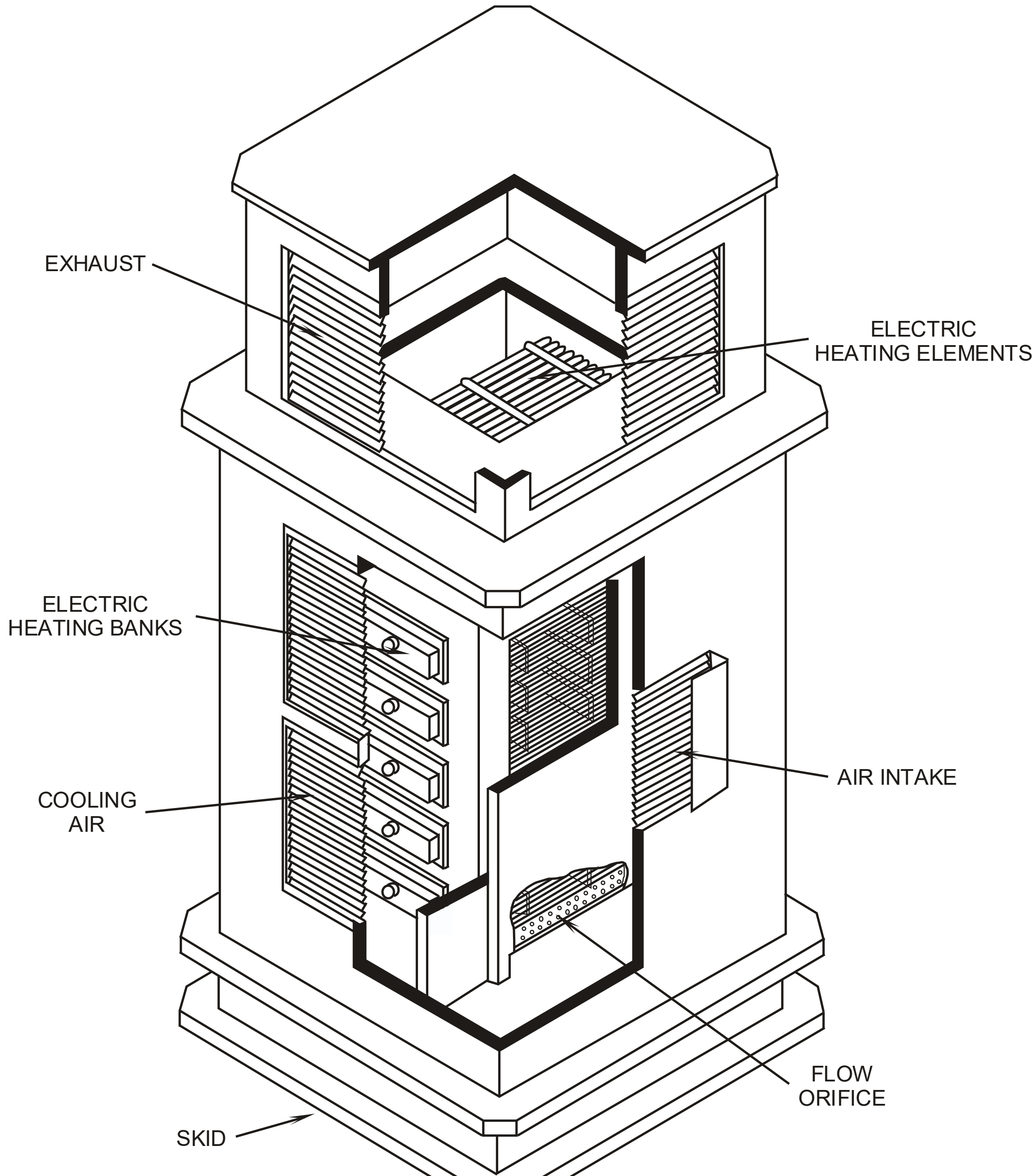

Figure 5.4-10 Hydrogen Recombiner Units

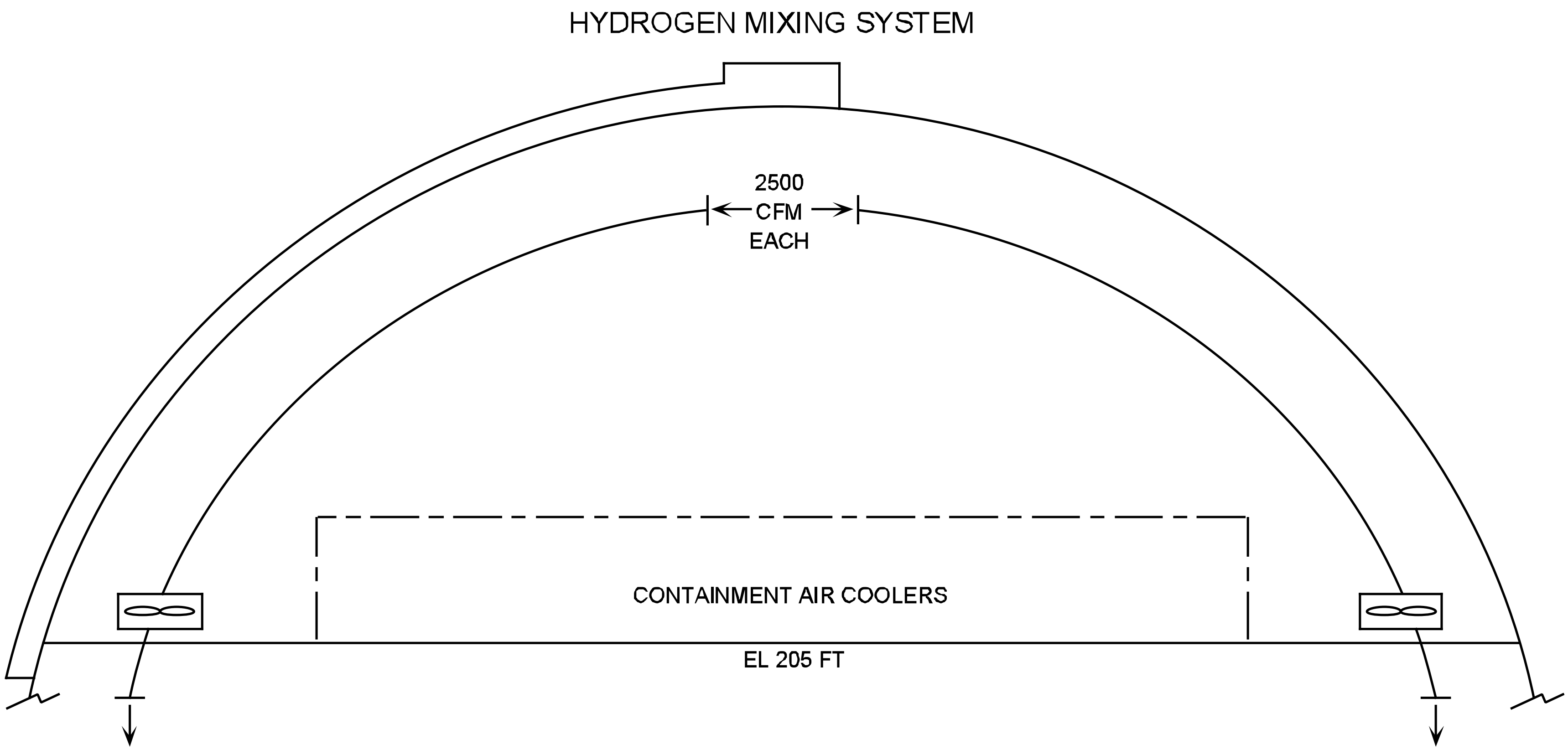

Figure 5.4-11 Hydrogen Mixing System

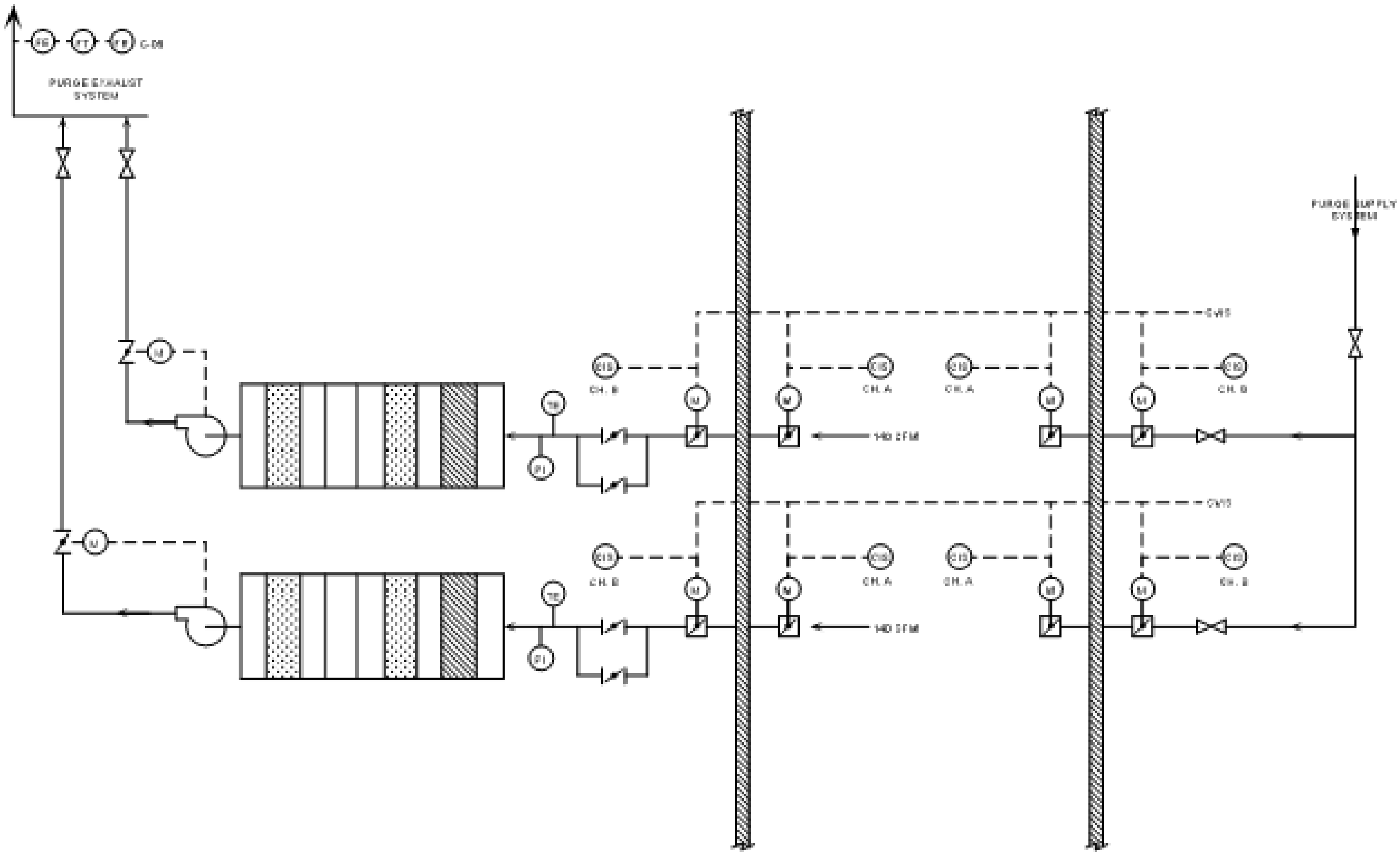

Figure 5.4-12 Hydrogen Vent System

CONTAINMENT SPRAY SYSTEM

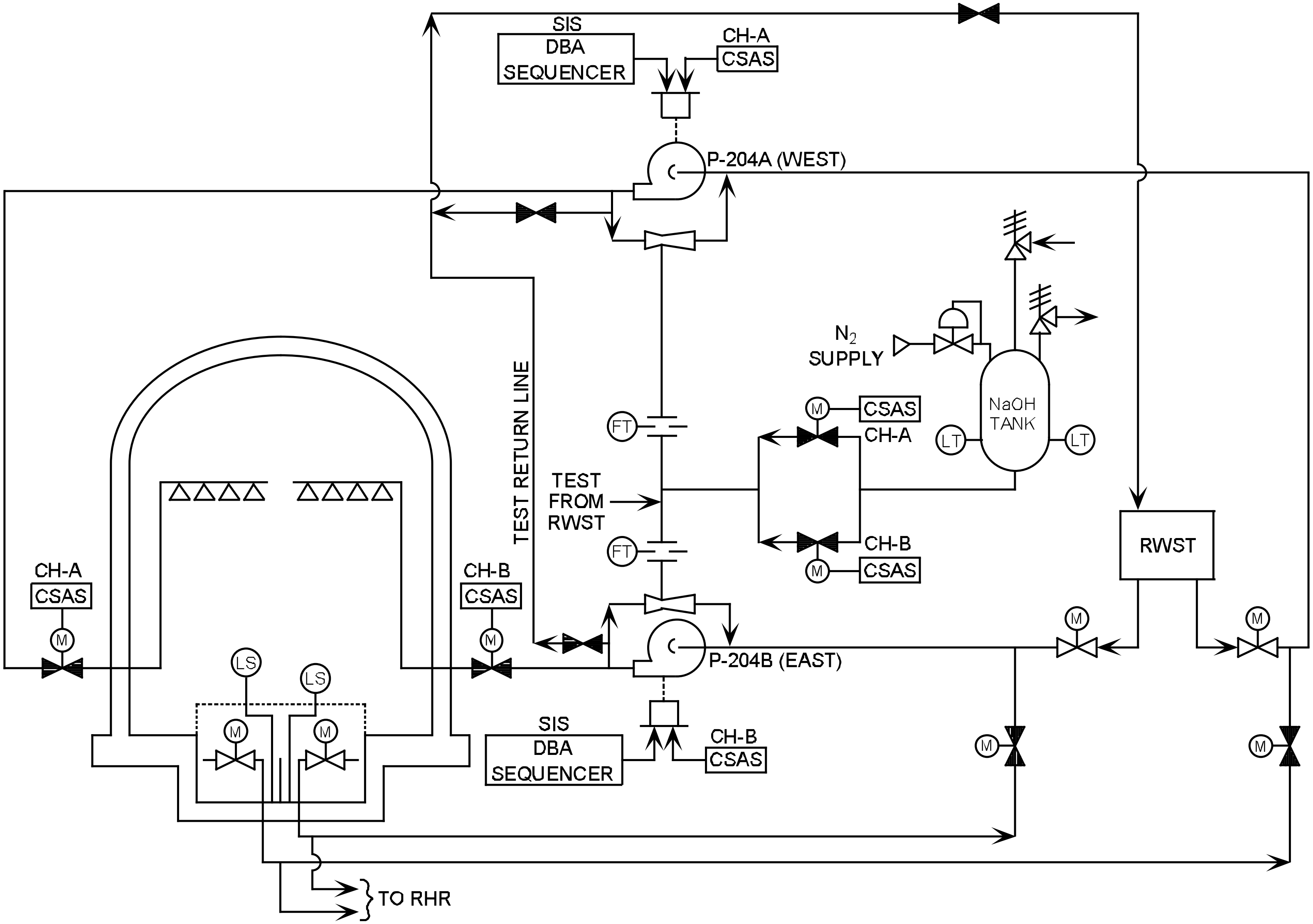

Figure 5.4-13 Containment Spray System

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Section 5.5

Auxiliary Feedwater System (AFW)

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5.5 AUXILIARY FEEDWATER SYSTEM (AFW)

Learning Objectives:

1. State the purposes of the Auxiliary Feedwater (AFW) System.

2. List all suction sources for the AFW pumps and under what conditions each is used.

3. List the five plant conditions that will result in an automatic start of the AFW system.

4. Explain how decay heat is removed following a plant trip and loss of offsite power.

5. Explain how the availability of other decay heat removal methods limits the AFW system's contribution to core damage frequency.

5.5.1 Introduction

The purpose of the auxiliary feedwater system (AFW) is to supply feedwater to the Steam Generators (SGs) when the main feedwater system is unavailable. The steam generators provide a heat sink for the Reactor Coolant System (RCS), which in turn limits the increase in reactor coolant system pressure. By limiting the pressure increase in the RCS, challenges to the integrity of the RCS pressure boundary via opening of the pressurizer Power-Operated Relief Valves (PORVs) or safety valves are reduced. The specific transients for which the AFW system is designed, are as follows:

- Loss of all main feedwater,
- Turbine trip and loss of offsite power, and
- Small-break loss-of-coolant accident (LOCA).

In addition, an electrically driven auxiliary feedwater pump is used to supply water to the steam generators during startups and shutdowns. This pump is not safety related, and its function is to reduce the wear and tear on the safety-grade auxiliary feedwater pumps and their prime movers.

5.5.1.1 Design Basis

The auxiliary feedwater system is comprised of two safety-related trains and is designated as an Engineering Safety Feature (ESF) system. Its design provides two independent and redundant means of supplying feedwater to the steam generators as a means for removing heat from the reactor coolant during accident conditions. This system is designed to operate under the adverse environmental conditions resulting from the design-basis accident (LOCA). This accident is the most limiting from a plant safety aspect, and the auxiliary feedwater system's capability to operate for this accident assures its proper operation for less severe accidents.

The entire AFW system is designed to meet Seismic Category I requirements with the following exceptions: the electric motor-driven auxiliary feedwater pump. the turbine and diesel-driven pump recirculation lines, and the CST. The exceptions described are Seismic Category II. The design life of the turbine-driven and diesel-driven pumps and their drivers is 40 years.

Each of the two safety-grade AFW pumps has the capability of supplying 100 percent of the feedwater requirements for safe shutdown of the RCS. Each safety-grade pump is capable of providing 880 gpm to the four steam generators. Each pump is rated at 960 gpm, which includes a minimum recirculation flow of 80 gpm. The pumps are rated for a pump head of 3400 ft (approximately 1472 psid), based on the most severe condition of pumping 880 gpm water into the steam generators with steam generator code safety valves discharging at their maximum set pressure (1170-1230 psig). Each pump is designed to start and deliver rated flow within 60 seconds of receiving an automatic start signal. This system is designed in accordance with the single-failure criterion.

The pumps take suction from two sources. The normal source is the Seismic Category II CST. In the case of failure of this source, water can be supplied to the safety-related pumps from the Seismic Category I SWS. Service Water is supplied to each pump through a separate Seismic Category I piping system. Each of these Seismic Category I SWSs is isolated from the other so that failure of one will not affect the other. Each service water line is also isolated from the Seismic Category II by nonreturn valves.

The discharge piping of each auxiliary feedwater pump is separated from the other by a check valve until they join into a single line prior to connecting with the main feedwater line of each steam generator. Each steam generator is separately supplied with auxiliary feedwater through its main feedwater line.

Auxiliary feedwater supply to each individual steam generator from the safety-related pumps will be automatically terminated by closure of the motor-operated flow control valves when high auxiliary feedwater flow to that steam generator is detected. This isolation will mitigate the consequences of a main steam or feed system rupture by preventing the affected steam generator from receiving the majority of auxiliary feed flow during the initial stages of accident recovery.

Complete physical and electrical separation is maintained throughout the pump control, control signals, electrical power supplies and instrumentation for each safety-related auxiliary feedwater pump. Thus, sufficient redundancy is provided in number of pumps, sources of water supply, and arrangement of piping and pump controls so that failure of anyone safety-related pump or its associated components will not affect the operation of the other safety-related pump. A complete failure analysis for the safety-related portion of the AFWS is given in the FSAR for most plants.

The requirement to meet the single-failure criterion by having two means of supplying auxiliary feedwater for a safe cooldown of the Plant during emergency conditions necessitates limiting conditions for operation as outlined in the Technical Specifications.

This criterion states that the system must perform adequately with a single active or passive failure. An active failure is one involving the failure of a pump to operate or the failure of a valve to open or shut as needed. The use of two independent channels of control/protection signals and two trains of auxiliary feedwater equipment ensures that a single active failure will not prevent proper operation of the system. Therefore, if one AFW pump fails to start (an active failure), the second AFW pump, in a separate independent train, has sufficient capacity to provide water to the steam generators. A passive failure is one that involves the failure of inactive components such as pipes or pressure vessels. A pipe leak from a weld joint is an example of a passive failure. Design studies assume that the maximum credible passive failure results in a 50-gpm leak for 30 minutes.

Specifically, the AFW system is capable of operating at its design values if an active failure occurs during the injection phase of a LOCA (the injection phase consists of water from the refueling water storage tank being injected into the RCS to cool the core). In addition, the system must be designed so that no passive failure occurs during the injection phase. When the recirculation phase (water being pumped into the RCS from the containment sump) begins, the AFW system is designed to perform its intended function with either an active or a passive failure.

The design flow that is required to be provided by the AFW system during a complete loss of normal and preferred power is 440 gpm to two of four SGs within 60 seconds of the initiation of the loss of offsite power. The actuation time and minimum injection flow prevent an excessive temperature rise in the reactor coolant that would lead to overfilling the pressurizer and causing an overpressure event. This overpressure condition would cause the PORVs on the pressurizer to lift. After the PORVs cycle several times, there is some probability that they would fail; their failure contributes to the core melt frequency of the plant's PRA.

The minimum of 440 gpm supplied to two of four steam generators is a generic Westinghouse performance requirement which serves to bound all Westinghouse AFW systems. However, for this reference plant, the system design does not have to be as restrictive. The actual criteria, as stated by the Final Safety Analysis Report (FSAR), to prevent overpressurizing the RCS for this design is a total of 426 gpm being fed to three out of four SGs within 60 seconds. This works out to an <u>actual</u> minimum flow of 142 gpm being fed from one safety-related auxiliary feedwater pump to each of the three SGs.

Taking into account allowable speed variations in the AFW pump prime movers and flow measurement errors (during normal conditions), the <u>indicated</u> minimum is actually set to 165 gpm. Assuming that one steam generator is faulted, flow is provided to three of the four SGs. With the flow control valves (CV-3004A1, A2, B1, B2, C1, C2, D1, D2) throttled to allow 165 gpm per AFW train per steam generator, 330 gpm is fed to each steam generator with both trains operating. This value is below the flow rate thought to be necessary to cause a water hammer (400 gpm).

The emergency operating procedure (EOP) entered after a reactor trip, when no accident is in progress, specifies a minimum adequate AFW flow of 495 gpm (165 gpm total to 3 SGs). For the remaining EOPs, which would be entered only if an accident were in progress, the water hammer concern is secondary to core decay heat removal. In addition, an adverse environmental flow measurement error of 98 gpm per feed line is assumed. This results in an indicated minimum required AFW flow (as stated in the EOPs) of 720 gpm: ([142 gpm/SG x 3 SGs] + [98 gpm/line x 3 lines]) = 720 gpm. This minimum required flow (720 gpm) is less than the capacity of one safety-related auxiliary feedwater pump (880 gpm).

As previously stated, the AFW system consists of two safety-related trains. One train's pump is driven by a steam turbine, and the redundant pump is driven by a diesel engine. The steam-driven turbine is powered from the main steam system. This turbine can operate with steam pressures as low as 110 psig and is ac power independent. The diesel is started by two 28-Vdc batteries and is dependent upon external power supplies for continued operation (to provide service water cooling).

The majority of the auxiliary feedwater system is designed to Seismic Category I requirements. The exceptions are the pump recirculation line, the condensate storage tank, and the electric AFW pump with its associated piping, valves, and support systems. These components are designated as Seismic Category II.

Following a plant trip concurrent with loss of offsite power, decay heat should be removed by feeding with AFW and steaming via the atmospheric relief valves (SG PORVs) or via the secondary safety valves.

5.5.2 System Description

The auxiliary feedwater system (Figure 5.5-1) consists of one steam-driven and one diesel-engine-driven auxiliary feedwater pump (each of which is safety related) with associated feedwater control valves, instruments, pipes, and controls. There is also a nonsafety-related motor-driven auxiliary feedwater pump that is used for feedwater addition during normal startups and shutdowns. Although this component is not safety related, it can fulfill certain action statement requirements in Technical Specifications and does have some operability requirements.

The normal supply of water to the AFW system is the Condensate Storage Tank (CST). The turbine-driven and diesel-driven pumps can also be supplied from the Seismic Category I Service Water System (SWS) in the event of loss of the supply from the Seismic Category II CST. The changeover of water supply from the CST to SWS is done manually by opening motor-operated valves in the Service Water lines to each pump. Manually opening of these valves is provided to prevent inadvertent flow of service water into the treated CST. Each safety-related AFW pump discharges to its own discharge header. A recirculation line, with a flow restrictor, returns part of each pump's discharge to the CST. This recirculation line is required to allow some flow in case the auxiliary feedwater flow control valves are completely closed. The recirculation flow prevents the pump from being overheated while operating at its shutoff head.

Each pump's discharge header divides into four lines, one for each steam generator. Each steam generator has two auxiliary feedwater control valves; one from the turbine-driven pump discharge, and one from the diesel-driven pump discharge. The two lines from each steam generator's auxiliary feedwater flow control valves combine into a common header which ties to the main feedwater line at the containment wall. Each motor-operated flow control valve has a downstream check valve along with upstream and downstream isolation valves. In the common line downstream of the auxiliary feedwater flow control valves is a flow element with two flow transmitters, which provide indication to meters in the main control room as well as in the remote shutdown station. A flow-sensing element just upstream of each control valve shuts its respective flow control valve if it detects flow greater than 500 gpm.

A single line from the condensate storage tank supplies the safety-related auxiliary feedwater pumps. This line branches into two separate lines just upstream of the pumps. Each pump suction line has a normally open globe valve and a check valve. The suction of each pump has a Seismic Category I service water connection with a normally closed motor operated valve. The valve is normally shut in order to prevent chloride contamination of the steam generators. In the event of a condensate storage tank failure, the service water supply is initiated by manual operation of the isolation valves from the control room.

The electric auxiliary feedwater pump (Figure 5.5-2) can only take suction on the condensate storage tank. It has a recirculation line that returns a portion of its flow to the condensate storage tank. The discharge line, with an air-operated flow control valve, splits into two parallel feed lines, each with a motor-operated isolation valve. One of the feed lines taps into the discharge line of the diesel-driven auxiliary feedwater pump, while the other taps into the discharge line of the steam-turbine-driven auxiliary feedwater pump.

The condensate and feedwater chemical injection system is designed to supply the following to the AFW System: Morpholine, hydrazine, boric acid and potentially other chemical additives in amounts required for corrosion control during periods of operation of the AFWS or during steam generator wet lay-up.

5.5.2.1 Instrumentation and Control

The AFWS is provided with the necessary controls for local or remote, and automatic or manual operation of the system. For the safety-related pumps, the local controls are at the Remote Shutdown station (45-foot elevation Control Building) and the remote controls are in the main control room. All controls and control signals for the steam turbine-driven pump and the diesel engine-driven pump are channelized. Physical separation between the safety-related pump controls is maintained in the Remote Shutdown station also. The electric motor-driven pump is controlled from the main control room. The breaker for the electric pump can also be controlled at the non-Class-IE 4.16-kV switchgear breaker cubicle in the Turbine Building on Elevation 69.

The AFW system is required to have redundant features. This is accomplished, in part, by having separate trains of pumps, control valves, and pipes. Two independent automatic start signal channels are used. Channel A receives inputs from train A of the Reactor Protection System (RPS). It also receives inputs from non-RPS (i.e., not processed through the RPS) sources, such as main feed pump tripped contacts. Similarly, channel B of the auxiliary feedwater automatic start circuitry receives signals from train B of the RPS and from other non-RPS sources.

The channel A automatic start circuitry controls the steam-turbine-driven pump, while channel B controls the diesel-driven pump.

The control logic for the two pumps is similar. Five signals will cause an auxiliary feedwater pump to automatically start:

1. An undervoltage condition on the ESF 4.16-kV bus A1 (A2) (A1 for the turbine-driven pump, A2 for the diesel driven pump,
2. At least two of three SG level detectors less than the low-low water level setpoint (10.7%) in any one of the four steam generators (can be blocked when SGs are drained for maintenance),
3. Safety injection actuation signal (SIAS),
4. Both main feed pumps tripped (can be blocked individually for either auxiliary feed pump), and
5. ATWS (anticipated transient without scram) mitigation system actuation circuit (AMSAC) actuation.

The fifth automatic start signal for the AFW pumps was added to address the following concerns. Sponsored studies conducted by Westinghouse and the NRC have shown that if a complete loss of normal feedwater or loss of electrical load occurs without a reactor trip, RCS pressure could exceed 3200 psig at thermal power levels above 70 percent. This occurrence assumes a common-mode failure in the reactor protection system which incapacitates auxiliary feed flow initiation and/or a turbine trip in addition to prohibiting a reactor trip. If this hypothetical event were to occur, an alternate method of providing AFW flow and turbine trip initiation is needed. 10 CFR 50.62 (the “ATWS rule”) requires plants to have an alternate method of starting the AFW system; AMSAC satisfies the requirement. This circuitry detects a loss of main feedwater and actuates a turbine trip and initiates AFW within a set time if reactor power has been greater than 40%. (The 40% value is more conservative than the analysis result of 70% in order to minimize the amount of RCS voiding during an ATWS event.)

The AMSAC logic is shown in Figure 5.5-3. Note that both trains of AMSAC must actuate to cause a turbine trip and AFW actuation. Four isolated SG level inputs (LT-519, -529, -538, and -547), and two isolated turbine first-stage pressure inputs (PT-505 and -506) provide actuation signal detection. Time delays of 25 seconds for SG level and 360 seconds for turbine power detection are provided to assist in the prevention of inadvertent actuation. Test actuation circuitry along with an installed maintenance bypass switch allows for system testing and deactivation. This circuitry is also deactivated by the operation of the SG low-low level AFW automatic start block switches. System actuation and status alarms are provided to ensure that operators are aware of the AMSAC system status.

When AFW actuation channel A is actuated by any of the signals listed above, a relay powered by 120-Vac preferred instrument bus Y11 is energized. This relay performs the following for the steam-turbine-driven pump:

1. Opens air-operated steam supply valves CV-1451, -1452, -1453, and -1454 (one valve from each steam generator),
2. Opens turbine trip and throttle valve MO-3071,

3. Isolates SG blowdown and SG sampling, and
4. Actuates an alarm for AUX FW AUTO START on the remote shutdown station (RSS) panel.

The operation of channel B, which starts the diesel-driven auxiliary feedwater pump, is similar to that of channel A. When channel B's relay is energized (powered by bus Y22), the following occurs:

1. Energizes the diesel start relay,
2. Opens service water isolation valve MO-3060B, which supplies cooling water to the diesel lube oil cooler, pump lube oil cooler, diesel engine jacket cooler, and speed increaser lube oil cooler,
3. Isolates SG blowdown and SG sampling, and
4. Actuates annunciator AFW PUMP A/B AUTO START.

One of the recognized problems with ensuring proper operation of an essential system like auxiliary feedwater is the ability to demonstrate that a proper flow path exists when the system is in standby. This means that some way of indicating manual valve position is needed. Microswitches on crucial manual valves in the auxiliary feedwater system sense when the valves are not open and provide alarms in the control room and at the remote shutdown station.

The valves monitored include the individual safety-related pump suction and discharge isolation valves and the two isolation valves for each flow control valve. These switches also provide full open indication at the remote shutdown station and in the control room on the safety injection equipment status lamp panel.

Pressure transmitters are provided in the discharge line of the auxiliary feedwater pumps and in the main steam lines from the steam generators. The pressure signals are transmitted to pressure differential converters which convert the difference in the two pressures into an electrical signal. The signal is transmitted to the auxiliary feedwater pump speed control system for the safety-related pumps and to a flow control valve, CV-2967, for the electric motor-driven pump to maintain a preset differential between the pump discharge and the main steam line.

A flow transmitter is provided on the auxiliary feedwater line to each steam generator to indicate flow at the Remote Shutdown station and in the control room. A conductivity element with a local indicator and a high conductivity alarm in the control room is provided for the safety-related pump minimum flow recirculation lines to detect leakage of service water into the AFWS during normal Plant operation.

Pressure transmitters, each with an indicator and low-pressure alarm in the control room, are provided for the safety-related pump suction lines to indicate a failure of water supply from the CST. A level transmitter is also provided on the CST for each of the safety-related pumps to provide automatic shutoff of the pump due to a low CST level.

The instrumentation provided for indications and alarm functions (e.g., pump suction and discharge pressures, tachometers, and ignition indicating lights), required for monitoring the operation of the pumps and drivers, are provided on local panels.

5.5.2.2 Service Water

Recall that the CST is not a Seismic Category I storage tank. Therefore, the service water system provides a safety-related backup water supply to the auxiliary feedwater system. In addition, it cools components associated with the diesel-driven pump and serves as a backup cooling source for components associated with the turbine-driven pump.

The service water supplies to the auxiliary feedwater pump suctions are normally isolated by motor-operated gate valves. These valves have no automatic control function and are controlled by switches having incorporated lockout devices.

For the diesel-driven auxiliary feedwater pump, service water supplies cooling water to the diesel jacket cooler, engine lube oil cooler and intercooler, pump lube oil cooler, and gear cooler on the speed increaser. Service water is supplied to the suction of an attached auxiliary water pump, which provides additional motive force for cooling flow through the engine lube oil cooler and intercooler (in series). The auxiliary water pump is belt driven off of the diesel engine. For the steam-driven auxiliary feedwater pump, service water is a backup cooling supply for the lube oil cooler for the pump and the bearing heat exchangers for the turbine. The normal cooling supply to those components is diverted pump discharge flow. Thus, the steam-driven pump is referred to as “self-cooling.”

5.5.2.3 Auxiliary Feedwater Pump Turbine Steam Supply Valves

The original system design called for motor-operated steam supply valves. This design has since been found inadequate because the system becomes dependent on the presence of AC power to operate correctly. For the turbine-driven auxiliary feedwater pump to be completely independent of AC power, the valves have been changed to three-inch, air-operated globe valves.

Each valve has a single, solenoid-operated, four-way valve in its air supply. The air supply taps off the existing air supply for the main steam isolation valves. The steam supply valves use a “balanced-piston” design (i.e., there is no internal spring to cause the valves to reposition to a specified failure state on loss of actuating air). Motive air is required to both open and close the valves. Accordingly, upon a loss of air supply, the valves fail “as is.” There is also a backup air supply consisting of four 15-gal accumulators (T-166A, -166B, -166C, and -166D), one for each steam supply valve. Each accumulator is designed to allow one valve cycle two hours after the normal air supply is lost. If accumulator pressure falls below 80 psig, alarms are initiated to warn of accumulator low pressure. Testing has shown that accumulator pressures as low as 45 psig have been sufficient to open the steam supply valves.

Each steam supply valve has a bypass line. The bypass line has two normally open isolation valves and a flow restricting orifice. The combined flow through all four orifices allows a nominal total of 500 lbm/hr steam flow to warm the steam supply lines and remove condensation. This prevents turbine damage from water hammer and moisture on startup. The bypass steam normally exhausts via an orificed line to the condenser. It may also vent to the atmosphere via a 3/4-in. line tapping off directly upstream of the turbine trip and throttle valve.

Control and indication power for the steam supply valves is supplied by 120-Vac preferred instrument power bus Y11 for CV-1451, -1452, -1453, and -1454. Control power supplies the solenoids on the four-way valves (SV-1451, -1452, -1453, and -1454). If a solenoid loses power, the valve positions to supply air to open its respective steam supply isolation valve. Thus the steam supply valves will automatically open if ac power is lost. This in itself will not drive the turbine, as the turbine trip and throttle valve remains closed.

It should be noted that the loss of a 120-Vac preferred instrument bus is relatively unlikely, since it is usually powered from a battery-backed 125-Vdc bus through an inverter (Chapter 6). If operating air is lost to a steam supply valve, it fails as is. There is no return spring in the valve actuator against which the operating air pressure acts.

The steam supply isolation valves can be manually operated with handwheels. Automatic opening of the steam supply isolation valves is initiated by the same conditions that cause automatic trip and throttle valve actuation.

5.5.2.4 Service Water to Auxiliary Feedwater Pump Cooler Valves

These normally closed valves (MO-3060A, and -3060B) can supply service water to cool various steam-turbine-driven AFW pump and diesel-driven AFW pump components. MO-3060A, which supplies cooling water to the turbine-driven AFW pump, is a two-in. motor-operated globe valve with an upstream isolation valve and a downstream check valve (not shown in this figure). However, because of the self-cooling nature of the turbine-driven AFW pump, as discussed below, service water is a backup means of cooling. The motor operator for MO-3060A has been electrically disconnected and must be manually opened to provide service water cooling. The service water supply to the diesel-driven feedwater pump, MO-3060B, is a six-in. motor-operated butterfly valve; it opens on receipt of a channel B pump start signal.

5.5.3 Component Descriptions

5.5.3.1 Auxiliary Feedwater Pumps

The safety-related diesel- and turbine-driven auxiliary feedwater pumps are identical six-stage, horizontal, centrifugal pumps designed for 2000 psig, 70°F water. They operate with a design flow rate of 960 gpm, including 80 gpm recirculation, at a 3400 ft (1472 psid) head. The rated speed of each pump is 4560 RPM. Each pump has a continuous minimum flow recirculation line with a pressure reducing orifice and a locked-open valve. The recirculation lines, downstream of the locked-open valves, join into a single line which connects to the CST.

Two lines are provided from the CST to supply condensate to the pumps. One-line supplies condensate to the electric motor-driven pump, the other line is Seismic Category I and branches into two lines to supply the turbine- and diesel-driven pumps. Each line is provided with a manually operated isolating valve. The two lines to the turbine- and diesel-driven pumps are also provided with nonreturn valves.

The turbine- and diesel-driven pumps are supplied with service water from a separate line from the SWS. Each of these lines is provided with a normally open butterfly type isolating valve, a normally closed motor-operated isolating valve, and a nonreturn valve, and is joined with the line from the CST to connect with the pump suction.

The turbine- and diesel-driven auxiliary feedwater pumps are located at Elevation 45 feet in the Turbine Building inside two separate reinforced concrete enclosures which are designed to meet Seismic Category I requirements. The electric-driven auxiliary feedwater pump is located south of the main condenser at Elevation 45 feet in the Turbine Building.

The turbine-driven auxiliary feedwater pump bearing heat exchangers and lube oil heat exchangers have the capability of being cooled from three sources. There are two sources of self-cooling, one from the second-stage impeller of the pump via the pump casing, and one from the recirculation line, and a third possible supply from the service water system. Using the self-cooling supplies for cooling makes the turbine-driven pump independent of ac power and able to operate on a loss of all power to the 4160-V buses.

The non-safety-related electric-driven auxiliary feedwater pump is also designed for 2000 psig, 90°F service. At a design operating speed of 3560 revolutions per minute (rpm) it is capable of pumping 1020 gpm of flow at 3400 ft head (1472 psid). This includes 140 gpm of recirculation flow back to the condensate storage tank. The eight-stage centrifugal pump driven by a 1250-hp ac motor is provided for general use during plant startups and shutdowns. An electric lube oil pump provides bearing lubrication on startup. As the pump accelerates, a shaft-driven pump provides the motive force for oil lubrication.

5.5.3.2 Condensate Storage Tank

The condensate storage tank (Figure 5.5-4) has a capacity of 450,000 gallons. The Technical Specifications require that this tank be operable by having an indicated volume of 239,000 gallons of water. This volume ensures the availability of 196,000 gallons of usable water. The assumptions are that there are 27,700 unusable gallons at the bottom of the tank (minimum vortexing level) and a possible 14,400 unavailable gallons due to level instrument error. The usable, unusable, and instrument error volumes are added together and rounded off to obtain 239,000 gallons. This volume ensures that there is enough water to maintain the plant in hot standby (using the SG safety valves) for two hours, and then cooling down the reactor coolant to 350°F over the next four hours. These times assume that 880 gpm of AFW flow is available. The 350°F cutoff point is where the residual heat removal system is capable of taking over and continuing the cooldown.

The auxiliary feed supply line is an eight-inch Seismic Category I pipe up to the metal bellows expansion joint adjacent to the bottom of CST. A debris strainer in the line (near the CST) prevents foreign material (e.g., from the collapse of the CST floating roof) from entering the suction of the safety-related AFW pumps. The combined pump recirculation line is a two-inch pipe.

The diesel-driven and turbine-driven AFW pumps have CST low level trips of 35% and 30% respectively. The turbine-driven AFW pump has the lower trip setpoint because it is the ac independent (hence, more reliable) pump. These trips provide an indication to the operator of a diminishing water volume in the CST. Control switches, one for each pump, on the main control board that can be used to block the low level trip, allowing subsequent pump restart.

The CST low-low level alarm, at 9% (55,000 gallons), alerts the operator to the impending loss of the CST as a source of water to the suction of the AFW pumps. This alarm warns the operator that an alternate source of auxiliary feedwater must be provided to ensure a continuing source of water to the steam generators and to prevent damage to the auxiliary feedwater pumps.

CST level indication and protective signals are provided by Seismic Category I instruments. The variable and reference legs to the level transmitters are heat traced to minimize the possibility that freezing conditions can cause erroneous level indications. The control power to the instrument channels is Class IE; however, the heat-trace power supply is non-Class IE.

The recirculation line has an in-line conductivity cell that supplies an alarm. This alarm is indicative of potential service water inleakage at the auxiliary feedwater pump suction.

5.5.3.3 Diesel Engine

The diesel-driven auxiliary feedwater pump unit consists of a Waukesha Model L5792DSIO 12-cylinder diesel engine rated at 1579 horsepower (at 1200 rpm) with a speed range of 450-1200 rpm, a Westinghouse-type SU-16-10 speed increaser with a ratio of 1:3.8 and a Bingham 4X6X10B-MSD centrifugal pump (P-102B).

The diesel engine is a 12-cylinder Waukesha model rated at 1579 bhp (at 1200 rpm) with a speed range of 450-1200 rpm. The diesel operates with a Westinghouse speed increaser, and has integral starting power supplies. A 28-Vdc battery provides power to electric motor starting units. Diesel fuel oil is supplied to the engine from a day tank through a gravity feed line. The engine has a closed cooling system and a self-actuated pressurized lubricating oil system with pumps, filters and lube oil coolers.

An oil priming pump maintains engine oil circulating during engine shutdown periods. Two 4000-watt heaters maintain engine jacket water temperature between 100°F and 120°F while shut down. Cooling water required for the oil coolers for the diesel-driven pump, speed increaser and driver and for the engine jacket water heat exchanger is supplied from the Service Water System (SWS). A connection is taken from the service water line to diesel-driven auxiliary feedwater pump and is provided with a motor-operated valve which opens automatically whenever the pump is started. The service water outlet from the oil coolers and jacket water heat exchangers is drained to the Dilution Structure.

The diesel is started automatically by a Channel B auxiliary feedwater pump start signal. The diesel may be manually started and controlled remotely from the main control board or from the remote shutdown station. It has the following automatic trips:

1. Overspeed - 1350 $\pm$50 rpm,
2. Low lube oil pressure - 20 psig (25 second time delay on startup),
3. High jacket water temperature - 205°F (blocked on auto starts only),
4. Starter over-crank - 112 seconds, and
5. Low CST level - 35% (blockable).

The speed of the diesel is automatically controlled (Figure 5.5-6) by the difference between the pump discharge pressure (measured by PT-3083B) and auctioneered high steam header pressure (measured by PT-516 or -545). This differential pressure signal is compared with an automatic setpoint in an auto-manual controller. The setpoint is normally 50% (150 psid).

Diesel Fuel Oil

The diesel fuel oil system is an ESF system. It supplies diesel fuel for the auxiliary feedwater pump diesel as well as the two site emergency diesel generators. Two independent trains of fuel oil supply are provided. Each consists of an underground storage tank, a transfer pump, and transfer piping. Each independent source of fuel supplies the auxiliary feedwater pump day tank. The day tank has sufficient capacity (500 gallons) to allow diesel operation at design capacity (960 gpm at 3400 ft of head) for 10 hours. The minimum allowed level in the AFW pump diesel fuel oil day tank per Technical Specifications is 450 gallons (69%) to fulfill the operability requirements for train B of AFW. Each storage tank has sufficient capacity to support both site emergency diesel generators running at full load for 4 days and the auxiliary feedwater pump diesel running for 24 hours.

5.5.3.4 Steam Turbine

A Terry turbine (K107A) drives auxiliary feedwater pump P-102A. It is a noncondensing, single-stage, horizontal-shaft turbine, of a split-casing design with an electro-hydraulic speed control, overspeed trip mechanism, and an integral trip throttle valve. The turbine is rated for inlet steam pressures of 885 - 1305 psig at full load down to 110 psig at plant startup and shutdown. It exhausts to the atmosphere via an 8-in. line and develops 1045 hp at its rated speed of 4560 rpm. A guard pipe has been installed around the turbine-driven auxiliary feedwater pump discharge line and steam line in the diesel-driven pump room so that a rupture in the turbine pump discharge or steam line will not damage the diesel-driven auxiliary feedwater pump.

The turbine receives steam (Figure 5.5-5) from all four steam generators via supply lines tapping from Seismic Category I sections of the main steam lines upstream of the Main Steam Isolation Valves (MSIVs). Each three-in. steam supply line has an air-operated supply valve, a manually operated isolation valve upstream, and a nonreturn valve downstream. The air-operated valves remain closed during normal operations. The steam supply lines join to form a combined four-in. steam header. This steam header has a normally open a-c motor-operated stop valve and a normally closed trip-and-throttle valve. The turbine exhaust steam to the atmosphere outside the building.

The turbine is started automatically upon receipt of a Channel A start signal, as described in section 5.8.2.1. This pump may be operated and controlled remotely from the main control board or from the remote shutdown station.

An auto-manual speed controller for the turbine develops an output based on an operator adjusted signal and the difference between the pump discharge pressure (measured by PT-3083A) and auctioneered high steam header pressure (measured by PT-514 or -536). In automatic control, the operator can vary the internal setpoint to control pump speed. Lowering the setpoint generates a lower controlling ΔP, causing a lower flow rate. Similarly, a higher setpoint yields a higher flow rate. The controller is normally set to control at 50% (150 psid). In manual control, the controller output depends on the manual potentiometer setting.

The turbine has the following trips:

1. Mechanical overspeed - 5500 ±100 rpm (120% of rated speed),
2. Electrical overspeed - 5100 ±50 rpm (112% of rated speed), and
3. Low CST level - 30% (blockable).

Either of the first two signals trips shut turbine trip-and-throttle valve MO-3071. When MO-3071 is tripped, a spring rapidly forces the valve shut. In this condition, the valve cannot be opened by the motor operator until the trip is reset. A low CST level condition causes MO-3071 to be driven shut by its motor operator. This method allows the turbine to be restarted after the CST level is restored (or after the low CST level trip is blocked) without the need to locally reset any mechanical devices.

Turbine Trip-and-Throttle Valve

MO-3071 is a four-inch, normally closed, motor-operated valve that is downstream of the a-c motor-operated stop valve MO-3170 and upstream of the d-c motor-operated turbine trip and throttle governor valve. The valve is physically mounted on the steam turbine. The trip-and -throttle valve serves two functions:

1. On turbine startup, it slowly strokes open and helps throttle steam flow to the governor valve until the governor valve can adequately control steam flow and turbine speed;
2. When the turbine undergoes an overspeed condition, it closes rapidly (trips shut) to cut off steam flow to the turbine.

A 3/4-inch diameter line with two normally open globe valves and a flow restrictor orifice is provided upstream of the trip and throttle valve. and is connected to the condenser. A flow of 500 pounds per hour of steam is maintained through the steam supply line to the trip and throttle valve via a 3/4-inch line and is routed to the condenser. This steam flow is sufficient to keep the steam supply line warm and thereby prevent condensation to avoid water hammer when the auxiliary feedwater turbine is required to start. The turbine-driven pump and driver are self-cooled.

Auxiliary Feedwater Pump Turbine Stop Valve

MO-3170 is a normally open, four-in., motor-operated valve, located downstream of the four air-operated main steam header supply valves (CV-1451, -1452, -1453, and -1454) and upstream of trip-and-throttle valve MO-3071 (Figure 5.5-5). This valve has no automatic opening or shutting functions. Control and indication power are from 480-Vac ESF bus B23.

5.5.3.5 AFW System Valves

Motor-operated valves are provided in steam lines to the turbine driver and service water lines to the pumps, lube oil coolers and jacket water heat exchangers, except for the air-operated valves in the four takeoff lines from the main steam lines. The air-operated valves are automatically controlled and remain closed during normal operation of the Plant. A Seismic Category I air accumulator with isolation check valves is provided for each air-operated valve as a backup air supply. Bypass valves and associated drains allow the downstream line to be kept warm. The motor-operated stop valve in the common steam supply line to the turbine driver upstream of the trip and the throttle valve *is* normally open.

The motor-operated valve in the service water line for the diesel-driven pump lube oil cooler and jacket water heat exchangers is closed during normal operation and opens automatically whenever the diesel-driven auxiliary feedwater pump starts. The motor-operated valves in service water lines to supply service water to the pumps in the event of loss of the source from the CST are manually controlled and, as described before, remain in a closed position during normal operation. The auxiliary feedwater lines to each steam generator are furnished with motor-operated control valves to control the flow.

The discharge lines from the auxiliary feedwater pumps are furnished with isolating gate valves and nonreturn valves to isolate the line or to prevent backflow in the event of a line break. The condensate lines and service water lines to the pumps are also provided with isolating and nonreturn valves. The pump minimum flow recirculation lines are provided with locked-open valves.

The manual feedwater valves which are utilized to provide proper auxiliary feedwater system lineup for automatic operation of the safety-related pumps are provided with limit switches. The limit switches provide indication of valve position (open/close) at indicating panels in the control room and at the Remote Shutdown station and the AFW Pumps Local Control station.

The electrical power supply for the motor-operated valves associated with the safety-related pumps meet the requirements of IEEE 308-1971, "IEEE Standard criterion for Class IE Electrical Systems for Nuclear Power Generating Systems". A description of Class IE systems provided for the Plant and the criterion with regard to redundancy and separation for these systems. Electrical power to the motor-operated valves associated with auxiliary feedwater pump P-102A is supplied from bus A; bus B supplies the electrical power to those associated with auxiliary feedwater pump P-I02B.

5.5.3.6 Auxiliary Feedwater Flow Control Valves

Each steam generator is supplied via two three-in. feed flow control valves (Figure 5.5-1), for a total of eight valves. Four of the valves (CV-3004A1, B1, C1, and D1) control flow from the turbine-driven pump. The other four valves (CV-3004A2, B2, C2, and D2) control flow from the diesel-driven pump. These valves receive control and indication power from 125-Vdc buses. During standby operation, the valves are throttled to provide a predetermined flow rate. When an individual flow control valve is correctly positioned (throttled to provide 165 gpm), a WHITE light is illuminated on the safety injection equipment status lamp panel for the appropriate train. The basis for the throttle settings is discussed in section 5.8.1.1. These valves have no automatic control functions. Each valve has remote and local manual controls.

If a high flow condition (> 500 gpm), as sensed in a flow element upstream of a flow control valve, develops, then that control valve shuts, as illustrated in Figure 5.5-7. Once one valve is closed due to a high flow signal, it prevents the other three auxiliary feedwater control valves in that train from closing due to high flow signals in their respective logic circuits. This logic in prevents more than one steam generator from losing feed flow due to this protection feature. Also, as shown in Figure 5.5-7, if a second steam generator experiences high flow due to a fault in a steam generator, its associated control valve can be closed from the control room or locally.

The high flow signal serves to isolate auxiliary feed to a steam generator with excessive flow. It is assumed that a flow rate over 500 gpm would be caused by a steam line or feed line break. In the steam break case, the steam generator depressurizes, thereby decreasing the flow resistance in the AFW supply piping to that SG and causing high feed flow. It is undesirable to feed a faulted steam generator because of the resultant excessive cooling of the primary system. During a feed break, the affected feed line has the least flow resistance and therefore inhibits maintaining the other (intact) steam generators as a heat sink.

5.5.4 System Operation

System operation considerations include those of normal Plant operation, emergency operation, normal Plant cooldown, and Plant startup.

5.5.4.1 Normal Plant Operations

During normal Plant operation the safety-related portion of the AFWS is not required to operate and is normally in remote-auto control. The two safety-related pumps are ready to start and deliver water at a minimum capacity of 440 gpm within 60 seconds of receiving a signal to start. The electric motor-driven pump is utilized during normal startup and shutdown Plant conditions to preclude unnecessary wear on the safety-related pumps.

The auxiliary feedwater system is normally aligned to allow automatic initiation of flow to the steam generators as follows. The flow control valves are in preset throttled positions. The auxiliary feedwater pump LOCKOUT switches are in NORMAL (allowing start on either the loss of both MFPs or low-low SG level). The maintenance LOCKOUT switches are in NORMAL. The steam header isolation valves to the turbine-driven auxiliary feed water pump are shut, while its associated steam stop valve (MO-3170) is open, and the turbine trip-and-throttle valve (MO-3071) is shut. Both pumps are in remote control with their respective control switches in AUTO. Their auto-manual controllers are in AUTOMATIC, each with a setpoint of 50% (150 psid).

When the auxiliary feedwater pumps are in standby, backflow from the main feedwater header is prevented by three check valves in the discharge line of each AFW pump (Figure 5.5-1). Some nuclear plants with similar AFW system designs have had problems with backleakage through the check valves, which has rendered affected AFW pumps inoperable.

Leakage of hot main feedwater (nominally 440°F) into an AFW pump discharge line causes voiding in the piping. If all the discharge check valves leak, backleakage could cause voiding in affected AFW pump. If the voiding is limited to the AFW discharge piping, a severe water hammer event could occur when the AFW pumps start and supply feedwater to the steam generators. If the AFW pumps are voided, they would be unable to supply adequate AFW flow when started, or the high temperature of the pump environment could damage pump components. The AFW pump discharge temperature must be checked when the pump is secured and periodically thereafter to verify that there is no backleakage of hot main feedwater into the AFW pump discharge piping.

5.5.4.2 Emergency Operation

If the control switches for the safety-related pumps are in the "auto" position, the following emergency conditions will cause automatic startup of the two auxiliary feedwater pumps:

1) Tripping of both steam generator feedwater pumps. (Feedwater pumps tripped auto-start block switch for each pump must be in NORMAL.)
2) Low-low water level signals from two out of three level transmitters of any steam generator. (Steam generator low-low level auto-start block switch for each pump must be in NORMAL.)
3) Any of the conditions which cause a Safety Injection Signal (SIS).
4) Loss of normal onsite as well as preferred a-c electric power sources (undervoltage on the 4.16 kV buses A1/A2).
5) Anticipated Transient without Scram (ATWS) Mitigating System (AKSAC) actuation. (Steam generator low-low level with a turbine load greater than 40-percent power.)

The steam supply valves *CV-1451, CV-1452, CV-1453,* and *CV-1454* are normally closed. Together with throttle valve MO-3071, they will open to supply steam to the turbine driver of pump P-102A. Simultaneously, the diesel engine driver of pump P-102B will start automatically and valve MO-3060B will open to supply service water to the *oil* coolers and the jacket water heat exchangers.

Both pumps take suction from the CST and deliver the water to all four steam generators. The speed of the pumps *is* controlled by the pressure differential controller to maintain a preset differential between the pump discharge and the main steam line.

The turbine-driven pump is capable of operating and supplying feedwater to the steam generators for at least 2 hours should a loss of all non-inverter backed a-c power occur. Cooling water to the lube oil and bearing coolers is supplied from the pump recirculation line. The four steam valves which supply the turbine are air-operated, will fail open on a loss of electrical power, and have Seismic Category I air flasks for a backup air supply. The control switch for these valves has a pull-to-lock position to allow valve isolation during steam generator failures.

In case of a low level in the CST, the auxiliary feedwater pumps will trip. This will also energize an annunciator in the control room. In the event suction from the CST is lost valves HO-3045A and MO-3045B can be opened from the control room to supply service water to the auxiliary feedwater pumps. The capability does exist to override the CST low level trip.

5.5.4.3 Normal Plant Shutdown

During normal shutdown, the feed flow reduces to <3 percent of full flow in about 1 hour, and the main feedwater pump continues to supply feedwater during this period. After this period the electric motor-driven auxiliary feedwater pump, the normal source of auxiliary feedwater, is used under manual control to supply condensate from the CST to the steam generators. The auxiliary feed flow to each steam generator is controlled by the motor-operated control valve, and the steam generated is dumped to the main condenser. The steam generator pressure reduces to 450 psig in approximately 2 hours.

After this period the AFWS continues to operate and supply feedwater to the steam generators until the reactor coolant reaches 350°F, at which time the Residual Heat Removal (RHR) System is utilized for further cooldown of the reactor coolant. The condensate pumps can also be used during this period to supply condensate to the steam generators until reactor coolant reaches 350°F and the RHR System takes over.

5.5.4.4 Plant Startup

During cold startup of the Plant, the condensate pump or the electric motor-driven auxiliary feedwater pump is used to supply feedwater to the steam generators until sufficient steam pressure is generated to allow startup of the steam generator feedwater pumps.

5.5.4.5 Electric-Driven Auxiliary Feedwater Pump

The electric auxiliary feedwater pump P-182 (Figure 5.5-2) is used to add feedwater to the steam generators during normal startup and shutdown conditions to minimize wear on the safety-grade auxiliary feed pumps. This component has no automatic start features and is not safety grade. The electric auxiliary feedwater pump is a three-phase, 60 cycle, 1250 hp, 4000-v motor which is powered from 4160-Vac bus A5. The motor *is* self-lubricating and self-cooling. Space heaters are used to prevent condensation of moisture within the motor enclosure during shutdown periods. The motor has thermal, overcurrent and undervoltage trips. Normal operating speed is 3600 rpm.

Even though the electric driven AFW pump has no automatic start features, it does have some automatic trip features. Below is a list of the automatic trip signals provided for this pump:

1. Low suction pressure - 12 psia (can be overridden),
2. Low pump bearing pressure - 3 psig,
3. 4.16-kV bus A5 undervoltage,
4. Phase overcurrent, and
5. Ground overcurrent.

Overriding the low suction pressure trip may be required in an emergency situation if the electric AFW pump is the last available means for providing feedwater to the steam generators.

An air-operated control valve, CV-2967, is positioned to control pump head. In automatic, the control system senses steam header pressure from PT-535 and compares it with pump discharge pressure measured downstream of the control valve. The ΔP signal is compared with an adjustable setpoint in the auto-manual controller, PDC-2967. The automatic controller setpoint is adjustable from 0 - 100%, which represents 0 - 200 psid. The normal setpoint is 50%, which is equivalent to 100 psid.

Downstream of the control valve, the pump discharge header splits into two lines, each with an isolation valve (MO-2947A, MO-2947B). These valves isolate feedwater from the discharge of the electric-driven pump to the discharge lines of the turbine-driven pump and diesel-driven pump. The valves are controlled from the main control board. To meet the requirements for separation of the two auxiliary feedwater trains, these valves are normally shut. When the electric auxiliary feedwater pump is used, no more than one isolation valve should be opened at a time to prevent cross connecting the two safety-related trains of auxiliary feedwater. Check valves provide for Seismic Category I isolation.

5.5.4.6 AFW System Problem Areas - Water Hammer

The degree of feedwater piping displacement at the Trojan plant indicates that it experienced moderate water hammer events during its operating life. These events were generated by small amounts of steam (approximately 5 in.^{3} in volume) being rapidly condensed by cold feedwater. During conditions of low feed flow, with SG levels below the feed rings, steam voids were created in the feed rings.

Two leakage paths out of the feedwater system were identified:

1. Backleakage through the system check valves of the main feedwater system, and
2. Leakage through a 0.025-in. gap between the SG nozzle and the sleeve of the feed ring.

This gap may have grown to 0.25 in. due to erosion. Steam voids form in the SG feed rings only if the SG levels are below the tops of the feed rings and the total feed flow rate is less than the leakage out of the system. The maximum leakage rate was calculated at 30 gpm. AFW flow rates in excess of 400 gpm per SG are thought to be necessary for a sudden collapse of steam voids, vice a gradual sweeping action which results in no water hammer. For this reason, the auxiliary feedwater control valves are preset to throttled positions which supply approximately 165 gpm per AFW train per steam generator.

Reactor Trip Scenario

After a reactor trip, the levels in the steam generators shrink due to the rapid reduction in steam flow. The main feedwater system is isolated when the low T_{avg} setpoint (564°F) is reached. This stops feed flow to the SGs about 2.5 seconds after the reactor trip. There is a 30 – 60-sec delay prior to the delivery of AFW flow. With feed flow secured, and SG level below the tops of the J tubes on top of the feed ring (20.6% narrow range [NR]), steam voids begin to form in the feed ring. The volume of all the J tubes is about 1.5 gallons. Void formation increases if the SG level drops below the bottom of the feed ring (9% NR) due to leakage through the nozzle-sleeve gap.

Hot Standby/Hot Shutdown Scenario

During hot standby and hot shutdown conditions, it is difficult to maintain continuous feed flow to the SGs due to low steaming and blowdown rates. During this operation the SGs are usually fed intermittently. If the SG level slowly decreases to below 20.6% and AFW flow to that SG is less than leakage (check-valve backleakage only at that level), then steam voids begin to form. If the level continues to decrease to below the bottom of the feed ring (9% NR), then draining of the feed ring would increase due to the additional leak path through the nozzle-sleeve gap. If subsequent AFW flow rates exceed 400 gpm, then water hammer may result.

5.5.5 PRA Insights

The AFW system provides feedwater to the steam generators to allow continued heat removal from the primary system when the main feedwater system is not available. In this capacity, the AFW system serves as one means of early core heat removal following a transient or small-break LOCA.

Loss of the AFW system is a small contributor to core damage frequency as part of major accident sequences (1.4% at Zion and 2.6% at Sequoyah). One of the reasons for the relatively small contribution is the ability of the plant to initiate bleed-and-feed cooling using high pressure injection and the pressurizer power-operated relief valves (PORVs). At a unit such as Surry, where two PORVs are required to open to provide sufficient bleed and feed capability, the AFW system can be a larger contributor (14.8%).

When performing the PRA for the AFW system certain items are plant specific, such as human error. If the AFW system is normally configured so that one pump is locked out, failure to start that pump becomes critical. Failure to correctly realign the system after testing or maintenance is another. Common-mode failures are also plant specific. One such failure is an undetected flow diversion through a cross-connect line to the second unit on multiple unit sites (Surry risk achievement factor - 400). A second example of a common-mode failure is steam binding of the AFW pumps due to main feedwater leakage through system check valves (Surry risk achievement factor - 400).

PRAs for 13 PWRs were analyzed to identify risk-important accident sequences involving the loss of AFW and to identify and risk-prioritize the component failure modes involved. Below is a list of four accident categories explaining how AFW failure is a contributor to the analysis. Included at the end of the list are the risk-important component failure modes.

1. Loss of Power System - A loss of offsite power is followed by the failure of the AFW system. Due to the loss of actuating power, the (PORVs) cannot be opened, preventing adequate bleed-and-feed cooling, resulting in core damage.

   A station blackout fails all ac power except the vital Class IE ac busses from the dc invertors. All decay heat removal systems, except the turbine-driven AFW pump, also fail. AFW subsequently fails due to battery depletion or hardware failures, resulting in core damage.

   A dc bus fails, causing a trip and failure of the power conversion system. One AFW motor-driven pump is failed by the bus loss, and the turbine-driven pump fails due to loss of the turbine or valve control power. AFW is subsequently lost completely due to other failures. Bleed-and-feed cooling fails because PORV control is lost, resulting in core damage.
2. Transient-Caused Reactor or Turbine Trip - A transient-caused trip is followed by a loss of the power conversion system and the AFW system. Bleed-and-feed cooling fails either due to a failure of the operator to initiate it, or due to hardware failures, resulting in core damage.
3. Loss of Main Feedwater - A feedwater line break affects the common water source to the steam generators from both main feedwater and AFW. If the operators fail to provide feedwater from alternate sources and fail to initiate bleed-and-feed cooling core damage will result.

   A loss of main feedwater trips the plant, and the AFW system fails due to operator error and hardware failures. If he operators fail to initiate bleed-and-feed cooling, core damage will result.
4. Steam Generator Tube Rupture (SGTR) - A SGTR is followed by a failure of the AFW system. Coolant is lost from the primary until the refueling water storage tank is depleted. High pressure injection fails since recirculation cannot be established from the empty containment recirculation sump, and core damage results.

Risk-Important Component Failure Modes

The generic component failure modes identified from the PRA analyses as important to AFW system failure are listed below in decreasing order of risk importance:

1. Turbine-driven pump failure to start or run,
2. Motor-driven pump failure to start or run,
3. Turbine- or motor-driven pump unavailable due to testing or maintenance, and
4. AFW system valve failures, such as failures of steam admission valves, trip and throttle valves, flow control valves, pump discharge valves, or pump suction valves, and valves in testing or maintenance.

Reductions in core damage frequency through improvements to the AFW system are negligible for the plants studied in NUREG-1150.

5.5.6 Summary

During emergency conditions, the Auxiliary Feedwater System (AFWS) automatically supplies water to the four steam generators to cool the RCS and thereby prevent release of reactor coolant through the pressurizer safety valves. The system also supplies water to the steam generators during normal Plant startup and shutdown. A portion of the AFWS is an engineered safety feature system.

The auxiliary feedwater system is an Engineered Safety Feature (ESF) system designed to Seismic Category I requirements. It is designed to delivering at least 440 gpm to two steam generators within 60 seconds of the loss of offsite power. To meet the single-failure requirement, the system has two independent trains of equipment. Each train takes suction on the Condensate Storage Tank (CST). Service Water (SW) provides a backup suction supply to the AFW pumps should the condensate storage tank become unavailable.

The auxiliary feedwater flow to the steam generators is controlled by throttle valves. These valves are preset to provide a desired flow of water to the steam generators. This flow is more than that needed to meet the decay heat requirements of the reactor following a reactor trip, but below the threshold value that could cause water hammers to occur in the feed piping or feed rings inside the steam generators. Pump speed is controlled by comparing the difference between pump discharge and steam header pressures with a desired setpoint differential pressure. This method of control ensures approximately the same feed flow rate for any given steam generator pressure.

The train A pump prime mover is a steam turbine. Each main steam line has a 3-in. steam supply line which taps off upstream of its main steam isolation valve. Each supply line contains an air-operated, fail-open isolation valve. The four steam supply lines join to form a common steam header with a motor-operated stop valve and a motor-operated trip-and-throttle valve. This pump is ac power independent and will continue to operate in the event of a station blackout.

The train B pump prime mover is a diesel engine. The diesel engine is cooled by B train Service Water (SW). It has two 28-Vdc batteries for starting and various control functions. The diesel-driven AFW pump requires some support from external vital ac power because service water cooling is necessary during operation.

A non-safety-grade electric-driven auxiliary feedwater pump is also installed. This pump takes suction on the Condensate Storage Tank (CST). It delivers flow to the discharge lines of the two safety-grade auxiliary feedwater pumps through a flow control valve and two motor-operated isolation valves. This pump is used to add feedwater to the steam generators during shutdown periods and startups. It saves wear and tear on the ESF equipment.

Systems which interface with the auxiliary feedwater system include:

- Condensate - The condensate storage tank provides a source of water for the auxiliary feedwater system. It has high- and low-level alarms and blockable low level trips of the turbine- and diesel-driven AFW pumps.
- Diesel Fuel Oil - A day tank is located above the auxiliary feedwater diesel engine and supplies fuel oil to the engine by gravity feed.
- Service Water – This system provides an alternate supply of auxiliary feedwater should the CST fail or empty. Service water is isolated from the pump suctions by motor-operated valves.

There are two independent sets of controls and indications for the auxiliary feedwater pumps. Each of the following signals automatically starts the auxiliary feedwater pumps:

1. Safety Injection Actuation Signal (SIAS),
2. Low-low steam generator water level (2/3 level transmitters on 1/4 SGs, can be blocked),
3. Undervoltage on 4.16-kVac ESF buses A1 and A2,
4. Loss of both main feed pumps (this signal can be blocked during a normal shutdown), and
5. AMSAC actuation.

When the steam turbine receives a start signal, the following actions occur:

1. Steam line isolation valves open.
2. The turbine trip-and-throttle valve opens.
3. The governor controls steam flow to accelerate the turbine to the desired speed.
4. Pump room cooling fans energize.
5. Steam generator blowdown and blowdown sample isolation valves shut.
6. Various alarms energize to indicate the pump start.

When the diesel engine receives a start signal, the sequence of events is the same as above, except that instead of steam and throttle valves opening, the diesel engine is started by the self-contained, battery-powered, dc electric motors.

The auxiliary feedwater system can be controlled from the control room or from the remote shutdown station.

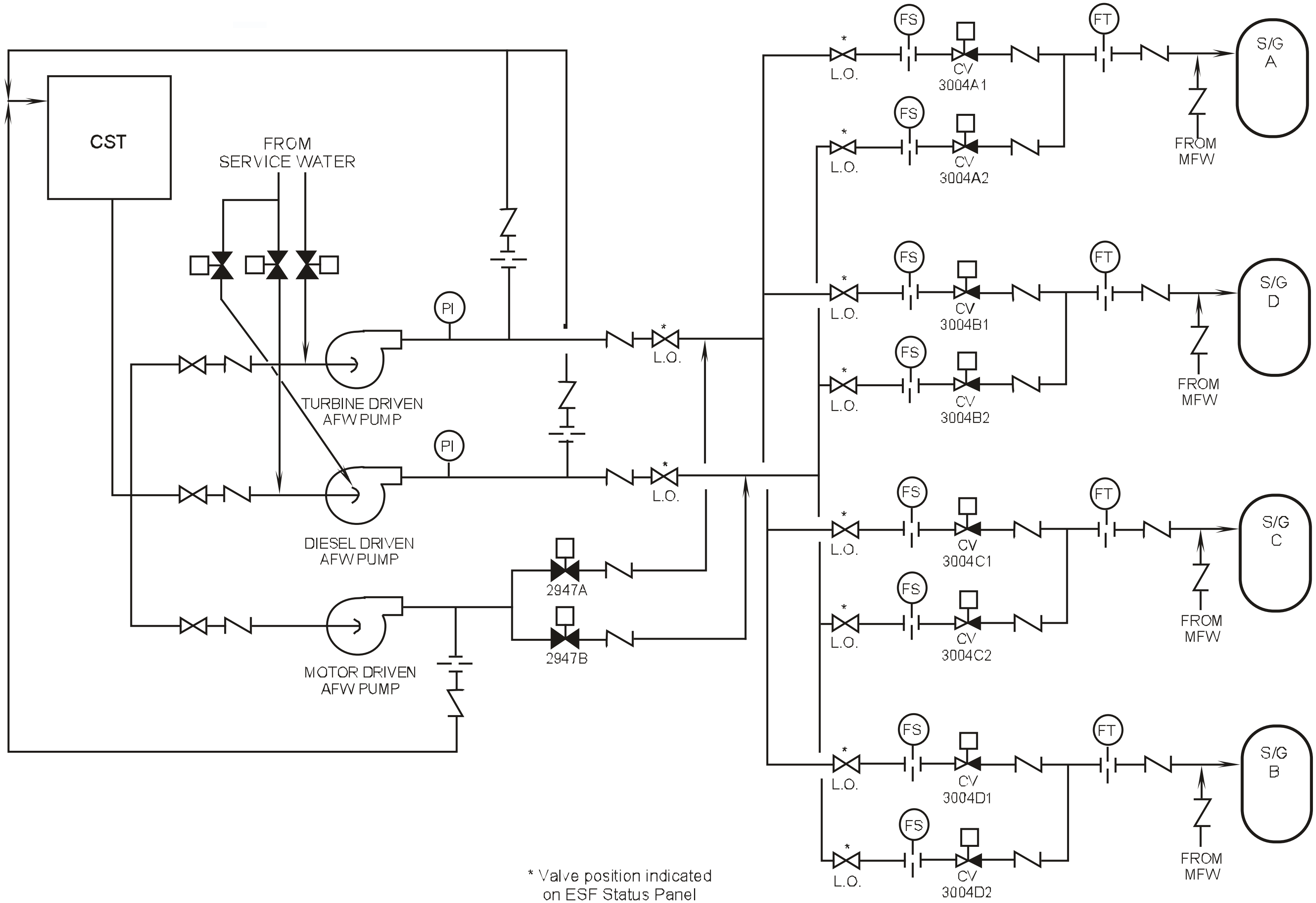


Figure 5.5-1 Auxiliary Feedwater System

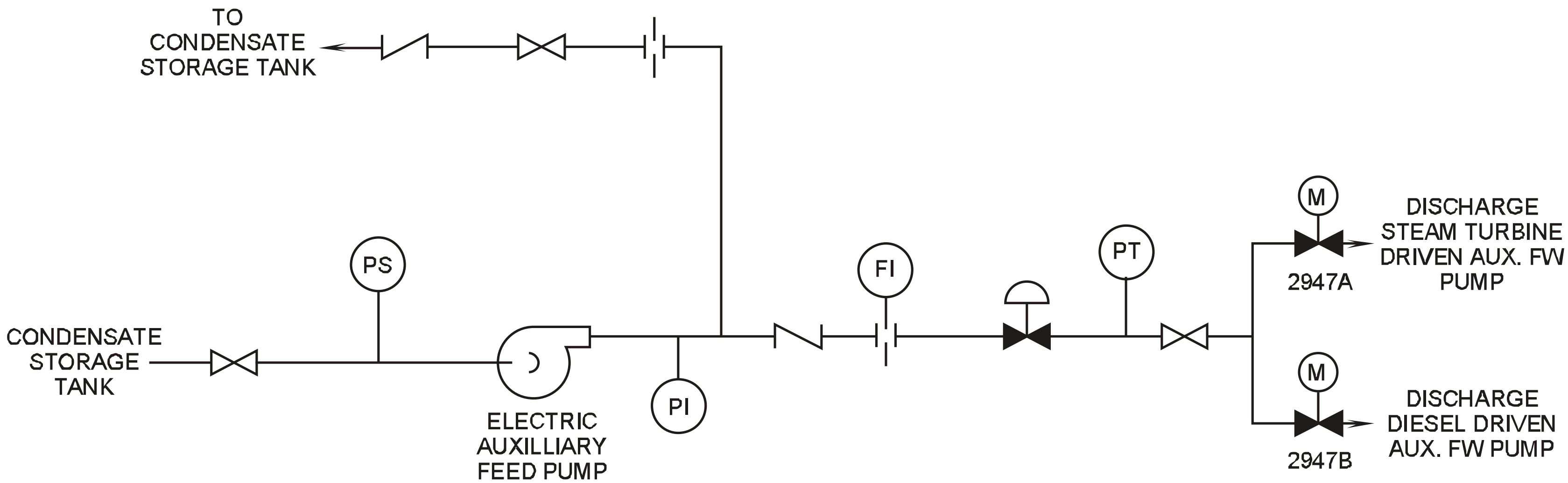


Figure 5.5-2 Electric Auxiliary Feedwater Pump

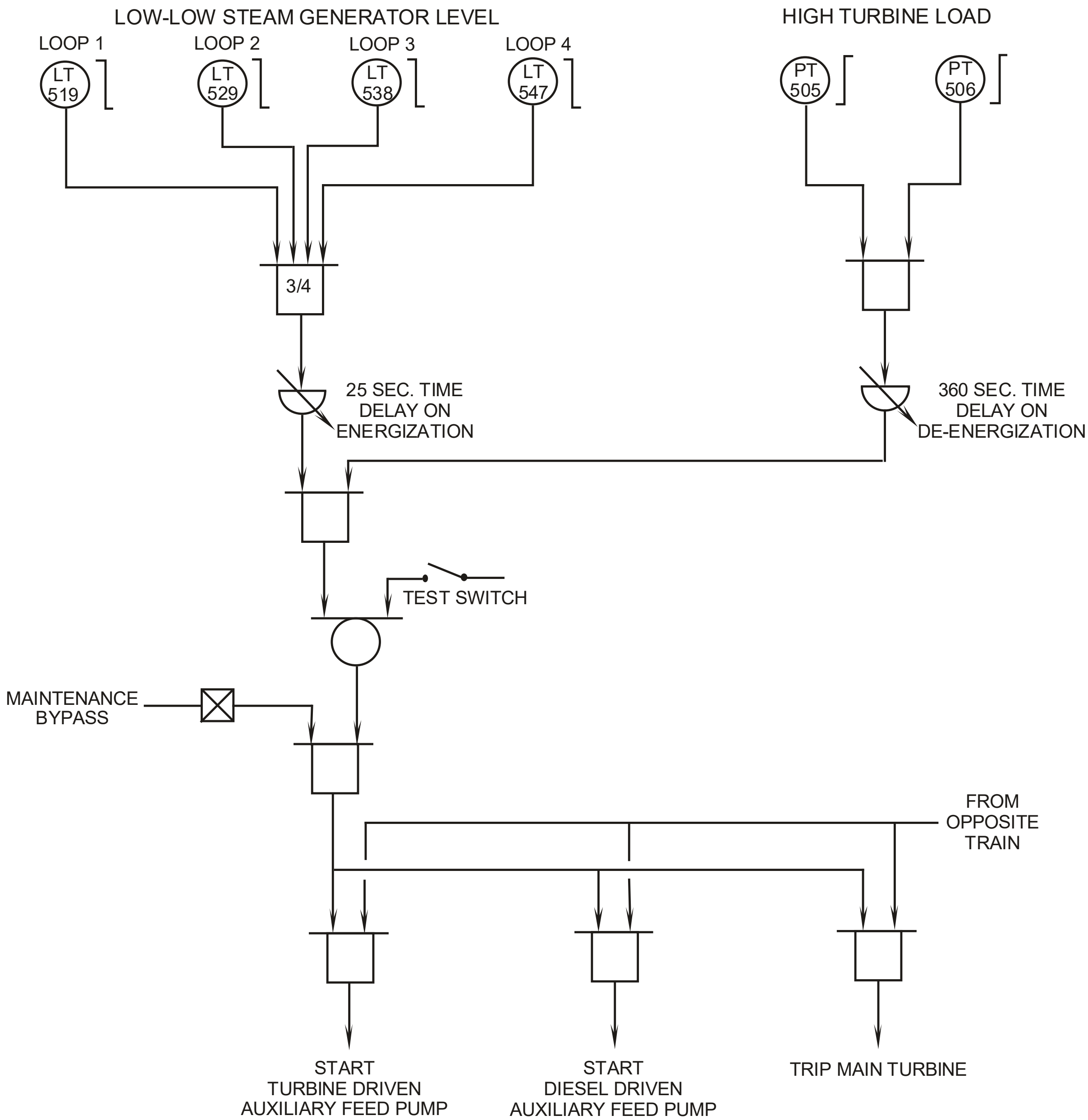


Figure 5.5-3 AMSAC Trip Circuit

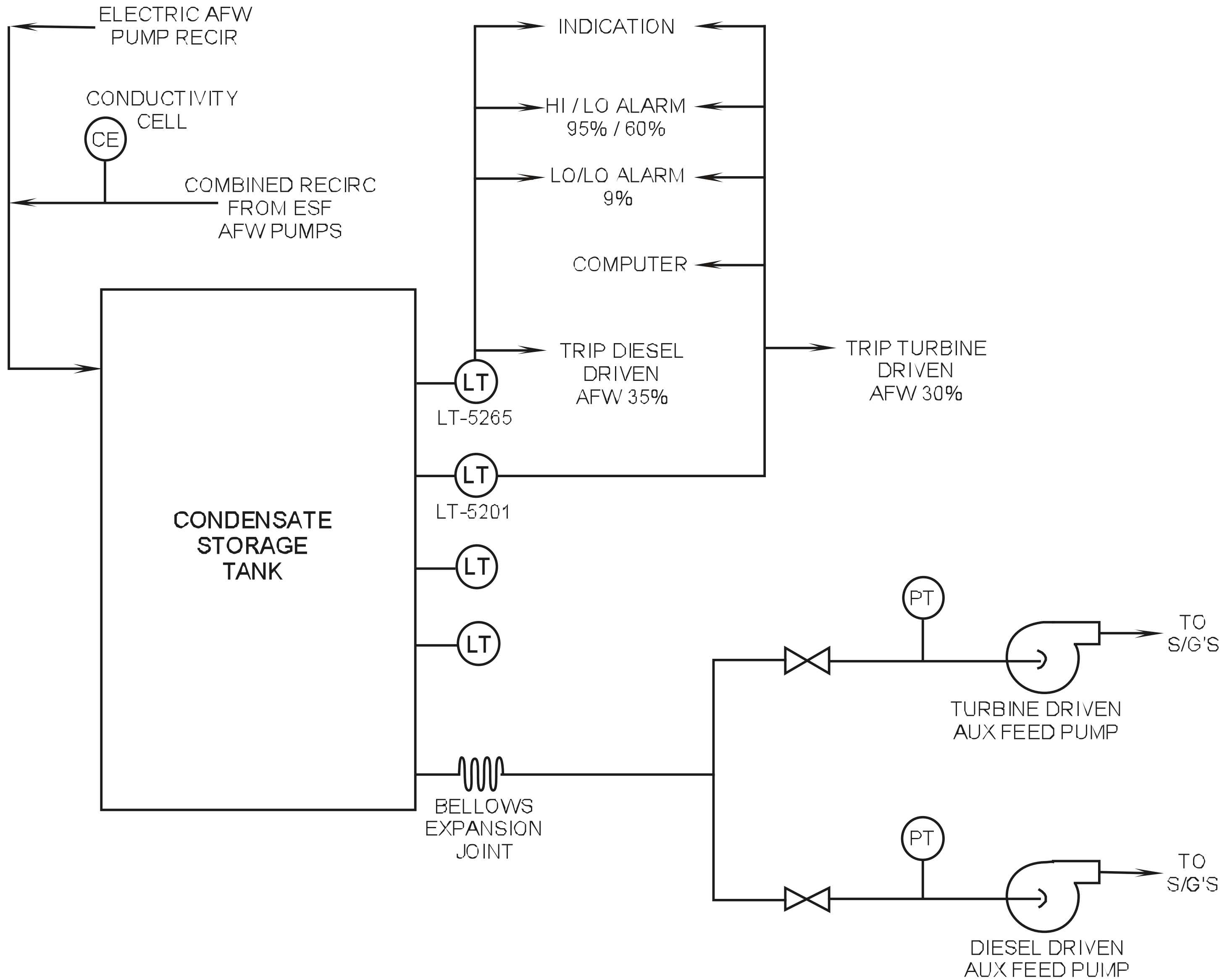


Figure 5.5-4 Condensate Storage Tank

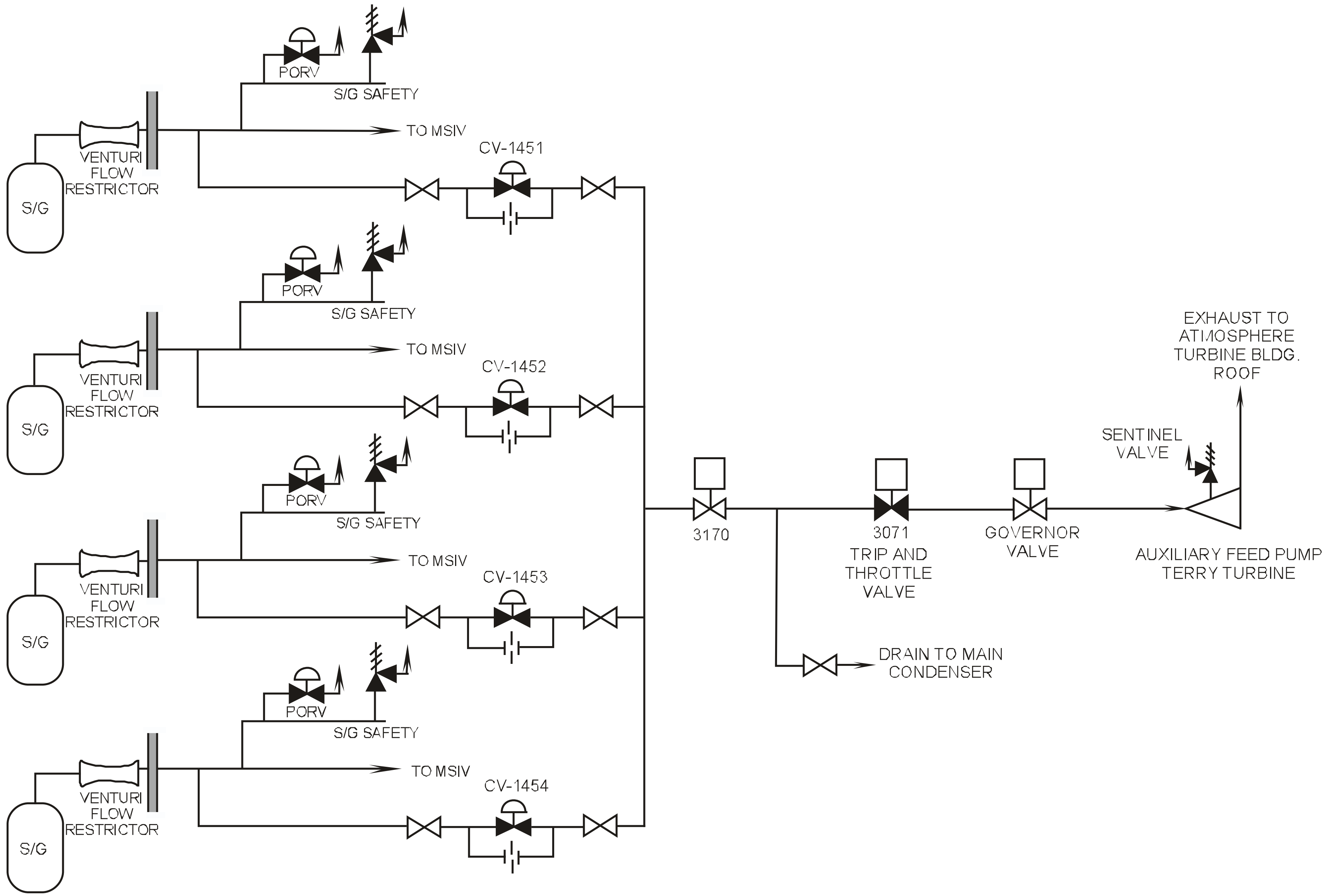


Figure 5.5-5 Steam Supplies to Turbine Driven Auxiliary Feed Pump

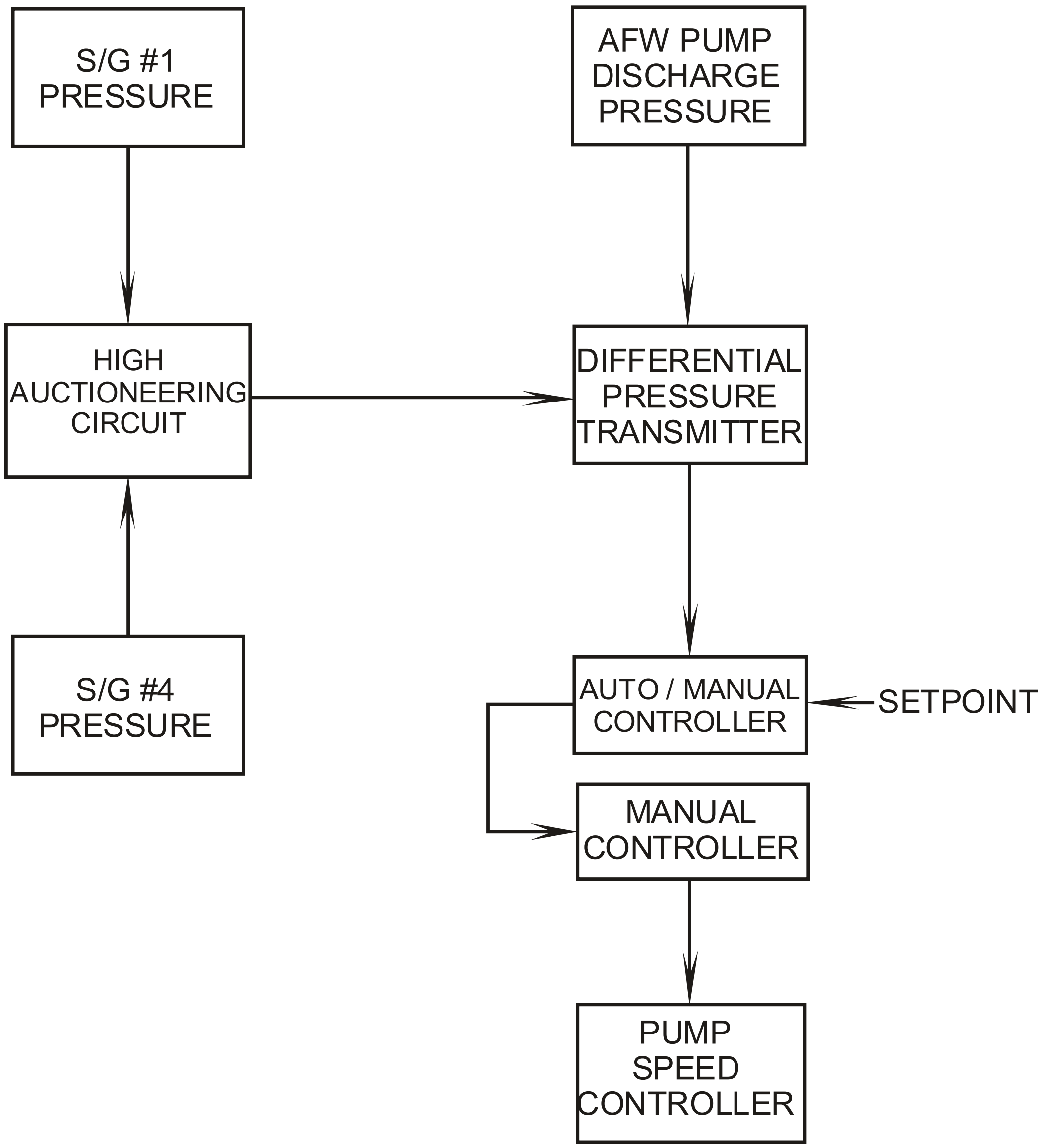


Figure 5.5-6 Train "B" (Diesel) AFW Pump ΔP Control

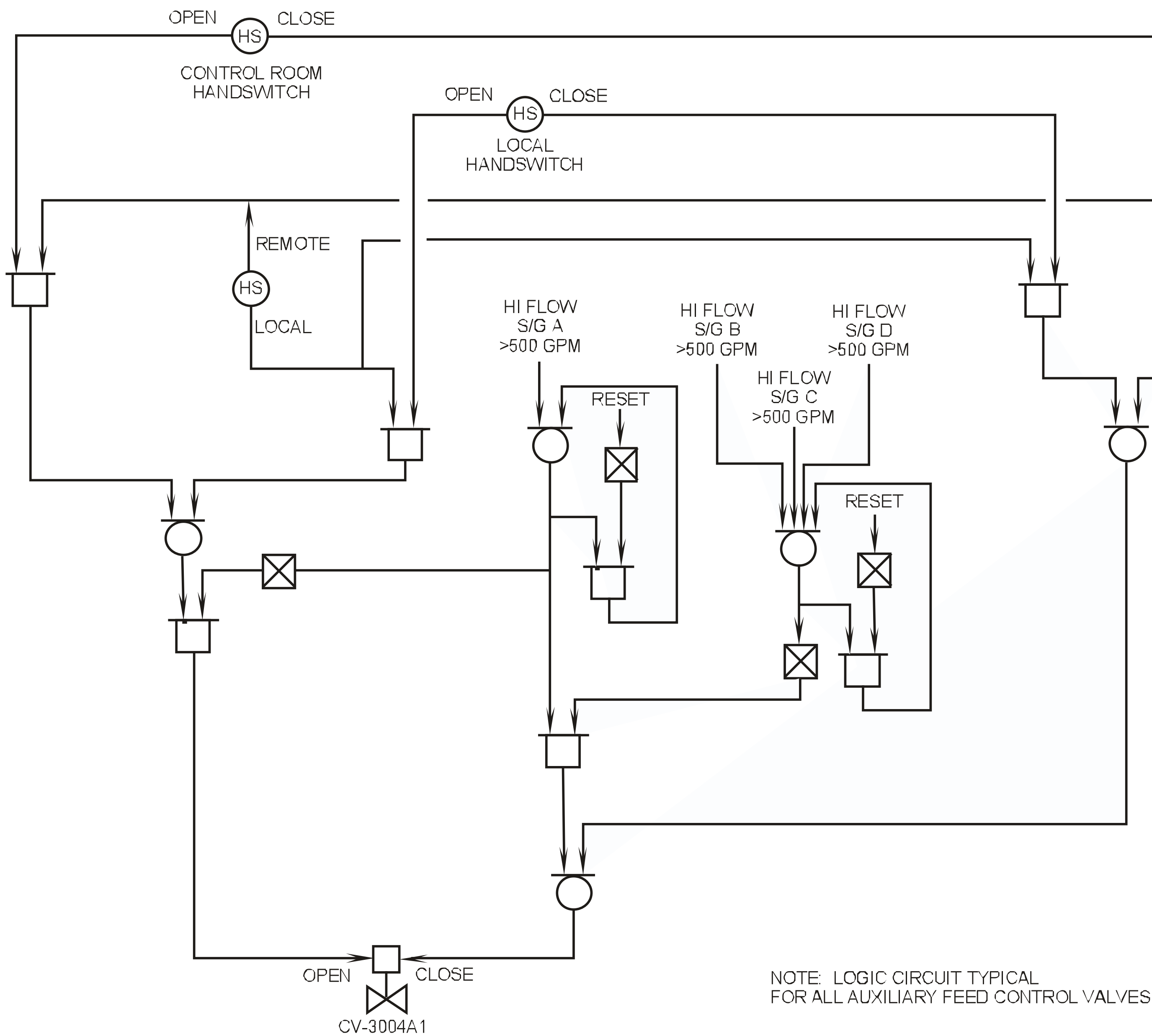
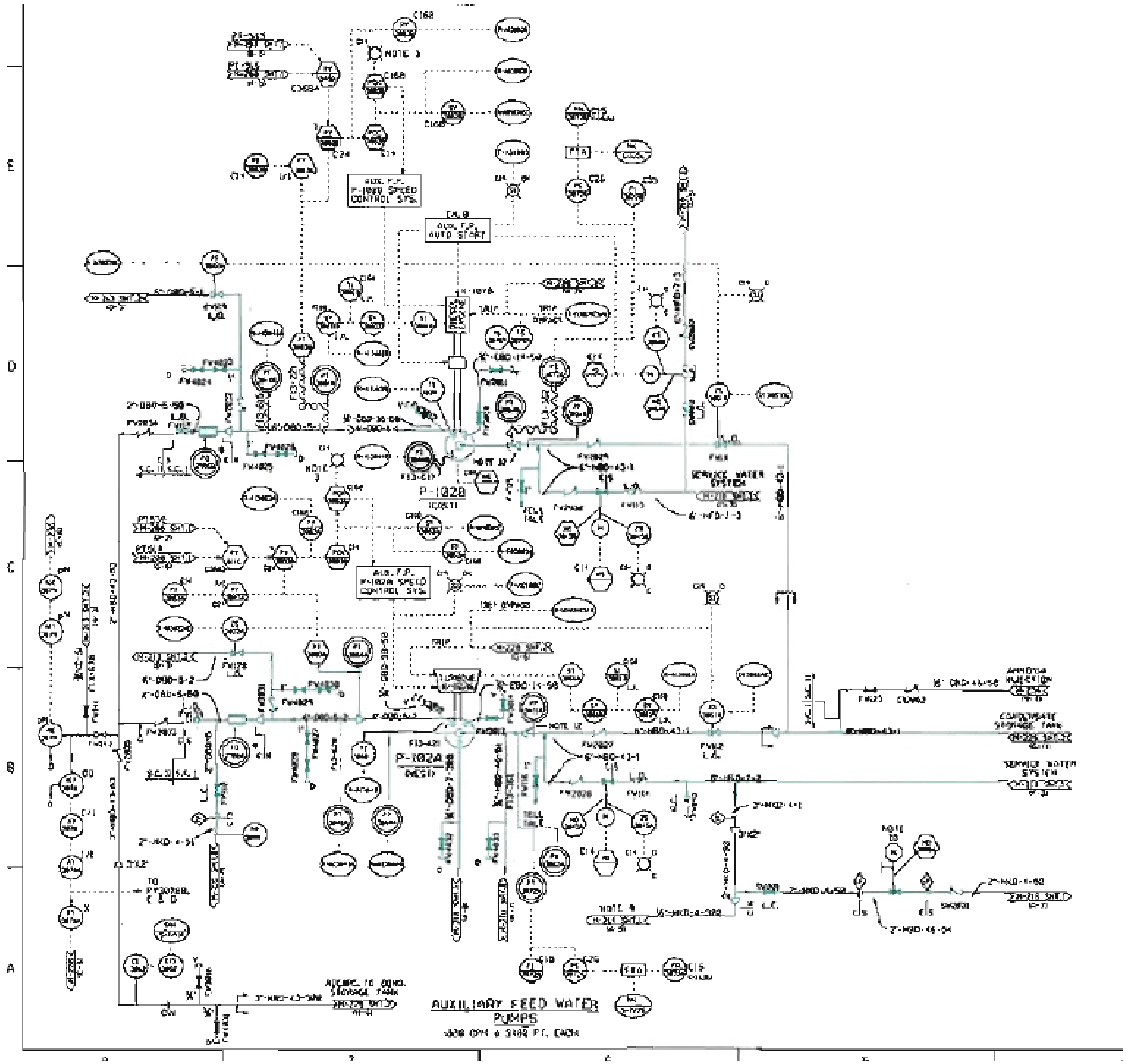
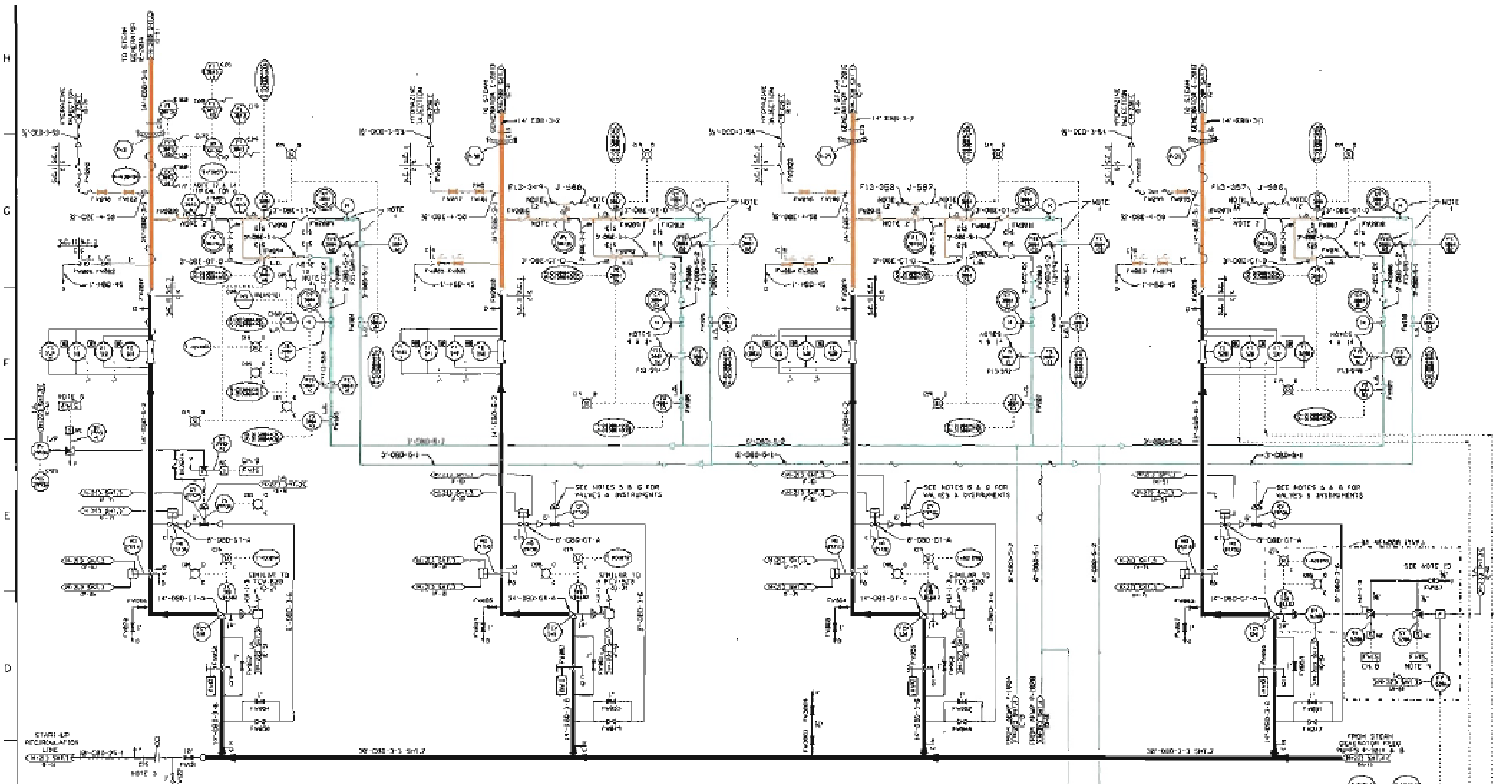
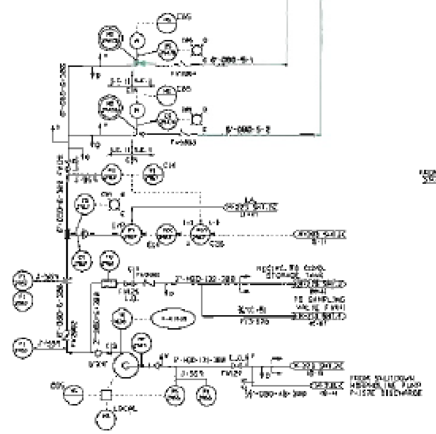


Figure 5.5-7 Auxiliary Feedwater Control Valve CV3004A1

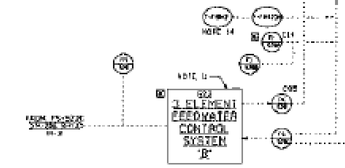


AUX. F.P. P-102B SPEED CONTROL SYS.
AUX. F.P. AUTO START
DIESEL ENGINE
P-102B
SERVICE WATER SYSTEM
AUX. F.P. P-102A SPEED CONTROL SYS.
TURBINE
P-102A
AMMONIA INJECTION
CONDENSATE STORAGE TANK
SERVICE WATER SYSTEM
TELL TALE
AUXILIARY FEED WATER PUMPS





P-182 ELEC. AUXILIARY FEEDWATER PUMP



A.F.W. INSTRUMENT DESIGNATIONS

FE	FT	FI	FI	[illegible]	FY/FCV	FY-√‾ EXTRACTOR		RBS I/O
3843A	3843A	[illegible]	[illegible]	3843A-CH2	[illegible]	[illegible]	[illegible]	[illegible]
3843B	3843B	[illegible]	[illegible]	3843B-CH2	[illegible]	[illegible]	[illegible]	[illegible]
3843C	3843C	[illegible]	[illegible]	3843C-CH1	[illegible]	[illegible]	[illegible]	[illegible]
3843D	3843D	[illegible]	[illegible]	3843D-CH1	[illegible]	[illegible]	[illegible]	[illegible]

FE	FT	FI	FY-√‾ EXTRACTOR
3843A	3843E	3843E	3843E
3843B	3843F	3843F	3843F
3843C	3843G	3843G	3843G
3843D	3843H	3843H	3843H

NOTES:

1. ENTIRE SYSTEM IS SEISMIC CATEGORY II EXCEPT AS NOTED.
2. PIPE SPEC. DOWNSTREAM OF ROOT VALVES FOR FE-3843A,B,C & D SHALL BE C80-R.
3. EVS LOCATED MAXIMUM 8' DOWNSTREAM OF 880 FLANGE. RECIRCULATION LINE SHOULD NOT BE USED WHEN SGFP IS OPERATING.
4. ZS (WITH INDICATING LIGHTS), FC, FY & HS ARE SHOWN FOR CV-3884A1 ON LOOP "A" AND ARE TYPICAL FOR OTHER VALVES (SEE INSTRUMENT INDEX FOR OTHER INSTRUMENTS):
   CV-3884A2
   CV-3884B1
   CV-3884B2
   CV-3884C1
   CV-3884C2
   CV-3884D1
   CV-3884D2
5. INSTRUMENTS & VALVES FOR INSTRUMENT AIR SERVICE SHOWN FOR CV-2993A ON FW LOOP "A" ARE TYPICAL FOR LOOPS "B", "C" & "D".

INSTRUMENTS & VALVES PER LOOP

CV-2993B	CV-2993C	CV-2993D
LOOP B	LOOP C	LOOP D
SV-2993B1	SV-2993C1	SV-2993D1
SV-2993B2	SV-2993C2	SV-2993D2
IA-2845	IA-2846	IA-2847
HIC-2993B	HIC-2993C	HIC-2993D
FY-2993B	FY-2993C	FY-2993D

6. CHANNEL "X" FEEDWATER ISOLATION SIGNAL (FWIS). REFER TO [illegible] DWG. NO. 5855034 SHT. 13 [illegible] (TYPICAL FOR 8 VALVES):

CONTROL VALVE	CHANNEL
CV-2993A	
SV-2993A1	X
SV-2993A2	Y
CV-2993B	
SV-2993B1	X
SV-2993B2	Y
CV-2993C	
SV-2993C1	X
SV-2993C2	Y
CV-2993D	
SV-2993D1	X
SV-2993D2	Y

9. CHANNEL "W" FEEDWATER ISOLATION SIGNAL (FWIS). REFER TO [illegible] DWG. NO. 5855034 SHT. 13 [illegible] (TYPICAL FOR 8 VALVES):

CONTROL VALVE	CHANNEL
FCV-510	
SV-510A	Y
SV-510B	X
FCV-520	
SV-520A	Y
SV-520B	X
FCV-530	
SV-530A	Y
SV-530B	X
FCV-540	
SV-540A	Y
SV-540B	X

10. LOCAL - REMOTE STATION LIGHT IN MAIN CONTROL BOARD IS LIT WHEN IN LOCAL.
11. TYPICAL FOR 4. REFER TO [illegible] DWG. NO. [illegible] SHT. 30 [illegible]
12. INSTRUMENTS FOR FT-3843B, C & D ARE IDENTICAL TO THAT FOR FE-3843A AS SHOWN AT COORD. [illegible] CROSS REFERENCE FOR INSTRUMENT NUMBERS ARE SHOWN ON TABLES AT COORD. C-8, B-8 & B-7,8.
13. FEEDWATER REGULATOR BLEEDOFF VALVE NUMBERS:

CONTROL VALVE	BLEEDOFF VALVE
FCV-510	FW-156
FCV-520	FW-157
FCV-530	FW-158
FCV-540	FW-159

BLEEDOFF VALVES ARE SET TO PROVIDE CONTROL VALVE CLOSING TIME OF 3 TO 5 SECONDS.

14. COMPUTER MONITORED INSTRUMENTS AND RESPECTIVE ADDRESS POINT NUMBERS ARE AS IN THE TABLE BELOW.

COMPUTER MONITORING

INSTRUMENT NUMBER	PLANT P-250 COMPUTER PT	TSC COMPUTER PT
FCV510	—	A0[illegible]
FT510	F0403A	F1038
FT511	F0404A	F1039
FCV520	—	A0[illegible]
FT520	F0423A	F1042
FT521	F0424A	F1043
FCV530	—	A0[illegible]
FT530	F0443A	F1046
FT531	F0444A	F1047
FCV540	—	A01897
FT540	F0463A	F1050
FT541	F0464A	F1051
MO2171A	—	MO[illegible]
MO2171B	—	MO[illegible]
MO2171C	—	MO[illegible]
MO2171D	—	MO[illegible]
CV3884A1	—	A01865
CV3884A2	—	A01866
CV3884B1	—	A01867
CV3884B2	—	A01868
CV3884C1	—	A01869
CV3884C2	—	A01870
CV3884D1	—	A01871
CV3884D2	—	A01872
FT3843E	—	F1059
FT3843F	—	F1060
FT3843G	—	F1061
FT3843H	—	F1062

Amendment 19
(December 1992)

TROJAN NUCLEAR PLANT
FSAR

CONDENSATE & FEEDWATER SYSTEM

SHT.2 OF 4

FIGURE 10.4-2 C

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Section 5.6

Containment Penetrations and Isolation Systems (CPIS)

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5.6 CONTAINMENT PENETRATION AND ISOLATION SYSTEMS (CPIS)

Learning Objectives:

1. State the purposes of the system.

2. Define the following:

   a. Deleted
   b. Containment Isolation Phase A
   c. Containment Isolation Phase B

3. List the signals that initiate phase A and phase B isolation.

5.6.1 Introduction

The purposes of the Containment Penetration and Isolation Systems (CPIS) are as follows:

1. Isolate nonessential containment penetrations during accident conditions, and
2. Provide leak-tight mechanical and electrical containment penetrations.

The primary means of minimizing the release of radioactive gases and particulates after an accident is the isolation of the reactor containment from the environment. Containment penetration and isolation systems are designed to limit any releases to within those allowed by Technical Specifications. Common leakage limits are between one tenth and four tenths of one percent of the containment volume per day.

10 CFR 50, Appendix J (Reactor Containment Leakage Testing for Water Cooled Power Reactors) requires that the actual leak rate be verified experimentally prior to operation and periodically thereafter.

All containment penetrations (both electrical and piping) are double barrier assemblies consisting of a closed sleeve, in most cases, or a double gasketed closure for special penetrations, such as the fuel transfer tube. The void space between the double barriers is continuously pressurized, by the penetration pressurization system, to a pressure in excess of the containment design pressure. Leakage from this system is monitored to indicate penetration leakage.

The containment isolation system provides the means of isolating fluid systems that pass through containment penetrations so as to confine any radioactivity that may be released into the containment following a loss of coolant accident. The containment isolation systems are required to function following an accident, to isolate non-safety-related fluid systems penetrating the containment. A particular system does not exist for containment isolation, but isolation design is achieved by applying common criteria to penetrations in many different fluid systems and by using ESF signals to actuate appropriate valves.

The main function of the containment isolation system is to provide containment integrity when needed. Containment integrity is defined to exist when:

1. The non-automatic containment isolation valves and blind flanges are closed as required.
2. The containment equipment hatch is properly closed.
3. At least one door in each containment personnel air lock is properly closed.
4. All automatic containment isolation valves are operable or are deactivated in the closed position or at least one valve in each line having an inoperable valve is closed and,
5. All requirements of the Technical Specifications with regard to containment leakage and test frequency are satisfied.

All containment penetrations and isolation systems are designed to be Seismic Category I.

5.6.2 Containment Penetration Types

5.6.2.1 Electrical Penetrations

Canister-type electrical penetration assemblies are used to extend conductors through the containment penetration nozzles. Figure 5.6-1 shows a typical electrical penetration assembly in place within a containment penetration nozzle. Hermetic (airtight) seals between each conductor and the metallic canister end header plates are obtained by the use of high strength, high temperature glass and ceramic materials.

There are five types of electrical penetration assemblies, classified by service and application as follows:

1. Type 1 - Medium voltage power service
2. Type 2 - Low voltage power service
3. Type 3 - Control service
4. Type 4 - Shielded instrumentation service
5. Type 5 - Triaxial instrumentation cable service

The penetrations associated with engineered safety features within the containment are fully rated for both normal and post Loss Of Coolant Accident (LOCA) operation.

5.6.2.2 Piping Penetrations

Double barrier piping penetrations are provided for all piping which passes through the containment as shown in Figure 5.6-2. The pipe is contained in a sleeve which is welded to the liner. Closure heads are welded to the sleeve and to the pipe, both inside and outside the containment, to form the double barriers. The annulus between the pipe and sleeve is continuously pressurized. Several pipes may pass through the same sleeve to minimize the number of containment penetrations required. In these cases, each pipe is welded to both closure heads.

The penetrations for main steam, feedwater, and steam generator blowdown are anchored outside the containment in such a way as to ensure containment integrity should any one of these lines rupture. These penetrations are provided with a bellows expansion joint on both the inside and the outside of the containment, which allows for differential movement between the containment wall and the anchor. The inside joint will also take up the differential movement of the hot pipe relative to the liner. The expansion joints have been designed so that, in the event of a pipe rupture within the sleeve, the inside joint will subsequently rupture, and the outside joint will remain intact, thereby maintaining containment integrity.

Hot penetrations are normally provided with some type of cooling to minimize drying of the containment concrete around the penetrations. Other hot penetrations, which are not anchored outside the containment for pipe rupture, are where required, provided with a single expansion joint, either inside or outside the containment, to allow for thermal movement of the pipe relative to the anchor.

5.6.2.3 Equipment and Personnel Access Hatches

The equipment hatch (as shown on Figure 5.6-3) is fabricated from welded steel and furnished with a double-gasketed flange and a bolted dished door. Equipment up to and including the size of the reactor vessel upper head O-ring seal can be transferred into and out of containment via this hatch. The hatch barrel is welded to the containment liner.

Two personnel air locks are provided for the containment, one of which is for normal access and penetrates the dished shaped door of the equipment hatch. The other is an emergency escape hatch located on the side of containment opposite the equipment hatch at grade level. Each personnel air lock is a double door, hydraulically-latched, welded steel assembly as shown in Figure 5.6-3. A quick-acting-type, equalizing valve connects the personnel lock with the interior of the containment structure. Its purpose is equalizing pressure in the escape lock and the containment when entering or leaving the containment structure.

The two doors in each personnel lock are interlocked to prevent both doors being opened simultaneously and to ensure that one door is completely closed before the opposite door can be opened. Remote indicating lights and annunciators in the control room indicate the status of these doors. An emergency lighting and communication system, operated from an external emergency power supply, is provided in the personnel lock interior.

5.6.2.4 Special Penetrations

A fuel transfer penetration is provided (see Figure 5.6-4) for fuel movements between the refueling cavity in the reactor containment and the spent fuel pit. The penetration consists of a 20-in. pipe located inside a 24-in. sleeve. The inner pipe acts as the transfer tube and is fitted with a double gasketed blind flange in the refueling cavity inside containment. A seal plate is welded to the containment liner and also to the inside tube. This seal plate and the blind flange act as the containment boundary.

Bellows expansion joints have been installed in the sleeve. These joints, which are welded to the sleeve and connected to the tube by welding to end plates, provide for normal and seismic differential building movements. The sleeve and expansion joints also serve to cover most of the welds on the tube inside the containment. The annulus between the sleeve and tube is continuously pressurized to demonstrate containment integrity.

Lines originating from the containment recirculation sumps penetrate the containment through the slab below the containment walls. In this case the pipe is contained in a sleeve which is buried in the slab. Both sleeve and pipe extend into the sump, where the sleeve is seal welded to both the pipe and the sump liner.

The sleeve and pipe also extend outside the containment to an isolation valve which is completely enclosed in a small tank. The sleeve terminates at the entrance to the tank where it is welded to the tank. At the outlet of the tank, the pipe is seal welded to the tank through an expansion joint which takes up the thermal expansion of the pipe.

The annulus between the pipe and sleeve, and the volume within the tank are continuously pressurized through a connection on the tank. The sleeve and tank serve as an extension of the containment boundary to maintain containment integrity in the event of a pipe break outside containment.

5.6.3 Containment Isolation Systems

5.6.3.1 Design Basis

The design basis for the containment isolation systems includes provisions for the following:

1. A double barrier at the containment penetration in those fluid systems that are not required to function following a LOCA or a secondary rupture inside the containment.
2. Automatic, fast closure of those valves required to close for containment integrity following an accident to minimize the release of any radioactive material.
3. A means of leak testing fluid system barriers that serve as containment isolations.
4. The capability to periodically test the operability of the containment isolation valves.

5.6.3.2 Initiation Signals

Containment isolation is accomplished by two separate signals designated as phase A and phase B. The phase A isolation is initiated by any Safety Injection Actuation Signal (SIAS) or manually from the control room. The Containment Isolation Signal (CIS-A) phase A isolates nonessential piping penetrations into the containment, such as the containment sump pump discharge, containment ventilation connections to atmosphere, etc. The most important penetrations not isolated on a phase A isolation are the penetrations for the component cooling water supplies to the reactor coolant pumps.

The Containment Isolation Signal (CIS-B) phase B is initiated by a high-high containment pressure signal or manually from the main control board. It isolates the remainder of the nonsafety penetrations (the Component Cooling Water (CCW) supplies to the reactor coolant pumps). This same high-high pressure signal also closes the main steam line isolation valves and initiates Containment Spray (CS).

5.6.3.3 Isolation Classes

The criteria defining the number and location of containment isolation valves in each fluid system depends on the function of the system and whether it is open or closed to the containment atmosphere or reactor coolant system. Four isolation classes of penetrations are defined as follows:

1. Isolation class I - lines which are open to the atmosphere outside the containment and are connected to the reactor coolant system or are open to the containment atmosphere. Each isolation class I system has a minimum of two isolation valves in series. Where system design permits, one valve is located inside, and one valve is located outside containment.
2. Isolation class II - lines which are connected to a closed system outside the containment and are connected to the reactor coolant system or are open to the containment atmosphere. Also included in isolation class II are fluid lines which are open to the atmosphere outside the containment and are separated from the reactor coolant system and the containment atmosphere by a closed system inside the containment. Each isolation class II system has a minimum of one isolation valve.
3. Isolation class III - lines which are connected to a closed system both inside and outside the containment. Isolation class III systems have as a minimum one isolation valve.
4. Isolation class IV - lines which must remain in service subsequent to a LOCA or a secondary pipe break inside the containment, such as the Emergency Core Cooling Systems (ECCS). Isolation valves on these lines are not automatically closed by the containment isolation signal. Each isolation class IV system has a minimum of one isolation valve (remote-manual operation).

The criteria for containment penetrations ensure that all fluid lines penetrating the containment have at least one isolation valve near the point of penetration. Most fluid lines that communicate directly with the containment atmosphere have, as a minimum, two isolation valves in series. These lines and isolation valves are designed to Seismic Category I specifications and are missile protected.

5.6.4 Systems Features and Interrelationships

A containment isolation signal initiates closing of automatic isolation valves in those lines which must be isolated immediately following an accident. There is no order of sequence of timing for containment isolation valve closure. However, on a loss of off-site ac power, the diesel will have to be started prior to the closure of the motor-operated valves. Air-operated valves used for containment isolation are designed to fail closed on loss of air.

Check valves are sometimes used as containment isolation valves where the differential pressure, under accident conditions, will close the valves to maintain containment integrity. Lines which, for safety reasons, must remain in service subsequent to an accident are provided with at least one isolation valve.

Each automatic isolation valve required to operate subsequent to an accident is additionally provided with a manual control switch for operation. The position of these automatic isolation valves are indicated by status lights in the main control room.

Containment isolation valves that are located inside the containment are designed to function under the radiation, pressure, and high temperature conditions existing during both normal operation and accident conditions.

Containment isolation valves are designed to Seismic Category I requirements. The valves are capable of operation during and after seismic loadings. Valves with operators or similar features of extended proportions are designed to withstand an inertial Safe Shutdown Earthquake (SSE) load in addition to normal operating loads. Electrical switches or other actuating mechanisms are designed to withstand the inertial load as a result of an SSE without changing position and causing change of position of the valve disc.

5.6.5 Summary

The containment isolation systems provide the means of isolating fluid systems that pass through containment penetrations so as to confine any radioactivity that may be released into the containment following an accident. The containment isolation systems are required to function following a design basis event to isolate nonsafety-related fluid systems that penetrate the containment.

Containment isolation is initiated in two levels: phase A and phase B. Containment isolation phase A (CIS-A) always exists if containment isolation phase B (CIS-B) exists (unless phase B is manually initiated). A containment isolation signal initiates closing of automatic isolation valves in those lines which are not required to respond to an accident. The positions of these automatic isolation valves are indicated by status lights in the main control room.

Containment isolation valves are designed to Seismic Category I requirements. These valves are capable of operation during and after seismic loadings.

Containment penetrations are designed to ensure that the leakage from the containment, at a maximum calculated containment pressure and temperature, does not exceed the limits of the plant’s Technical Specifications.

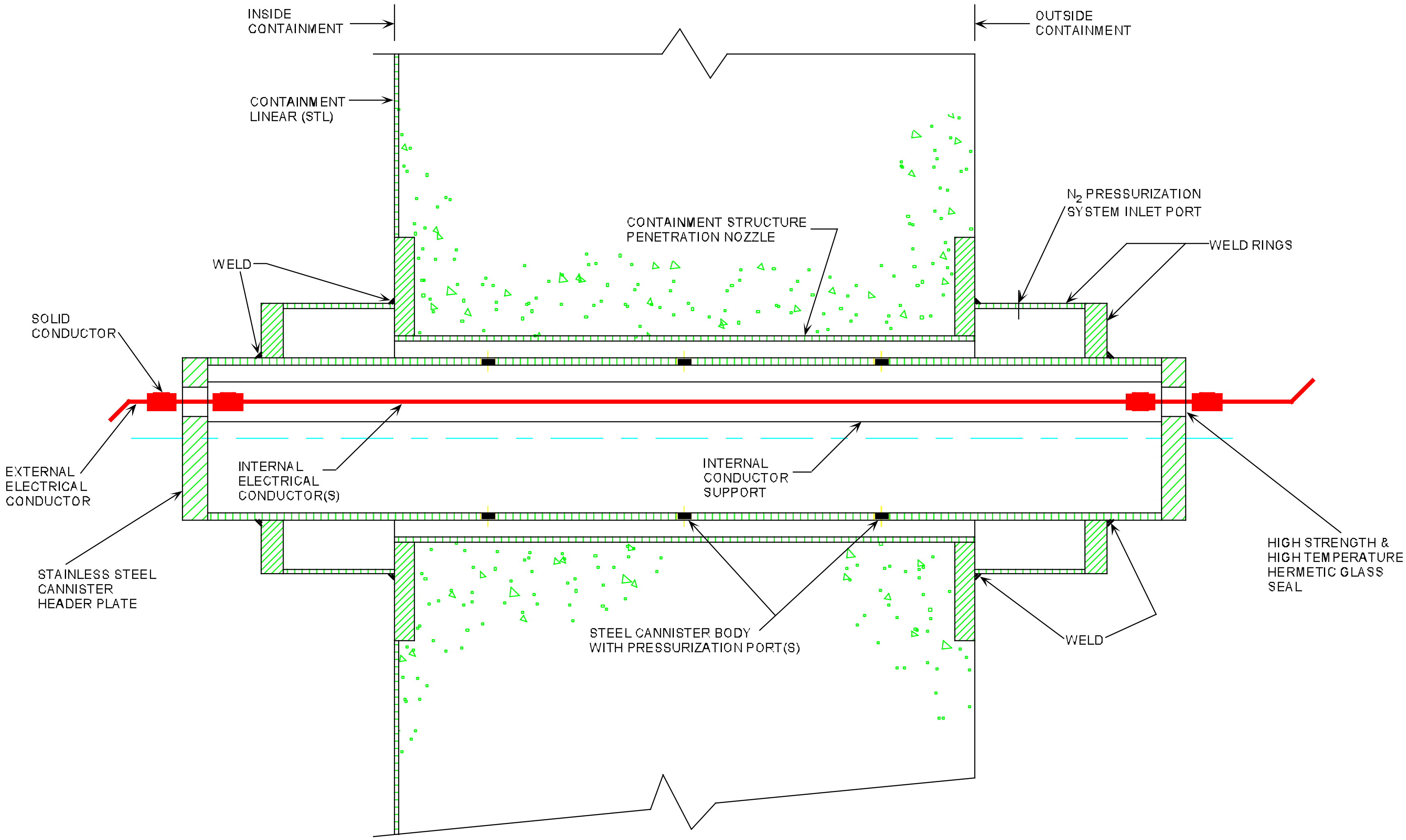
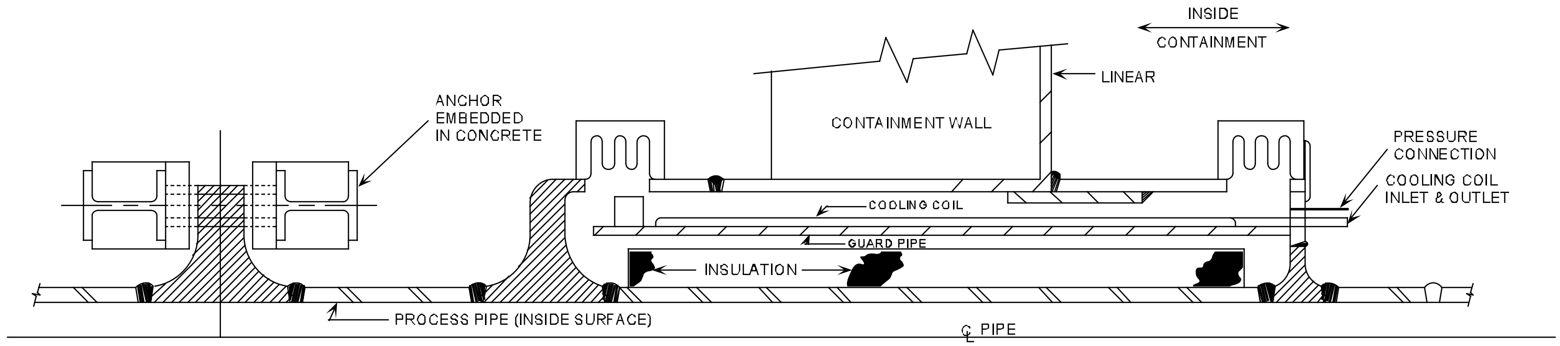
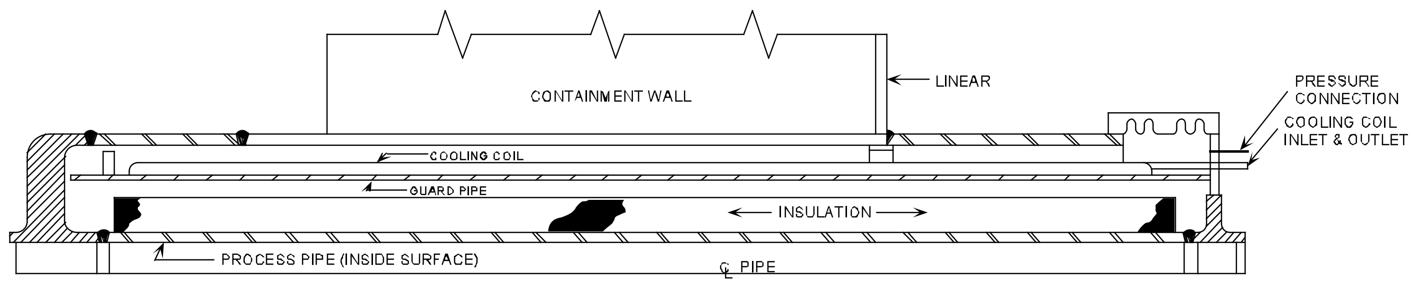


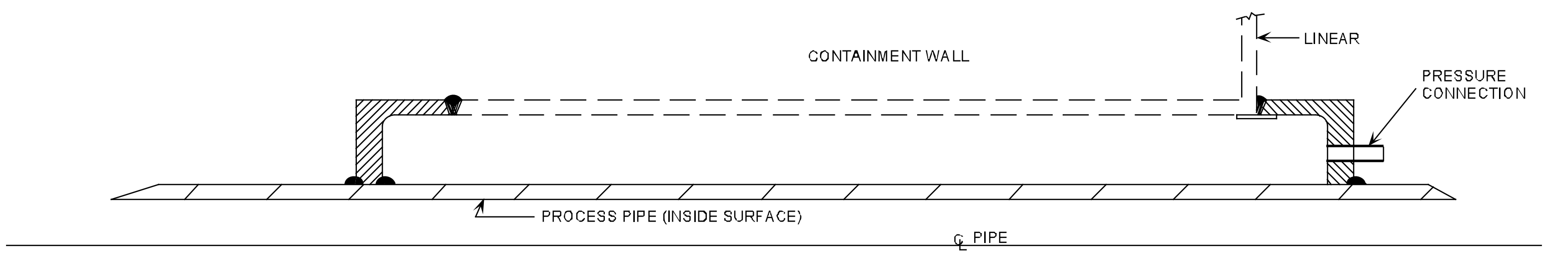
Figure 5.6-1 Typical Electrical Penetration



MAIN STEAM & FEED WATER PENETRATION ASSEMBLY

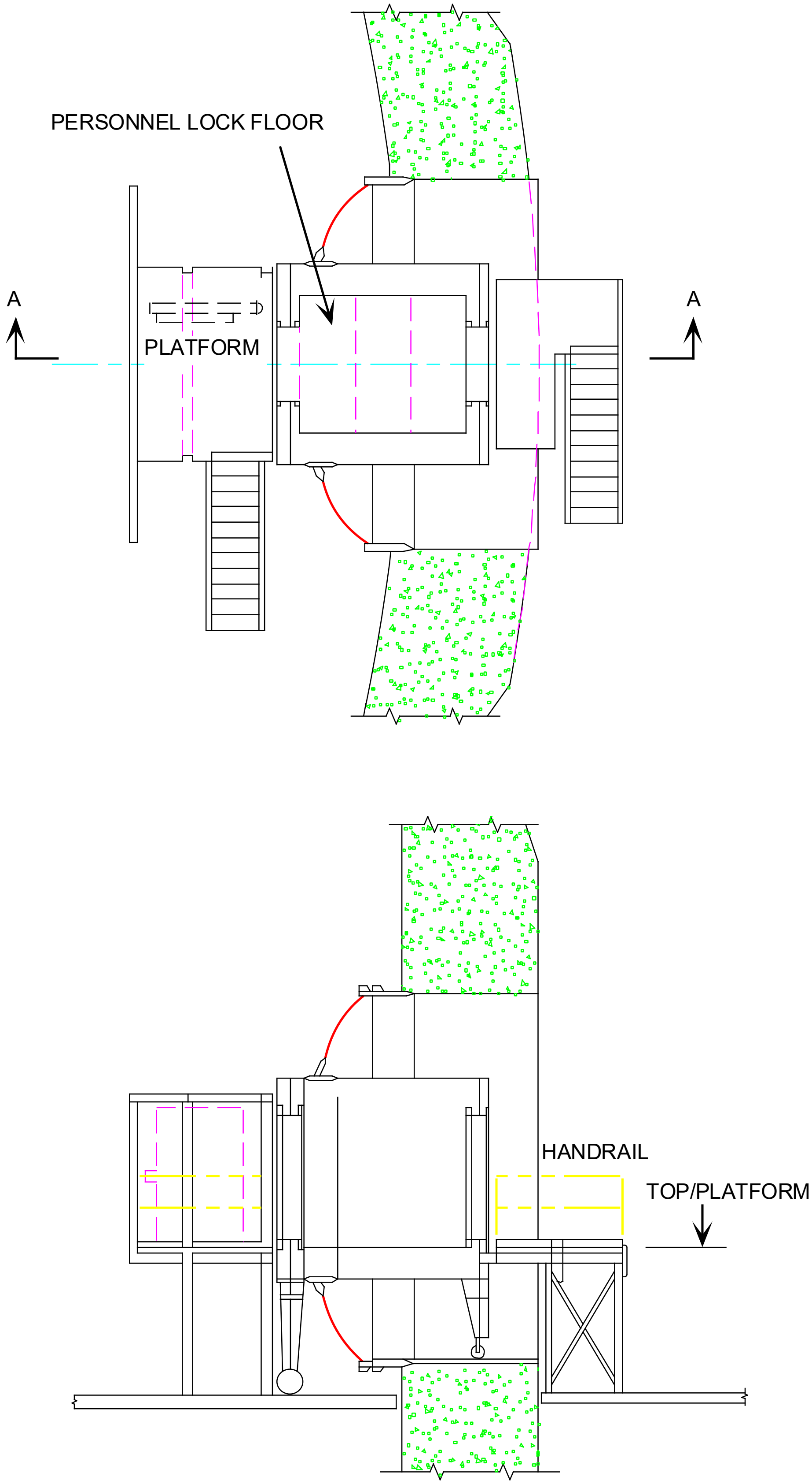


TYPICAL HOT PENETRATION ASSEMBLY



TYPICAL COLD PENETRATION ASSEMBLY

Figure 5.6-2 Typical Piping Penetration



SECTION A-A

Figure 5.6-3 Equipment/Personnel Hatch

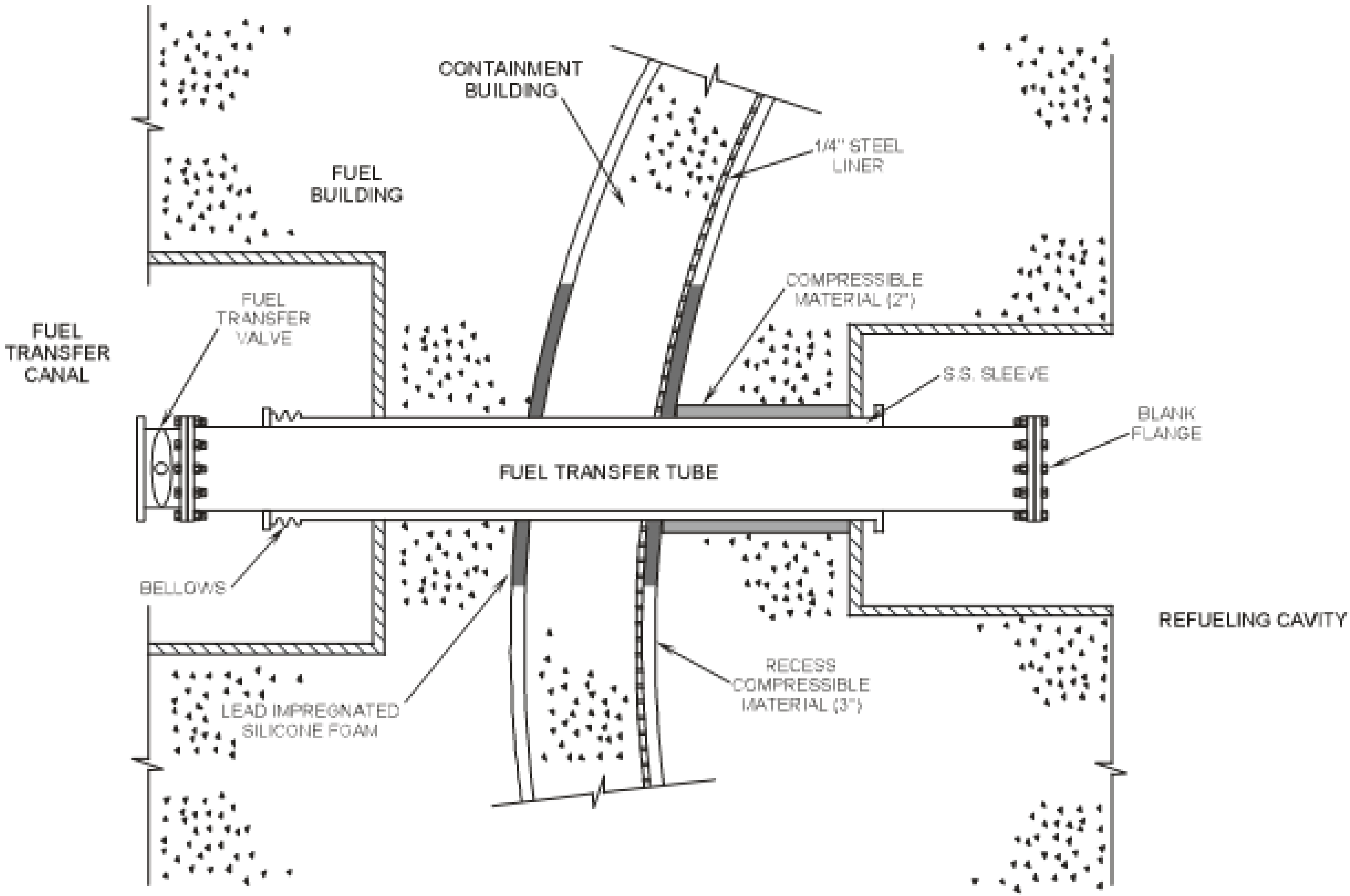


Figure 5.6-4 Fuel Transfer Tube

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Section 5.7

Generic Auxiliary Feedwater (AFW) System

"READ ONLY SELF STUDY MATERIAL"

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5.7 AUXILIARY FEEDWATER (AFW) SYSTEM

Learning Objectives:

1. State the purposes of the Auxiliary Feedwater (AFW) System.

2. List all suction sources for the AFW pumps and under what conditions each is used.

3. List the five plant conditions that will result in an automatic start of the AFW system.

4. Explain how decay heat is removed following a plant trip and loss of offsite power.

5. Explain how a minimum volume of water in the condensate storage tank is reserved for the AFW system.

6. Explain how the availability of other decay heat removal methods limits the AFW system's contribution to core damage frequency.

5.7.1 Introduction

The purposes of the Auxiliary Feed Water (AFW) system are as follows:

1. To provide feedwater to the steam generators to maintain a heat sink for the following conditions.

   a. Loss of Main Feed Water (MFW),
   b. Unit trip and loss of offsite power, and
   c. Small-break Loss Of Coolant Accident (LOCA).

2. To provide a source of feedwater to the steam generators during plant startup and shutdown.

The AFW system supplies, in the event of a loss of the main feedwater, sufficient feedwater to the steam generators to remove primary system stored heat and residual core energy (decay heat). AFW must also be available under accident conditions, such as a small-break loss-of-coolant accident, so the plant can be brought to a safe shutdown condition.

The AFW system is designed to automatically start and supply sufficient feedwater to prevent the relief of primary coolant through the pressurizer safety valves. The AFW system has an adequate suction source and flow capacity to maintain the reactor at hot standby for a period of time and then cool the reactor coolant to a temperature at which the residual heat Removal (RHR) system may be placed in operation.

5.7.2 System Description

The AFW system, as shown in Figure 5.7-1, has two electric-motor-driven pumps and one turbine-driven pump. Each of the electric-driven pumps supplies two different steam generators; the turbine-driven pump supplies all four steam generators. All three pumps automatically deliver rated flow within one minute upon receipt of an automatic start signal.

The preferred source of water for all auxiliary feedwater pumps is the Condensate Storage Tank (CST), which is required by the plant’s Technical Specifications to contain a minimum amount of water available to the AFW system. An additional unlimited backup water supply, Essential Service Water (ESW), is supplied to the AFW system. A separate train of ESW feeds each electric-driven pump (e.g., Train A of ESW feeds the A AFW pump), while the turbine-driven pump can receive backup water from either train of ESW.

To protect the AFW pumps from a loss of suction, the ESW supply valves are automatically (or remote-manually) opened if the suction pressure is low on two-out-of-three pressure detectors, and the AFW pump is running.

Since the ESW system supplies poor quality water, it is not used except in emergencies when the normal condensate supply is unavailable.

The AFW system is designed to deliver 40 to 120°F water for pressures ranging from the RHR system operating pressure (equivalent to approximately 110 psig in the steam generators) to the highest setpoint of the steam generator safety valves (1234 psig).

The AFW system piping is designed for pressures up to approximately 1650 psig where necessary. Separate engineered safety features (ESF) quality electrical power subsystems and control air subsystems serve the AFW pumps and their associated valves.

In addition to using high quality components and materials, the AFW system provides complete redundancy in pump capacity and water supply for all cases for which the system is required. Under all credible accident conditions each steam generator, not affected by the accident, will be supplied with its required feedwater. Only two steam generators are required to be operable for any credible accident condition.

Redundant electrical power and air supplies assure reliable system initiation and operation. The electric-motor-driven pumps are powered from vital ac distribution sources, while the turbine-driven pump takes steam from either of two main steam lines, up stream of the main steam isolation valves (MSIVs).

5.7.3 Component Descriptions

5.7.3.1 Motor-Driven Auxiliary Feedwater Pumps

The motor-driven pumps are multistage, horizontal, centrifugal pumps, each of which supplies 440 gpm at a discharge pressure of about 1300 psig. The motor-driven pump design data are shown in Table 5.7-1. Power to the motor-driven AFW pumps is supplied from the 4.16-kVac Class IE vital distribution boards. Local switches permit local operation of the pumps. The switches in the control room have three positions: "Run," "Stop," and "Pull to Lock." The pull-to-lock (PTL) feature prevents the pumps from starting, even if an automatic start signal were present.

The following five conditions will automatically start both motor-driven AFW pumps:

1. Low-Low water level in any single steam generator,
2. Loss of one Main Feed Pump (MFP) if power is greater than 80 percent,
3. Loss of both MFPs at any power level,
4. Safety Injection Actuation Signal (SIAS), and
5. Loss Of Power (LOP) to the Class IE power distribution system.

5.7.3.2 Turbine-Driven Auxiliary Feedwater Pump

The turbine driven pump is a multistage, horizontal, centrifugal pump. It is capable of delivering 880 gpm at a discharge pressure of approximately 1200 psig. This pump's design data is shown in Table 5.7-1.

The steam-driven pump is driven by a horizontal, noncondensing turbine. The turbine is rated at 1100 hp and is designed to operate with a supply steam pressure varying from 1275 psig down to 100 psig. The steam to drive the turbine is supplied from the main steam system, with the piping penetrations located upstream of the Main Steam Isolation Valves (MSIVs). The steam supply comes from steam generators number 2 and 3. Each supply line has an air-operated main valve and an associated bypass valve. The bypass valves are used for warming the turbine and are operated from the main control board.

During the AFW pump turbine operation, steam is supplied to the unit through normally shut flow control valve FC-HV-312. The control of the turbine speed is accomplished by adjusting the governor valve (HV-313) from the main control board.

To remove moisture in the main steam supply steam traps have been provided where necessary. Drains have also been provided on the turbine casing, steam chest and exhaust piping. The exhaust from the AFW pump turbine is directed to the atmosphere.

The five automatic start signals for the turbine driven auxiliary feed pump are as follows:

1. Low-low steam generator level in 2 of 4 generators,
2. Loss of one MFP if power is greater than 80 percent,
3. Loss of both MFPs at any power level,

4. Safety Injection Actuation Signal (SIAS), and
5. Loss Of Power (LOP) to either Class IE vital distribution system.

5.7.3.3 Level Control Valves

The AFW system contains eight (8) level control valves. Four (4) valves are located on the auxiliary feed lines feeding the steam generators from the motor-driven AFW pumps. The remaining four (4) level control valves are on the auxiliary feed lines coming from the turbine-driven auxiliary feed pump. Each valve has a toggle switch which allows the operator to manually open or close the valve. Normally, the valves are fully closed and will automatically control steam generator level to a preselected setpoint upon an automatic actuation signal.

At some plants, these level control valves are provided with loop-break protection circuitry. This is accomplished by monitoring the pressure between the level control valve and its associated steam generator. If the pressure in this section of piping drops to a pre-selected setpoint (normally 100 psig), a signal is sent to close the level control valve. This protective feature is supplied so that, in the event of a steam or feedwater break, the auxiliary feedwater system will not continue to feed the faulted steam generator.

5.7.3.4 Water Supplies

The AFW system has redundant water supplies. The normal suction source is provided by gravity feed from the condensate storage tank, which is sized to meet the normal operating and accident needs. Each AFW pump takes its suction on a common header through a check valve and a normally open isolation valve. The suction pressure for the AFW pumps is normally indicated in the control room.

Availability of water from the CST for the AFW system is guaranteed by a standpipe in the supply line to the main condenser. Other means may be used at other facilities to ensure a minimum level in the CST. Other methods include a level control valve which closes when the quantity of water in the condensate storage tank drops to a preset value, or the supply line to the main condenser is tapped into the side of the condensate storage tank at a height that ensures a minimum level for the AFW system.

In the event that the CST is not seismically qualified, an emergency water supply must be provided as a backup. This backup supply must be seismically rated and must have some method for automatic initiation if needed.

There are three pressure switches located on the suction line for each AFW pump which are used to switch the suction from the CST to the safety-related ESW system (which is seismically qualified). To prevent an inadvertent injection of ESW into the steam generators, automatic opening of the ESW supply valves is initiated by a 2-out-of-3 logic on low AFW pump suction pressure coincident with an AFW pump running.

On the discharge of each motor-driven pump, there is a blind flange connection for the installation of a spool piece to tie the high pressure fire protection system into the

AFW system. The pressure in the steam generator must be below 120 psig for use of the high pressure fire protection system.

5.7.4 System Features and Interrelationships

The safety-related portions of the AFW system are designed for seismic events and meet the single failure criteria requirements, including the consideration that the rupture of a feedwater line could be the initiating event. This system will provide the required feed flow to two or more steam generators regardless of any single active or passive failure.

The valves associated with the turbine-driven pump are served by both electric and control air subsystems, with appropriate measures precluding any interaction between the two subsystems. The turbine-driven pump receives control power from a third dc electric channel that is distinct from the channels serving the electric pumps.

In the event of a loss of site power, 440 gpm of AFW delivered to two steam generators prevents relief of reactor coolant via the pressurizer safety valves, and ensures that the water levels in the steam generators remain above the required minimum for tube coverage. If the AFW system were not to respond for ten minutes, then 880 gpm would be required to meet the above requirements. The AFW system meets the single-failure assumptions of the Final Safety Analysis Report (FSAR).

Following a LOCA, primary-to-secondary heat transfer in the steam generators, with the AFW system providing the heat sink, may be necessary for decay heat removal. For a spectrum of small-break LOCAs, the cooling flow through the reactor (emergency core cooling injection and flow out of the break) is not sufficient by itself to avoid core damage.

Generally, AFW components are constructed of carbon steel. The condensate storage tanks are lined to prevent corrosion; while other components are protected by chemical additions to the water.

5.7.5 PRA Insights

The AFW system provides feedwater to the steam generators to allow continued heat removal from the primary system when the main feedwater system is not available. In this capacity, the AFW system serves as one means of early core heat removal following a transient or small-break LOCA.

Loss of the AFW system is a small contributor to core damage frequency as part of major accident sequences (1.4% at Zion and 2.6% at Sequoyah). One of the reasons for the relatively small contribution is the ability of the plant to initiate bleed-and-feed cooling using high pressure injection and the pressurizer Power-Operated Relief Valves (PORVs). At a unit such as Surry, where two PORVs are required to open to provide sufficient bleed and feed capability, the AFW system can be a larger contributor (14.8%).

When performing the PRA for the AFW system certain items are plant specific, such as human error. If the AFW system is normally configured so that one pump is locked out, failure to start that pump becomes critical. Failure to correctly realign the system after testing or maintenance is another. Common-mode failures are also plant specific. One such failure is an undetected flow diversion through a cross-connect line to the second unit on multiple unit sites (Surry risk achievement factor - 400). A second example of a common-mode failure is steam binding of the AFW pumps due to main feedwater leakage through system check valves (Surry risk achievement factor - 400).

PRAs for 13 PWRs were analyzed to identify risk-important accident sequences involving the loss of AFW and to identify and risk-prioritize the component failure modes involved. Below is a list of four accident categories explaining how AFW failure is a contributor to the analysis. Included at the end of the list are the risk-important component failure modes.

1. Loss of Power (LOP) System - A loss of offsite power is followed by the failure of the AFW system. Due to the loss of actuating power, the (PORVs) cannot be opened, preventing adequate bleed-and-feed cooling, resulting in core damage.

   A Station Black Out (SBO) fails all ac power except the vital Class IE ac busses from the dc invertors. All decay heat removal systems, except the turbine-driven AFW pump, also fail. AFW subsequently fails due to battery depletion or hardware failures, resulting in core damage.

   A dc bus fails, causing a trip and failure of the power conversion system. One AFW motor-driven pump is failed by the bus loss, and the turbine-driven pump fails due to loss of the turbine or valve control power. AFW is subsequently lost completely due to other failures. Bleed-and-feed cooling fails because PORV control is lost, resulting in core damage.

2. Transient-Caused Reactor or Turbine Trip - A transient-caused trip is followed by a loss of the power conversion system and the AFW system. Bleed-and-feed cooling fails either due to a failure of the operator to initiate it, or due to hardware failures, resulting in core damage.

3. Loss of Main Feedwater - A feedwater line break affects the common water source to the steam generators from both main feedwater and AFW. If the operators fail to provide feedwater from alternate sources and fail to initiate bleed-and-feed cooling core damage will result.

   A loss of main feedwater trips the plant, and the AFW system fails due to operator error and hardware failures. If he operators fail to initiate bleed-and-feed cooling, core damage will result.

4. Steam Generator Tube Rupture (SGTR) - A SGTR is followed by a failure of the AFW system. Coolant is lost from the primary until the refueling water storage tank is depleted. High pressure injection fails since recirculation cannot be

established from the empty containment recirculation sump, and core damage results.

Risk-Important Component Failure Modes

The generic component failure modes identified from the PRA analyses as important to AFW system failure are listed below in decreasing order of risk importance:

1. Turbine-driven pump failure to start or run,
2. Motor-driven pump failure to start or run,
3. Turbine- or motor-driven pump unavailable due to testing or maintenance, and
4. AFW system valve failures, such as failures of steam admission valves, trip and throttle valves, flow control valves, pump discharge valves, or pump suction valves, and valves in testing or maintenance.

Reductions in core damage frequency through improvements to the AFW system are negligible for the plants studied in NUREG-1150.

5.7.6 Summary

The AFW system supplies high pressure feedwater to the steam generators to maintain a water inventory for removal of heat energy from the RCS by secondary side steam release in the event of the inoperability of the main feedwater system or during startup and shutdown evolutions. The discharge pressure generated by the AFW pumps is sufficient to deliver feedwater into the steam generators at any pressure up to the safety valve setpoint pressure. The capacity of the AFW system is designed so that the four steam generators will not boil dry, nor will the primary side relieve fluid through the pressurizer relief valves following a loss of main feedwater flow in conjunction with a unit trip.

The AFW system consists of two subsystems. One subsystem utilizes a steam-turbine-driven pump, with the steam capable of being supplied from the No. 2 or No. 3 steam lines upstream of the MSIVs. This system supplies a total of 880 gpm to all four steam generators. The second subsystem utilizes two motor-driven pumps, each with a capacity of 440 gpm. The discharge piping is arranged so that each motor-driven pump supplies two steam generators.

The automatic start signals for the auxiliary feed pumps are as follows:

1. Motor- and turbine-driven pumps:

    a. Loss of both main feed pumps,
    b. Loss of one main feed pump if power is > 80%,
    c. Low-low level in two or more steam generators,
    d. Safety injection actuation signal, and
    e. Loss of power to the Class IE vital distribution system.

2. Motor-driven pumps only:

a. Low-low level in any single steam generator.

The preferred source of water for all AFW pumps is the CST. A Technical Specification minimum of 280,000 gallons is required for the AFW system. As an unlimited backup water supply, a separate ESW system suction is provided for each pump.

In addition, at some plants, the fire protection system may be connected with a spool piece to the auxiliary feed system downstream of each electric-driven pump. This feature allows raw water to be supplied directly to the steam generators. It would only be used if there were no other water source, or in the unlikely event that no auxiliary feedwater pumps were available.

Table 5.7-1 AFW System Design Data

Number of pumps per unit	3
Motor driven	2
Turbine driven	1
Design flow rate, gpm	
Motor-driven pumps, each	440
Turbine-driven pump	880
System design pressure, psig	1650
Design feedwater temperature, °F	40 - 120
Design discharge head, psig	
Motor-driven pumps	1300
Turbine-driven pump	1200

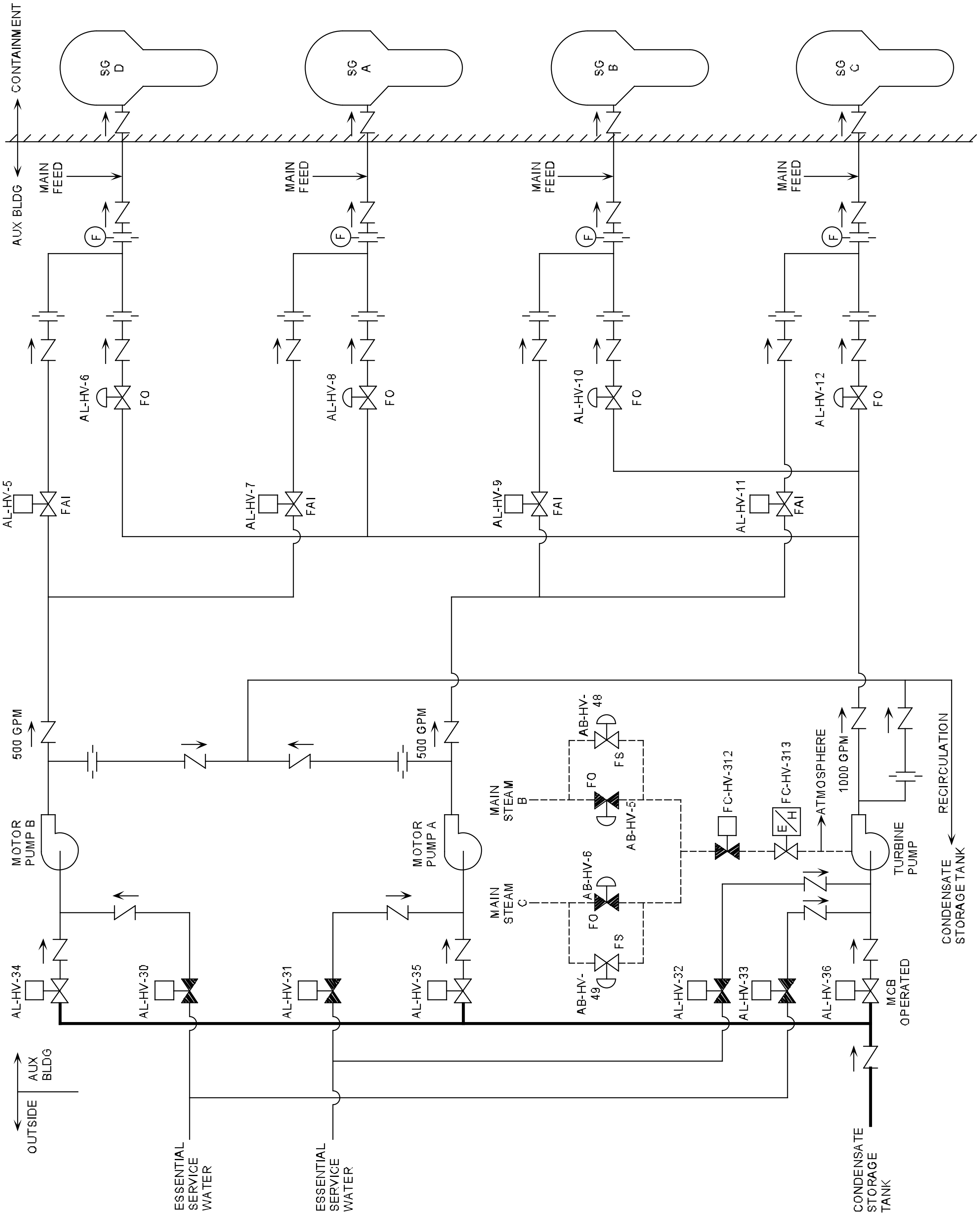

Figure 5.7-1 Auxiliary Feedwater System

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Section 6.0

Electrical Distribution System

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6.0 ELECTRICAL DISTRIBUTION SYSTEM

Learning Objectives:

1. State the purposes of the electrical distribution system.

2. Define the following:

    a. Offsite distribution
    b. Onsite distribution
    c. Class 1E distribution
    d. Standby power source
    e. Preferred power source

3. Explain how a reliable source of power is ensured to the following:

    a. The 4.16-kv and 480-vac safety related distribution buses
    b. The 125-vdc instrumentation and control buses
    c. The 120-vac instrumentation buses

4. Describe the response of the non-Class 1E electrical distribution system to a turbine-generator trip.

5. Describe the operation of the Class 1E electrical distribution system for all combinations of loss of offsite power and engineered safety features actuation signal.

6. List the automatic start signals for the emergency diesel generators.

7. Explain the effect of an automatic start signal on the diesel generator protection system.

8. Explain why a station blackout in conjunction with a reactor coolant pump seal failure is a high contributor to core damage frequency.

6.0.1 Introduction

The purposes of the electrical distribution system are to:

1. Provide a reliable source of electrical power to the engineered safety features equipment,
2. Provide a reliable source of control and instrumentation power,
3. Provide power to station auxiliary equipment, and
4. Direct the main generator's output to the utility's distribution system.

The designs of electrical distribution systems vary considerably between commercial nuclear power plants and can be significantly different in the nomenclature used to designate the system components, bus voltages, and the numbers and physical arrangements of components. All plants have the following generic features:

a. High voltage offsite distribution,
b. High voltage and medium voltage onsite distribution, and
c. Low voltage control and instrumentation distribution.

This chapter describes the electrical systems as they are modeled on the Westinghouse simulator at the Technical Training Center. The simulator is based on the Trojan plant design, but the electrical system is representative of a typical plant electrical distribution system.

6.0.2 Class 1E Distribution

Class 1E is the safety classification of the electrical equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing the significant release of radioactive material to the environment. All safety-related electrical equipment and systems are designated Class 1E.

6.0.3 Offsite (Preferred) Power Distribution

The offsite (preferred) power distribution system includes two or more power sources capable of operating independently of the onsite or standby power sources. It encompasses the grid, transmission lines (overhead or underground), transmission line control systems, switchyard battery systems, common station service transformers, interconnecting buswork, and circuit breakers provided to supply electric power to safety-related and other equipment.

The offsite (preferred) power distribution system is, as the name implies, the preferred source of power for Class 1E loads during accident conditions. The offsite (preferred) power distribution system may be considered as two or more connections, however made, to the utility grid for supplying power to the plant's Class 1E loads.

General design criterion 17 of 10CFR50, Appendix A states that electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

6.0.4 Onsite (Standby) Power Distribution

The onsite (standby) power distribution system includes those power sources, distribution systems, and vital supporting systems provided to supply power to safety-related equipment and capable of operating independently of the offsite power distribution system.

The onsite (standby) power distribution system is the Class 1E portion of a nuclear plant's auxiliary power system. It includes an ac distribution system, a dc power system, an uninterruptable ac power system and an emergency (diesel generator) power system. Its preferred source of ac power is the offsite power distribution system. If the preferred source is not available, ac power is provided by onsite diesel generators.

In accordance with general design criterion 17 of 10CFR50, Appendix A, the onsite electric power system is provided to permit the functioning of structures, systems, and components important to safety. The safety function for the onsite electric power system (assuming the offsite system is not functioning) is to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electric power supplies, including the batteries, and the onsite electric distribution system, are required to have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

6.0.5 PRA Insights

Because of the dependence on electrical power for most of the systems involved in the mitigation of an accident, failure of the electrical system is a major contributor to the core damage frequency. The contribution is attributed in part to scenarios involving station blackouts and losses of offsite power. In general, power problems contribute to about 62% of the total core damage frequency at Surry (38%-station blackout, 4% - loss of offsite power, and 20% - loss of various ac and dc busses), 3% at Zion (2% - station blackout and 1% - loss of offsite power), and 8% at Sequoyah (5% - station blackout and 3% - loss of a dc bus).

The major problem associated with a loss of power, especially a station blackout, is the probability of a reactor coolant pump seal failure, leading to a small-break loss of coolant accident (LOCA). This problem is magnified by the unavailability of the high-pressure injection system to inject cooling water due to the loss of power.

The other sequences involving the loss of power as an initiator also involve the failures of systems such as the auxiliary feedwater system, the failure of a pressurizer power-operated relief valve to shut, and the failure of the pressurizer relief valves to open to enable feed and bleed. Probable causes of the loss of power initiator include:

- Failure of the emergency diesel generators to start,
- Failure of the emergency diesel generators to run after starting,
- Failure to recover ac power,
- Unavailability of the diesel generators due to testing or maintenance, and
- A local fault of an inverter, which prevents the automatic actuation of the auxiliary feedwater pumps.

NUREG-1150 studies on importance measures have pointed out several areas which can be of major significance to the risk achievement and to risk reduction. For risk achievement, the time the seal-failure LOCA occurs after the loss of power (1-10 hours), the time required to deplete the batteries, and the assumptions for the recovery of offsite power are the major areas which tended to increase the probability of core damage.

For risk reduction, the probability of core damage can be significantly reduced if the probability of the loss of offsite power (a factor of 1.9 for Surry), the nonrecovery of ac power (for Surry, a factor of 1.5 if recovery is within 1 hour and a factor of 1.7 if recovery is within 2 hours), the nonrecovery of high pressure injection, or the seal-failure LOCA can be reduced (factor of 1.5 at Surry).

The contribution of human error to core damage frequency is plant specific. If the auxiliary feedwater system is normally configured so that one pump is locked out, failure to start that pump becomes critical. Failure to correctly realign the system after testing or maintenance is another.

In March of 1990, the Vogtle nuclear plant experienced a loss of all ac power for a short period of time as a result of an unusual power lineup, a loss of offsite power (due to a truck knocking over a tower into a transformer), and the subsequent failure to start of the diesel generators. One of the diesel generators was disassembled for maintenance, and the other did not start immediately. All ac power was lost for 36 minutes, before the emergency starting of a diesel generator. Offsite power was not restored for about two hours. During this time the primary temperature increased at a rate of 1.3°F/min. The plant had been shut down for a period of time, so the decay heat was not very significant.

However, had the loss of power occurred with a large decay heat load, the temperature increase would have been substantial. In this case, the existing plant conditions minimized the consequences of a loss of all ac power, and the time period that all ac power was lost was just over a half hour. Since the plant was already cooled down, the effect on the reactor coolant pump seals was negligible. Far worse consequences would have resulted if the plant had been at power and the same events had occurred.

6.0.6 Summary

The following sections of this chapter discuss the 230-kv electrical system (6.1), the 12.47-kv electrical system (6.2), the 4.16-kv electrical system (6.3), the 480-vac electrical system (6.4), the 120-vac electrical system (6.5), the 125-vdc electrical system (6.6), and the main generator (6.7). The introduction, definitions, design criteria, and PRA information of this section apply to the systems that are discussed in the remaining sections.

6.1 230-kv Electrical System

The 230-kv electrical system, shown in Figure 6-2, provides power produced by the main generator to the distribution grid. Additionally, as shown in Figure 6-1, the system supplies electrical power to plant engineered safety feature (ESF) equipment and auxiliary loads during operating and shutdown conditions.

6.1.1 Detailed Description

During normal plant operation, the main generator provides electrical power at 22 kv through an isolated phase bus and two parallel-connected main transformers to the 230-kv west and east buses through two power circuit breakers (PCBs).

The west bus supplies power to:

a. St. Mary's via a PCB,
b. Alston #1 via a PCB, and
c. startup transformer #1.

The east bus supplies power to:

a. Alston #2 via a PCB,
b. Rivergate via a PCB, and
c. startup transformer #2.

This offsite power system provides the following reliability and flexibility:

1. Any transmission line can be isolated under normal or fault conditions without affecting the power flow of the other lines.
2. Either 230-kv bus, with its associated circuit breakers and protective relaying, can be isolated without interruption of power to the other 230-kv bus.
3. Either startup transformer can be shut down under normal or fault conditions without interruption of power to the other transformer.
4. Any circuit switcher or circuit breaker can be opened and removed from service under normal conditions for routine maintenance, repair, or replacement with no loss of power to the offsite power system.
5. No failure of a single transmission line, a circuit breaker, a major bus, or the main generator will cause the loss of all offsite power to the onsite distribution system.

Four overhead transmission lines transmit the power from the Trojan switchyard to Rivergate, St. Mary’s, and the switchyard at Alston. The four transmission lines, the Trojan switchyard, and the two startup transformers constitute the offsite power supply. This 230-kv offsite power supply is divided into two independent sources.

The first source includes:

a. St. Mary’s - Trojan 230-kv transmission line,

b. Alston - Trojan #1 230-kv transmission line,
c. 230-kv bus #1 (west), and
d. Startup transformer #1.

The second source includes:

a. Rivergate - Trojan 230-kv transmission line,
b. Alston - Trojan #2 230-kv transmission line,
c. 230-kv bus #2 (east), and
d. Startup transformer #2.

Figure 6-2 illustrates the two-bus (east and west), four-line switchyard arrangement that provides maximum system flexibility and availability. There are two PCBs for the main generator and one circuit switcher for each of the two startup transformers.

During normal operation all line disconnect links/switches, PCBs, and circuit switchers are closed. In this arrangement, the 230-kv system is powered by the main generator. Power is then available to the grid via the 230-kv system. Power for plant auxiliaries is normally supplied through the unit auxiliary transformer. Load-side breakers from the normally energized startup transformers are open. However, if power from the unit auxiliary transformer is unavailable, these breakers will close and provide the preferred source of power from the grid to the plant.

During plant shutdowns, the generator bus disconnects and PCBs are open and all line PCBs and disconnects are closed. The startup transformer circuit switchers, disconnect switches, and load-side breakers are closed, and the plant receives power from the grid via the startup transformers. In this condition the unit auxiliary transformer load breakers are open.

6.1.2 Component Descriptions

6.1.2.1 Potential Transformers

Potential transformers provide metering and protection for electrical buses and supply relay polarization voltage, undervoltage relays, and signals for wattmeters and var meters in the control house and the control room. The potential transformers on the line side of each line PCB supply voltmeters, synchronizing circuits, and synchronization check relays in the control house and in the control room. Potential transformers on the generator side of each generator PCB supply voltmeter and synchronizing circuits and a synchronization check relay. Bus potential transformers, which also perform metering and relay functions, are provided on each of the 230-kv buses.

6.1.2.2 Current Transformers

Current transformers located on the bushings of each line PCB supply ammeters, var meters, and watt meters in the control house and in the control room. Bushing current transformers on the generator side of each generator PCB supply ammeters, var meters, and wattmeters in the control room. Both of these current transformers also supply a significant number of protective relays and telemetering devices.

6.1.2.3 Power Circuit Breakers

The power circuit breakers (PCB) provide a means of connecting the switchyard buses with and isolating them from the main generator, the east and west buses, and the loads supplied by the 230-kv electrical system. All PCBs are located in the switchyard. They are air-operated, oil-filled, high-speed breakers. Each generator PCB has a 3000-amp continuous rating and is normally operated from the control room. When selected for "backfeed" or "cycle," the generator PCBs can be operated from the switchyard control house. The line PCBs are physically the same as the generator PCBs except that each line PCB has a continuous rating of 2000 amp. They can be operated from the switchyard control house or the control room. The breakers are air operated to close and spring operated to open. Thus, energy is stored to open them even after a loss of power.

Control power for the protective relays and trip devices is provided by the switchyard 125-vdc bus. Protective relays are operated by current transformers and/or potential transformers. The compressor motor is powered by station service 240-vac. The line PCBs are interlocked to prevent their closure from the switchyard control house unless the applicable local synchronizing switch is turned to the “on” position. In order to close a line PCB from the control room, the appropriate line must be energized, the synchronizing check relay must be in synchronizing to prevent relying only on the synchronizing check relays, and the applicable synchronizing switch should be turned to the “on” position to monitor the switching operation. Generator PCBs are interlocked with synchronizing check relays, which prevent paralleling unsynchronized power supplies.

6.1.2.4 Circuit Switchers

Circuit switchers combine the features of disconnects and circuit breakers. Each has a continuous service rating of 230 kv and 1600 amp. Each operates by breaking the circuit within its interrupting section and isolating the circuit with conventional disconnect blades. Like a circuit breaker, the interrupting unit carries the continuous rated current when the disconnect blade is closed, and is controlled by a completely enclosed linkage. A control unit correlates the opening of the disconnect blades with the action of the interrupting unit, preventing reclosing of the blades until the interrupting unit contacts have closed. The interrupter unit is gas filled to help break the load arc. A motor is used to open the disconnect blades once the interrupter has opened. It also closes the circuit after the interrupter contacts close. A shunt trip is also provided to open contacts rapidly should a fault develop in a startup transformer.

6.1.2.5 Disconnect Switches

Disconnect switches are used to isolate PCBs and circuit switchers. This allows repairs to be accomplished without putting down entire buses and provides the visible air gap required for personnel working on high voltage components. They are manually operated from the local station only and are not designed to be opened under load. Therefore, a PCB or circuit switcher must be open prior to opening its load-side and supply-side disconnects. Ground disconnects are installed to ground the line PCBs when maintenance on the line is being performed. The ground disconnect and the line disconnect are mechanically interlocked to prevent their simultaneous closure.

6.1.2.6 Startup Transformers

The startup transformers provide the preferred path of power for the plant during a design-basis accident, and should be continuously available. Two emergency diesel generators provide backup power to the plant engineered safety feature (ESF) buses should the startup transformers become unavailable.

Each of the two startup transformers has a single primary winding which supplies an intermediate winding that, in turn, supplies the secondary (low voltage) side of the transformer. The low voltage side of each transformer is connected to the onsite 12.47-kv distribution system with fifteen underground cables. The cable runs from each transformer are physically separated from each other. The high voltage side of each startup transformer is connected to a separate 230-kv bus, which is fed from two offsite transmission lines.

Normal "live-bus" transfers between the preferred source (startup transformers) and the normal source (unit auxiliary transformer) during startup and shutdown are manually initiated, with momentary source paralleling during transfer so that all auxiliaries continue to operate. Following a turbine-generator trip, there is an automatic "fast" transfer to the startup transformers if this preferred source is available. The startup transformers are sized to provide all auxiliary station power during normal plant startups and all ESF loads during emergency operation.

Should it be necessary to remove a bus from service, the startup transformer on the affected side will be isolated and its high-side disconnect tagged open. The line side PCBs will be opened and then the generator breaker to that side will be opened. All three bus side disconnects will be tagged open.

During shutdown conditions, the main generator is secured, and its PCBs are open. The two startup transformers will be supplied with power from the grid. If the startup transformers are unavailable, alternate connections to the 230- kv system for the ESF buses are available through the main and unit auxiliary transformers. This is accomplished by removing the disconnect links in the isolated phase bus between the generator and the main transformers. Power is sent by backfeeders to the plant from the 230-kv buses via the generator breakers to the main transformer, and then through the unit auxiliary transformer to 12.47-kv buses H1 and H2.

6.1.3 Summary

The 230-kv electrical system provides power produced by the main generator to the distribution grid. The system also supplies electrical power to the plant ESF equipment and auxiliary loads during operating and shutdown conditions.

6.2 12.47-kv Electrical System

The 12.47-kv electrical system provides power to two buses for distribution to all plant electrical loads during normal operation. It also supplies large motors necessary for plant operation, such as those which drive the reactor coolant pumps (RCPs), circulating water pumps, and condensate pumps. Figure 6-3 shows the 12.47-kv distribution system.

6.2.1 Detailed Description

The 12.47-kv system is comprised of distribution buses designated H1 and H2. During normal plant operation, the 12.47-kv buses receive power from the main generator through the unit auxiliary transformer. Bus H1 is normally supplied by the "X" winding of the unit auxiliary transformer and bus H2 is supplied by the “Y” winding. If the main generator is not in operation or is tripped, the 12.47-kv buses are supplied from the offsite 230-kv system through the startup transformers. The supply for bus H1 is the #1 startup transformer, and the supply for bus H2 is the #2 startup transformer. Although the 12.47-kv system is not safety related, a two-bus arrangement is provided to achieve the required reliability for supplying plant house loads during normal operation.

6.2.2 Component Descriptions

6.2.2.1 Unit Auxiliary Transformer

The unit auxiliary transformer steps down the main generator output voltage from 22 kv to 12.47 kv for system distribution. The transformer has one primary (high voltage) winding energized from the main generator, and two secondary (low voltage) windings, designated "X" and "Y."

The transformer is connected in a “delta-wye” configuration. The “wye” secondary utilizes a resistance grounding which reduces the transient overvoltage when a faulted equipment's breaker trips or during arcing line-to-ground faults. The “delta” winding on the generator side protects the generator from a single-phase fault on the secondary side.

The transformer cooling is a forced-oil system consisting of oil circulation throughout the transformer and then to radiators which are forced-air cooled. The cooling system is similar to that of the main transformer, which is discussed in section 6.4.

The unit auxiliary transformer feeds buses H1 and H2. The feeder breakers are 2000-amp air circuit breakers. Opening and closing control power for bus H1 and H2 breakers is supplied from the 125-vdc system.

6.2.2.2 Startup Transformers

The two startup transformers receive power from the 230-kv buses. Startup transformer #1 is powered from the west bus and #2 is supplied by the east bus. During normal operation, the startup transformers are in standby (energized) and will be available to supply the 12.47-kv buses automatically in the event of a generator lockout. Loads are transferred to the startup transformers manually during a controlled plant shutdown. The transformers are cooled by forced-air and natural-circulation-oil radiators. They are located in the switchyard. The primary and secondary windings are wye connected, with the secondary wye connection being resistance grounded.

6.2.3 12.47-kv Load Controls

All 12.47-kv loads trip on:

a. ground,
b. overcurrent, or
c. undervoltage that exists for greater than two seconds (for the RCP breakers to trip, the unit auxiliary transformer normal feeder must also be open).

Each motor load, in addition to the ground and overcurrent relays previously mentioned, is also provided with a differential trip. In addition, the reactor coolant pumps utilize an additional overcurrent relay as a backup for trip purposes and an underfrequency trip at 57.7 hz.

6.2.4 12.47-kv Undervoltage, Underfrequency, and RCP Breaker Trips

The undervoltage and underfrequency reactor trip signals provide reactor core protection against departure from nucleate boiling in the event of loss of core flow due to loss of voltage or underfrequency to more than one reactor coolant pump.

6.2.4.1 Undervoltage Trips

The undervoltage condition is sensed on each bus by two undervoltage relays. If an undervoltage condition (less than 68.6% of normal voltage) is sensed, both relays de-energize, shutting their associated contacts wired in series to energize a time delay relay. If the undervoltage condition exists for greater than two seconds, the time delay relay will shut its associated contact, which energizes auxiliary relays to trip the breakers for all loads except the reactor coolant pumps. In addition, each reactor coolant pump's trip circuit has a contact which closes when the auxiliary relay energizes. This contact is in series with a "b" contact energized from the position of the unit auxiliary transformer 12.47-kv feeder breaker. When the feeder breaker is open, the "b" contact is shut. With both contacts shut, the reactor coolant pumps powered by that bus will trip.

If an undervoltage condition (less than 68.6% of normal voltage) is sensed on both buses (by at least one of the two sensors on each bus) for greater than 0.01 sec, a reactor trip signal is generated if reactor power is greater than 10% (P-7 permissive).

6.2.4.2 Underfrequency Trips

The underfrequency condition (less than 57.7 hz) is sensed on each bus by two underfrequency relays. If an underfrequency condition is sensed on both buses (by at least one of the two sensors on each bus) for greater than 1/6 sec, a trip signal is sent to each reactor coolant pump. Additionally, a reactor trip signal is generated if reactor power is greater than 10% (P-7).

6.2.4.3 RCP Breaker Position Trip

In addition to the underfrequency and undervoltage trips for the reactor coolant pumps, a reactor trip generated by reactor coolant pump breaker position is provided. This trip provides anticipatory reactor core protection against departure from nucleate boiling resulting from the opening of two or more pump breakers if reactor power is greater than 10% (P-7).

6.2.5 Instrumentation

Each 12.47-kv bus is equipped with two potential transformers which provide input to underfrequency, undervoltage, and synchronism check circuits. Also, various current transformers are used to supply the protection and alarm relays previously discussed as well as indicators.

Ammeters and voltmeters are located on the switchgear and in the control room. A voltmeter and ammeter selector switch is provided in the control room for individual phase currents and phase-to-phase voltages for each bus. Also located in the control room are wattmeters and watthour meters for each bus.

6.2.6 Summary

The 12.47-kv electrical system provides power to all plant electrical loads during normal operation, including reactor coolant pumps, circulating water pumps, and condensate pumps. It is not a safety-related system, but it is very reliable due to its two-bus arrangement.

6.3 4.16-kv Electrical System

The 4.16-kv electrical system, as shown in Figure 6-4, consists of four buses. Two of these buses, A1 and A2, are classified as ESF buses which supply power to equipment that is vital for the safe shutdown of the reactor plant. Either ESF bus can supply sufficient power to auxiliaries to safely shut down the reactor. Though not ESF buses, A5 and A6 supply power to equipment that is vital for plant operation but not needed to achieve a safe shutdown condition. The four-bus arrangement is utilized to provide electrical separation between the ESF and non-ESF systems and to provide electrical and physical separation between the two redundant ESF power supplies. The system is designed such that no single component failure will prevent operation of the required loads necessary to achieve a safe shutdown condition. Redundant power sources and automatic load transfers are provided to ensure continuous equipment operation under emergency conditions.

6.3.1 Detailed Description

The 4.16-kv system, shown on Figure 6-4, normally receives power from the 12.47-kv buses through the two unit substation transformers. Each transformer supplies two buses, one ESF bus and one non-ESF bus. Buses A1 and A5 receive power from bus H1, while buses A2 and A6 receive power from bus H2. During normal operation, the 12.47-kv buses receive power from the main generator via the unit auxiliary transformer. When the main generator is not available, the 12.47-kv buses are supplied from the 230-kv system through the two startup transformers. If there were a failure of the 12.47-kv power source or a fault in either of the transformers, each of the ESF buses would be supplied from an emergency diesel generator.

Each emergency diesel generator is capable of starting and providing power to its ESF bus within 10 seconds of receiving an auto-start signal. To prevent rapid loading of the emergency diesel generators after starting, all loads are initially tripped and later sequenced on by one of two sequencers, the shutdown sequencer (also referred to as the safe-shutdown or normal shutdown sequencer) or the DBA (design basis accident) sequencer, depending on the initiating circumstances. Buses A5 and A6 can be supplied by either unit substation transformer via a bus tie circuit breaker.

Only one 4.16-kv bus may be de-energized at a time. The reactor should be placed in a hot shutdown condition prior to de-energizing a non-ESF bus. Prior to de-energizing an ESF bus, the reactor should be placed in a cold shutdown condition. ESF buses A1 and A2 are never energized from the same power supply because a single fault could cause a loss of the entire 4.16-kv ESF electrical system.

6.3.2 Component Descriptions

6.3.2.1 Air Circuit Breakers

All the buses and loads discussed in this section are connected through air circuit breakers (ACBs). These breakers use 125-vdc control power. Each has a nominal continuous load rating of 1200 amp with an instantaneous interrupting capacity of 29,000 amp. Specific interlocks, permissives and trips are discussed in more detail throughout this system description.

The ACBs are provided with “operate,” “test,” and “withdrawn” positions. In the “operate” position, the ACB is fully inserted into the switchgear and is ready for operation. It is operated either from the control room or locally from the ACB cubicle. A remote-local switch is provided on the cubicle door to select the operating location. In the “test” position the ACB is partially withdrawn from the cubicle and the power stabs are disconnected from the bus. The ACB still receives control power through the longer control power stabs. In the “test” position the ACB functions in the same manner as described above except that it cannot pass load current since the power stab bases are disconnected from the bus. This mode is used for ACB testing. In the “withdrawn” position the ACB is fully withdrawn (racked out) from the cubicle. The power stabs and the control power stabs are disconnected and the ACB cannot be operated unless a local ACB bar is used for spring charging. Manual release pushbuttons or levers are used to close/open the ACB.

6.3.2.2 Unit Substation Transformers

Unit substation transformers (USTs) #1 and #2 are powered by 12.47-kv buses H1 and H2, respectively. The USTs reduce voltage from 12.47 kv to 4.16 kv for system distribution. The two USTs are located adjacent to the main transformers. Each is rated at 10 Mva at 55EC or 11.2 Mva at 65EC and is self-cooled, which means that no forced cooling mechanism is employed. Each UST is rated at sufficient capacity to supply all 4.16-kv loads on all buses and to start the largest load while all other loads are energized.

6.3.2.3 Emergency Diesel Generators

The emergency diesel generators (EDGs) automatically provide power at 4.16 kv to ESF buses A1 and A2 within 10 seconds following a loss of power to those buses. Each EDG is rated at 4.16 kv, 3 phase, 60 hz, and 900 rpm, with a continuous load rating of 4418 kw.

An EDG can be manually started remotely from the control room or locally. An EDG starts automatically with any of the following conditions:

1. A safety injection actuation signal (SIS) has been generated.
2. An undervoltage condition has been generated on the EDG's associated 4.16-kv ESF bus. An undervoltage signal is generated for two different voltage levels: (a) loss of voltage (bus voltage less than 2.56 kv for at least one second) and (b) degraded voltage (bus voltage less than 3.85 kv for greater than 55 seconds). Undervoltage protection is provided by undervoltage relays arranged in a one-of-two-taken-twice logic configuration. Additional responses to an undervoltage condition are discussed in section 6.3.2.5.
3. An undervoltage condition exists on the secondary side of the associated startup transformer, as sensed by each of two undervoltage relays. This signal automatically starts the EDG in anticipation of a possible undervoltage condition on its associated 4.16-kv ESF bus. (This automatic start is a specific feature of the plant modeled by the Westinghouse [Trojan] simulator and does not typically exist at operating Westinghouse plants.)

The generator output ACBs are operated either locally or in the control room. Tripping and closing power is from the 125-vdc electrical system. To manually close the EDG output ACB remotely, all of the following conditions must be satisfied:

- Either the ESF bus normal feeder must be tripped or the synchronizing switch must be on,

- The bus lockout relay must be reset, and
- The EDG lockout relays must be reset.

For local operation, the ESF bus normal feeder must be tripped since there is no synchronizing switch for this evolution at the local switchgear.

For the EDG ACB to close automatically all of the following conditions must be met:

The bus lockout relay must be reset,

1. The EDG lockout relays must be reset,
2. Either <u>NO</u> turbine trip occurred within the last second <u>or</u> the remote control switch is <u>NOT</u> "red flagged,"
3. The remote control switch must be in NORMAL,

4. The EDG must be at rated voltage (greater than 3.85 kv), rated speed (greater than 850 rpm), and an auto start signal must be present,
5. An undervoltage condition exists on the associated ESF bus, and
6. The normal supply ACB must be open.

These interlocks prevent the EDG from:

1. Being paralleled out of phase (because the bus is not energized),
2. Being placed on a bus which has an existing fault (because the lockout relays are reset), and
3. Being closed onto an energized bus (because the undervoltage relay has actuated).

If an EDG is supplying its associated ESF bus with the normal feeder closed while the main generator is operating and a turbine trip occurs, a relay will trip the EDG ACB to prevent overload. However, to allow automatic startup and load sequencing, this trip signal is automatically removed after one second.

When the EDG receives an automatic start signal, on an SI signal or an undervoltage condition, some of the protection trips are bypassed. This is to prevent an undesired EDG trip when the EDG is needed to supply 1E loads.

An EDG output ACB can be manually tripped by using the control switch or automatically on an engine stop or idle signal, a lockout relay, an EDG emergency trip, or a turbine trip if the normal bus feeder is closed.

6.3.2.4 ESF Switchgear A1 and A2

The ESF buses provide continuous power to various vital ac loads which are necessary for the safe shutdown of the reactor plant. Buses A1 and A2 supply all ESF loads in the plant. ESF channel A loads are powered from bus A1 and ESF Channel B loads are supplied from bus A2. Some non-ESF loads, for which it is desirable to have manually switched access to the EDGs, are also supplied from the ESF buses.

The loads supplied by ESF bus A1 are:

- Service water pump A,
- Containment spray pump A,
- Component cooling water pump A,
- Load center B01,
- Transfer switch for service water pump C,
- Transfer switch for component cooling water pump C,
- Centrifugal charging pump A,
- Safety injection pump A,
- Residual heat removal pump A,
- Load center B03, and
- Positive displacement charging pump (alternate).

The loads supplied by bus A2 are:

- Service water pump B,
- Containment spray pump B,
- Component cooling water pump B,
- Load center B02,
- Transfer switch for service water pump C,
- Transfer switch for component cooling water pump C,
- Centrifugal charging pump B,
- Safety injection pump B,
- Residual heat removal pump B,
- Load center B04, and
- Positive displacement charging pump (normal).

The transfer switches for the "C" service water and component cooling water pumps are used as a means of shifting the power supply of the spare pumps to either train A or train B as necessary to maintain separate power supplies to the operating pumps.

A similar feature is available for the positive displacement charging pump. Transfer switches allow the positive displacement pump to be powered from its normal supply, bus A2 or its alternate supply bus A1. A key interlock prevents both transfer switches from being closed simultaneously, thereby avoiding inadvertent paralleling of buses A1 and A2.

The ACBs to all the bus loads will trip on an overcurrent condition and on a ground condition. Each motor is also equipped with a thermal overload relay for alarm functions only. The non-motor-load ACBs do not have the thermal overload alarm. The inputs to the overload, overcurrent, and ground relays are from current transformers.

Overcurrent and ground relaying on the bus will actuate the lockout relays, which will trip all potential or actual power supplies to the bus (except as noted in the EDG ACB description). All loads are equipped with local and remote ammeters in the same locations as the control switches. Ammeter phase selector switches are also provided to enable monitoring of each individual phase since only one meter face is utilized for all three phases.

When an undervoltage condition exists on bus A1 or A2, all load ACBs on the associated bus except for feeders to load centers will trip. This is done to allow a startup of the associated EDG in an unloaded condition.

6.3.2.5 ESF Bus Feeder ACBs

The ESF bus incoming ACBs are physically identical to the other 4.16-kv ACBs in the system with the exception of trips and interlocks. Tripping and closing power is supplied by the 125-vdc electrical system, as previously discussed. The ACBs are operated either locally with the local control switches or from the control room.

To close an ESF bus feeder ACB, all of the following conditions must be satisfied:

1. The bus lockout relay must be reset,

2. The unit substation transformer lockout relay must be reset, and
3. For remote operation, the synchronizing switch must be on. For local operation, the EDG output ACB must be tripped.

An ESF bus feeder ACB trips automatically if any one of the following occurs:

1. A bus lockout signal is generated,
2. A unit substation transformer lockout signal is generated,
3. A bus undervoltage relay actuates and the associated EDG automatically starts and attains normal speed and voltage, or
4. A bus voltage greater than 2.56 kv but less than 3.85 kv is maintained for greater than 55 seconds

A bus lockout is caused by either a phase overcurrent or a ground overcurrent on the bus feeder. This condition energizes the lockout relay and trips the ESF bus feeder ACB and removes a permissive for closing the EDG output ACB.

An ESF bus undervoltage condition energizes the undervoltage auxiliary relays. The undervoltage auxiliary relay will cause the following:

- A trip of the bus feeder ACB,
- Trips of all 4.16-kv load ACBs except those which supply load centers,
- A start signal for the associated EDG,
- A permissive to close the EDG ACB,
- Delaying the DBA or shutdown sequencer from operating until voltage is restored to the bus,
- An auxiliary feed pump start permissive, and
- Energizing of the undervoltage relays which trip all containment air coolers and non-essential 480-v loads.

Two levels of undervoltage protection are provided. Primary protection is provided against an undervoltage of less than 2560 volts for greater than one second. The one second time delay is selected because motor damage could be sustained if operation were to continue at this low voltage for greater than 1.1 seconds.

Secondary protection, commonly referred to as degraded grid protection, is provided against an undervoltage of less than 3850 volts. “Degraded grid” is a term describing a low voltage condition affecting an ESF bus which results in a voltage on the bus that if sustained longer than 60 seconds could result in motor insulation damage due to the higher than normal currents. If a safety injection signal (SIS) is present, the normal feeder is closed, and voltage drops to less than 3850 volts for more than 4 seconds, the undervoltage relay is energized. If there is not an SIS present, then the undervoltage condition must continue an additional 51 seconds (a total of 55 seconds) before the undervoltage relay energizes.

6.3.2.6 DBA and Shutdown Sequencers

Upon initiation of a diesel generator start signal and closure of the EDG ACB, certain small loads supplied from the ESF motor control centers are energized immediately since they are not stripped on undervoltage. To allow the EDGs to start unloaded, the undervoltage scheme will strip all large motor loads (including the containment air coolers) and non-ESF loads off the 4.16-kv bus and connected 480-volt load centers. Depending on the plant conditions at the time of the initiating event, either of two sequencers will begin loading the bus either to safely shut down the plant or to meet emergency needs in response to a safety injection signal.

Each sequencer consists of Agastat timers which are simultaneously energized, and which perform their functions in a timed sequence. The DBA sequencer consists of 10 Agastat timers. The shutdown sequencer consists of four timers. The sequence and timing for energizing loads in accordance with the DBA sequencer are shown in the following table:

Sequence	Load	Time (sec)
1.	CCP and ESF switchgear room coolers	2.0
2.	Safety injection pump	6.5
3.*	Containment spray pump	11.0
4.	RHR pump	15.5
5.	CCW pump	20.0
6.	SW pump	24.5
7.	Containment air coolers	29.0
8.*	Containment spray pump	40.0

* The containment spray pump has two separate start signals. The first start signal at 11 seconds will start the pump only if there is also a simultaneous Hi-Hi containment pressure signal. If the pump starts, it will continue to run. If there is not a simultaneous Hi-Hi containment pressure signal with the 11-second start signal, the pump will not be enabled to start until the second start signal at 40 seconds. The 40-second start signal locks in, after which the pump will start whenever a Hi-Hi containment pressure signal is received. This feature prevents spurious starting of the containment spray pump during the interval from 11 to 40 seconds when other loads are being started on the diesel generator.

The sequence and timing for energizing loads in accordance with the shutdown sequencer are shown in the following table:

Sequence	Load	Time (sec)
1.	CCP and ESF switchgear room coolers	2.0
2.	CCW pump	6.5
3.	SW pump	11.0

(Note that auxiliary feedwater [AFW] pumps do not appear on the lists of equipment powered by ESF buses or as equipment energized by the DBA and shutdown sequencers. The AFW system modeled by the Westinghouse simulator [described in Chapter 5.8] has no motor-driven pumps which have to be loaded onto ESF buses, so the steam-driven and diesel-driven pumps of that system are started directly by an SIS or by an ESF bus undervoltage condition. For a plant with a more typical AFW system like that described in Chapter 5.7, each motor-driven pump would be supplied by a separate ESF bus, and each motor-driven pump would be energized [probably late in the sequence] by both sequencers associated with its train.)

In general, each Agastat timer serves a dual function: it starts the next load in the starting sequence and removes the start demand from the previous load in the starting sequence. As an example, with the DBA sequencer, the centrifugal charging pump is started at 2 seconds, and the start circuit is "opened" at 6.5 seconds when the safety injection pump is started. This feature prevents the simultaneous starting of more than one motor on the EDG, which could damage the generator or actuate protection. Exceptions to this scheme are the start signals for the containment air coolers and service water pumps. Another exception to this scheme is the "lock-in" signal for the containment spray pump. When the timer energizes it bypasses the first start circuit and does not have another relay to reopen its circuit. The DBA sequencer must be reset (SIS reset) to remove the start signal from the pump circuit.

Each DBA sequencer requires only the initiation of a safety injection signal and the availability of voltage on the associated 4.16-kv bus to energize and begin its sequence. Therefore, it does not absolutely require the start of the EDG or the initiation of the undervoltage scheme to function. The shutdown sequencer is designed to function after a loss of offsite power to enable a safe shutdown of the plant. In order for it to energize, the EDG must be at rated speed and voltage, the EDG ACB must be closed, and power must be restored to the 4.16-kv bus. If a safety injection signal occurs simultaneously with the loss of offsite power, the shutdown sequencer will <u>not</u> energize, but as soon as power is restored to the bus the DBA sequencer will start. It is important to note that even though the sequencers will start specific loads automatically, there is nothing to prevent the operator from starting any load at any time. Furthermore, once a load is sequenced on, there are no interlocks in the load circuitry to prevent opening its ACB, whether inadvertent, intentional, or automatic. (Only the last containment spray pump to start is equipped with a "lock-in" signal. This relay prevents tripping except when the switch is placed in the pull-to-lock position and is in the circuit until the SIS is reset.) However, it should be noted that the containment spray pumps will operate only when a Hi-Hi containment pressure of 30 psig is reached.

6.3.2.7 Non-ESF Switchgear A5 and A6

The non-ESF buses provide power to vital loads necessary for plant operation but not necessarily required for reactor shutdown in the event of a design basis accident. The A5 and A6 switchgear and the ACB controls and operations are identical to those of the ESF switchgear discussed earlier.

Bus A5 supplies the following loads:

- Heater drain pump A,
- Cooling tower makeup pump A,
- Pressurizer heater load center,
- Several load centers,
- Startup auxiliary feed pump, and
- A5/A6 bus tie ACB.

Bus A6 supplies the following loads:

- Heater drain pump B,
- Cooling tower makeup pump B,
- Pressurizer heater load center,
- Several load centers, and
- A motor control center.

All load ACBs on buses A5 and A6 have the same protection devices as those discussed in the ESF bus description. That is, the motor ACBs are equipped with ground and overcurrent trips and thermal overload alarm protection. All other loads have only the ground and overcurrent trips. On an undervoltage condition on a non-ESF bus, all load ACBs will trip, including the load center ACBs. Undervoltage protection for the non-ESF buses is more simplified than that for the ESF buses and consists of two undervoltage relays per bus. Upon sensing an undervoltage of 2.5 kv, the undervoltage relays energize a one-second timer (to allow for transient voltage dips); the timer energizes a relay which completely strips the bus. For this reason all loads on buses A5 and A6 will require restarting/re-energizing following a sustained loss of voltage for greater than one second.

6.3.2.8 Bus A5/A6 Tie ACB

Buses A5 and A6 can be connected through an ACB. Although rated at 1200 amp, this ACB is limited to 800 amp due to metering limitations. This rating may become limiting during abnormal electric lineups in which one unit substation transformer is supplying all buses.

To close the A5/A6 tie ACB, the following conditions must be satisfied:

1. The synchronizing switch must be on,
2. Bus A5 and A6 lockout relays must be reset, and
3. Either bus H1 or H2 must be energized.

It is important to note that regardless of whether the ACB is operated remotely or locally, the synchronizing switch must be on. For other ACBs discussed in previous sections of this chapter, this prerequisite applies only to remote closing of an ACB. With regard to the A5/A6 tie ACB, even if one of the buses is de-energize, the synchronizing switch must still be on.

The A5/A6 tie ACB trips automatically if any one of the following occurs:

- A bus lockout signal,
- Low voltage on both 12.47-kv buses, or
- Phase or ground overcurrent protection is actuated.

The A5 and A6 bus feeder ACBs are operated locally or from the control room. To close a non-ESF bus feeder ACB:

1. The synchronizing switch must be on for both local and remote operation,
2. The unit substation transformer lockout relay must be reset, and
3. The bus lockout relay must be reset.

A non-ESF bus feeder ACB trips automatically if either of the following occurs:

1. A bus lockout signal, or
2. A unit substation transformer lockout signal.

6.3.3 Summary

The 4.16-kv electrical system consists of four buses. Two of these buses are classified as ESF buses which supply power to equipment that is vital for the safe shutdown of the reactor plant. The two non-ESF buses, supply power to equipment that is vital for plant operation but not needed to achieve a safe shutdown condition.

6.4 480-vac Electrical System

The 480-vac electrical system is the most extensive electrical system in the plant, supplying a majority of plant electrical loads. This system supplies power to both ESF and non-ESF load groups. The ESF portion is required to enable a safe shutdown of the reactor in the event of a plant accident. The ESF load centers and motor control centers supply power to two physically and electrically independent load groups, each of which is capable of supplying the necessary auxiliaries to safely shut down the reactor. In addition to the normal and auxiliary power sources, the 4.16-kv ESF safety trains, and in turn the 480-vac ESF loads, are supplied with standby diesel generator power (to permit a safe reactor shutdown and long-term cooling capability for all design conditions.)

6.4.1 Detailed Description

The 480-vac electrical system is designed to provide sufficient power for both the ESF and non- ESF loads from load centers and motor control centers. The motor control centers supply small motor loads, station lighting, battery chargers, and 208/120-vac instrument buses through transformers.

The 480-vac electrical system is divided into three separate categories:

- The 480-vac ESF electrical system,
- The 480-vac non-ESF electrical system, and
- The 480-vac heating and ventilating electrical system.

The ESF portion of the system (Figure 6-5) is powered by the 4.16-kv electrical system buses A1 and A2 directly through four 4.16-kv/480-v step-down transformers. Each train of the 480-vac electrical system powers 100% redundant vital loads and is in turn powered from a separate 4.16-kv bus. In other words, safety systems have identical components powered from independent and electrically separated power supplies, such that in the unlikely event that one of the safety buses fails, the other bus is capable of completely performing its intended safety function.

The non-ESF portion of the 480-vac system is powered from 4.16-kv electrical system buses A5 and A6 directly through 10 4.16-kv/480-v step-down transformers. Both the heating and ventilating portion and the non-ESF portion of the system are divided to permit the maximum operability and reliability possible.

The 480-vac heating and ventilating electrical system is supplied from 12.47-kv electrical system buses H1 and H2 directly through eight 12.47-kv/480-v step-down transformers. This portion of the 480-vac system is divided such that approximately one half of the load groups are supplied from bus H1 and the remaining load groups are supplied from bus H2.

All of the 480-vac systems consist of the following major components:

1. Load centers (LCs) - the large distribution switchgear which contains metal-enclosed, drawout-type air circuit breakers. The LCs supply motor control centers and motors of greater than 100 hp.
2. Motor control centers (MCCs) - distribution points which supply the majority of in-plant loads. MCCs contain molded- case circuit breakers, motor controllers, and transformers.
3. Circuit breakers - interrupting devices utilized to connect and disconnect LCs, MCCs, and individual loads from the particular power supply.
4. Transformers - devices utilized to change an ac voltages and currents. A transformer can be either a step-up (voltage increase) or step-down (voltage decrease) transformer. The current varies inversely with voltage. The current is also dependent on the load on the transformer.

6.4.2 Component Descriptions

6.4.2.1 Transformers

The majority of transformers utilized throughout the 480-vac systems are of the indoor, dry, air-cooled type. Three transformers installed outdoors are sealed and filled with octafluorocyclobutane (C_4F_8), an inert gas. The heating and ventilating electrical system transformers are rated for 12.47 kv and the ESF and non-ESF electrical system transformers are rated for 4.16 kv. Most of the secondaries of the transformers are connected in a grounded "Y" configuration yielding an output of 480 vac. The delta-wye configuration used on most transformers enhances fault isolation. This configuration acts as a filter such that instabilities on the high voltage side of a transformer are not transferred to the low voltage side of that transformer. The transformers which power the pressurizer heaters are connected in delta-delta configurations to enable single-phase 480-vac power to be taken from the transformer secondaries, which is required to operate the heaters. All transformers utilized in the 480-vac system are rated from 500 kva to 1000 kva.

6.4.2.2 Circuit Breakers

Two types of circuit breakers are utilized throughout the 480-vac distribution system, air circuit breakers and molded-case breakers. Air circuit breakers are large metal-enclosed, drawout-type circuit breakers located in the load centers. Smaller molded-case breakers are utilized as the 480-vac MCC load feeders. These breakers have a lower current rating than that of the air circuit breakers. They are not provided with remote operating capability since they normally do not provide control functions for their associated load.

6.4.3 Summary

The 480-vac electrical system supplies a majority of plant electrical loads. This system supplies power to both ESF and non-ESF load groups. The ESF portion is required to enable a safe shutdown of the reactor in the event of a plant accident.

6.5 120-vac Electrical System

The 120-vac electrical system is designed to provide reliable power for control and instrumentation. The 120-vac electrical system is composed of the following subsystems:

- The preferred system, and
- The nonpreferred system.

The preferred system is safety related. It provides control and instrumentation power to equipment that is required for the safe shutdown of the reactor.

The nonpreferred system, which is also called the 208/120-v instrument system, is not safety related. It provides power to equipment that is not required for the safe shutdown of the reactor.

6.5.1 Preferred System

The preferred system is composed of two physically separate, electrically independent, redundant trains. Each train consists of two preferred instrument buses and two inverters (Figure 6-6).

Each train is made up of two channels, which are color coded because of their safety functions. Train A consists of channels I (red) and III (blue), and train B consists of channels II (white) and IV (yellow).

The purpose of the preferred system is to supply reliable, continuous Class 1E electrical power to the engineered safety feature (ESF) equipment, the four reactor protection system (RPS) channels (I, II, III, and IV), and essential plant instrumentation and control equipment required for plant startup, operation, and shutdown. Note that the system provides this power under all conditions, including the complete loss of offsite and onsite power.

The preferred system satisfies the following design criteria:

- Seismic qualification,
- Quality assurance,
- Redundancy/diversity,
- Environmental qualification,
- Fire protection, and
- Environmental protection.

The seismic criteria are satisfied because the system is designed to withstand the effects of earthquakes without the loss of the ability to perform its safety functions. Since the preferred system is designed to remain functional in the event of a safe shutdown earthquake, it is designated safety related and Seismic Category I (SCI).

The quality assurance criteria are satisfied because the system is designed, fabricated, created, and tested to quality standards commensurate with the importance of the safety functions to be performed.

The redundancy/diversity criteria are satisfied because the system has sufficient independence, redundancy, and testability to perform its safety function assuming a single failure. The preferred system satisfies the following specific redundancy/diversity requirements:

1. The system is an uninterruptable power system with diverse onsite power supplies as input sources. The input sources are of the same ESF train (A or B) as the inverters they supply.
2. The system has physically separate and independent trains to support the two trains of ESF loads (A and B) and the four RPS channels (I, II, III, and IV).
3. Each train is redundant with no cross connection between trains so that a failure in one train does not affect the other.
4. Each train supplies electrical power at a sufficient capacity for plant startup, operation, or shutdown with a total loss of main ac power, and assuming the worst-case accident loading.

The environmental qualification criteria are satisfied because the system is designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss of coolant accidents.

The fire protection criteria are satisfied because the system is designed and located to minimize the probability and effects of fires and explosions.

The environmental protection criteria are satisfied because the system is designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without the loss of the ability to perform its safety functions, and because the system is appropriately protected against dynamic effects, including missiles, pipe whips, and discharging fluids.

Figure 6-7 shows that each inverter has two power supplies, each of which is ultimately powered from a 4.16-kv ESF bus. The normal power supply is an underground 125-vdc bus. The alternate power supply is a 480-vac motor control center. If the normal power supply should fail, the inverter will automatically shift to its alternate power supply to prevent an interruption of power to the associated preferred instrument bus.

Each preferred instrument bus also has two power supplies, but only one of these is ultimately powered from an ESF bus. An inverter is the normal (Class 1E) power supply for each preferred instrument bus. A nonpreferred instrument bus is the alternate (non-Class 1E) power supply for each preferred instrument bus. Figure 6-7 shows that the alternate power supplies completely bypass the inverters and their two sources of Class 1E power. Note that the only time a preferred instrument bus is powered from its alternate power supply is when its normal power supply must be removed from service for maintenance or repair.

Unlike the power supplies for the inverters, the power supplies for the preferred instrument buses are not equipped with an automatic transfer feature; therefore, when an inverter fails or needs maintenance, the associated preferred instrument bus power supply must be manually transferred to its alternate source.

Consider a preferred instrument bus. Normally, an inverter supplies power to the bus. When the inverter is not available, the bus can be powered from a nonpreferred bus. The main feeder breakers to the preferred bus are mechanically interlocked such that if one is closed, the other opens. Since they are "break-before-make" connections, both breakers cannot be closed simultaneously; however, both breakers can be opened simultaneously to de-energize the bus. This interlock prevents the Class 1E and the non-Class 1E power supplies from being electrically paralleled.

The major loads on train A of the preferred electrical system include ESF train A equipment and RPS channels I and III. The major loads on train B of the system include ESF train B equipment and RPS channels II and IV. Since the ESF loads and circuits are divided into two completely redundant groups which are electrically independent and physically separated, only one preferred instrument train is needed to achieve and maintain a safe shutdown condition.

6.5.1.1 Inverters

Although the component shown in Figure 6-7 is commonly referred to as an "inverter," it is not a true inverter. Instead, it is an uninterruptable power supply (UPS) because it provides the preferred instrument buses with uninterruptable power from two Class 1E sources. However, since these components are frequently called "inverters," that is what they will be called in this system description.

The true inverters are the components within the UPSs that actually convert 125-vdc power into 120-vac power. These components will be called "static inverters" in order to distinguish them from the UPSs, or "inverters."

Figure 6-7 shows the four basic components installed in each inverter cabinet. These components are:

- A dc-to-ac solid-state static inverter,
- A solid-state static switch,
- A 480/120 v transformer, and
- A manual bypass switch.

The function of the static inverter is to convert the 125-vdc input into a single-phase, 120-vac, 60-hz output. The static inverter provides the normal source of preferred instrument power. The function of the static switch is to automatically transfer the selected source of preferred instrument power from the static inverter to the transformer if the static inverter fails. The function of the transformer is to step down a single phase of the 480-vac input to a 120-vac, 60-hz output. The transformer provides the alternate source of preferred instrument power. The function of the manual bypass switch is to allow the static inverter and static switch to be manually bypassed for maintenance or repairs.

During normal operation of the preferred system, each static inverter converts the 125-vdc input power to a 120-vac output power, which is fed through the static switch and the manual bypass switch to the associated preferred instrument bus.

If the alternate power source is energized, the static switch of an inverter will automatically transfer to the alternate power source when any of the following static inverter faults is sensed:

- Low input voltage,
- Low output voltage,
- High output voltage,
- High output current, or
- Low control logic voltage.

(Note: The static switch is not "normal seeking"; therefore, if the static switch automatically transfers the load to the alternate source and the normal source is later restored, it will not automatically transfer the load back to the normal source. This will have to be done manually.)

6.5.2 Nonpreferred System

The nonpreferred system consists of four buses which are powered from the 480-vac system through three bus transformers as shown in Figure 6-6. The nonpreferred system supplies reliable power to various indication and control circuits that are necessary for the proper operation of the plant but are not required to be operable in order to achieve a safe reactor shutdown.

The nonpreferred buses are powered from 480-vac ESF motor control centers (MCCs). The supply breakers from the MCCs are mechanically interlocked via input bus transfer switches to prevent any pair of supply breakers from being closed at the same time. This feature ensures that the ESF MCCs are not electrically paralleled through the nonpreferred instrument buses. Power from the MCCs is applied to regulating transformers, each of which provides three single-phase outputs of 120-vac power for system distribution.

Most of the loads on the nonpreferred instrument buses are indicating and control panels and various control valves. As shown in Figure 6-6, bus Y01 can supply the train A preferred instrument buses, although that is not the normal lineup. Similarly, bus Y02 can supply the train B preferred instrument buses. In addition, buses Y01 and Y02 power the digital rod position indication cabinet through a transfer switch which ensures that the cabinet is powered from only one source at a time (normally Y01).

6.5.3 Summary

The 120-vac electrical system provides reliable power for control and instrumentation. The 120-vac electrical system is composed of the preferred system and the nonpreferred system. The preferred system is safety related and provides control and instrumentation power to equipment that is required for the safe shutdown of the reactor. The nonpreferred system is not safety related and provides power to equipment that is not required for the safe shutdown of the reactor.

6.6 125-vdc Electrical System

The purpose of the 125-vdc electrical system is to supply reliable, continuous Class 1E electrical power to engineered safety feature (ESF) equipment and non-safety-related equipment required for startup, normal operation, and safe shutdown of the plant. The 125-vdc system provides this power for a specified time under all plant conditions, including the complete loss of offsite and onsite ac power sources.

6.6.1 System Description

The 125-vdc electrical system is composed of two physically separate, electrically independent, redundant trains. Figure 6-8 shows the arrangements of both trains. Each train contains a large lead-acid battery. The batteries are continuously connected to the dc distribution system and are maintained in a fully charged condition by their respective battery chargers during normal plant operations. The batteries have a passive role in the system during normal operations. When an abnormal condition results in a failure of the battery charger to power all dc loads, the associated battery is called upon to provide the necessary power, thereby ensuring continuity of operation. The batteries may only be needed during the short period required for starting the emergency diesel generators (EDGs), or they may be called upon to supply power for an extended period of time in the event of a loss of all ac power. In either case, it is absolutely essential that the batteries function properly if the plant safety systems are to operate as required.

Each train provides power for a redundant ESF load group and is arranged so that the battery or any one charger can independently supply the buses in that train. Normally, one battery charger in each train rectifies 480-vac power to 125-vdc power to supply the system loads and to maintain the battery in a fully charged condition. The battery in each train will supply the system loads if the in-service battery charger fails or if a complete loss of offsite and onsite ac power occurs.

The 125-vdc system satisfies the following design criteria:

- Seismic qualification,
- Quality assurance,
- Redundancy/diversity,
- Environmental qualification,
- Fire protection, and
- Environmental protection.

The seismic qualification criteria are satisfied because the system is designed to withstand the effects of earthquakes without the loss of the ability to perform its safety functions. Since the 125-vdc system is designed to remain functional in the event of a safe shutdown earthquake, it is designated safety related and Seismic Category I.

The quality assurance criteria are satisfied because the system is designed, fabricated, created, and tested to quality standards commensurate with the importance of the safety functions to be performed.

The redundancy/diversity criteria are satisfied because the system has sufficient independence, redundancy, and testability to perform its safety functions assuming a single failure. The 125-vdc system satisfies the following specific redundancy/diversity requirements:

1. The system is an ungrounded dc system for safety and greater reliability.
2. The system has physically separate and independent trains to support the two trains of ESF loads (A and B).
3. Each train is redundant, with no cross-connections, so that the failure of one train does not affect the other.
4. Each train supplies dc electrical power at a sufficient capacity for normal plant startup, operation, or shutdown and during a total loss of ac power if there is a worst-case accident loading.

The environmental qualification criteria are satisfied because the system is designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss of coolant accidents.

The fire protection criteria are satisfied because the system is designed and located to minimize the probability and effects of fires and explosions. Fire detection and suppression systems minimize the adverse effects of fire.

The environmental protection criteria are satisfied because the system is designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without the loss of the ability to perform its safety functions, and because the system is appropriately protected against dynamic effects, including missiles, pipe whips, and discharging fluids.

Figure 6-8 shows that each battery charger is powered from a different 480-vac ESF Motor Control Center (MCC). Normally, each train is aligned such that the dc buses are cross-connected through the battery breakers with the bus tie breaker open. This arrangement improves reliability during fault conditions because the bus tie breaker is a non-tripping breaker. Since the battery chargers are not designed with load-sharing capabilities, only one battery charger is in operation to supply the bus loads and maintain the battery in a fully charged condition. Figure 6-8 shows that the major loads on each train include two inverters, two dc distribution panels, and emergency dc lighting (which is usually selected to train B).

The dc distribution panels supply power to the following types of loads: annunciators, indicating lights, solenoid valves, control relays, small dc motors, switchgear (close and tripping power for all 12.47-kv, 4.16-kv, and some 480- v breakers), reactor trip and trip bypass breakers (close, trip, and indication power), and the EDGs (field flash, air start solenoid, control circuit, and fuel pump power).

6.6.2 Component Descriptions

6.6.2.1 Battery Chargers

The battery chargers are the normal power supplies for the dc buses. The basic components installed in each battery charger cabinet are:

- An input power breaker,
- A 480/120-v transformer,
- A solid-state rectifier,
- An output power breaker, and
- A charger failure relay.

The function of the input power breaker is to supply the transformer with power from the 480-vac ESF MCC. The function of the transformer is to step down the 480-vac input from the MCC to a 120-vac output. The transformer also provides physical separation between the 480-vac system and the 125-vdc system. The function of the solid-state rectifier is to convert the 120-vac output from the transformer into a smooth, nominal 125-vdc output. The function of the output power breaker is to supply the output from the rectifier to the 125-vdc ESF bus. The function of the charger failure relay is to detect a loss of charger output due to a failure in the charger's ac power input or dc power output. The charger failure relays supply a common trouble alarm for each train. The alarm associated with the charger failure relays is delayed approximately 45 seconds by the alarm circuitry in order to prevent normal fluctuations in the charger output from causing a false alarm.

The battery charger is provided with a fail-safe filtering circuit across the output to limit any transient change in dc voltage to $\pm$ 2% of the rated voltage in the event that the battery is disconnected from the charger. The charger is designed to prevent the battery from discharging back into any internal charger load in the event of an ac power supply failure or a charger failure.

The maximum post-accident steady-state load with ac power available is only 171 amp per charger (assuming only one charger per train is in service). Since each charger is rated for 200 amp, a single charger per train would be capable of carrying the required post-accident loads while recharging the battery in that train.

6.6.2.2 Batteries

The batteries serve as backup dc power supplies for the 125-vdc buses. If the operating battery charger in a train should fail, the associated battery will automatically supply power to the dc buses until the standby battery charger can be placed in service. In the event of a loss of a station blackout, the batteries will automatically supply power to the dc buses until ac power is restored (e.g., by automatic startup of the EDGs) or for a specified time interval which depends on the loads being supplied.

The proper battery size (i.e., battery capacity) for the plant is determined by the amount of starting and running current each load draws and the length of time each load needs to be supplied from the batteries during an accident. Note that emergency lighting is selected to train B. Also, note that the train A battery is required to be operable for two hours, but the train B battery is required to be operable for only 30 minutes. The battery duty cycles, or accident load profiles, are created from the list of design loads by plotting the total current drawn by those loads versus time.

Each battery is located in a separate room. The battery room exhaust system continuously operates to ventilate the battery rooms to reduce any hydrogen accumulation (especially during charging operations), and exhausts it to the atmosphere. A loss of ventilation will not result in hazardous hydrogen levels until approximately 15 days later. In addition, the loss of ventilation to either battery room is annunciated in the control room. Each room has a space heater to maintain the air temperature between 70EF and 80EF. A low air temperature in either battery room is also annunciated in the control room. The combined effects of ventilation and the battery room space heaters ensure that the maximum temperature spread for all connected cells does not exceed 5EF. Operation with high temperature gradients between cells contributes to nonuniform charging and premature aging of cells.

Each battery consists of 60 cells which are series connected to achieve a nominal terminal voltage of 125 v. Each lead-acid battery cell consists of a group of positive and negative electrodes, or plates, connected together and encased in a vented, transparent container.

6.6.3 Summary

The 125-vdc electrical system supplies reliable, continuous Class 1E electrical power to ESF equipment and non-ESF equipment required for startup, normal operation, and safe shutdown of the plant. The 125-vdc system provides this power for a specified time under all plant conditions, including the complete loss of offsite and onsite ac power sources.

6.7 Main Generator

The main generator produces electrical power and transmits that power to the offsite distribution system. It also supplies power for normal operation of the nuclear generating unit through the unit auxiliary transformer.

Power is taken from the main generator through a high voltage bushing assembly and transmitted through the isolated phase bus to the main transformer. The voltage is stepped up from 22 kv to 230 kv by the main transformer for delivery to the high voltage overhead transmission system. Figure 6-9 provides a basic illustration of the system.

6.7.1 Detailed Description

The main generator, located in the turbine building, is driven at 1800 rpm by the main turbine and converts the mechanical energy of the turbine into 3-phase, 22-kv, 60-hz electrical power at a 1,280,000-kva rating. The unit is a four-pole, wye-connected machine with a rated power factor of .95. Its construction consists of the casing, the stator core, the rotor, the inner and outer end shields, and bearings.

6.7.1.1 Generator Construction

The generator casing and end shields are of a welded, gas-tight construction. The gas-tight construction prevents the escape of the hydrogen gas used as the cooling medium. The casing houses and supports the stationary armature winding, the rotor, and the hydrogen gas coolers. Because the outer end shields are designed to support the weight of the rotor and prevent the escape of the hydrogen cooling gas, they contain the rotor bearings and the hydrogen shaft seals. The bearings are horizontally split, tin-base, babbitt-lined journal bearings. The hydrogen seals are located inboard of the bearings to allow bearing maintenance without gas evacuation of the generator. The bearing ring at the collector end is insulated from the end shield to prevent stray shaft electrical currents from circulating through the bearings. The bearings are forced-oil lubricated by the turbine-generator lube oil system. The inner end shields are located between the armature winding and outer end shields and serve to separate the cooling fan suction and discharge. Fan nozzles, attached to the inner end shields, provide optimum gas flow for the cooling fans.

6.7.1.2 Stator Core

The stator core is made up of segmented, insulated, silicon sheet steel with radial slots for installation of the stator bars. The core must be made of a high permeability steel so that it can easily pass the lines of flux. This feature reduces the amount of field current necessary to achieve the high terminal voltage. The reason several thin insulated sheets are used rather than a single section is to minimize circulating eddy currents within the core. Excessive eddy currents could lead to core overheating. After assembly, the core is varnished and baked for corrosion resistance and further insulation. The core is contained within the stator frame, which is made up of the casing and end shields.

6.7.1.3 Stator Winding

The armature winding is comprised of insulated bars of hollow copper strands joined at the ends to form coils and connected in the proper phase belts by connection rings. The copper strands are arranged in the form of a rectangular bar such that each strand shares an equal load current. This method of winding is accomplished by spiraling each strand along the entire bar length such that each strand occupies every radial position at some point in the bar. In addition to ensuring equal load current, this arrangement also minimizes current losses within the bar. Each bar is individually insulated with mica tape.

The individual hollow strands are joined at each end of the bar by a clip assembly forming a manifold. De-ionized water, used for cooling purposes, is supplied to one end of the winding by a flexible Teflon hose. The cooling outlet header is located on the opposite end of the winding. To prevent flux leakage from the end of the stator core to the retaining rings on the field, a copper flux shield is installed over the steel clamping flange at each end of the stator core. This tends to reduce losses in the end turns of the stator windings.

6.7.1.4 Rotor

The rotor is machined from a single steel forging. A center axial hole is drilled the length of the rotor to carry the leads from the collector rings to the field windings. Slots are machined radially in the rotor to contain the field coils. The field windings consist of rectangular bars formed into coils and held in place by textolite wedges. Several turns in one pair of slots around one pole form a coil, and several coils assembled around each pole (located 90E apart) form the field winding. The end turns of the winding are held in place on the rotor by retaining rings which are attached to centering rings on the rotor shaft. The turns of the windings have a series of holes for cooling purposes and are individually insulated. All turns are series wired and attached to the connection bars in the center bore hole of the shaft. These connections are made by terminal studs. Current is supplied to the field windings through self-lubricated graphite brushes that ride on collector rings installed on the end of the rotor shaft. Current then travels through additional terminal studs to the connection bars located in the shaft centerline. Each field-side and collector-side terminal stud is gasketed to prevent gas leakage.

6.7.2 Generator Cooling

All generator components, with the exception of the stator windings, are cooled by hydrogen gas. Hydrogen is chosen as the coolant because it is non-corrosive and has a high electrical resistance and a relatively high thermal conductively. It is also a low density gas, reducing windage and ventilating losses. The gas is circulated at 90,000 cfm by two fans, one mounted on each end of the generator and driven by the rotor. The gas is forced through the radial ducts in the core, removing the heat generated in the electrical production process, and is then circulated through four gas coolers and back to the suction sides of the fans. The rated hydrogen pressure is 75 psig; the minimum allowable pressure is 30 psig. The generator contains 5180 cubic feet of hydrogen at 98% purity.

High and low pressure areas are established within the frame by plates in the frame and back of the core and by the outside wrapper plate. Hydrogen is circulated through these areas by tubes and ducts. The four gas coolers are vertically mounted in the frame, one on each corner.

Any one cooler may be serviced with the generator at load. The coolers are supplied with water from the turbine building cooling water system.

Stator cooling is accomplished by deionized water from the stator cooling water system. The water is supplied to the clip assembly of each individual hollow strand and then into an annular header connected to the stator cooling water system.

6.7.3 Component Descriptions

6.7.3.1 Excitation System

The alternator-exciter produces the output current used by the main generator's field. It is a direct-coupled, four-pole, ac synchronous generator driven by the main generator rotor. Located on the end of the main generator, it has a construction similar to that of the main generator except that it is air cooled and self excited during operation. Two fans, mounted on either end of the alternator-exciter shaft, circulate filtered air throughout the exciter. Circulated air is cooled by heat exchangers mounted on top of the exciter housing. The heat exchangers are cooled by the turbine building cooling water system. The alternating current from the smaller ac generator (exciter) is rectified by a group of power rectifiers to furnish direct current for the main generator field.

As shown in Figure 6-9, generator excitation is controlled by varying the field current to the exciter. The exciter field excitation is controlled by a static voltage regulator. The regulator is a thyristor type containing silicon-controlled rectifiers (SCRs) in the output circuit that drives the exciter field. The regulator includes both automatic and manual control functions to regulate the generator terminal voltage or the generator field voltage, respectively.

The SCR control signal comes from the AC regulator or DC regulator as selected by the transfer panel. With the exciter operating in manual control, the DC regulator holds generator field voltage constant. With the exciter operating in automatic control, the AC voltage regulator holds generator terminal voltage constant. A transfer voltmeter is used for matching signals to provide for a smooth transfer between the two regulators.

6.7.3.2 DC Voltage Regulator

In DC voltage operation, the generator field voltage is sensed to control and keep the exciter output constant. The DC regulator consists of three basic elements. The front end senses exciter output voltage and compares it with a reference voltage to produce an error signal. The error signal is increased by the amplifier stage for the SCR bridge firing circuit. The controlling set point for the regulator is adjusted in the control room. The inputs to the DC regulator include a feedback signal from the exciter voltage and a current input to act as an auxiliary power source during transient conditions when the exciter voltage may be low.

6.7.3.3 AC Voltage Regulator

Alternator-exciter field excitation is controlled in the same way in both AC and DC operation. The AC regulator senses generator output terminal voltage to keep it constant under varying load conditions. The basic control system scheme is the one used in DC operation, with some major signal differences. The error signal produced by the front end is essentially the same, except that the AC regulator's range is more limited and the terminal voltage signal is compensated. A reactive current compensator (droop circuit) causes a decrease in the terminal voltage signal with an increase in generator reactive load. The terminal voltage signal is decreased as load increases, regardless of the voltage drop between generator and grid. A comparison circuit receives a compensated voltage signal, compares it to the reference voltage, and produces a compensated error signal. This signal is proceessed as described in the preceding section; the result is an output to the SCR bridge firing circuit.

6.7.3.4 Relaying and Control Circuits

Relaying and control circuits are operated by dc power, which is supplied from storage batteries for maximum reliability. The following control functions are provided:

- Field breaker,
- Regulator transfer and lockout,
- Exciter field bridge overcurrent,
- Generator field bridge overcurrent,
- Exciter field flashing, and
- Motor-driven DC regulator setpoint adjuster.

6.7.3.5 Generator Synchronizing Circuit

The synchronizing check relays ensure that the main generator output breakers close only when the main generator is synchronized to the grid. The synchrocloser relay (semi-automatic) controls the closure of the first output breaker to the grid. It provides a close signal to the breaker such that it will close when the synchroscope is at 0°, provided the following conditions are met:

1. The synchroscope is rotating at one to three rpm in the "fast" direction,
2. The switchyard voltage is between 218 and 249 kv,
3. The voltage differential between the generator and switchyard is within 10 kv, and
4. The breaker control switch is selected to "close."

The manual synchronizing relay (zero slip) controls the closure of the second output breaker when the slip frequency is zero, such as when the generator has been synchronized with the grid with the first output breaker. It provides a close signal to the breaker when the following conditions are met:

1. The phase angle is ∀10°,

2. A time delay of seven seconds has passed with slip frequency at zero (synchroscope stopped), and
3. The breaker control switch is selected to "close."

6.7.4 Main Generator Protection

6.7.4.1 Turbine Trips

A turbine trip will result in a generator trip (opening of the generator output breakers). Some turbine trips (in which there are no electrical faults which require tripping the generator from the network) allow a delay in generator tripping of 30 seconds. This delayed trip ensures that the reactor coolant pumps remain in operation for 30 seconds following the trip, ensuring an adequate coastdown time. The delay also helps to prevent an overspeed condition by using the steam that is still present in the valve chests, turbines, and moisture separator reheaters to generate some electrical power after the turbine inlet valves are tripped closed. Power from the grid is reversed through the main transformer to the unit auxiliary transformer supplying all auxiliary loads. When the generator trips, a fast transfer of the 12.47-kv buses to the startup transformers occurs, and power is maintained to the auxiliaries.

The following turbine trips allow a 30-sec delay of the generator trip:

- High steam generator level,
- Low condenser vacuum,
- Reactor trip/safety injection,
- Low electrohydraulic control (EHC) hydraulic pressure,
- Loss of EHC pressure,
- High turbine vibration,
- Loss of 24 vdc/125 vdc,
- High exhaust hood temperature,
- Underfrequency, and
- Overspeed.

The following turbine trips results in an immediate generator trip:

- Manual,
- Backup overspeed,
- Loss of two speed signals,
- Thrust bearing wear/low oil pressure,
- Loss of stator coolant,
- Low shaft lube oil pump pressure, and
- Moisture separator drain tank level.

6.7.4.2 Generator Lockout Relays

A generator lockout signal will trip the main turbine, the exciter breaker, the main generator output breakers, and the unit auxiliary transformer output breakers. It will also initiate a fast transfer of power to the startup transformers. Relays are energized to lock out the generator in the event of a generator, main transformer, or unit auxiliary transformer fault.

6.7.5 Main Transformer

The main transformer increases the line voltage of the generator output from 22 to 230 kv for distribution. By raising the line voltage, hysteresis and resistance losses are significantly reduced, thus minimizing conductor heating. The increased line voltage eliminates the need for costly bus cooling systems and reduces the expense of distribution systems. The main transformer is actually two transformers in parallel which receive power from the isophase buswork and, after raising the voltage to 230 kv, deliver it to the high voltage overhead transmission system. Each transformer can carry two-thirds of the total station generating capability.

Each transformer consists of three single-phase transformers. The high voltage winding is wye connected with a solid-grounded neutral, while the low voltage winding is delta connected. Each phase is a 22-to-230-kv, outdoor, oil-filled transformer rated at 535 Mva. The 230-kv power from the main transformers is transmitted by the overhead transmission system to the switchyard.

6.7.6 General System Operation

6.7.6.1 Normal Operation

During operation the voltage regulator is adjusted to maintain the proper reactive loading, and the DC regulator position is verified to be near that of the AC regulator. This allows a smooth transfer in case control is shifted to the DC regulator.

6.7.6.2 System Shutdown

At 20% load, the 12.47-kv buses are manually transferred from the unit auxiliary transformers to the startup transformers. When the reactor power is reduced to 5%, the turbine is tripped and the generator output and exciter field breakers trip open. The voltage regulator is placed in manual, excitation current is removed, and the unit is secured.

6.7.6.3 System Operations While Shutdown

The main generator output breakers can be cycled from the switchyard control house. Exercising the breakers should ensure that they will close in a timely manner prior to plant startup.

When a startup transformer is required to be removed from service, its 12.47-kv bus may be energized (backfed) via the main and unit auxilary transformers through the generator output breaker(s). The operators will be able to control the generator output breakers from the control room.

6.7.6.4 Generator Operating Limits

The operation of a generator involves certain limiting conditions. A generator has so many variable operating factors that the operating limits cannot be easily or simply specified. The purpose of the operating limits is primarily to protect the generator from excessive temperature. The capability or capacity of a generator is limited by the hot-spot temperatures in various elements of the component, such as the stator winding, rotor winding, and the stator iron, and by the temperature differential across the insulation of the winding. Any one of these points may be the limiting location depending on the load, power factor, etc. High temperature causes damage to the winding insulation which may lead to an internal fault. The insulation damage results from embrittlement due to the elevated temperature. Brittle insulation is subject to cracking and loss of its insulating properties. This type of damage is basically a result of the temperature existing at a point. Another type of temperature-related damage occurs from the differential expansion between the winding conductors and the core. The thermal expansion causes relative movement with resultant abrasion and damage to the insulation.

The heat produced in the generator or any other electrical apparatus is a function of the current and the resistance (I^2R). As current increases, the amount of heat produced increases rapidly due to the current squared term. This heat must be removed by the cooling medium (either hydrogen gas or liquid).

In the newest and largest generators another factor, other than temperature, is becoming important in prescribing operating limits. Electromagnetic forces acting on various components of the generator are now of significance. The large capacity of such a generator produces magnetic fields of great strength. These strong fields are constantly revolving and apply fluctuating forces to the generator components. Movement induced by these forces can cause vibration and eventual failure of components which are not properly restrained.

There are other factors that play important roles in limiting the operation of a generator. These are rotor vibration, generator frame distortion, and reactive capability limits.

Vibration of the rotor due to imbalance does not constitute an electrical problem. It may, however, cause damage to bearings and/or seals. A typical limit is five mils.

The reactive capability curve defines the operating limits which ensure that hot-spot temperature conditions are not excessive. The curve is based on design and test information and includes allowances for manufacturing tolerances.

The basic limitation is on the apparent power in Mva (mega-volt-amperes), not on the true power in Mw. The heating effect of current is independent of whether the current is in or out of phase with the voltage. If the basic limitation is Mva rating and the voltage is relatively constant, then the limit is essentially governed by the generator current over a limited operating range. It is sometimes desirable to operate the generator at power factors considerably different from unity. For this type of operation, the use of a reactive capability curve is essential.

6.7.7 Summary

The main generator produces electrical power and transmits that power to the offsite distribution system. The generator output voltage is stepped up from 22 kv to 230 kv by the main transformer for delivery to the high voltage overhead transmission system. It also supplies power for normal operation of station equipment.

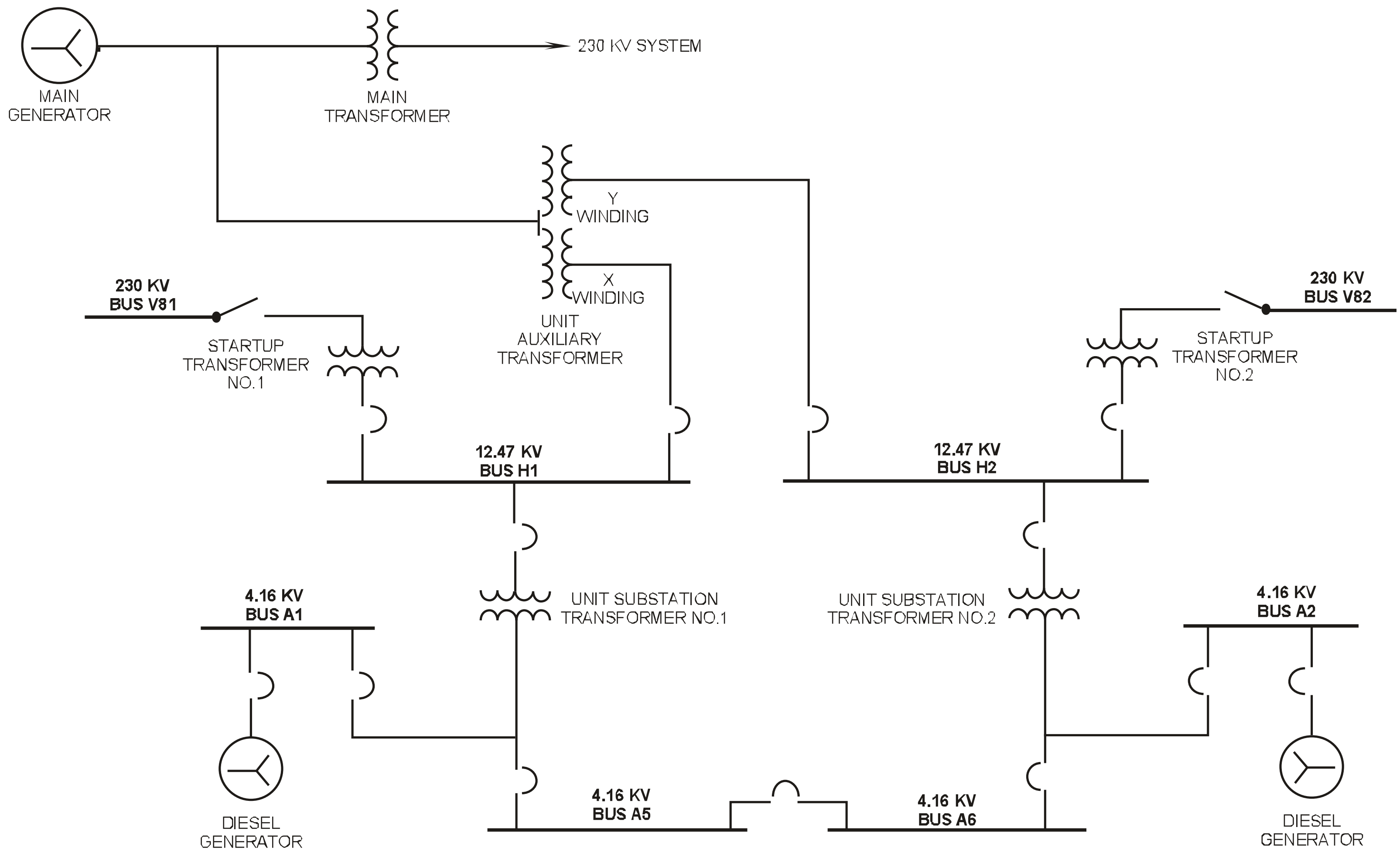

Figure 6-1 Main Generator, 230-kv, 12.47-kv, 4.16-kv, Diesel Generator Composite

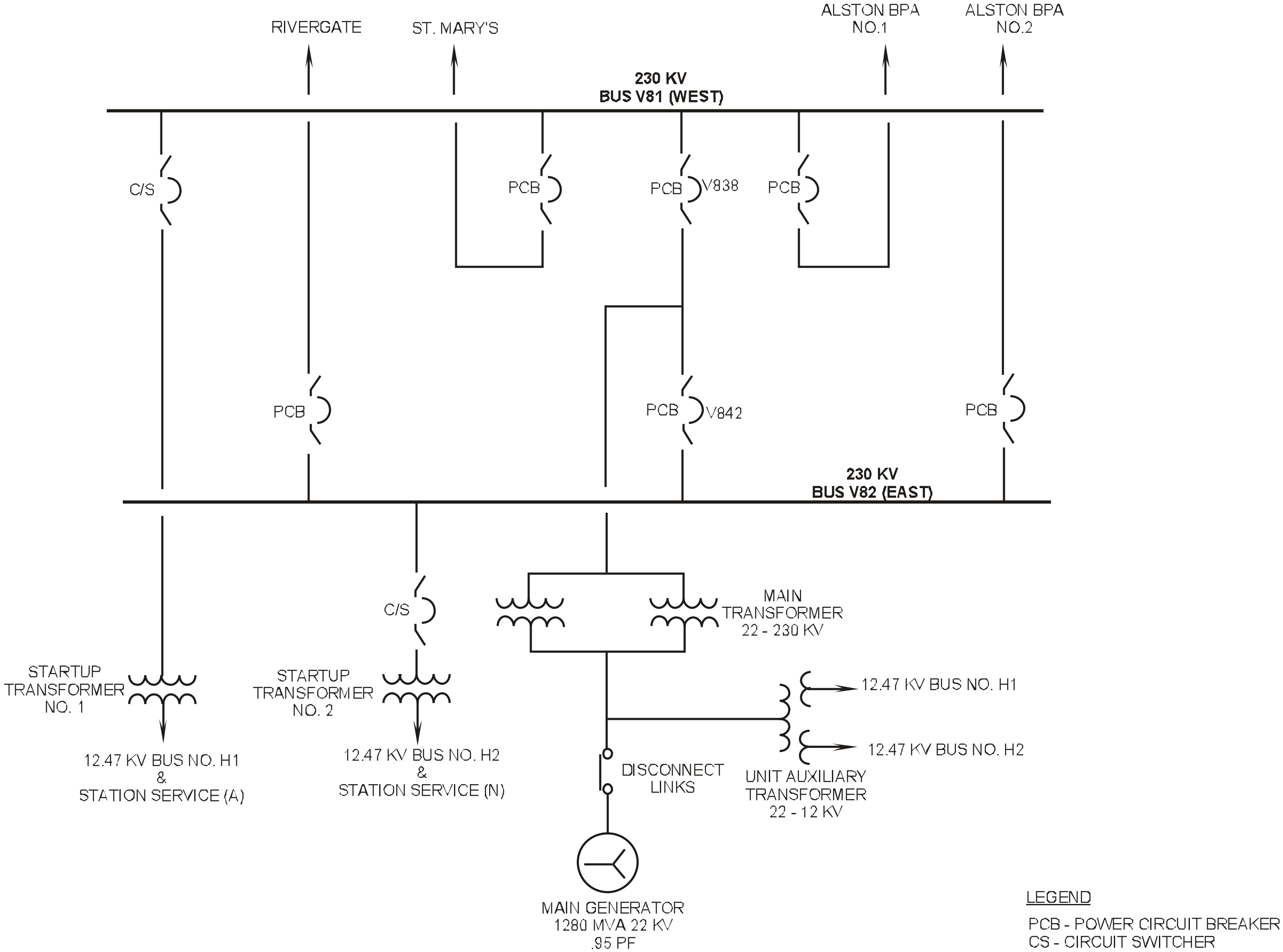

Figure 6-2 230-kv System

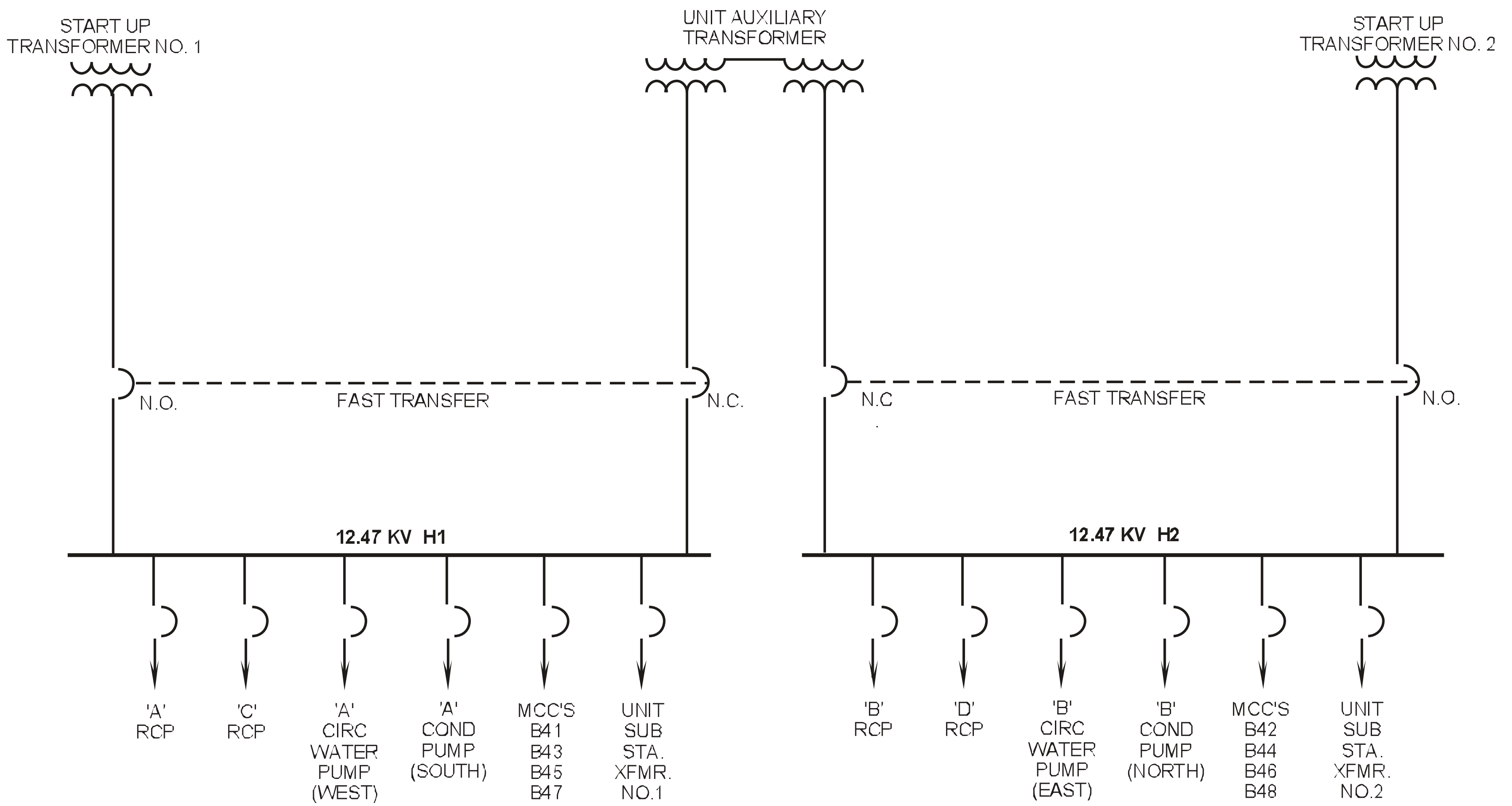

Figure 6-3 12.47-kv Distribution

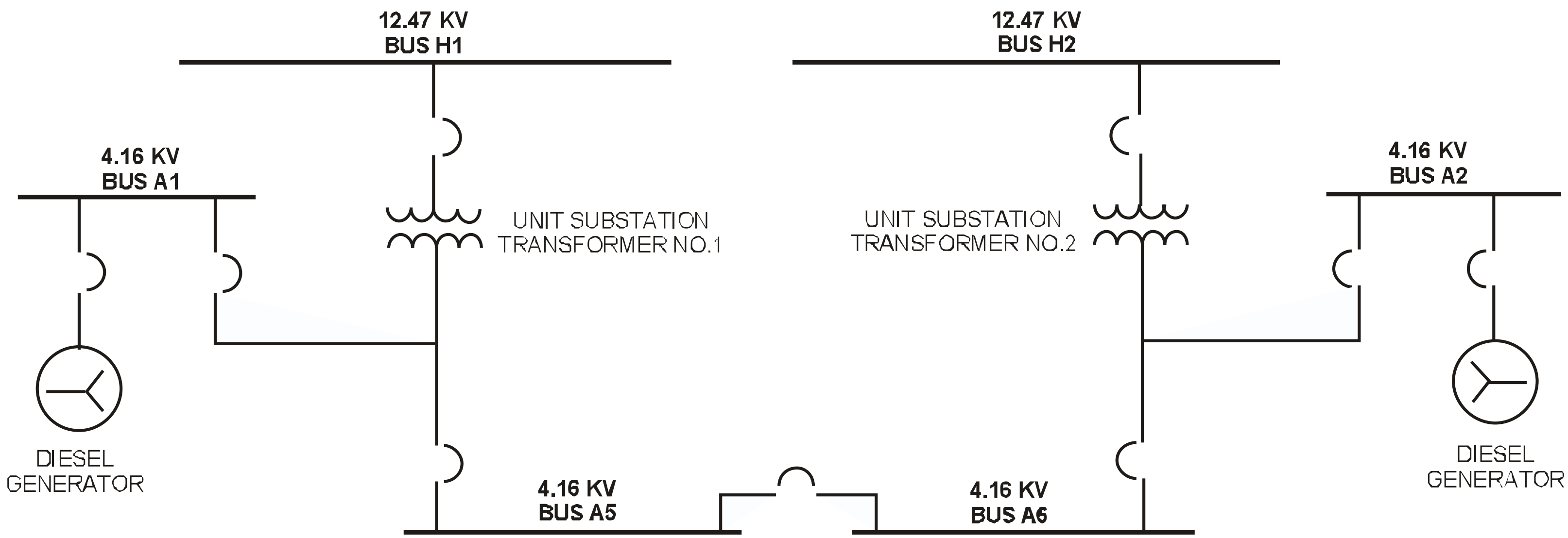

Figure 6-4 4.16-kv Electrical Distribution

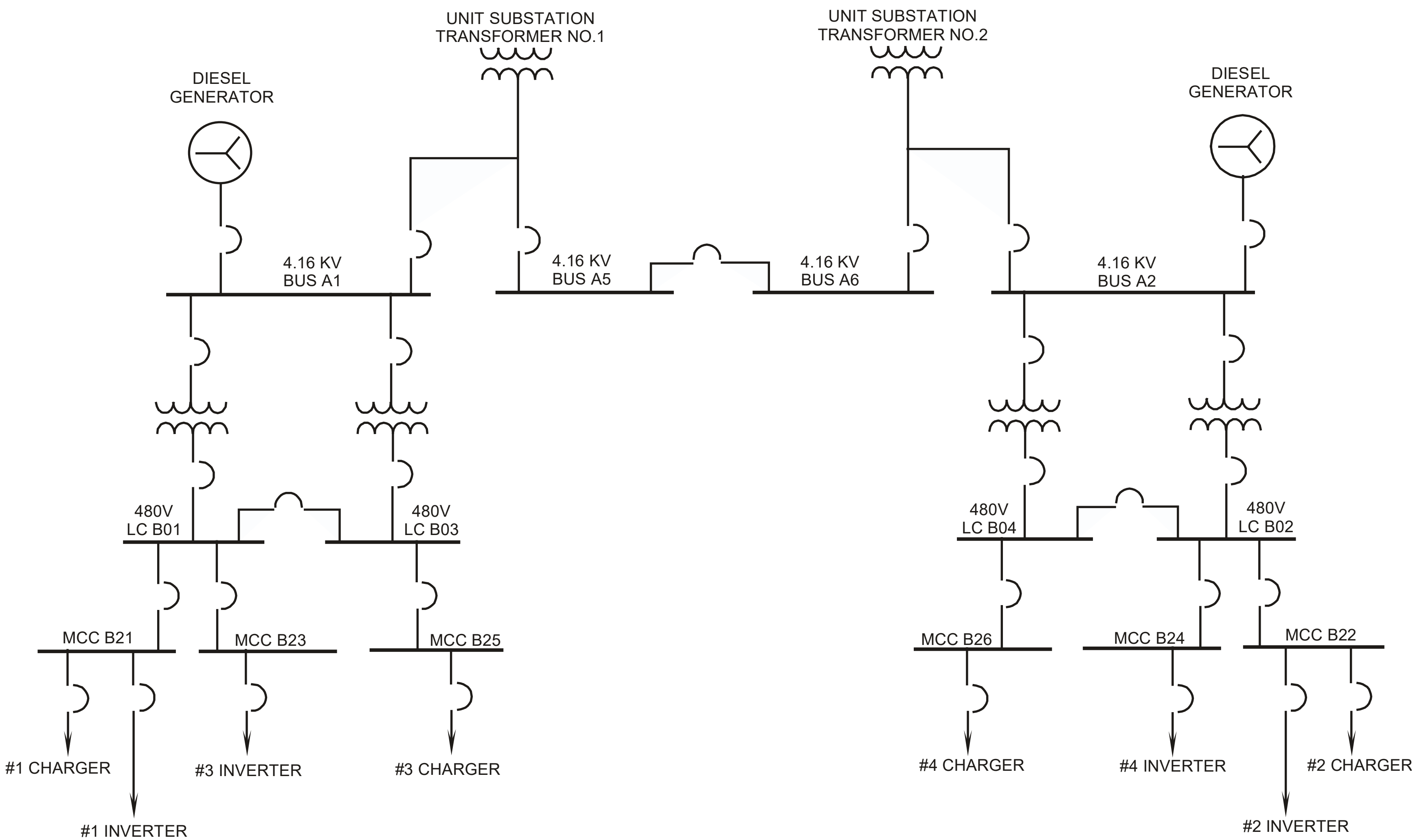

Figure 6-5 Class 1E Electrical Distribution

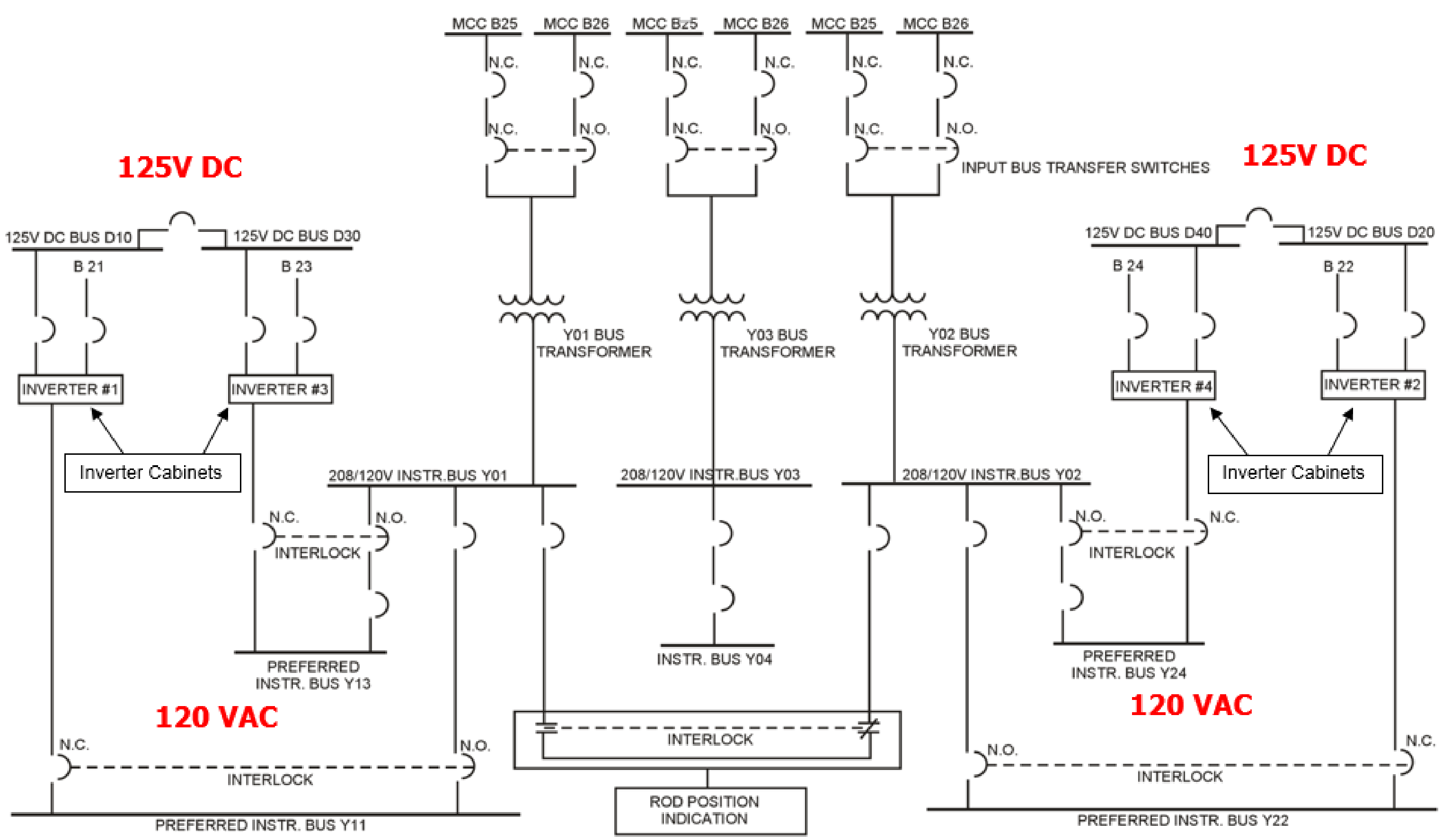

Figure 6-6 120-vac Instrument System

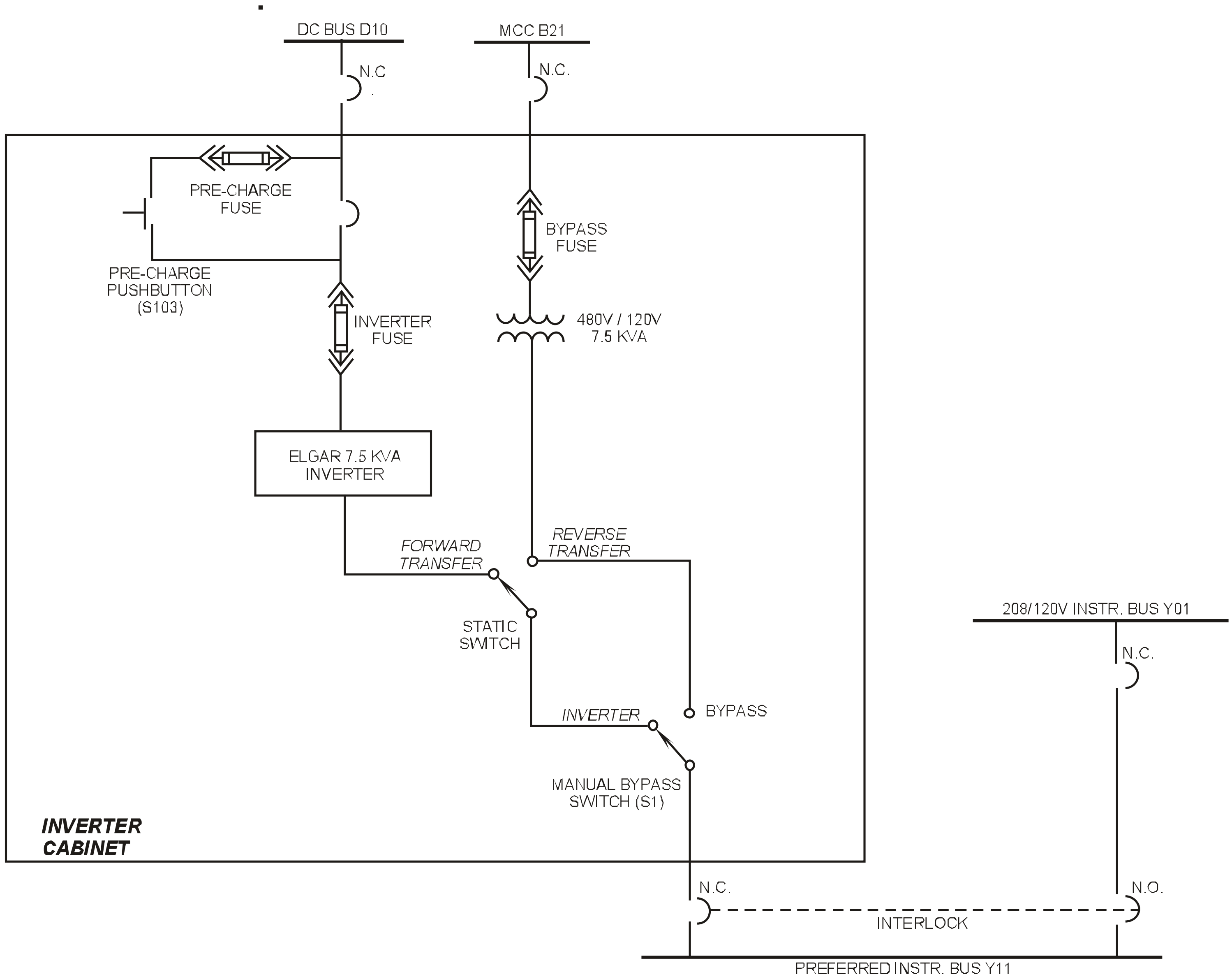

Figure 6-7 Inverter

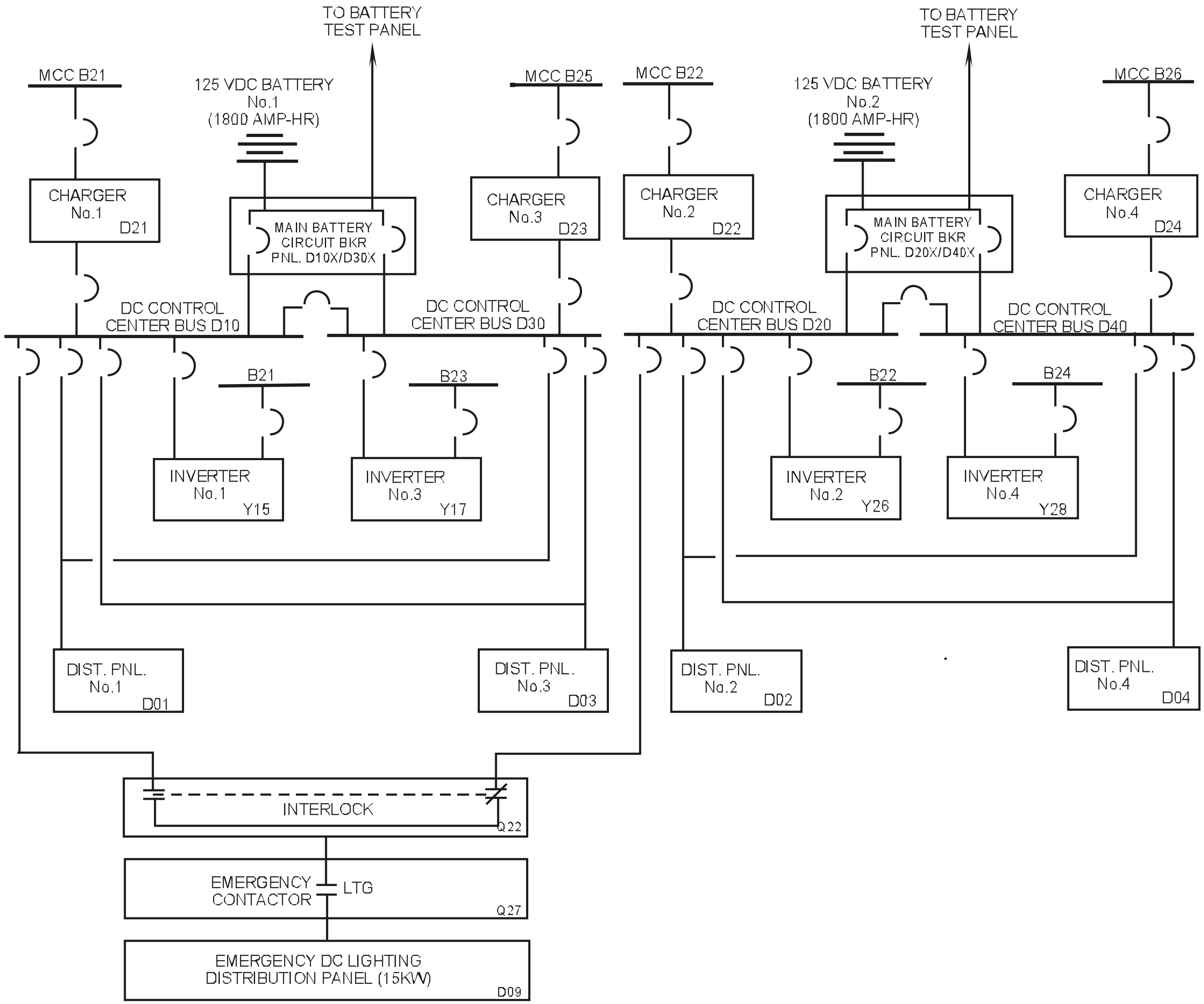

Figure 6-8 125-vdc Distribution System

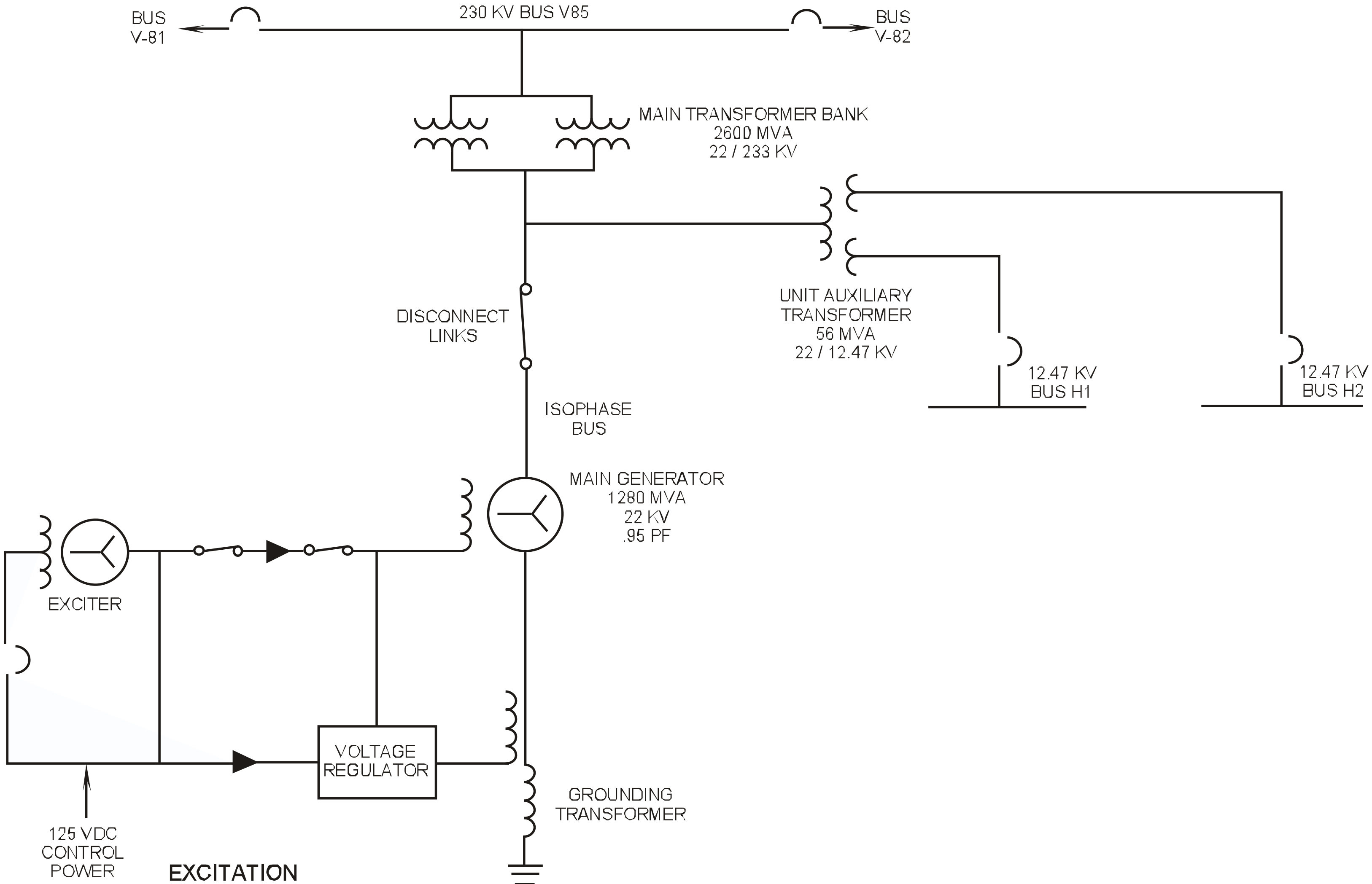

Figure 6-9 Main Generator Schematic

Westinghouse Technology Systems Manual

Chapter 7

SECONDARY PLANT SYSTEMS

Section

Westinghouse Technology Systems Manual

Section 7.1

Main and Auxiliary Steam Systems

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7.1 MAIN AND AUXILIARY STEAM SYSTEMS

Learning Objectives:

1. State the purposes of the main and auxiliary steam systems.

2. Identify the portion of the main steam system that is Seismic Category I.

3. List the components and connections located in the Seismic Category I portion of the main steam system, and explain the purpose of each.

4. Explain how the main steam system design prevents the blowdown of more than one steam generator during a steam line rupture accident.

5. Describe the steam flowpaths for decay heat removal after a plant trip:

    a. With offsite power available, and
    b. Without offsite power available.

7.1.1 Introduction

The purposes of the main steam system are:

1. To transfer steam from the steam generators to the turbine-generator and other secondary system components,
2. To provide overpressure protection for the steam generators, and
3. To provide diverse methods of decay heat removal.

The auxiliary steam system supplies steam to the gland steam system, main air ejectors, and hogging air ejectors during plant startups and shutdowns and to various loads in the auxiliary and fuel buildings.

7.1.2 Main Steam System Description

At full power, the four steam generators supply steam via four main steam lines to the main steam system at a rate of 15.07 X 10^6 lbm/hr at 895 psig. Each main steam line contains only one piping connection between its associated steam generator and its containment penetration. This connection is for flow measurement across the steam flow restrictor. Refer to Figure 7.1-1.

Directly outside containment, each 28-in. main steam line contains penetrations for a steam supply to the Turbine-Driven (TD) Auxiliary Feed Water (AFW) pump, for a power-operated atmospheric relief valve, and for five code safety valves. Downstream of these penetrations are the Main Steam Isolation Valves (MSIVs) and main steam check valves. A three-in. MSIV bypass valve is provided in parallel with the MSIV. The MSIVs and bypass valves isolate the main steam lines from each other in the event of a steam line break. Each main steam line supplies steam to the high pressure turbine through throttle (stop) and governor (control) valves.

Upstream of the throttle valves, the main steam lines are cross-connected by a 28-in. bypass header, which equalizes the four steam line pressures and thereby ensures equal loading of the steam generators. The bypass header also supplies steam to:

- The second-stage heaters of the Moisture Separator Reheaters (MSRs),
- The Main Feed Pump (MFP) turbines,
- The main condenser air ejectors,
- The gland steam system, and
- The Steam Dump (SD) system.

From the throttle and governor valves, steam enters the high-pressure turbine at four entry points and drives the main turbine-generator. Steam is exhausted from the high pressure turbine via six 42-in. lines to two MSRs. Refer to Figure 7.1-2. In the MSRs the high pressure turbine exhaust (cold reheat) steam is dried and is slightly superheated through two stages of reheating. The heating media are extraction steam from the high pressure turbine second stage (first stage of reheating) and main steam from the bypass header (second stage of reheating). A more detailed description of the MSRs is provided in Chapter 7.4.

The reheated steam exits each MSR via three 42-in. lines and enters the three low pressure turbines through combined intermediate valves (six valves total, one for each outlet from each MSR). Some of the reheated steam from one MSR is routed to the Main Feed Pump (MFP) turbines during operation at high power levels. Each of the low-pressure turbines exhausts steam to one of the three shells of the main condenser.

Some of the steam passing through the high- and low-pressure turbines is extracted from various turbine stages and is used to preheat feedwater as it is supplied to the Steam Generators (SGs). Also, as mentioned above, second-stage extraction steam from the high pressure turbine is used to reheat steam in the MSRs. Additional discussion concerning the use of extraction steam for feedwater heating is provided in Chapter 7.2.

7.1.2.1 Safety Considerations

The safety considerations associated with the main steam system apply to the portions of the main steam lines which extend from the steam generator steam outlets to the main steam check valves. The following discussion identifies the safety-related features of the piping and components of this portion of the main steam system.

The piping in each main steam line is Seismic Category I from the steam outlet of the steam generator to the first piping restraint downstream of the main steam check valve (the steam generators themselves are also Seismic Category I). This portion of the main steam system must not be damaged as a consequence of reactor coolant system damage. Conversely, a main steam line break must not cause damage to the reactor coolant system. This portion of the main steam system is also essential for the safe shutdown of the plant (1) with offsite power available (by providing steam flowpaths to the steam dump system for decay heat removal), as well as (2) following a loss of offsite power (by providing steam flowpaths to the atmospheric relief valves for decay heat removal).

The main steam lines downstream of the main steam check valves are not seismically qualified. If they pass through a seismically qualified structure such as the auxiliary building, the structure and equipment within must be protected from possible damage resulting from a main steam line break. For example, at some plants the steam lines are routed through concrete tunnels.

Safety-related components in the main steam lines include:

- The flow restrictors,
- The Power-Operated Relief Valves (PORVs),
- The steam generator safety valves,
- The steam supplies to the turbine-driven AFW pump, and
- The MSIVs and main steam check valves.

The flow restrictor in each main steam line limits the escaping steam flow rate and the resultant thrust forces on the affected piping following a steam line break. Limiting the steam flow rate also minimizes the cooldown of the reactor coolant system.

The steam supplies to the turbine-driven AFW pump are also Seismic Category I, as the AFW system is required for reactor decay heat removal during plant shutdowns. The four supply lines provide both redundancy and dependability of supply. Isolation and check valves in each supply line maintain physical separation of the main steam lines by preventing any interconnecting backflow (see Figure 7.1-1).

The safety-related aspects of the PORVs, safety valves, MSIVs, and main steam check valves are discussed in the component descriptions of section 7.1.3.

7.1.2.2 Accident Considerations

The failure of any main steam line, the malfunction of a valve installed therein, or any consequential damage must not:

- Reduce the feed flow capability of the AFW system below the minimum required,
- Render inoperable any engineered safety feature (i.e., controls, electric cables, containment cooling system piping, etc.),
- Initiate a loss of coolant accident,
- Cause uncontrolled flow from more than one steam generator, or
- Result in the containment pressure exceeding its design limit.

For a Loss Of Coolant Accident (LOCA), the plant's control and protection systems will not prevent the initial discharge of steam to the main condenser or atmosphere associated with a turbine trip. If steam generator tube leaks were present prior to the accident, some radioactivity accumulated in the secondary inventory of the steam generators could be discharged through the steam line PORVs or safety valves. The total plant releases associated with a loss of coolant accident, including releases from the secondary plant, must be within 10 CFR 100 limits.

Any radioactive releases associated with a main steam line break or steam generator tube rupture also must be within 10 CFR 100 limits. To limit the releases and resulting doses associated with these accidents, technical specification limits are placed on primary and secondary activities and primary-to-secondary leakage.

7.1.3 Main Steam System Component Descriptions

7.1.3.1 Flow Restrictors

The dry, saturated steam leaving the second-stage moisture separators exits each steam generator through a steam flow restrictor (see Figure 7.1-1). Each restrictor is located in containment as close as possible to its associated steam generator outlet nozzle to minimize the length of piping preceding the restriction. This arrangement limits the probability of a steam line break upstream of the restrictor. The restrictor consists of a venturi nozzle insert welded into carbon steel pipe. The converging and diverging sections of the nozzle are carbon steel with an Inconel throat liner.

The flow restrictor is designed to limit the blowdown rate of steam released from its associated steam generator to 9.68×10^6 lbm/hr in the event of a steam line rupture downstream of the restrictor. Limiting the steam flow rate limits the cooldown rate of the reactor coolant and the accompanying rate of positive reactivity addition to the core. Also, limiting the flow from a steam line break minimizes piping forces and the potential for pipe whip.

During normal operation, each flow restrictor offers minimal resistance to steam flow and provides a differential pressure for the measurement of steam flow.

7.1.3.2 Main Steam Instrumentation

Each main steam line contains two steam flow transmitters, four steam pressure transmitters, and one radiation monitor upstream of the MSIV and a second radiation monitor downstream of the MSIV. These instruments provide inputs for plant control and protection as well as indication and alarms. Refer to Figure 7.1-3.

The two flow transmitters in each steam line, located inside containment, sense the differential pressure across the flow restrictor (part of the differential pressure is the internal pressure drop across the upper moisture separator section of the associated steam generator, as shown in Figure 7.1-3). Each steam flow transmitter provides an input to the logic for (1) the high steam flow engineered safety features actuation and steam line isolation and (2) the reactor trip for anticipated loss of heat sink. Either flow transmitter can be selected to provide an input to (1) the flow mismatch portion of the feedwater control system for the associated steam generator and (2) the load reference portion of the MFP speed control system (see Chapter 11.1).

Of the four pressure transmitters on each steam line, one supplies an input for actuation of that line's PORV. The other three provide inputs to the feedwater control system and to the reactor protection system. The three protection-grade channels provide inputs to the protection logic for (1) the high steam line differential pressure engineered safety features actuation and (2) the high steam flow engineered safety features actuation and steam line isolation. Two of the protection-grade channels provide density compensation for separate steam flow channels. Four of the plant's 12 protection-grade steam line pressure channels provide inputs to the AFW pump speed controllers (see Chapter 5.8). All of the pressure transmitters are located outside containment and upstream of the MSIVs.

The upstream radiation monitor for each steam line is a Geiger-Mueller detector which monitors the background gamma radiation level in the main steam pipe. The downstream monitor is a scintillation detector sensitive to nitrogen-16. Both monitors supply plant indication panels and control room alarms. Either monitor can provide indication of a steam generator tube rupture. These radiation monitors are discussed further in Chapter 16.0.

7.1.3.3 Power-Operated Relief Valves (PORVs)

The PORV (also called an atmospheric relief valve or atmospheric dump valve) in each steam line is a 6-in. air-operated, spring-opposed globe valve capable of relieving approximately 10% of the rated steam flow at no-load pressure from each steam generator (2.5% of the total steam system flow). The PORVs are mounted outside containment on the main steam support structure. Each PORV has a nominal setpoint of 1125 psig, which is approximately half the difference between the no-load steam generator pressure and the lowest set pressure of the safety valves. The PORVs thus lift to relieve an overpressure condition before the safety valves do.

In addition to providing overpressure protection for the steam generators and the Seismic Category I portion of the main steam system, the PORVs provide a means of removing heat from the reactor coolant system. If the main condenser is unavailable or the steam dumps are inoperable, the PORVs are manually controlled from the control room to relieve steam to the atmosphere and thereby to cool down the plant. The PORVs thus allow the removal of decay heat in the event of a loss of offsite power (the steam generators would be fed by the AFW system to provide the secondary inventory for heat removal). The PORVs can also be operated from the remote shutdown station.

Figure 7.1-4 illustrates the development of an air signal to open a PORV. The PORV fails shut on a loss of instrument air or electrical signal. Figure 7.1-4 also shows the backup nitrogen control system for the PORVs. A worst-case fire is projected to disable both the electrical signals and the pneumatic supplies to the PORVs; the nitrogen control system allows PORV operation under such conditions. To operate a PORV with the backup system, the plant's nitrogen system is un-isolated and a three-way ball valve is repositioned to admit nitrogen to the PORV actuator (the ball valve is normally positioned to admit instrument air to the PORV actuator). The nitrogen regulator is then adjusted to obtain the desired opening signal.

7.1.3.4 Steam Generator Safety Valves

Each main steam line has five six-in. spring-loaded steam generator safety valves (see Figure 7.1-5). The safety valves provide overpressure protection for the steam generators and the main steam piping. The valves have staggered set pressures to provide an increased relieving capacity with an increasing overpressure. The set pressures for the five valves are 1170, 1200, 1210, 1220, and 1230 psig; the highest setpoint is less than 110% of the steam generator design pressure in accordance with the ASME Boiler and Pressure Vessel Code. The combined capacity of the 20 safety valves is 16,467,380 lbm/hr, which is 109% of full-power steam flow. In addition to providing overpressure protection, the safety valves remove plant decay heat when the steam dumps and secondary PORVs are unavailable.

The safety valves relieve to the atmosphere via opposing discharge ports. They are located on the main steam support structure outside containment. The exhaust stacks for the safety valves and the PORVs extend approximately 13 ft above the turbine building roof.

7.1.3.5 AFW Pump Steam Supplies

Connected to each main steam line upstream of the MSIV is a three-in. line which supplies steam to the turbine-driven AFW pump. The air-operated isolation valve in the line is automatically opened by an AFW system actuation signal (see Chapter 5.8) and can be manually operated from the control room or remote shutdown station. A normally energized four-way solenoid valve (not shown in Figure 7.1-1) supplies air to the top port of each isolation valve's operating cylinder to keep the isolation valve closed; de-energizing the solenoid valve admits air to the bottom port of the operating cylinder and opens the isolation valve. The AFW pump steam supply valves thus fail open on a loss of ac power.

To facilitate a rapid start of the turbine-driven AFW pump, the steam supply lines are kept warm by 3/4-in. bypass lines which skirt the steam supply isolation valves. In addition, connected to each isolation valve's air supply is a 15-gal accumulator capable of supporting three valve cycles 20 minutes after instrument air is lost.

7.1.3.6 High Pressure Drains

Each main steam line has a high pressure drain tap outside containment. This one-in. line directs condensate to the B main condenser via an isolation valve and steam trap. The drain lines remove moisture from the steam lines during system startups and are isolated during operation at power. The isolation valves are automatically closed by a steam line isolation signal.

Each drain line has a connection to the plant's nitrogen system. Nitrogen is supplied via the drain lines to the gas spaces in the steam generators during wet layup periods for shutdown corrosion control.

7.1.3.7 Main Steam Isolation Valves (MSIVs)

The MSIV in each main steam line is a 28-in. air-operated stop-check valve (see Figure 7.1-6). During normal operation each MSIV is held open by the instrument air pressure applied to the valve's operator. When the MSIV is shut, instrument air is vented from the valve's operator, allowing the weight of the valve disc, spring force, and main steam pressure to seat the disc in the closed position. Instrument air to the valve operator is supplied via two series solenoid valves (see Figure 7.1-7). The solenoid valves are normally de-energized; energizing one or both solenoid valves will vent the MSIV's operator and shut the MSIV.

Evidence of a steam line rupture results in the actuation of a steam line isolation signal, which closes the MSIVs, MSIV bypass valves, and high pressure drain valves. A steam line isolation signal is initiated by either of the following:

1. High-high containment pressure (sensed by two out of four pressure detectors), or
2. High steam line flow (sensed by one out of two flow detectors in two out of four steam lines) coincident with either:
   a. Low steam pressure (sensed in two out of four steam lines), or
   b. Low-low T_{avg} (sensed in two out of four coolant loops).

Each engineered safety feature train provides an isolation signal to a separate solenoid valve for each MSIV. The steam line isolation signal is delayed 0.5 seconds by a time-delay relay before it energizes the MSIV solenoid valves. The affected valves do not close if the signal clears in less than 0.5 seconds. The MSIVs interrupt steam flow within five seconds of receipt of the isolation signal.

Each MSIV can be manually operated with a control room switch, which de-energizes (to open) or energizes (to close) one of the two MSIV solenoid valves (the other solenoid valve remains de-energized). Connected to each MSIV operator air supply line upstream of the solenoid valves is an accumulator capable of keeping the MSIV open for 15 minutes following the loss of instrument air.

The MSIVs are designed to provide protection against the following accidents:

- A break in the bypass header downstream of the MSIVs, by preventing the uncontrolled blowdown of all steam generators,
- A break in a main steam line outside containment and upstream of the MSIV, by isolating the affected steam generator from the others and thereby preventing the uncontrolled blowdown of more than one steam generator,
- A break in a main steam line inside containment, by isolating the affected steam generator from the others and thereby preventing the uncontrolled blowdown of more than one steam generator and limiting the resultant containment pressure increase, and
- A steam generator tube rupture, by minimizing the spread of contamination to the secondary systems and to the environment.

7.1.3.8 Main Steam Check Valves

Each main steam line has a main steam check valve located immediately downstream of the MSIV. The main steam check valves provide protection against an upstream steam line break coincident with the failure of an MSIV to shut. Each main steam check valve is a 28-in. reverse-seating swing-check valve with a position indicator mounted on the valve shaft (see Figure 7.1-8). The MSIVs and main steam check valves are located in the main steam support structure outside containment.

7.1.3.9 MSIV Bypass Valves

In parallel with the MSIV in each main steam line is an MSIV bypass valve (see Figure 7.1-1). The MSIV bypass valves are used to warm up the piping downstream of the MSIVs and to equalize the pressure across the MSIV disks during steam system startups. Each MSIV bypass valve is a three-in. air-operated double-disk gate valve. Instrument air is supplied to each bypass valve via series solenoid valves, which are energized to close the bypass valves and de-energized to open them. The MSIV bypass valves are closed by a steam line isolation signal. The bypass valves are located in the main steam support structure.

7.1.4 Auxiliary Steam System Description

The auxiliary steam system supplies steam to the gland steam system, main air ejectors, and hogging air ejectors during plant startups and shutdowns and to various loads in the auxiliary and fuel buildings. As shown in Figure 7.1-9, the secondary plant steam loads are supplied by the startup boiler, while the auxiliary and fuel building loads can be supplied either with steam from the startup boiler or high-pressure turbine exhaust steam.

The startup boiler has a steam supply rating of 64,000 lb/hr at 150 psig. The boiler's burner has a rated fuel consumption of 580 gph at a fuel oil supply pressure of 125 psig. The startup boiler is supplied with water from the startup boiler water storage tank, which in turn is supplied from either the condensate storage tank or the demineralized water storage tank. The boiler supplies its steam loads via a stop-check valve and a locally operated steam line stop valve.

The startup boiler has a chemistry control system (not shown in Figure 7.1-9) for the addition of corrosion-inhibiting chemicals (primarily hydrazine) during boiler operation and shutdown. If the boiler is not to be maintained in wet layup after it is shut down, it is supplied with a nitrogen purge.

The auxiliary steam system supplies the following major loads in the auxiliary and fuel buildings:

- Boric acid evaporators,
- Boric acid batch tank,
- Decontamination system, and
- Cask washdown pit.

Of these, the boric acid evaporators constitute the primary load. These loads are supplied with extraction steam from high pressure turbine exhaust during plant operation and with steam from the startup boiler during plant shutdowns and when sufficient turbine exhaust steam is unavailable. Each load is normally isolated from the steam sources; steam is supplied only as needed for operation of a particular component or system.

Auxiliary steam is provided via a pressure control valve which is normally set to maintain a pressure of 40 - 50 psig. The steam supply line is protected from overpressure by an overpressure stop valve and a spring-loaded relief valve.

Condensate from the boric acid evaporators and boric acid batch tank is collected and returned to the secondary cycle (condensate from the other auxiliary steam loads is treated as radioactive liquid waste). Condensate is collected in the auxiliary steam condensate receiver and pumped by the level-controlled auxiliary steam condensate return pump to main condenser shell C. Any remaining steam which reaches the condensate receiver is condensed in the auxiliary steam vent condenser. The suction of the condensate return pump is monitored by a conductivity element; a high conductivity condition causes isolation of the return path to the main condenser and rejection of the return pump's discharge back to the condensate receiver. The receiver then overflows via a standpipe to the liquid waste processing system.

7.1.5 Summary

During normal operation the four steam generators deliver saturated steam through four separate steam lines to the main turbine. These lines are cross-connected by a bypass header to ensure that the steam generators are loaded equally. The bypass header also supplies steam to a number of secondary plant components.

Each main steam line is provided with an isolation valve and check valve just outside containment. The main steam piping from the steam generators to these valves is Seismic Category I and contains several safety-related features. The main steam isolation valves automatically close on either of the following signals:

- High steam line flow coincident with low steam pressure or low-low T_{avg}, or
- High-high containment pressure.

In the low pressure portion of the main steam system, exhaust steam from the high-pressure turbine is directed to the MSRs, where it is dried and reheated before it is supplied to the low-pressure turbines and the main feed pump turbines.

The auxiliary steam system supplies steam to several secondary plant components during startups and shutdowns and to fuel and auxiliary building loads as needed.

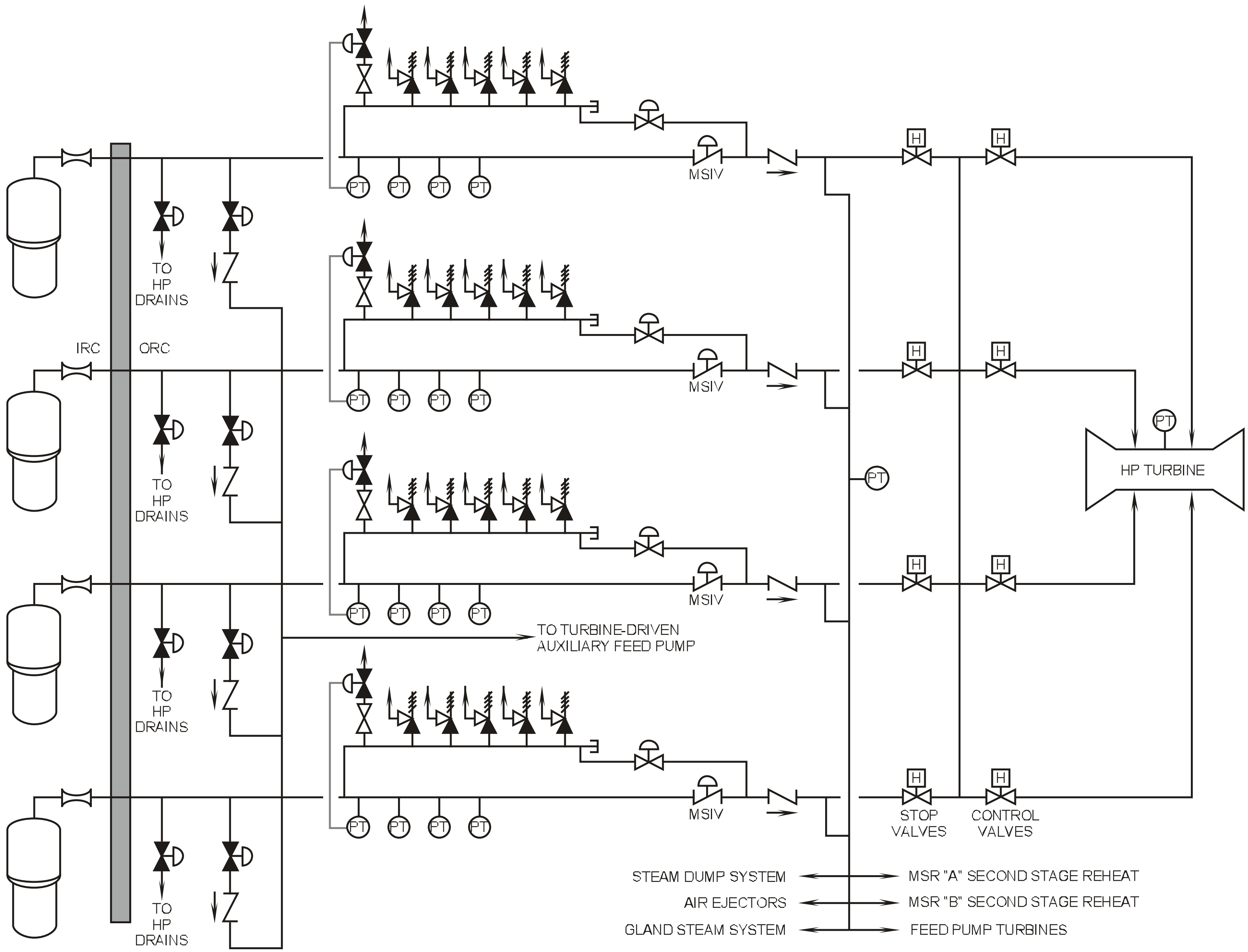

Figure 7.1-1 Main Steam System (High Pressure)

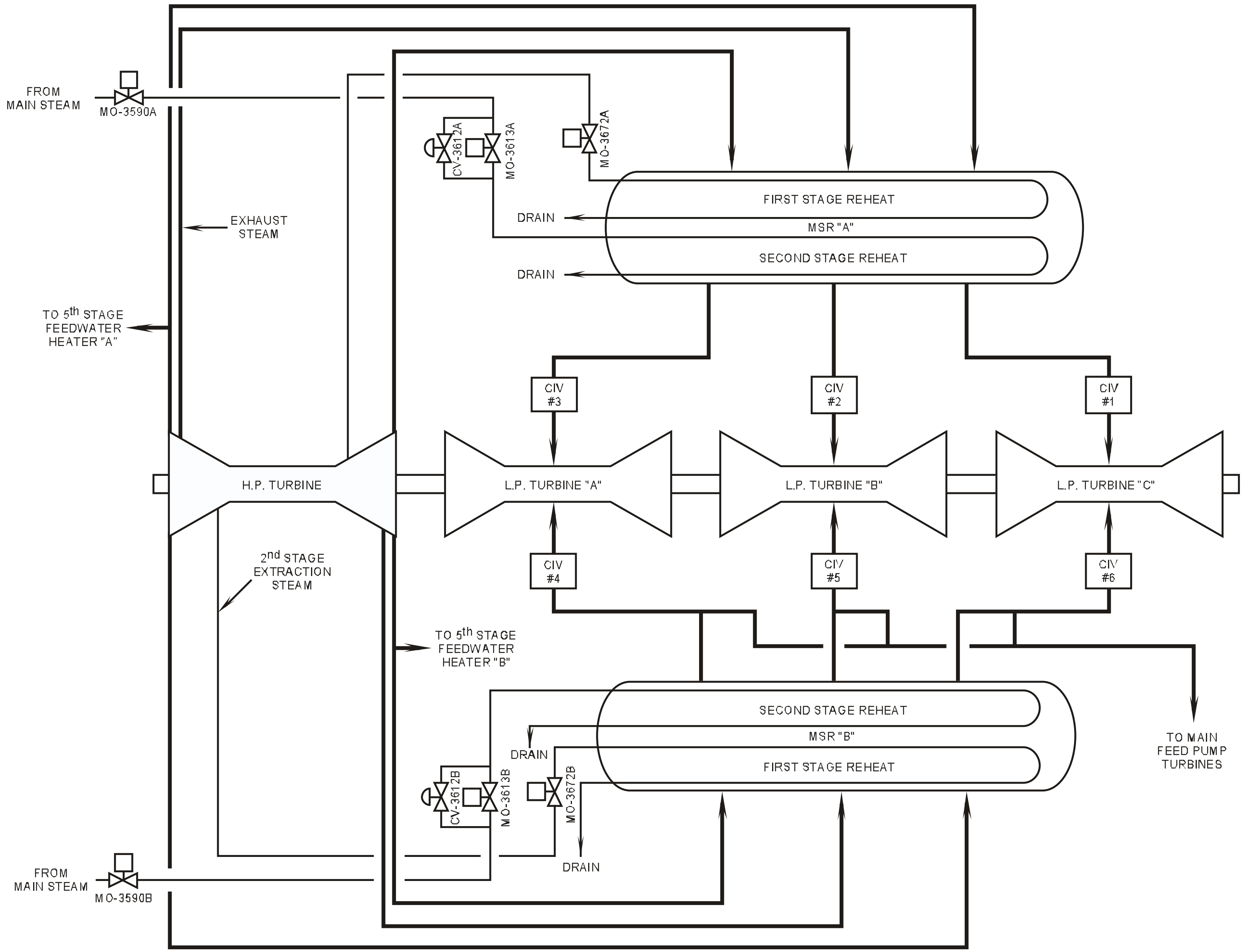

Figure 7.1-2 Main Steam System (Low Pressure)

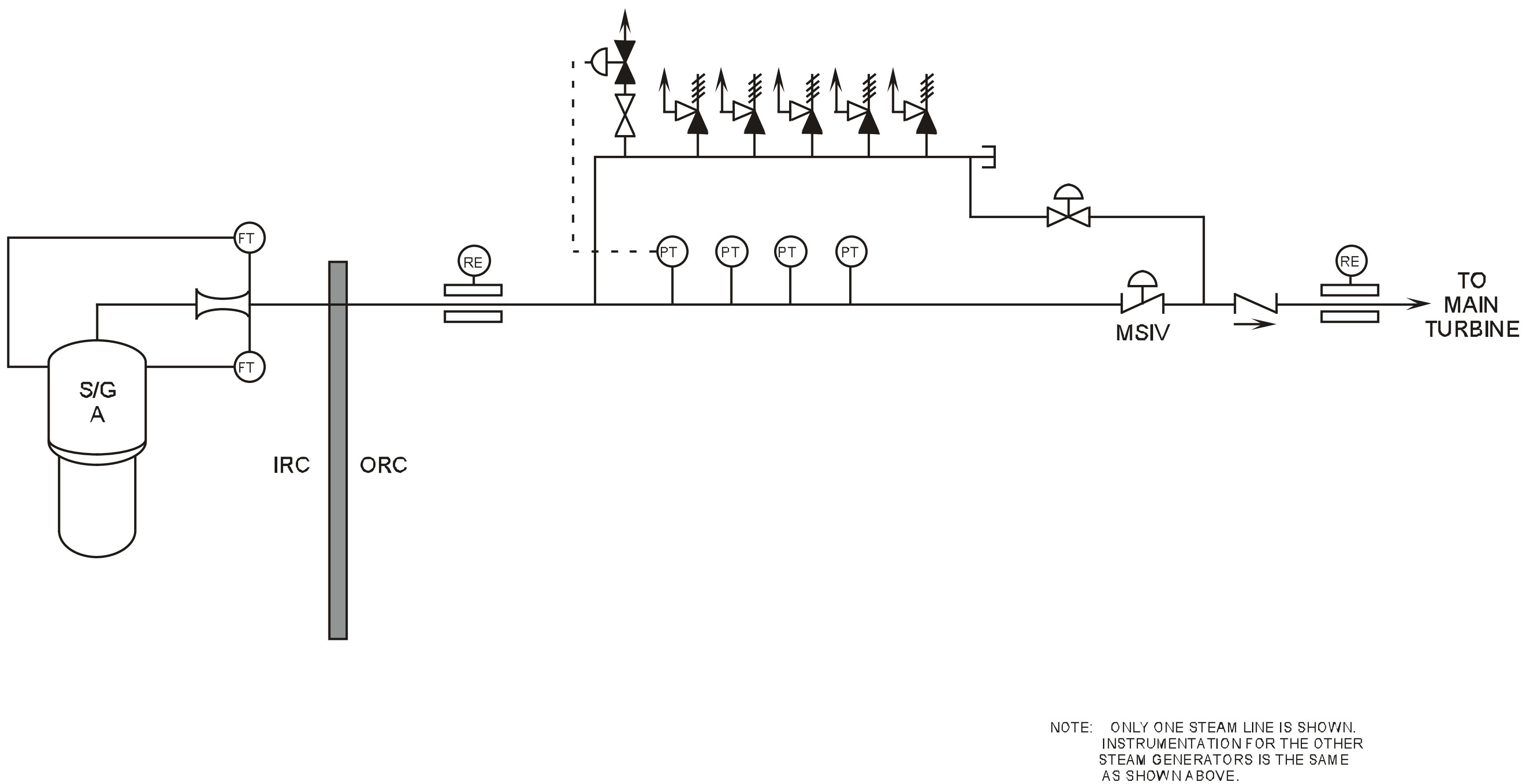

Figure 7.1-3 Main Steam Instrumentation

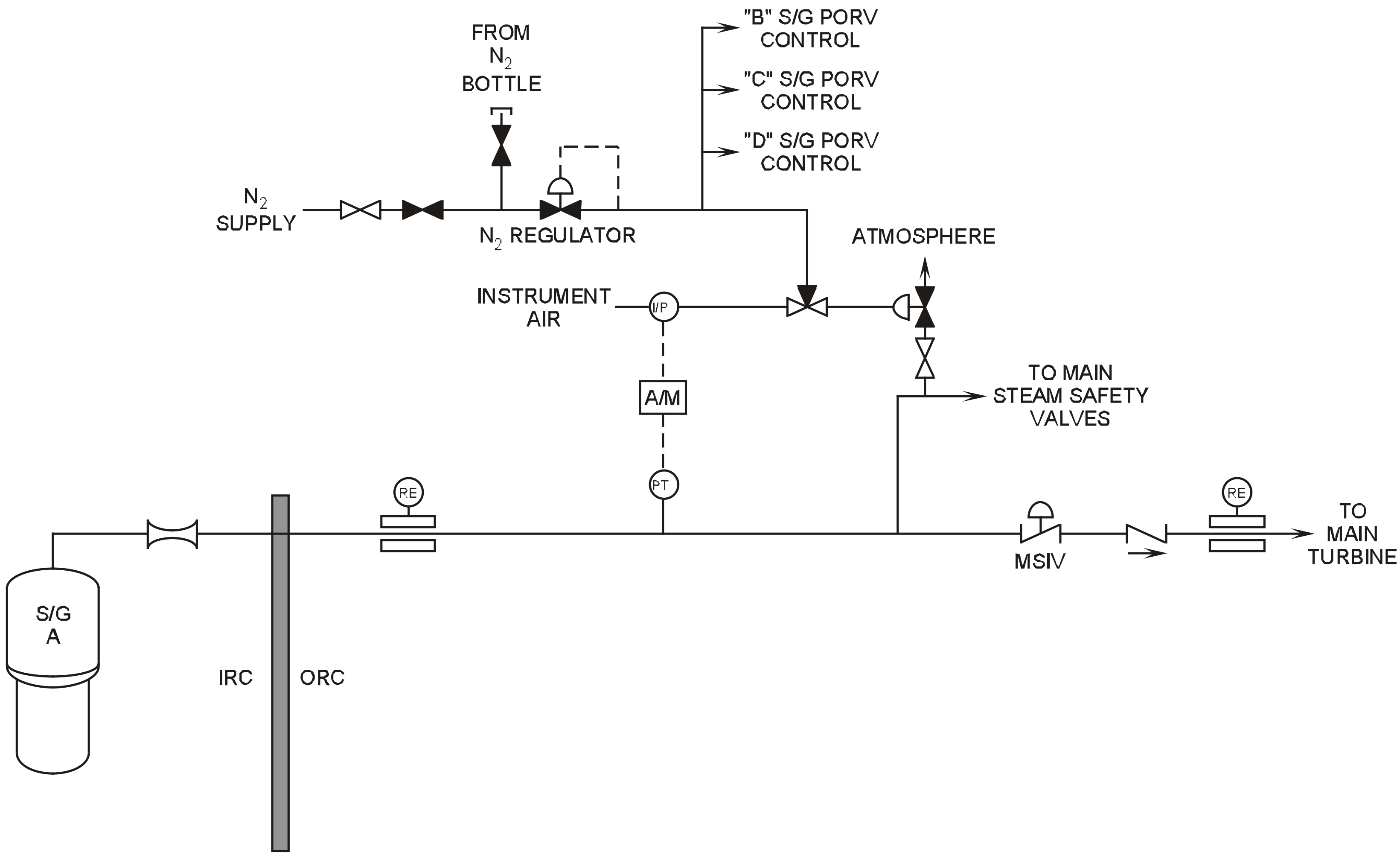

Figure 7.1-4 Steam Generator PORV Control

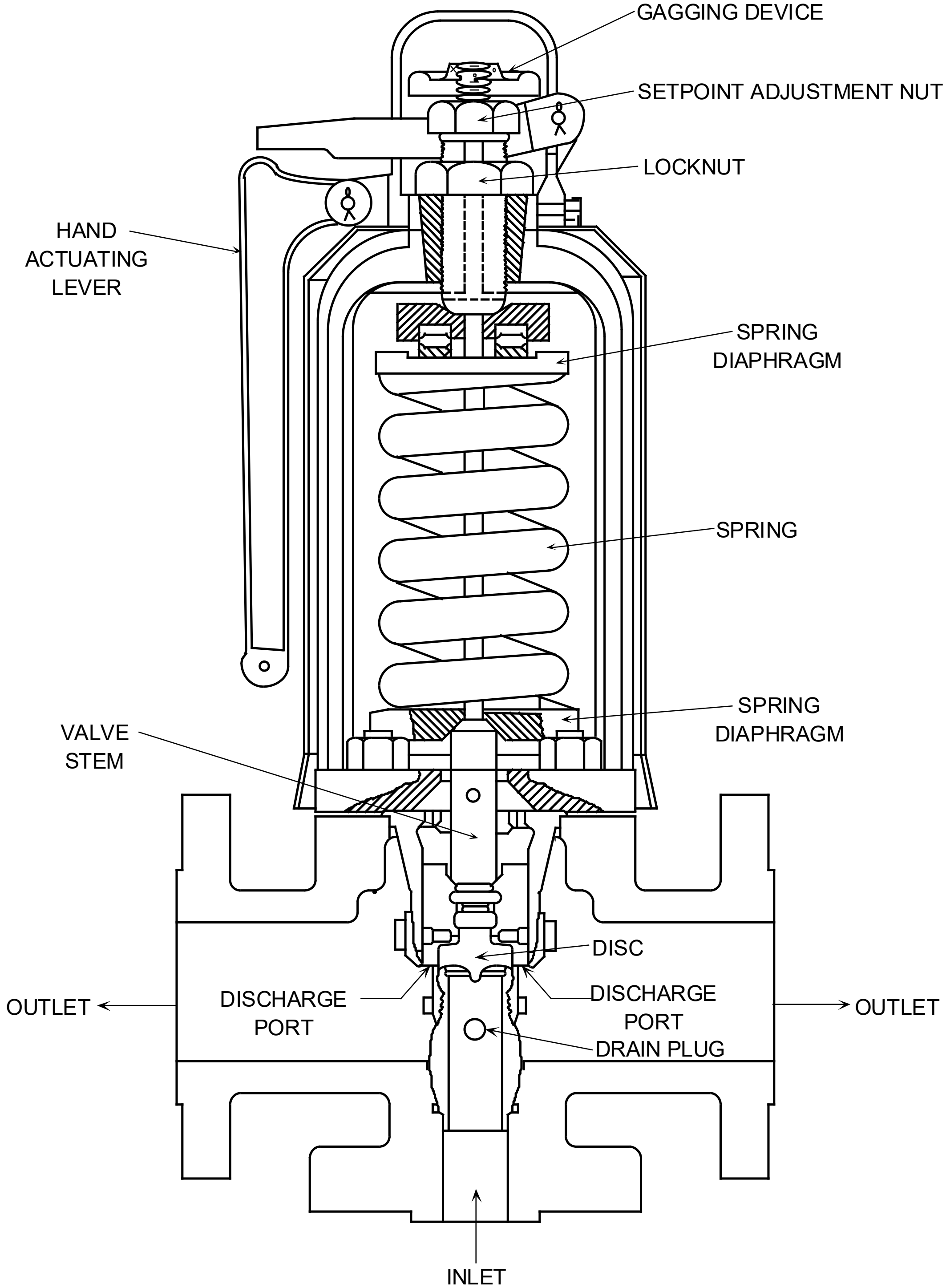

Figure 7.1-5 Main Steam Safety Valve

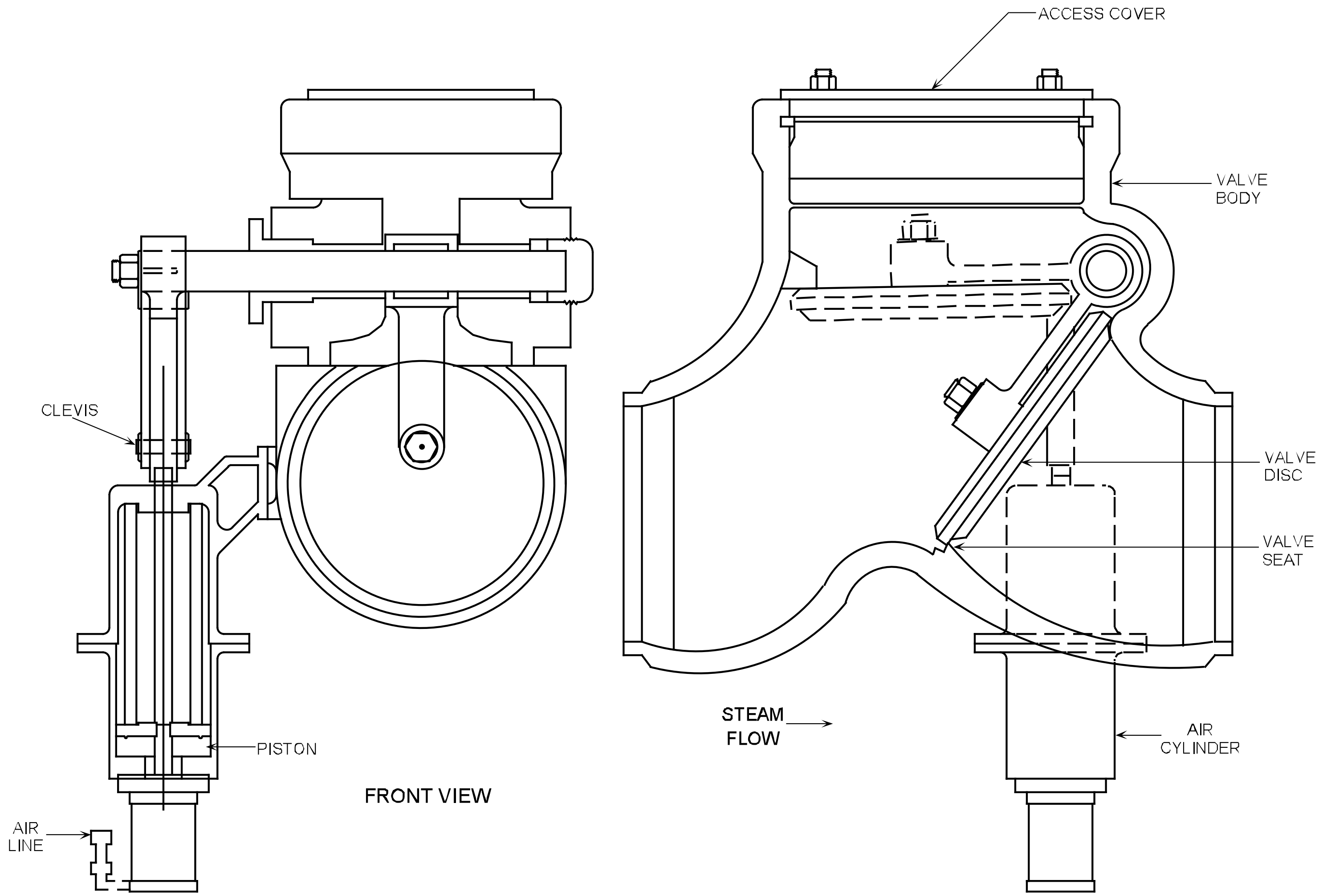

Figure 7.1-6 Main Steam Isolation Valve

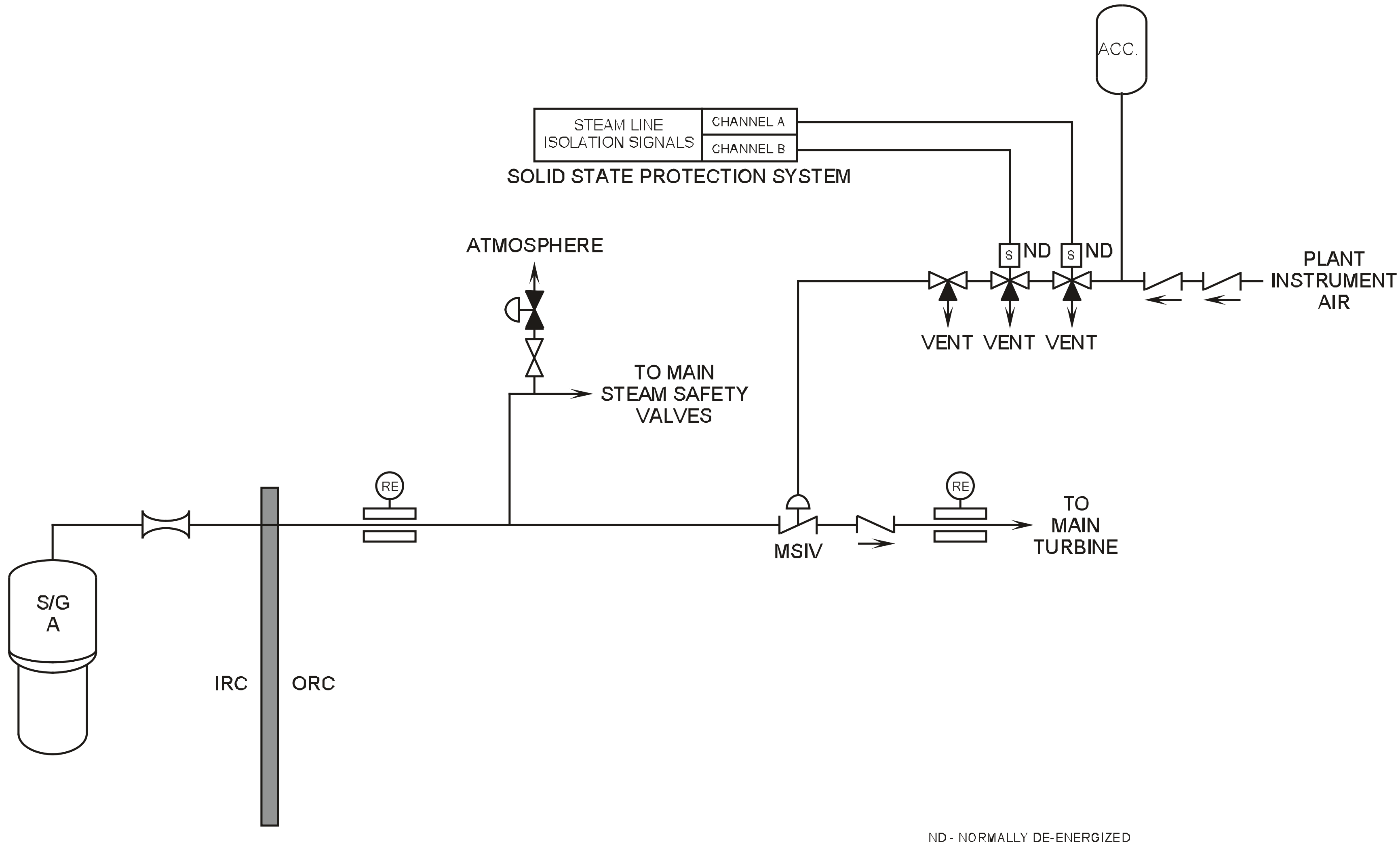

Figure 7.1-7 Main Steam Isolation valve Control

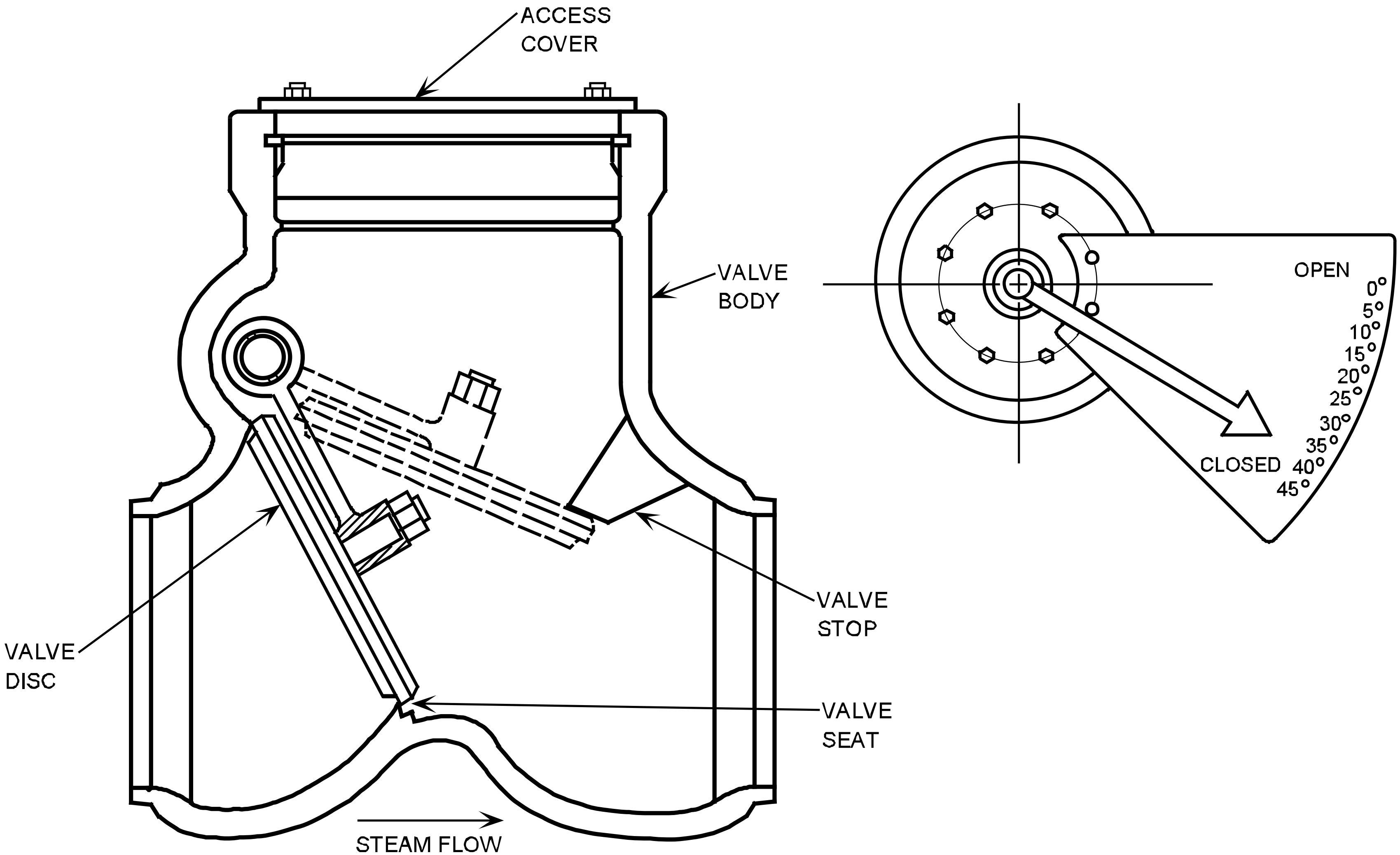

Figure 7.1-8 Main Steam Check Valve

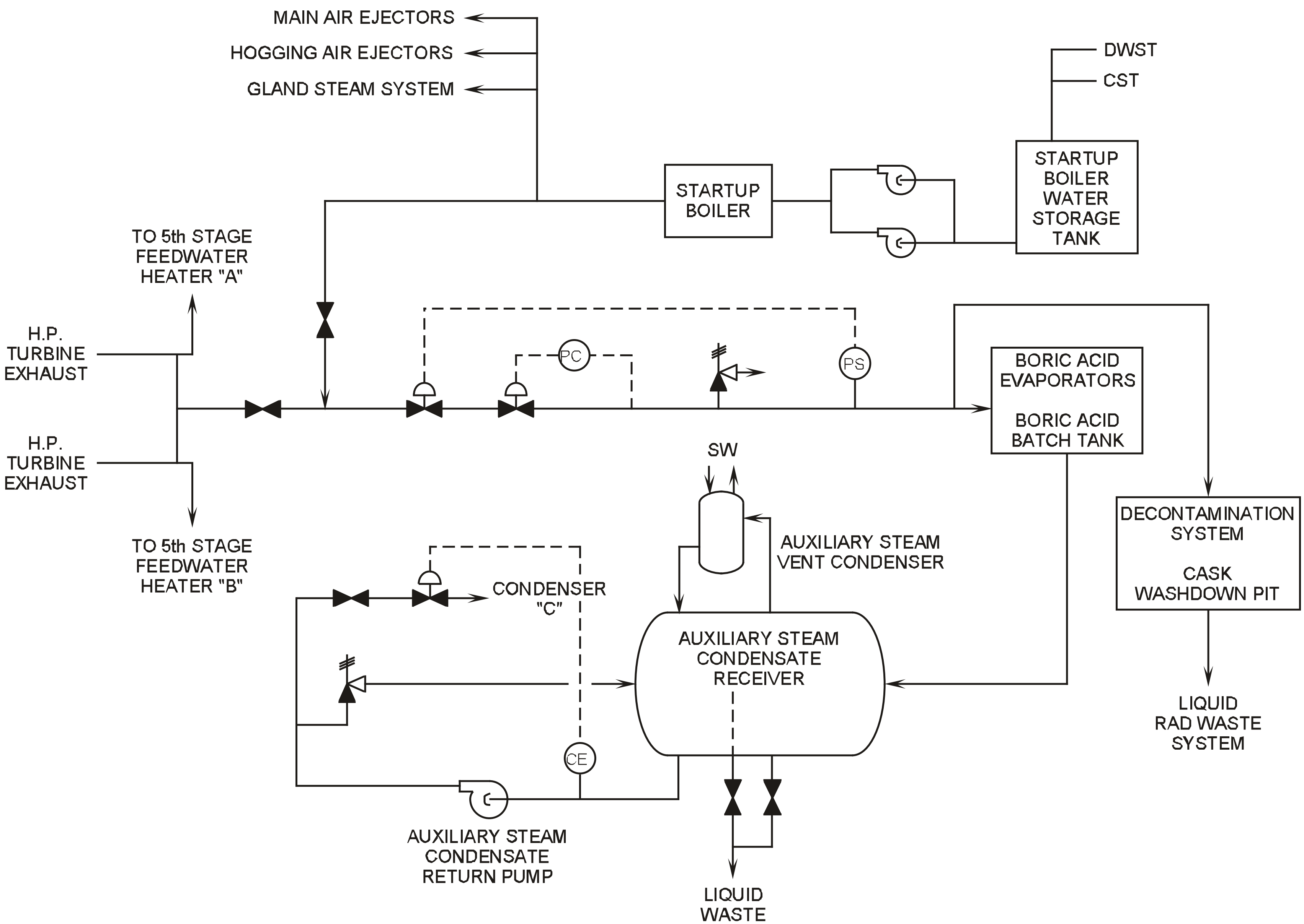

Figure 7.1-9 Auxiliary Steam System

Westinghouse Technology Systems Manual

Section 7.2

<u>Condensate and Feedwater System</u>

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7.2 CONDENSATE AND FEEDWATER SYSTEM

Learning Objectives:

1. List in proper flowpath order and state the purpose of the following condensate and feedwater system components:

    a. Condenser
    b. Condensate (hotwell) pumps
    c. Demineralizers
    d. Low pressure feedwater heaters
    e. Main feed pumps (MFPs)
    f. High pressure feedwater heaters
    g. Feedwater regulating and bypass valves
    h. Feedwater isolation valves (FWIVs)
    i. Steam generators
    j. Startup auxiliary feedwater (AFW) pump
    k. Heater drain system
    l. Condensate storage tank (CST)

2. List the components and connections located in the Seismic Category I portion of the feedwater system piping, and explain the purpose of each.

3. Explain how cascading heater drains increase plant efficiency.

7.2.1 Introduction

The purposes of the condensate and feedwater system are as follows:

1) To transfer water from the main condenser to the steam generators and to preheat it,
2) To collect and distribute heater drains, and
3) To purify secondary water and to maintain secondary chemistry control.

The condensate and feedwater system returns the condensed low-pressure turbine exhaust steam from the main condenser to the steam generators. The simplified flow path for this system is shown in Figure 7.2-1. The condensed turbine exhaust steam is collected in the hotwell sections of the main condenser. Each motor-driven condensate (hotwell) pump takes suction on the hotwell and pumps the condensate through the low pressure feedwater heaters. The condensate flow can be directed through the condensate demineralizers. The condensate demineralizers (ion exchangers) remove soluble impurities from the condensate. The low pressure heaters increase the temperature of the condensate before it reaches the suction of the main feedwater pumps.

The turbine-driven feedwater pumps increase the pressure of the condensate, now called feedwater, to a pressure greater than steam generator pressure and direct the feedwater to the steam generators. Before it reaches the steam generators, the feedwater passes through the high pressure feedwater heaters, the feedwater regulating valves, and the feedwater isolation valves. The high pressure heaters provide the final heating of the feedwater, the feedwater regulating valves control the water levels in the steam generators, and the feedwater isolation valves provide the means by which the safety-grade portions of the feedwater system can be isolated from the nonsafety-grade portions during accidents and certain transients. In the steam generators, the feedwater is converted to steam, and the secondary cycle is repeated.

In this section, detailed descriptions of the following topics are provided:

- Condensate system,
- Feedwater system,
- Heater drain system, and
- Secondary chemistry control.

7.2.2 System Description

7.2.2.1 Condensate System

The condensate system preheats, pressurizes, and purifies the condensate collected in the main condenser and transports it to the suctions of the main feedwater pumps. Refer to Figure 7.2-2. The condensate system contains two 70% capacity, motor-driven pumps, the condensate demineralizers, and five stages of low pressure feedwater heating.

The main condenser condenses and collects steam from the low-pressure turbine exhaust and/or the steam dump system (Chapter 11.2). The heat sink required to condense the steam is provided by the circulating water system (Chapter 14.3). The circulating water flows through the inside of the condenser tubes, and the exhaust steam is condensed on the outside of the tubes. The condensed steam (condensate) is collected in the three hotwell sections (hotwells A, B, and C) of the main condenser.

The hotwells provide a storage reservoir for the condensate system. This system is shown in detail in Figure 7.2-2. Each of the three condenser hotwells is divided into A train and B train sections. The A and B train sections are interconnected, and the trains are cross-connected at the B condenser hotwell. Each condensate pump takes suction on its associated train of hotwell sections and raises the pressure of the condensate. Downstream of the condensate pumps are connections to the condensate demineralizers.

The condensate demineralizer system consists of eight demineralizers containing filters coated with resin (precoat) as well as systems for removing spent precoat and applying fresh precoat. Refer to Figure 7.2-3. Each demineralizer vessel is a cylindrical tank with a bottom head, 6 ft in diameter and 10.8 ft in overall height. The vessels are made of carbon steel with epoxy phenolic coatings. Each vessel holds 420 nylon filter elements coated with ion exchange resin. The condensate passes through the precoat material first and then through the filters; the condensate is thus purified via ion exchange and filtration. Each vessel can treat 4317 gpm of condensate at 134.5°F and 565 psig.

During normal operation, six vessels contain precoat material consisting of ammonia cation and hydroxide anion resins, while a seventh vessel contains precoat material consisting of hydrogen cation and hydroxide anion resins. The first six vessels are capable of full condensate flow, while the flow through the seventh demineralizer is throttled manually to maintain condensate pH between 9.3 and 9.6. (The eighth demineralizer would be in standby or undergoing replacement of spent precoat.)

The condensate demineralizer system has a flow balancing controller which ensures equal flow through all demineralizers that are maintained in automatic operation. Without flow balancing, the “cleaner” demineralizers would pass more flow than the “dirtier” ones, due to the differential pressures (ΔPs) across the filter elements; eventually all demineralizers would be equally dirty. This condition would necessitate replacement of the precoat in all demineralizers at the same time. As a demineralizer’s precoat is exhausted, the conductivity of the vessel contents and the ΔP across the vessel increase. The condensate demineralizer bypass valves will open automatically if the ΔP across any demineralizer exceeds 60 psid.

When demineralizer conditions necessitate precoat replacement, the demineralizer is removed from service. The spent precoat is back washed from the filter elements with water from the CST. The resultant resin-water mixture is drained to the backwash receiver tank for processing. Fresh anion and cation resins are then combined as a slurry and pumped into the demineralizer vessel by the precoat pump.

The demineralizers are not normally in service continuously because morpholine, used to control secondary pH (see Section 7.2.2.4), exhausts demineralizer resin at a high rate. During at-power operation, the demineralizers are placed in service when there are condenser tube leaks or when some contaminant has been introduced into the secondary. Condensate flow through the demineralizers is established on either a single-train or two-train basis by closing either or both of the condensate demineralizer bypass valves. During a startup, condensate (feed) flow is recirculated to the condenser via the demineralizers to establish the appropriate secondary chemistry parameters.

Downstream of the connections to the condensate demineralizer system are five stages of low pressure heaters. Refer to Figure 7.2-2. In each condensate train, the first two stages of heating consist of three parallel paths of two heaters each; the condensate flow then converges and passes through three single-heater stages. The 12 heaters which comprise the first 2 stages of heating are located in the condenser shells. Each train of low pressure heaters can only be isolated at the outlet of the fifth-stage heater. Therefore, in order to repair one heater, all first- through fifth-stage heaters in the associated string must be taken out of service. If a string of heaters is taken out of service, power must be reduced to 70% or less.

All feedwater heaters are U-tube heat exchangers. Refer to Figure 7.2-4. The shells are carbon steel, and the tubes are stainless steel. Steam enters the shell side of each heater, and condensate flows through the U tubes. The steam passes over the tubes and heats the condensate. The condensed steam collects in the drain cooler section of the heat exchanger. The drain cooler is a water-to-water heat exchanger formed within the heater shell by a baffle which envelopes some of the tubes at the condensate (or feedwater) inlet. The condensed heating steam is subcooled there before it drains from the heater. The heater drain system is discussed in Section 7.2.2.3.

The first five stages of feedwater heating increase the condensate temperature from 120°F to 360°F. Heating steam for the first four stages of feedwater heating is supplied by extraction steam from the low pressure turbine. Steam for the first-, second-, third-, and fourth-stage heaters is taken from the eleventh, tenth, eighth, and seventh stages of the low pressure turbines, respectively. Steam for the fifth-stage heaters is taken from the high pressure turbine exhaust. Preheating the condensate (feedwater) results in an efficiency gain of approximately 15% over non-preheating systems.

The discharges of the low pressure heater trains are cross-connected by a 16-in. header. The heater drain pumps also discharge to this header. The combined condensate and heater drain flow provides the suction for the main feed pumps.

7.2.2.2 Feedwater System

The feedwater system preheats and pressurizes the discharge from the condensate system and the heater drain pumps and transports it to the steam generators. The feedwater system extends from the feed pump suction valves to the inlets of the steam generators. Refer to Figure 7.2-5. The feedwater system includes two 70% capacity, variable speed, turbine-driven pumps and two trains of high pressure feedwater heaters.

The MFPs discharge to the high pressure feedwater heaters via cross-connected headers. The high pressure heaters consist of two trains of two heaters each. The high pressure heaters are U-tube heat exchangers constructed of carbon steel shells and stainless steel tubes. The heaters have integral drain coolers and a tube-side (feedwater) design pressure of 1700 psig. The feedwater temperature is raised from 360°F to 397°F in the sixth-stage heaters and to 440°F in the seventh-stage heaters. The extraction steam supplying these heaters is taken from the fourth stage of the high pressure turbine for the sixth-stage heaters and from the second stage of the high pressure turbine for the seventh-stage heaters. One high pressure feedwater heater string can be isolated, provided that plant power is first reduced to 95% or less.

Feedwater from the high pressure heater trains flows into a common 30-in. feed header. This common header contains a pressure transmitter (PT-508) which provides indication on the main control board and an input to the MFP speed control system. The header also contains a recirculation line to the main condenser. This line directs recirculation of feedwater for demineralization, deaeration, and filtration of the feedwater during plant startups. The recirculation line isolation valve is shut during normal at-power operation.

The common feed header splits into four 14-in. feed lines which supply the individual steam generators. Each feed line contains a 14-in. feedwater regulating valve and a 6-in. bypass valve in parallel. Each feedwater regulating valve has an automatic control system which is discussed in detail in Chapter 11.1. The bypass valves are operated manually. Immediately downstream of each feedwater regulating and bypass valve is a feedwater isolation valve (FWIV).

From the first piping restraints upstream of each set of FWIVs to the steam generator feedwater inlet, the feedwater piping is Seismic Category I. Downstream of the feedwater isolation valves, each feed line contains a flow venturi with two flow transmitters. The function of the flow transmitters is discussed in Chapter 11.1. Downstream of each venturi is a check valve. The check valve prevents the loss of steam generator inventory through an upstream feedwater system break. Downstream of the check valve are connections for shutdown chemistry addition and for auxiliary feedwater entry.

7.2.2.3 Heater Drain System

The heater drain system collects condensed steam from the moisture separator reheaters (MSRs) and from the high and low pressure feedwater heaters and returns it to the condensate and feedwater system. Refer to Figures 7.2-6 and 7.2-7.

The drains from the seventh-stage heaters are cascaded or drained to the sixth-stage heaters, which in turn drain to the fifth-stage heaters. The cascading effect ends with the fifth-stage heaters; they drain to the heater drain tanks. Two heater drain pumps transport the collected drains from the heater drain tanks to the condensate system cross-connect header downstream of the low pressure heaters. During full-power operation, the heater drain pumps supply about one third of the total flow at the suctions of the MFPs. Plant power is limited to 90% with only one operating heater drain pump.

The drains from the low pressure heaters are also cascaded. The fourth-stage heaters drain to the third-stage heaters, the third-stage heaters drain to the second-stage heaters, the second-stage heaters drain to the first-stage heaters, and the first-stage heaters drain to the main condenser. The cascading of heater drains improves secondary plant efficiency by allowing the repeated use of relatively hot water for feedwater heating; if each heater were to drain directly to the condenser, a great deal of energy would be lost from the system. Preheating of the feedwater by extraction steam and heater drains means that nearly all of the energy transferred to the feedwater in the steam generators by the reactor coolant system is added as the latent heat of vaporization; comparatively little sensible heating is required to bring the feedwater to saturation.

7.2.2.4 Steam Generator Chemistry Control

During plant operation the control of steam generator chemistry is accomplished by the purification of condensate, by the injection of chemicals into the condensate system to scavenge oxygen and to control pH, and by steam generator blowdown.

Purification of the condensate is performed by the condensate demineralizer system through the ionic exchange process. Ionic impurities (from condenser tube leaks, poor-quality makeup water, etc.) in the condensate system are removed on an as-needed basis by placing the demineralizers in service.

The condensate and feedwater chemical injection system is designed to supply the following to the condensate system, the AFWS and main feedwater systems:

1) Morpholine to the condensate in an amount required for adjustment of pH of the feedwater during normal operation. (Morpholine will not be used for cycle 14 secondary system pH control)
2) Hydrazine to the condensate in an amount required to scavenge oxygen during normal operation.
3) Ammonium chloride (or other chloride solution) to the condensate or feedwater in an amount required to control the steam generator cation-to-anion ratio per Chemistry Procedures. steam generator chloride concentrations will be maintained below the specifications of the Chemistry Procedures and FSAR.

Chemical injection of hydrazine (N_2H_4) for oxygen control and morpholine (C_4H_9NO) for pH control contributes to steam generator chemistry control by minimizing corrosion. Morpholine injection is secured when the condensate demineralizer system is placed in service, and secondary pH is affected by hydrazine addition only (some of the hydrazine decomposes into ammonia [NH_3], a weak base). These chemicals are pumped into a low temperature portion of the condensate system just downstream of the demineralizer system connections (see Figure 7.2-2) to prevent the breakdown of hydrazine. Separate connections for shutdown chemical addition are immediately upstream of the feedwater containment penetrations (see Figure 7.2-5). The volatility of the chemical treatment prevents undesirable chemical concentrations in the steam generators.

Each steam generator acts as a chemical concentrator. The boiling of the feedwater leaves concentrated impurities in the steam generator, which are removed by the steam generator blowdown system. The blowdown system, as shown in Figure 7.2-8, consists of blowdown taps from each steam generator, isolation valves, blowdown flow control valves, a blowdown tank, a heat exchanger, a pump, blowdown ion exchangers and filter, a radiation monitor, and piping for blowdown discharge to the condenser and to the environment.

The function of the steam generator blowdown system is to maintain the steam generator secondary-side water within the chemical specifications prescribed, while treating the blowdown for return to the condenser. Primarily, the steam generator blowdown system will remove impurities that come from sources such as primary-to-secondary leakage, main condenser leakage, and corrosion products.

The blowdown flow rate from each of the four steam generators is individually, manually controlled (100 gpm maximum per steam generator). The blowdown water entering the blowdown tank undergoes a pressure drop across the blowdown flow control valves; some of the water flashes to steam. Most of the steam is condensed by the water in the tank, the rest is directed to the condenser (< 50% power), to feedwater heater 3B (> 50% power), or to the atmosphere (condenser not available). The liquid effluent from the blowdown tank is cooled in the blowdown heat exchanger (service water is the heat sink), purified, and filtered before being discharged to the condenser or to the environment.

7.2.3 Component Descriptions

7.2.3.1 Condensate System Components

Main Condenser

The main condenser is a single-pass, three-shell, multipressure, deaerating, surface condenser. Each shell is located below one of the three low pressure turbines. The condenser tubes are arranged in bundles which cross the condenser shells perpendicular to the longitudinal axis of the main turbine. Refer to Figure 7.2-9.

Each condenser shell is connected to its associated low-pressure turbine's outer casing by an expansion bellows, which isolates turbine expansion and vibration from the condenser. The first- and second-stage feedwater heaters are located in the upper portion of each condenser shell just below the entry of turbine exhaust. This area of the condenser shell is called the neck. Each of the low pressure heater trains has first- and second-stage heaters located inside each condenser shell. Each pair of first- and second-stage heaters is installed within a single shell, so that each condenser shell actually contains two heater shells. This arrangement saves floor space, reduces the insulation required for the heaters, and allows shorter piping runs. Below the low pressure heaters are the tube bundles.

The main condenser tubes are constructed of titanium, which is virtually impervious to corrosion. (The condensers at several plants have been retrofitted with titanium tubes for improved corrosion performance.) Each of the approximately 60,000 tubes is 1.25 in. in diameter; tube lengths vary between condenser shells. A different pressure is maintained in each of the three shells. The shells are designed to operate at the following pressures at full power: 3.30 in. Hg for the low pressure (A) shell, 4.00 in. Hg for the intermediate pressure (B) shell, and 5.11 in. Hg for the high pressure (C) shell. The interconnected hotwells below the three shells are maintained at a pressure of 6.73 in. Hg.

Circulating water flows through the three condenser shells in series, entering first the low pressure shell, then the intermediate pressure shell, and finally the high pressure shell. Refer to Figure 7.2-10. The circulating water is heated as it flows through the shells. In order to maintain the heat transfer capability of each condenser shell approximately equal, the heat transfer surface area increases in the direction of circulating water flow. Each shell has the same number of tubes; different heat transfer areas are accomplished with different tube lengths. The tube lengths are 35 ft in the low pressure shell, 45 ft in the intermediate pressure shell, and 55 ft in the high pressure shell. The total heat transfer surface area of the condenser is approximately 900,000 ft^2. The tubes are supported by divider plates spaced along their length. The tubes are welded to tube sheets attached to the inlet and outlet water boxes.

At the center of each tube bundle is a gas collecting space. Noncondensible gases are directed across the relatively cold central tubes and then routed through air off-take piping that penetrates the inlet water boxes. The air off-take pipes of the three shells are connected in parallel. Noncondensible gases are then directed to the suctions of the air ejector assemblies. If gases were not removed, a reduction in vacuum and a loss of turbine efficiency would result.

Gases leaking into the condenser or being stripped from the condensate can blanket the condenser tubes. This would reduce the heat transfer capability of the condenser. The condenser air removal system removes air and noncondensible gases from the condenser shells. During plant startups the three hogging air ejectors draw air from the condenser shells to establish the initial condenser vacuum. During plant operations one or both of the main air ejector assemblies maintain a minimum condenser vacuum of 25 in. Hg. Refer to Figure 7.2-11.

The air ejectors are jet pumps supplied with main steam through a reducing valve. The two 100% capacity, two-stage main air ejector assemblies exhaust to the turbine roof via inter and after condensers and the off-gas system. Conductivity monitors are placed on the inter and after condenser drains to detect condenser tube leaks. A radiation monitor samples gases in the off-gas system prior to their release above the turbine building roof, and gases can be directed through a charcoal adsorber if necessary. The 1200-scfm, single-stage hogging air ejectors exhaust directly to the atmosphere outside the turbine building.

Condensed water in the condenser shells collects below the tube bundles on intermediate bottom plates in the hotwells. Refer to Figure 7.2-12. Condensers A and B have two such plates, which form intermediate and lower hotwell sections, while condenser C has only one. At each intermediate bottom plate, the condensate flows into sumps which contain heatup devices, each of which is a series of perforated plates. The plates break up the condensate into droplets which are heated as they fall through steam. In the lower hotwell section of each condenser, the steam is provided by feed pump turbine exhaust. The feed pump turbine exhaust is piped to the lower hotwell of condenser C first and then to the lower hotwells of the other two condensers via steam crossover piping. Some of the feed pump turbine exhaust steam is directed from the condenser C lower hotwell into the condenser C shell. Similarly, heating steam from the condenser C shell is supplied to the intermediate hotwells of the other two condensers via crossover piping. The steam passages are sized and orificed so that, at design load and circulating water temperature, the appropriate pressures are maintained in the various sections of the condensers.

The lower hotwell of each condenser is divided into train A and train B sections by a longitudinal plate. The train A sections are interconnected, as are the train B sections. The longitudinal plate in the B condenser hotwell has a hole to equalize the levels in the two hotwell sections. Condenser B has separate train A and train B hotwell level control systems, only one of which is in service at any time due to the level balancing in the B condenser hotwell described above. As the other condenser hotwells are connected to the condenser B hotwell, controlling the B hotwell level provides control of the entire condenser hotwell inventory. Inventory control is discussed in more detail in Section 7.2.3.5. The train A and train B condensate pumps take suction on the condenser B train A and train B hotwell sections, respectively.

Condensate (Hotwell) Pumps

Two condensate pumps take suction on condenser B through suction strainers and manual isolation valves. The pumps are eight-stage, vertical, centrifugal pumps driven by 3950-hp motors. The pumps are powered from 12.47-kVac service buses. The thrust and upper guide bearings of the pump motors are oil lubricated; the motor oil coolers are cooled by the bearing cooling water system. Each pump's lower radial bearing is grease lubricated and air cooled. Cooling water for the condensate pump shaft seals is supplied by the condensate transfer pumps. Each condensate pump supplies 11,000 gpm with 1100 ft of head (approximately 477 psi).

The discharge of each pump is provided with a recirculation line to the hotwell of condenser B to protect the pump from overheating. The recirculation valve in each line is controlled as a function of the associated pump's discharge flow. Each valve opens with a discharge flow rate of 3500 gpm and closes with a flow rate of 7000 gpm. The recirculation valves are automatically opened by a feedwater isolation signal.

Operation with the condensate demineralizers bypassed causes an increase in the discharge pressure of the condensate pumps due to the reduced flow resistance. The increased pressure at the discharge of the heater drain pumps decreases the flow from the heater drain tank, resulting in the loss of heater drain tank level control. To avoid this effect, with the demineralizers bypassed the recirculation valve for one condensate pump is manually opened about 50%, thereby reducing condensate pump discharge pressure and increasing heater drain pump flow.

The discharge of each pump is equipped with a motor-operated isolation valve, which is manually operated from the main control board. The isolation valve is closed when the pump is off and opened after the pump is started. Downstream of the discharge isolation valves and the discharge flow elements, the condensate trains are cross-connected by a 24-in. line. The discharge of each pump can be aligned to the condensate demineralizer system. The discharge of condensate pump B also supplies the MFP seal water system and the heater drain pump seals.

7.2.3.2 Feedwater System Components

Main Feedwater Pumps

The MFPs are horizontal, single-stage, centrifugal pumps, each coupled to a nine-stage impulse turbine. Each pump has a dedicated lubricating oil system for its bearings. Each pump has a variable capacity up to 19,800 gpm with a discharge head of 2020 ft. Each pump can support operation up to 70% of main turbine load. An independent speed controller, operated automatically or manually, is provided for each pump. The turbine speed is varied to maintain a programmed ΔP across the feedwater regulating valves. The MFP speed control program is discussed in Chapter 11.1.

Each MFP turbine is supplied with steam from the main steam bypass header during startups and low-load operations and with reheated steam from one MSR during normal operation at higher loads. Steam is supplied via a dual control valve system, with one control valve from each steam supply.

The control valve from the main steam (high pressure) supply does not begin to open until the control valve from the MSR (low pressure) supply is fully open. During low-load and startup conditions, both turbine control valves are open, with the main steam supply controlling MFP speed. At higher load conditions, the MSR supply pressure will be high enough to handle any demands on the MFPs, and the main steam supply control valve for each pump will be fully shut. The MFPs are equipped with protective trips, some of which trip an individual pump and some of which trip both pumps. The following is a list of individual MFP trips:

- Low lubricating oil pressure (5 psig),
- Turbine overspeed (5850 rpm),
- Low turbine exhaust vacuum (20 in. Hg),
- High turbine exhaust temperature (230°F),
- Excessive thrust bearing wear,
- High discharge pressure (1850 psig),
- Suction isolation valve not fully open, and
- Associated condensate pump trip.

Any of the following conditions will cause a trip of both MFPs:

- Engineered safety features actuation signal,
- Reactor trip (P-4) and low T_{avg} (564°F),
- High steam generator level (89.3%), as sensed by two out of three level detectors on any steam generator, and
- Low suction pressure (195 psig).

Each MFP has a recirculation line to condenser C. The lines ensure minimum flow through the pumps. The minimum flow valves are automatically controlled by suction flow transmitters. Each recirculation valve opens when the flow through its associated pump drops to less than 4000 gpm, and it closes when the flow increases above 9000 gpm. The recirculation valves automatically open with a feedwater isolation signal.

Feedwater Isolation Valves (FWIVs)

Immediately downstream of each feedwater regulating valve and each bypass valve is an FWIV. (An FWIV for each regulating and bypass valve is specific to the Trojan plant design; Westinghouse design plants more typically have one FWIV for each steam generator, i.e., one FWIV for each regulating valve/bypass valve pair.) The valves have hydraulic operators; a nitrogen-charged accumulator supplies the hydraulic fluid for each valve. Each accumulator is capable of one closure and one opening of its associated FWIV before hydraulic pressure is restored. The valves have a maximum closing time of 16 seconds.

The FWIVs are automatically closed by a feedwater isolation signal, which is generated by any of the following:

- High steam generator level (83.9%), as sensed by two out of three level detectors on any steam generator,

- Engineered safety features actuation signal, and
- Reactor trip (P-4) and low T_{avg} (564°F), as sensed in two out of four reactor coolant loops.

Each FWIV can also be manually opened or closed at a control panel in the turbine building. (Controls for the FWIVs are more typically located in the main control room at a Westinghouse design plant.)

7.2.3.3 Startup Auxiliary Feedwater Pump

To avoid wear and tear on the safety-grade auxiliary feedwater (AFW) pumps, a nonsafety-grade startup AFW pump provides feed flow to the steam generators during normal startups and shutdown periods, when main steam and MSR steam are not available. The 1250-hp, motor-driven, eight-stage centrifugal pump supplies 1020 gpm (including 140 gpm of recirculation flow) at a discharge head of 3400 ft (1472 psi). The pump has no automatic start features. It is normally powered from a plant service bus but can be aligned to diesel generator A.

The startup AFW pump takes suction on the condensate storage tank and discharges to the discharge line of either the diesel-driven or turbine-driven AFW pump. Refer to Figure 7.2-13. An isolation valve for each discharge path is provided; one must be shut during operation of the startup AFW pump to ensure separation of the two safety-grade AFW trains. Upstream of the discharge isolation valves is a manually or automatically controlled flow control valve. In automatic, the control system throttles flow to maintain a selected ΔP between the pump discharge and steam generator C. The normal setpoint is 100 psid.

7.2.3.4 Heater Drain System Components

The heater drain system collects the condensate from the feedwater heaters and MSRs and returns it to the condensate and feedwater system. Refer to Figures 7.2-6 and 7.2-7. The system consists of six drain tanks for the two MSRs and associated piping, the feedwater heater shells and associated piping, two heater drain tank pumps, and two heater drain tanks.

Moisture Separator Reheater Drains

Each MSR has three drain tanks: one for the condensate from the first-stage heater tubes (first-stage reheater drain tank), one for the condensate from the second-stage heater tubes (second-stage reheater drain tank), and one for the condensate from the MSR shell (moisture separator drain tank). These drain tanks are located below the MSR shells and function to provide a seal between the high pressure steam in the MSRs and the lower pressure feedwater heater shells or heater drain tanks to which they drain. Each drain tank has a level control system to maintain the water seal.

The second-stage reheater drain tanks receive the condensate from the MSR second-stage reheater tubes. These tanks normally drain to the seventh-stage feedwater heater shells. The drain flow from each tank is automatically controlled to maintain tank level. The level control valve closes automatically on a high level in the associated seventh-stage heater shell, regardless of tank level. A high drain tank level causes its alternate drain valve to open, allowing the tank to drain to one of the heater drain tanks.

The first-stage reheater drain tanks receive the condensate from the MSR first-stage reheater tubes. These tanks normally drain to the sixth-stage feedwater heater shells. The drain flow from each tank is automatically controlled to maintain tank level. The level control valve closes automatically on a high level in the associated sixth-stage heater shell, regardless of tank level. A high drain tank level causes its alternate drain valve to open, allowing the tank to drain to one of the heater drain tanks.

The moisture separator drain tanks receive drains from the MSR shells. This condensate is the moisture removed from the cold reheat steam by the chevron separators in the MSRs. The drain flow into each tank is about 1.5×10^6 lbm/hr at 100% load. These tanks normally drain to the heater drain tanks. The drain flow from each moisture separator drain tank is automatically controlled to maintain tank level. A high moisture separator drain tank level causes its alternate drain valve to open, allowing the tank to drain to condenser A.

Each of the six MSR drain tanks is vented to the source of the drains to remove noncondensible gases.

High Pressure Heater Drains

The seventh-stage heater shells receive heating steam from the second stage of the high-pressure turbine and drains from the second-stage reheater drain tanks. These heaters normally drain to the sixth-stage heater shells. The drain flow from each seventh-stage heater is automatically controlled to maintain shell level. The level control valve closes automatically on a high level in the associated sixth-stage heater shell, regardless of the seventh-stage shell level. A high shell level causes the heater's alternate drain valve to open, allowing the heater to drain to a heater drain tank. A very high shell level causes the drain and extraction steam inlets to the heater to isolate.

The sixth-stage heater shells receive heating steam from the fourth stage of the high-pressure turbine and drains from the first-stage reheater drain tanks and seventh-stage heaters. These heaters normally drain to the fifth-stage heater shells. The drain flow from each sixth-stage heater is automatically controlled to maintain shell level. The level control valve closes automatically on a high level in the associated fifth-stage heater shell, regardless of the sixth-stage shell level. A high shell level causes the heater's alternate drain valve to open, allowing the heater to drain to a heater drain tank. A very high shell level causes the drain and extraction steam inlets to the heater to isolate.

The fifth-stage heater shells receive heating steam from high pressure turbine exhaust and drains from the sixth-stage heaters. These heaters have no drain coolers and drain directly to the heater drain tanks without level control. A very high fifth-stage shell level causes the drain and extraction steam inlets to the heater to isolate.

Heater Drain Tanks and Pumps

The heater drain tanks are horizontal 13,120-gal tanks. Each tank normally receives drains from its associated fifth-stage heater and moisture separator drain tank. Each tank also receives alternate drains from the associated sixth- and seventh-stage heaters and first- and second-stage reheater drain tanks. Each tank is designed for 220 psig and 400°F. The tanks are cross-connected by a 20-in. line. A dump valve which taps off the cross-connection drains the tanks to condenser A on a high level in either tank.

Each heater drain pump takes suction on one of the heater drain tanks. The pumps are canned-suction, vertical, centrifugal pumps rated at 5950 gpm and 575 psig. The pumps are powered from station service buses. The heater drain pump seals are supplied with cooling water from the condensate pumps.

A heater drain tank level control system maintains levels in the tanks by controlling the heater drain pump discharge valves. If the combined pump discharge flow is less than 2400 gpm, the recirculation lines to the heater drain tanks open to prevent pump overheating. The pumps discharge into a combined header which taps into the condensate cross-connect header just upstream of the MFP suctions.

Low Pressure Heater Drains

The control of inputs to and outputs from the low pressure heaters is similar to that of the high pressure heaters. The fourth-stage heater shells receive heating steam from the seventh stage of the low pressure turbines. These heaters normally drain to the third-stage heater shells. The drain flow from each heater is automatically controlled to maintain shell level. The level control valve closes automatically on a high level in the associated third-stage heater shell, regardless of the fourth-stage shell level. A high shell level causes the heater’s alternate drain valve to open, allowing the heater to drain to condenser C. A very high shell level causes the extraction steam inlet to the heater to isolate.

The third-stage heater shells receive heating steam from the eighth stage of the low-pressure turbines and drains from the fourth-stage heaters. Each heater normally drains to the three second-stage heater shells of the same condensate train. The drain flow from each heater is automatically controlled to maintain shell level. The level control valve closes automatically on a high level in any of the associated second-stage heater shells, regardless of the third-stage shell level. A high shell level causes the heater’s alternate drain valve to open, allowing the heater to drain to condenser C. A very high shell level causes the extraction steam and drain inlets to the heater to isolate.

As discussed in the main condenser description, each pair of first-and second-stage heaters is contained within a single shell, with the heaters separated by a longitudinal partition plate. These heaters are located in the necks of the three condenser shells. There are a total of 6 pairs of first- and second-stage heaters (12 heaters total), one from each condensate train in each condenser shell.

Each second-stage heater shell receives heating steam from the tenth stage of one low pressure turbine and about one third of the drains from its associated third-stage heater. Each heater normally drains to the first-stage heater with which it is paired. The drain flow from each heater is automatically controlled to maintain shell level. The level control valve closes automatically on a high level in its associated first-stage heater shell, regardless of the second-stage shell level. A high shell level causes the heater's alternate drain valve to open, allowing the heater to drain to the condenser shell in which it is situated. A very high shell level causes the drain inlet to the heater to isolate.

Each first-stage heater shell receives heating steam from the eleventh stage of one low pressure turbine and drains from its associated second-stage heater. Each heater normally drains to the condenser shell in which it is situated. The drain flow from each heater is automatically controlled to maintain shell level. A high shell level causes the heater's alternate drain valve to open, which bypasses the normal level control valve. A very high shell level causes the drain inlet to the heater to isolate.

The first- and second-stage heaters do not have isolation valves for the incoming extraction steam. The extraction steam supplies to these heaters are equipped with check valves designed to prevent reverse steam flow from the heaters to the low pressure turbines. A large condensate tube leak could cause inflow to a heater shell in excess of the capacities of the normal level control and alternate drain valves. In such an instance, water could back up into the extraction steam supply piping and leak past the check valve, causing damage to the affected low pressure turbine. When the rate of tube leakage to a heater shell exceeds the drain capacity, the condensate flow to that heater (and thus to the entire condensate train) must be isolated to prevent turbine damage.

7.2.3.5 Condensate Storage Tank (CST)

The CST is the source of makeup water for the condensate and feedwater system and also the primary source of water for the AFW system. The CST is a covered, outdoor storage tank with a capacity of 450,000 gal. Technical Specifications require a minimum stored volume of 239,000 gal, which accounts for 27,700 unusable gal in the bottom of the tank and a 14,400-gal allowance for level instrument error. This volume ensures that there is a sufficient supply for the AFW system to maintain the plant in hot standby for two hours and then to cool down the plant to 350EF in four hours. The CST level transmitters provide indication, high- and low-level alarms, and low-level AFW pump trips.

The in-service condenser hotwell level control system controls the condensate and feedwater system inventory by either rejecting condensate to or gravity draining water from the CST. Figure 7.2-2 shows the components involved in level control. The normal setpoint for the hotwell level of condenser B is 24 in. When the level reaches 28 in., the condensate reject valve downstream of one of the condensate pumps begins to open; the valve is fully open with a hotwell level of 40 in. The makeup valve begins to open when the hotwell level falls to 21 in.; the valve is fully open with a hotwell level of 8 in.

7.2.4 System Operation

During the early stages of a plant startup, the startup AFW pump typically provides feed flow to the steam generators. Decay heat and reactor coolant pump heat are transferred to the feedwater in the steam generators.

As the temperature of the reactor coolant system increases toward the normal operating band, the condensate and feedwater systems are readied for service. If necessary, the system is filled and vented. The fill water comes from the CST. The lubricating oil systems for the two MFPs are verified operable and placed in service, in preparation for pump operation. Next, one of the condensate pumps is started, and its associated discharge valve is opened. The MFP recirculation valves are opened, allowing recirculation of condensate through the idle MFPs to the condenser hotwell. Gland steam and seal water to the MFPs will be started at this time.

Once a condensate pump has been placed in service, the condensate and feedwater systems are aligned for secondary plant cleanup. The startup recirculation valve is opened, and condensate flow is directed through the condensate demineralizers and throughout the system, up to the common feed header downstream of the high pressure heaters. If the conditions warrant it, the recirculation flow can be limited to smaller portions of the system through the use of the condensate pump or MFP recirculation valves and the closing of appropriate isolation valves. Secondary cleanup is continued until all secondary chemistry parameters are satisfied and within their respective limits. The FWIVs remain closed during the cleanup process.

Once reactor power has reached the point of adding heat, one of the MFPs is started. The operator resets the feedwater isolation signal, closes the startup recirculation valve, and manually rolls the MFP with an individual pump governor control switch. When the maximum output of the governor control switch has been reached and normal operating conditions for the pump have been attained, the individual pump's speed controller is placed in automatic (slaved to the MFP master speed controller). The operator then manually controls the pump's speed with the master speed controller by maintaining a suitable ΔP between the feedwater and steam pressures. The bypass valve FWIVs are opened, and the bypass valves are throttled open while the AFW flow control valves are throttled closed. The steam generator water levels are maintained at the appropriate values at low powers through manual control of the bypass valves and the MFP master speed controller.

When the plant reaches approximately 20% power, the MFP master speed controller is placed in automatic, and steam generator water level control is shifted from the bypass valves to the feedwater regulating valves. The individual water level controllers are placed in automatic. During the remainder of the power ascension, the second condensate pump and MFP are placed in service before power exceeds 70%, the first heater drain pump is placed in service at approximately 30% power, and the second heater drain pump is placed in service before power exceeds 90%.

7.2.5 PRA Insights

The purpose of the plant's power conversion system is to convert the heat removed from the reactor core into electrical energy, which is provided to consumers by that plant's utility. Even though the plant's Technical Specifications contain few provisions which apply to the main feedwater portion of the power conversion system, there are some transients initiated by the loss of feedwater which can lead to core damage. However, the associated sequences typically account for a very small fraction of the total core damage frequency (0.6% for Sequoyah and an insignificant percentage for Zion, Surry, and Trojan). Modifications to the power conversion system would not contribute significantly to risk reduction or risk achievement values.

7.2.6 Summary

The main condenser is a multi-pressure, three-shell, surface condenser. The condenser receives exhaust steam from the low pressure turbines, steam dumps, and the MFP turbines. Condensate enters the condenser from the condensate pump recirculation lines, the MFP recirculation lines, the low pressure feedwater heater drains, and the CST (hotwell makeup). The condensate pumps transfer the condensate from the main condenser through the demineralizers and low pressure heaters to the suction of the MFPs. The MFPs take suction on the discharge from the condensate pumps and heater drain pumps and transfer feedwater through the high pressure heaters, feedwater regulating valves or bypass valves, and FWIVs to the steam generators. The condensate and feedwater system supplies an automatically controlled flow of high pressure, preheated feedwater to maintain the desired steam generator water levels.

The heater drain system improves plant efficiency by collecting the high temperature drainage from the MSRs and feedwater heaters and by transferring the drains back to the condensate and feedwater system.

During plant operation the control of steam generator chemistry is accomplished by the purification of condensate, by the injection of chemicals into the condensate system to scavenge oxygen and to control pH, and by steam generator blowdown.

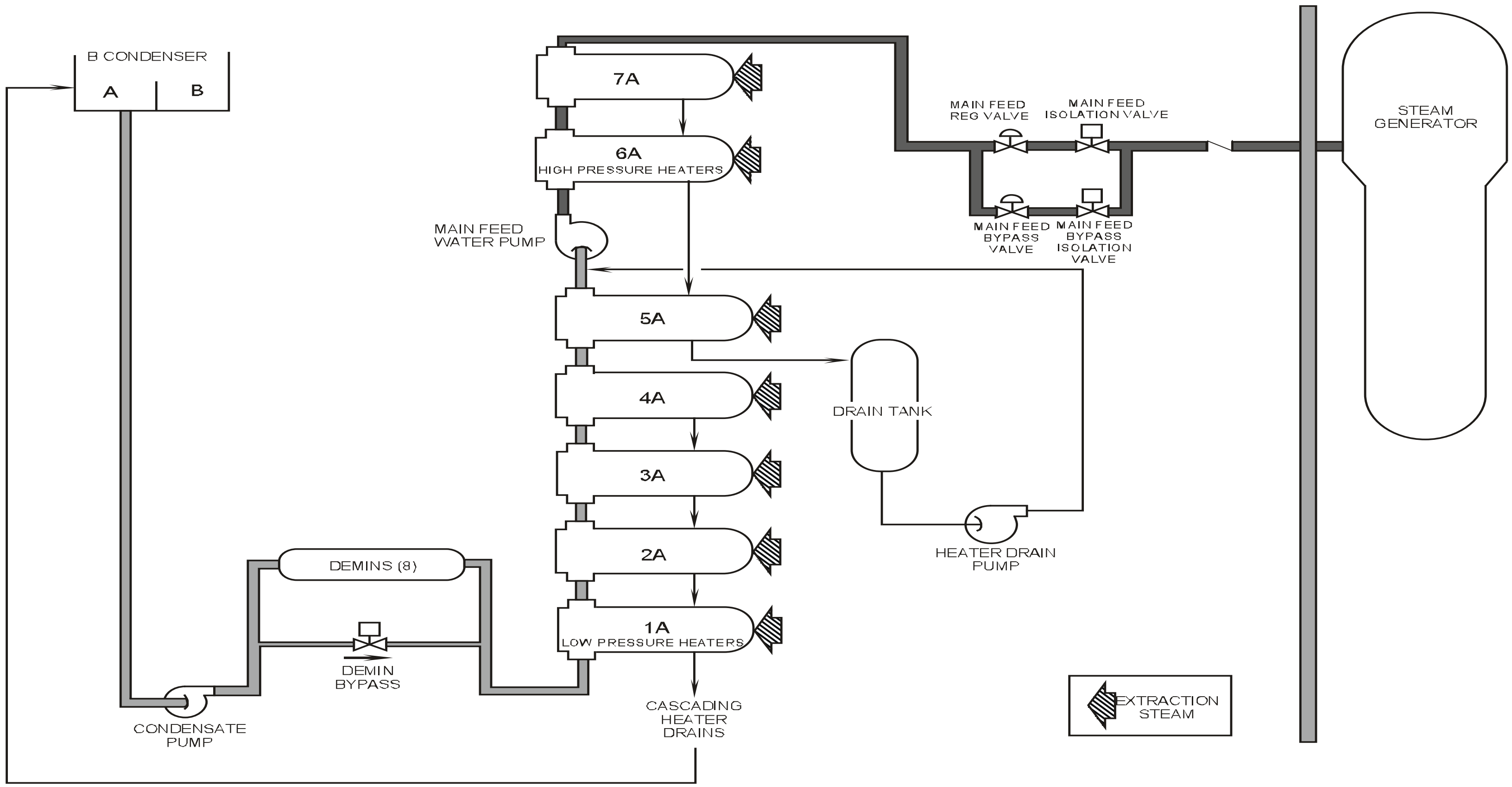


Figure 7.2-1 Simplified Condensate and Feed System

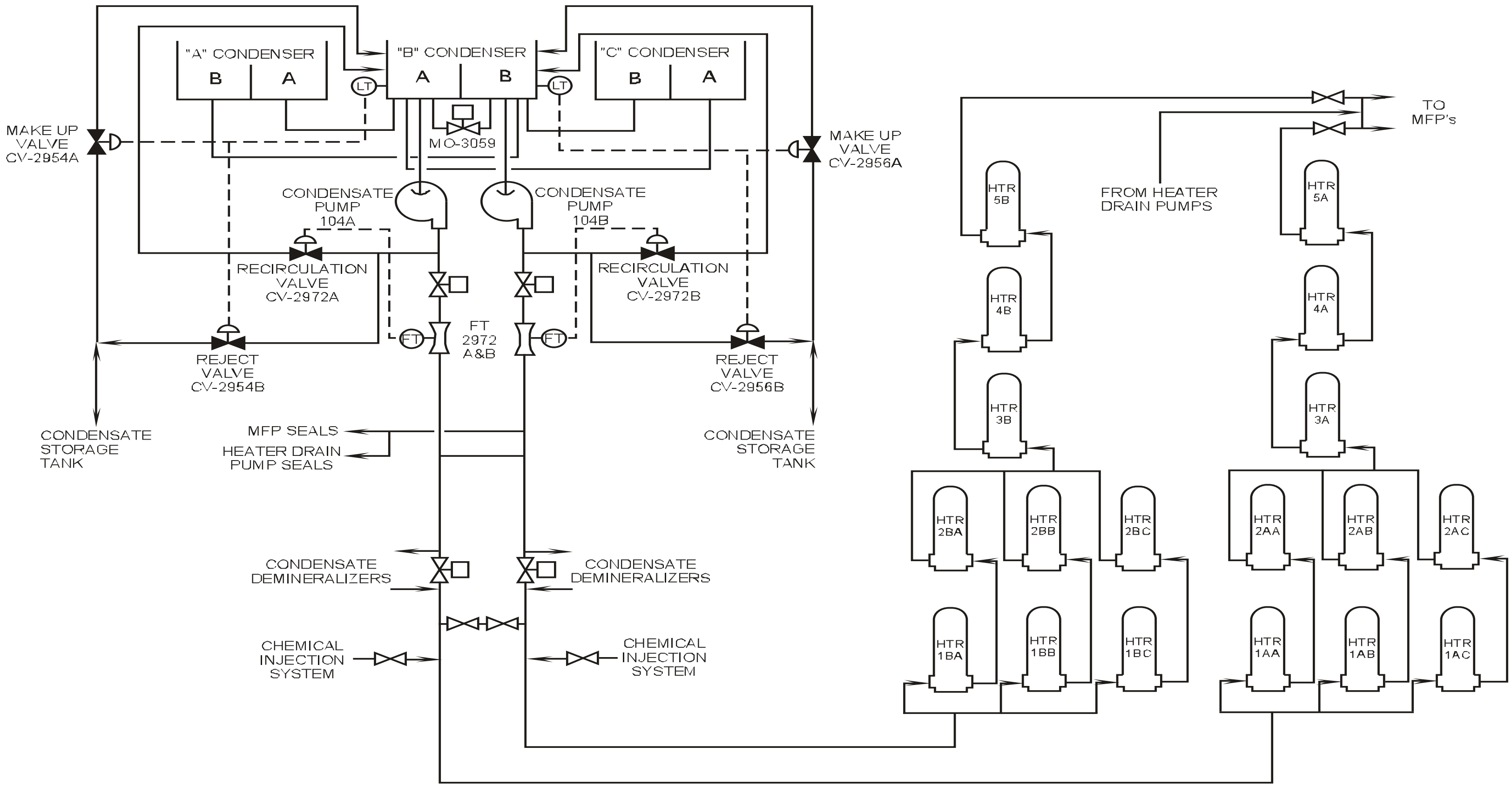


Figure 7.2-2 Condensate System

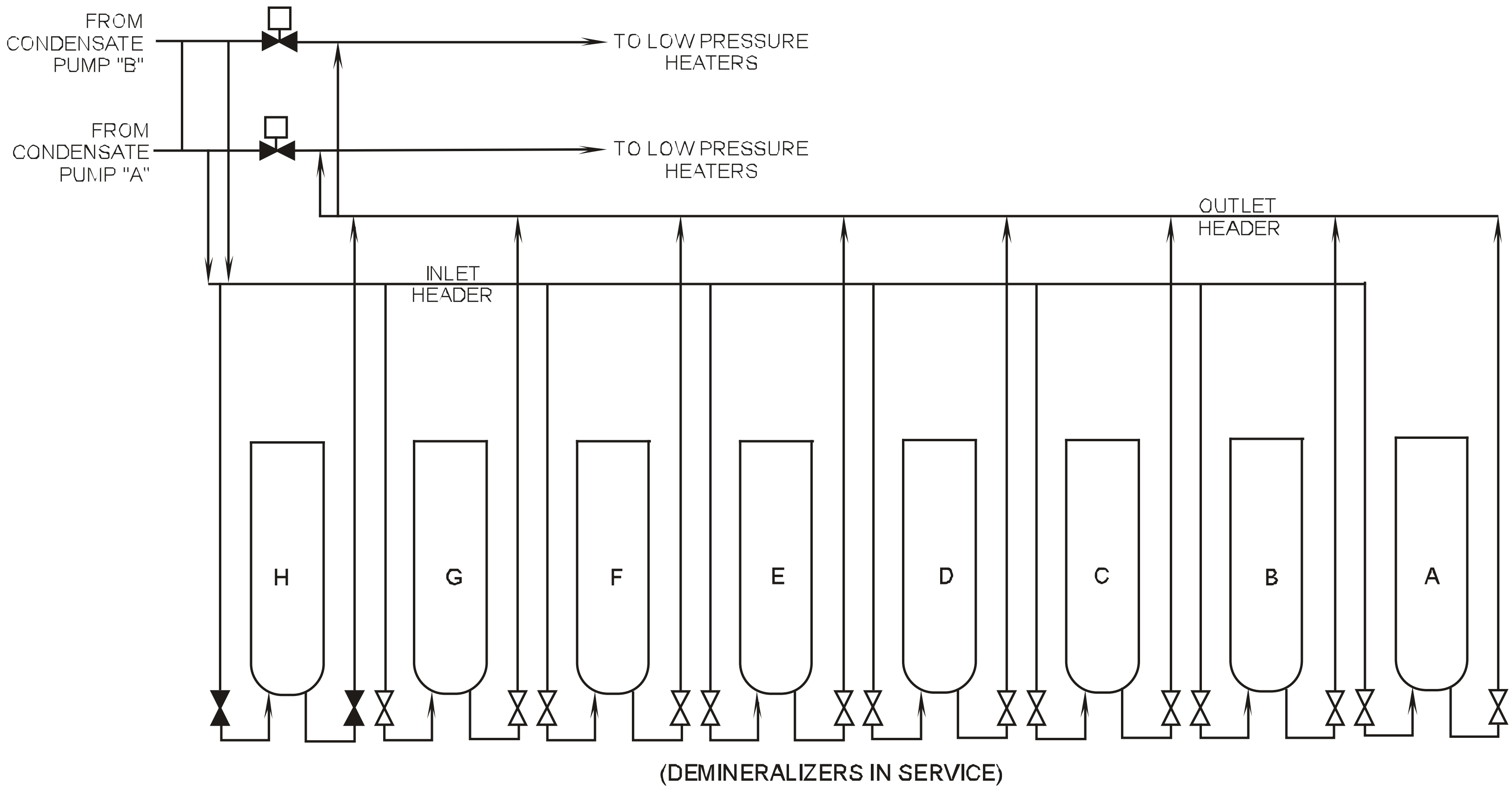


Figure 7.2-3 Condensate Demineralizer System

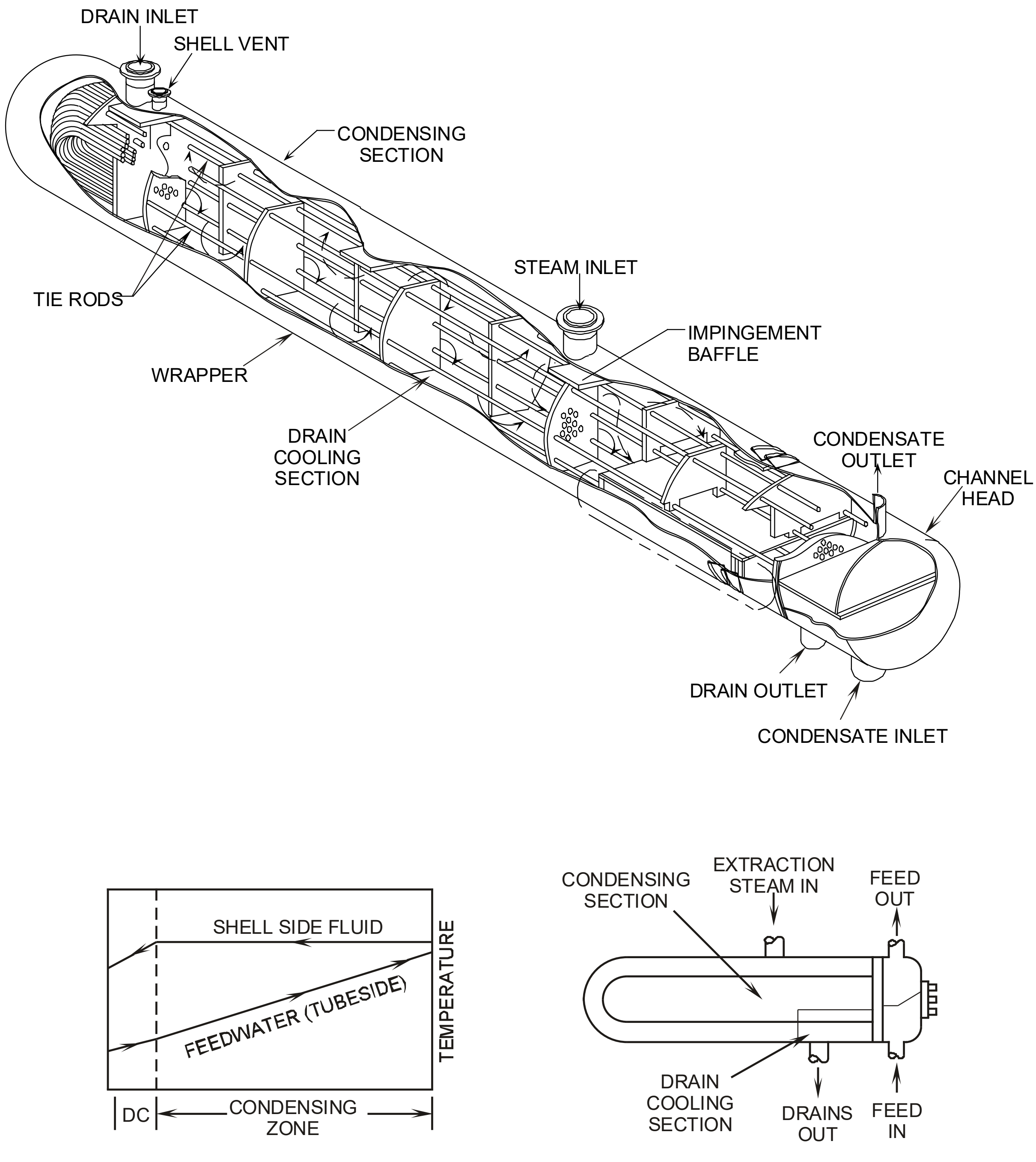


Figure 7.2-4 Feedwater Heater

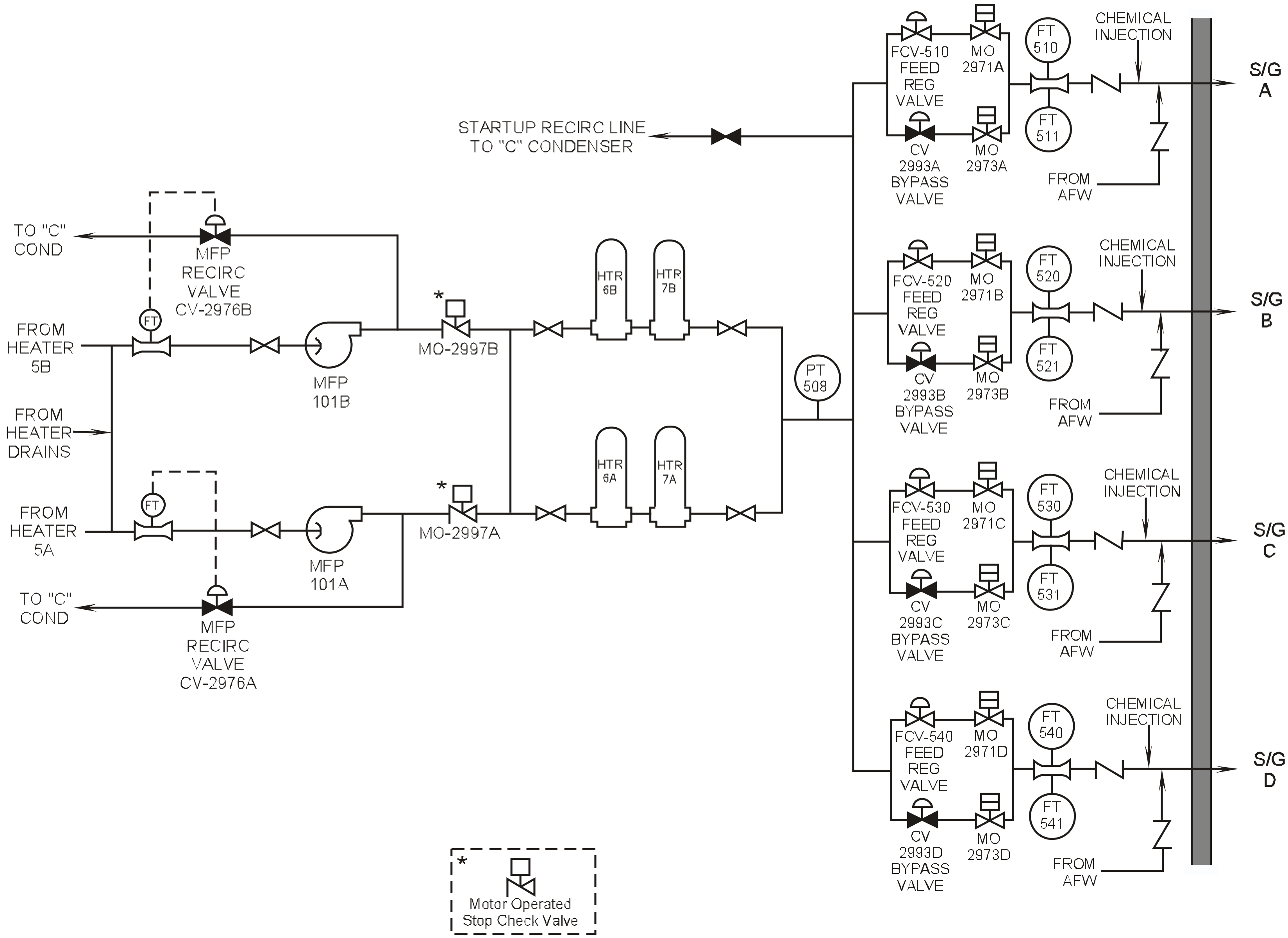
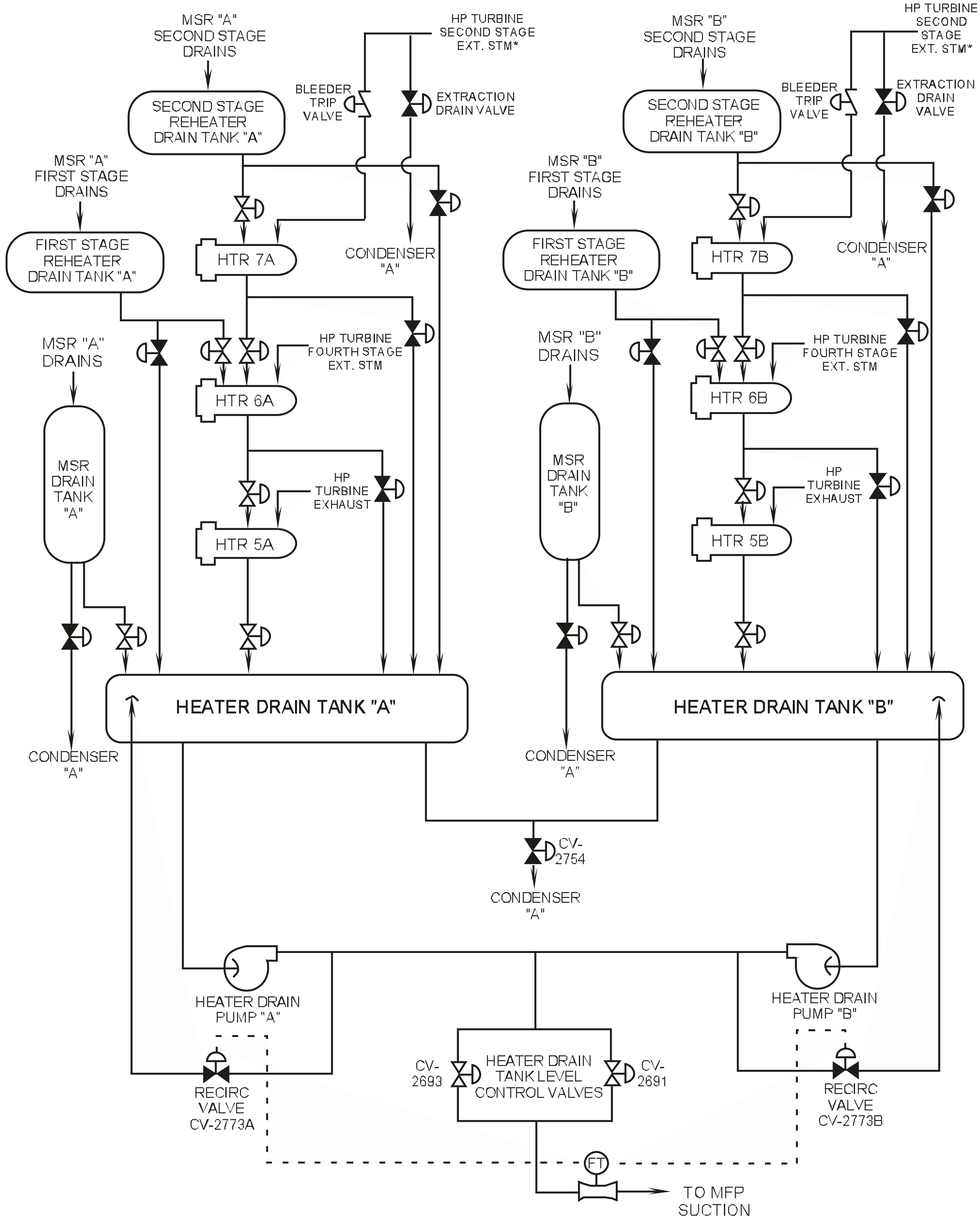


Figure 7.2-5 Feedwater System



*EXTRACTION STEAM SUPPLY AND DRAIN ARRANGEMENT TO EACH HEATER IN THIS FIGURE IS SIMILAR TO THAT SHOWN FOR HEATERS 7A & 7B. THE ARRANGEMENT IS NOT REPEATED FOR SIMPLICITY.

Figure 7.2-6 Moisture Separator / High Pressure Drains

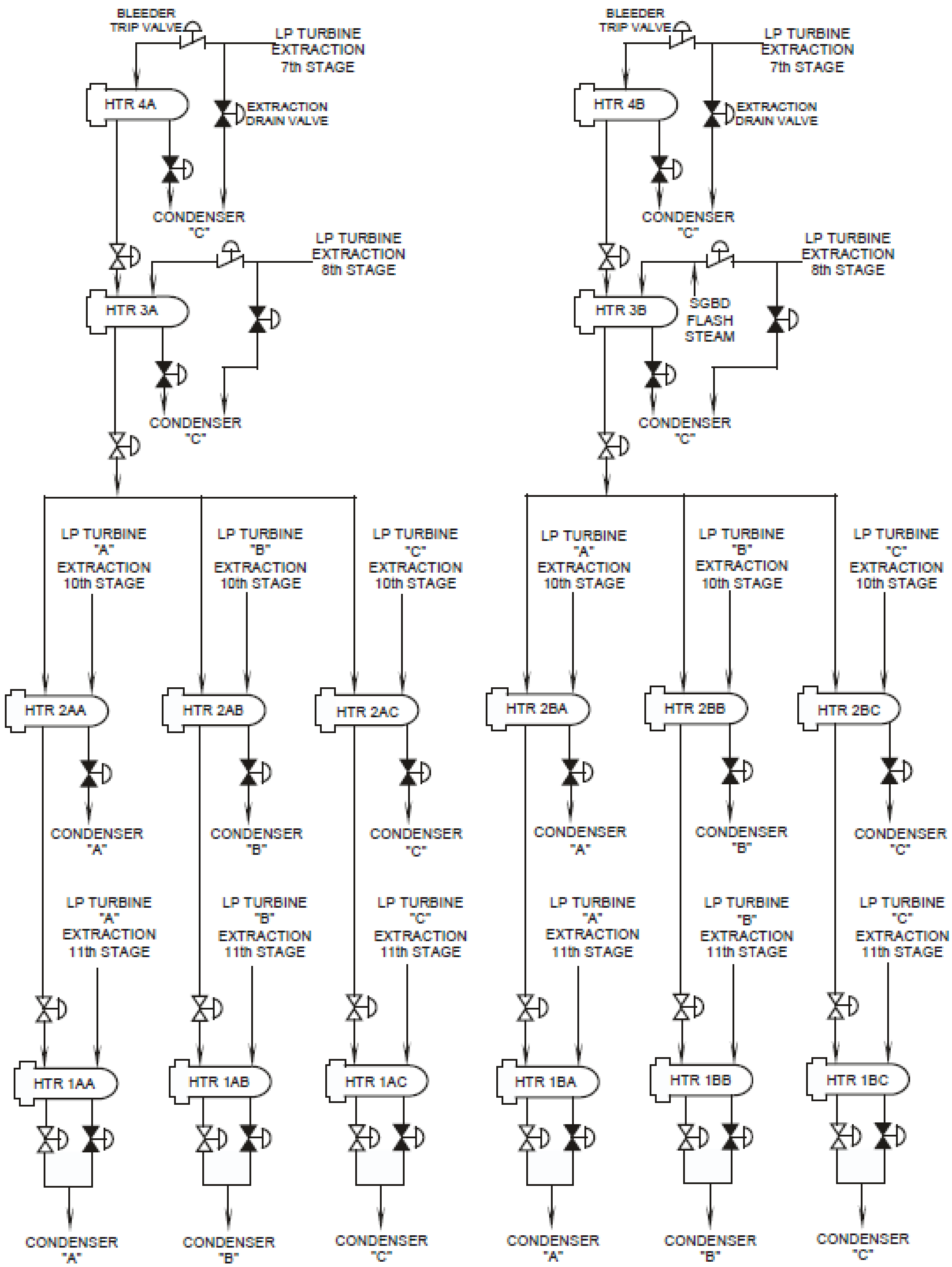


Figure 7.2-7 Low Pressure Heater Drains

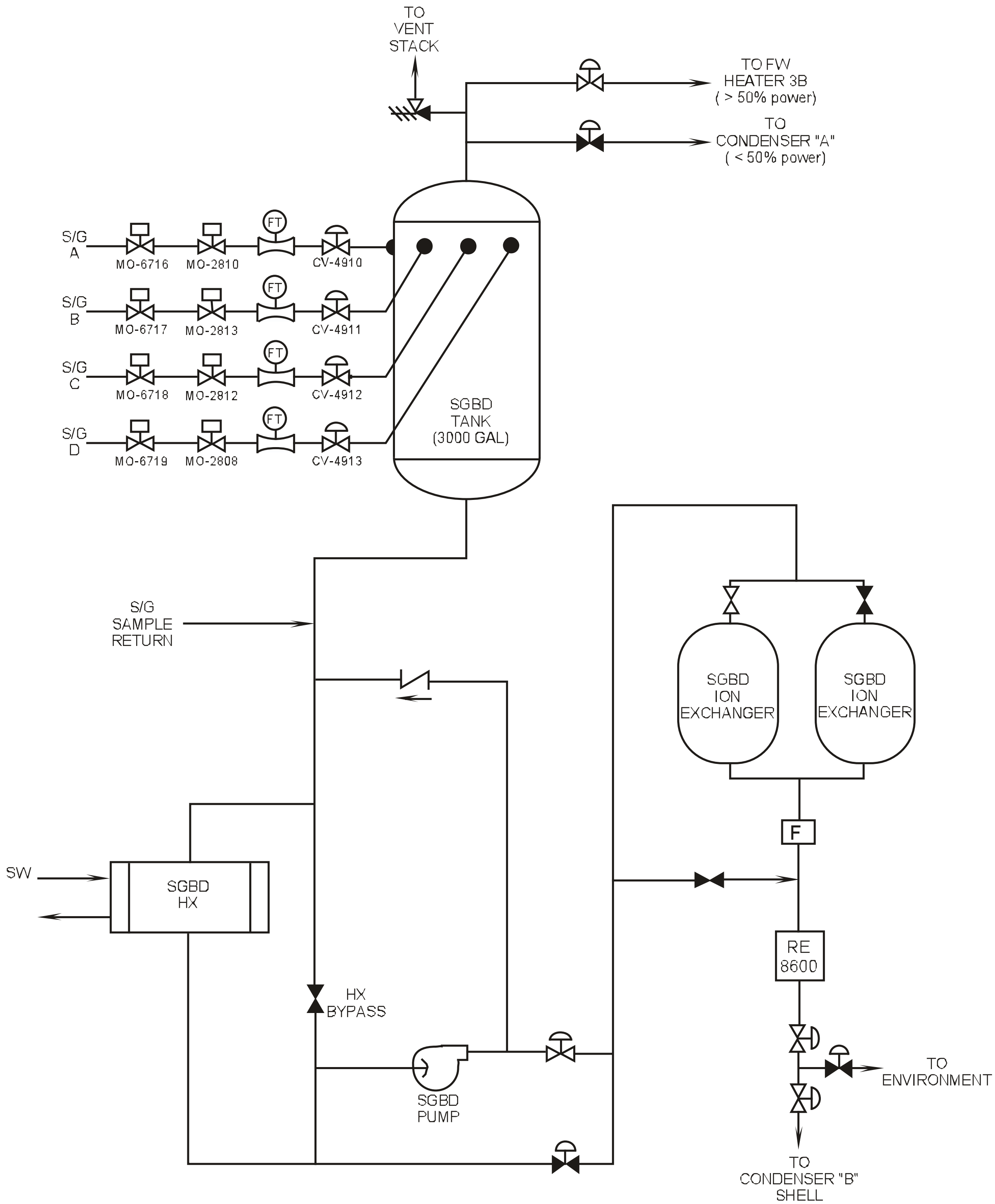


Figure 7.2-8 Steam Generator Blowdown System

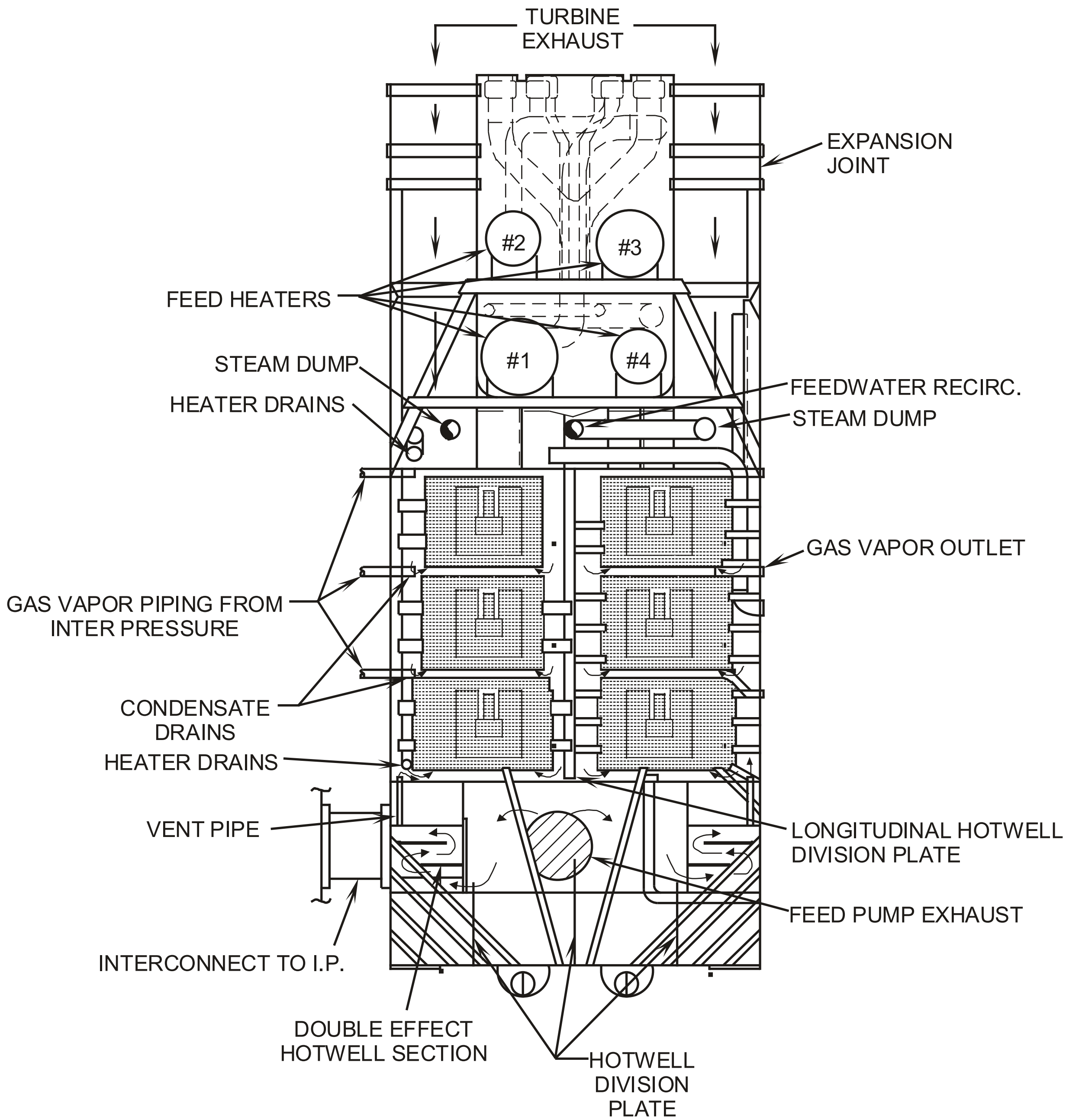


Figure 7.2-9 Condensers A, B & C Front View

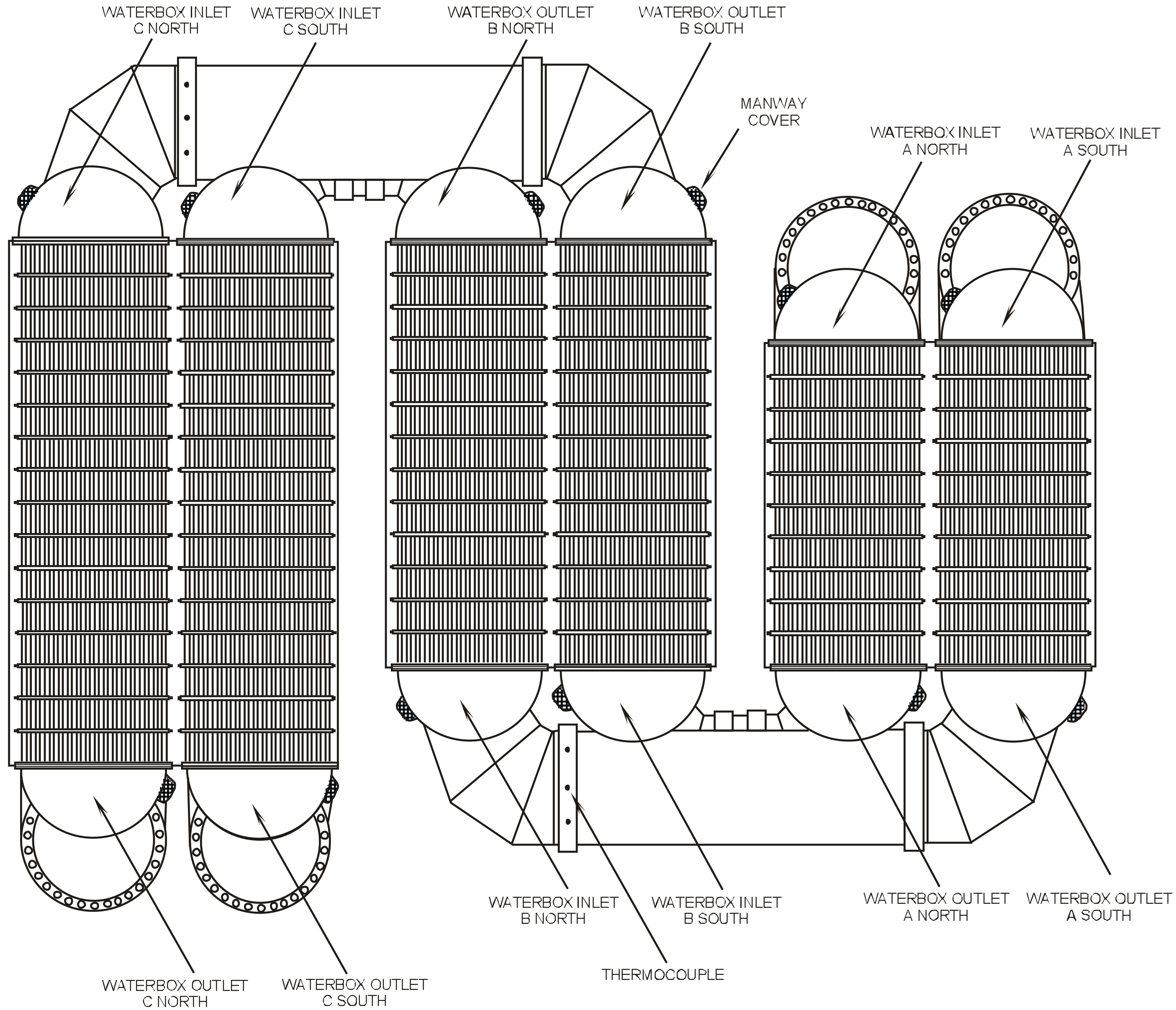


Figure 7.2-10 Circulating Water Top View

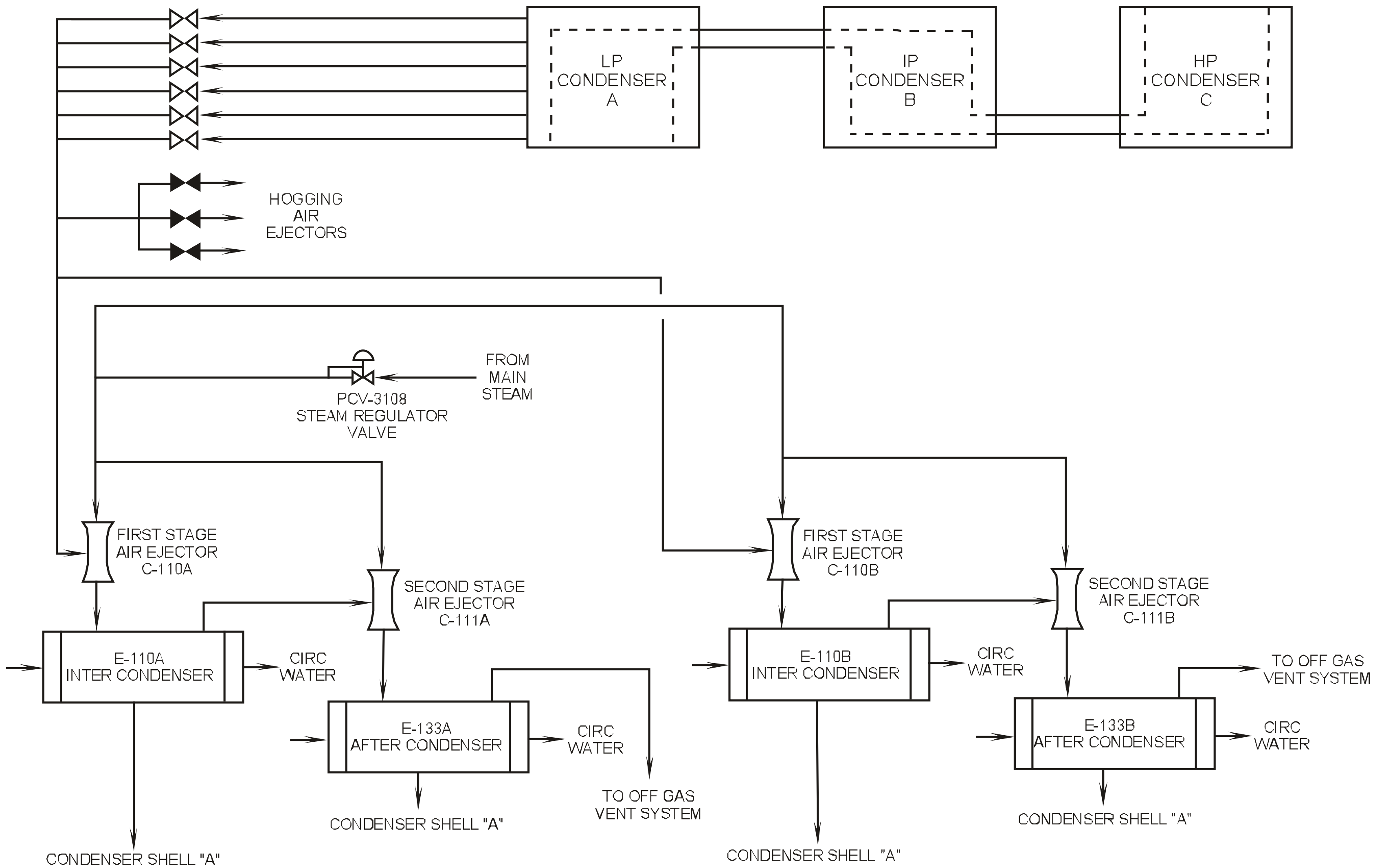


Figure 7.2-11 Main Air Ejector System

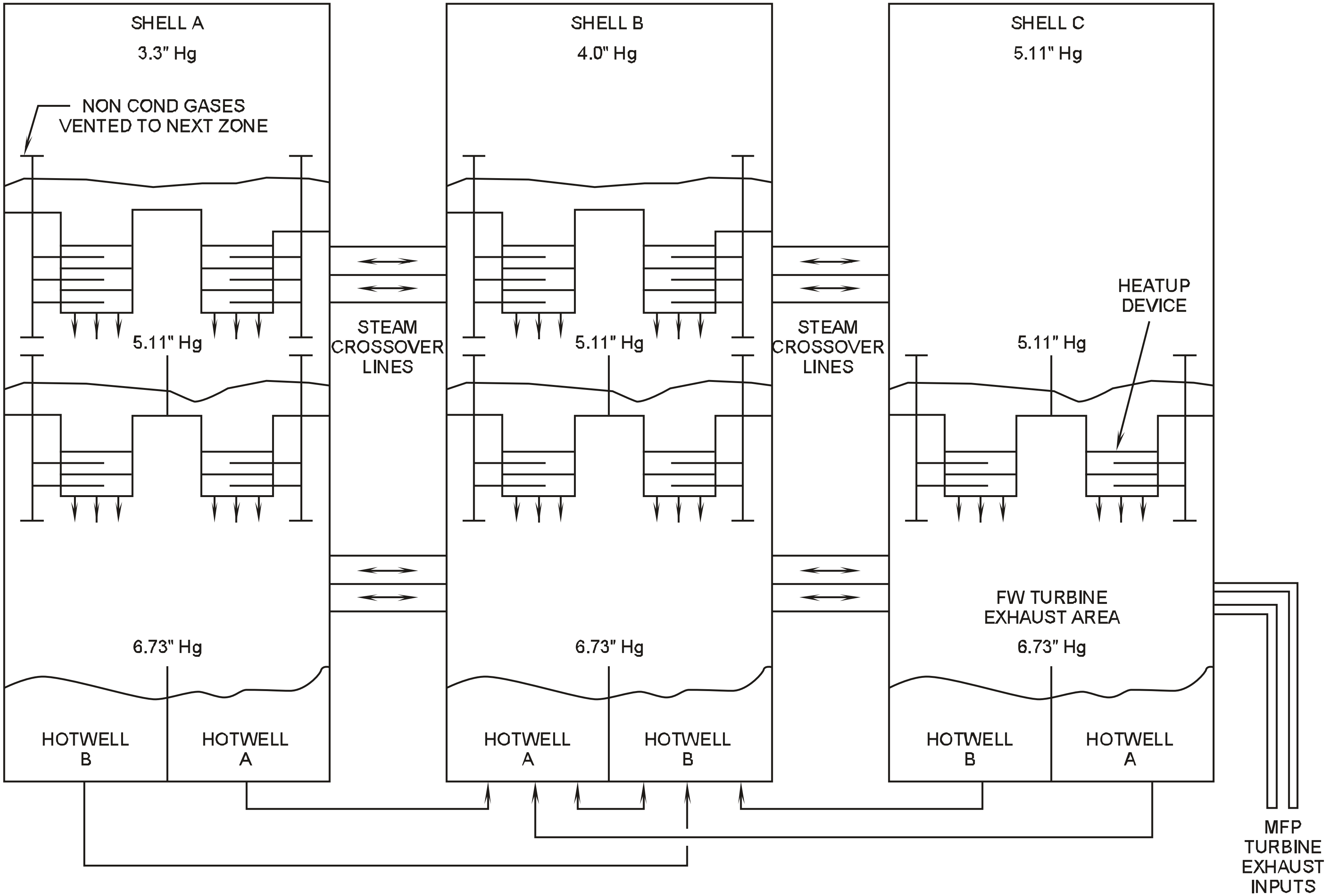


Figure 7.2-12 Condenser Hotwells

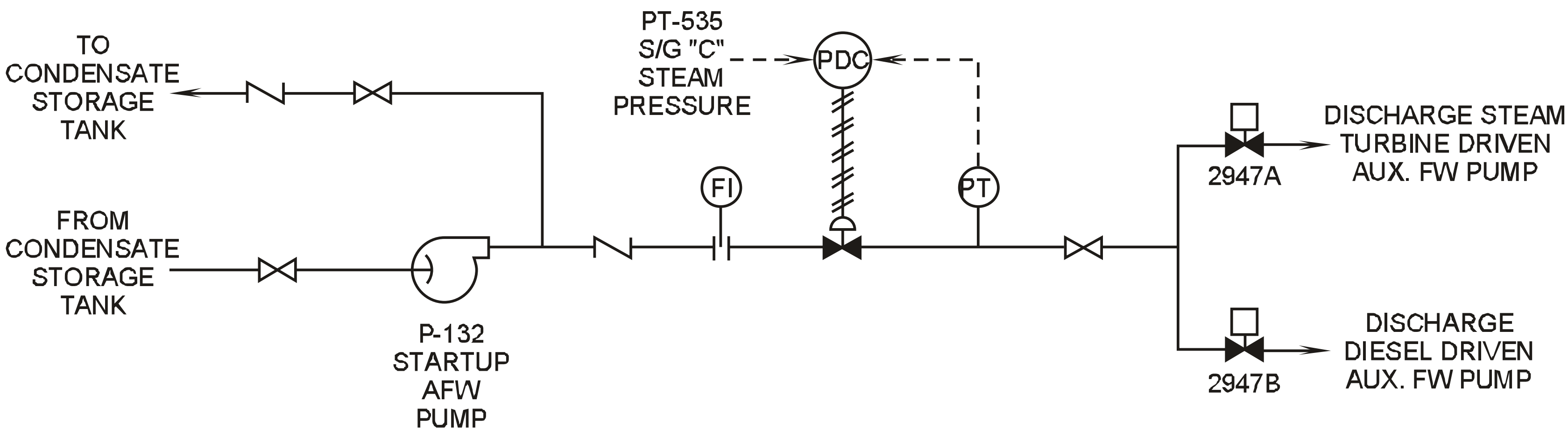


Figure 7.2-13 Startup Auxiliary Feedwater Pump

MAIN CONDENSER PERFORMANCE AND DATA

Characteristics	Shell A	Shell B	Shell C
Total heat load, Btu/hr	2.4493×10^9*	2.4486×10^9	2.4890×10^9
Absolute pressure in condensing zone, in Hg (with 95°F** circulating water temperature at inlet to Shell A)	3.20	3.93	5.02
Circulating water flow, gpm	428,600	428,600	428,600
Average velocity in tube, ft/sec	5.94	5.94	5.94
Total surface area, ft^2	230,600	292,980	362,540
Cleanliness factor, %	90	90	90
Tube outside diameter, in.	1.25	1.25	1.25
Bundle tube BWG	25	25	25
Outer tube BWG	20	20	20
Air cooler tube BWG	25	25	25
Tube overall length, ft	35	45	55
Number of tubes:			
Bundle (ASTM SB-338 Gr. 2, Titanium)	16,208	16,208	16,208
Outer (ASTM SB-338 Gr. 2, Titanium)	1,876	1,876	1,876
Air Cooler (ASTM SB-338 Gr. 2, Titanium	2,160	2,160	2,160

* There will be approximately a 1.8 percent increase in this heat load when the SGBS tank flashed steam is dumped to the main condenser rather than to the No. 3B Feedwater Heater. The condenser will carry this added heat load only during Plant startup, shutdown or when the No. 3B Heater is unavailable.

** 95°F is the maximum inlet circulating water temperature. Normal circulating water temperature is approximately 70°F.

Westinghouse Technology Systems Manual

Section 7.3

Westinghouse Turbine and Auxiliaries

“READ ONLY SELF STUDY MATERIAL”

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7.3 WESTINGHOUSE TURBINE AND AUXILIARIES

Learning Objectives:

1. State the purposes of the turbine and turbine auxiliaries.

2. Identify the sources of heating steam to the Moisture Separator Reheaters (MSRs).

3. State the purposes of the following turbine valves:

   a. Throttle (stop) valves,
   b. Governor (control) valves,
   c. Reheat stop valves, and
   d. Intercept valves.

7.3.1 Introduction

The purposes of the turbine and turbine auxiliaries are as follows:

1. To convert the thermal energy of steam to mechanical energy to turn the main generator,
2. To provide turbine shaft sealing,
3. To provide turbine generator lubricating oil and auto-stop oil for the turbine trip system, and
4. To provide dry, superheated steam to the low-pressure turbines to reduce moisture erosion and to increase plant efficiency.

7.3.2 Main Turbine

7.3.2.1 System Description

The main turbine consists of one high pressure turbine and three low pressure turbines coupled to a single shaft. The four turbines that comprise the main turbine are coupled to the generator and exciter; they serve as the prime mover for these components. A cross section of the turbine is shown in Figure 7.3-1. Steam enters the main turbine at the high-pressure turbine through the turbine throttle (stop) and governor (control) valves.

The thermal energy of the steam is converted to mechanical energy in the high-pressure turbine, and the steam is exhausted to the Moisture Separator Reheaters (MSRs). In each MSR the steam is dried, reheated, and superheated prior to its entry into the low pressure turbines. The superheated steam is routed through the reheat stop and intercept valves as it travels from the MSRs to the low-pressure turbines. Energy conversion occurs again in the low pressure turbines as the steam expands into the vacuum of the main condenser.

7.3.2.2 Component Descriptions

High Pressure Turbine

The high-pressure turbine is a double-flow turbine with a rateau (impulse) stage followed by several stages of reaction blading in each end of the turbine. Main steam enters the high pressure turbine through two steam chests (Figure 7.3-2). The steam chest outlets are connected to the high pressure casing through four inlet points; steam from the steam chest flows to each end of the high pressure turbine. Extraction steam exits the turbine via interstage outlets. The high-pressure turbine exhaust outlets direct steam to the MSRs.

The high-pressure turbine rotor is supported by two bearings, and one end is coupled to the low-pressure turbines. An auxiliary shaft coupled to the opposite end of the high-pressure turbine is used to drive the impeller of a shaft-driven oil pump.

Throttle Valves

The turbine throttle valves (sometimes referred to as stop valves), located in throttle valve/steam chest assemblies, serve two functions: the control of turbine speed when in the full arc steam admission mode during heatup of the turbine, and rapid closure (tripping shut) to isolate steam flow to the high-pressure turbine upon a turbine trip.

During the first steps of the turbine startup, steam is admitted to the turbine through all four governor (control) valves with the speed of the turbine being controlled by the throttle (stop) valves. This mode of operation (full arc admission) allows even heating of turbine components. Speed control is accomplished by small internal poppet valves built into the main discs of the throttle valves. The speed error signal from the Electro Hydraulic Control (EHC) system controls the positions of the internal poppets.

During the final stages of the turbine startup, the throttle valves are wide open. In this mode of operation (partial arc admission), the governor valves control speed and/or load. If a turbine trip signal is present, the high pressure hydraulic fluid will be dumped from the throttle valves. The dumping of the high pressure fluid allows spring force to rapidly close the throttle valves. Since all turbine valves close on a turbine trip, the throttle valves and governor valves provide redundant isolation of steam flow to the high-pressure turbine.

Governor Valves

The governor valves (sometimes referred to as control valves) function to regulate the speed of the turbine during partial arc admission (during the last stages of heatup) and to control load when the unit is supplying power to the grid. These valves control turbine speed when a load rejection occurs and isolate steam flow to the high pressure turbine when the turbine trips. The governor valves are located in the steam chest assemblies and are shown in Figure 7.3-2.

During partial arc admission, the speed error signal positions the governor valves by controlling the EHC fluid supply to the valves. When the main generator is on line, the positions of the governor valves are controlled as a function of reference load, impulse pressure feedback, and speed error. The trip function of the governor valves is accomplished through the dumping of high-pressure oil from the valve operators, thus allowing spring force to close the valves.

When a load rejection occurs, speed control is achieved through the dumping of high pressure oil from the governor valves, which are then closed by spring force. This action isolates the flow of steam to the high-pressure turbine and prevents a turbine overspeed trip (the intercept valves simultaneously isolate steam from the MSRs to the low-pressure turbines).

Low Pressure Turbines

Each of the three low pressure turbines is a dual-flow, reaction, condensing turbine. Steam from the moisture separator reheaters enters the low pressure turbines after passing through the reheat stop and intercept valves. In the low pressure turbines, steam is expanded through several reaction stages before it is exhausted to the condenser. Interstage extraction points provide steam for feedwater heating. Each low pressure turbine is supported by two journal bearings. Condenser overpressure protection is provided by rupture discs in the low-pressure turbine casings.

Reheat Stop Valves

A large quantity of steam is available in the shell side of the moisture separator reheaters. Therefore, the steam supply from the moisture separator reheaters to the low pressure turbines must be isolated on a turbine trip; otherwise, turbine damage from overspeeding will occur. The reheat stop valves isolate the moisture separator reheaters from the low pressure turbines. Each reheat stop valve is a butterfly valve held in the open position by high pressure oil. When the turbine is tripped, the oil is dumped from the valve operators, allowing spring force to close the valves.

Intercept Valves

The purpose of the intercept valves is to isolate the flow of steam from the moisture separator reheaters during a turbine trip or load rejection. The intercept valves are identical in construction to the reheat stop valves and provide redundant isolation on a turbine trip.

The closure of the intercept valves on a load rejection prevents the steam contained in the moisture separator reheaters from overspeeding the main turbine and thereby causing a turbine trip.

7.3.3 Gland Steam System

7.3.3.1 System Description

During plant operation the entry of air into and the exit of steam from the turbine are prevented at those points where the rotor penetrates the turbine casings. These functions are accomplished through the design of the rotor/casing penetrations (glands) and through the operation of the gland steam system.

The gland steam system (Figure 7.3-3) has two sources of steam supply: the auxiliary boiler and the main steam system. In the initial phases of a startup from cold shutdown, gland steam is supplied from the auxiliary boiler. Once the plant is heated up, the gland steam requirements are supplied by the main steam system.

Either of the two supplies provides steam through a seal supply regulator which, in turn, supplies a sealing steam distribution header. The high pressure turbine glands are supplied through a common regulating valve, while each low pressure turbine gland is supplied through an individual regulator. The distribution header also supplies sealing steam to the main feed pump turbines. Each feed pump turbine has its own seal steam regulating valve.

At higher plant powers (greater than approximately 40%), steam from inside the high-pressure turbine casing will leak past the inner turbine glands to supply gland sealing steam. The direction of steam flow through the gland seal supply piping is thus reversed from that at low powers. Seal steam to the low-pressure turbine glands is always provided by the gland seal steam supply header.

Each turbine gland is a labyrinth-type seal consisting of seal strips mounted in the turbine casing. The seal strips clear the rotor surface with just enough margin to prevent rubbing during operation. Gland seal supply and exhaust piping is connected to each gland.

The gland exhaust portion of the system consists of the gland steam condenser, gland steam condenser exhausters, and associated piping. A slight vacuum is created in the gland steam condenser by the gland steam condenser exhausters. This vacuum is felt at the turbine glands; the differential pressure between the glands and the condenser causes the flow of excess gland steam and air to the gland steam condenser.

Condensate system flow condenses the gland exhaust steam, and the exhausters remove noncondensible gases from the condenser. The condensed steam drains to a collecting tank, and the air is exhausted to the atmosphere. The gland steam condenser also receives turbine valve steam leakage.

7.3.3.2 Component Descriptions

Main Seal Supply Regulator

This regulator reduces the steam inlet pressure to a value of 140 psig. The valve capacity is such that sufficient gland steam flow can be supplied with an inlet pressure as low as 185 psig. A motor-operated inlet valve is provided for regulator isolation.

A motor-operated bypass valve is installed for use in the event of a regulator failure. Both of the motor-operated valves are controlled from the control room. Control room pressure indication is supplied from a pressure transmitter located downstream of the main supply regulator. The relief valve located downstream of the main seal supply regulator protects against over pressurization and lifts at 315 psig.

Turbine Seal Regulators

The turbine seal regulators reduce seal steam pressure to 16 psia and supply steam to the turbine glands. Each of the regulator valves is a pneumatically operated, diaphragm-controlled globe valve. The valves modulate to maintain the downstream pressure. Manually operated inlet, outlet, and bypass valves are installed to provide regulator maintenance capability while maintaining the seal steam supply. A locally mounted pressure gage provides indication of the supply pressure for each gland.

Spillover Valve

The spillover valve maintains the correct steam pressure at the high-pressure turbine glands when the high-pressure turbine exhaust pressure exceeds the gland steam supply pressure. The valve dumps excess steam to the first-stage feedwater heater shells. Motor-operated inlet isolation and bypass valves are installed so that gland pressure can be maintained in the event of regulator failure. These valves are controlled from the control room. Overpressure protection is provided by a relief valve set at 105 psig.

Gland Steam Condenser

The gland steam condenser is a tube-and-shell heat exchanger. Condensate flow through the heat exchanger tubes serves as the heat exchange medium. The condensed gland exhaust steam drains to a collecting tank and eventually returns to the condensate system. Noncondensible gases are removed from the shell side of the heat exchanger by the gland steam condenser exhausters.

Gland Steam Condenser Exhausters

These 480-Vac fans function to remove noncondensible gases from the shell side of the gland steam condenser and help maintain a slight negative pressure (approximately 14.6 psia) in the gland steam condenser. The gland steam condenser exhausters discharge to the turbine building roof.

7.3.3.3 System Operation

When the turbine is tripped or is very lightly loaded, gland steam is supplied to the high pressure and low pressure turbines via the main seal supply regulator and their individual gland regulators (Figure 7.3-4). A vacuum is present at the exhaust of both the high and low pressure turbines. In these situations, gland sealing steam flows through each labyrinth seal to the gland exhaust connection. This flow of steam creates a positive pressure at the gland, which prevents the entry of air into the turbine casing. At the gland exhaust connection, gland sealing steam combines with any air in-leakage, and this steam/air mixture flows to the gland steam condenser due to the slight negative pressure maintained at the shell side of the heat exchanger.

As the turbine load increases, the high-pressure turbine exhaust pressure becomes positive and overcomes the gland seal steam supply pressure. The flow of steam through the gland seal steam supply piping is reversed. The turbine exhaust pressure causes the spillover valve to open, relieving excess steam to the shell sides of the first-stage feedwater heaters. The combination of the spillover valve and the high pressure turbine seal supply regulator maintains the correct high pressure turbine gland seal pressure. Any steam that finds its way to the gland exhaust connection combines with air in-leakage and flows to the gland steam condenser.

7.3.4 Turbine Lubricating Oil System

7.3.4.1 System Description

The turbine lubricating oil system, shown in Figure 7.3-5, provides lubricating oil for the turbine, generator, and exciter bearings; lift oil for turning gear operations; backup seal oil for the generator hydrogen seals; and auto-stop oil for the turbine trip system.

Lubricating Oil

The lubricating oil for the bearings (eight turbine bearings, two generator bearings, and one exciter bearing) is supplied by either of the motor-driven lube oil pumps or by the shaft-driven lube oil pump via the discharge of the ejector. When the turbine speed is below 90% of rated speed, lubricating oil is supplied by the ac lube oil pump, with the dc lube oil pump in standby. With turbine speeds greater than 90% of rated speed, the motor-driven pump(s) may be stopped, and the shaft-driven pump supplies the required lubricating oil. Regardless of the source of lubricating oil, bearing lubrication is supplied from the lube oil reservoir to each bearing via the lube oil coolers. The lube oil coolers cool the oil prior to its injection into the bearings. The bearing oil drains back to the reservoir through a basket strainer.

Turning Gear System

When the turbine comes to rest after shutdown, operators place the turning gear in service to prevent the turbine rotors from bowing. The turning gear is motor driven and is coupled to the turbine shaft between the generator and the last low pressure turbine. Bearing lift oil, supplied by the bearing lift oil pump, is injected at a high pressure to lift the turbine shaft. The speed of the shaft during turning gear operations is approximately 1.5 rpm.

Backup Seal Oil Supply

The application of hydrogen as a cooling medium for the main generator requires the use of oil-pressure floating ring seals to prevent hydrogen leakage where the shaft extends through the generator housing. The seal oil backup pump and/or the shaft-driven pump provides a backup source of hydrogen seal oil to the generator seals. In addition, the seal oil backup pump is one of the two pumps which can supply auto-stop oil.

Auto-Stop Oil

Auto-stop oil provides the interface between the high pressure electro hydraulic fluid and the turbine lubricating oil system. In addition to the interface function, the auto-stop oil system provides turbine trips on low lube oil pressure, low vacuum, thrust bearing wear, and overspeed. Solenoid trips are also provided through the auto-stop oil system. Auto-stop oil may be provided by the shaft-driven pump or the seal oil backup pump.

7.3.4.2 Component Descriptions

Shaft-Driven Lube Oil Pump

The shaft-driven lube oil pump is a single-stage centrifugal pump driven by an extension shaft that is coupled to the high-pressure turbine element. At normal operating speed (1800 rpm), the pump discharges oil at pressures between 320 and 380 psig when supplied with a suction pressure of 10-45 psig. The shaft-driven pump is not self priming.

During a turbine startup the pump is supplied with a suction from the motor-driven oil pumps. While operating at normal speeds, the shaft-driven oil pump suction is supplied by the ejector, which utilizes high pressure oil from the shaft-driven oil pump discharge as an operating medium.

The oil discharged by the shaft-driven pump during normal operation is used for the following purposes:

- Supplies bearing lubrication,
- Operates the ejector,
- Supplies auto-stop oil, and
- Supplies backup seal oil.

Motor-Driven Lube Oil Pumps

The motor-driven centrifugal oil pumps provide lubricating oil to the bearings and suction to the shaft-driven lube oil pump at turbine speeds less than 90% of rated speed. Either the ac motor-driven pump or the dc motor-driven pump can provide bearing oil at a supply pressure of 14 - 18 psig. The ac motor-driven pump, also called the bearing gear oil pump, is normally used during turbine startup and automatically starts when bearing oil pressure drops to 11 - 12 psig. The dc motor-driven oil pump is designed to provide bearing lubrication for the turbine/generator in the event of a loss of all ac power and automatically starts when bearing oil pressure drops to 10 - 11 psig.

Lube Oil Reservoir

This 15,000-gal tank serves as a storage and supply tank for the lubricating oil system. The ejector, seal oil backup pump, and motor-driven lube oil pumps are located within the lube oil reservoir. Oil drains from the bearings are returned to the reservoir through a removable strainer.

Lube Oil Coolers

These tube-and-shell heat exchangers cool the bearing lube oil supply. Oil flows on the shell side and raw cooling water flows through the tube side. Oil flow to and from the coolers is controlled by three-way valves.

Bearing Lift Oil Pump

The positive displacement bearing lift oil pump supplies high pressure oil (1200-1500 psig) to the undersides of the bearings to lift the turbine rotor for turning gear operations. The motor is interlocked with turbine speed; it automatically stops and starts with a turbine speed of approximately 600 rpm.

Turning Gear

The turning gear motor drives a pinion that engages a bull gear located on the turbine rotor. A bearing oil pressure of 3-5 psig and a lift oil pressure of at least 850 psig are required for turning gear operation. A low speed switch allows automatic starting of the turning gear when the turbine speed decreases to less than 1.5 rpm. A high speed switch prevents the operator from inadvertently starting the turning gear with a turbine speed of greater than 100 rpm.

Seal Oil Backup Pump

The seal oil backup pump is an ac electrically driven centrifugal pump. The seal oil backup pump supplies backup oil to the generator hydrogen seals and supplies auto-stop oil when the turbine speed is below 90% of rated speed. The pump discharges oil at pressures between 115 and 125 psig and must be in service to latch the turbine. The seal oil backup pump will automatically start if the bearing oil pressure decreases to 11-12 psig.

Ejector

The ejector, located in the lube oil reservoir, provides bearing oil and the shaft-driven lube oil pump suction when the turbine is at normal operating speed. The discharge of oil from the shaft-driven lube oil pump flows through the “throat” of the ejector, which causes oil to flow from the lube oil reservoir to the ejector discharge. From the ejector discharge, oil flows to the shaft-driven pump suction and to the bearings.

Turbine Bearings

Eleven journal bearings and a thrust bearing, located on the generator end of the middle low-pressure turbine, are installed in the turbine/generator unit.

The journal bearings are constructed of steel and have babbitt faces. Each bearing sits in a pedestal and consists of two semicircular halves. A bearing pedestal cap, bolted to the pedestal, completes the bearing assembly. Drilled passages through the upper and lower halves of the bearing supply lubricating and lift oil, respectively.

The thrust bearing accepts axial loads developed by the main turbine. The thrust bearing assembly is of the leveling plate design, which automatically distributes the load equally on the thrust shoes. The leveling plates allow the thrust shoes to take positions such that the centers of loading of the faces are all in the same plane. Consequently, each shoe takes an equal share of the load. The thrust of the rotor is transmitted to the shoes by a collar machined integrally with the turbine rotor shaft.

7.3.5 Moisture Separator Reheaters

7.3.5.1 System Description

The moisture separator reheaters provide dry, superheated steam to the low pressure turbines. Low pressure steam to the main feed pump turbines is also supplied by the moisture separator reheaters. The MSRs improve secondary system efficiency and minimize moisture erosion of the low-pressure turbine blading.

The exhaust steam from the high-pressure turbine is routed to the shell side of each moisture separator reheater, where moisture is removed by chevron separators. The steam then flows past two reheating tube bundles. The first of these bundles, called first-stage reheat, receives turbine extraction steam from the high pressure turbine. The second bundle, or second-stage reheat, receives steam from the main steam system. The steam exiting the moisture separator reheaters is piped to the low pressure turbines via the reheat and intercept valves. Reheated steam from the moisture separator reheaters is also supplied to the main feed pump turbines. The supply lines connect to the main feed pump turbine low pressure stop valves.

7.3.5.2 Component Descriptions

Moisture Separator Reheater Shell

The exhaust steam from the high-pressure turbine enters each moisture separator reheater via the shell end (Figure 7.3-6). The steam is directed up through the chevron separators to the reheat tube bundles. The separated moisture from the turbine exhaust is directed to a heater drain tank. The shell is constructed of carbon steel. Relief valves mounted on the shell provide overpressure protection.

First-Stage Reheat Bundle

The first-stage reheat tube bundle receives high pressure turbine extraction steam. The flow of steam through the bundle adds energy to the high pressure turbine exhaust steam. The flow of steam to the first-stage reheat tube bundle is controlled by a pneumatic control valve that receives signals from the reheater control system (see Section 11.4). The condensate that results from the heat transfer across the first-stage tube bundle is drained to the next-to-last-stage feedwater heater shells.

Second-Stage Reheat Bundle

Steam from the main steam system is supplied to the second-stage reheat tube bundle via a pneumatic valve controlled by the reheater control system. Condensate from the second stage of reheat is drained to the last-stage feedwater heater shells.

Main Feed Pump Supply

The MSRs supply low pressure steam to the main feed pump turbines. The MSRs usually supply the pump turbines when secondary power has increased to 35% of rated load. With this alignment, the high pressure steam supply from the main steam system to the pump turbines is secured.

7.3.6 Summary

The nuclear steam supply system supplies steam to the main turbine. The main turbine consists of one high pressure turbine and three low pressure turbines coupled to the main generator. Hydraulically controlled governor valves regulate the flow of steam to the turbine, thereby maintaining a desired speed or electric load for the grid.

Dry, superheated steam is supplied to the low-pressure turbines by the moisture separator reheaters. The MSRs improve secondary cycle efficiency and minimize low pressure turbine blade erosion. In addition, the MSRs supply dry, superheated steam to the main feed pump turbines.

The gland steam system is designed to prevent air entry into the turbine or steam leakage out of the turbine. The turbine lubricating oil system provides all required lubrication for the turbine bearings. In addition, the turbine lubricating oil system provides backup seal oil to the generator and auto-stop oil to the turbine trip system.

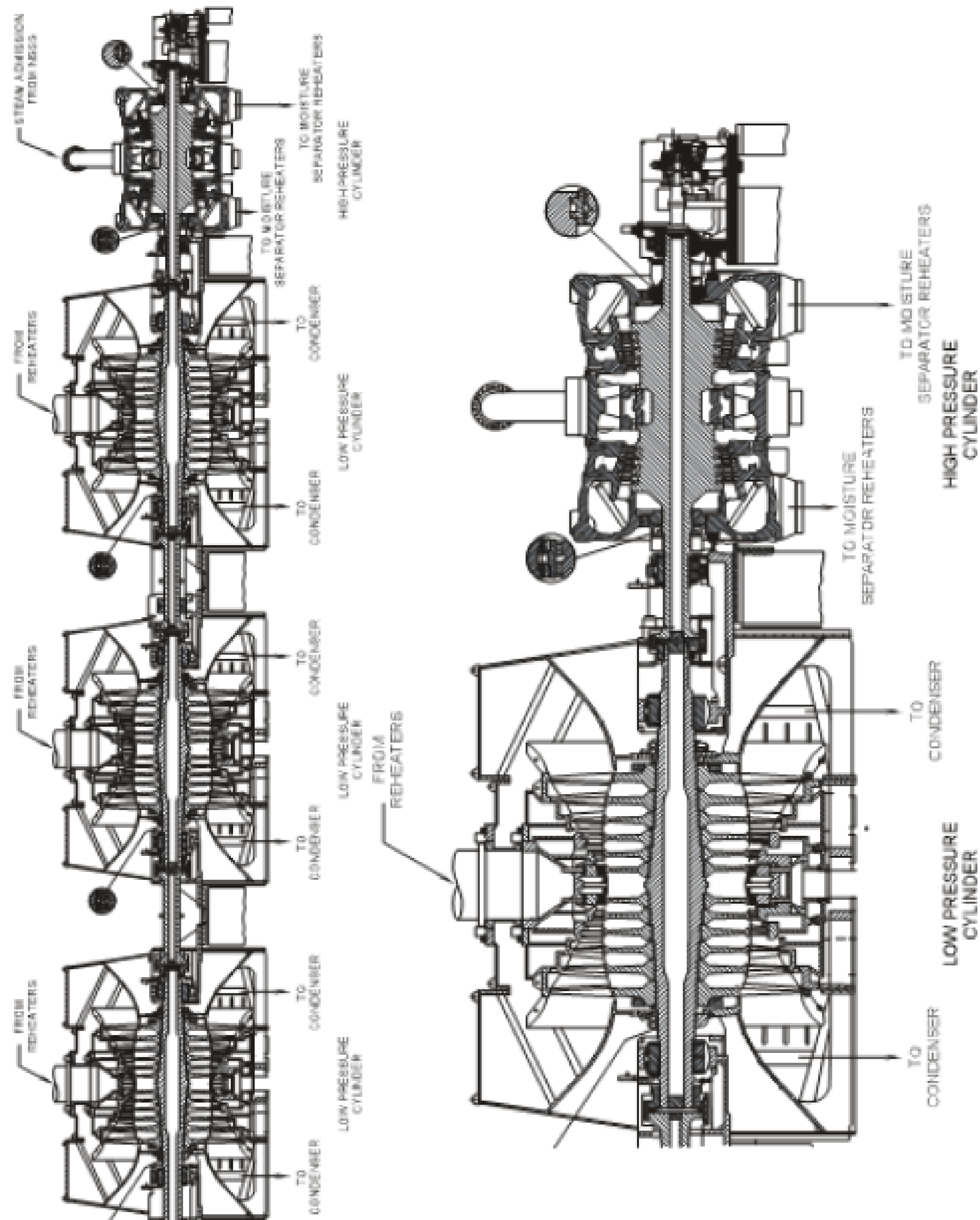

Figure 7.3-1 Main Turbine Cross Section

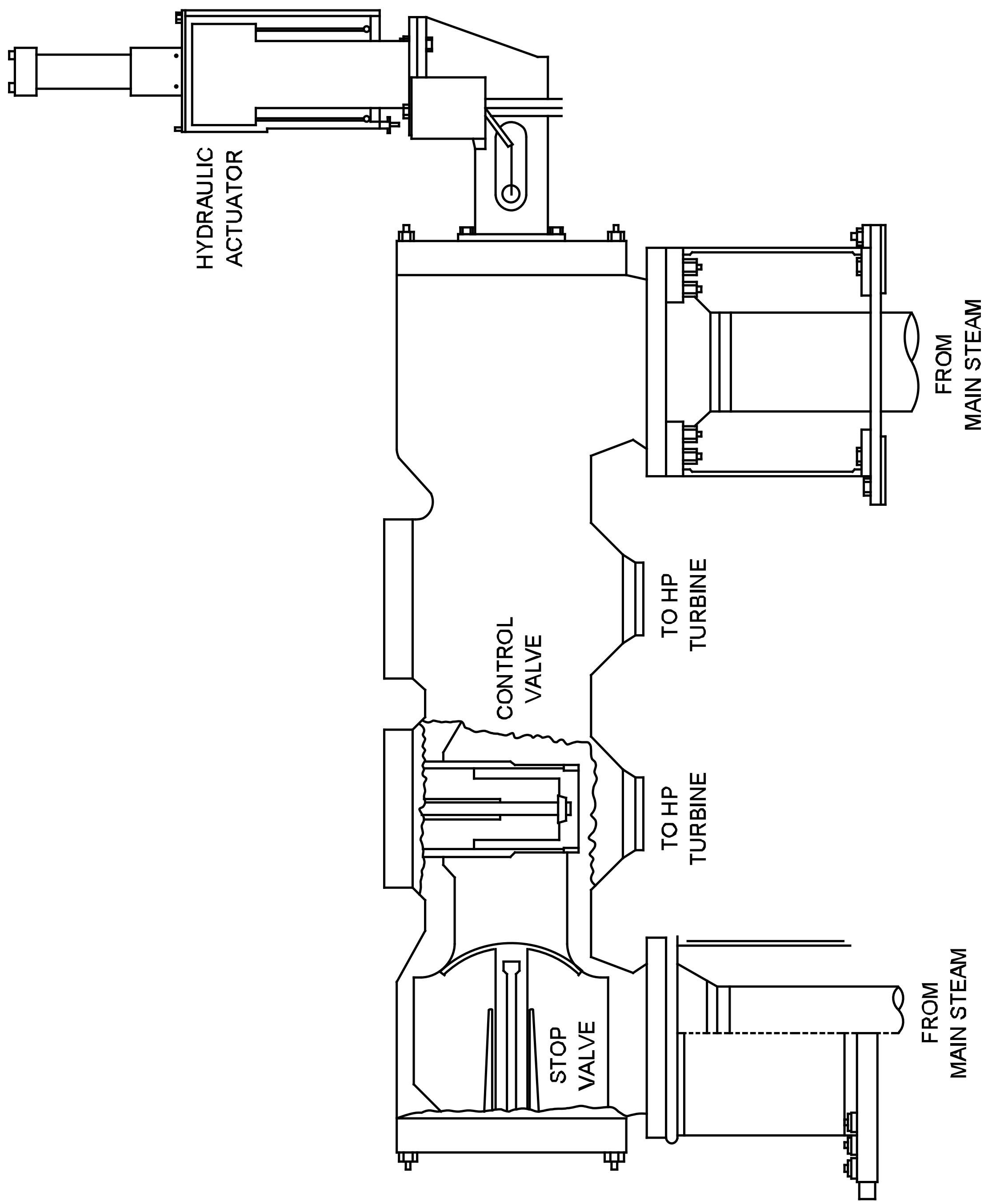

Figure 7.3-2 Turbine Steam Chests

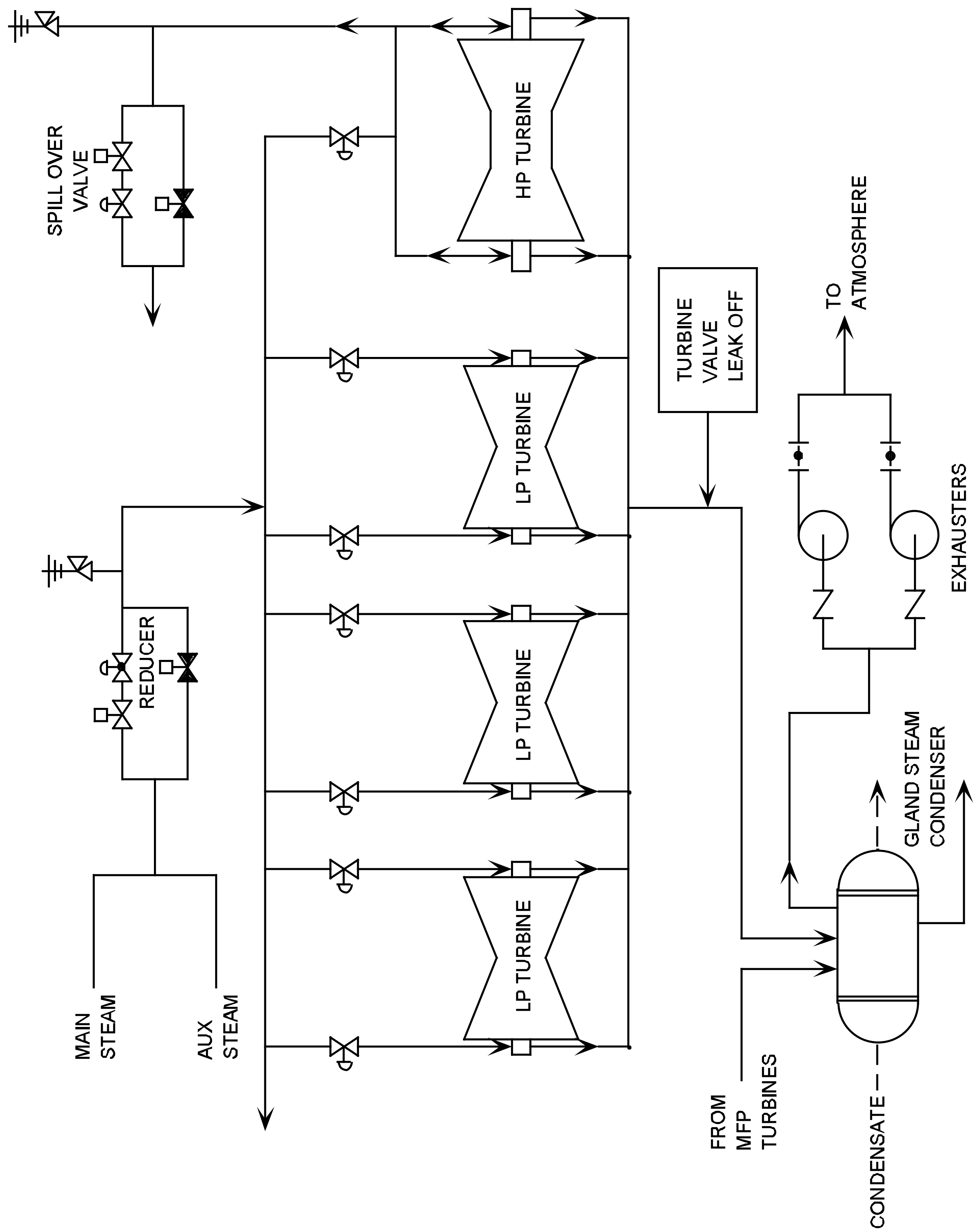

Figure 7.3-3 Gland Steam System

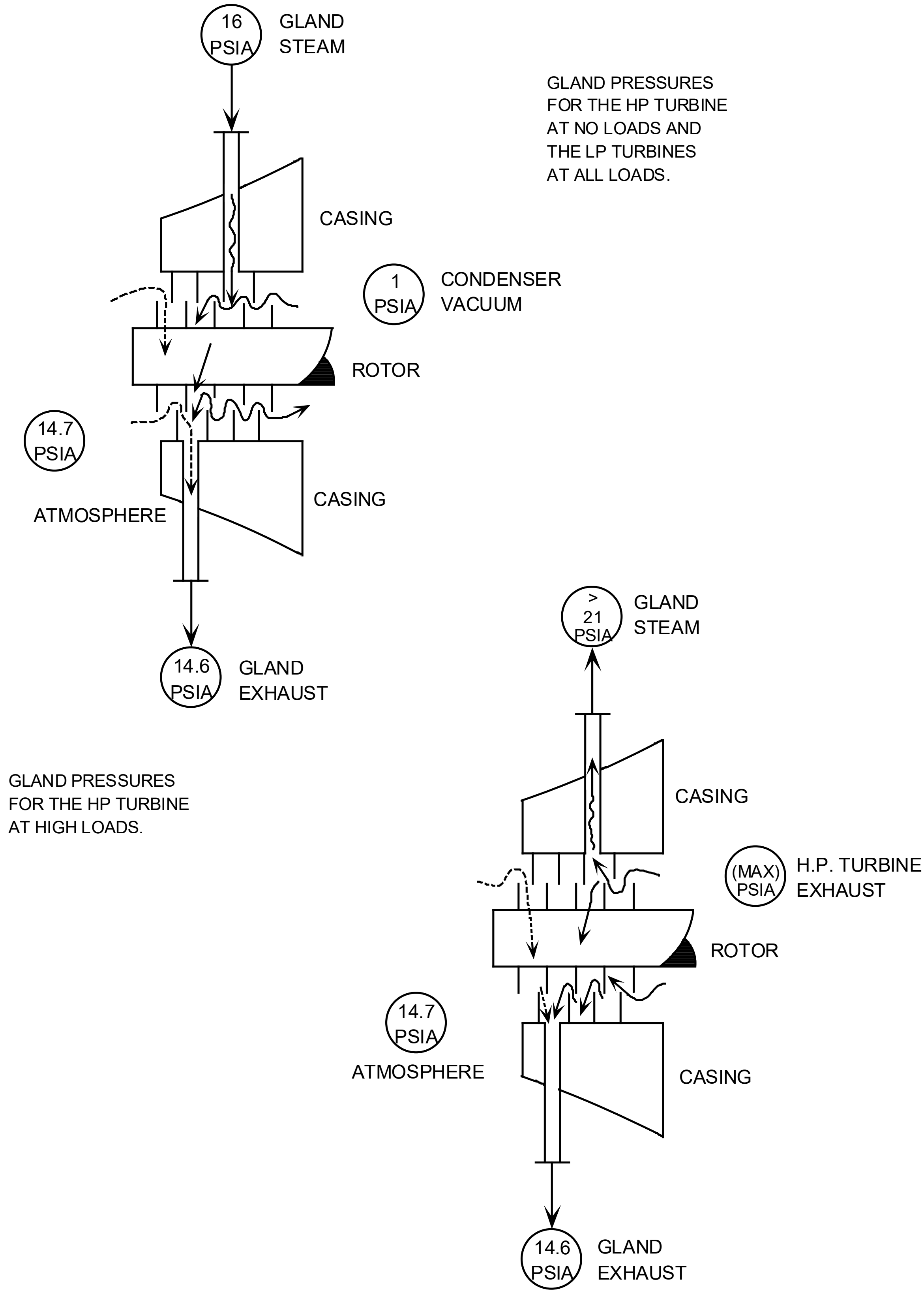

Figure 7.3-4 Gland Steam / Exhaust Pressures

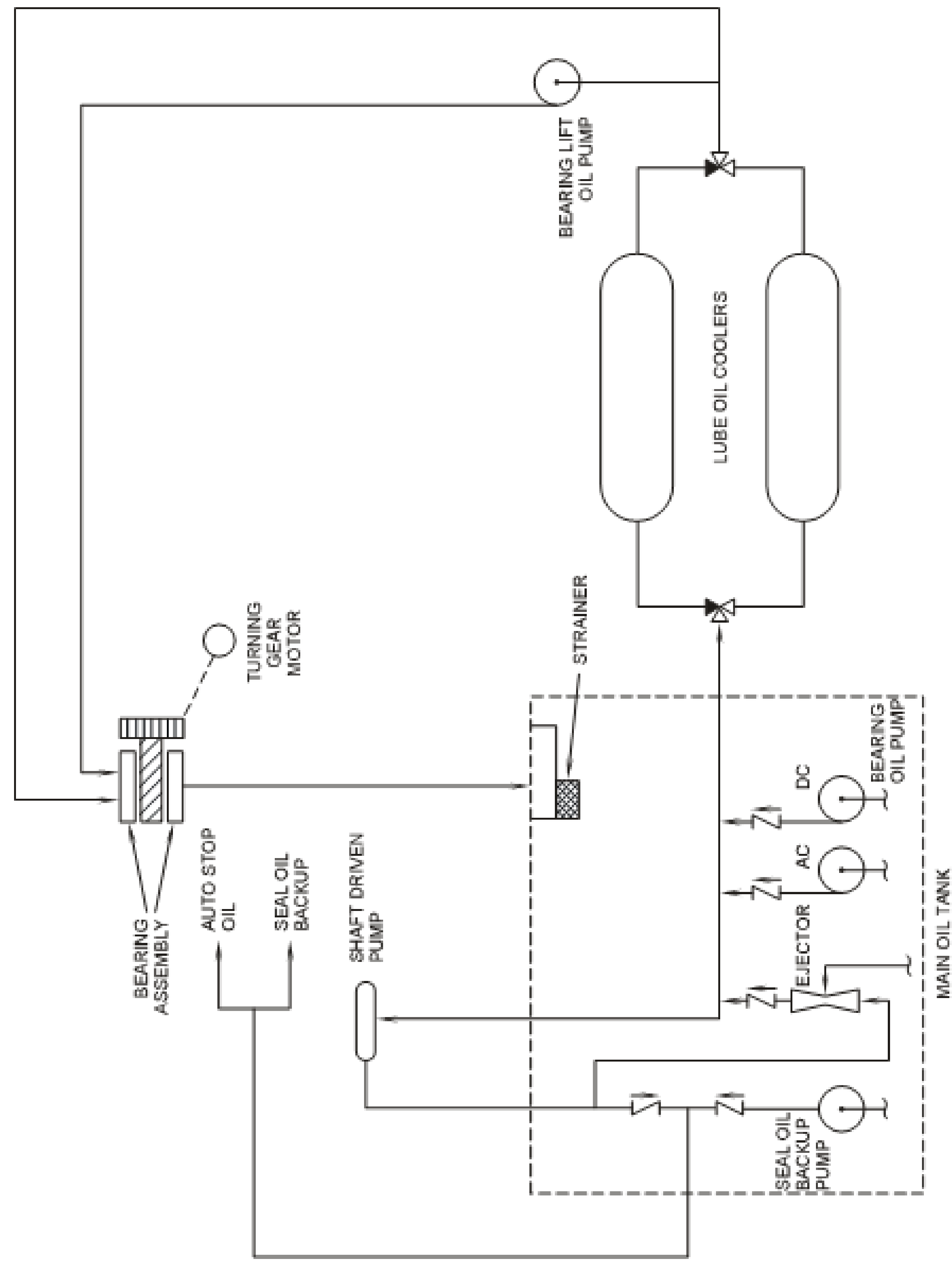

Figure 7.3-5 Simplified Lube Oil System

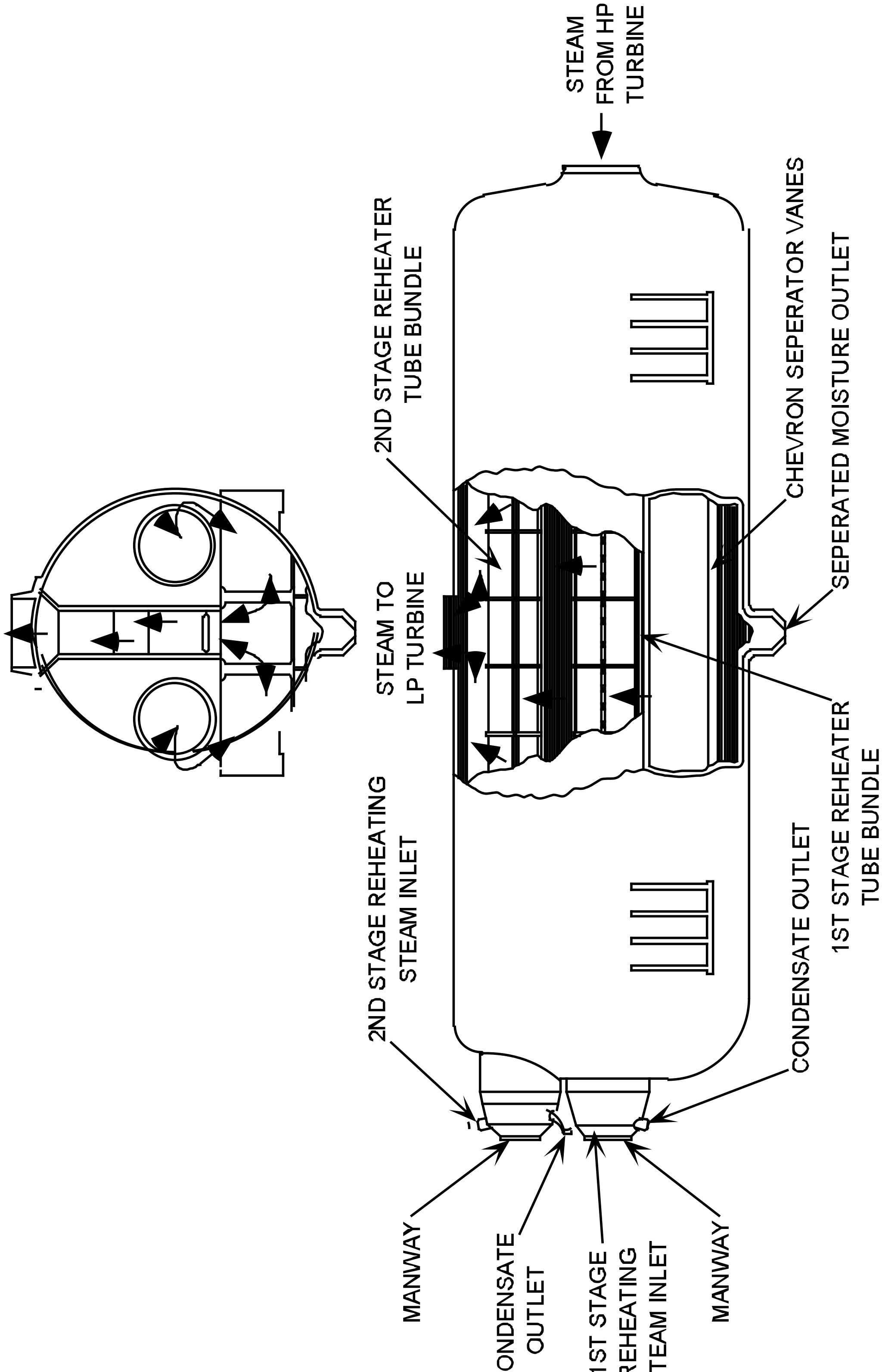

Figure 7.3-6 Moisture Separator Reheater

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Section 7.4

General Electric Turbine and Auxiliaries

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7.4 GENERAL ELECTRIC TURBINE AND AUXILIARIES

Learning Objectives:

1. State the purposes of the turbine and turbine auxiliaries.

2. Identify the sources of heating steam to the Moisture Separator Reheaters (MSRs).

3. State the purposes of the following turbine valves:

    a. Stop valves,
    b. Control valves, and
    c. Combined intermediate valves.

7.4.1 Introduction

The purposes of the turbine and auxiliaries are as follows:

1. To convert the thermal energy of the steam to mechanical energy to turn the main generator,
2. To provide turbine shaft sealing,
3. To provide turbine-generator lubricating oil, and
4. To provide dry, superheated steam to the low-pressure turbines to reduce moisture erosion and to increase plant efficiency.

7.4.2 Main Turbine

7.4.2.1 System Description

The main turbine consists of one high pressure turbine and three low pressure turbines coupled to a single shaft. The four turbines that comprise the main turbine are coupled to the generator and exciter; they serve as the prime mover for these components. A cross-section of the turbine is shown in Figure 7.4-1. Steam enters the main turbine at the high-pressure turbine through the turbine stop (throttle) and control (governor) valves.

The thermal energy of the steam is converted to mechanical energy in the high-pressure turbine, and the steam is exhausted to the Moisture Separator Reheaters (MSRs). In each MSR the steam is dried, reheated, and superheated prior to its entry into the low-pressure turbines. The superheated steam is routed through the intermediate stop and intercept valves as it travels from the MSRs to the low-pressure turbines. Energy conversion occurs again in the low-pressure turbines as the steam expands into the vacuum of the main condenser.

7.4.2.2 Component Descriptions

High Pressure Turbine

The high-pressure turbine is a double-flow turbine with six stages in each direction. The first three stages are rateau (impulse) stages, and the last three stages are reaction stages. Steam enters the four nozzle block segments at the center of the high-pressure turbine and flows axially in both directions. About one fifth of the steam entering the turbine at 100% power is extracted from the second and fourth stages for moisture removal, feedwater heating, and reheating of the high-pressure turbine exhaust steam. Most of the steam supplied to the turbine does work in all six stages and exhausts through six cold reheat (cross-around) lines to the two MSRs, as shown in Figure 7.4-2.

The turbine rotor assembly, which consists of the rotor and the turbine wheels (the wheels contain the rotating blades), is machined from a single casting. The rotating blades (buckets) are secured to the wheels with dovetail joints. The turbine rotor is supported by two elliptical journal bearings, which carry the rotor's weight and limit its radial motion.

Stop Valves

The four stop valves supply steam to the main turbine and close rapidly to isolate the steam flow to the high-pressure turbine when the turbine trips. The stop valves are located just upstream of the control valves. The stop valve casings are welded to the control valve casings, and all four casing units are welded together to form a single assembly. The below-seat chambers of the stop valves are cross-connected, as are the steam headers upstream of the stop valves; this arrangement allows the opening of one stop valve to equalize the pressure across all four valve disks.

The stop valves are identical 28-in., reverse-seating globe valves, with the exception that the #2 stop valve contains an internal bypass valve (see Figure 7.4-3). Opening the internal bypass valve accounts for a small amount of valve stem movement for this valve. When opened, the bypass valve uncovers holes in the main valve disk, allowing steam to flow from the inlet to the outlet with the main disk seated. Opening the internal bypass valve in the #2 stop valve equalizes the pressure across the stop valve main disks to allow valve opening (a stop valve's hydraulic operator cannot open the valve with a differential pressure of greater than 150 psi across the main disk). The bypass valve is also used to provide warming steam for the turbine steam chests and the high-pressure turbine shell during turbine startups (see Chapter 11 .5).

The #2 stop valve position is controlled by the Electro Hydraulic Control (EHC) system. The other three stop valves are "slaved" to the #2 stop valve through a limit switch associated with the #2 stop valve. (See Chapter 11.5 for details on stop valve control.)

Control Valves

The four control valves, located immediately downstream of the stop valves, are positioned by the EHC system for the control of turbine speed and load (see Chapter 11.5). Rapid closure of the control valves when the turbine trips provides redundant isolation of the steam flow to the high-pressure turbine. The control valves admit steam to the high-pressure turbine via four internal nozzle block segments at the center of the turbine rotor.

Each of the control valves is a 28-in., spherically seated globe valve (see Figure 7.4-4). Each valve contains a small internal pilot valve within the main valve disk. When a control valve is opened, the first portion of stem movement opens the pilot valve, thereby reducing the differential pressure across the main valve disk and reducing the opening force required of the valve's hydraulic operator. Further stem movement causes the pilot valve to engage the main disk and open the valve.

Low Pressure Turbines

Each of the three low pressure turbines is a double-flow, condensing turbine with seven reaction stages in each direction. The MSRs supply steam via the combined intermediate valves to the center of each turbine; the steam then flows axially in both directions. About one fourth of the steam entering each low-pressure turbine at 100% power is extracted from the seventh, eighth, tenth, and eleventh stages for moisture removal and feedwater heating (the low-pressure turbine stages are numbered 7 - 13). Most of the steam supplied to each turbine does work in all seven stages and exhausts to the main condenser.

The rotor of each low-pressure turbine is machined from a single forging. The turbine wheels are manufactured separately and shrunk onto the rotor. The rotating blades are attached to the wheels with dovetail joints. Due to the steam expansion that occurs in the low-pressure turbine, the blade height and stage diameter increase with each succeeding stage. The last-stage blading of each low-pressure turbine is 38 in. long. Each low-pressure turbine is supported by two journal bearings.

Combined Intermediate Valves

Each of the six combined intermediate valves consists of two valves in one body, the intercept valve and the intermediate stop valve. Refer to Figure 7.4-5. The two valves share the same seating surface but are equipped with separate operators. The intercept valves and intermediate stop valves are completely open during normal operation. All 12 valves shut when the turbine trips to provide redundant isolation of the low-pressure turbines from the reheat steam supply. The intercept valves can also shut partially or completely to limit turbine overspeed following a load rejection. Intercept valves #1, #2, and #3 are controlled by the EHC system; intercept valves #4, #5, and #6 are slaved to the controlled intercept valves through limit switches associated with the controlled valves. The intermediate stop valves are automatically opened when the master trip reset pushbutton is depressed. (See Chapter11.5 for a discussion of valve operation.)

Each intercept valve disk is hollow and cylindrically shaped to accommodate the disk of its associated intermediate stop valve. This arrangement permits the intermediate stop valve to open or close with the intercept valve completely closed. Equalizing holes in the intercept valve disk minimize the differential pressure across the disk and allow opening of the intercept valve even against maximum reheat steam pressure. Each intermediate stop valve can be opened with a differential pressure across the seat of no greater than 150 psi. The intermediate stop valves are thus opened during the turbine startup sequence before all other turbine valves are opened so that the differential pressure across the valve seats is minimized.

7.4.3 Gland Steam System

7.4.3.1 System Description

During plant operation the entry of air into and the exit of steam from the main turbine must be prevented at those points where the rotor penetrates the turbine casings. These functions are accomplished through the labyrinth design of the rotor/casing penetrations (glands) and through the operation of the gland steam system. The system is designed to handle the steam and air flows that would exist with twice the normal turbine penetration clearances.

The gland steam system (Figure 7.4-6) supplies steam to the turbine glands of the high- and low-pressure turbines and of the main feed pump turbines. During startup and low-load operation, the sealing steam distribution header has two sources of steam supply: the startup boiler and the main steam system. A regulating valve controls the steam pressure supplied by either source. In the initial phases of a startup from cold shutdown conditions, gland steam is supplied from the startup boiler. Once the plant has been heated up and an adequate supply of main steam is available, gland steam is supplied from the main steam system. The sealing steam distribution header also receives low pressure stem leakage from the high-pressure turbine stop and control valves.

At higher plant powers (greater than approximately 40%), the direction of steam flow in portions of the gland steam system changes. Steam from inside the high-pressure turbine casing leaks past the inner turbine glands and into the sealing steam distribution header. Similarly, steam leaks from the main feed pump turbine glands to the distribution header (although at a much smaller flow rate). The steam leakage from these sources supplies the sealing steam for the low-pressure turbine glands at high powers. The unloading valves on the distribution header relieve any excess steam pressure during this mode of operation. (Note: The arrows in Figure 7.4-6 indicate the two possible flow directions in certain portions of the system.)

Steam leakage from the inner turbine packing and air leakage through the outer turbine packing (see Figure 7.4-7) is extracted from the turbine glands by the steam packing exhauster. The exhauster condenses the incoming steam and returns the condensate to the main condenser via a drain tank. The exhauster blower maintains a slight vacuum in the exhauster and discharges air and other noncondensible gases to the turbine building roof.

7.4.3.2 Component Descriptions

Gland Seal Regulating Valve

The gland seal regulating valve (CV-3588 in Figure 7.4-6) is a four-in., air-operated gate valve. The valve's position is controlled by a pressure controller, which supplies instrument air to the valve's operator based on the pressure sensed in the sealing steam distribution header. The pressure controller maintains the gland steam supply pressure between 2.5 and 4.5 psig. Control of the distribution header pressure by the regulating valve is expected only with turbine loads less than 40%. If the regulating valve or its associated controller is inoperable, the operator can maintain the gland steam supply pressure with the regulating valve bypass valve (MO-3586), which is controlled with a control room switch.

Unloading Valves

The two unloading valves are eight-in., direct-acting backpressure regulating valves. Pressure from the regulating valve controller's sensing line acts against spring force in each unloading valve's operator. The unloading valves are set to crack open with a gland steam pressure of 3.5 psig and to open fully with a pressure of 5.5 psig. At loads greater than 40%, the unloading valves are open to relieve excess steam leakage from the high-pressure turbine glands to the main condenser. The normal steam flow through the unloading valves at full power is 19,190 lbm/hr. If the valves are inoperable, the operator can manually dump steam to the condenser with the manual unloading valve (MO-3603), which is controlled with a control room switch.

Turbine Glands

The turbine glands contain labyrinth packing, which provide effective seals for the shaft penetrations. Each labyrinth seal is made up of stationary, spring-backed packing rings and machined grooves in the turbine rotor (see Figure 7.4-7). The packing rings hold stationary teeth arranged concentrically, with very small radial clearances between the teeth and the rotor. The narrow passages between the stationary packing and the rotor produce a cumulative pressure drop, which presents a large resistance to steam or air flow in the axial direction. This seal design minimizes but does not totally eliminate steam outleakage and air inleakage; the applied sealing steam completely seals the glands.

As shown in Figure 7.4-7, the high-pressure turbine is sealed at both ends with three sets of packing. At low loads, sealing steam from the gland steam distribution header pressurizes the annulus formed by the inner and middle sets of packing to prevent air inleakage into the turbine. Sealing steam which leaks past the middle set of packing, and air which leaks past the outer set, enter the annulus maintained at a vacuum by the steam packing exhauster. At higher loads, the higher stage pressures inside the high-pressure turbine casing prevent air inleakage. Instead, steam leaks past the inner set of packing and flows in the reverse direction to the gland steam distribution header to serve as the sealing steam supply for the low-pressure turbines. Again, any leakage of steam and/or air past the middle and outer sets of packing is extracted by the steam packing exhauster.

Sealing of the low-pressure turbines, which exhaust to a vacuum, is always accomplished in the manner described for the high-pressure turbine at low loads.

Steam Packing Exhauster

The steam packing exhauster maintains a vacuum in the outer annuli of the turbine glands to prevent the escape of steam from the turbines into the turbine building.

The exhauster is a shell-and-tube heat exchanger cooled by the turbine building cooling water system. The condensed steam is drained from the exhauster to the main condenser via a loop seal and drain tank. The drain tank level is maintained by a level control valve in the drain line to the condenser. The slight vacuum in the exhauster shell is maintained by the exhauster blower.

7.4.3.3 System Operation

During a plant startup, the gland steam system is placed in service before the turbine startup sequence is initiated. The initial source of steam to the gland steam system is the startup boiler. As the startup progresses and sufficient main steam becomes available, the gland steam supply source is transferred to the main steam system. During normal operation, the gland steam system distribution header pressure is automatically maintained by the gland seal regulating valve and the unloading valves. Sealing steam to the turbine glands is maintained during a shutdown until the condenser vacuum is broken. This practice prevents an inrush of cold air into the turbine casings, which could result in a bowed rotor. Operation of the gland steam system is not required during a shutdown after the condenser vacuum has been broken.

7.4.4 Turbine Lubricating Oil System

7.4.4.1 System Description

The turbine lubricating oil system, illustrated in Figure 7.4-8, supports turbine-generator operation by supplying lubricating oil to the eight turbine journal bearings, the thrust bearing, the two generator bearings, the two exciter bearings, and the turning gear. Under normal operating conditions, the main shaft oil pump, driven by the turbine shaft, supplies oil to the turbine and generator bearings. The suction head for the main shaft oil pump is provided by the lubricating oil booster pump, which takes suction on the lubricating oil reservoir. In addition to supplying the bearing supply header, the main shaft oil pump also supplies oil to the hydraulic turbine which drives the lubricating oil booster pump. Return oil from the bearings gravity drains into the lubricating oil reservoir.

The turbine lubricating oil system includes additional pumps for supplying lubricating oil when the turbine is not in service: the motor suction pump, the turning gear oil pump, and the emergency bearing oil pump. The lubricating oil system also includes bearing lift oil pumps, which supply high pressure oil to turbine and generator bearings in support of turning gear operation. Detailed descriptions of the components mentioned here are provided in the following section.

The system is designed for fire safety. Any pressurized oil supply line which passes near a hot steam line or potentially hot turbine component is enclosed within an oil drain line or guard pipe. The drain and guard pipes drain to the lubricating oil reservoir, ensuring that there is no loss of oil in the event of a supply line rupture.

7.4.4.2 Component Descriptions

Main Shaft Oil Pump

The main shaft oil pump maintains the normal bearing oil pressure under normal operating conditions. The pump is a single-stage centrifugal pump driven by the turbine shaft through a step-up gear assembly and is located in the front standard. The pump suction is supplied with oil at 15 - 20 psig from the electrically driven motor suction pump during startups and from the lubricating oil booster pump during normal operation. The main shaft oil pump develops a discharge pressure sufficient for turbine operation at turbine speeds greater than 1350 rpm. With the turbine at rated speed, the main shaft oil pump discharges oil at a pressure of 235 psig to the booster pump turbine and bearing supply header.

Motor Suction Pump

The motor suction pump supplies oil to the suction of the main shaft oil pump when the turbine speed is less than 1800 rpm. The pump is a single-stage centrifugal pump driven by a 60-hp ac motor. The pump is located inside the lubricating oil reservoir, and the motor is mounted atop the reservoir. The pump is started manually with a control room switch during turbine startups. With the turbine at rated speed, the pump is idle, and its control switch is in the automatic position. The motor suction pump starts automatically when the lubricating oil booster pump discharge pressure falls below 10 psig.

Lubricating Oil Booster Pump

The lubricating oil booster pump supplies the suction head required by the main shaft oil pump during normal operation. The pump is a single-stage centrifugal pump driven by the discharge of the main shaft oil pump via a hydraulic turbine. The lubricating oil pump is located inside the lubricating oil reservoir. Under normal operating conditions, it supplies a suction pressure of 15 - 20 psig to the main shaft oil pump. The booster pump turbine exhaust oil is supplied to the bearing supply header, where it joins the flow supplied directly by the main shaft oil pump.

Turning Gear Oil Pump

Because the main shaft oil pump cannot provide adequate bearing lubrication with turbine speeds less than 1350 rpm, the turning gear oil pump is provided as the pumping source of lubricating oil during turbine startups and shutdowns. The pump is a single-stage centrifugal pump driven by a 50-hp ac motor. The pump is located inside the lubricating oil reservoir, and the motor is mounted atop the reservoir. The pump is operated manually during startups and shutdowns. With the turbine at rated speed, the pump is idle, and its control switch is in the automatic position. The turning gear oil pump starts automatically when either the bearing supply header pressure falls below 15 psig or the main shaft oil pump discharge pressure falls below 190 psig.

Emergency Bearing Oil Pump

The emergency bearing oil pump supplies lubricating oil to the turbine and generator bearings for the safe shutdown of the turbine-generator when ac power is not available. The pump is a single-stage centrifugal pump driven by a 30-hp dc motor. The pump is located inside the lubricating oil reservoir, and the motor is mounted atop the reservoir. Under normal operating conditions, the pump is idle, and its control switch is in the automatic position. The emergency bearing oil pump starts automatically whenever the turning gear oil pump discharge pressure is less than 10 psig coincident with a main shaft oil pump discharge pressure of less than 180 psig.

Baffler Valves

Two flow regulating valves, called baffler valves, in the lubricating oil system correctly apportion the main shaft oil pump discharge to the lubricating oil booster pump turbine and the bearing supply header. The valves are manually adjusted so that the bearing supply header pressure is maintained at 25 psig and that the discharge pressure of the lubricating oil booster pump is maintained between 15 and 20 psig.

Lubricating Oil Coolers

Before it is supplied to the turbine bearings, the lubricating oil is cooled in one of the two lubricating oil coolers. As each is a 100% capacity cooler, only one is in service at a time. The in-service cooler is determined by the position of the transfer valve. Cooling water from the turbine building cooling water system flows through the tubes, and lubricating oil flows through the shell of the in-service cooler. A flow control valve regulates the cooling water flow to maintain a lubricating oil reservoir temperature of l20°F.

Lubricating Oil Reservoir

The lubricating oil reservoir stores the return oil from the lubricating oil system and provides the necessary suction head for each system pump located inside the reservoir. Oil gravity drains from the turbine and generator bearings and enters the reservoir through two wire screens arranged in series. The reservoir's total capacity is 10,000 gal; the normally maintained oil volume is 7450 gal. The additional capacity accommodates the volume of oil which returns from the system piping when the lubricating oil system is shut down. The reservoir level instrumentation supplies high and low level alarms, with setpoints of ± four in. from the normal level (five ft), and a high-high level alarm, with a setpoint of four in. below the top of the reservoir. The high-high level alarm warns of a potential overflow.

Vapor Extractor

Air and other vapors are constantly removed from the lubricating oil reservoir by the vapor extractor. The extractor is a centrifugal blower driven by a 7.5-hp motor. The extractor takes suction on the reservoir and discharges through a mist eliminator to the turbine building roof. Because the vapor extractor maintains a slight vacuum in the reservoir, it also ventilates the lubricating oil drain lines from the turbine and generator bearings. Effective ventilation of the system enhances the removal of some of the contaminating influences that might affect the service life of the lubricating oil.

Bearing Lift Oil Pumps

The lubricating oil supply lines to bearings #3 through #10 (eight journal bearings which support the three low pressure turbines and the generator) differ from the other oil supply lines in that they are provided with bearing lift oil pumps. Operation of the bearing lift oil pumps reduces the torque on the turning gear motor and reduces the turning gear teeth stresses. The lift oil pumps serve these purposes by supplying high pressure oil to the lower halves of the bearings (the underside of the turbine shaft); the oil actually lifts the turbine shaft. In each bearing supplied by a lift oil pump, the high pressure oil passes through the lower half of the bearing into a recessed pocket. The pocket is located in the babbitt surface of the bearing. When sufficient pressure is built up in all of the bearings, the shaft will lift approximately two to five mils.

Each of the eight bearing lift oil pumps is a positive displacement pump driven by a five-hp ac motor. Each of the pumps supplies a single bearing. Upon initial starting, each pump generates a discharge pressure of 3000 - 3500 psig. As the shaft lifts, the pressure drops to about 900 psig. Each pump has a filter in its suction line for the removal of foreign material and a relief valve in its discharge line for overpressure protection. Pump running indication is provided for each pump by a pressure switch in its discharge line.

The bearing lift oil pumps can be started manually with control room switches or automatically through the operation of the low speed switch when the turbine speed decreases to 1.5 rpm (indicating that turning gear operation is required; refer to the turning gear description in the following paragraphs). The lift oil pumps are manually started when the turbine speed decreases to 900 rpm following a turbine trip. A starting permissive for each pump is supplied by a pressure switch which senses the pressure in the pump’s suction line; a pump start is permitted when suction pressure is greater than six psig. Similarly, a running pump will trip if its suction pressure falls below one psig.

Turning Gear

The function of the turning gear is to prevent turbine shaft distortion when it is being heated or cooled. Damage to the turbine because of rubbing between the moving and stationary components is therefore prevented. The turning gear slowly rotates the shaft when the turbine is shutdown and is being heated or cooled. The slow rotation ensures an even circumferential temperature distribution around the rotor.

The turning gear is a motor-driven pinion that meshes with a bull gear located on the turbine shaft between bearings #8 and #9 (i.e., between the last low-pressure turbine and the generator). The pinion is driven at 900 rpm by a 60-hp, single-speed motor. The pinion drives the bull gear (and thus the turbine shaft) at 1.5 rpm.

The turning gear can be manually engaged by turning a wrench on the projection of the shaft engaging mechanism or by depressing a pushbutton at the local turning gear control panel. The pushbutton energizes a solenoid-operated valve which applies instrument air pressure to the turning gear engaging mechanism. The air pressure acts on a piston which, through mechanical linkage, forces the pinion to mesh with the bull gear. The solenoid-operated valve is also energized (and the turning gear engagement sequence is initiated) when the turning gear is automatically engaged by the low speed switch, which actuates when the turbine speed drops to 1.5 rpm. Automatic engagement of the turning gear or manual engagement with the local pushbutton is permitted when the turning gear motor is running.

The turning gear motor is started manually with a local control switch or automatically by the low speed switch described above. With an automatic start of the turning gear, there is a time delay between motor starting and gear engagement to ensure that the turning gear motor starts unloaded. Three permissives must be satisfied to start the turning gear motor either manually or automatically:

1. At least one bearing lift oil pump is running (as indicated by a pump discharge pressure of greater than 840 psig),
2. Bearing supply header pressure is greater than 10 psig, and
3. The generator output breakers are open.

In addition, an interlock provided by the speed control unit of the EHC system prevents automatic starting of the turning gear motor when the turbine speed exceeds 100 rpm.

7.4.4.3 System Operation

With the plant shutdown, the turning gear oil pump and the bearing lift oil pumps are running to supply the turbine and generator bearing lubrication requirements and to support turning gear operation. In preparation for rolling the turbine, the motor suction pump is started to provide a suction head for the main shaft oil pump. The emergency bearing oil pump is idle, and its control switch is in automatic.

As the turbine speed increases, the speed of the main shaft lubricating oil pump increases, and the pump begins to develop a discharge pressure. The main shaft oil pump provides lubricating oil flow via the baffler valves to the turbine driver for the lubricating oil booster pump and to the bearing supply header. At low turbine speeds, the main shaft oil pump does not provide sufficient flow to support turbine operation; the turning gear oil pump supplies the majority of lubricating oil flow to the turbine and generator bearings.

When the turbine speed reaches 900 rpm, operation of the bearing lift oil pumps is no longer necessary, and the pumps are manually stopped. As the turbine speed approaches 1800 rpm, the discharge pressures of the main shaft oil pump and the lubricating oil booster pump gradually increase. When the turbine has reached rated speed, the discharge pressure of the main shaft lubricating oil pump exceeds that of the turning gear oil pump, and the main shaft lubricating oil pump supplies all oil flow to the bearings. Also, the lubricating oil booster pump is now supplying the suction head to the main shaft lubricating oil pump.

With the turbine at rated speed, the motor suction pump and the turning gear oil pump are manually stopped to complete the normal operating alignment of the turbine lubricating oil system. The control switches for these pumps are placed in automatic. The motor suction pump, the turning gear oil pump, and the emergency bearing oil pump will automatically start as required by system conditions.

7.4.5 Moisture Separator Reheaters (MSRs)

7.4.5.1 System Description

Two identical moisture separator reheaters convert the "wet" exhaust steam from the high-pressure turbine into the dry, superheated steam supplied to the low-pressure turbines. MSR B also supplies low pressure steam to the main feed pump turbines. The exhaust steam entering the MSRs at 370°F and a moisture content of 12% is reheated to an exit temperature of 504°F. In the MSRs the steam is dried by moisture separators and heated by two stages of reheater tube bundles. The MSRs improve the plant's secondary cycle efficiency and minimize moisture-induced erosion of the low-pressure turbine blading.

7.4.5.2 Component Descriptions

MSR Shells and Moisture Separators

Each MSR shell is a cylindrical vessel 74 ft long and 12 ft in diameter. The carbon steel shell is 1.25 in. thick and has a design pressure of 270 psig. Three relief valves mounted atop each MSR provide overpressure protection. High pressure turbine exhaust steam (also called cold reheat steam) enters each shell at the bottom via three inlet nozzles and exits the top of the shell, having been dried and reheated, via three outlet nozzles. Each outlet line supplies one low pressure turbine.

In each MSR, the incoming steam encounters impingement baffles at each inlet. Refer to Figure 7.4-9. The baffles direct the steam flow axially to the primary steam lines located in the lower portion of the MSR. From the primary steam lines the steam bleeds into the moisture separator panels. The chevron-type moisture separator panels force the steam to undergo abrupt changes in direction; the dense moisture droplets are deposited on the chevron plates. The removed moisture collects at the base of the MSR and drains through six 10-in. penetrations to a common 24-in. header, which in turn drains to the MSR drain tank (each MSR has an associated drain tank). The dried steam exiting the moisture separators is directed upward through the first- and second-stage reheater tube bundles. The reheated steam exits the top of the MSR via the outlet nozzles.

First-Stage Reheater Tube Bundles

Each first-stage reheater tube bundle is comprised of 690 stainless steel tubes. The straight-run sections of the tubes are 58 ft in length, and the tubes are one in. in diameter. As shown in Figure 7.4-2, the first-stage tube bundles are supplied with second-stage extraction steam from the high-pressure turbine via steam supply valves MO-3672A (MSR A) and MO-3672B (MSR B). The steam supply valves have no associated control system; the steam supply to the first-stage reheater tube bundles increases with extraction steam pressure as the turbine load is increased. The steam supply valves are opened when the turbine speed has reached 1800 rpm during plant startups. The condensate formed in the first-stage reheater tube bundles drains to the first-stage reheater drain tanks (one drain tank per MSR).

Second-Stage Reheater Tube Bundles

The construction of the second-stage reheater tube bundles is identical to that of the first-stage bundles, except that each second-stage bundle contains 621 tubes. As shown in Figure 7.4-2, the second-stage reheater tube bundles are supplied with steam from the main steam system bypass header via steam supply isolation valves MO-3590A (MSR A) and MO-3590B (MSR B). These valves are open when the turbine load exceeds 15%. Two parallel valves regulate the steam flow to each second-stage reheater tube bundle: an air-operated low load control valve (CV-36l2A for MSR A and CV-3612B for MSR B) and a motor-operated high load valve (MO-36l3A for MSR A and MO-3613B for MSR B). The condensate formed in the second-stage reheater tube bundles drains to the second-stage reheater drain tanks (one drain tank per MSR).

The second-stage reheat control system controls the positions of the parallel valves in the second-stage reheater supply lines. The control system modulates the positions of the low load control valves over the turbine load range of 15 - 60%. The valve positions are varied to maintain the appropriate second-stage reheater supply pressure for the existing turbine load. The inputs to the controller for each low load control valve are (1) a signal proportional to the supply header pressure downstream of the valve and (2) a signal proportional to the shell-side pressure of MSR B (an indication of turbine load). Any error between these signals results in a valve position change. The control system automatically opens the high load valves when the turbine load reaches 60% (as indicated by the MSR B shell-side pressure) to reduce the pressure drops in the second-stage reheater supply lines for high turbine loads.

7.4.5.3 System Operation

During a plant startup, the first-stage reheater steam supply valves are manually opened when the turbine speed has reached 1800 rpm. The steam flow to the first-stage reheater tube bundles increases as the high-pressure turbine extraction steam pressure increases with turbine load. When the turbine load reaches 15%, the second-stage reheater steam supply isolation valves are manually opened. For turbine loads in the range of 15 - 60%, the second-stage reheat control system controls the main steam supply to the second-stage reheater tube bundles via the low load control valves. When the turbine load exceeds 60%, the operator verifies that the control system has opened the high load valves which supply the second-stage reheaters.

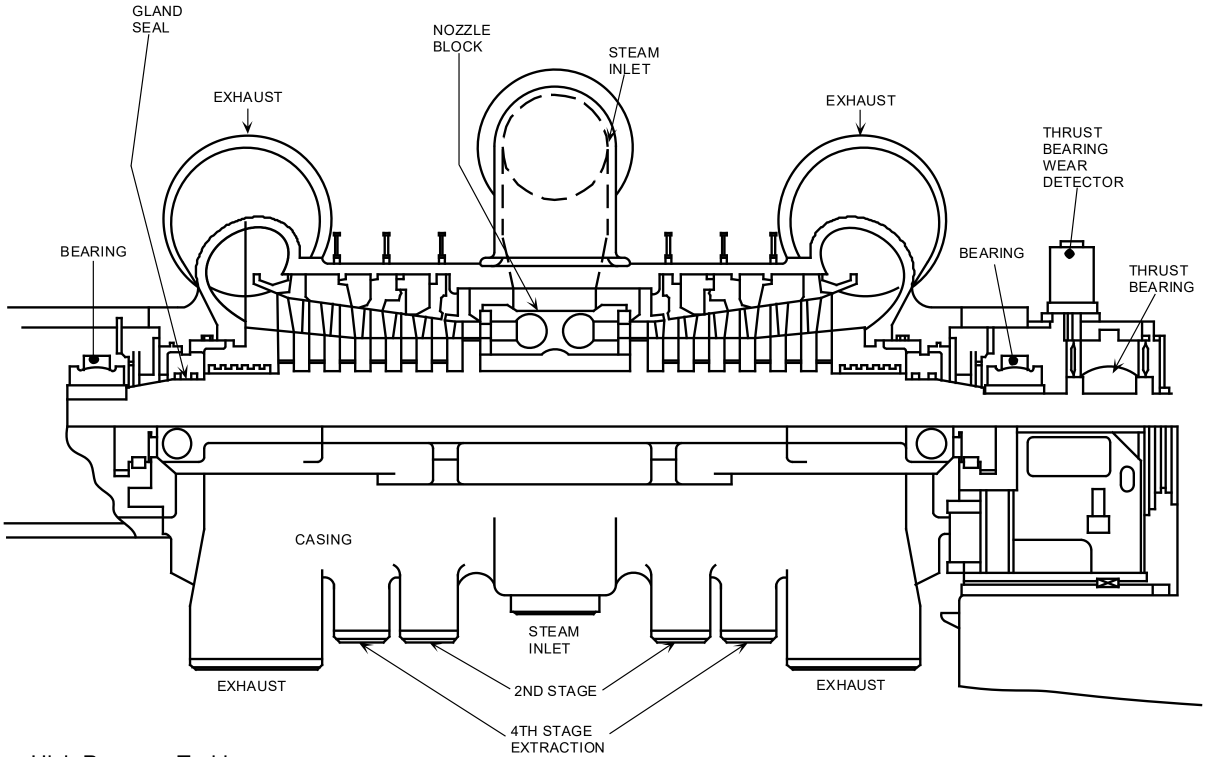
During a plant shutdown, the operator verifies that the high load valves close when the turbine load has been reduced to less than 60%. The operator manually closes the second-stage reheater steam supply valves when the turbine load reaches 15%. Once the turbine has tripped, the operator manually closes the first-stage reheater supply valves.

7.4.6 Summary

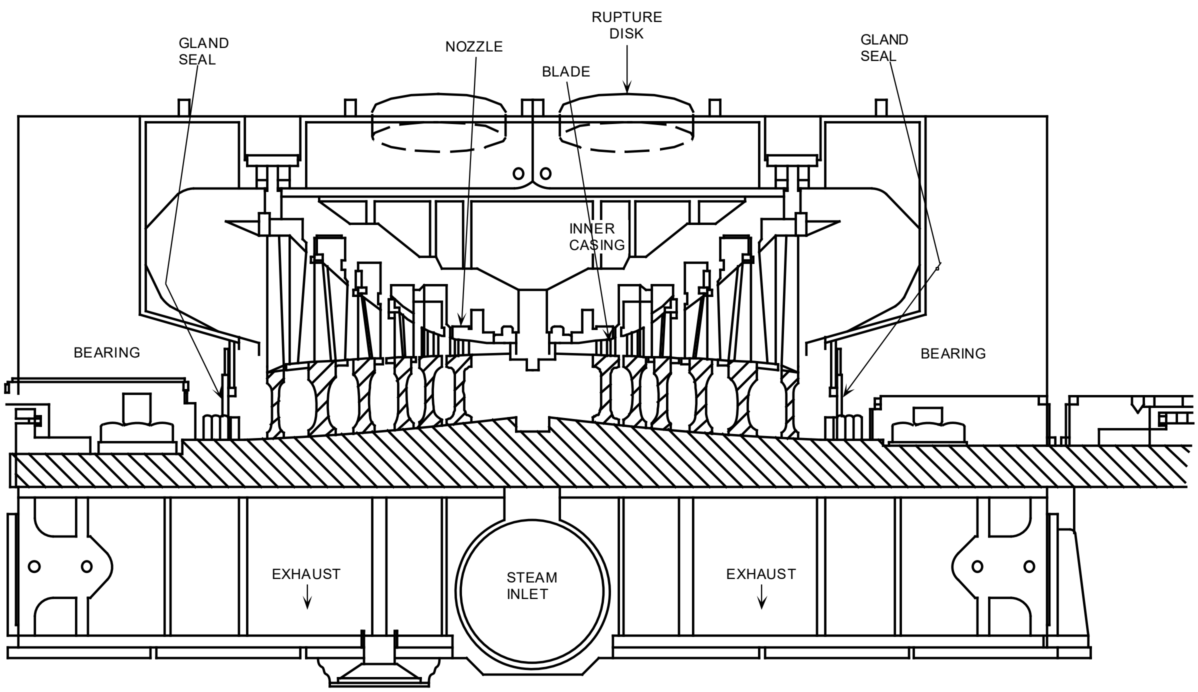
The nuclear steam supply system supplies steam to the main turbine. The main turbine consists of one high pressure turbine and three low pressure turbines coupled to the main generator. Hydraulically operated control valves regulate the flow of steam to the turbines, thereby adjusting the turbine speed in accordance with operator commands or maintaining a desired electric load for the grid.

Dry, superheated steam is supplied to the low-pressure turbines by the moisture separator reheaters. The MSRs improve secondary cycle efficiency and minimize low pressure turbine blade erosion. In addition, one of the MSRs supplies steam to the main feed pump turbines.

The gland steam system is designed to prevent air entry into the turbine or steam leakage out of the turbine. The turbine lubricating oil system provides all required lubrication for the turbine and generator bearings.



High Pressure Turbine



Low Pressure Turbine

Figure 7.4-1 Main Turbine Cross Section

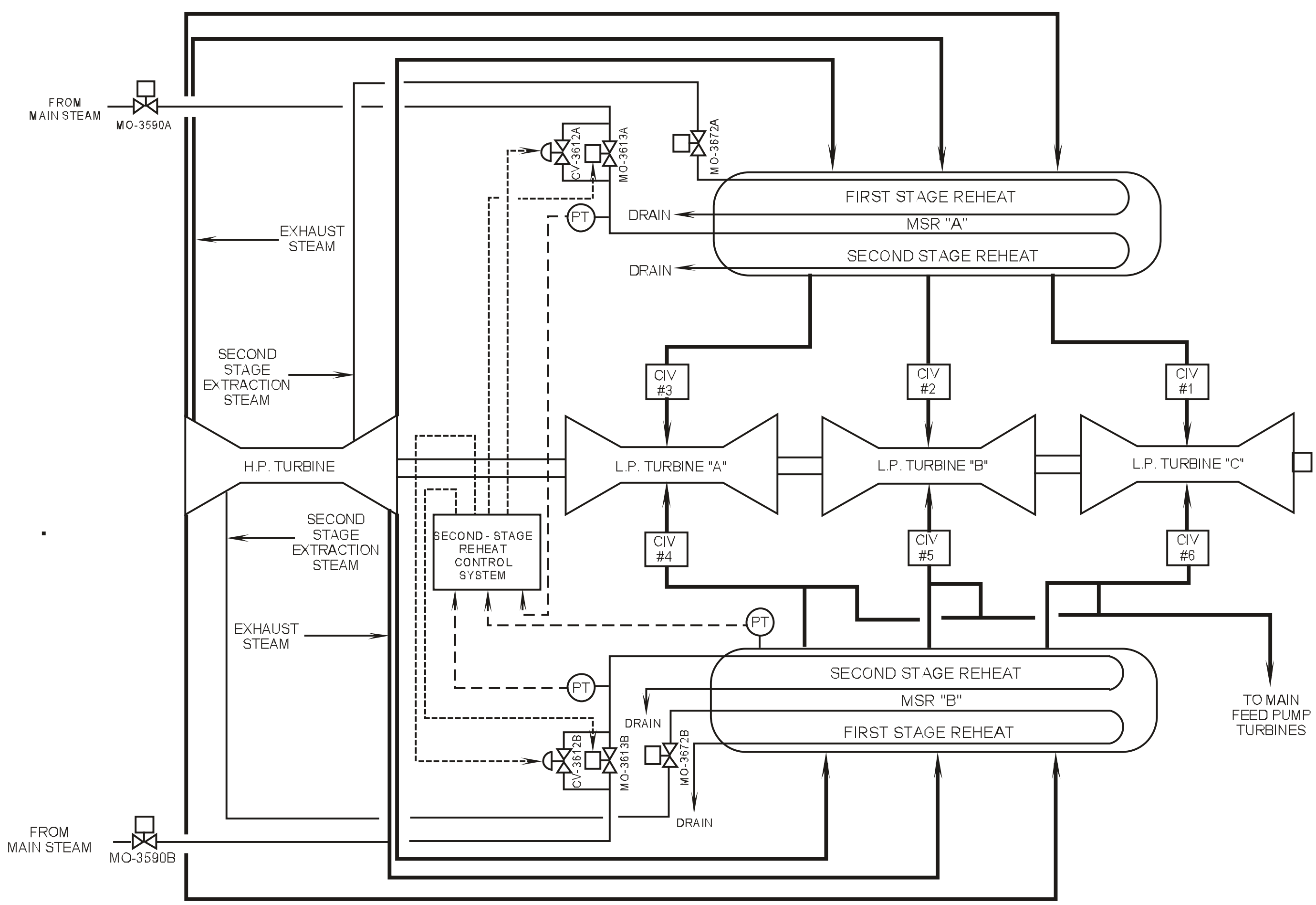


Figure 7.4-2 Main Steam System – Low Pressure

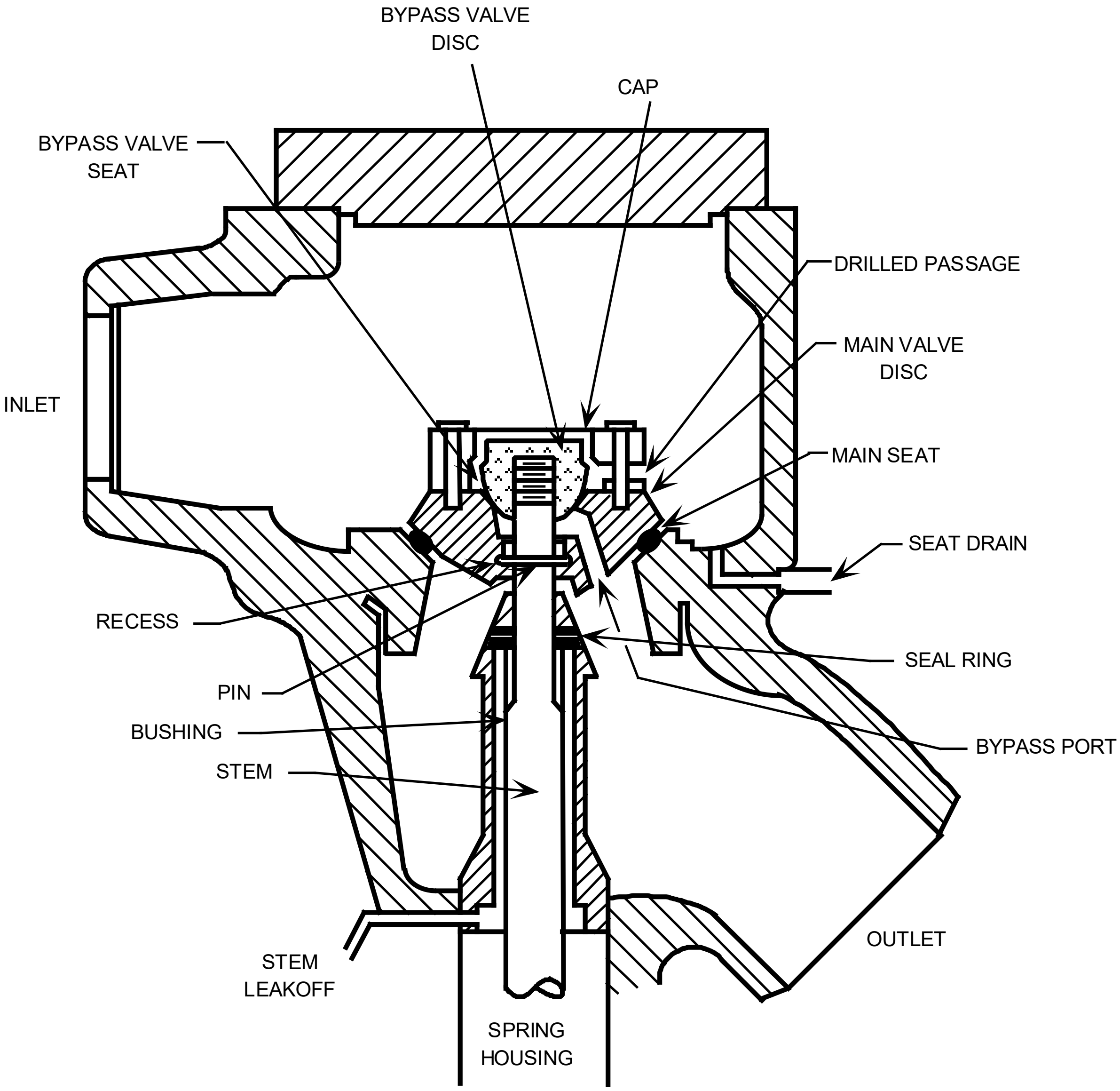


Figure 7.4-3 Stop Valve

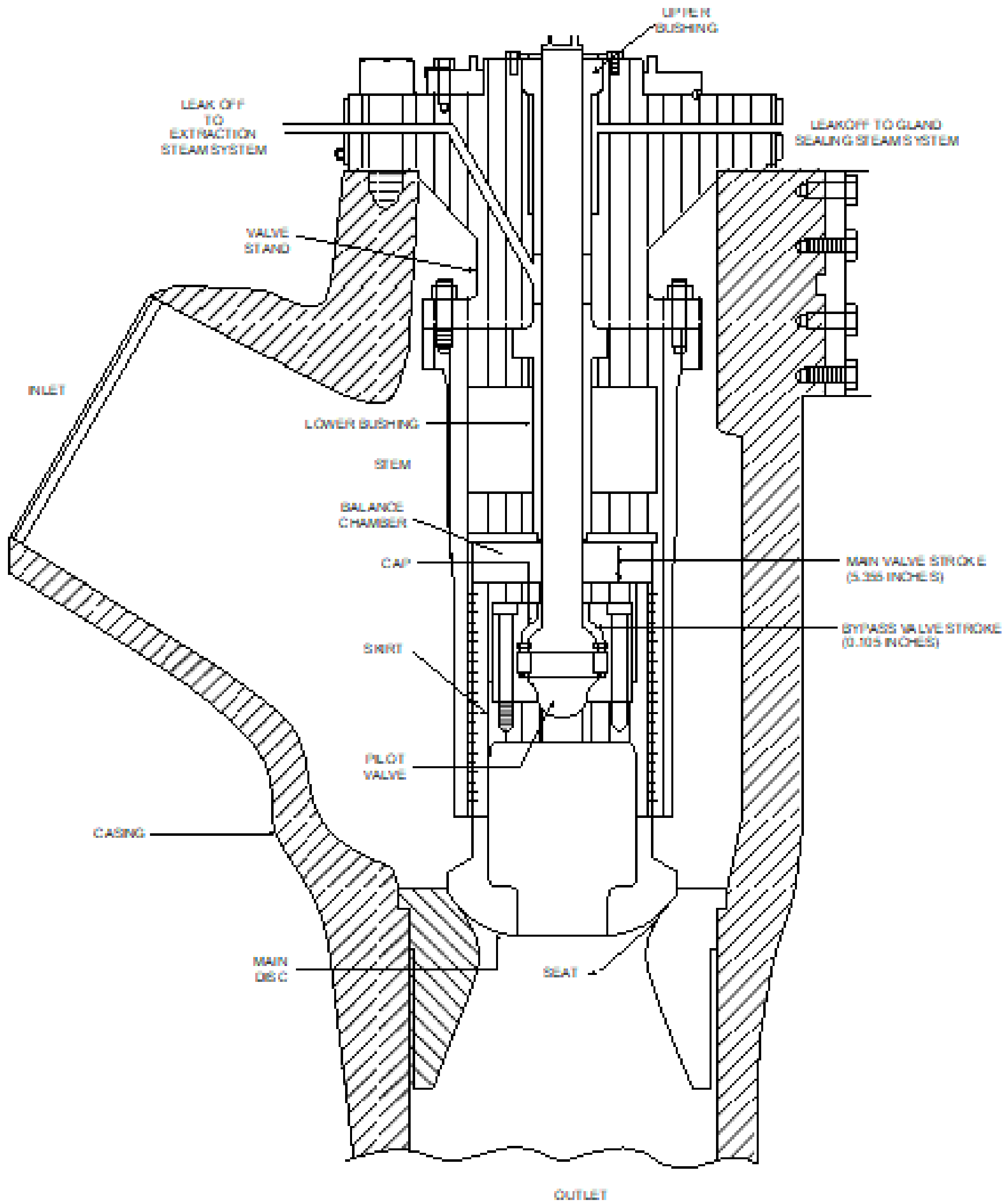


Figure 7.4-4 Control Valve

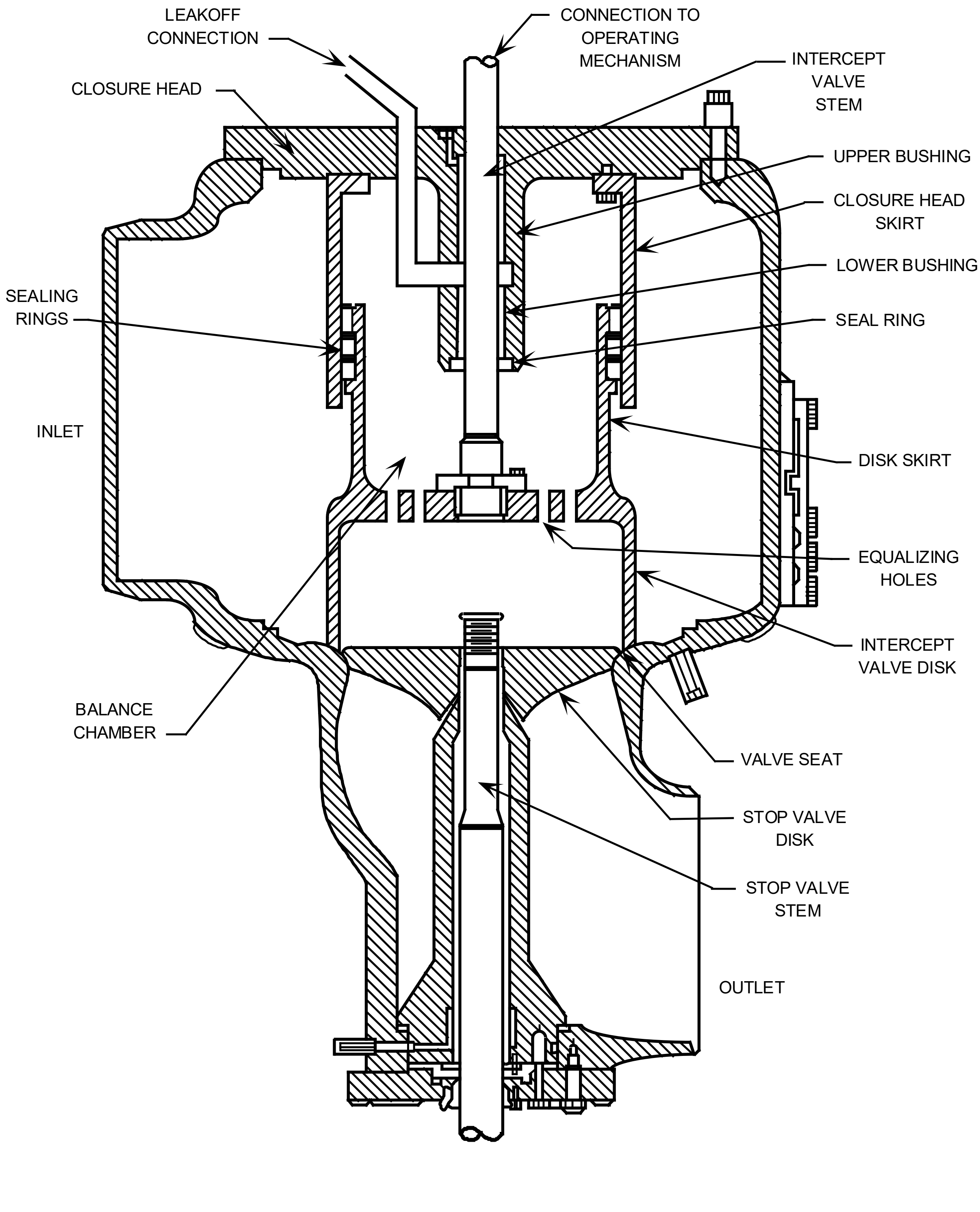


Figure 7.4-5 Combined Intermediate Valve

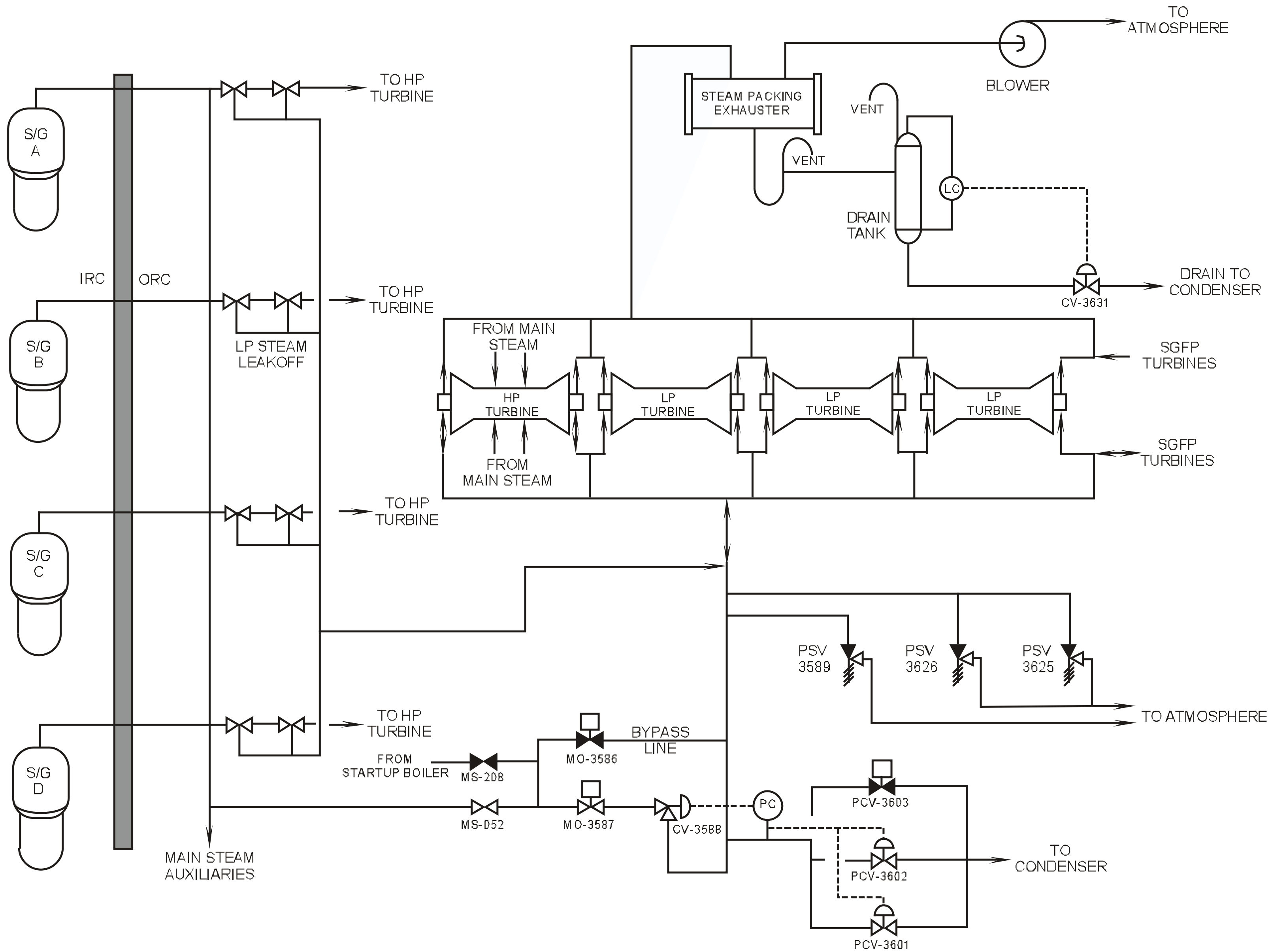


Figure 7.4-6 Gland Steam System

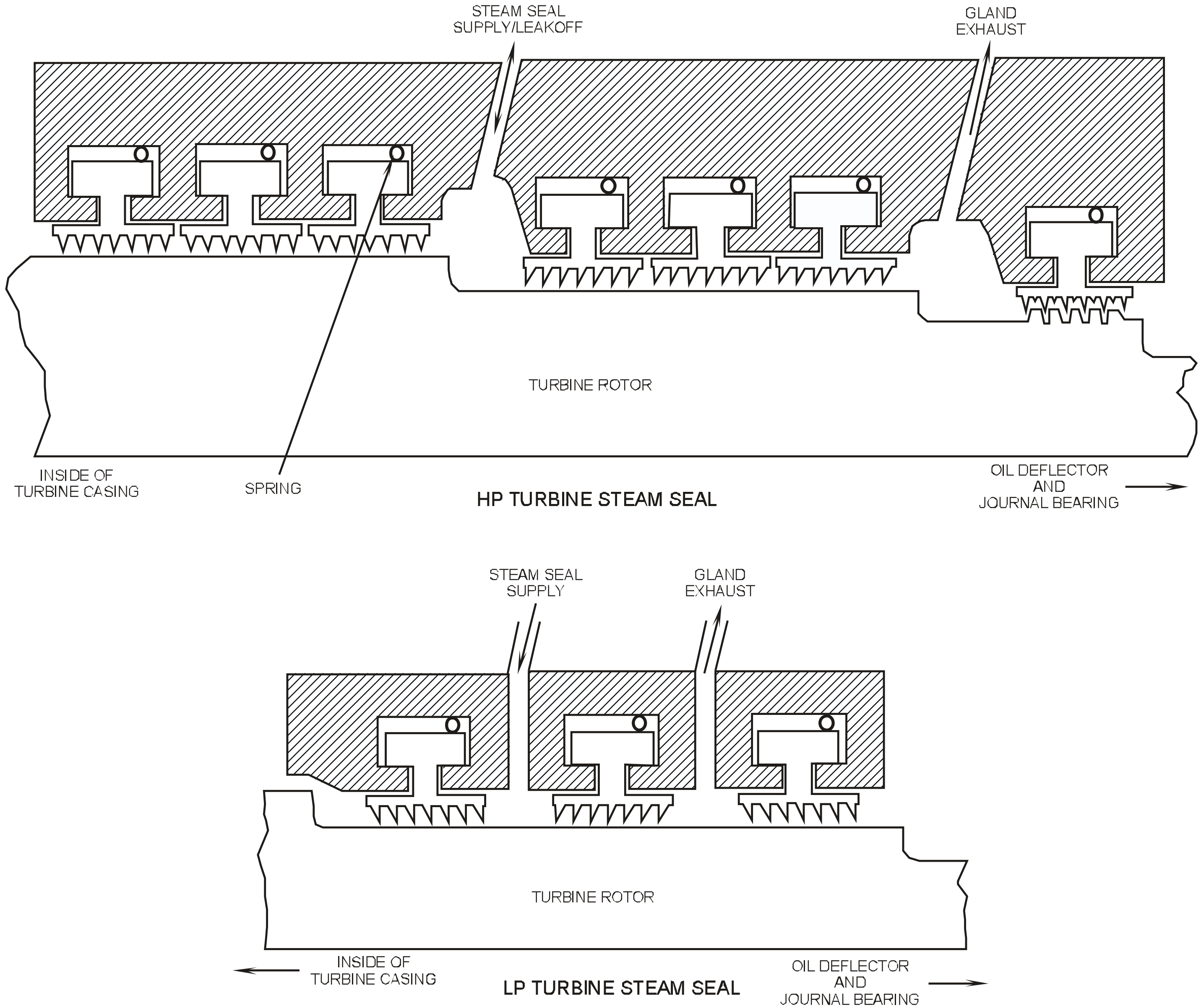


Figure 7.4-7 Turbine Glands

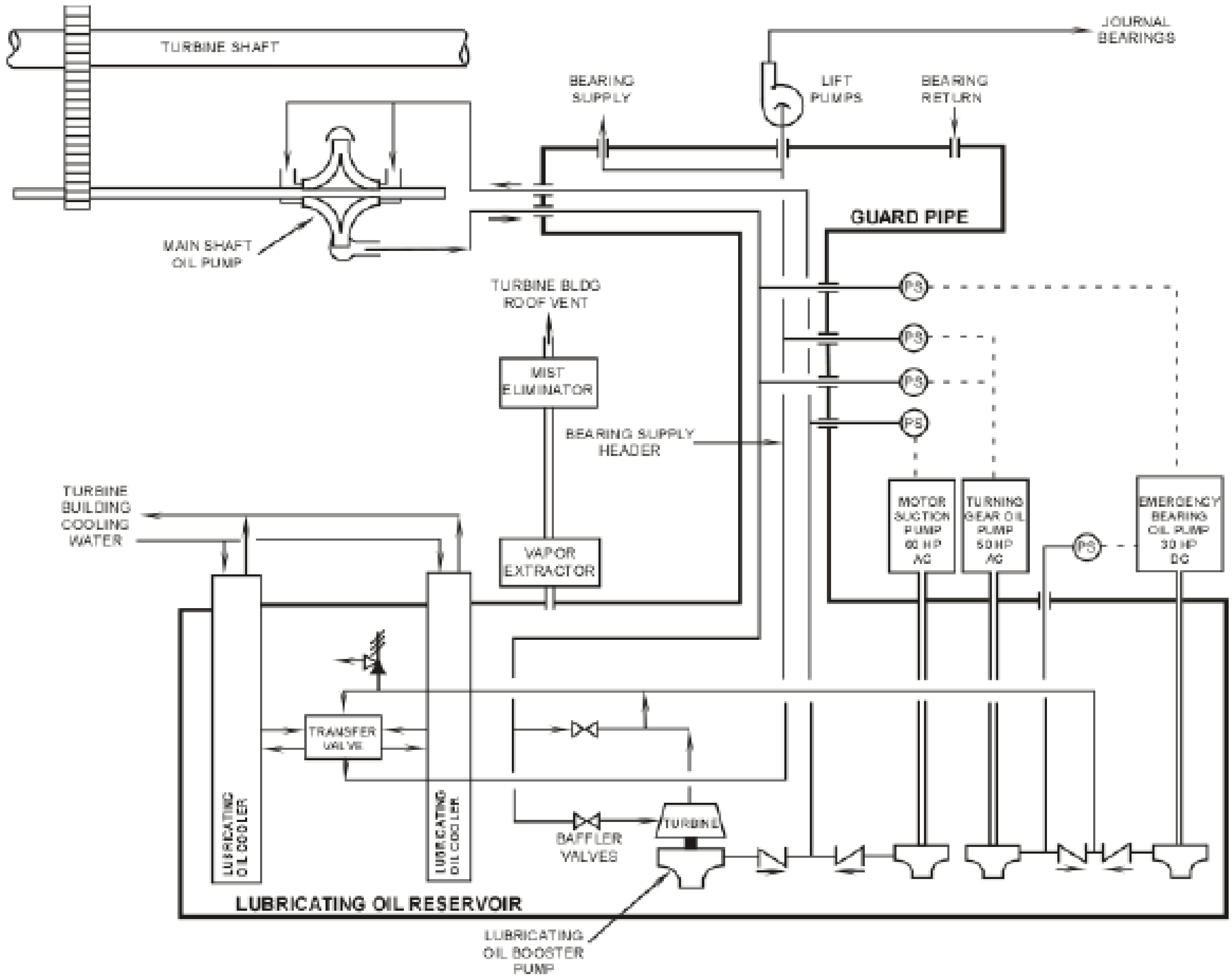


Figure 7.4-8 Turbine Lubricating Oil System

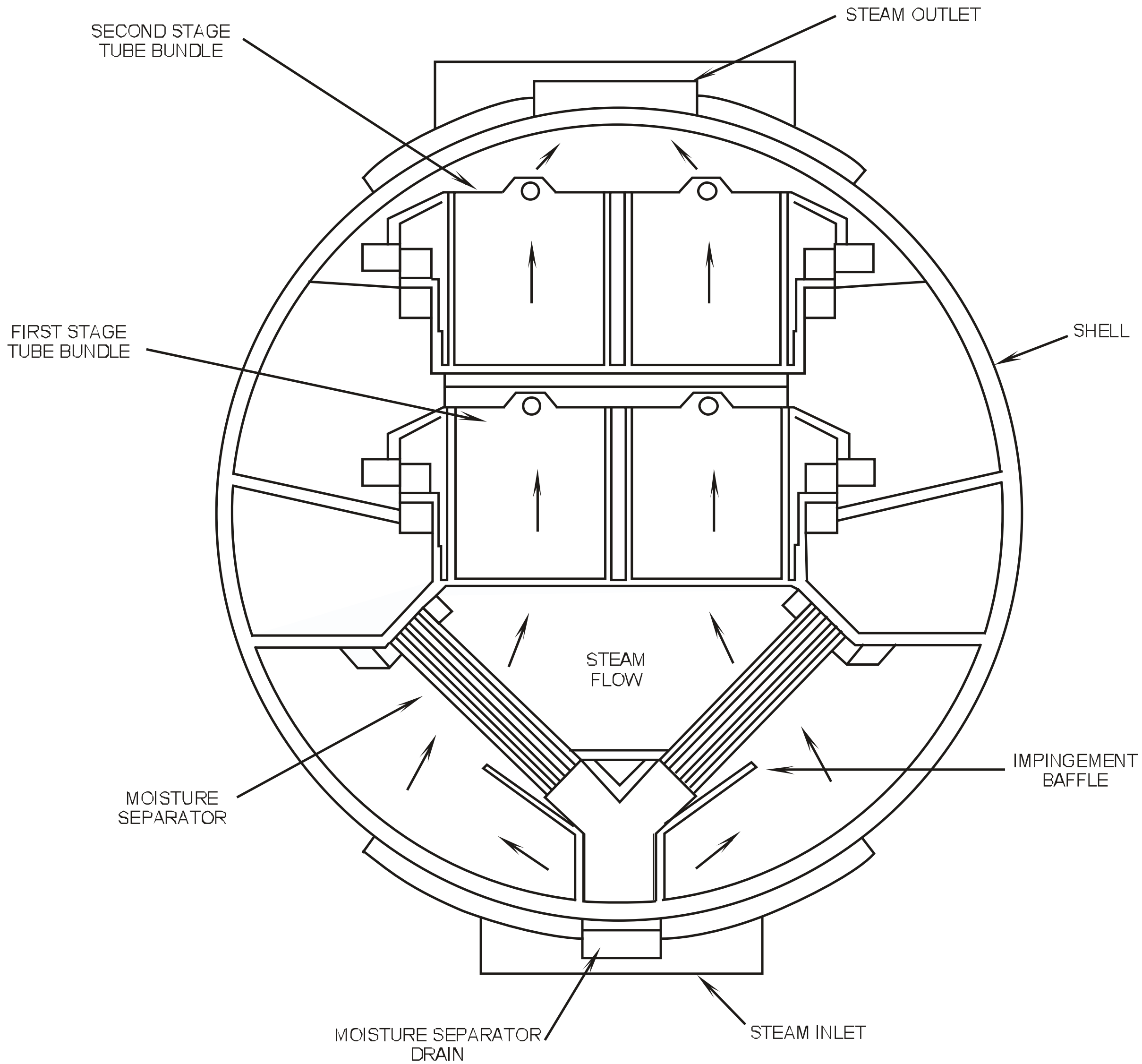


Figure 7.4-9 Moisture Separator Reheater (End View)

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Chapter 8

ROD CONTROL AND INSTRUMENTATION

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8.0 ROD CONTROL AND INSTRUMENTATION

Introduction

The fundamental control philosophy for a Westinghouse Nuclear Steam Supply System is based on the fact that reactor power follows turbine load, or, more accurately secondary load (including all steam flow, leaks, feedwater variations, and etc.) As we learned in reactor physics, as turbine load increases more heat is removed from the primary system and RCS Average Temperature (Tavg) tends to decrease and add positive activity (negative moderator temperature coefficient) which causes reactor power to increase as turbine load increases. In Chapter 1, we determined that a Tavg program is used to limit the change in RCS temperature as turbine load is increased which reduces the volume change in the RCS from no-load to full-load and allows the use of a smaller RCS pressurizer while minimizing the drop in steam header pressure.

Since reactor power inherently follows secondary load, Westinghouse determined to use secondary load as the reference for controlling reactor power and Tavg. An accurate indication of turbine load which has a linear increase from no-load to 100% Turbine Load is derived from Turbine 1st Stage Pressure. Turbine 1st Stage Pressure is the pressure between the first and second impulse blades of the high pressure turbine. It has a value of zero with no-load steam flow through the high pressure turbine and increases linearly with load to a value of approximately 600 psig at 100% turbine load.

Since the Westinghouse control philosophy is for reactor power to follow turbine load, Turbine 1st Stage Pressure is used to generate a reference signal for controlling RCS Tavg. This reference signal is called Tref. It is used in the Reactor Rod Control circuit to produce a reference temperature from no-load to 100% Power (557°F to 585°F). Tref is also used in the Steam Dump Control circuit which is discussed chapter 11.2 (See Figure 8.0-1).

The linear response to increasing turbine load also allows Turbine 1st Stage Pressure to be used as a load reference for generating the High Steam Flow Safety Injection Signals (Chapter 12.3), the control interlock for blocking auto rod withdrawal less than 15% load (C-5), and the SG reference level for the SG level control system (Figure 8.0-1)

The purpose of the Rod Control System (Section 8.1) is to maintain a programmed average temperature in the reactor coolant system by regulating the reactivity in the core. An error between the programmed reference temperature (T_{ref}), based on turbine impulse pressure, and the highest average temperature (T_{avg}) of the reactor coolant, generates a signal to cause automatic rod movement. Rod speed is varied, depending on the magnitude of the error between T_{ref} and T_{avg}. Rod direction (either into or out of the core) is dependent on whether T_{avg} is higher or lower than T_{ref}.

The rods are separated into two functional categories, shutdown rods and control rods, with each category consisting of several individual banks. The shutdown banks provide a large negative reactivity insertion upon a reactor trip and insure that the reactor shuts down and remains subcritical. The shutdown banks are always fully withdrawn during normal operation and are placed in this position by manual rod control prior to criticality.

The control bank rods are used to start up the reactor. After criticality is achieved, these rods are used to regulate the reactivity in the core to maintain the programmed T_{avg}. In addition, these are the only rods that can be manipulated under automatic rod control.

Power to the rod drive mechanisms is supplied by two motor generator sets, which are powered from two separate 480-volt, three-phase buses. The AC power from the MG sets is distributed to the rod control power cabinets via two series connected reactor trip breakers. A reactor trip signal, opening either one or both trip breakers, removes power from the rod drive mechanisms. Once power is removed from the magnetic coils of the rod drive mechanisms, all rods (shutdown and control) fall into the core by gravity.

The locations of the rods within the core are displayed by both individual rod position indication and group position indication. The individual rod position indication may be either the analog type (Section 8.2) or the digital type (Section 8.3), depending on the age of the plant. Older plants normally have the analog type of position indication. The group rod position indication is a demanded position indication, and receives the same signal that induces rod motion.

There are operating and Technical Specification restrictions placed on rod position during power operations. One such restriction, called the rod insertion limits (Section 8.4), ensures that the reactor can be shut down from its present condition, assuming various design considerations.

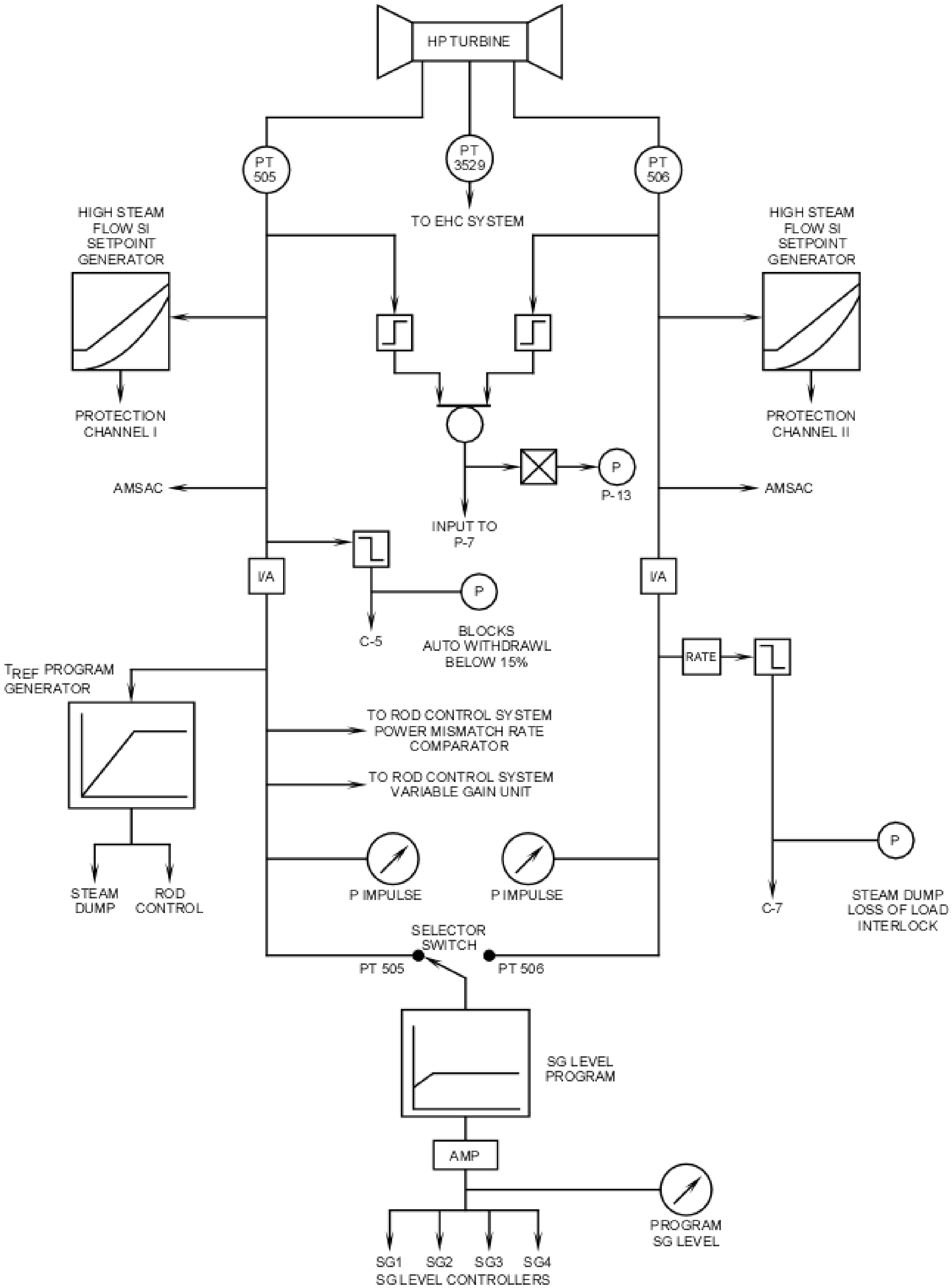

Figure 8.0-1 Turbine Impulse Pressure Functional Diagram

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Section 8.1

Rod Control System

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8.1 ROD CONTROL SYSTEM

Learning Objectives:

1. State the purposes of the rod control system.

2. List the inputs to the automatic rod control system and explain why each is used.

3. Explain why the rate of change of difference between the turbine and nuclear powers is used in the power mismatch circuit.

4. Deleted.

5. Given a list, arrange in proper order the stepping sequence of the Control Rod Drive Mechanism (CRDM).

6. List the rod withdrawal stops that occur in both automatic and manual rod control.

7. Describe the effects of an "urgent failure" in the logic cabinet and in a power cabinet.

8. Explain how individual rod motion is achieved.

9. Briefly describe the functions of the Bank Overlap Unit (BOU).

10. Briefly describe the rod speed program and explain the purposes of "deadband" and "lock-up."

8.1.1 Introduction

The purpose of the rod control system is to control the motion of the neutron absorbing full length rods (rods). This control system moves the rods, in response to demand signals from either the reactor operator (for start-up, shutdown, and power operations), or from the automatic rod control system (power operations) to maintain a programmed reactor coolant system average temperature (T_{avg}). It also releases the rods in response to manual or automatic reactor trip signals, allowing the rods to fall into the core, shutting down the reactor.

The rod control system is used to compensate for fast short-term reactivity changes, such as those resulting from power changes and xenon transients. Compensation for slower long term effects, such as fuel depletion, gradual xenon and samarium changes, is accomplished by adjusting the boron concentration in the reactor coolant. Refer to Section 4.1 (chemical and volume control system).

Between 15% and 100% power, the automatic rod control system maintains the average temperature of the primary coolant at a programmed value by adjusting the reactivity in the core. Automatic rod control below 15% turbine power is not provided.

By design, this system is capable of handling the following transients: a 10% step load increase or decrease, a 5% per minute ramp load increase or decrease, or a 50% step load decrease with the aid of the steam dump system (Section 11.2) and without actuating the pressurizer relief valves or generating a reactor trip.

The first two transients (a $\pm$10% step, or a $\pm$5% per minute ramp change in power), can occur during power operation and design transients. During these design transients, the rod control system provides adequate reactivity addition rates so that the average temperature of the reactor coolant remains within $\pm$5°F of the temperature program. As long as T_{avg} is within its program the steam dump system will not actuate. However, the rod control system reactivity addition rates are insufficient to reduce power quickly enough to prevent a significant temperature mismatch from developing during a 50% step loss of load. In this case, the steam dump system removes the excess heat generated by the reactor until the rod control system reduces the temperature of the reactor coolant to the new program value.

As previously stated, one of the purposes of the rod control system is to maintain a programmed average temperature in the reactor coolant system by regulating the reactivity in the core. Deviation of the average temperature from the program temperature by more than a preselected amount results in automatic rod movement to return T_{avg} to program. The rod speed varies with the size of the temperature deviation. The direction of rod movement is dependent upon whether the average temperature of the reactor coolant is higher or lower than the program temperature.

The rods are separated into two functional categories: shutdown rods and control rods. Each category consists of a number of individual rods which are arranged in banks. Each bank contains between four and nine rods which are moved together. The shutdown banks are always in the fully withdrawn position during power operations and are moved into this position at a fixed speed in manual bank control prior to criticality. The shutdown banks provide a large negative reactivity insertion upon a reactor trip to ensure the reactor achieves and maintains subcriticality.

The control banks are the only rods that can be manipulated under automatic rod control. The control banks are used: to change the reactivity in the core, to take the reactor critical, and during automatic control of this system, to maintain the average temperature of the reactor coolant at the programmed temperature. In addition, the control banks also fall into the core following a reactor trip signal, to aid the shutdown banks in placing the reactor in a subcritical condition.

8.1.2 System Description

In the automatic mode of control as shown in Figure 8.1-1, the rod control system uses three input signals to control the positioning of the control rods; auctioneered high T_{avg}, auctioneered high nuclear power, and turbine first stage pressure (P_{imp}). These three inputs are used in two comparison circuits to develop a total error signal which is processed by the reactor control unit.

The power mismatch circuit compares auctioneered high nuclear power with P_{imp}. If a rate of change of the difference between the two signals (P_{imp} and auctioneered high nuclear power) exists, the power mismatch circuit generates an error signal. As the rate of change of the difference increases, so does the magnitude of the error signal.

The summing unit compares T_{ref} (generated from P_{imp}) and auctioneered high T_{avg}. Any difference between these two signals (T_{ref} - T_{avg}) produces a temperature error signal. This error signal is algebraically summed with the error signal produced by the power mismatch circuit. The result is a total error signal which is sent to the reactor control unit.

The reactor control unit generates an analog signal. The polarity and magnitude of this signal determines the speed and the direction of rod motion. When the bank selector switch is placed in automatic, the output from the reactor control unit is sent to the logic cabinet.

Analog signals generated in the reactor control unit are converted into digital signals by the pulser located within the logic cabinet. After the signal is converted into a digital output, the digitized pulses are transmitted to the power cabinets. Within the logic cabinet, signals are developed that determine rod speed, rod direction, the control bank to be moved, and the group of rods within a control bank to be moved. The rod stop interlocks, also located within the logic cabinet, prevent outward rod motion during predefined conditions.

Each power cabinet receives electrical power from the rod drive motor-generator (MG) sets through two series reactor trip breakers and/or their associated bypass breakers. Each power cabinet distributes electrical power to the proper coils within the control rod drive mechanisms. Signals from the logic cabinet activate and deactivate components within the power cabinets that initiate the stepping sequence of rod drive mechanisms. Each power cabinet is capable of supplying up to three groups of rods.

Manual control of the rods is accomplished by placing the bank selector switch in the manual position. This action switches the logic cabinet input from the reactor control unit to the bank selector switch. Rod motion is achieved by using the IN-HOLD-OUT switch.

8.1.3 Control Rod Drive Mechanism (CRDM)

The control rod drive mechanism is used to withdraw or insert the full-length rods. The complete drive mechanism, shown in Figure 8.1-2, consists of the internal latching assemblies (grippers), the rod drive shaft assembly, the pressure housing, and the magnetic coil stack. Every single rod has its own drive mechanism. The control rod drive mechanism is an electromagnetic jack and is sometimes referred to as a magnetic jack assembly or a "mag jack."

The movable and stationary gripper latches engage the rod drive shaft when their respective coils are energized. The movable grippers are used to raise or lower the control rod drive shaft when the lift coil is energized or de-energized. The stationary grippers are used to hold the drive shaft in position whenever rod motion is not required. A reactor trip is achieved by simply removing the electrical power from the coils, which allows springs to disengage the grippers from the rod drive shaft, and the rod falls by gravity into the core.

Three magnetic coils induce a magnetic flux through the pressure housing to operate the internal latching mechanisms. Energizing and de-energizing the magnetic coils in a fixed sequence causes the internal mechanisms to either engage or disengage from the grooved drive shaft. This, in turn, moves the rod one step into or one step out of the core in discrete 5/8-in. steps.

During steady-state plant operation, the control rod drive mechanism's stationary grippers hold the control rod withdrawn from the core in a static position. When rod movement is required, a signal is sent from the rod control system to withdraw (section 8.1.3.1) or insert (section 8.1.3.2) the control rod in a prescribed sequence, which is described in the following sections.

8.1.3.1 Control Rod Withdrawal

1. Movable Gripper Coil - ON - The movable gripper armature raises and swings the movable gripper latches into one of the grooves on the rod drive shaft.
2. Stationary Gripper Coil - OFF - Gravity causes the stationary gripper latches and armature to move downward until the load of the drive shaft is transferred to the movable gripper latches. Simultaneously, the stationary gripper latches swing out of the drive shaft groove.
3. Lift Coil - ON - Once energized, the magnetic force from this coil pulls up the movable gripper latch assembly. Since the movable grippers are coupled to the rod drive shaft, the rod is raised 5/8 in.
4. Stationary Gripper Coil - ON - The stationary gripper armature raises, swinging the stationary gripper latches into a drive shaft groove. The latches contact the shaft and lift it 1/16 in. The load is transferred from the movable to the stationary gripper latches.
5. Movable Gripper Coil - OFF - The movable gripper armature separates from the lift armature under the force of the spring and gravity. Three links, pinned to the movable gripper armature, swing the three movable gripper latches out of the drive shaft groove.
6. Lift Coil - OFF - The lift armature and the movable gripper latches drop 5/8 in. to a position adjacent to the next groove.

8.1.3.2 Control Rod Insertion

1. Lift Coil - ON - The movable gripper latches are raised 5/8 in. to a position adjacent to a shaft groove.
2. Movable Gripper Coil - ON -The movable gripper armature raises and swings the movable gripper latches into a groove.
3. Stationary Gripper Coil - OFF - The stationary gripper armature moves downward and swings the stationary gripper latches out of the groove.
4. Lift Coil - OFF - Gravity and spring force separates the lift armature from the lift magnet poles, and the control rod drops down 5/8 in.
5. Stationary Gripper Coil - ON - The stationary gripper armature raises, swinging the stationary gripper latches into a drive shaft groove. The latches contact the

shaft and lift it 1/16 in. The load is transferred from the movable to the stationary gripper latches.

6. Movable Gripper Coil - OFF - The movable gripper armature separates from the lift armature under the force of the spring and gravity. Three links, pinned to the movable gripper armature, swing the three movable gripper latches out of the drive shaft groove.

Each sequence (withdrawal or insertion) is called a step or a cycle, and the result is that the rod moves 5/8 in. for each demanded step. This sequence can be repeated at a rate of up to 72 times per minute. The control rods can, therefore, be withdrawn or inserted at a rate up to 45 in./min.

8.1.4 Rod Control System Signal Processing

The mode of operation of the rod control system is selected by the reactor operator via the bank selector switch located on the main control board. This switch allows for either manual, automatic, or individual bank select operation. All positions of this switch are explained in section 8.1.4.1.

8.1.4.1 Bank Selector Switch

The bank selector switch is a ten (eleven in some plants) position switch that permits selection of individual banks, manual control, or automatic control. A description of each position is given below.

MANUAL

In this position, the control rods are withdrawn or inserted by the use of the IN-HOLD-OUT switch. The bank sequence and overlap program (section 8.1.5) is maintained with the rods in manual rod control. The rod speed is adjustable between 8 and 72 steps/min. with a potentiometer located within the rod control cabinet. The speed normally selected for manual operation is 48 steps/min.

AUTOMATIC

Placing the bank selector switch in automatic electrically disconnects the IN-HOLD-OUT switch. Rod motion (direction and speed) is determined by the reactor control unit (section 8.1.4.5). The control bank sequence and the overlap program is maintained by the bank overlap unit located inside the logic cabinet. Inputs for the reactor control unit come from the power mismatch and the temperature mismatch circuits. These circuits are explained in sections 8.1.4.2 and 8.1.4.3, respectively.

CONTROL BANK A

Control bank A rods can be moved manually using the IN-HOLD-OUT switch. The rod sequence and overlap is not maintained; that is, the bank overlap unit (section 8.1.5.4) program is overridden. The rod speed signal in this position is the same as that for manual operation (48 steps/min).

CONTROL BANK B, C, D

Same as Control Bank A.

SHUTDOWN BANK A

In this position, shutdown bank A rods are moved using the IN-HOLD-OUT switch. Rod speed is preset by an adjustable stepping rate potentiometer located in the rod control cabinet. The normal preselected speed is 64 steps/min.

SHUTDOWN BANKS B, C, D

Same as shutdown bank A.

8.1.4.2 Power Mismatch Circuit

The power mismatch circuit provides a fast, stable response to a change in load. Its purpose is to anticipate a change in the average temperature of the reactor coolant due to turbine load changes. If nuclear and turbine power are changing at different rates, the resulting power mismatch will change T_{avg}. This circuit provides an error signal to the summing unit which increases rod speed at the beginning of a transient. Moving the rods faster, earlier in a transient, helps reduce the magnitude of error between T_{avg} and T_{ref}.

The inputs into this circuit (Figure 8.1-3) are nuclear (primary) power and turbine (secondary) power. The nuclear power input signal for automatic rod control is obtained from the highest of the four power range excore nuclear instruments. All four power range signals are sent to an auctioneering unit which allows the highest signal to pass through, and is referred to as auctioneered high nuclear power. The turbine power signal is generated from the first stage impulse chamber pressure of the high pressure turbine. This signal is referred to as $P_{impulse}$ or P_{imp}.

The rate comparator of the power mismatch circuit monitors the two power inputs and provides an output if, and only if, there is a rate of change of the difference between the inputs. This rate comparator prevents the power mismatch circuit from responding to steady state calibration differences between nuclear and turbine power. The larger the rate of change of power mismatch, the larger the output from the rate comparator.

A nonlinear gain unit is placed at the output of the rate comparator. Its function is to convert the power mismatch signal to an equivalent temperature signal. In addition, this signal is amplified as a function of the magnitude of the input. That is, for power mismatches of less than 1% the unit operates on low gain (0.3°F signal per percent power deviation). For larger mismatches (> 1%), the unit operates on high gain (1.5°F signal per percent power deviation).

A variable gain unit is located directly after the nonlinear gain unit. This component provides a higher gain to the power mismatch error signal at low power levels and a lower gain at high power levels. The lower gain at higher power levels limits the likelihood that rapid rod motion (and the associated rate of reactivity change) could cause a significant overshoot during a power change. Moreover, minimizing rapid overshoots with reactor power near 100% helps to avoid violating the plant’s licensed power limit. The variable gain unit ensures that the power mismatch circuit provides adequate control at low power levels and stable operation at higher power levels. Since the output from this unit is inversely proportional to turbine load, a P_{imp} signal is provided for the reference power input. Between 0% and 50% power this unit provides a gain of two. Between 50% and 100% turbine load, it provides a gain inversely proportional to turbine power, i.e., 1/(% power). At turbine loads equal to or greater than 100% this unit provides a gain of one.

The output from the power mismatch circuit is combined at the summer with the temperature mismatch error as described below.

8.1.4.3 Temperature Mismatch Circuit

This circuit provides fine control during steady-state operation and returns T_{avg} to T_{ref} after a transient. The inputs into this circuit (Figure 8.1-3) are auctioneered high T_{avg} and reference temperature (T_{ref}). The T_{avg} input is obtained from an auctioneering unit which monitors the four T_{avg} channels and allows the highest T_{avg} to pass through to the input of the temperature mismatch circuit. The reference temperature (the desired or programmed temperature) is generated from P_{imp} (turbine power). The temperature mismatch circuit compares T_{avg} (the actual temperature) to T_{ref} (the desired temperature) and generates an error signal if there is a mismatch between these two inputs. Any resultant error signal is sent to the summing unit.

8.1.4.4 Summing Unit

The summing unit algebraically sums the signals from the power mismatch circuit and the temperature mismatch circuit. Its output represents a total temperature error, and this signal is sent to the reactor control unit.

8.1.4.5 Reactor Control Unit (RCU)

The reactor control unit generates the rod speed program as shown in Figure 8.1-4. The reactor control unit receives an input from the summing unit and converts this signal into a rod speed and direction signal. The speed and direction signal is sent to the pulser (section 8.1.5.1) located within the logic cabinet.

A deadband of ±1.5°F, which includes a 0.5°F lock-up, is employed to eliminate continuous rod stepping and bistable chattering. The lock-up can be explained by referring to Figure 8.1-4 and examining a signal for rod withdrawal. When the total error signal reaches +1.5°F, the output from the reactor control unit demands the minimum rod speed to return T_{avg} to program. As the rods step out, T_{avg} increases, reducing the total error signal. When the total error signal reaches +1°F, the unit turns off, stopping rod motion. This 0.5°F difference between starting and stopping rod motion prevents the bistable from chattering (turning on and off continuously).

Rod speed is determined by the total error signal. For small error signals, ±1.5°F to ±3°F, the reactor control unit produces an output demanding a minimum speed of eight steps per minute. This minimum rod speed is based upon a minimum response of the rod control system for small errors generated by this system. A slow speed prevents excessive movement of the rods which could cause a temperature overshoot. Temperature overshoots could cause hunting by the rods, i.e., excessive rod movement. As the temperature error signal increases from ±3°F to ±5°F, the rod speed program enters a proportional speed region. This region calls for 32 steps/min/°F. This gain is selected to be consistent with the need for increased rod motion to limit transient temperature overshoot while, at the same time, preventing overcompensation and temperature oscillations. With an error of 5°F or greater, the rod speed programmer of the reactor control unit generates a maximum rod speed of 72 steps/min. The maximum rod speed is based upon a maximum response to a large error signal and upon the physical limitations of the rod drive mechanism, with the latter being the limiting factor.

8.1.5 Logic Cabinet

The logic cabinet contains the following components: the pulser, the master cycler, the bank overlap unit, and the slave cyclers. The function of the logic cabinet is to generate the necessary signals to step the rods into or out of the core. The logic cabinet receives command signals from either the IN-HOLD-OUT switch (when in manual), or from the reactor control unit (when in automatic). In response to these signals, the logic cabinet selects the appropriate bank of rods to maintain the proper sequence and overlap. It then supplies the proper stepping sequence to the power cabinets (section 8.1.6) to move the selected bank(s) of rods.

The withdrawal sequence for the control banks is A, B, C, D. The overlap between banks (the time when two separate banks move together) is such that as control bank A passes the center of the core, control bank B begins moving. This sequencing and overlap is chosen to produce relatively even reactivity additions per step of rod movement and to minimize the effect of rod motion on core peaking factors.

The rods in the four control banks (and the rods in shutdown banks A and B) are subdivided into groups of rods. Shutdown banks C, and D, (which contain only four rods each) are not divided into groups.

Upon receipt of a command signal for "IN" or "OUT" rod motion, the rods move at a predetermined speed with staggered stepping of groups within the banks. Upon removal of the command signal, all rod motion stops. However, a group of rods still in sequential motion completes its entire step before halting. Reversal of direction is programmed so that the last group that ceased motion is the first group to move in the new direction. Staggered stepping of the groups within banks is controlled by the master cycler (section 8.1.5.2).

Proper rod sequencing and overlap are controlled by the bank overlap unit (section 8.1.5.4). A summary of the bank overlap and sequencing is given below.

1. Two groups within the same bank are stepped so that the relative position of each group within a bank will not differ by more than one step.
2. Control bank withdrawals are programmed; so that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank. When the first bank reaches the top of the core, it stops, while the second bank continues to move toward its fully withdrawn position. When the second

bank reaches a preset position, the third bank begins to move out, and so on. The control bank insertion sequence is the opposite of the withdrawal sequence (i.e., the last bank withdrawn is the first bank to be inserted).

3. The overlap between successive control banks is adjustable with an accuracy of ±1 step. Normally the overlap is set at 100 steps. As an example, once control bank A has reached 131 steps, control bank B starts to withdraw. Control bank B steps out simultaneously with control bank A during control bank A's last 100 steps, hence the 100-step overlap.

A programmed signal is also sent to the slave cyclers (section 8.1.5.3). The slave cyclers cause the rods to sequence through one step by signaling the power cabinets to operate the coils of the magnetic jack as described in section 8.1.4.

8.1.5.1 Pulser

The function of the pulser is to convert the analog output from the reactor control unit into a digital signal. The pulser generates pulses at a rate proportional to the speed signal, which corresponds to a control rod bank stepping rate of 8 to 72 steps/min. The pulser multiplies the speed signal by a factor of six and, therefore, pulses at 48 to 432 pulses/min. When the reactor control unit output exceeds 1.5°F the pulser begins to pulse at 48 pulses/min. Each pulse advances or reverses the master cycler by one step.

8.1.5.2 Master Cycler

The master cycler receives rod speed and direction signals from the pulser and converts these signals into "Go" pulses. This device also directs these Go pulses to the proper slave cyclers (section 8.1.5.3). The master cycler accomplishes this function by using a reversible clock/counter which operates over a range of zero to five counts. It counts once for each pulse from the pulser circuit and, therefore, goes through one complete cycle after receiving six pulses.

An out-motion pulse signal increases the master cycler's count, while an inward-motion pulse decreases the count. The master cycler sends an output to the slave cyclers, in the form of GO pulses, every time it passes the zero or the three on the clock. At count zero, a GO pulse is sent to the slave cyclers controlling group one rods (1AC and 1BD), and at count three a GO pulse is sent to the slave cyclers controlling group two rods (2AC and 2BD). The master cycler divides the pulser's pulse rate by six and produces two evenly spaced pulses for the slave cyclers.

The bank overlap unit determines whether the group one or the group two slave cyclers actually receive a pulse. Since the pulser multiplies by six and the master cycler divides by six, the rod speed is processed correctly. The multiplication by six is designed to allow the flexibility of having two groups of rods per bank. This arrangement allows sequencing of groups within banks. A bank has taken a complete step when both groups within that bank have taken a step in the same direction. Because of the reversible feature of the counter, the last rod group that moved is the first group to move if a different direction is called for. For example, if the last demanded rod motion was outward and the master cycler happened to stop at count four, group two would have been the last to step (passing through three increasing: 0,1,2,3,4). If the next demand signal is for inward motion, the master cycler would count back toward zero and move group two into the core first (i.e., counting from 4,3,2,1, etc.). The clock reversal feature insures the proper sequencing of the groups. The bank overlap unit is notified each time the master cycler counts a zero or a three, so that the BOU can track the total number of steps.

Before the master cycler can properly distribute the GO pulses, it must know which bank to move and in what direction to move the rods. This is accomplished by information received from either the bank selector switch (section 8.1.4.1) or the bank selector switch through the bank overlap unit (section 8.1.5.4).

8.1.5.3 Slave Cycler

The function of the slave cycler is to generate current orders to its associated power cabinet. These orders move the rod drive mechanisms through one cycle of insertion or withdrawal. Each slave cycler provides signals to only one power cabinet.

A "GO" pulse from the master cycler starts the operation of the slave cycler (Figure 8.1-5). The slave cycler is a seven-bit binary counter that counts from 0 to 127, and performs this operation in 780 milliseconds. Once the counter reaches 127, it resets to zero and awaits another GO pulse from the master cycler.

The stationary gripper, movable gripper, and lift coils of the control rod drive mechanism receive current orders from different count points generated by the slave cycler. These orders correspond to:

- Magnitude - the amount of current (full, reduced, or zero) that is applied to a coil,
- Duration - the length of time the signal is supplied to a coil, and
- Time - when the current is applied to or removed from a particular coil.

The rod group has taken one step into or out of the core after the counting sequence is complete.

Since the rod drive mechanism coils require different actuation sequences for either an IN cycle or an OUT cycle (section 8.1.4), the slave cycler must know which sequence to use. The sequence is determined by the master cycler.

8.1.5.4 Bank Overlap Unit

The bank overlap unit (BOU) determines the sequence and overlap of the control banks. It also provides multiplexing signals (section 8.1.6.3) to the power cabinets.

The bank overlap unit receives counts from the master cycler and records one IN or one OUT count for the insertion or withdrawal of the two groups of rods within a bank of rods. The BOU provides an input into the master cycler for each count it registers. This feedback directs the "GO" pulses from the master cycler to the proper slave cyclers.

The BOU maintains the control rod sequence and overlap by counting all steps taken by the control rods. It records these steps as counts on a reversible counter that counts from 0 to 999. Thumbwheel switches located on the bank overlap unit preset the range of the overlap. During withdrawal of the control banks, control bank A withdraws first until it reaches a preselected setpoint, for example 131 steps on the control bank A step counters or 131 counts on the BOU. When control bank A takes its 132nd step, control bank B takes its first step. Control banks A and B move in unison until control bank A reaches the top of the core (231 steps on control bank A or 231 counts on the BOU), and control bank A then stops moving. Control bank B continues to withdraw, until it reaches the next preselected overlap point (131 steps on bank B or 262 counts on the BOU). As control bank B takes its 132nd step, control bank C takes its first step. This sequence and overlap continues until all control banks are withdrawn from the core.

When two banks are in an overlap region, groups are withdrawn simultaneously. For instance, if control bank A and B are moving in the overlap region, group 1 of both banks move simultaneously. Similarly, the group 2 rods of the overlapped banks move simultaneously.

8.1.6 Power Cabinet

The circuitry layout for a typical power cabinet is shown on Figure 8.1-6. The function of this cabinet is to convert a three-phase ac power input into an amplitude-controlled dc voltage. It then directs this dc voltage to the rod drive mechanism coils.

Each power cabinet is designed to accommodate three groups of drive mechanisms, and each group contains four individual drive mechanisms. A fifth mechanism may be connected to one of the three groups as required by the rod grouping on some four-loop plants. The design of the power cabinets allows the motion of only one group of rods, with the remaining two groups of rods held in a stationary position. The method used to operate one group of rods and hold the other rod groups stationary is explained in sections 8.1.6.1 - 8.1.6.4.

Electrical power to the power cabinets is supplied via two parallel motor-generator sets operating from two separate, nonvital, 480-Vac, three-phase buses. Each generator is driven by a 150-hp induction motor and supplies 260 volts line to line through two, redundant, series-connected reactor trip breakers. Removing electrical power to the power cabinets (opening either of the reactor trip breakers), de-energizes all mechanism coils, and the rods drop into the core. Reactor trip bypass breakers can be connected in parallel with the reactor trip breakers to facilitate on-line testing of the reactor protection system (Chapter 12). The use of these bypass breakers is under administrative control.

8.1.6.1 Thyristors

A thyristor is a generic title referring to a class of electronic devices, one of which is the silicon-controlled rectifier (SCR). This device functions as a current controlled switch. The outstanding features of the SCR are the speed of switching (turning on and off) and the ability to control high currents. Load currents of tens to hundreds of amperes may be turned on in as little as three microseconds and turned off in about 30 microseconds. The thyristor is an essential part of the power cabinet, which supplies high, reduced, or zero current to the stationary, movable, and lift coils. These devices are show on Figure 8.1-6.

8.1.6.2 Half-Wave Bridge

If rectifiers, instead of thyristors, were installed in the power cabinet in each phase of the ac power supply, a fixed dc current would flow to the various coils. The purposes of the power cabinet, however, are: to supply three accurate current levels (full, reduced, or zero), to provide these currents for a fixed period of time, and to arrive at these fixed points in the fastest possible time. This is accomplished by gating (turning on) the half-wave bridge network at different phase angles (time intervals). This converts the ac supply to a variable dc supply. The variable dc output from this network allows the profiling (changing) of the current as needed for the stepping sequence.

8.1.6.3 Multiplexing Circuit

Figure 8.1-6 is an illustration of power cabinet 1BD. This cabinet contains the electronics for moving the group one rods of control bank B, control bank D, and shutdown bank B. The circuitry is arranged, through multiplexing, to allow rod motion of only one of the three groups at any time. For example, assume that the mechanisms for group one, control bank B have been selected for movement. The movable grippers multiplexing thyristor for control bank B is turned on, and the movable grippers' thyristors for control bank D and shutdown bank B are turned off.

In the lift coil circuit, the four multiplexing thyristors for control bank B are turned on, and the multiplexing thyristors (four each) for control bank D and shutdown bank B are turned off. The stationary gripper circuit for control bank D and shutdown bank B receive a constant hold current signal, which is explained in section 8.1.6.4. The power cabinet is aligned to move group 1, control bank B mechanisms. The multiplexing signals come from the bank overlap unit.

8.1.6.4 Firing Circuit

The firing circuits located within the power cabinet receive signals sent from a slave cycler. Their purpose is to gate the bridge thyristors to the proper current commands as dictated by the slave cycler. The power cabinet contains a total of five firing circuits. Each firing circuit supplies signals to its associated bridge thyristor. The arrangement of these circuits is as follows: the stationary gripper circuits (three firing circuits), movable gripper circuit (one firing circuit), and lift coil circuit (one firing circuit).

A simplified block diagram of the firing circuit (representative of any of the five provided) is shown in Figure 8.1-6. When a firing circuit receives an input from the slave cycler, it gates (turns on) its associated bridge thyristor. The thyristors adjust the current signal (either full, reduced, or zero) to the magnetic coils. The current, from the coils, is sampled to provide a feedback signal into the firing circuit. If the current being sampled is not the same as demanded by the slave cycler, the firing angle of the bridge thyristor is varied to obtain the exact current demanded by the slave cycler.

As explained in the multiplexing section (section 8.1.6.3), the stationary gripper circuits for the banks that are not to be moved receive a hold current signal. This is accomplished by an inhibit signal input into the firing circuits. The inhibit signal is generated by the bank overlap unit and overrides any signals entering the firing circuit from the slave cycler.

When an inhibit signal is present, the firing circuit gates the bridge thyristor for the non-moving rods at a reduced current. This signal remains in the circuit until the moving rods have sequenced through one step. The slave cycler inhibit signal is only supplied to the three firing circuits associated with the stationary gripper circuits. This circuit is provided to keep the gripper coils energized for the banks not being stepped, thereby holding these rods in a static position.

8.1.6.5 DC Hold Cabinet

A failure within a power cabinet may require the replacement of a printed circuit card, a fuse, or another electronic component. To prevent dropping rods during maintenance, and to avoid the need for a separate external power source, each power cabinet contains three switches, which may be used to energize any one of the three groups of stationary gripper coils. The maintenance power source (125 Vdc for latching and 70 Vdc for holding) is taken from the load side of the reactor trip breakers and is distributed to the power cabinets via the dc hold cabinet. Therefore, if a group of rods were on the hold cabinet and a reactor trip signal opened the reactor trip breakers, these rods would de-energize and trip into the core along with all the other rods.

This power supply is designed so that it can latch or hold a maximum of six mechanisms. Therefore, placing more than one group of rods on the hold cabinet could result in overloading the power supply. To apply hold voltage, the switch is rotated from the OFF position to the LATCH position and held in that position for at least one second. It is then rotated to the HOLD position. The 125 Vdc supply is used to assure latching of the stationary grippers, while the 70 Vdc supply is used to hold the grippers without overheating the coils.

8.1.6.6 Lift Coil Disconnect Switches

A lift coil disconnect switch is furnished for each rod drive mechanism. These switches are located in the rod disconnect switch panel located in the control room or the auxiliary building in close proximity to the control room. These switches are used to move an individual rod (e.g., to retrieve a dropped rod). By disconnecting the lift coils of all the rods in the bank containing the dropped rod, except the lift coil of the dropped rod, the dropped rod may be returned to its original position.

8.1.7 System Interrelations

8.1.7.1 Control and Indications

All controls used for normal system operation are located on the main control board. The major components are:

- Bank selector switch (section 8.1.4.1),
- IN-HOLD-OUT switch,
- Rod speed indication and the IN-OUT lights (section 8.1.7.2),
- Group and bank position indication (Section 8.2), and
- Individual rod position indication (Section 8.2).

In addition to these controls and indications, there are various annunciators and rod stop interlocks, which are explained in this section.

8.1.7.2 In-Out Lights

In-and-out lamps on the control board indicate that rod motion has been requested by either the IN-HOLD-OUT switch or the reactor control unit.

8.1.7.3 Interlocks and Rod Stops

Commands for manual and automatic rod motion must pass through various permissive circuits in the rod control system prior to generating the actual call for rod motion. The following interlocks are provided by the full-length rod control system:

Manual Rod Withdrawal Stops

1. Power range high flux rod stop, 1/4, power range power > 103%,
2. Intermediate range high flux rod stop, 1/2, intermediate range power > 20%,
3. Overtemperature ΔT (OTΔT) rod stop and runback, 2/4, loop ΔT > (OTΔT reactor trip setpoint - 3%), and
4. Overpower ΔT (OPΔT) rod stop and runback, 2/4, loop ΔT > (OPΔT reactor trip setpoint - 3%).

Automatic Rod Withdrawal Stops

1. Power range high flux rod stop, 1/4, power range power > 103%,
2. Intermediate range high flux rod stop, 1/2, intermediate range power > 20%,
3. Overtemperature ΔT (OTΔT) rod stop and runback, 2/4, loop ΔT > (OTΔT reactor trip setpoint - 3%),
4. Overpower ΔT (OPΔT) rod stop and runback, 2/4, loop ΔT > (OPΔT reactor trip setpoint - 3%),
5. Low power interlock, 1/1, turbine power (impulse pressure) < 15%, and
6. Control bank D withdrawal interlock, demanded bank D position > 223 steps.

These interlocks or rod stops only prevent outward rod motion. The rods can always be inserted into the core using either manual or automatic rod control.

8.1.7.4 Non-Urgent Failure Alarms

The rod control system has two non-urgent failure alarms, one for the logic cabinet and one for the power cabinets. In either case, the probability of dropping a rod is very remote since this alarm is generated by a loss of one of the redundant power supplies. Actuation of this alarm does not affect the ability to move rods.

One annunciator window (ROD CONTROL NON-URGENT FAILURE) is used for an alarm in either a logic cabinet or a power cabinet. The annunciator is actuated whenever any one of the three redundant power supplies is lost inside the logic cabinet, or if a power cabinet loses one of its two power supplies.

8.1.7.5 Urgent Failure Alarms

An urgent failure is a failure which could affect rod motion and includes the possibility of dropping a rod. The urgent failure alarm can be generated from either the logic or power cabinets. Depending upon the source of the urgent failure, rod motion is inhibited as described below.

The ROD CONTROL URGENT FAILURE annunciator is actuated when any one of the following conditions occurs inside the **Logic Cabinet**:

- *Slave Cycler Failure*- Slave cycler failure occurs when a slave cycler receives a GO pulse before completing the previous step, a slave cycler cycles without a GO pulse, or a slave cycler receives a GO pulse but does not cycle
- *Oscillator Failure*- occurs when the oscillator stops running
- *Card Interlock Circuit*- continuity link is open

If any of these conditions exist, the rod control system inhibits all automatic and manual rod motion. Rods may be moved only by selecting an individual bank on the bank selector switch. Rods affected by a slave cycler failure will not move even if the individual bank is selected.

The ROD CONTROL URGENT FAILURE annunciator is also actuated when any one of the following conditions occurs inside a P**ower Cabinet**:

- *Regulation Failure*- coil current does not match the current order or full current is on for too long
- *Phase Failure*- voltage to the coils has excessive ripple
- *Logic Error*- simultaneous zero current order to the stationary and the movable grippers
- *Multiplex Error*- when any rod, or group of rods, not selected by the multiplex function is getting current in the movable or lift coils
- *Card Interlock Circuit*- any power cabinet printed circuit card loose or missing

If any of these conditions exist, the rod control system inhibits all automatic and manual rod motion. In addition to stopping all rod motion, the following occurs inside the affected power cabinet:

a. All power is removed from the lift coils, and
b. Low current is applied to engage both the stationary and the movable gripper coils.

This action is initiated to prevent dropping a rod. During an urgent failure in a power cabinet, rods can only be moved in individual bank select with the exception of those rods in the affected cabinet.

After an urgent failure, rods cannot be moved in manual or automatic until the problem is corrected. In addition, the alarm must be reset at both the affected power cabinet and the main control board before rod motion can be restored.

8.1.8 Shutdown Bank C & D Control

Shutdown banks C and D are selected individually by the bank selector switch and are manually controlled by the IN-HOLD-OUT switch. Since there are no control banks in this power cabinet, the control circuit consists of only a pulser and slave cycler. The pulser and slave cycler units are identical to the units previously described. Multiplexing for this cabinet comes from the bank selector switch. A potentiometer is located in the pulser unit and is used to adjust the rod speed (normally set at 72 steps per minute), for these groups of rods.

8.1.9 Summary

The rod control system provides reactivity control to compensate for rapid short term variations in the reactivity of the core. The rods are divided into two functional categories; shutdown rods and control rods. The shutdown rods are fully withdrawn prior to criticality and serve only to provide a large amount of negative reactivity upon a reactor trip. The control rods provide not only shutdown reactivity upon a trip, but also provide the reactivity control needed for startup and power operation.

Overlapping the control rods helps maintain a relatively constant reactivity addition rate to the core. The overlap occurs near the middle of the core. After the first control bank reaches the mid-plane of the core the second control banks begins to withdraw. During the overlap period, two separate control banks step together. The rods are also moved in a preselected sequence; i.e., control bank A is the first bank of control rods to be moved, followed by control bank B, etc. The bank overlap unit determines this sequence and overlap. This sequence and overlap is maintained as long as the bank selector switch is selected to manual or automatic.

System operation is determined by the bank selector switch. It may be positioned to select an individual shutdown bank or an individual control bank or positioned to operate in either manual or automatic. In the manual mode, the reactor operator controls the reactivity addition to the core by manually adjusting the height of the control banks. The bank selector switch is placed in manual when conducting a reactor start-up. After the secondary load exceeds 15% power the bank selector switch is usually placed into the automatic position. Based on signals supplied to the reactor control unit, rod speed and direction are determined. Due to the output of the reactor control unit the control rods step at a programmed speed and in the proper direction to return T_{avg} to the desired temperature.

The control inputs for this system (in automatic) are provided by two deviation or mismatch signals as described below:

1. The temperature mismatch circuit, which compares T_{avg} (actual temperature) to T_{ref} (desired temperature), and
2. The power mismatch circuit, which compares auctioneered high nuclear power to P_{imp} (turbine power).

The temperature mismatch circuit provides fine control which maintains T_{avg} within 1.5°F of T_{ref}, while the power mismatch circuit starts or stops rod motion in an anticipation of a change in T_{avg}. These circuits acting together provide good system response and control stability.

The power cabinets receive input signals from the logic cabinet. In response to these signals the drive mechanisms sequence the rods into or out of the core. Two motor-generator sets provide power to the rod drive mechanisms via two series reactor trip breakers. Opening either of the two reactor trip breakers de-energizes the rod drive mechanisms, allowing the rods to fall, by gravity, into the core.

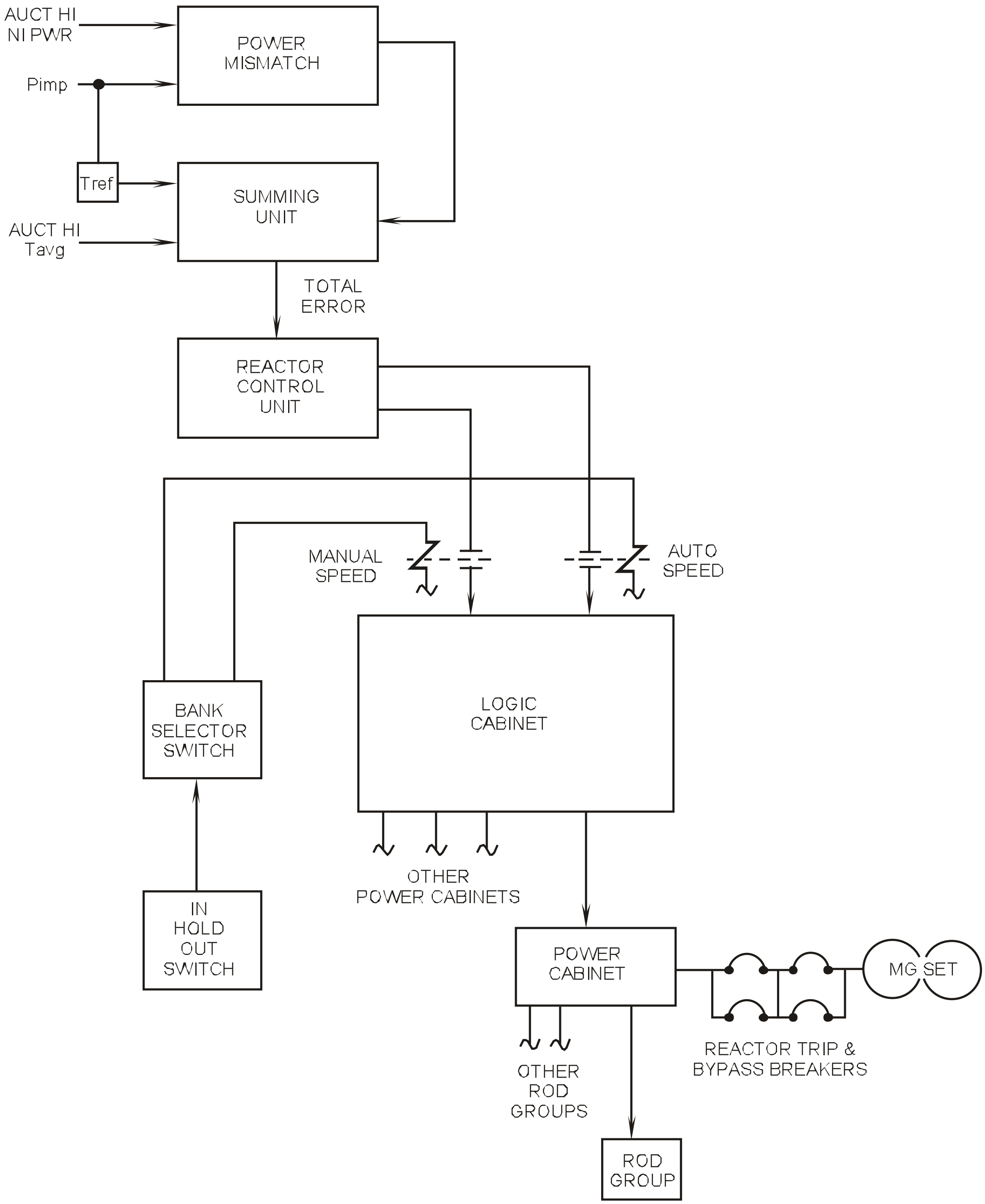


Figure 8.1-1 Rod Control System Block Diagram

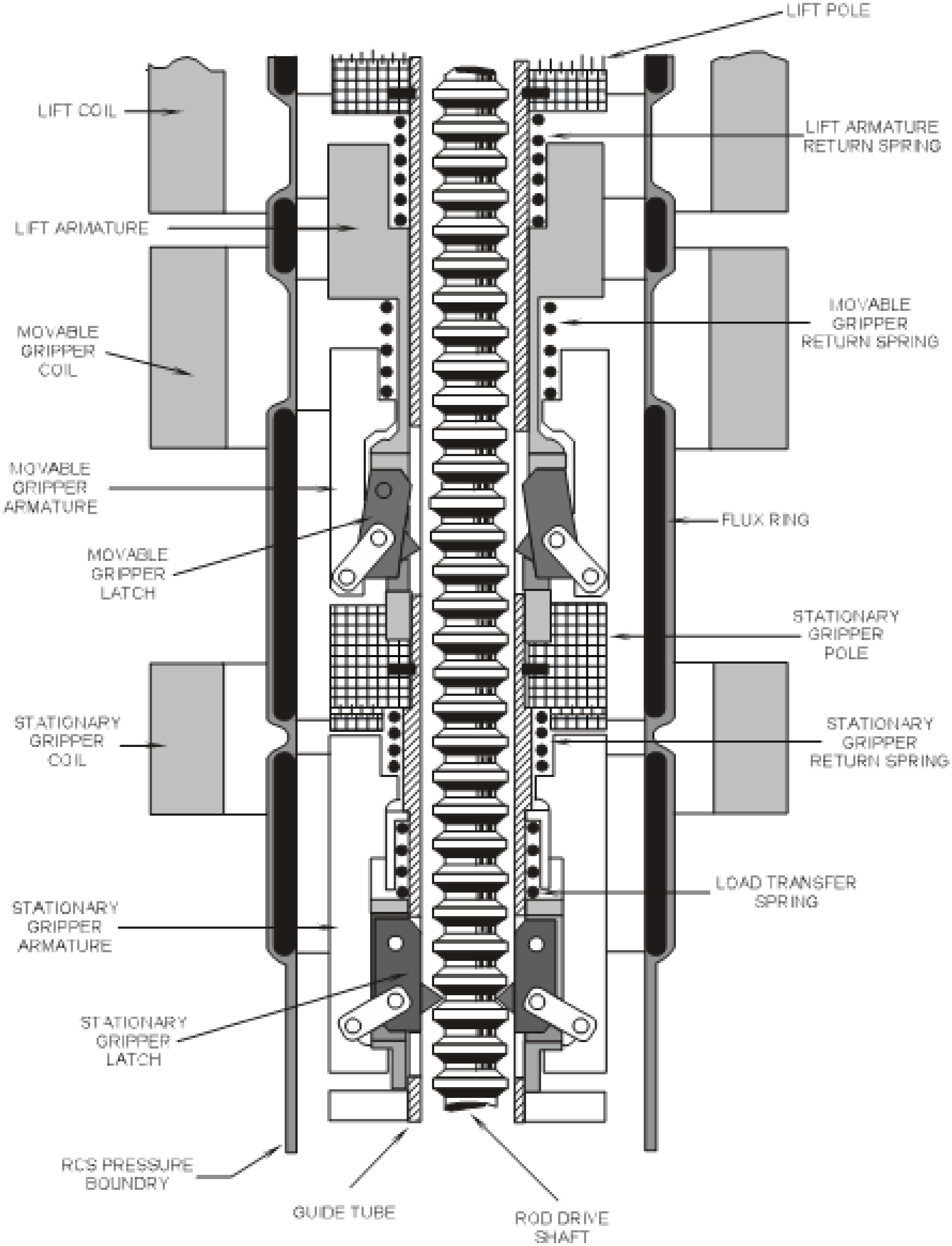


Figure 8.1-2 Magnetic Jack Assembly

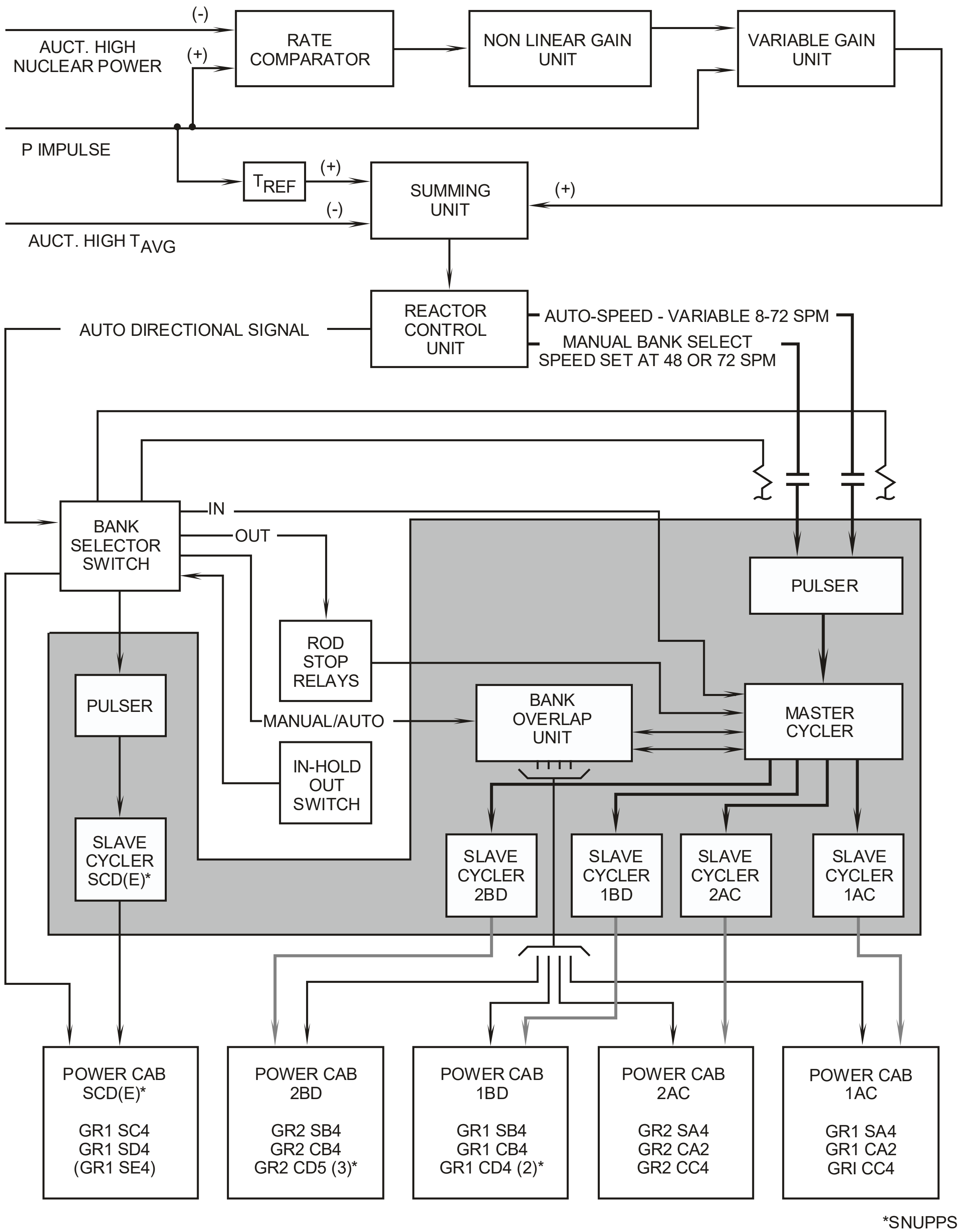


Figure 8.1-3 Full Length Rod Control

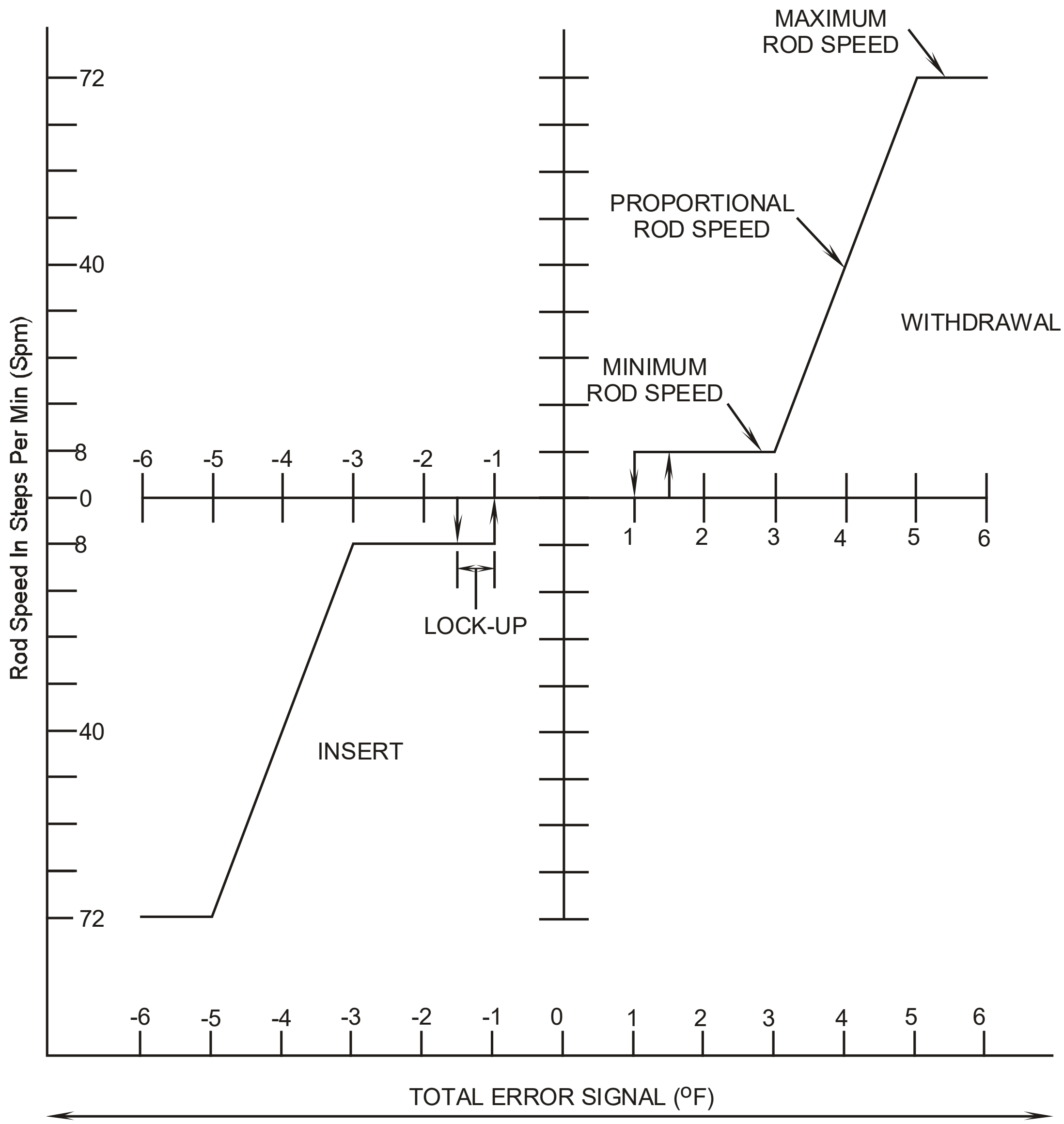
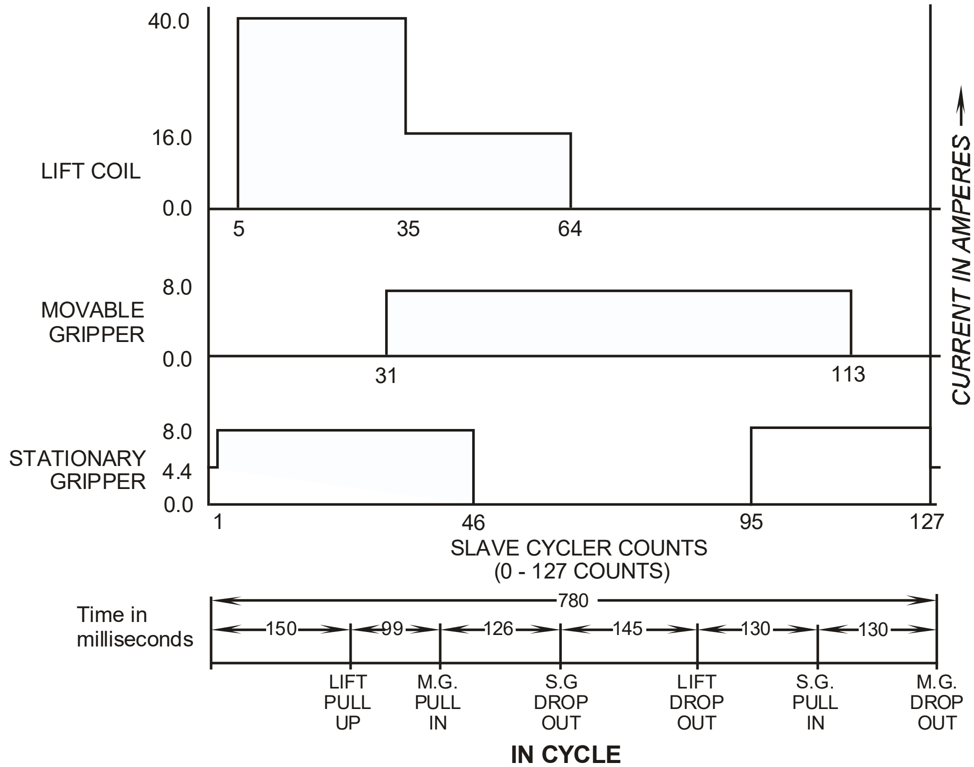


Figure 8.1-4 Rod Speed Program



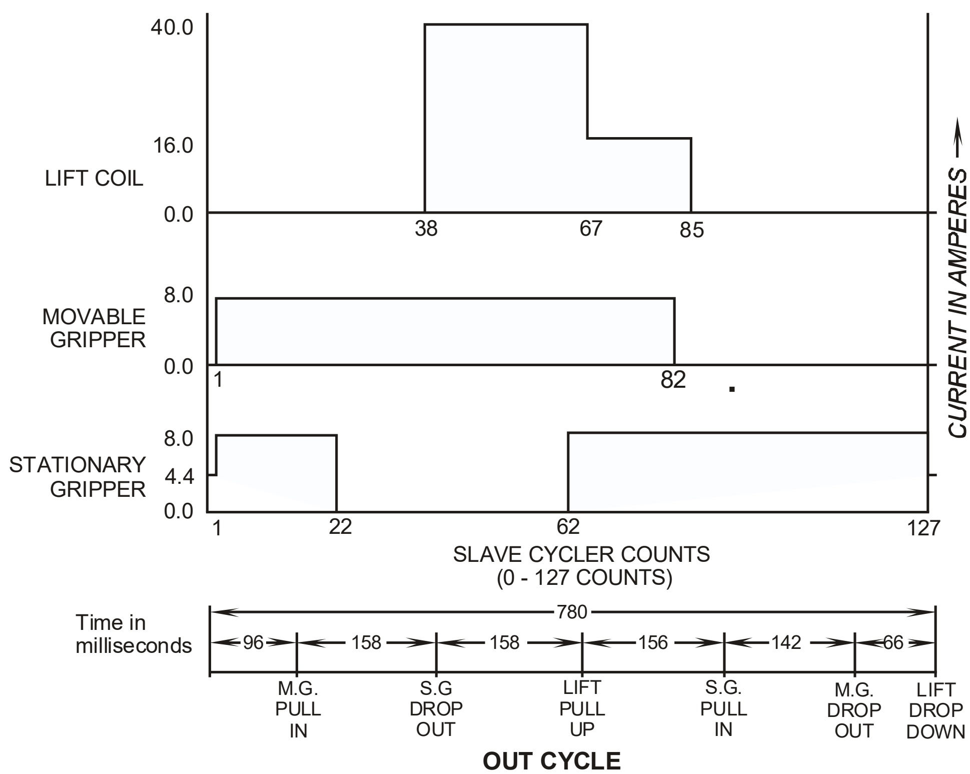


Figure 8.1-5 Slave Cycler Timing Program

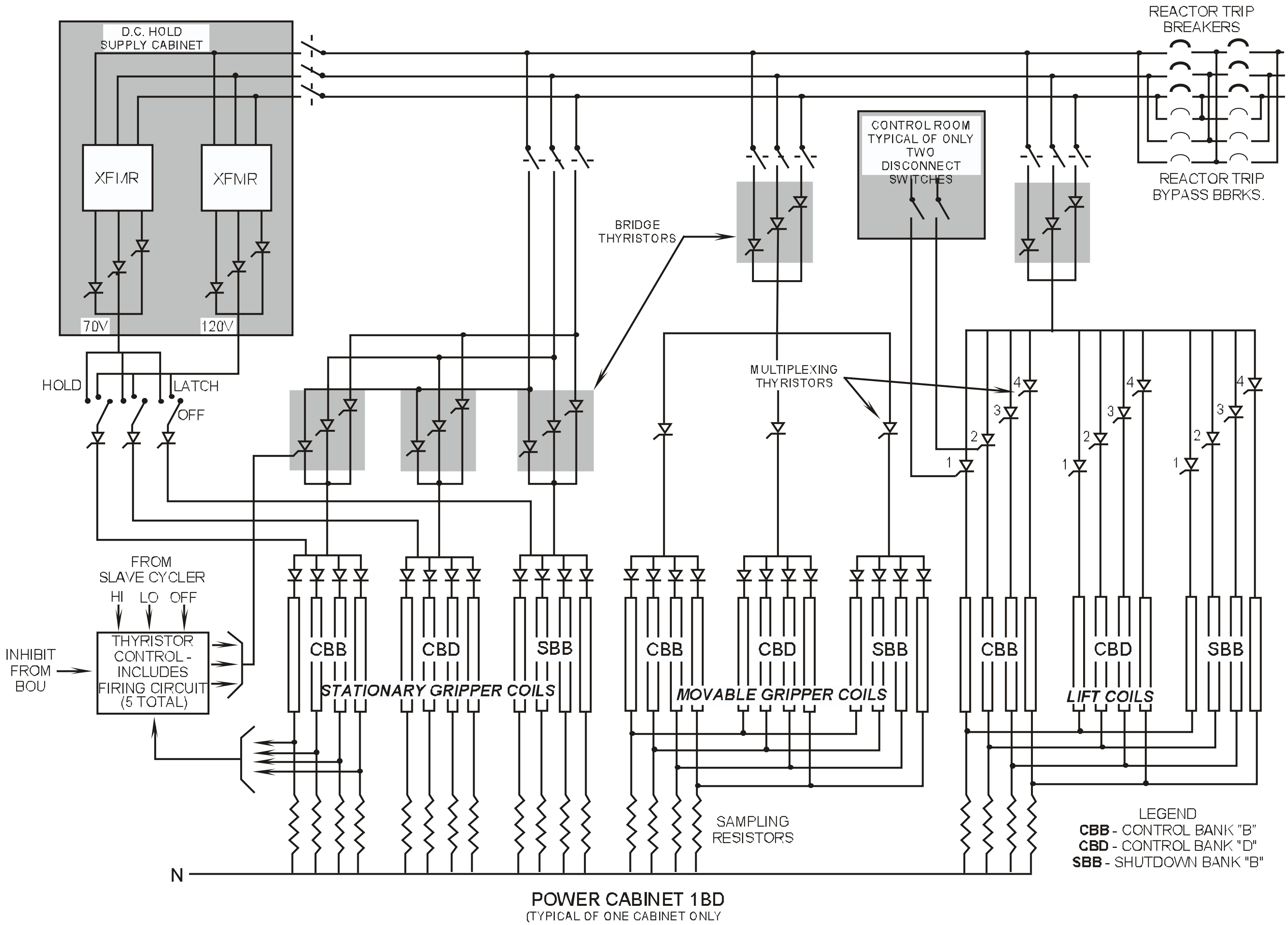


Figure 8.1-6 Solid State Power Cabinet

Westinghouse Technology Systems Manual

Section 8.2

Analog Rod Position Indication ARPI

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8.2 ANALOG ROD POSITION INDICATION (ARPI)

Learning Objectives:

1. State the purpose of the Rod Position Indication (RPI) system.

2. Briefly describe the operation of the following:

   a. Analog individual rod position indication (IRPI),
   b. Group demand position indication, and
   c. Bank demand position indication.

3. List the conditions that will initiate a rod deviation alarm.

8.2.1 Introduction

The purpose of the rod position indication system is to provide indication of actual and demanded control rod positions. In addition, this system provides alarms to alert the reactor operator to misaligned rods, or to the fact that the required shutdown margin is not available due to excessive rod insertion. (See Section 8.4 for information on Rod Insertion Limits [RILs]).

In Westinghouse plants, there are several methods used to determine rod position. For group demand indication, there are the demand step counters, which receive signals from the rod control system logic cabinet (Section 8.1). This system assumes that the rods of a specific group are at their demanded positions. For bank demand indication, there are the pulse-to-analog converters for the control banks, which also receive demanded position signals from the logic cabinet.

The third method of determining rod position is with the use of the individual rod position indication system. This system measures the actual position of each rod, regardless of its demanded position.

There are two types of individual rod position indication found in Westinghouse plants: the analog system and the digital system. The analog system is described in the following paragraphs; the digital system is described in Section 8.3.

8.2.2 System Description

8.2.2.1 Group Demand Position Indication

The group demand position indications display the positions that all groups of rods should have assumed in response to demands for rod motion generated within the rod control system. The demand position display for each rod group is an electro-mechanical add/subtract step counter which receives a count, or pulse, each time its associated group of rods is demanded by the logic cabinet to withdraw or insert. The step counters are located on the main control board. This demand position indication system is used in conjunction with either the analog or digital individual rod position indication system.

8.2.2.2 Analog Position Indication

The analog individual rod position indication (IRPI) system furnishes an indication of the actual position each rod has assumed in response to the rod control system command signals. The analog system consists of field mounted detectors, cabinet mounted electronic equipment, and control board mounted meters and annunciators.

Figure 8.2-1 shows a typical analog rod position channel. Individual rod position information is sent to the plant computer, control board indication, and control board annunciators. This figure also shows that the output from the pulse-to-analog converter (Section 8.2.3.5) for that rod's bank affects the status of the rod bottom/rod drop alarm circuit.

Each rod position detector is mounted on the outside of the pressure housing of a control rod drive mechanism. The vertical position of the rod drive shaft within the rod position detector produces an ac electrical output signal which is directly proportional to the rod's vertical position. This signal is transmitted, by means of a shielded cable, to a signal conditioning circuit, which converts the ac rod position electrical signal into an adjustable dc analog position signal. This analog signal is then supplied to the following:

- A rod bottom bistable,
- A control board meter, and
- The plant computer.

The rod bottom bistable provides indication and an alarm when a rod has moved below a predetermined position. The output of this bistable actuates a control room annunciator ("ROD BOTTOM/ROD DROP") and the rod bottom light for the associated rod. Each rod bottom light is located just below an individual rod position indicator located on the main control board. Each rod position channel also has the capability of being tested by means of a built-in test panel. The reactor operator is alerted to a channel test by the control room annunciator "RPI IN TEST."

8.2.3 Component Descriptions

8.2.3.1 Detector

Each actual rod position detector is a linear transformer which is mounted outside, and concentric with, the rod drive pressure housing. The detector consists of alternately stacked primary and secondary coil windings, and the rod drive shaft acts as the moveable armature of the transformer. The position of the rod drive shaft within the rod position detector determines the amount of magnetic coupling between the primary and secondary windings. With the rod drive shaft fully inserted into the core, the magnetic coupling between the primary and secondary windings is small. Therefore, the signal induced in the secondary windings is small (8 Vac).

When the rod is withdrawn from the core, the relatively high permeability of the rod drive shaft causes an increase in the magnetic coupling between the primary and secondary windings. As the magnetic coupling increases, the magnitude of this output signal increases proportionally to indicate actual rod position.

The power supply to the rod position equipment cabinet is 120-Vac regulated instrument power. The 120 Vac is then reduced to 15 Vac, which is used as the excitation voltage supplied to the primary windings. This reduction in voltage is accomplished through a dropping resistor located inside the rod position equipment cabinet. The detector output, or secondary coil winding voltage, is normally 8 to 12.5 Vac, which corresponds to 0 to 230 steps. This output voltage is transmitted to the signal conditioning module.

8.2.3.2 Signal Conditioning Module

Each rod position detector has an associated signal conditioning module. This module, located in the rod position equipment cabinet, receives an ac voltage input from the secondary windings. This ac signal is rectified and processed so that the output of the module is 11 to 16.8 Vdc. This range of dc voltage corresponds to the range of actual rod positions from fully inserted to fully withdrawn. The resultant dc signal from this module is sent to the main control board for indication, to the plant computer for rod position monitoring, and to the rod bottom bistable for visual indication and an alarm to indicate that the rod has been inserted past a preselected setpoint.

The signal conditioning module includes zero and span adjustments to facilitate channel calibration, as well as test points for monitoring the dc signal. In addition, the module has adjustments for calibrating the control board indicator from zero to full scale. When placed in “TEST,” the TEST-OPERATE switch, mounted on the front of the module, disconnects the detector output leads and allows the insertion of a test signal for checking the operation of the cabinet channel electronics from essentially the cabinet input terminals to the various output devices.

8.2.3.3 Rod Bottom Bistable

The rod bottom bistable (an electronic switch) serves as a simple level comparator. It receives its input signal from the signal conditioning module. The bistable output is used to light a rod bottom light and to operate a control relay which generates the “ROD BOTTOM/ROD DROP” alarm. When the output from the signal conditioning module reaches a preselected dc voltage (meaning that the rod is more deeply inserted than the rod bottom setpoint), the bistable trips (de-energizes), thereby removing power from the control relay, which in turn causes the ROD BOTTOM/ROD DROP alarm to actuate. When the bistable is in the tripped condition, it also turns on the rod bottom light. Each rod position detector has an associated rod bottom light; this light is located just below the individual rod position indicator. The trip setpoint (de-energizing point) for the rod bottom bistable is adjustable over the lower 25% (0-57 steps) of rod travel. The setpoint is generally selected at 20 steps from the bottom of the core.

8.2.3.4 Rod Bottom/Rod Drop Alarm Circuit

The rod bottom/rod drop alarm circuit is shown in Figure 8.2-2. For simplicity, only three rods from each control bank and three shutdown rods are shown.

The purpose of this alarm is to alert the reactor operator in the event of a rod dropping below a predetermined setpoint. Since the rod bottom/rod drop alarm is a single alarm with multiple inputs, selected input signals are disarmed during a reactor startup. Without this feature, the alarm would be in the alarmed state until every rod is withdrawn greater than the setpoint. This condition would prevent an actual dropped rod event from causing a new dropped rod alarm during a reactor startup.

As shown in Figure 8.2-2, the disarming signal for a particular rod's position input to the rod drop alarm is provided by a contact controlled by the status of a control bank's rod bottom/rod drop alarm bypass bistable. This bypass bistable receives an input (bank demand position) from that bank's pulse-to-analog converter (Section 8.2.3.5). In the bistable the input signal is compared to a preselected setpoint (usually set at 35 steps from the bottom of the core). If the bank demand position is below this setpoint, the contact in the circuit supplying the rod bottom/rod drop alarm is open, thereby preventing an actual rod position of less than 20 steps from actuating the rod drop alarm. However, the open contact has no effect on the status of the rod bottom light for that rod. Only control banks B, C, and D are provided with rod bottom/rod drop alarm bypass bistables. As control banks B, C, and D are withdrawn above 35 steps, the bypass bistables cause the contacts in the rod bottom/rod drop alarm circuit to close. After these contacts are closed, any rod in one of those three banks falling below 20 steps will actuate the alarm. In other words, a bank B, C, or D control rod at the bottom of the core (withdrawn no farther than 20 steps) generates the rod bottom/rod drop alarm only when it is not demanded to be there.

Control bank A does not have an associated bypass bistable because it is the first control bank withdrawn during a reactor startup. When control bank A rods have been withdrawn to greater than 20 steps, the rod bottom/rod drop alarm circuit clears (the alarm inputs for rods in control banks B, C, and D are disarmed), and any subsequent dropped rod will actuate the alarm.

8.2.3.5 Pulse-To-Analog Converters

A pulse-to-analog converter is furnished for each control bank. The converter receives the control bank demand position pulses (up and down counts) from the rod control logic cabinet (bank overlap unit) and converts the count signal to an equivalent dc analog signal which is proportional to the bank demand position. This signal is sent to the rod bottom/rod drop alarm bypass bistable for control bank B, C, or D (Section 8.2.3.4). The output from the pulse-to-analog converter is also sent to the rod insertion limit comparator for the associated bank (Section 8.4).

The output from each converter is supplied to a common local display panel. The panel's selector switch allows the operator to display the demanded position of either of the four control banks. The panel also has provisions for manually pulsing a particular bank's converter either up or down if required. All converters are reset by the rod control startup pushbutton located on the main control board.

8.2.3.6 Test Panel

The rod position equipment cabinet contains a test panel, shown in Figure 8.2-1, which is used in conjunction with the signal condition modules. The test panel supplies a variable ac signal (simulates the detector output) for checking the output of a particular signal conditioning module and the operation of the associated rod bottom bistable. The operator is alerted to a test of a signal conditioning module by the “RPI IN TEST” control room annunciator.

8.2.3.7 Control Board Position Indicator

Each control rod has an associated position indicator mounted on the main control board. The indicator is a meter providing the rod’s actual position in terms of steps withdrawn from the bottom of the core. Each indicator receives the rod position dc analog signal from its signal conditioning module. Calibration of an indicator (zero to full scale deflection) is accomplished by adjustments performed at the signal conditioning module. All indicators are grouped in banks (i.e., control bank A, control bank B, etc.). This arrangement facilitates the visual detection of rod deviations within in a bank. Comparisons of the indicated actual rod positions serve as a backup to the rod deviation monitoring program of the plant computer. Mounted beneath each analog rod position indicator is the associated rod bottom light.

8.2.3.8 Rod Deviation Monitor

The rod deviation monitor is a plant computer program that receives inputs from the rod control system logic cabinet and each signal conditioning module. This program monitors the various inputs and, if certain conditions exist, alerts the reactor operator by means of the “COMPUTER ALARM ROD DEVIATION AND SEQUENCE NIS POWER RANGE” control room annunciator. This alarm alerts the operator to one or more of the following conditions:

1. Improper sequence (i.e., the sequence of control bank withdrawal should be A, B, C, D; and the sequence for insertion should be D, C, B, A). If the control banks move out of sequence, this alarm is generated.
2. Any shutdown bank rod less than 220 steps withdrawn.
3. Any rod within a bank greater than 12 steps from the bank demand.
4. Any two rods in the same bank greater than 12 steps from each other.

8.2.4 Summary

The analog rod position indication system uses a linear transformer to continuously measure the actual position of each individual rod. The rod position is transmitted as an ac analog signal, which is then converted to a dc analog signal in the associated signal conditioning module.

From the signal conditioning modules, signals are sent to the plant computer, individual position indicators located on the main control board, and the rod bottom bistables.

A rod bottom bistable trips whenever its associated control rod is inserted below a predetermined setpoint. When the bistable trips, the “ROD BOTTOM/ ROD DROP” alarm actuates. Control banks B, C, and D are equipped with rod bottom/rod drop alarm bypass bistables. Each of these bistables control contacts which defeat the inputs to the ROD BOTTOM/ROD DROP alarm for the rods of a particular bank, until that bank has been withdrawn from the core by more than a preselected amount.

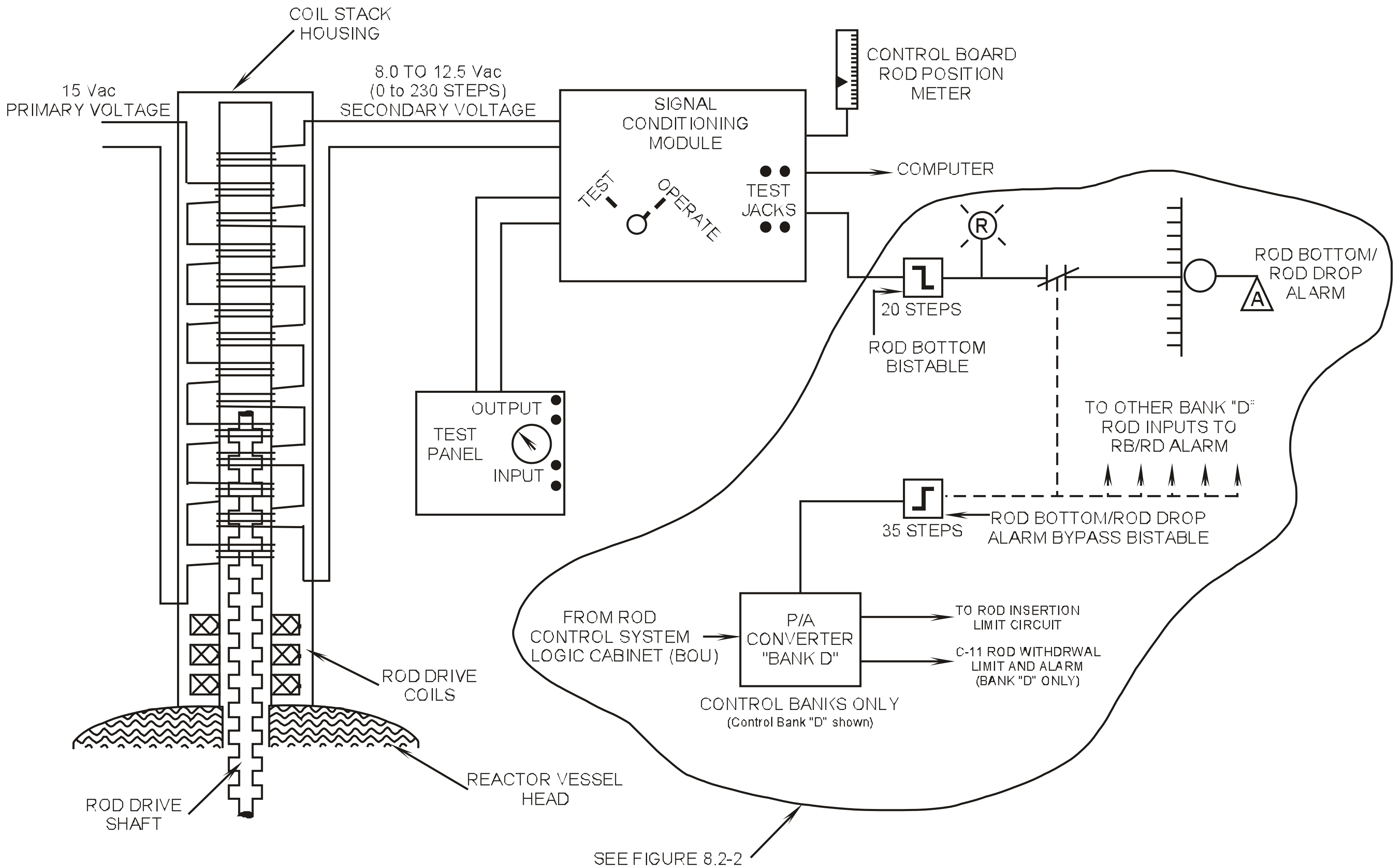

Figure 8.2-1 Rod Position Indication System

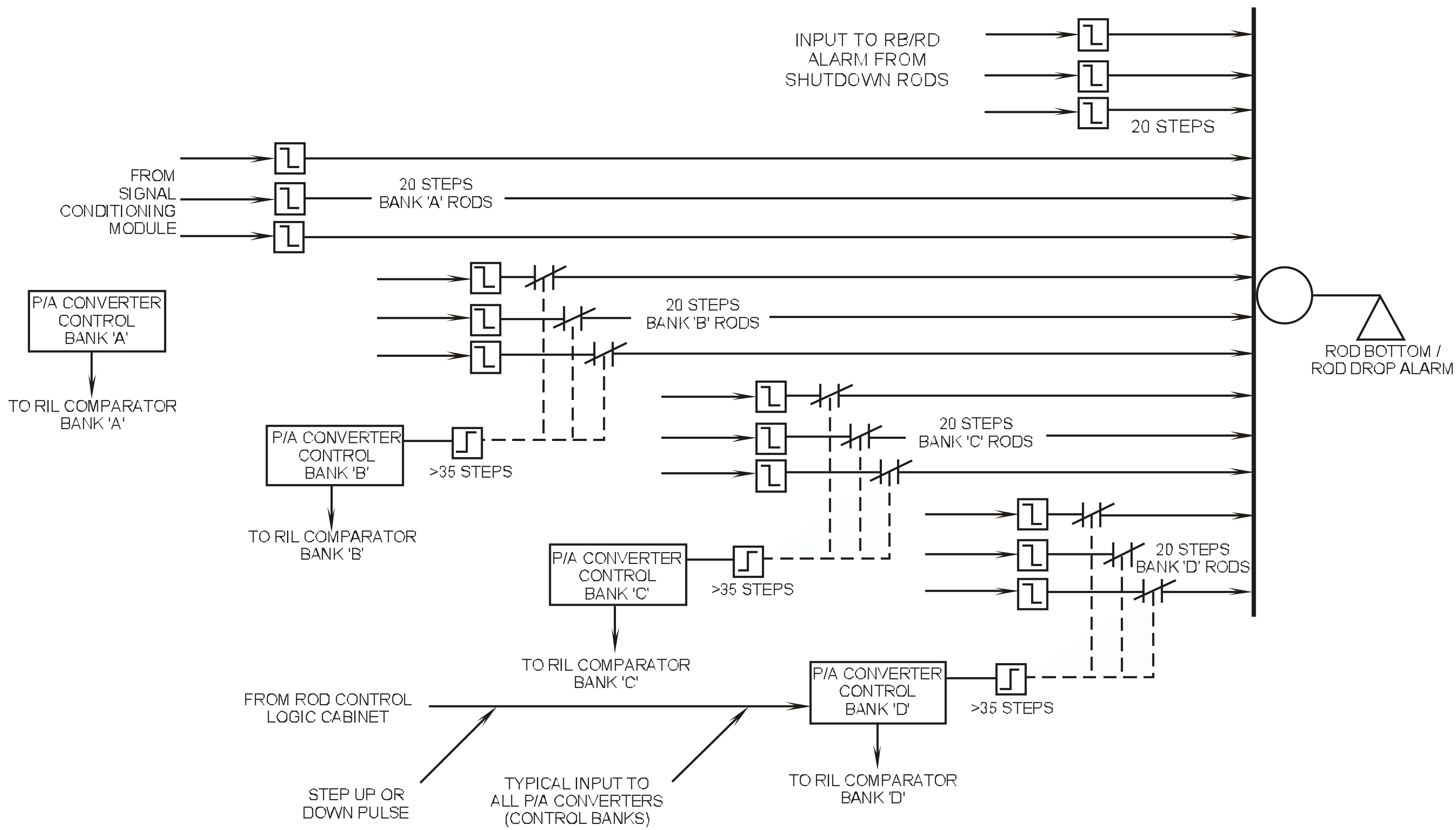

Figure 8.2-2 Rod Bottom / Rod Drop Alarm Circuit

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Section 8.3

Digital Rod Position Indication DRPI

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8.3 DIGITAL ROD POSITION INDICATION (DRPI)

Learning Objectives:

1. State the purpose of the rod position indication system.

2. Briefly describe the operation of the Digital individual rod position indication (DRPI),

3. List the conditions that will initiate a rod deviation alarm.

8.3.1 Introduction

The purpose of the rod position indication system is to provide indication of actual and demanded control rod positions. In addition, this system provides alarms to alert the reactor operator to misaligned rods, or to the fact that the required shutdown margin is not available due to excessive rod insertion. (See Section 8.4 for information on Rod Insertion Limits [RILs]).

As explained in Section 8.2, there are two different systems employed for rod position indication: the first system is the demand step counters (Section 8.2.2.1), and the second is the individual rod position indication system. Two types of individual rod position indication systems are used in Westinghouse plants. The older design is the analog system (Section 8.2), and the newer design is the Digital Rod Position Indication system (DRPI). The digital system is explained in this section.

8.3.2 System Description

In Westinghouse plants, there are several methods used to determine rod position. For group demand indication, there are the demand step counters, which receive signals from the rod control system logic cabinet (Section 8.1). This system assumes that the rods of a specific group are at their demanded positions. For bank demand indication, there are the pulse-to-analog converters for the control banks, which also receive demanded position signals from the logic cabinet.

The digital rod position indication system continuously senses and displays rod position information for each rod (control and shutdown). The system consists of one locally mounted detector stack for each rod, two data cabinets located inside the containment, and one display unit mounted on the main control board.

Each digital rod position detector stack consists of a hollow tube with 42 individual coils mounted on the outside of the tube. This detector stack is placed over the rod drive shaft travel housing. When the tip of the rod drive shaft is located within a coil, the voltage drop across that coil increases. As a result, the voltage drop in that coil is greater than the voltage drop in the next higher coil (a coil where the rod drive shaft is not located). The voltage differences between coils are detected by data cabinets.

Within the two data cabinets (data cabinets A & B), the voltages across the sensing resistors are continuously monitored. Differential amplifiers located inside the data cabinets compare the voltage drops produced by adjacent coils and generate an output according to the difference in voltages. Each data cabinet's output is a digital signal equivalent to actual rod position.

The information from the two data cabinets is sent to central control units located within the DRPI display unit. The central control units add both signals together (data A & B) to obtain full accuracy rod position. This position signal is sent to a display card for each individual rod on the DRPI display unit, and it is also sent to the plant computer.

On the display unit there is one column of lights for each rod. Each column of lights consists of 40 Light-Emitting Diodes (LEDs). Thirty-eight of the forty LEDs are used to indicate actual rod position. Each LED represents six steps of rod position with an accuracy of ± 4 steps (section 8.3.3.3). The bottom LED in each column represents the "Rod at Bottom" position. The top LED is used for "General Warning." The general warning alarm and the other DRPI alarms are discussed in Section 8.3.4.

8.3.3 Component Description

8.3.3.1 Detector Stack

Each detector stack consists of 42 discrete coils mounted axially on the rod drive travel housing with their vertical positions fixed at 3.75-in. centers (Figure 8.3-1). Recall that each rod step is 5/8 in., therefore, 3.75 in. equals six steps. The coils are interlaced into two separate data channels - the odd numbered coils forming data channel A, and the even numbered coils forming data channel B. All of the channel A coil windings are connected in parallel to a 6-volt ac power source mounted inside the A data cabinet. The output signals from the A coils are brought out separately and directed to the A data cabinet. The B coil windings are similarly connected to the B data cabinet.

The position of a rod is determined by measuring the voltage drop across each coil's sensing resistor, which is in series with the coil. As the ferromagnetic rod drive shaft passes through a coil, the voltage drop across the coil increases. The voltage drop across the sensing resistor thus decreases. The voltage drops associated with the A and B coil windings are analyzed in the data cabinets to determine actual rod position.

8.3.3.2 Data Cabinets

The data cabinets (A and B) are located inside the containment (Figure 8.3-2). They contain the necessary circuitry to compare the sensing resistor voltage drops and generate an output signal corresponding to actual rod position. The data cabinets amplify the coil signals and deliver the amplified signal to a level-tracking detector. A level-tracking detector selects the largest differential signal between two adjacent coils (corresponding to a rod position) and sends that signal to the display unit in the main control room.

8.3.3.3 Display Unit

The display unit is located on the main control board and consists of a column of lights for each rod. The light emitting diodes (LEDs) provide information of actual rod position. Only one LED per rod is lit at a time, and each light corresponds to 6 steps, as shown in Figure 8.3-3. With the system at full accuracy, the displayed rod position is within ± 4 steps (± 2.5 in.).

The central control cards receive data signals from the data cabinets (Figure 8.3-1). These cards check the received position indication information for errors. Assuming that there are no errors, each central control card combines the inputs from both data cabinets and generates a rod position. Figure 8.3-4 shows the output from the data cabinets and the full accuracy rod position indication. As an example, assume that a rod is at 15 steps. The Data A and B indication could be as low as 12 steps, or as high as 18 steps. The accuracy of picking up a coil's center is ± 1 step. This results in a ± 4 step accuracy for the combined A and B signal.

The central control card is the one common point between data channels A and B. To prevent a loss of system position monitoring upon a failure of a central control card, two additional cards are used (Figure 8.3-1). The three control cards operate on a majority vote with an automatic disconnect upon a disagreement. If a card is automatically disconnected, local alarm lights illuminate. Mounted on the rear of the display unit is a four-position switch. This switch allows the operator to disconnect any one of the three central control cards removing it from service. Removing a control card from service allows a technician to troubleshoot or perform maintenance on a faulty card.

8.3.4 DRPI Circuit Failures and Alarms

The DRPI system provides the plant computer with position data that is used for routine data logging and rod deviation analysis. A "Computer Rod Deviation" alarm is generated if any of the following conditions exist:

- Rods operating out of sequence,
- A deviation of ± 12 steps between any rod and its bank demand,
- A deviation of ± 12 steps between any two rods in the same bank, or
- Any shutdown rod below 220 steps.

An "RPI Rod Deviation" alarm is generated if a deviation of ± 12 steps exists between any rod and its associated bank demand position. This alarm is displayed on the main control board and on the DRPI display unit.

If a circuit failure eliminates the data from one of the coil sets, the DRPI system places that rod's position indication to "half-accuracy." The failed data is blocked while the data information from non-affected cabinet is doubled. An "RPI Non-Urgent Failure" alarm is generated on the main control board, and a "General Warning" LED is illuminated on the rod position display unit.

As previously stated, the "RPI Non-Urgent Failure" annunciator alarms if there is an error in either the A or B data for any rod. When the annunciator alarms, either the

“Data A Failure 1, 2, 3" or “Data B Failure 1, 2, 3" LED group on the control board display flashes. The rod whose position is in question is denoted by a flashing “General Warning” LED.

The half-accuracy position of the rod is visible until the source of the failure is identified, and the problem corrected. During half-accuracy operation, the position of the rod is solely determined by the good data; either A or B. Therefore, rod movement is traced by the lighting of every other LED (i.e., every other step position in 6-step increments). The discrepancy between the indicated position on the control board display and the rod demand step counter reading may be as great as 10 steps during half-accuracy operation.

Half-accuracy indication is shown on Figure 8.3-4. If the data B channel fails, the system goes to half accuracy on the data A channel only. The normal data A signal is doubled by the central control card. For example, if the actual rod position were 15 steps, the half-accuracy position from data channel A could be either 24 or 12 steps (+ 9, - 3). Accounting for the ± 1 step coil center accuracy, the resultant indicated accuracy is + 10, - 4 steps. For a data A channel failure, the system half-accuracy (on data channel B only) would be - 10, + 4 steps.

The system accuracy decreases to -10, +4 steps with a data A failure, or +10, -4 steps for a data B failure. If a failure occurs in both channels (data A and data B), the system alerts the operator with the following;

- A “Rod Bottom” light,
- A “General Warning” light,
- An “Urgent Failure alarm,” and
- A “Rod Deviation” alarm.

The “Rod Bottom” alarm is generated when a rod is at the bottom of the core and the rest of the rods in its group is off the bottom. A “Two or More Rods at Bottom” alarm is generated if two or more rods in any bank are on the bottom. A “Rod Bottom” alarm is also generated if a bank is on the bottom while the next sequential bank is not. This could be an indication of a dropped bank or improper control bank sequencing. Both rod bottom alarms are bypassed on control banks B, C, and D when all rods of those banks are indicating on the bottom, and control bank A is greater than six steps.

An “RPI Urgent Alarm” occurs if an error or a failure is detected in the information from both data cabinets. A “Rod Bottom” alarm also occurs when an “RPI Urgent Alarm” actuates. When the “RPI Urgent Alarm” annunciator alarms, the Urgent Alarm 1, 2, 3 light group on the control board display also flashes. The rod whose position is in question is denoted by a flashing “General Warning” LED. In addition, that rod's position will not be available, and its associated Rod Bottom LED is energized.

8.3.5 Rod Drop Testing

An additional feature of the digital rod position detectors is the capability of recording rod drop test measurements. If the 60-cycle ac voltage is removed from a detector coil stack, a rod dropping through the coils induces a voltage which causes a current flow in the common line to the coils. This induced current can be recorded to monitor rod drop performance. Plant Technical Specifications require that rod drop tests be performed periodically and after certain maintenance outages.

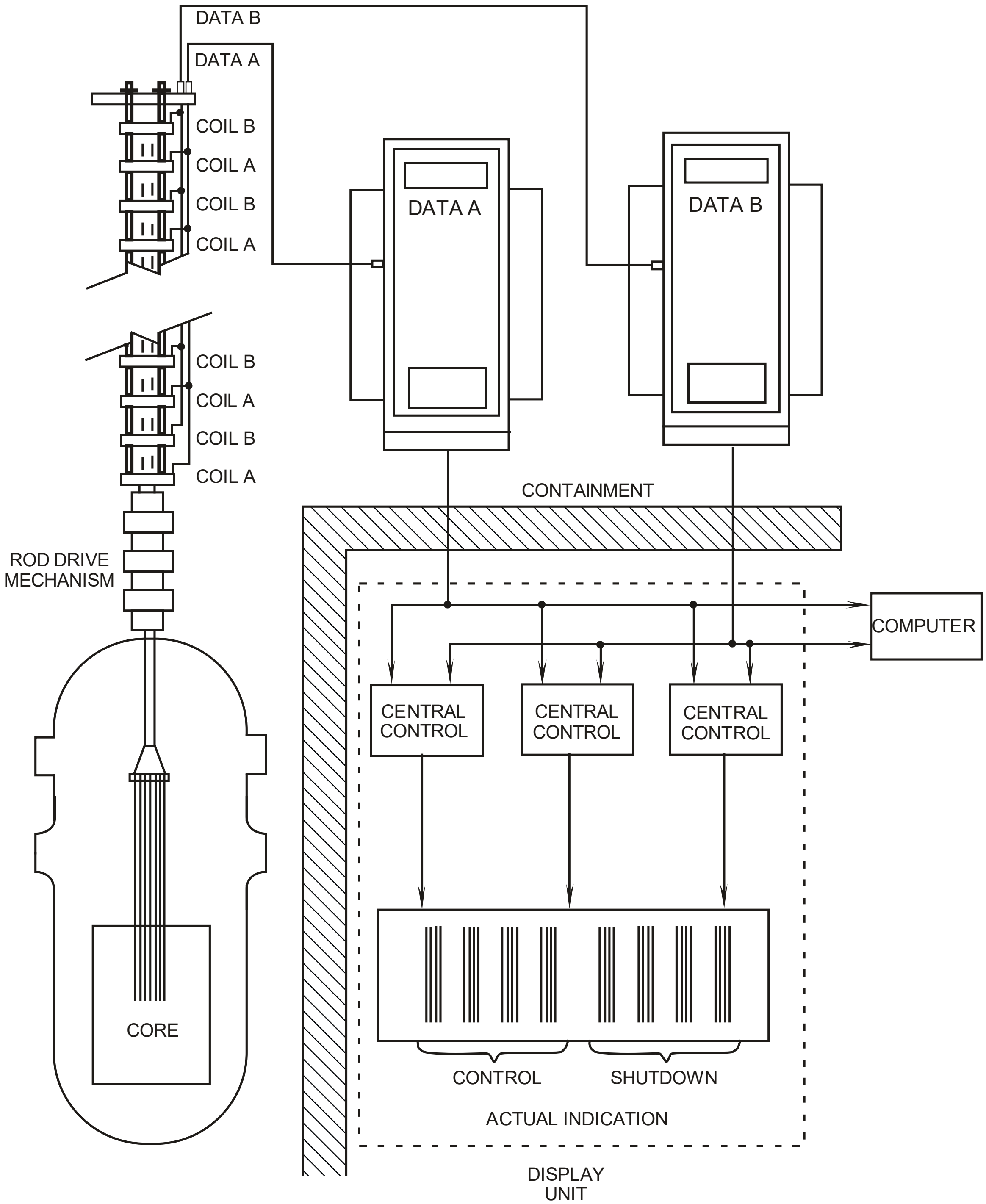

Figure 8.3-1 Digital Rod Position Indication

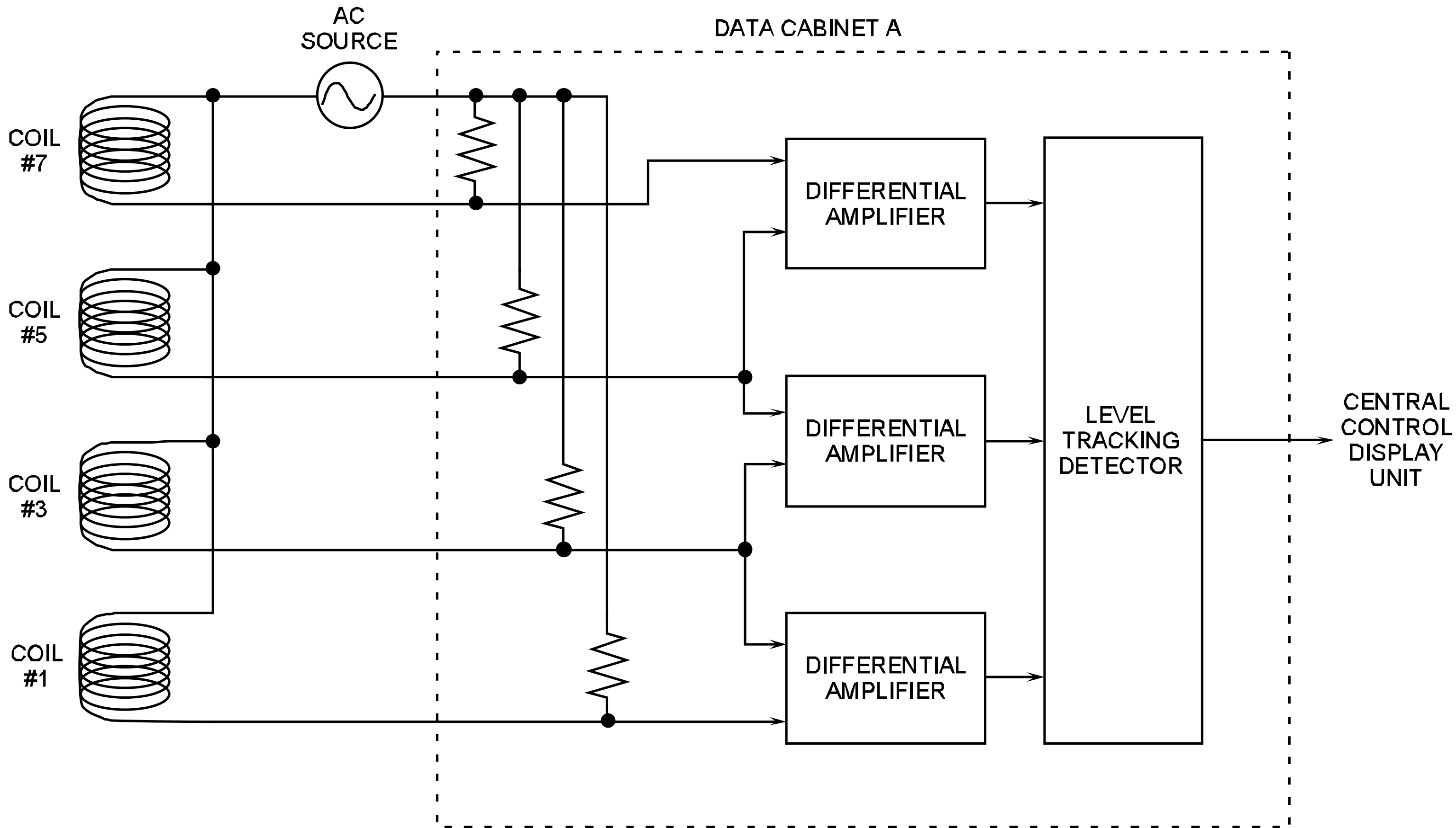

Figure 8.3-2 Detector Signal Flow

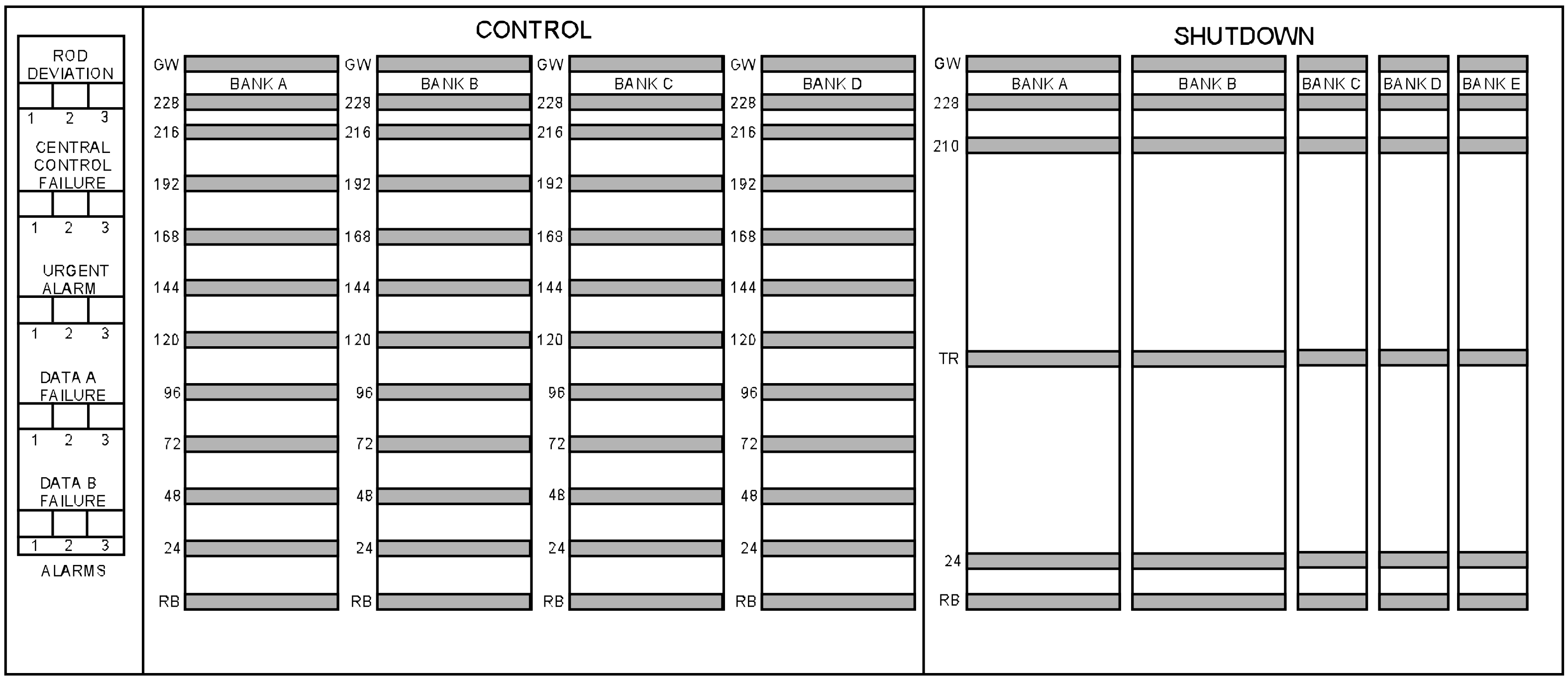

Figure 8.3-3 DRPI Control Board Indication

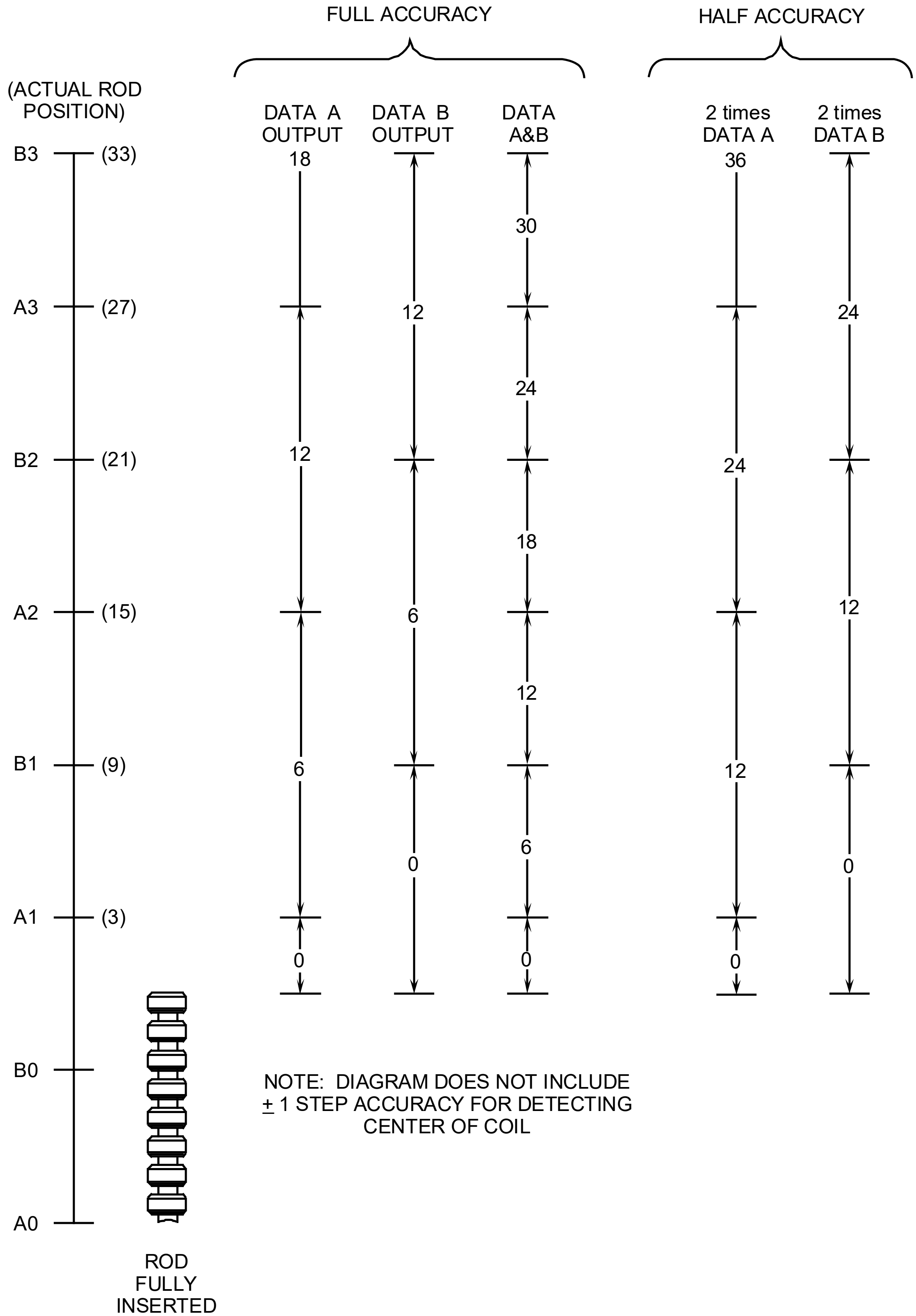

Figure 8.3-4 DRPI Coil Outputs

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Section 8.4

Rod Insertion Limits RIL

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8.4 ROD INSERTION LIMITS (RIL)

Learning Objectives:

1. State the purposes of the control rod insertion limits (RILs).

2. List the inputs to the rod insertion limit computers and comparators.

3. Explain why the rod insertion limits increase with increasing reactor power.

8.4.1 Introduction

The rod insertion limits ensure that the control rods are sufficiently withdrawn to:

a. Maintain an adequate shutdown margin,
b. Maintain nuclear peaking factors within limits, and
c. Minimize the reactivity effects on the core due to an ejected rod.

To comply with the rod insertion limits (one limit for each of the control banks), the rods may be inserted no farther than a certain number of steps into the core for a specific power level. A limiting condition for operation (LCO) of the plant's technical specifications addresses this limit. This chapter discusses the assumptions, considerations, and calculations used to determine the rod insertion limits.

8.4.2 Assumptions and Considerations

Compliance with the rod insertion limits ensures that there is enough negative reactivity associated with the rods to place the reactor in the hot standby condition following a reactor trip. Compliance with the RILs further ensures that, in conjunction with the operation of engineered safety feature systems, the negative reactivity margin provided by the rod insertion prevents acceptable fuel design limits from being exceeded during a reactivity addition accident. A typical value for this reactivity margin is -1.3 %ΔK/K. The analyses which verify the adequacy of the RILs entail the following conservative assumptions:

1. The highest worth rod is stuck in the fully withdrawn position. As a result, the negative reactivity associated with this rod is not available to shut down the reactor upon a trip.
2. The reactor is operating with the highest power defect (Section 2.1) for a given power level, which occurs at the core's end of life (EOL).
3. The plant is operating with the highest possible deviation from the programmed T_{avg} for a given power level.

The above list reflects the assumptions used in the accident analysis section of a plant's Final Safety Analysis Report (FSAR). As an illustration of the need for an adequate shutdown margin (which is ensured by satisfying the RILs), consider the accident analyses associated with excessive secondary heat removal events in the Trojan (TTC simulator plant) FSAR. Each of these events causes a rapid cooldown of the reactor coolant, which adds positive reactivity to the core and may result in a return to criticality. The analysis for the inadvertent opening of an atmospheric steam relief valve, steam generator safety valve, or steam dump valve (a condition II event, see Section 5.0) shows that the rod insertion upon the resulting reactor trip and borated Emergency Core Cooling System (ECCS) injection maintain subcriticality during the cooldown, and core damage is prevented. For the more severe steam line rupture (a condition IV event, see Section 5.0), the analysis shows that the coolant temperature decrease does cause a return to power, but the negative reactivity from rod insertion and ECCS injection again prevents core damage (departure from nucleate boiling is avoided).

In addition to providing a sufficient shutdown margin, the rod insertion limits must satisfy additional considerations. First, setting the insertion limits as low as possible (rods greatly inserted into the core) is desirable to allow the largest range of rod motion for power maneuvering. However, setting the insertion limits as high as possible (rods barely inserted into the core) is desirable to ensure that the limits on nuclear peaking factors are not exceeded. Inserting control rods into the core suppresses neutron flux (and power) in the vicinity of the rods and causes increased power densities in rod-free areas. Operating with rods largely withdrawn should limit local peaks in power density. Finally, operating with the rods largely withdrawn reduces the positive reactivity addition associated with a hypothetical rod ejection accident.

The rod insertion limits ultimately selected for the plant provide some maneuvering flexibility while providing a sufficient shutdown margin, limiting power peaking, and limiting the effects of a rod ejection.

8.4.3 Component Descriptions

8.4.3.1 Rod Insertion Limit Computer

Consider the reactivity changes associated with a reactor power increase. Because of the increases in fuel temperature and moderator temperature which accompany a power increase, the power defect adds negative reactivity to the core. Accordingly, the magnitude of the power defect increases with core power (see Section 2.1). To maintain the criticality of the core, the reactor operator must add an equal amount of positive reactivity. Positive reactivity addition can be accomplished via control rod withdrawal or boron dilution, or a combination of the two. Conversely, when a reactor trip occurs and the plant control systems establish the no-load coolant temperature, the removal of the power defect adds positive reactivity to the core. A higher power level means a greater positive reactivity addition upon a trip. Because there is no other rapidly available source of negative reactivity, the negative reactivity associated with the shutdown and control banks must alone counteract the positive reactivity addition associated with the power defect. Hence, the shutdown margin consideration dictates that the control rods must be maintained at a more withdrawn position (the rod insertion limits must increase) as reactor power and the associated power defect increase.

Increasing the rod insertion limits with power is also dictated by the other considerations discussed in Section 8.4.2. Operating with the control rods deeply inserted causes a large peak-to-average ratio for power density; without rod withdrawal the peak local power density approaches an unacceptable level as the core average power density increases. Also, a higher starting position for the rods is needed at higher powers to limit the effects of a rod ejection, because less additional core energy is needed to cause fuel damage at higher powers. Maintaining rod positions higher than the RILs limits the reactivity addition and resulting power increase from an ejected rod.

The actual values of the rod insertion limits for a particular power level are chosen to satisfy the most limiting of the considerations discussed above.

To account for the variation of the rod insertion limits with power level, two parameters proportional to power are input to the rod insertion limit computer for each control bank: auctioneered high ΔT and auctioneered high T_{avg} (Figure 8.4-1). ΔT is directly proportional to power, and T_{avg} is programmed as a function of power. Because the auctioneering units select the highest values of ΔT and T_{avg}, the rod insertion limit calculations use a conservatively high representation of power. Each rod insertion limit computer calculates the insertion limit for a particular control rod bank in accordance with the following equation:

$$RIL = K_1 (T_{avg} - 557°F) + K_2 (\%\Delta T) + K_3$$

Where:

1. RIL = the limit for rod insertion for a selected control bank.
2. K_1 is a constant used to compensate for the effect of a higher moderator temperature on the power defect if the plant is operating with a higher temperature program than the design T_{avg} program. If a plant is operating with an escalated T_{avg}, the extra reactivity associated with the greater cooldown of the reactor coolant following a reactor trip must be accounted for. Most plants operate in accordance with their normal programmed T_{avg} bands; therefore, the normally assigned value for K_1 is zero.
3. (T_{avg} – 557°F) = auctioneered high T_{avg} minus the no-load T_{avg} (557°F).
4. K_2 accounts for the power defect, since the auctioneered high ΔT varies directly with power. The constant K_2 (expressed in steps per % power) times the $\%\Delta T$ results in a given number of rod steps. This factor ensures that the calculated rod insertion limit provides enough negative reactivity to shut down the reactor with a sufficient margin from a given power level. (Note: K_2 is the slope of each RIL line segment shown in Figure 8.4-2.)
5. ($\%\Delta T$) = the auctioneered high ΔT expressed in terms of percent power. If the expected ΔT for 100% power is approximately 64°F (a typical value), the input to the rod insertion limit equation at full power would be 100%, i.e., (64/64) x 100%. If the ΔT is 32°F, then the input to the rod insertion limit computer would be 50%, i.e., (32/64) x 100%.
6. K_3 provides the minimum insertion limit setpoint (in steps) for hot zero power, i.e., the minimum insertion for criticality. K_3 is the Y intercept of a particular RIL line segment shown in Figure 8.4-2.

The values for these constants vary depending upon plant design, fuel loading, fuel design, and rod worth. These values can be found in the Precautions, Limitations, and Setpoints (PLS) document for a given Westinghouse plant. A typical set of constants is listed below:

	K_1	K_2 (steps/%)	K_3 (steps)
Control Bank C	0	1.99	118
Control Bank D	0	1.99	- 10

Figure 8.4-2 displays the rod insertion limits for different control banks versus reactor power. (The figure and the underlying equations for the limits are typical for Westinghouse plants, but not necessarily correct for the plant modeled by the TTC's Westinghouse simulator.) For example, calculations for the rod insertion limits for control banks C and D with plant at 50% power are as follows:

CONTROL BANK C:

RIL = K_1 (T_{avg} - 557°F) + K_2 (%ΔT) + K_3

RIL = 0 (571°F - 557°F) + 1.99 (50) + 118

RIL = 0 + 99.5 + 118

RIL = 217.5 steps on Bank C

CONTROL BANK D:

RIL = K_1 (T_{avg} - 557°F) + K_2 (%ΔT) + K_3

RIL = 0 (571°F - 557°F) + 1.99 (50) + (- 10)

RIL = 0 + 99.5 - 10

RIL = 89.5 steps on Bank D

After the computer calculates the insertion limit for a particular control bank, the calculated limit is sent to that bank's RIL comparator circuit.

8.4.3.2 Rod Insertion Limit Comparator

Each rod insertion limit comparator receives two input signals for comparison (see Figure 8.4-1). The first input comes from a rod insertion limit computer, which provides the rod insertion limit for a control bank. The second input comes from that bank's pulse-to-analog converter (Section 8.2). This input represents the demanded bank position. The rod insertion limit comparator compares the calculated rod insertion limit to the demanded bank position. Each comparator generates two control room alarms: one for the demanded bank position approaching the RIL, and another for the demanded bank position equaling the RIL. These alarms are the "ROD LIMIT Lo" and "ROD LIMIT Lo-Lo" alarms. The equations for determining the setpoints of these alarms are as follows:

- Rod Limit Low setpoint = RIL + 10 steps
- Rod Limit Low-Low setpoint = RIL

The purpose of these alarms is to provide the reactor operator with a warning of excessive rod insertion for the existing power level. To exit the alarming condition, the operators can borate the reactor coolant to cause rod withdrawal or reduce turbine load while maintaining the rod position. If the “ROD LIMIT Lo-Lo” alarm is alarming, the technical specification limit for rod insertion has been violated. To comply with required actions, the operator has the option of either, within an hour, verifying that the shutdown margin is acceptable or borating the reactor coolant to restore an acceptable shutdown margin. In addition, within two hours of the rod insertion limits being violated, the control bank(s) must be restored to within their limit(s).

8.4.4 Summary

The rod insertion limits constitute a Technical Specification (TS) LCO placed on how far the control rods may be inserted into the core. These limits ensure that there is sufficient negative reactivity associated with the rods to shut down the core, with a sufficient margin, upon a reactor trip. Maintaining control bank positions above the rod insertion limits also helps to maintain nuclear peaking factors within limits and minimizes the reactivity effects of an ejected rod. Each rod insertion limit computer calculates an insertion limit in accordance with the input values of auctioneered high ΔT and T_{avg} (although the T_{avg} term is usually multiplied by a constant value of zero). Each calculated insertion limit is compared with the demanded position for one of the control banks; control room alarms warn of excessive rod insertion.

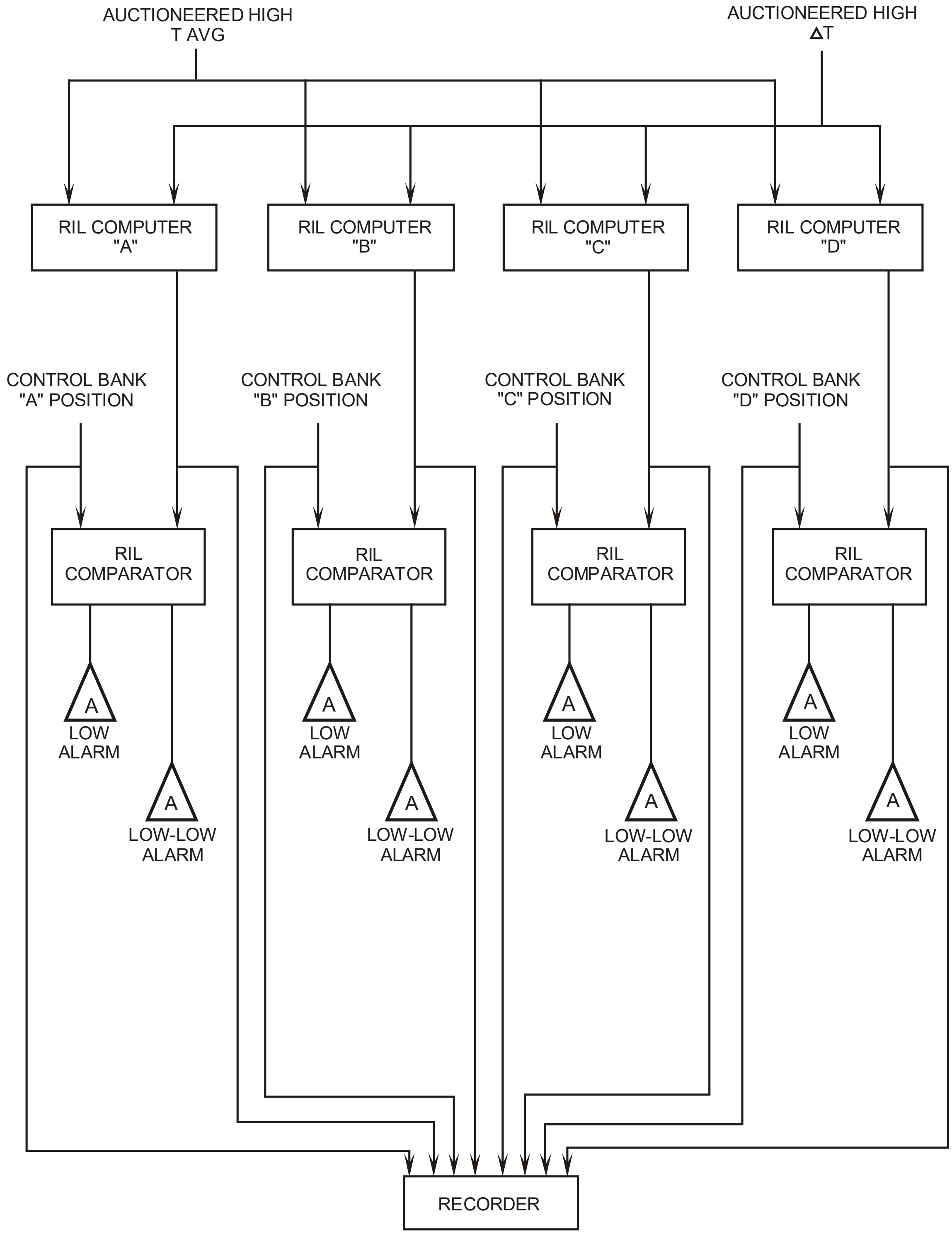

Figure 8.4-1 Rod Insertion Limit Circuit

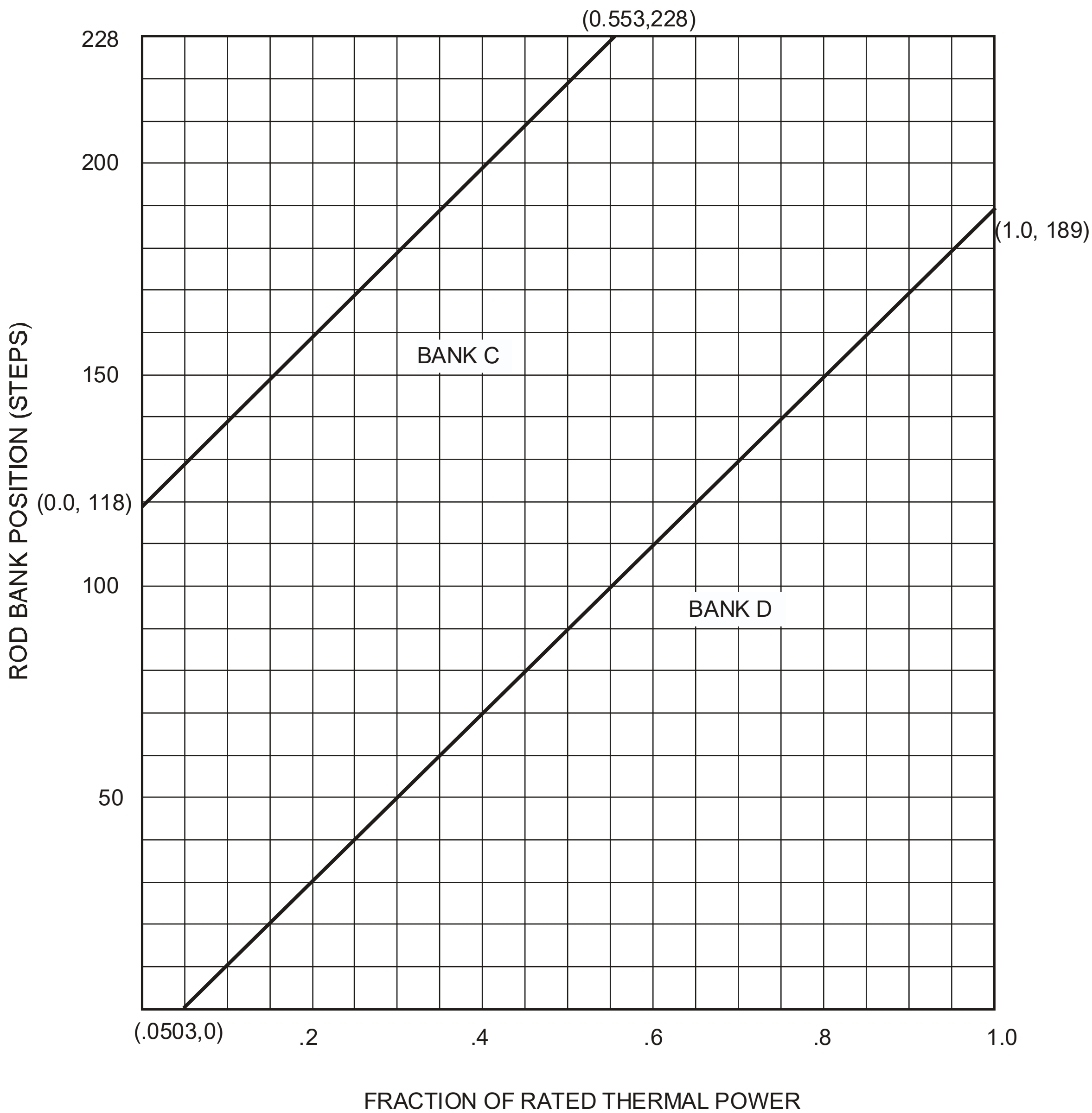

Figure 8.4-2 Rod Insertion Limits vs. Thermal Power

Westinghouse Technology Systems Manual

Chapter 9

NEUTRON MONITORING SYSTEMS (NIS)

Section

9.0 NEUTRON MONITORING SYSTEMS (NIS)

The neutron monitoring systems monitor the neutron flux level of the reactor core by detecting leakage neutrons from the core and by detecting neutron flux levels from within the core. These neutron monitoring functions are satisfied by two completely independent neutron monitoring systems. The excore nuclear instrumentation system (Section 9.1) monitors leakage neutrons, while the incore nuclear instrumentation system (Section 9.2) monitors the neutron flux level within the core.

The excore system monitors leakage neutrons as a measure of core power and provides control and protection inputs to the rod control system and the reactor protection system. The incore system is used periodically to monitor relative core power distribution via its movable detector system. Additionally, the incore instrumentation system utilizes thermocouples, located at the outlet of the fuel region, to provide a diverse indication of the relative power distribution for the operator.

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Section 9.1

Excore Nuclear Instrumentation

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9.1 EXCORE NUCLEAR INSTRUMENTATION

Learning Objectives:

1. List the purposes of the excore nuclear instrumentation system.

2. List the reactor protection system inputs provided by the excore nuclear instrumentation system and the purpose (basis) of each.

3. List the interlocks and permissives provided by the excore nuclear instrumentation system and the purpose (basis) of each.

4. Explain how the excore nuclear instrumentation system is capable of detecting both axial and radial (azimuthal) power distribution.

5. Explain how the power range signal is calibrated to indicate reactor thermal output.

6. Explain why gamma compensation is required only in the source and intermediate ranges.

7. Explain the effects of an improperly compensated intermediate range.

8. Explain why channel test signals are additive to the channel outputs.

9.1.1 Introduction

The purposes of the excore nuclear instrumentation system are to:

1. Provide indication of reactor power from shutdown to full power conditions,
2. Provide inputs to the reactor protection system during startup and power operation,
3. Provide reactor power information to the automatic rod control system, and
4. Provide axial and radial power distribution information during power operations.

The excore nuclear instrumentation system monitors the power level of the reactor by detecting neutron leakage from the reactor core. Leakage neutron flux from the core is monitored for two primary reasons. First, core neutron leakage is directly proportional to the core neutron flux (power level), and second, it is much easier to design and maintain neutron detectors which do not need to operate within the hostile environment of the reactor core.

Three overlapping ranges of excore instrumentation monitor the neutron flux level generated in the core from a few counts per second up to approximately 10^{15} neutrons/cm^2/sec (200 percent of full power). The three different ranges of indication are source, intermediate, and power. Monitoring and protective functions are provided by two independent source range channels, two independent intermediate range channels, and four independent power range channels. The power range instruments also provide an input into the automatic rod control system.

Auxiliary channels provide a source range audio count rate signal or “beeper,” for audible indication of changes to the neutron flux rate. In addition, the source and intermediate range startup rates are provided to the reactor operator. This information is used by the reactor operator to determine the approach to criticality and to monitor how rapidly reactor power is changing.

The instrument racks for this system are usually located in the control room area, where they may be visible to the operator. Information generated by this system is displayed on individual channel drawers installed in the excore instrumentation cabinets and on the reactor control section of the main control board. The excore nuclear instrumentation system is considered a safety related system and its components are powered from vital (Class 1E) power supplies.

9.1.2 System Description

9.1.2.1 Excore Nuclear Instrumentation System

Neutron detectors, utilizing solid-state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition up to 200% of full power. Since the neutron flux covers a wide range (12 decades), three ranges of instrumentation are used to obtain accurate flux level measurements (Figure 9.1-1). The lowest level (source range) covers six decades of neutron flux.

The lowest observed count rate (indicated by the source range) depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. The next higher range of nuclear instrumentation (intermediate range) spans eight decades. The design of this instrument is chosen to provide overlap between the upper output of the source range channels and the full span of the power range instruments. The highest range of indication (power range) spans approximately two decades. The power range provides a linear display of power and overlaps with the upper portion of the intermediate range channels.

The primary function of the excore nuclear instrumentation system is to protect the reactor core from overpower by monitoring the neutron flux and generating appropriate alarms and reactor trips to shutdown the reactor when required. Each range of instrumentation (source, intermediate, and power) provides overpower reactor trip protection during operation in that range. The overlap of instrument ranges provides reliable protection at all flux levels. During reactor startup, as the neutron flux level is increased and satisfactory instrumentation operation is obtained in a higher range, the overpower protection trip for the lower range may be manually removed by the operator in accordance with administrative procedures. However, automatic reinstatement of the lower range trip settings is provided when reducing power level.

The source, intermediate and power range detectors are placed in instrument wells located within the concrete shield surrounding the reactor vessel (Figure 9.1-2). The instrument well is movable and is positioned by a push-bar located outside the concrete shield wall. If an individual detector requires maintenance or replacement, the instrument well is pulled away from the reactor vessel to a location under an access pipe which is sealed by a water tight cap. After maintenance is complete, the instrument well is pushed back to a position adjacent to the reactor vessel. Failure to return the instrument well to its original position results in an incorrect indication of power due to the change in detector-core geometry.

9.1.2.2 Source Range (SR)

The source range instrumentation consists of two independent channels, designated as source range channels N-31 and N-32. Both channels are physically and functionally identical. As shown in Figure 9.1-3, the source range detectors are located 180 degrees apart outside the bottom half of the core. This location provides the maximum sensitivity to low power neutron level increases. The source range circuits monitor and indicate the neutron flux level of the reactor core and the rate by which the neutron flux changes during a reactor shutdown and the initial phase of start-up. The rate of change of the neutron population is indicated as Start Up Rate (SUR). The SUR is the number of decades (powers of ten) that the neutron flux (reactor power) is changing per minute and is indicated as decades per minute (DPM).

Indication of source range neutron population and its rate of change are provided at the nuclear instrumentation cabinets and at the reactor control panel. The source range indication has a span of 10^0 to 10^6 cps (counts per second) and the source range SUR has a range of - 0.5 DPM to + 5 DPM.

Each source range channel, Figure 9.1-4, utilizes a preamplifier assembly which amplifies the neutron pulses from the BF_3 proportional counter detector to a workable level (a discussion of the BF_3 proportional counter is provided in section 9.1.4). The circuitry of each channel shapes and integrates the pulses, provides amplification, discriminates against gammas and background noise, produces a logarithmic neutron level signal, and amplifies the log signal prior to its indication.

One of the principal problems in the source range is trying to distinguish the relatively small number of pulses produced by neutrons from the large number of pulses produced by gamma radiation during source range operation. Thus gamma discrimination is of particular interest during shutdown after the reactor core has operated long enough to establish an accumulation of fission products. This condition produces a high gamma field and a low neutron flux around the detector.

The meter face is calibrated to indicate counts/sec and represents the number of neutron pulses generated per second. This instrument can indicate up to a maximum neutron count rate of 10^6 cps. The count rate signal is also applied to bistable relay assemblies which in turn generate signals for remote protection equipment. The noise-discriminated pulse signal from either source range channel is also applied to an audio count rate drawer assembly and, together with a scaler-timer assembly, converts and amplifies the neutron pulses into an audible tone heard in the control room and in the containment.

Source range channel selection for audio monitoring is accomplished at the front panel of the audio count rate drawer. Integrated pulses are also applied to the comparator and rate drawer assembly where the rate of change of neutron flux is computed. The output rate signal is coupled to local and remote SUR meters.

9.1.2.3 Intermediate Range (IR)

The intermediate range instruments consist of two independent channels, designated as intermediate range channels N-35 and N-36. Both channels are physically and functionally identical. As shown on Figure 9.1-3, the intermediate range detectors are located 180 degrees apart outside the midpoint of the core. The detectors share the same instrument well as the source range detectors. The midpoint of the core location allows the detectors to monitor the neutron population changes from low power operations to full power. The intermediate range channels monitor the neutron flux of the core and provide signals to the rate circuits to compute its rate-of-change. The intermediate range channels, which cover a span of eight decades, come on scale when the source range channel indications reach approximately 10^3 counts/sec. The intermediate instruments monitor neutron flux from this level through full power operation.

As shown in Figure 9.1-4, each intermediate range circuit receives a signal proportional to neutron flux from a compensated ion chamber detector. Gamma compensation is accomplished by the electronic arrangement of the detector. The intermediate range channel, with the exception of the detector, is housed in the intermediate range drawer assembly.

A logarithmic current measuring circuit is used to monitor reactor power over a range of eight decades (10^{-11} to 10^{-3} amperes). Indications of intermediate range neutron flux level and SUR are provided at the nuclear instrumentation cabinets and at the reactor control panel. The neutron flux level signal is also applied to bistable relay assemblies, which in turn generate signals for a protection-grade permissive, an interlock, and a reactor trip on high neutron flux.

9.1.2.4 Power Range (PR)

The power range circuits consist of four independent channels, designated as power range channels N-41 through N-44. All four channels are physically and functionally identical. Each power range channel employs an upper and a lower uncompensated ion chamber detector which provide current signals to the power range circuits. As shown on Figure 9.1-3, the power range detectors are located 90 degrees apart. Each location consists of an upper detector and a lower detector, mounted inside the same instrument well. The outputs of both detectors (upper and lower) are combined to produce a channel total power signal. The eight detector outputs (four upper detectors and four lower detectors) are compared to each other to provide power distribution information to the reactor operator.

Within each power range channel, as shown in Figure 9.1-5, the upper detector and lower detector current signals are monitored, summed and amplified, at the summing and level amplifier, to develop a voltage which is directly proportional to reactor power. The summed signal is monitored in percent full power, ranging from zero to 120 percent. The output of each power range channel provides reactor trip signals, alarms and input for control functions. In addition, electronic signals are sent to a channel and a detector current comparator. The channel current comparator assembly uses the output of the four power range channels to verify that the detectors are properly calibrated with respect to each other. The detector current comparator (one comparator for the upper detectors and one for the lower detectors) monitors the four upper or four lower detector outputs to determine if power is being evenly produced throughout the core.

9.1.3 Component Descriptions

9.1.3.1 Source Range (SR) Channel

The nuclear instrumentation system is supplied with two independent source range channels as shown in Figure 9.1-4. Boron triflouride proportional counters (N-31 and N-32) provide pulse signals to the source range channels. These detectors are installed on opposite flat portions of the core, near the primary/secondary neutron sources, at an elevation approximating one quarter of the core height. The preamplified detector signal is received by the source range instrumentation conditioning equipment located in separate drawers in separate control room racks.

The detector signal, which is a count rate proportional to the neutron flux leakage, is conditioned for conversion to an analog signal proportional to the logarithm of the neutron flux count rate. The signal received from the counter has a range of 1 to 10^6 pulses per second and is received through a fixed-gain pulse preamplifier.

The preamplifier is located close to the detector to increase the signal-to-noise ratio and also furnishes high voltage coupling to the detector. The preamplifier assembly has internal provisions for generating self-test frequencies of 60 to 10^6 counts per second. These test oscillator circuits are energized by a switch located on the associated source range drawer. The source range channel power supplies furnish low voltage for preamplifier operation and for the drawer-mounted modules.

The preamplifier output is received at the pulse-amplifier/discriminator located in the source range drawer. This module provides amplification and discrimination, both of which are adjustable. Discrimination is provided between neutron flux pulses, and gamma-generated pulses. The discriminator circuit cuts off the low amplitude gamma-induced pulses. The discriminator provides two outputs; one output (isolated) to a scaler-timer unit in the audio-visual channel and the other to a pulse shaper (transistorized) circuit which supplies a constant amplitude pulse to the log integrator module in the source range drawer.

The pulses from the pulse amplifier are supplied to the pulse shaper which shapes it into a square wave. The output waveform has a constant amplitude at half the frequency of the input frequency. Two input pulses are required to produce an output pulse. The pulse driver receives the standard amplitude pulse from the pulse shaper and provides the drive through impedance matching stages to apply the pulses to a log pulse integrator.

The log pulse integrator assembly receives the square wave pulses from the pulse drive assembly and integrates these pulses to provide a current output proportional to the logarithm of the average pulse rate. The current is then applied to a current summing network and the level amplifier for amplification.

The level amplifier receives the log-level voltage output from the log pulse integrator. The assembly amplifies the voltage to produce an output which is displayed on a meter calibrated logarithmically from 10^0 to 10^6 cps. The output is also applied to bistables, and an isolation amplifier for remote indication.

Reactor trip signals provided by these bistables are transmitted to the protection logic cabinets where the necessary matrices involved in generating reactor trip signals are formed. All logic matrices associated with plant protection or control functions are located in the protection logic or auxiliary relay cabinets, respectively.

During shutdown periods, a high neutron flux in the core actuates a bistable which alerts plant personnel to abnormal reactivity increases. This alarm provides both local visual and audible annunciation (high flux at shutdown), and remote audible annunciation (containment evacuation).

These annunciators ensure that the plant operator is alerted to any unusual or unsafe condition. The bistable alarm function is manually blocked by deliberate operator action during a reactor startup. Blocking is continuously annunciated at the control board during source range operation. The high flux at shutdown alarm setpoint is normally set at approximately one decade above the steady-state shutdown flux level.

The high source range flux level reactor trip bistable provides an input into the reactor protection system. Its purpose is to initiate a reactor trip to mitigate startup reactivity excursions during power operations in the source range. When the intermediate range indication is on scale, P-6 (the source range block permissive) is energized and the source range reactor trip may be manually blocked by the operator. Once the channels are blocked, the high voltage is removed from the source range detectors. Removing the high voltage protects the detectors from damage due to the high currents produced by the increased neutron flux levels present at higher reactor power levels. The blocking action is physically accomplished by actuating two momentary-contact switches located on the main control board. While these trips are blocked, the SOURCE RANGE TRIP BLOCKED annunciator is continuously illuminated on the main control board.

If a one-decade overlap exists between the top of the source range and the bottom of the intermediate range, the source range block permissive P-6 is generated. The one decade overlap insures that the intermediate range is available and indicating before increasing reactor power above the source range. This permissive, P-6, is generated when at least one of the two intermediate range instruments exceeds the setpoint of 10^{-10}. At the moment the permissive is made up, the source range indication is approximately 3/5 decade below the source range HIGH FLUX LEVEL REACTOR TRIP setpoint (10^5 cps).

A bistable is used to indicate that the voltage to the detector has failed. A loss of high voltage on either source range channel provides control board annunciation. During a reactor startup when the source range high voltage is intentionally turned off (as mentioned above), the loss of high voltage annunciator is backlit until reactor power exceeds 10% (P-10 Nuclear power above 10%). When P-10 is made up the source range loss of high voltage annunciator is de-energized which prevents the annunciation of a condition which is not abnormal.

Testing of the source range channels is accomplished by switches on the individual source range instrument drawers. An operation selector switch on the source range instrument drawer selects the test signal to be inserted. All test signals are additive to the signal from the detector. Therefore, the resultant channel level will be conservative, equal to the imposed test signal plus the detector signal.

An electrical interlock between the Level Trip Bypass switch and the Operation Selector switch prevents inadvertent actuation of the reactor trip circuits (i.e., the channel cannot be put into the test mode unless the trip is bypassed). The trip bypass is annunciated on the source range drawer and on the main control board.

Each source range channel supplies signals to the following instrumentation.

- Remote count rate meter (NI-31B and NI-32B) - The remote meters are driven by isolation amplifiers. The meters are mounted on the main control board and calibrated logarithmically from 1 to 10^6 counts per second.
- Remote recorder (NR-45) - This two-pen recorder is capable of continuously recording any two nuclear instrumentation channels. Each pen receives a signal through a multi position switch which can select any one of the eight nuclear channels.

The source range channel instrument drawer is shown on Figure 9.1-6. The instrument drawer switches and indications are discussed individually below:

- Detector volt meter - monitors the high voltage power supply output to the BF_3 proportional counter.
- Neutron Level Meter - Indicates the neutron level output of the BF_3 proportional counter for the source range channel. The meter indication is in counts per second between 10^0 and 10^6, calibrated logarithmically.
- Instrument Power On Lamp - Indicates that 118 Volts ac instrument power is applied to drawer instrument power supplies.
- Control Power On Lamp - Indicates that 118 Volts ac control power is applied to drawer control signal circuits.
- Channel On Test Lamp - Indicates that the drawer OPERATION SELECTOR switch is in a test position.
- Loss of Detector Volts Lamp - Indicates that the high voltage supplied to the BF_3 proportional counter is removed, or is low due to a fault in the system. Setpoint is 70% of normal voltage.
- Level Trip Lamp - Lights when the neutron count rate exceeds 10^5 cps.
- Level Trip Bypass Lamp - Lights when LEVEL TRIP switch is placed in the BYPASS position to test and calibrate the source range channel circuits.
- High Flux at Shutdown Lamp - Indicates when the neutron level exceeds the preset level during reactor shutdown.

- Bistable Trip (Spare) Lamp - A spare indication lamp designed and manufactured into the cabinet for possible use in the future.
- AC Instrument and Control Power Fuses - Provide overcurrent protection for drawer circuitry.
- Level Trip Switch - A two position rotary switch which enables test and calibration of the source range channel in conjunction with the OPERATION SELECTOR switch. In the BYPASS position, the LEVEL TRIP BYPASS lamp illuminates, the OPERATION SELECTOR switch is enabled, and a signal is continuously provided to the reactor protection system to prevent a reactor trip during testing (see bistable detail on Figure 9.1-4).
- Operation Selector Switch - An eight-position switch enabled by the LEVEL TRIP switch permits the generation of test signals for test and calibration of the source range channel. In the 60 CPS, 10^3 CPS, 10^5 CPS or 10^6 CPS positions, a Test Calibrate Module inserts an appropriate signal to the input of the pulse amplifier. This allows verification of the operating accuracy of the circuits within the source range drawer. In the 60 CPS PREAMP and the 10^6 CPS PREAMP positions one of two test oscillator modules in the preamplifier is energized to generate a known signal for testing the preamplifier and the long run of triaxial cable between the preamplifier and the source range drawer.
- Level Adjust Potentiometer - Provides an adjustable test signal for insertion directly into the level amplifier. This enables the adjustment of the trip level of the various bistable circuits within the drawer assembly. The control is effective only when the OPERATION SELECTOR switch is in the LEVEL ADJ position.

9.1.3.2 Intermediate Range (IR) Channel

As shown in Figure 9.1-4, two independent, compensated ionization chambers provide extended neutron flux coverage from the upper portion of the source range to approximately 200 percent reactor power. Compensated ionization chambers (N-35 and N-36) serve as neutron sensors for the intermediate range channels and are located in the same instrument wells as the source range detectors (a discussion of the compensated ion chamber is given in section 9.1.4). Each intermediate range channel consists of one compensated ionization chamber which uses high density polyethylene as a moderator and as an insulator. The detectors are positioned at an elevation corresponding to half the core height. Each intermediate range channel is supplied with a positive high voltage and high negative compensating voltage to its respective detector. Compensating voltage is used to cancel out the gamma contribution to the total current signal. Therefore, the signal current delivered to the intermediate range channel circuitry is from neutrons only (Figures 9.1-15 and 9.1-16). Both high voltage supplies are adjustable through controls located inside the channel drawer.

The equipment for each channel, including the high voltage and compensating voltage power supplies, is mounted in separate drawers. The detector signal is received by the intermediate range logarithmic amplifier. This unit produces an analog voltage output signal which is proportional to the logarithm of the input current. This output signal is used for local indication and is sent to the inputs of the various bistables within the intermediate range drawer. Local indication is provided by a meter mounted on the front panel of the drawer. The meter face has a logarithmic scale with a span of 10^{-11} to 10^{-3} amperes. The isolation amplifier is similar to that used in the source range. Six separate bistables are used in the intermediate range drawer to perform the following functions:

- Loss of high voltage (alarm),
- Loss of compensating high voltage (alarm),
- Permissive P-6 (10^{-10} amps),
- Rod stop C-1 (blocks automatic and manual rod withdrawal at 20% power current equivalent),
- Reactor trip (25% power current equivalent), and
- Spare.

The intermediate range permissive, P-6, allows the blocking of the source range trip. Bistable outputs from each intermediate range channel are combined in a one-of-two matrix to provide the permissive function and control board status indication of the availability of the permissive. As explained earlier, this permissive (P-6) permits the manual blocking of the source range trip and removes the high voltage from the source range detector. One blocking switch is provided for each logic train. The source range trip is automatically reinstated, as required by IEEE 279 1971, if the power level as indicated by both intermediate range channels decreases below the P-6 setpoint.

The source range high voltage and trip functions may also be manually reactivated if required. This is accomplished by operation of two control board-mounted, momentary contact switches. This provision, however, is only operable below permissive P-10 (10% reactor power), which is generated by the power range channels. Above P-10, the capability to reinstate the source range is automatically blocked. A one-of-two logic from the intermediate range channels supplies a rod withdrawal rod stop and control board annunciation. Blocking of the rod withdrawal stop is manually performed when nuclear power is above permissive P-10.

The intermediate range reactor trip is provided to limit a reactivity excursion when operating in the intermediate range during a reactor startup. Redundant control board switches are used to block the rod stops and the reactor trip on high current equivalent power. These blocks are manually inserted when the power range instrumentation indicates proper operation through activation of the P-10 permissive. As with the source range instrumentation when power decreases, the intermediate range trip functions are automatically reinstated. High voltage failure monitors provide both local and remote annunciation upon failure of the respective high voltage supplies. A common INTERMEDIATE RANGE LOSS OF DETECTOR VOLTAGE and separate INTERMEDIATE RANGE LOSS OF COMPENSATING VOLTAGE control board annunciators are provided.

Testing of each intermediate range channel is provided by a test-calibrate module which injects a test signal at the input to the log amplifier. The signal is controlled by the OPERATION SELECTOR switch on the front of each intermediate range drawer.

As in source range testing, the OPERATION SELECTOR switch on the intermediate range must be operated in coincidence with a LEVEL TRIP BYPASS switch. An electrical interlock between these switches prevents the interjection of a test signal unless the LEVEL TRIP BYPASS is in operation. Removal of the trip bypass also removes the test signal. The test signals, like the source range test signals, are superimposed upon the detector output signal.

Each intermediate range channel supplies signals to the following instrumentation.

- Remote level meter (NI-35B and NI-36B) - The remote meters are driven by isolation amplifiers. The meters are mounted on the main control board and calibrated logarithmically from 10^{-11} to 10^{-3} amperes.
- Remoter recorder (NR-45) - This is the same 2-pen recorder described for the source range. A level signal from the isolation amplifier is supplied to the recorder.

The intermediate range channel instrument drawer is shown on Figure 9.1-7. The instrument drawer's switches and indications are discussed individually below:

- Neutron Level Meter - Indicates the current level output of the compensated ion chamber. Meter indication is in amperes ranging over eight decades between 10^{-11} and 10^{-3}.
- Instrument Power On Lamp - Indicates that 118 Volts ac instrument power is applied to drawer instrument power supplies.
- Control Power On Lamp - Indicates that 118 Volts ac control power is applied to drawer control signal circuits.
- Channel On Test Lamp - Indicates that a test signal has been applied to the drawer through the operation of the OPERATION SELECTOR switch.
- Level Trip Bypass Lamp - Lights when LEVEL TRIP switch is placed in the BYPASS position to perform test and calibration functions.
- High Level Trip Lamp - Lights when the neutron flux level signal in the intermediate range channel reaches a current equivalent to 25% power.
- High Level Rod Stop Lamp - Lights when the neutron flux level in the intermediate range channel reaches a current equivalent to 20% power.
- Power Above Permissive P-6 Lamp - Lights when the current level reaches 10^{-10} amps increasing.
- Bistable Trip (Spare) Lamp - A spare indication lamp designed and manufactured into the cabinet for possible use in the future.
- Loss of Detector Voltage Lamp - Indicates a loss of or reduced high voltage supplied to the compensated ion chamber.
- Loss of Compensating Voltage Lamp - Indicates a loss of, or a reduced voltage, supplied to the compensating circuit of the compensated ion chambers.
- AC instrument and control power fuses - Provide overcurrent protection for drawer circuitry.
- Level Trip Switch - Enables test and calibration of the intermediate range channel in conjunction with OPERATION SELECTOR switch and TEST MODE switch. In the BYPASS position the LEVEL TRIP BYPASS indicator lights, the test/calibrate module is energized, and a signal is provided to the reactor protection system to prevent a reactor trip during testing (see bistable

detail on Figure 9.1-4). In the bypass position, the IR Rod Stop C-1 is also defeated.

- Operation Selector Switch - A ten-position switch which applies test signals from the test calibrate module to the intermediate range channel circuits.
- Test Mode Switch - A two-position switch (FIXED/VARIABLE). In the FIXED position, it allows the test/calibrate module to provide a fixed current level selected by the OPERATION SELECTOR switch. In the VARIABLE position, a potentiometer is switched into the test calibrate module circuitry to provide current variations about the selected level.
- Variable Potentiometer - Varies current output from the test/calibrate module above or below the current level selected by the OPERATION SELECTOR switch. Control is activated only when the TEST MODE switch is in the VARIABLE position.

9.1.3.3 Power Range (PR) Channel

As shown in Figures 9.1-3 and 9.1-5, four, dual section, uncompensated ionization chambers (N-41A and N-41B through N-44A and N-44B) are used for power range neutron flux leakage detection. Each channel provides two current signals corresponding to the neutron flux in the upper (A) and lower (B) sections of a core quadrant. Each detector has a total neutron-sensitive length of ten feet. A description of an uncompensated ionization chamber is provided in Section 9.1.4.

The four power range channels are energized from separate vital ac instrument power supplies and are housed in separate racks so that a single failure will not cause a loss of protective functions. Each power range channel drawer B converts the vital ac instrument power into a regulated low (± 25 volts dc) and a high (+300 to +1500 volts dc) voltage source. The high voltage power supply has a current limiting feature so that for extreme current demands by the detector (such as an overpower condition), the power supply is maintained at a constant current output. This feature maintains an output from the detector (prevents the detector from becoming saturated and its indication failing off-scale low) and assures an output for proper reactor protection actions.

The individual current signals, one from each of the two sections of the detector, are proportional to upper and lower core neutron flux levels. These signals are received at the channel input and pass through separate ammeter shunt assemblies. The meter range switch selects shunt resistors for the meter, but never interrupts the ion chamber signal to the power range channel. The circuit is designed so that a failure of the meter or its associated switch will not interrupt the signal to the power range circuitry. Individual detector currents are displayed on two drawer-mounted meters. Isolation amplifiers in the detector current circuit supply signals to the overpower and overtemperature ΔT protection circuitry in the reactor protection system.

The isolation amplifiers also provide an output for the remote recorders (NR-41, NR-42, NR-43, or NR-44), the remote meters (NI-41C, NI-42C, NI-43C, or NI-44C), the computer, and the axial and radial flux deviation circuitry. The individual detector current signals (top and bottom) are sent to a summing and level amplifier which produces a linear signal proportional to the neutron flux in the core quadrant associated with that channel.

The output signal from the summing and level amplifier (calibrated to a thermal power value as calculated by a secondary heat balance) corresponds to 0 to 120 percent of full power and is displayed on a power meter on the power range drawer. This same signal is delivered directly to the remainder of the power range circuitry for control, protection, and indication.

The rate circuit associated with each power range channel calculates the rate of change of nuclear power and a reactor trip signal is generated on either a high positive or a high negative rate. A high positive rate is indicative of an ejected rod, while a high negative rate indicates one or more dropped full length rods. The rate unit compares actual power with a delayed power signal received through a lag network and amplifies the difference between the two signals. This amplified difference signal is simultaneously delivered to two bistables set to trip when the difference signal exceeds a preset amount. Both of these bistables if actuated, seal in ensuring that the necessary protective action is initiated and carried to completion even though the rate-of-change signal is only momentary.

A switch on the power range drawer (RESET-NORMAL) must be manually operated to remove the seal in function and reset the bistable. This action also removes the trip signal from the RPS trip logic matrix. The rate trips cannot be blocked and are always active. The setpoints are chosen so that normal design transients do not actuate either of the rate trips.

Other bistables which receive the power level signal from the summing and level amplifier are non-seal in and perform the following functions:

- Overpower rod stop C-2 (blocks automatic and manual rod withdrawal),
- Permissive function P-8 (single loop loss of flow permissive),
- Permissive function P-9 (turbine trip - reactor trip permissive),
- Permissive function P-10 (nuclear at power permissive),
- Power range trip, low setpoint (25%), and
- Power range, high setpoint (109%).

The overpower rod stop (C-2) is a nonprotective function that actuates at 103% nuclear power to stop control rod withdrawal. This action may prevent the high range reactor trip from occurring at 109% nuclear power. Logic for the rod stop is one-out-of-four channels (1/4). Individual channel rod stops may be manually defeated to allow testing or continued operation with a failed channel.

The nuclear at power permissive (P-10) employs a 2/4 logic at 10% nuclear power. When this permissive is actuated, the operator is permitted to manually block both the Power Range Low Setpoint Trip (25% power), the Intermediate Range Hi Flux Trip (also at 25%), and the Intermediate Range Rod Stop (20%). The P-10 permissive prevents manual reinitiation of the high voltage power supply to the source range detectors. At high flux levels the source range detectors would be damaged if energized.

The turbine trip - reactor trip permissive (P-9) allows the unit to withstand a turbine trip below 50% power without a direct reactor trip. P-9 requires a 2/4 logic from the power range channels.

The single loop loss of flow permissive (P-8) is provided to allow loss of flow in one reactor coolant system loop (single reactor coolant pump trip) without a direct reactor trip when power is below 39%.

The power range high flux, low setpoint trip (25% increasing) provides startup reactivity excursion protection and can be manually blocked when power is above the nuclear at power permissive P-10.

The power range high flux, high setpoint trip (109%) limits reactor power due to reactivity addition events and limits the maximum power level to a value consistent with that assumed in the accident analysis section of the plant's FSAR. The trip cannot be blocked and remains active at all times to prevent an overpower condition. An additional bistable monitors the high voltage power supply to the detectors. If voltage drops to a preset level, a LOSS OF DETECTOR HIGH VOLTAGE alarm is actuated at the control panel.

A test-calibrate module provides a means of superimposing a test signal onto the detector output. The variable test signal can be directed either to detector A, to detector B, or to both detectors simultaneously. Since the test signal is additive, a channel in test cannot indicate less than actual detector output. This feature prevents a technician from inadvertently lowering the output of a detector, thereby changing the trip logic from a two-out-of-four to a two-out-of-three coincidence. The test signal is used to raise the output of the summing and level amplifier to check the setpoints of all the bistables associated with each channel and to calibrate the isolation amplifiers in the individual detector current circuitry.

Operation of the rate trip bistables is verified by changing the test signal rapidly (i.e. increasing or decreasing the potentiometers position). During such tests, only one channel at a time is checked. Bypassing the channel in test is not necessary (and physically cannot be done) since a 2/4 trip logic is used in the reactor protection system and the channel in test still responds to reactor power changes.

Each power range channel provides signals to the following:

- Remote recorder (NR-45) - Each power range supplies a 0 to 120 percent of full power signal to the selector switches for the two-pen nuclear recorder NR-45. Any two nuclear instrument channels can be monitored continuously during power range operation. Also, any two of the four power range channels can be selected for recording axial flux difference (AFD) on NR-45.
- Remote meters (NI-41B through NI-44B) - These meters (located on the main control board) continuously display the power level signal from each channel on a linear scale calibrated from 0 - 120% of full power.
- Overpower recorder (NR-46 and NR-47) - A pair of two-pen recorders are used to monitor the individual nuclear power indications from the four power ranges. Each recorder provides continuous monitoring of two power range channels and has a full scale deflection time of 0.25 seconds. The recorders are capable of displaying overpower excursions up to 200 percent of full power.
- Ion chamber output recorders (NR-41 through NR-44) - Four two-pen recorders are provided on the control board to record the calibrated upper

and lower detector ouputs. Comparison of the traces provides quadrant power distribution indication.

- Remote delta flux meters (NI-41C through NI-44C) - Four control board mounted meters display the flux difference between the upper and lower ion chambers for each of the power range detectors. The indication is calibrated to conform with the axial offset as determined by incore flux measurements. The scale of this meter is ± 30 percent.

The power range channel instrument drawers are shown in Figures 9.1-8 and 9.1-9. The instrument drawer switches and indications are discussed individually below:

Power Range Drawer A

- Percent full power meter - output of the summing and level amplifier. Meter indication is 0 - 120 percent.
- Control Power Fuses - Protect control power line against current overloads.
- Control Power On Lamp - Indicates 118 Volts ac control power is applied to drawer assembly control circuits.
- Loss of Detector Voltage Lamp - Indicates a loss of or reduced high voltage supplied to the uncompensated ion chamber.
- Overpower Trip High Range Lamp - Indicates that reactor power has reached the high flux, high setpoint of 109% of full power.
- Overpower Rod Stop Lamp - Indicates that reactor power has reached the overpower rod stop setpoint of 103% (control-grade interlock C-2).
- Reactor Trip Low Range Lamp - Indicates that reactor power has reached the high flux, low setpoint of 25%.
- Power Above Permissive P-10 Lamp - Indicates that reactor power has reached 10% allowing operator action to block the intermediate range trip and rod stop, and the power range high flux, low setpoint (25%) trip.
- Power Above Permissive P-8 Lamp - Indicates that reactor power has reached 39% which enables the single loop loss-of-flow trip.
- Positive Rate Trip Lamp - Indicates, that a rapid increase in power has been sensed indicating an ejected control rod. Setpoint is + 5% change in 2 seconds.
- Negative Rate Trip Lamp - Indicates that a rapid decrease in power has been sensed indicating one or more dropped control rods. Setpoint is - 5% change in 2 seconds.
- Rate Mode Switch - A switch that resets the positive and negative rate trip bistables.

Power Range Drawer B

- Detector Current Meter (A) - Indicates the current level output of the upper uncompensated ion chamber section (detector A) of the power range channel. Meter indication is current level ranging between 0 to 5 milliamperes.

- Detector Current Meter (B) - Indicates the current level output of the lower uncompensated section (detector B) of the power range channel. Meter indication is current level ranging between 0 to 5 milliamperes.
- Detector A and B Range Milliamperes Switches - Four-position range switches which select the correct shunt resistor for the detector current meters. The meters display the detector A and B current including test current level. Selectable ranges are 0.1, 0.5, 1 and 5 milliamperes full scale.
- Detector A Test Signal Potentiometer - Varies the test current level to the power range channel circuit through the detector current meter for the detector A source. Current is inserted only when the DETECTOR A or DETECTOR A & B position is selected by the OPERATION SELECTOR switch.
- Detector B Test Signal Potentiometer - Varies the test current level to the power range channel circuit through the DETECTOR CURRENT meter for the detector B source. Current is inserted only when the DETECTOR B or DETECTOR A & B position is selected by the OPERATION SELECTOR switch.
- Operation Selector Switch - A four-position switch which enables the test circuitry of the power range channel. In the DET A or DET B position, the DETECTOR A or B TEST SIGNAL potentiometer output is connected in parallel with the associated detector. In the DET A & B position, both potentiometers are connected simultaneously.
- Gain Potentiometer - Adjusts gain of summing and level amplifier to calibrate the power range channel to the power output as determined by secondary plant heat balance (calorimetric) measurements.
- Instrument Power Fuses - Protect instrument power line against current overloads.
- Instrument Power On Lamp - Indicates 118 Volts ac instrument power is applied to drawer assembly power supplies.
- Channel on Test Lamp - Indicates a test signal position has been selected through the operation of the OPERATION SELECTOR switch.

9.1.3.4 Count Rate (CR)

The audio count rate circuit (shown on Figure 9.1-4) provides an audible signal, in the control room and in containment, which is proportional to the neutron flux level in the core when the reactor power is in the source range. The purpose of the system is to alert plant personnel to reactivity changes which might affect shutdown margin and radiation levels inside containment.

The audio count rate channel assembly (Figure 9.1-10) receives pulses from either source range channel. The pulses are transmitted through a selector switch to the scaler-timer chassis. The scaler-timer (Figure 9.1-11) provides binary coded decimal (BCD) signal output in accordance with the counting rate of the input signal.

The resultant digital data is decoded and used to trigger an oscillator, subsequently producing an audible tone burst at a repetition rate proportional to the source range count rate. Switch selection of appropriate BCD output, divides the input count rate by factors of ten, one hundred, one thousand, or ten thousand to maintain a discrete audible signal. A speaker mounted on the drawer assembly and one mounted near the reactor (in containment) provides audible monitoring of reactor power level during shutdown conditions. Therefore, if the count rate increases, the rate at which the audible tone burst occurs also increases. The local and remote speakers receive their signals from separate audio amplifiers. A selector switch on the rear panel of the drawer assembly provides the means of powering the remote speaker from either amplifier in the event of an amplifier failure.

Audio Count Rate Circuit

- Sources of Signals - The signals come from either source range channels N-31 or N-32.
- Scaler-Timer - The scaler-timer receives signal pulses from the discriminator output of the selected source range channel. The pulses are counted through decimal counters and then read out to the audio count rate channel drawer assembly in the form of BCD logic. The scaler-timer can also be used as a means of accurate counting to obtain plateau values for the source range detectors at low count rates. The scaler-timer also provides accurate measurement of the source range counts for calculating the inverse count rate ratios.
- Audio-Multiplier - A range switch which controls the division of the pulses received from the selected source range channel to obtain a suitable listening rate.
- Speakers - The local speaker at the nuclear instrumentation system rack and a remote speaker near the reactor (in containment) produce audible pulses for monitoring the neutron flux count rate.

Audio Count Rate Drawer - Figure 9.1-10

- Audio Power On Lamp - Indicates 118 Volt ac power is applied to the drawer assembly.
- Scaler Power On Lamp - Indicates 118 Volt ac power is applied to the scaler-timer assembly.
- AC Audio Channel Power Fuses - Protect input circuit transformer against primary power current overloads, and isolates audio channel faults from the scaler-timer circuitry.
- AC Timer Scaler Power Fuses - Protect scaler-timer against primary power current overloads.
- Channel Selector Switch - Selects source range channel N31 or source range channel N32 input signals for the input to the scaler-timer for audio monitoring.
- Volume Potentiometer - Controls the audio level output from the local loudspeaker.
- Audio Multiplier Switch - Selects the division of the audible count rate to produce a discernible rate. Division is accomplished in 4 steps; by 10, 100, 1000, and 10,000.
- Amplifier Selector Switch - Selects an amplifier circuit in the drawer assembly to drive the local and remote loud speakers. In the NORMAL position, amplifier A1 is used for the local speaker and amplifier A2 is used for the

remote speaker. In the A1 position, amplifier A1 is used only to drive the remote speaker; in the A2 position, amplifier A2 is used only to drive the remote speaker. In the A1 only and A2 only positions, the local speaker is inactive.

9.1.3.5 Rate Calculating Circuit

The startup rate circuits in the comparator and rate drawer assembly receive signals from each source range channel and each intermediate range channel. The rate unit computes the rate of change of neutron flux (startup rate) for each input channel. The rate circuit assemblies within the comparator and rate drawer derive an output proportional to the rate at which the power level signal is changing; an independent rate output is computed for each channel. Each rate output signal can be selected for display on a common panel meter and is supplied to its dedicated main control board meter.

Rate Calculating Circuit - Figure 9.1-4

- Source of Signals - The signals for computing startup rate (SUR) come from four sources; NC-31 or NC-32 (source range channels) or NC-35 or NC-36 (intermediate range channels).
- SUR Amplifier - The startup rate amplifiers receive signals from the source range and intermediate range drawers. The startup rate amplifier produces a signal directly proportional to the rate-of-change of the input.
- Indication - There is one local meter for SUR information plus 4 SUR meters on the main control board. The SUR meters read between - 0.5 dpm and 5.0 dpm.

Comparator and Rate Drawer - Figure 9.1-12

- Startup Rate Meter - Indicates the rate-of-change of neutron level from a selected source or intermediate range channel. Meter indication is in decades per minute (DPM) over a range of -0.5 to 5.
- Instrument Power On Lamp - Indicates 118 Volts ac control power is applied to drawer assembly instrumentation.
- Control Power On Lamp - Indicates 118 Volts ac control power is applied to drawer assembly control signal circuits.
- Rate Channel Test Lamp - Lights when RATE TEST switch is placed in the 1 DPM or 5 DPM position to perform test and calibration functions.
- Channel Selector Switch - Selects either source range channel or either intermediate range channel.
- Rate Test Switch - Enables generation of rate test signals for calibration of the source range and intermediate range channel rate amplifiers.

9.1.3.6 Power Range Channel Current Comparator

The comparator circuit compares the power indications from the four power range channels and generates a signal proportional to the percent of full power deviation between channels. The purpose of this alarm is to alert the operator to a possible miscalibration between power range instruments. A bistable is tripped at a deviation level of 2 percent to provide an alarm function.

Channel Current Comparator Circuit - Figure 9.1-5

- Sources of Signals - Four power range level signals are generated by isolation amplifiers in power range channels NC-41 through NC-44.
- Comparator - These power range channel input signals are compared to monitor radial power distribution. If a deviation in indicated output power does occur between any two channels, the comparator develops an output proportional to the amount of deviation, which is then applied to a bistable.
- Bistable - If the deviation between the highest indicating and the lowest indicating power range channel is greater than 2 percent, the bistable is tripped. The comparator also can indicate a power range channel drift or failure. Using the COMPARATOR CHANNEL DEFEAT switch, any single channel output can be eliminated from comparison during a test or the failure of a channel.

Comparator and Rate Drawer - Figure 9.1-12

- Channel Deviation Lamp - Lights when the average power level of any two of the four power range channels deviate from each other by 2 percent.
- Comparator Defeat Lamp - Lights when the CHANNEL DEFEAT Switch is placed in one of the four power range positions in order to remove a power range channel from the comparator circuits.
- Comparator Channel Defeat Switch - Removes a power range channel which is faulty or in test so that the three remaining channels may be compared.
- AC Instrument Power Fuses - Protect instrument power line against current overloads.
- AC Control Power Fuses - Protect control power line against current overloads.

9.1.3.7 Power Range Detector Current Comparator

The power range detector current comparator monitors core radial power distribution by comparing the relative power of the 4 quadrants of the upper half of the core and by comparing the relative power of the 4 quadrants of the lower half of the core. The output of each upper detector is compared with the average of the upper detectors. If a ratio of 1.02 is calculated, a DETECTOR FLUX DEVIATION alarm is generated. This ratio is the technical specification limit for quadrant power tilt ratio. An identical calculation is performed for the lower detectors. This circuit provides an alarm function only. The technical specification limits are satisfied by performing a quadrant power tilt ratio calculation manually or through the use of the plant computer.

Detector Current Comparator Circuit - Figure 9.1-5

- Calibrated signals from each upper detector and each lower detector of the four power range channels are sent to their respective averaging amplifiers via isolation amplifiers.
- Averaging Amplifier - The averaging circuits combine the inputs to generate an average of the upper detectors and an average of the lower detectors.
- Comparator - The comparator circuit performs two functions:

  - Compares each of the four calibrated detector inputs with the average, and
  - Energizes an annunciator if any input is greater than the average by a ratio of 1.02. This alarm function is automatically defeated when all channels are below 50% of their full power output. This is indicated by a lamp on the drawer and by actuation of the “detector flux deviation” alarm on the main control board.

Detector Current Comparator (Upper Portion of Drawer) - Figure 9.1-13

- All (upper) Channels Below 50% of Full Power Lamp.
- Channel Defeat Lamp - Lights when UPPER SECTION defeat switch is placed in any position except the normal. This lamp indicates that one channel is not being compared with the others.
- Upper Section Deviation Lamp - Indicates that a radial power deviation has occurred in the upper half of the core.
- Instrument Power On Lamp - Indicates 118 volts AC power is applied to drawer instrumentation.
- Spare Lamp.
- All (lower) Channels Below 50% of Full Power Lamp.
- Channel Defeat Lamp - Lights when LOWER SECTION defeat switch is placed in any position except normal. This lamp indicates that one channel is not being compared with the others.
- Lower Section Deviation Lamp - Indicates that a radial power deviation has occurred in the lower half of the core.
- Upper Section Defeat Switch - A five position switch which removes a channel which is faulted or being tested from the upper detector comparator.
- Lower Section Defeat Switch - A five-position switch which removes a channel which is faulted or being tested from the lower detector comparator.
- AC Instrument Power Fuses - Protects drawer assembly power supply circuits.

9.1.3.8 Miscellaneous Control and Indication Drawer

As shown in Figure 9.1-13 the miscellaneous control and indication drawer contains switches to bypass channels from control circuitry during testing or failed channel conditions.

- Rod Stop Bypass - Automatic rod withdrawal is inhibited following an overpower rod stop condition. Positioning either ROD STOP BYPASS switch to the indicated channel bypass position removes the rod stop function for that channel.

- Power Mismatch Bypass - The four power range channel levels are normally transmitted to a high auctioneer circuit in the automatic reactor control programmer for comparison with turbine power for the rod drive system. Bypass switches allow up to two power range channels to be removed from the auctioneering circuit during testing or failed channel operation.

9.1.4 Neutron Detector Operation

Neutrons are uncharged particles and as such cannot cause ionizations directly. Neutrons must interact with matter by means of a nuclear reaction which in turn generates charged particles. The charged particles cause ionization within a gas-filled detector and the ion pairs produce a voltage pulse or some mean level current when collected at the electrodes of the detector. The nuclear reaction which produces these charged particles in the excore detector is as follows:

$$ {}_{0}^{1}n + {}_{5}^{10}B \rightarrow {}_{5}^{11}B \rightarrow {}_{3}^{7}Li + \alpha + energy $$

The charged particles resulting from this reaction are:

$$ \alpha^{++} \quad \text{and} \quad {}_{3}^{7}Li^{+++} $$

These charged particles produce ionizations as they pass through the gas-filled detectors.

9.1.4.1 Source Range (SR) Detector

The source range detector, Figure 9.1-14, is a BF_3 gas-filled detector. In this detector, the incident neutron generates the charged particles (Li and α) which are highly ionizing. Due to the voltage at which the detector is operated, additional ionizations called secondary ionizations are caused by the initial ionization. This produces a large pulse for each neutron event. Gamma radiation also produces ionization of the gas in the detector, but at a lower amplitude. Gamma-induced pulses are, therefore, of a lower amplitude than neutron-induced pulses.

9.1.4.2 Intermediate Range (IR) Detector

The intermediate range detector (Figure 9.1-15) is a gas-filled, compensated ion chamber. This detector is actually two detectors in one case. One of the chambers is coated with boron enriched with B-10 and is, therefore, sensitive to neutrons and gammas. The second chamber is uncoated and is, sensitive only to gamma radiation. By connecting the two chambers so that their output currents are electrically opposed, the net electrical output from the detector will be an algebraic sum of the two ionization currents, which is equal to the neutron current only. Mathematically, it could be written as:

$$ i_n + i_g = \textit{neutron-induced current} + \textit{gamma-induced current} $$

i_g = *gamma-induced current*

$i_{total} = (i_n + i_g) - i_g$

$i_{total} = i_n$

Normally, compensated ion chambers are designed to operate slightly undercompensated (Figure 9.1-16).

9.1.4.3 Power Range (PR) Detector

The power range detector, Figure 9.1-17, is an uncompensated ion chamber. The detector consists of a single cylindrical chamber whose operation is identical to that of the boron-lined chamber of the compensated ion chamber. This chamber is sensitive to both gamma and neutrons; however, in the power range of operation the neutron flux level is many times greater than the gamma flux. Also, while operating in the power range, gamma flux is proportional to the reactor power. Therefore, no gamma compensation is required in the power range. The power range instruments are calibrated on the bases of a secondary heat balance to display percent of full thermal power.

The movable incore neutron flux detectors (incore detectors), in conjunction with the plant computer, INCORE Code, present a true representation of the actual neutron flux distribution within the reactor core. Meanwhile, the excore nuclear instruments (excore detectors) rely upon leakage neutrons to determine the flux distribution within the core. Due to the distance and shielding between the reactor core and the excore detectors, these detectors cannot provide a “true” representation of the flux distribution within the core. Since the excore detectors provide reactor protection signals and also provide the reactor operator with continuously monitored indication of power and flux distributions within the core, it is necessary to calibrate the excore detectors.

9.1.5 System Interrelationships

9.1.5.1 Calibration of Excore Detectors

Each excore power range channel consists of two six-foot detectors (one upper detector and one lower detector). The upper detector, in theory, should monitor and provide an output that is representative of the power in the upper six feet of the core while the lower detector should provide an indication of the power in the lower half of the core. However, in reality this is not the case; neutrons leaking from the core do not necessarily leak from the core at 90 degree angles. Some of the leakage neutrons generated in the lower half of the core will be detected by the upper detector and conversely the lower detector will indicate neutrons that were produced in the upper half of the core. Since the core must be protected from departure from nucleate boiling (DNB) and excessive power generation in both the upper and lower halves of the core, it is essential that the inputs to the protective circuitry reflect the actual conditions in the core.

Providing the correct information to the reactor protection system is accomplished by calibrating the excore detectors to the conditions that exist within the core. This calibration procedure is called the incore-excore calibration. The core conditions and a synopsis of this calibration procedure can be found in Section 9.2 (Incore Nuclear Instrumentation), section 9.2.4.3.

9.1.6 Summary

The excore nuclear instrumentation system monitors reactor power from shutdown levels in the source range, through the intermediate range and to greater than 100 percent of full power in the power range. This is accomplished by means of thermal neutron flux detectors located in instrument wells in the primary shield adjacent to the reactor vessel. The system provides indication, control and alarm signals for reactor protection and operation. The location of the detectors at discrete axial and radial locations allows detection of core axial and radial power distribution. Power range channels are calibrated to indicate percent rated thermal power by a secondary heat balance (calorimetric). Excore power distribution circuitry is calibrated using information obtained from the movable incore instrumentation.

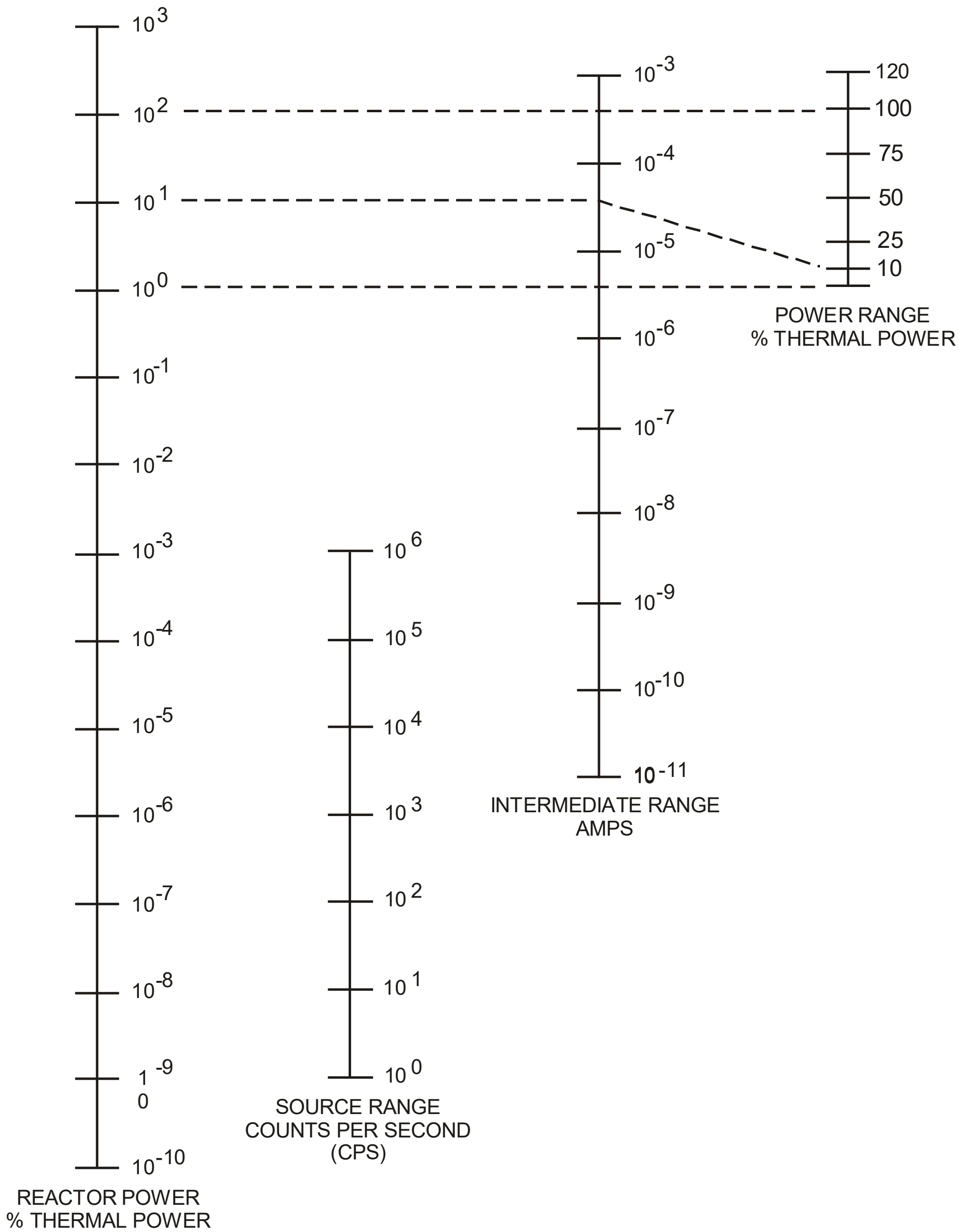


Figure 9.1-1 Neutron Detectors Range of Operation

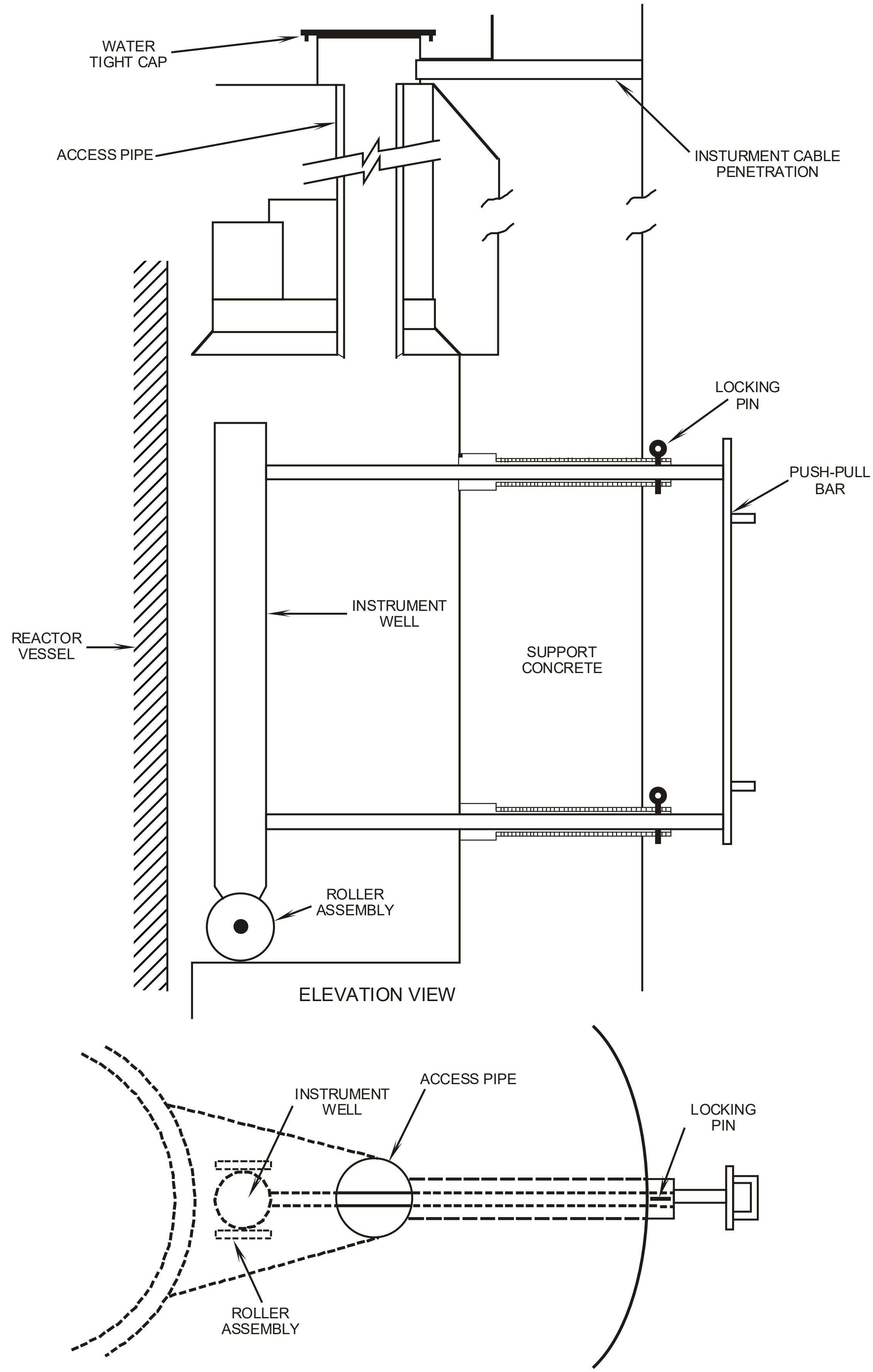
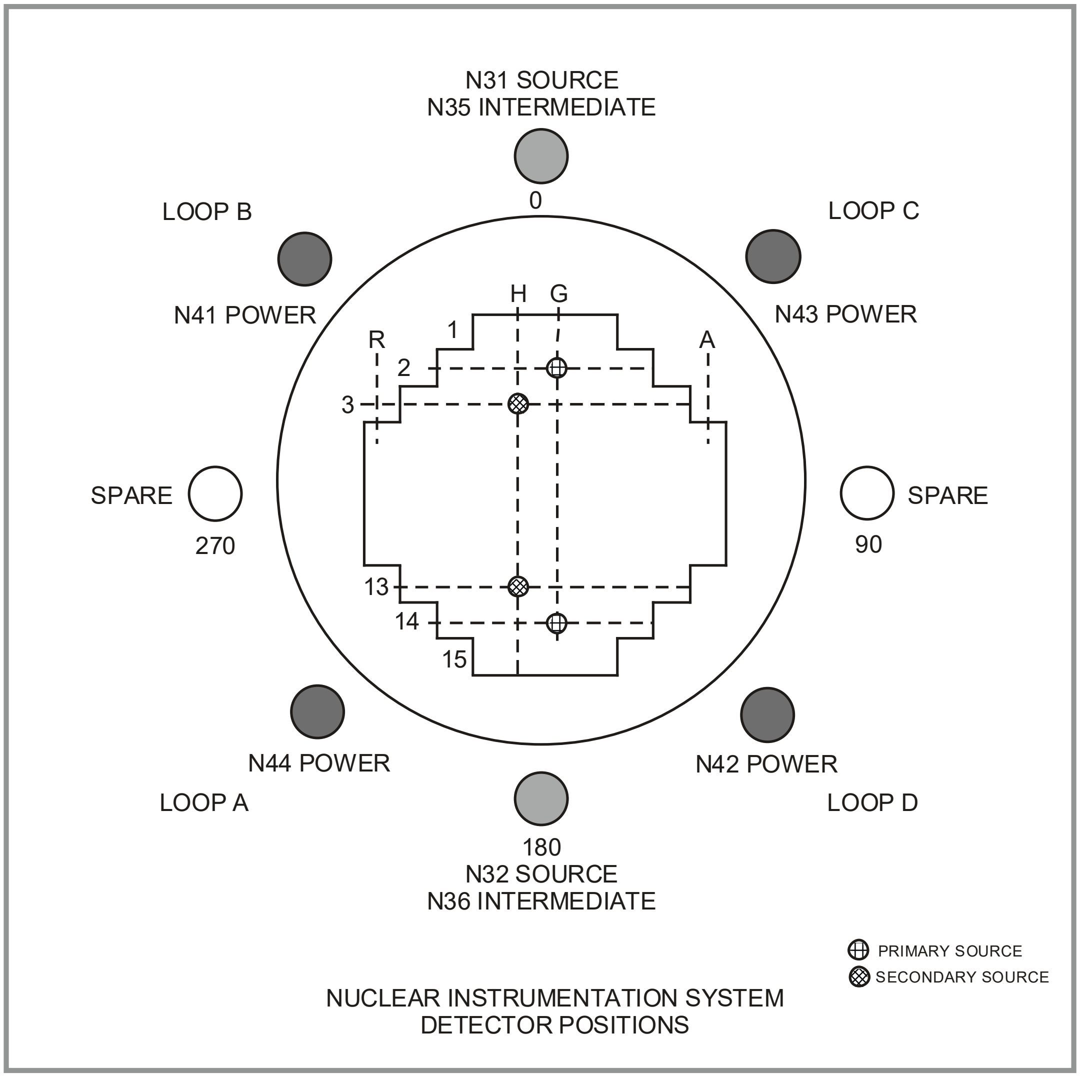


Figure 9.1-2 Detector Instrumentation Wells



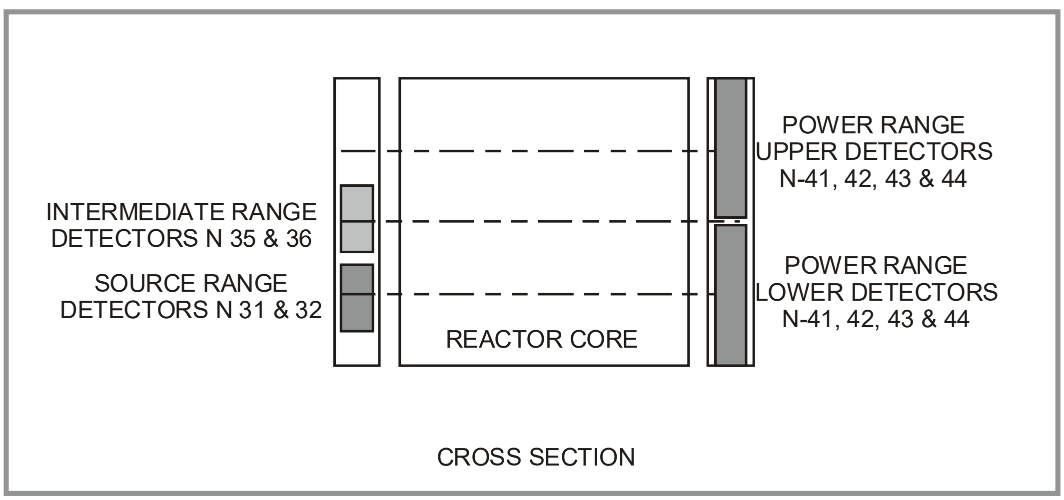


Figure 9.1-3 Nuclear Instrument Detector Locations

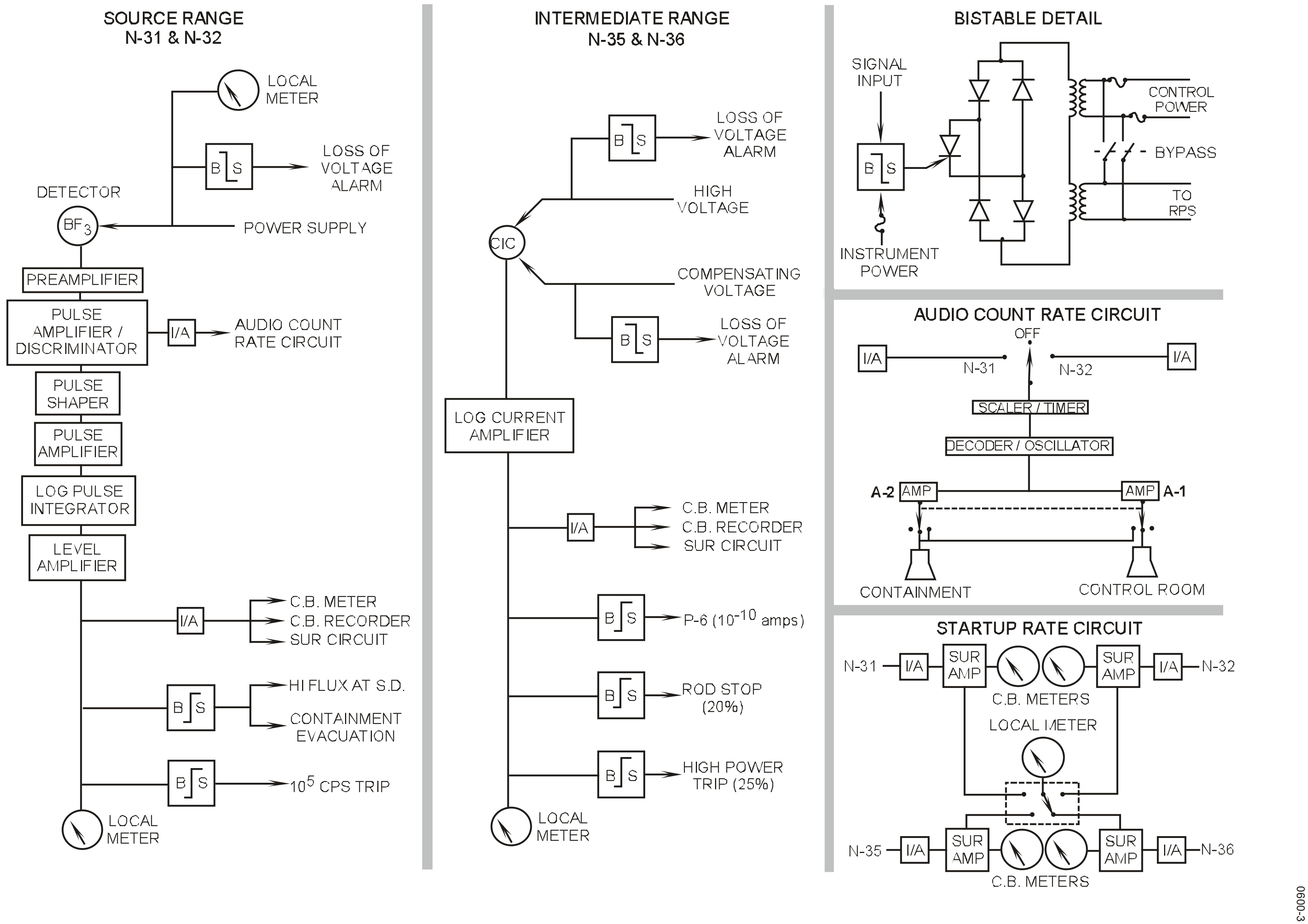


Figure 9.1-4 Source and Intermediate Range Block Diagrams

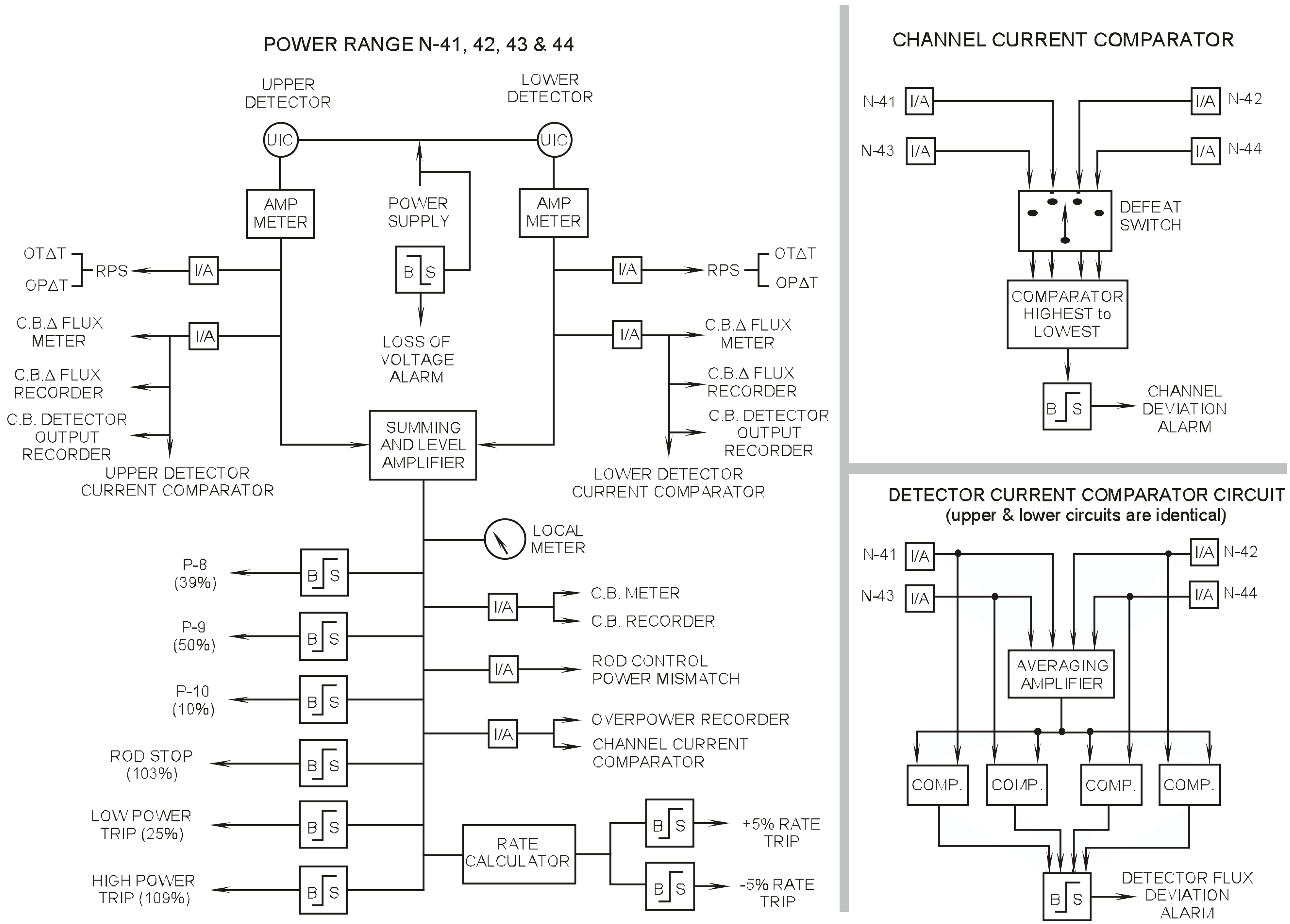


Figure 9.1-5 Power Range Channel Block Diagram

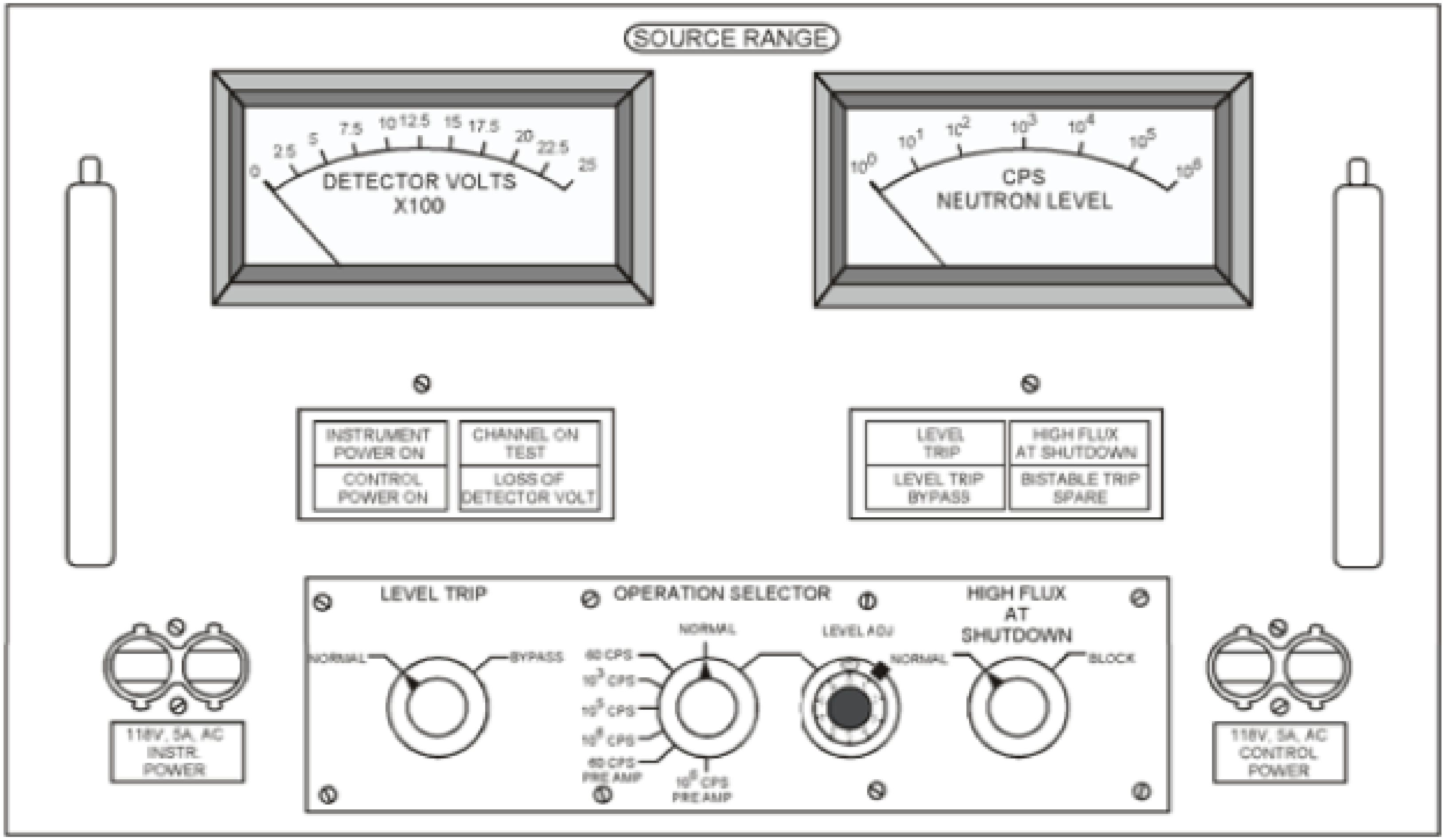


Figure 9.1-6 Source Range Drawer

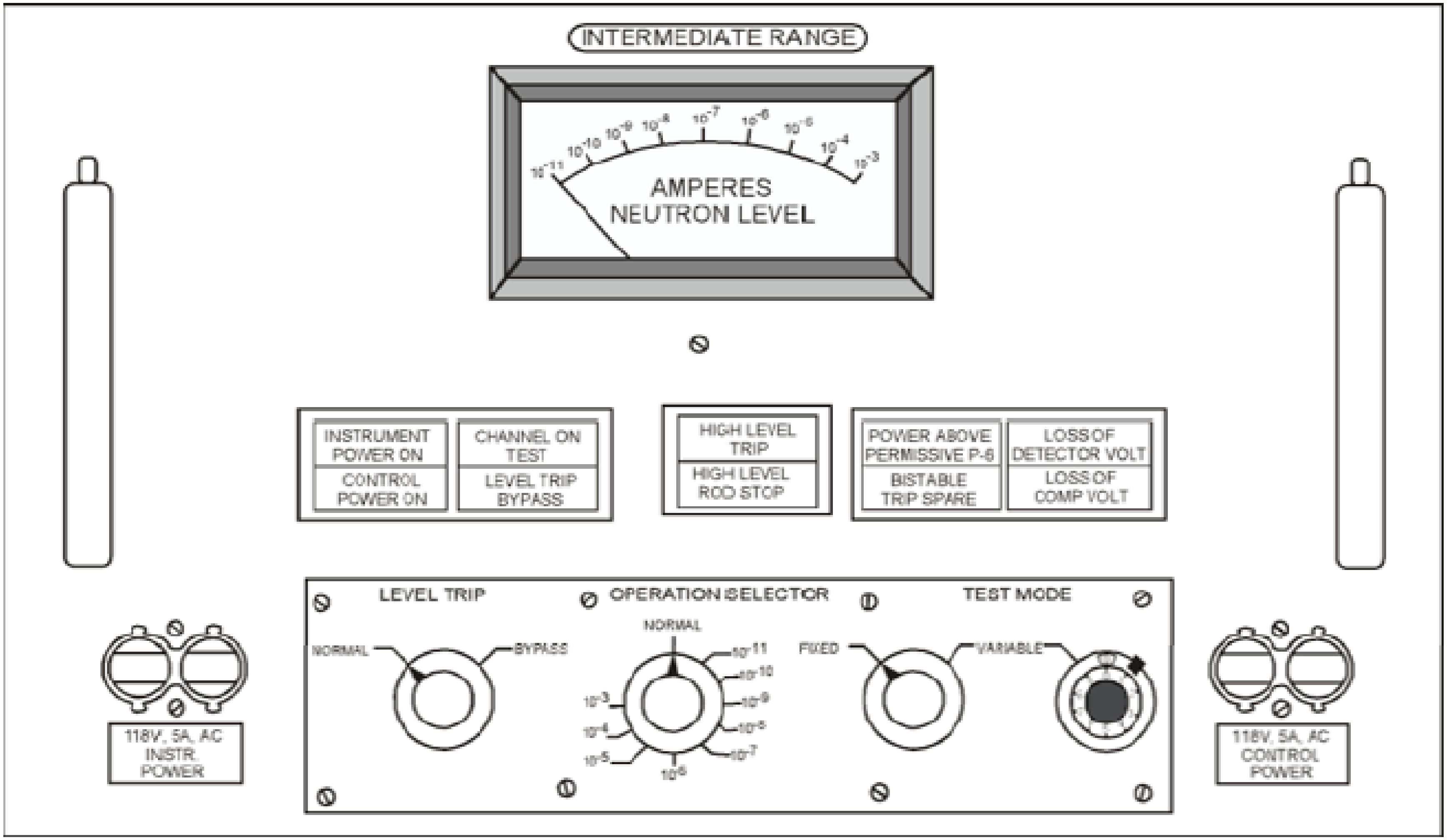


Figure 9.1-7 Intermediate Range Drawer

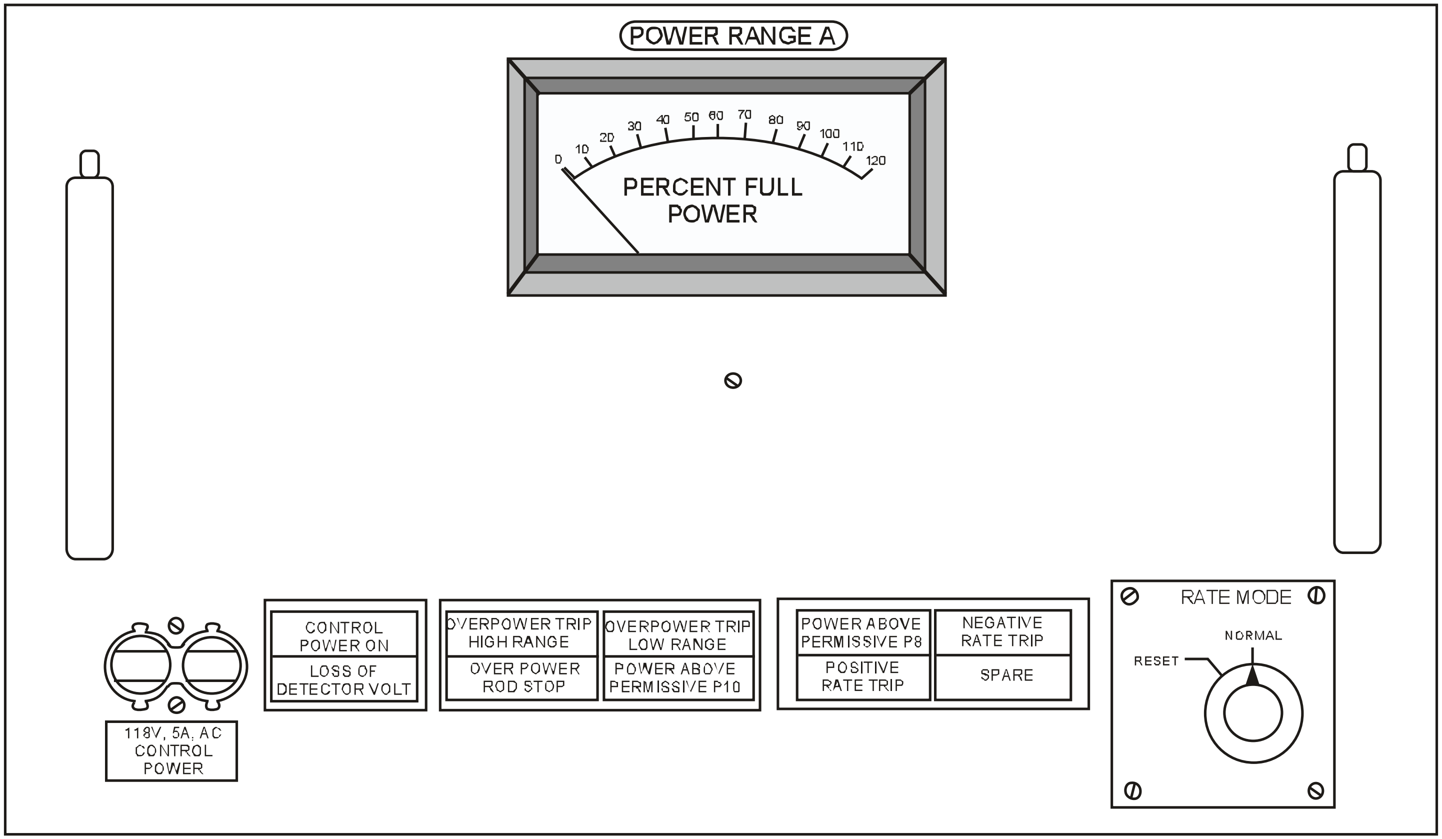


Figure 9.1-8 Power Range Drawer "A"

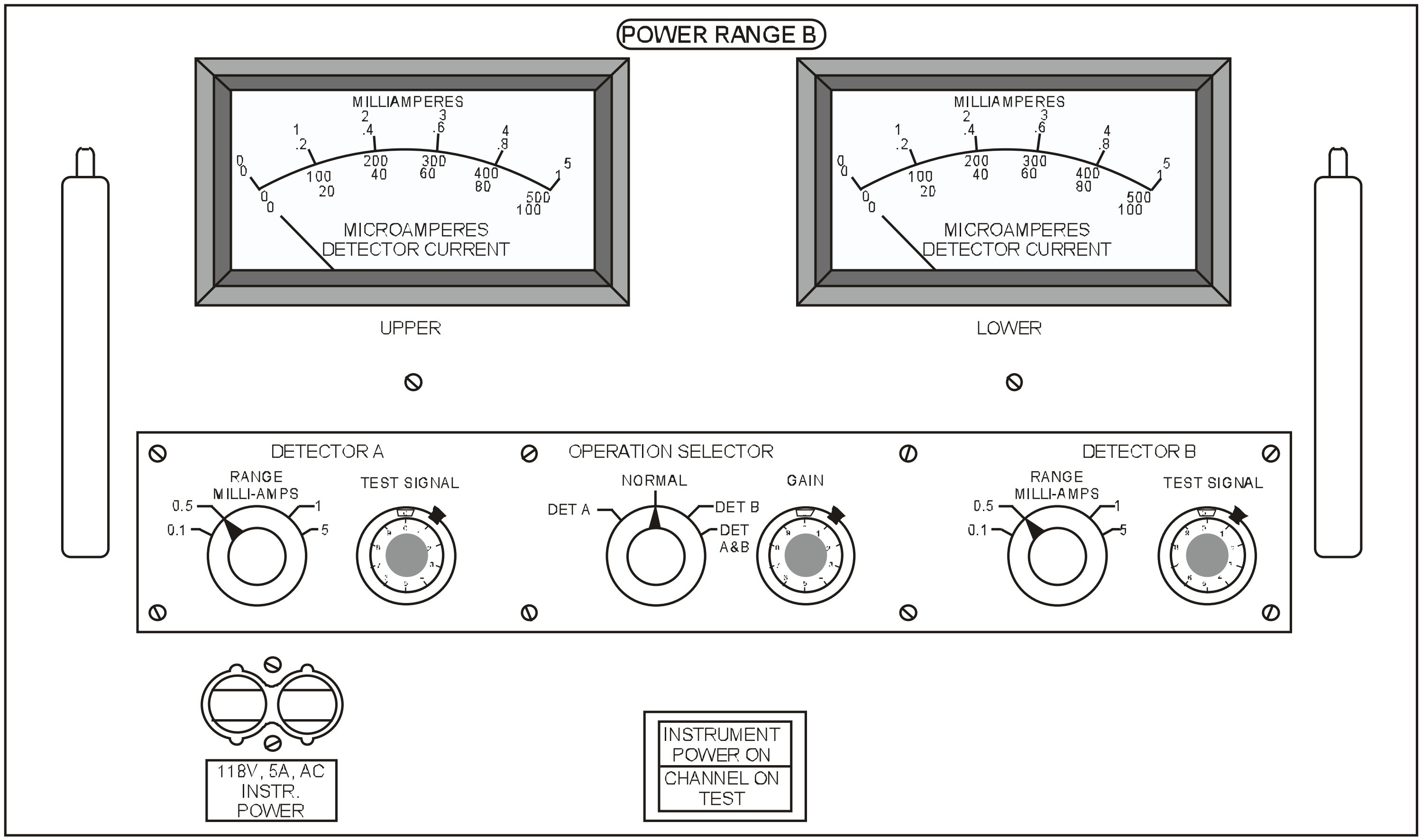


Figure 9.1-9 Power Range Drawer "B"

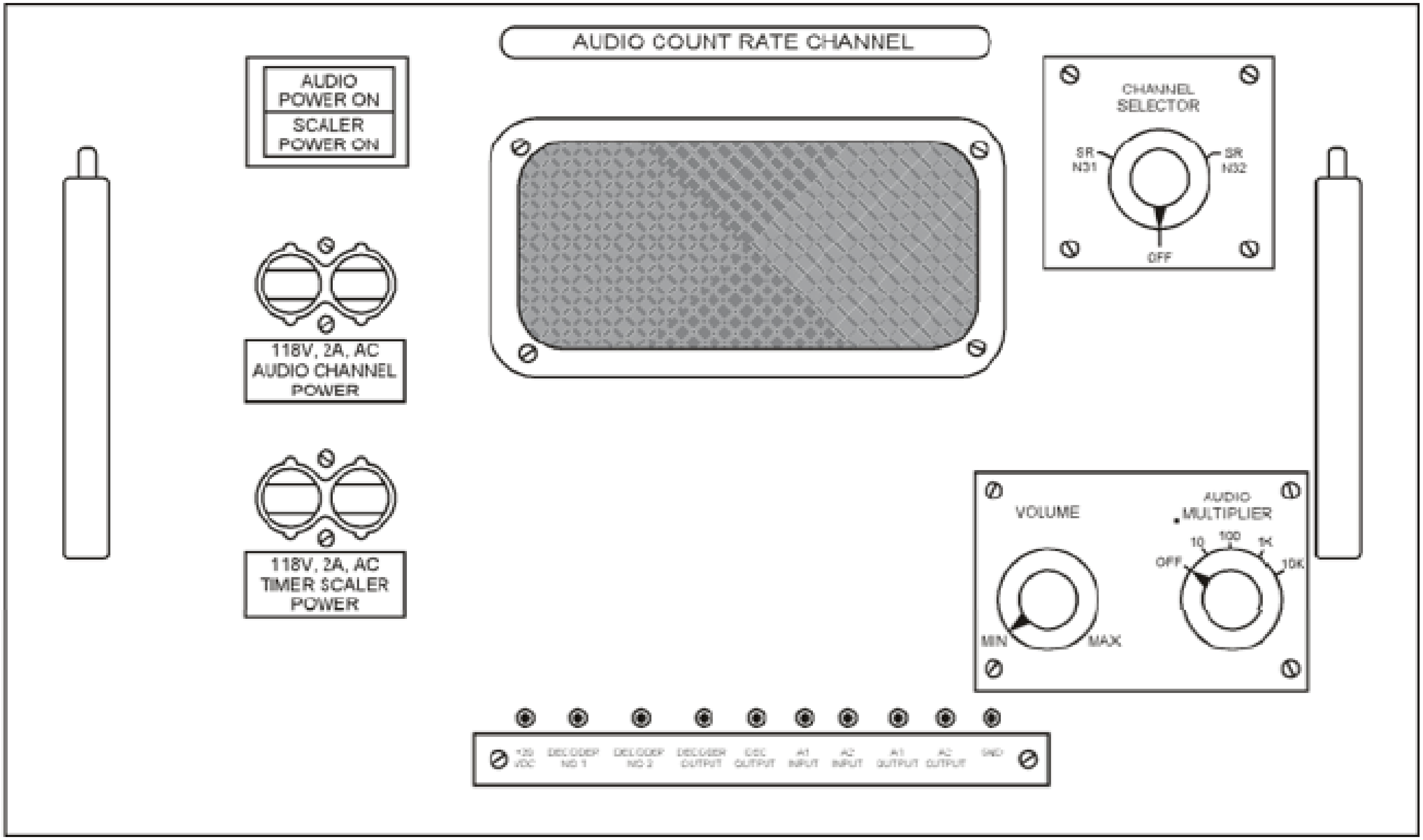


Figure 9.1-10 Audio Count Rate Channel

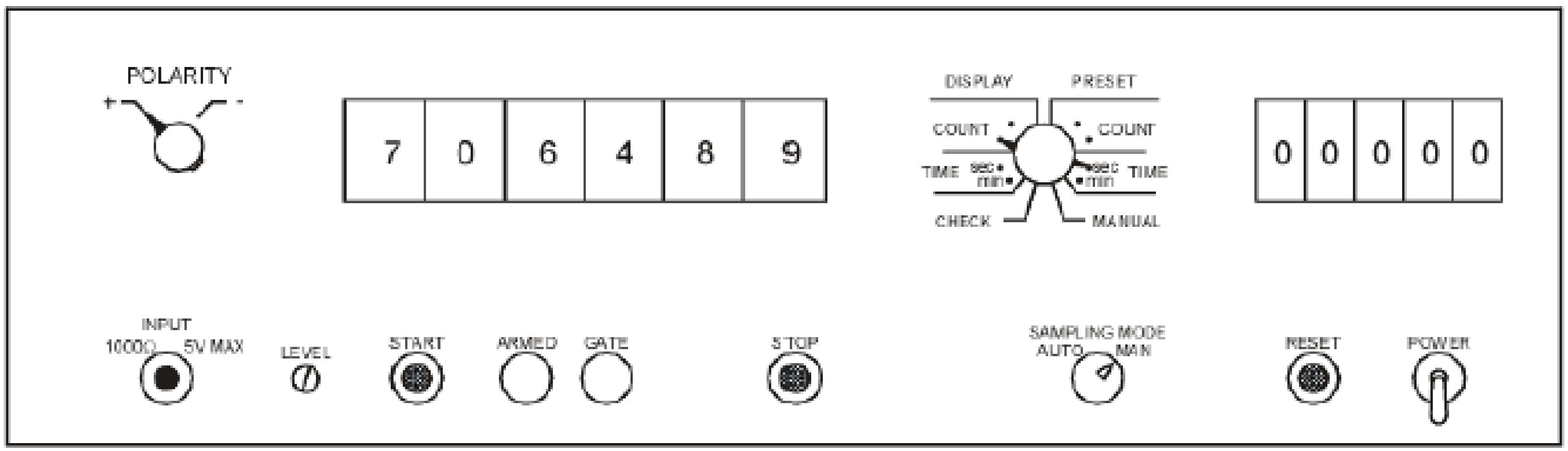


Figure 9.1-11 Scaler Timer Drawer

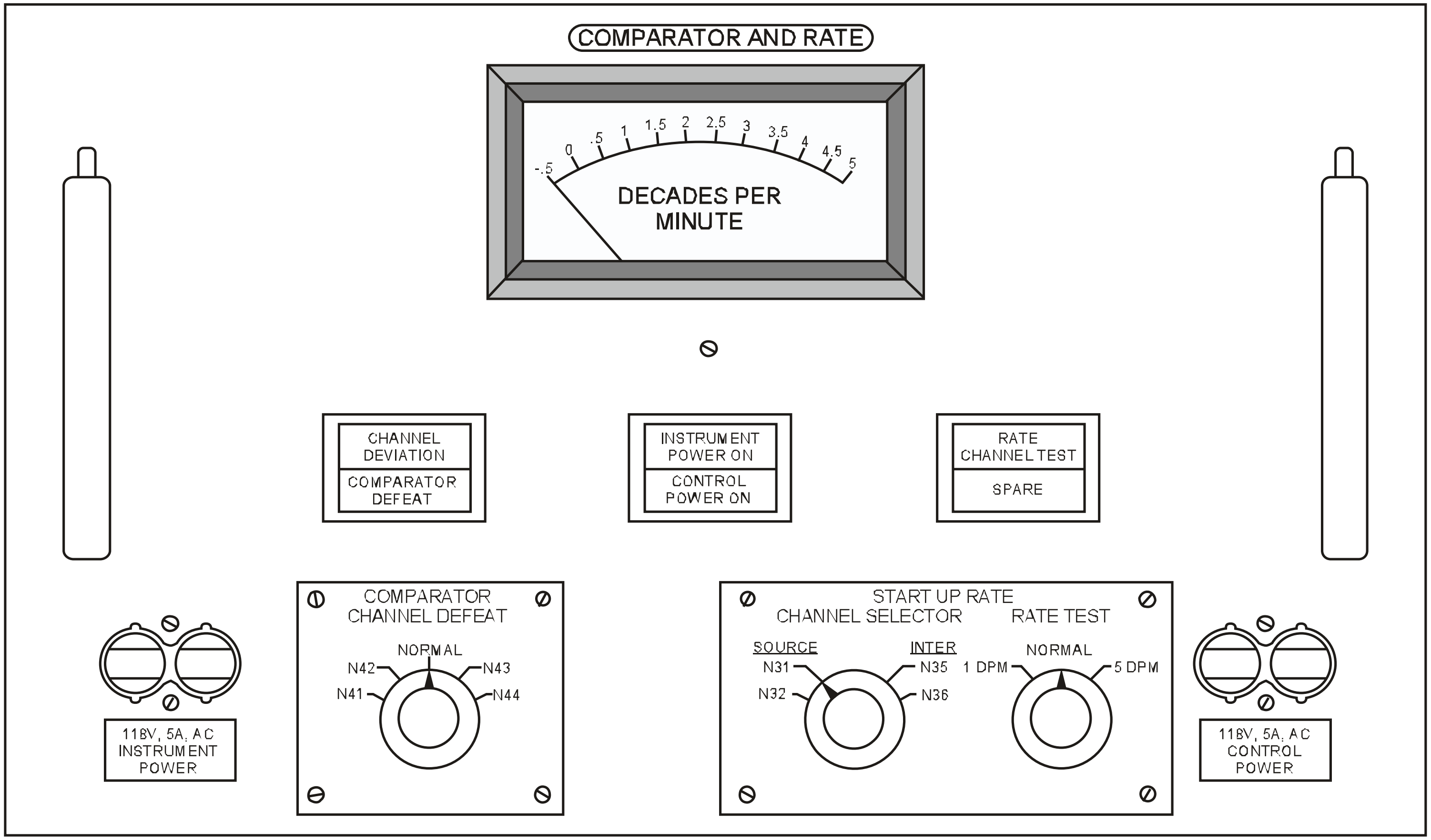


Figure 9.1-12 Comparator and Rate Drawer

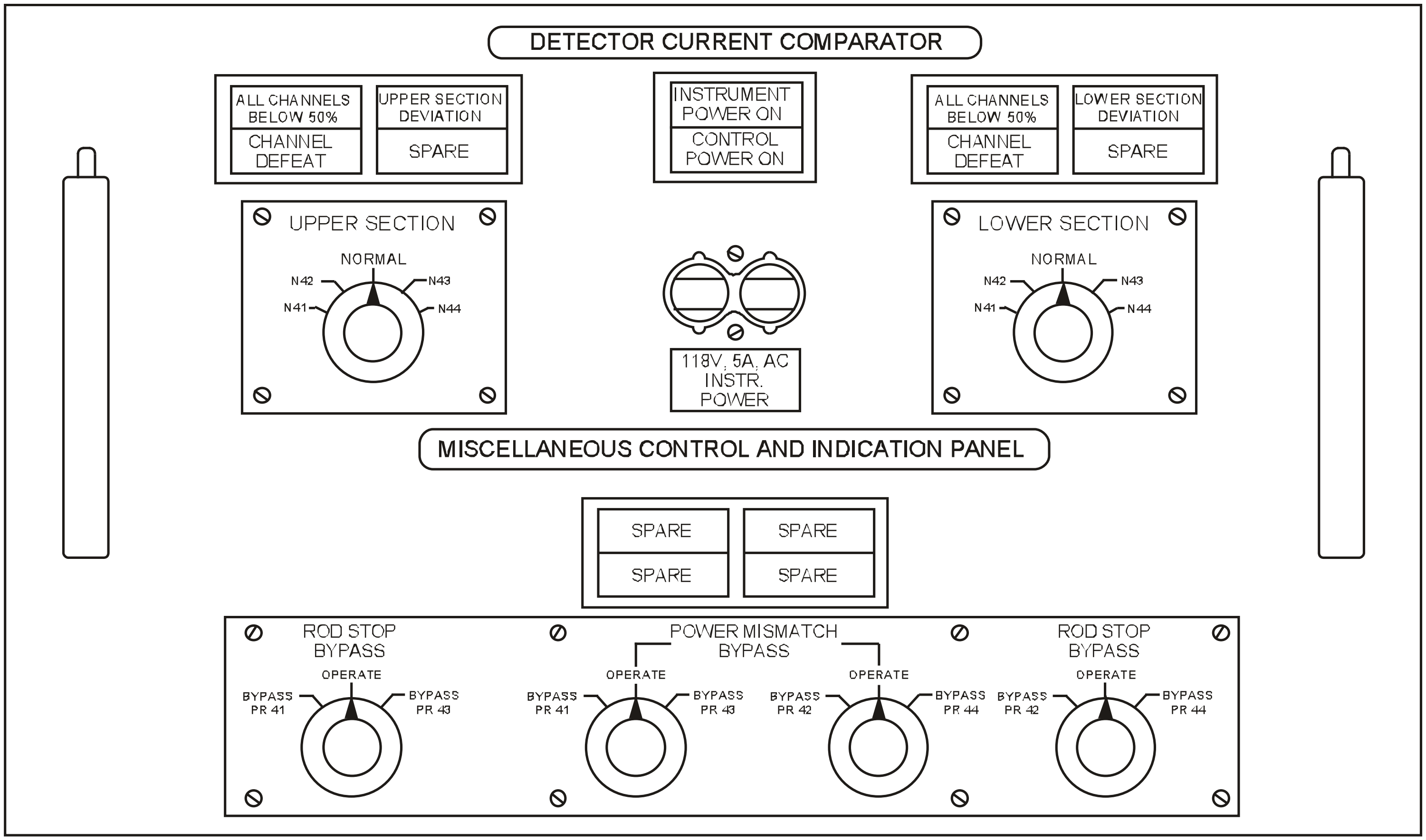


Figure 9.1-13 Detector Current Comparator

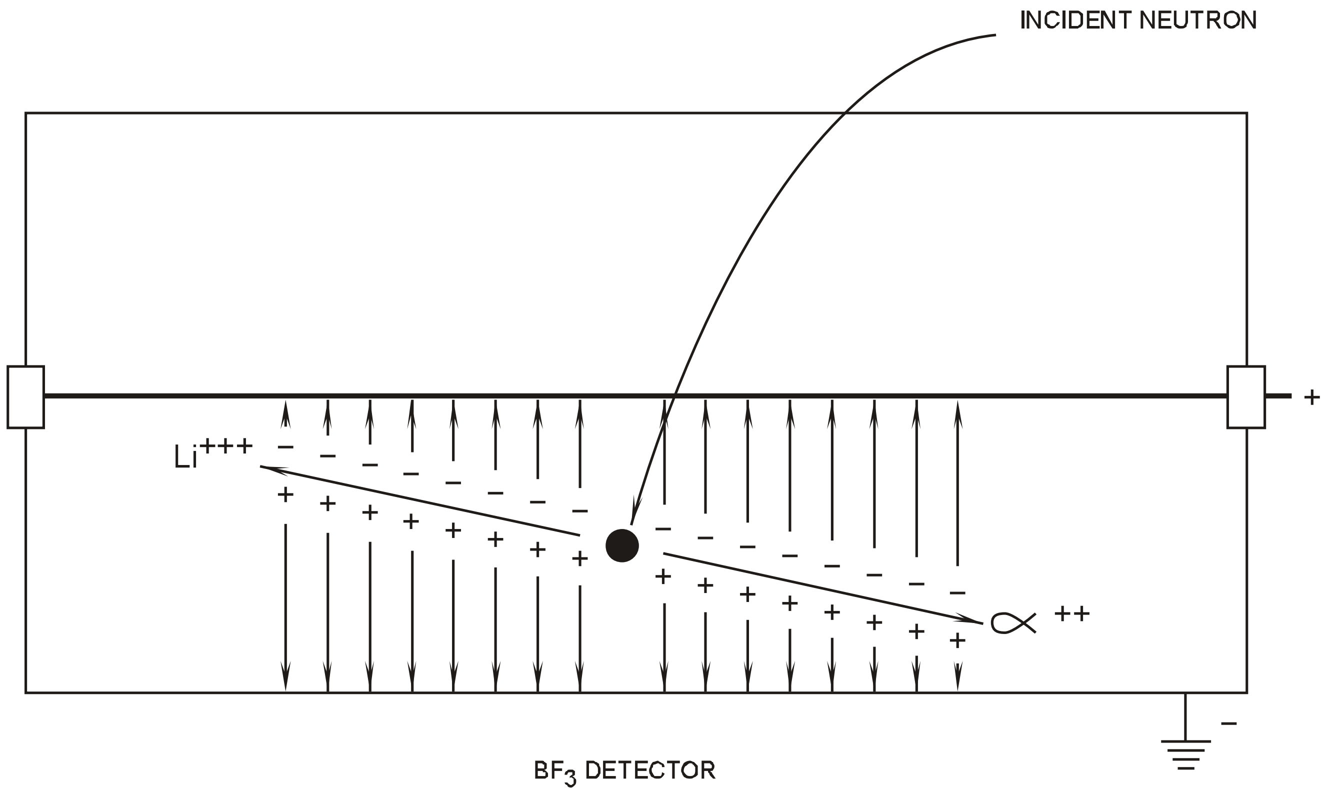


Figure 9.1-14 BF_3 Detector

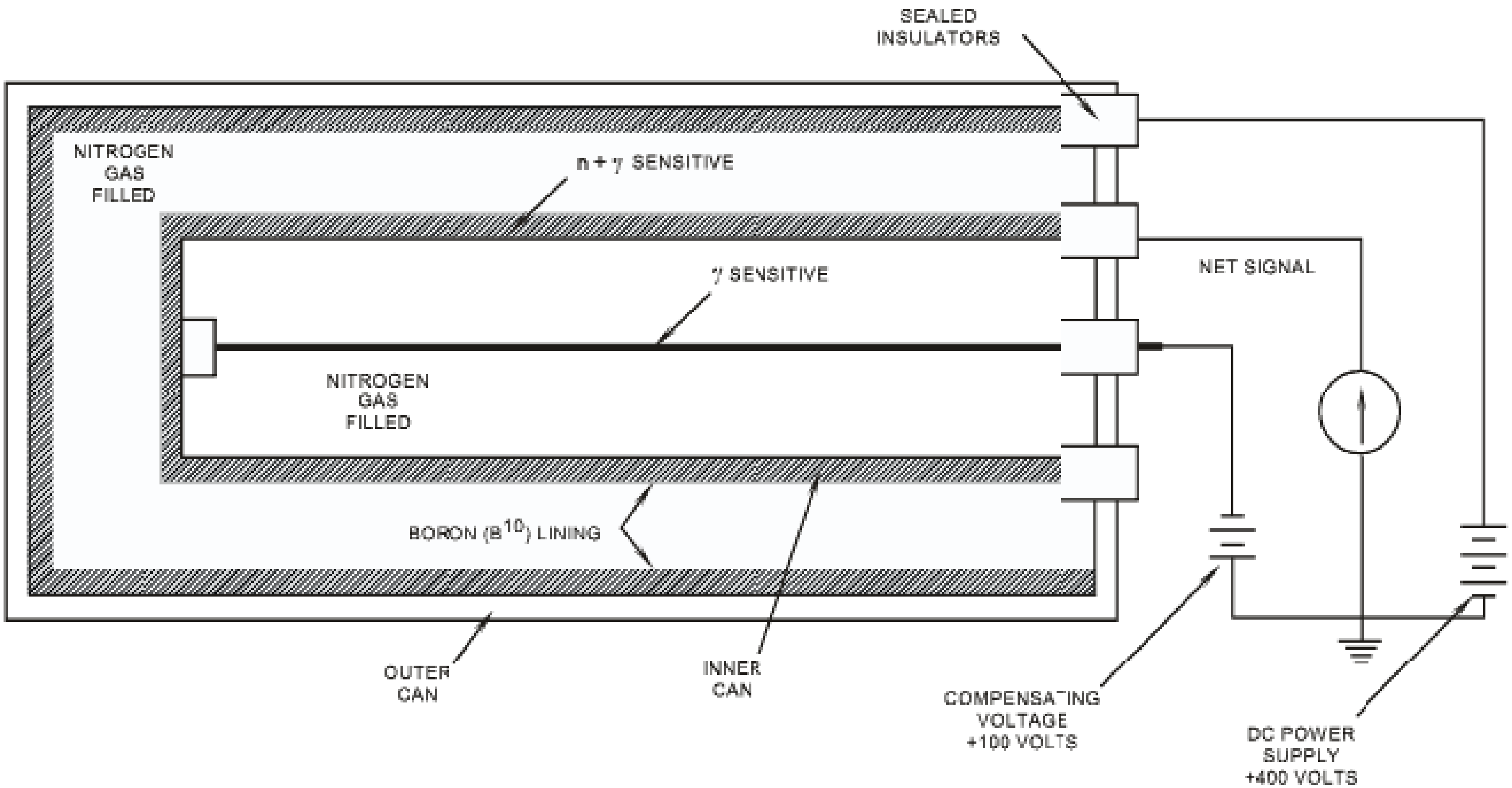


Figure 9.1-15 Gamma Compensated Ion Chamber

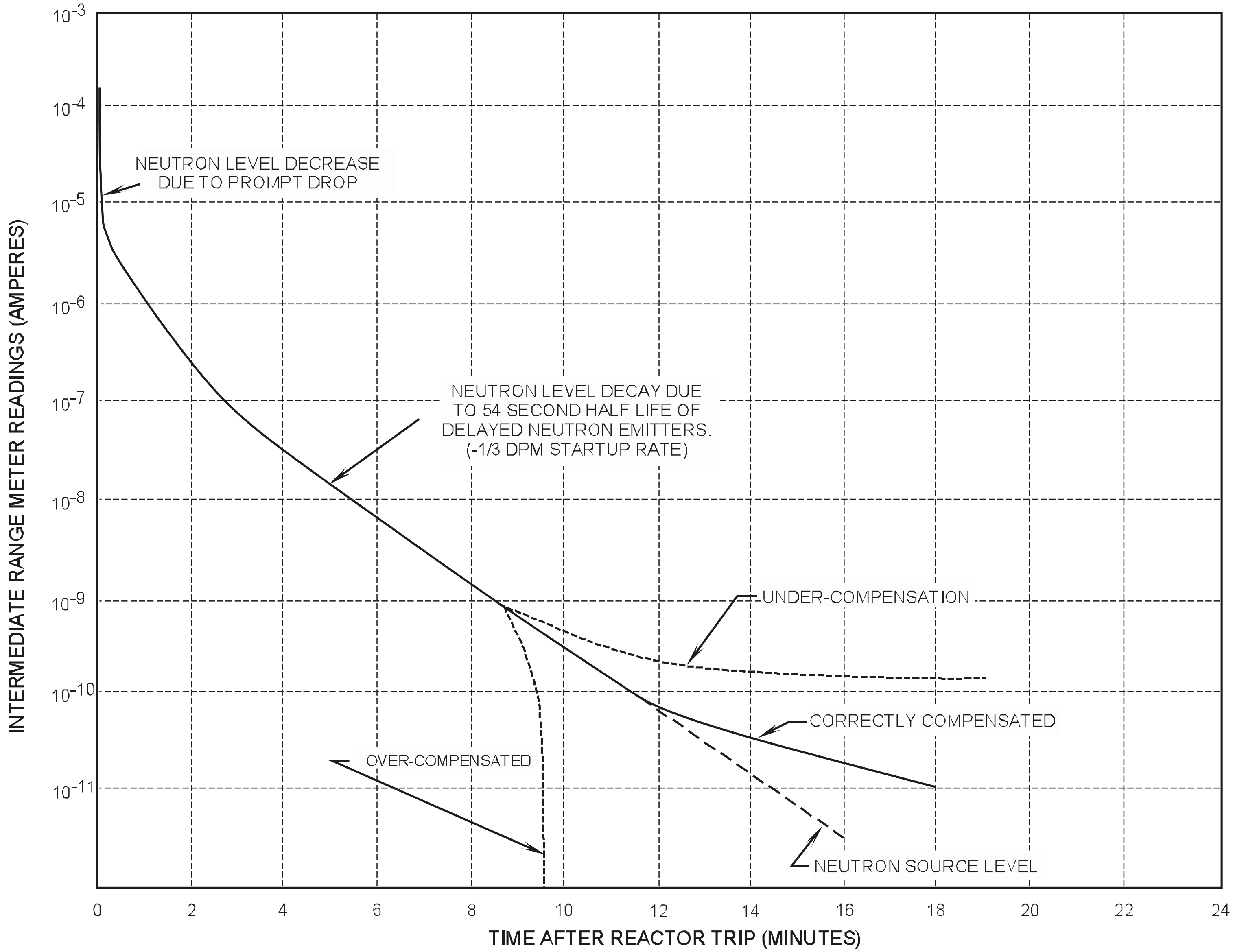


Figure 9.1-16 Gamma Compensation Curve

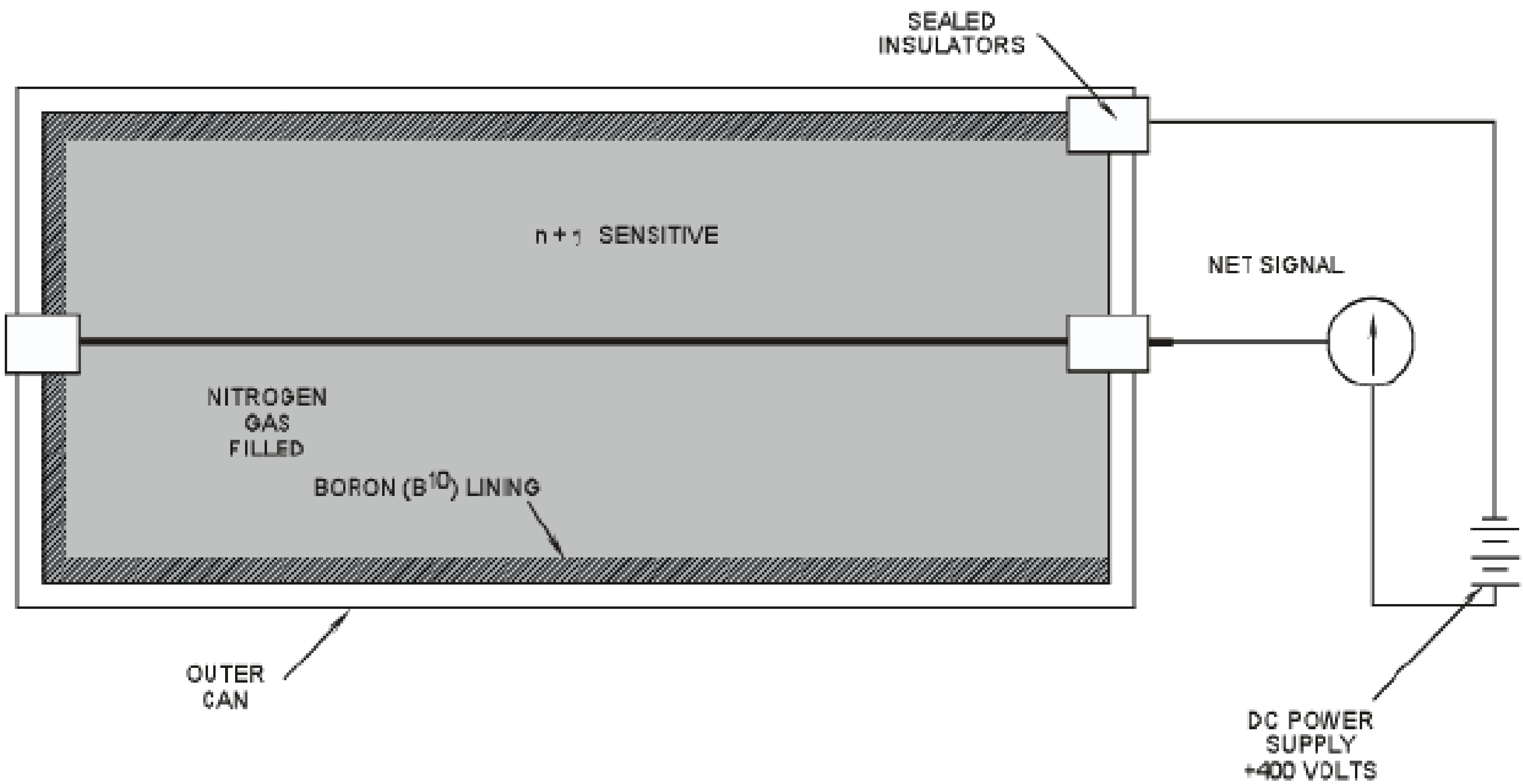


Figure 9.1-17 Uncompensated Ion Chamber

Westinghouse Technology Systems Manual

Section 9.2

Incore Instrumentation System

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9.2 INCORE INSTRUMENTATION SYSTEM

Learning Objectives:

1. State the purposes of the incore instrumentation system.

2. Briefly describe the two types of incore instrumentation and the information available from each.

3. Describe the method used to detect flux thimble leakage.

4. Deleted.

5. List the uses of the data obtained from the incore instrumentation.

9.2.1 Introduction

The purposes of the incore instrumentation system are to provide information on neutron flux distribution and fuel assembly outlet temperatures at selected core locations. The incore instrumentation system provides data acquisition only and performs no protective or plant operational control functions. The incore instrumentation system includes the movable incore neutron flux monitoring system and the incore temperature monitoring system. The number of incore temperature monitoring thermocouples and the number of flux thimble paths available within the core for the movable detectors varies according to whether the plant is a two-, three-, or four-loop Westinghouse design. The locations of the incore flux thimbles and thermocouples within the reactor core of a four-loop Westinghouse plant are shown in Figure 9.2-1.

The incore neutron monitoring system consists of miniature fission chambers with sufficient sensitivity to permit measurement of localized neutron flux distribution variations within the reactor core. The data obtained from the incore neutron flux monitoring system is used to:

1. Routinely verify that the following power distribution hot channel factors are in compliance with technical specification limits:

   a. Heat flux hot channel factor ($F_Q(Z)$), and
   b. Nuclear enthalpy rise hot channel factor ($F^N_{\Delta H}$);

2. Calibrate the excore power range nuclear instruments for Axial flux Difference (AFD);
3. Verify control rod positions when the rod position indication system is inoperable; and
4. Verify that the Quadrant Power Tilt Ratio (QPTR) meets the technical specification limit with core power > 75% and with one or more power range neutron flux channels inoperable.

The incore temperature monitoring system consists of fixed thermocouples, referred to as Core Exit Thermocouples (CETs), positioned at the top of the upper core plate.

They measure the core outlet coolant temperatures of instrumented fuel assemblies. This data is used to:

1. Provide inputs to the subcooling margin monitors,
2. Provide the operators with indications of inadequate core cooling conditions during emergency situations, and
3. Provide inputs to plant computer computational applications which use core-exit temperatures to determine fuel assembly enthalpy rises and limited power distribution information. This information is not used to verify compliance with technical specification requirements. Anomalous core-exit thermocouple readings may indicate a serious core condition and should be investigated.

9.2.2 System Description

9.2.2.1 Incore Neutron Monitoring System

Movable miniature fission chamber detectors (Figure 9.2-2), containing U_30_8 (uranium oxide) enriched to greater than 90 percent in U-235, enable detailed neutron flux (power level) mapping of the reactor core. Each detector is attached to a flexible drive cable that can be driven into selected core locations by the plant operating staff. When not in use, the detectors are stored in a shielded concrete vault to minimize radiation exposure to plant personnel.

Figure 9.2-3 shows the basic system for the insertion of the movable miniature fission chamber into the core. Retractable detector thimbles, into which the miniature detectors are driven, are positioned as shown. Since these retractable detector thimbles are sealed at the leading (reactor) end, they are dry inside. The thimbles thus serve as a pressure barrier between the reactor water pressure (design pressure of 2500 psig) and the atmosphere. Mechanical high pressure seals between the retractable thimbles and the conduits are provided at the seal table. During normal plant operation, these retractable thimbles are stationary and fully inserted into selected fuel assemblies. The detector thimbles are retracted from the core before refueling or during core maintenance periods at which time the reactor coolant system is depressurized.

The drive system for the insertion and withdrawal of miniature fission chamber detectors consists of drive units, limit switch assemblies, five-path rotary transfer devices, ten-path rotary transfer devices, and isolation valves. The drive units are mounted permanently on a platform directly above the seal table. The remaining components, between the drive units and the seal table, are mounted on a movable support assembly which is moved aside when the retractable detector thimbles are withdrawn from the core. The drive units push the hollow helical-wrap drive cables, with the miniature fission chamber detectors attached, into the core. The helical-wrap drive cables have small diameter coaxial cables threaded through their hollow centers for transmitting the current signal produced by the miniature fission chamber detector.

The six movable incore detectors, a typical number for a Westinghouse designed four-loop unit, are designated Detector A through Detector F, as shown on Figure 9.2-4. Additional movable incore detector information may be found in Table 9.2-1.

During normal operation, each detector is used to measure the relative neutron flux in the detector thimbles connected to the correspondingly-lettered ten-path rotary transfer device; i.e., detector A is normally selected to a core path provided by the “A” ten-path transfer device. However, by means of the operation selector switch (five-path transfer device), each detector can also be routed through several other paths. Each detector can be sent into each path of the next sequentially-lettered ten-path transfer device to serve as an operational spare detector for those thimbles (i.e., A for B, B for C, C for D, etc.). For detector normalization purposes, each detector can be routed separately into a common calibrate path, thus providing direct correlation of the detectors. Each detector can also be routed into any path of common group “C”, or to a shielded area for storage.

The readout and control equipment are mounted in a control console (equipment racks) located in the control room. This equipment provides indication and control to make flux maps of the reactor core either by semiautomatic control or by manual manipulation of the controls. The control console contains separate controls, digital position display and power supplies for each detector.

Common equipment, including core path display panel, one common control panel, special low level readout, and two-pen recorders, are also included in the console assembly (Figures 9.2-5 and 9.2-6).

9.2.2.2 Incore Temperature Monitoring System

Fixed incore thermocouples, made of chromel-alumel, are provided to monitor the outlet temperature of selected fuel assemblies. Fuel assembly inlet and outlet temperatures are used to determine the heat input, or enthalpy rise (Δh), of the fuel assembly. When the enthalpy of the monitored assemblies at various locations is compared, a radial power distribution map can be generated. The core locations for the CET’s for a typical four-loop plant are shown in Figure 9.2-1. Additional thermocouple information is provided in Table 9.2-2.

The thermocouple sensing elements are mounted on and above the upper core plate at the point where the reactor coolant exits the fuel assemblies (Figure 9.2-7). The thermocouple leads are sheathed in stainless steel conduits and are routed from the upper core plate to the upper support plate inside of support columns. The conduits are then routed from above the upper support plate to the reactor head penetrations via thermocouple port columns which exit the reactor vessel head with thirteen thermocouple leads exiting from each of the five thermocouple port columns. A sealing arrangement is provided for each of the thermocouple port column penetrations and is part of the reactor coolant system pressure boundary (Figure 9.2-8).

The thermocouple leads are routed to either of two reference junction boxes. The reference junction box temperature is controlled where the transition is made between the chromel-alumel thermocouple leads and the copper instrument wires. If the temperature at this transition is allowed to vary unacceptable errors would be introduced in the temperature signal.

The Core Exit Thermocouples (CETs) have the advantage of continuously providing data which is easily converted to power by determining the enthalpy rise in the instrumented fuel assemblies. As opposed to the incore flux detectors, which are operated on an intermittent basis, the CETs provide continuous on-line radial power sharing measurements. However, this instrumentation system has the disadvantage of measurement uncertainties and possible errors due to reactor coolant flow mixing patterns at the detector location. To reduce the uncertainty in the thermocouple measurements and provide an accurate radial power measurement for on-line monitoring, the incore thermocouples are normalized to incore flux detector data during periodic surveillance tests. The CET readings are continuously monitored by the plant computer and may be read individually in the control room.

9.2.3 Component Descriptions

9.2.3.1 Conduits, Guide Thimbles, Isolation Valves, and Seal Table

Referring to Figure 9.2-3, stainless steel conduits extend from the bottom of the seal table down through the instrument tunnel and then up to the bottom of the reactor vessel. The conduits are welded, to the bottom of a seal table and to the penetration nozzles on the lower reactor vessel head, to form a leak-tight boundary. Therefore, the conduits, once filled with reactor coolant, become an extension to the reactor coolant system pressure boundary. The conduits guide and protect the guide thimbles between the seal table and the lower reactor vessel head.

The guide thimbles are closed at their leading (reactor) end and open at their trailing (seal table) end. The guide thimbles are dry on the inside and serve as a pressure boundary between the reactor coolant system (2500 psia design pressure) and the atmosphere. The somewhat flexible stainless steel guide thimbles are inserted through the seal table into the conduits. They are pushed from the seal table to the bottom of the reactor vessel head and pass through the penetration nozzles. From here they are inserted through the instrument guide tubes or the instrument guide extensions. Finally the guide thimbles are routed through the lower internals to the fuel assemblies. The guide thimbles remain stationary in the fuel assemblies during reactor operation and are retracted for refueling, maintenance, periodic inservice inspections, and work on the reactor vessel internals. Since the guide thimbles are withdrawn by pulling them upward on the trailing ends, ample room for the 14 feet of withdrawal must be provided. To accomplish this, the five and ten path rotary transfer devices are configured so they are capable of being moved away from the seal table.

The seal table is a 3/8-in. thick, rectangular (8'6" by 2'6"), stainless steel plate mounted over the instrument tunnel. The seal table has 58 penetrations for guide thimbles and has two drain holes. The seal table guide thimble penetrations are sealed with high pressure swagelok fittings during normal operations and low pressure swagelok fittings during refueling.

A manually operated stainless steel isolation valve is provided at the seal table for each guide thimble. When closed, the isolation valve forms a 2500 psia barrier to prevent steam leakage from the reactor coolant system in the event of rupture of the guide thimble. The isolation valves are not designed to isolate a guide thimble with a detector or a drive cable inserted into the guide thimble. Therefore, prior to closing this isolation valve, the incore detector and its drive cable must be withdrawn to a position above the isolation valve.

9.2.3.2 Drive Unit Assemblies

As shown in Figure 9.2-9, each movable detector has a drive unit assembly. Each drive unit assembly is comprised of the following components:

1. Gear motor and slip clutch - One two-speed reversible synchronous gear-motor is provided. The drive motor is 3-phase, 460 volts, 60 Hz, 3600/600 rpm with a gear reducer and is capable of starting under maximum load. The motor incorporates an integral brake when not in operation. The continuous duty rating of this motor provides sufficient power to push a drive cable and detector through any guide path.
2. Drive box - The drive box is designed to operate with the helical-wrap drive cable. The 5-inch hobbed drive wheel is driven by the gear-motor through a slip clutch. Low speed for the drive cable is 12 ft/min, and high speed is 72 ft/min.
3. Storage reel - The storage equipment consists of a spring-loaded take-up reel with an integral locking device. The reel has sufficient take-up torque to prevent the drive unit from overrunning the reel at maximum speed during a change from low to high speed, or during braking. The storage reel accommodates 175 feet of drive cable and includes slip-ring assemblies which permit lead-out of electrical signals while the reel is rotating.
4. Position transmitter - A position encoder is supplied which is capable of operating control panel indicators reading from 0000.0 to 9999.9 inches. The encoder is driven at a speed proportional to the drive cable speed by means of a gear train from the drive wheel shaft. Signals from the encoder are in binary-coded-decimal form for position readout and controlled through the control console.
5. Withdrawal limit switch (Figure 9.2-6) - A withdrawal limit switch, actuated by the detector, is provided at the inlet of each of the five-path rotary transfer devices. This withdrawal limit switch provides the following functions:

    a. Prevents the operation of both the five- and ten-path transfer devices associated with it when the detector is forward of the limit,
    b. Stops automatic withdrawal when the detector reaches the withdrawal limit, and
    c. Actuates cable position lamps on the drive unit control panel in the control room.

6. Safety Switch - A safety switch located near the outlet of the drive unit prevents any attempt to withdraw the detector back over the wheel.

9.2.3.3 Transfer Device Assemblies and Isolation Valves

1. Five-Path Rotary Transfer Device and Limit Switch (Figure 9.2-9):
    a. One five-path rotary transfer device is provided with each drive unit for routing the detector into one of the five possible paths. The 5-path transfer device consists of an S-shaped tube mounted inside a rotating assembly. This assembly is bearing-mounted at each end and can be positioned to any one

of the five outlets. When an electrical signal is applied to change the detector path, the S-shaped tube is moved to the selected outlet path position. Cam-actuated microswitches send signals to the control panel for feedback of path selection.

b. A withdrawal limit switch, actuated by the detector, is provided near the inlet of each five-path transfer device. This switch prevents operation of the five-path rotary transfer device unless the detector and cable is in the withdrawn position. The switch also stops automatic withdrawal when the detector reaches the withdrawal limit switch.

2. Wye Units - Wye unit assemblies are mounted as required to reduce the amount of interconnecting tubing between the five-path and ten-path rotary transfer assemblies. Wye units are also installed between the five-path transfer devices and the calibration path.
3. Ten-path Rotary Transfer Device - Each ten-path rotary transfer device is capable of routing a movable incore detector into each of ten different selectable flux thimbles. Cam-actuated microswitches send signals to the control console for feedback of path selection. Detector-actuated path indicator switches near the outlets of the ten-path transfer devices send signals to the path display panel in the control console for verification of proper core paths.

9.2.3.4 Interconnecting Tubing Runs

Interconnecting tubing runs are supplied for connecting the drive unit assemblies to the safety and withdrawal limit switches, and for connecting the 5-path transfer devices to its associated wye units and 10-path transfer devices. Additional tubing runs are supplied for connecting the 5-path transfer devices to the calibration path and to the concrete shielded storage area. Tubing runs also connect the 10-path transfer devices to the isolation valves, and connect the isolation valves to the seal table. The isolation valve to seal table tubing runs are designed for 2500 psia and 650°F.

9.2.3.5 Detector and Drive Cable Assemblies

The incore flux detector, a fission chamber, is 0.188 inches in diameter and 2.1 inches long. A bullet-shaped stainless steel shell (0.199 in. O.D.) encapsulates the fission chamber. The stainless steel shell is welded to the leading end of a helical-wrap drive cable. Each incore flux detector is designed to have a minimum thermal neutron sensitivity of 1.0×10^{-17} amps/nv (where nv = neutron flux in neutrons / cm^2-sec) and a maximum gamma sensitivity of 3.0×10^{-14} amps/R/hr.

The carbon steel drive cable is a hollow-core helical wrapped cable which meshes with the hobbed drive wheel within the drive box. Each drive cable has an outside diameter of 0.199-inches, and an inside diameter of 0.065 inches. The flux detector is attached to a coaxial cable, 0.040 inches in diameter, which is threaded back through the hollow drive cable and terminates at the trailing end, with several feet of slack ending in an amphenol connector. The drive cables (when new) are approximately 175 feet long. This length allows one or two subsequent cuts of a 12 - 14 foot section before the cable becomes too short for use. Such cuts may be required for factory replacement of the flux detectors.

9.2.3.6 Readout and Control Equipment

Readout and control equipment are provided as described below and as shown on Figures 9.2-5 and 9.2-6.

1. Position Indication and Control - One position indication and control panel is provided for each detector. As an example the position indication and controls for the “A” detector are derived from signals sent from the “A” drive unit, and similarly for the other detectors. The Binary-Coded-Decimal (BCD) position signal from each encoder is presented as a nixie tube display of five decimal digits from 0000.0 to 9999.9 inches.
2. Operation Selector Switch - A six-position switch is provided for each detector drive to align the five-path rotary transfer device to the position associated with the selected mode of operation. Indicator lights, adjacent to the switch position, are energized by microswitches. These microswitches actuate when the five-path rotary transfer device has reached the selected position. The operation selector switch positions are discussed below:

    a. OFF - When the operation selector switch is placed in the OFF position, a red light adjacent to the switch is actuated, the detector is prohibited from moving, and the drive motor control relays are prevented from being energized. In addition, the five-path rotary transfer device is aligned to its NORMAL position.
    b. NORMAL - When the operation selector switch is placed in the NORMAL position, the five-path rotary transfer device is positioned to its normal ten-path rotary transfer device.
    c. CALIBRATE - When the operation selector switch is placed in the CALIBRATE position, the five-path rotary transfer device is positioned to the wye units for the calibrate path.
    d. EMERGENCY - When the operation selector switch is placed in the EMERGENCY position, the five-path rotary transfer device is positioned to the next sequentially lettered ten-path rotary transfer device (drive A to ten-path rotary device B, drive B to ten-path rotary device C, etc.).

    e. COMMON GROUP - When the operation selector switch is placed in the COMMON GROUP position, the five-path rotary transfer device is positioned to ten-path rotary transfer device C.

    f. STORAGE - When the operation selector switch is placed in the STORAGE position, the five-path rotary transfer device is positioned to the lead shielded concrete storage area located in the seal table room.

3. Ten-Path Selector Switch - A ten-position individual path selector switch is provided for each group to align the ten-path transfer device with the selected detector thimble within that group. Indicator lights adjacent to the switch positions are energized by microswitches on the associated ten-path rotary transfer device. These microswitches close when the ten-path rotary transfer device has reached the selected position.

Path selection is always achieved on the path selector switch associated with the ten-path transfer device through which the detector must pass (e.g., if the A detector is to be operated in the EMERGENCY mode, path selection is made on the B path selector switch). Detector-actuated microswitches at the outlet of the ten-path transfer devices energize path-display lights on the control console to indicate that the detector has actually reached that position in the selected path.

4. Common Controls - Common control of all detectors (simultaneous detector operation) or individual detector insertion and plotting are provided. The operating circuits are electrically interlocked to prevent attempted simultaneous insertion of two detectors into the same path under automatic control. The withdrawal limit switch is interlocked with the five-path and ten-path rotary transfer devices to prevent their rotation or realignment unless the associated detector is in the withdrawn position.
5. Position Control - The position readout devices are also used in the control system to provide stop signals to the detector drive unit at a preset distance from the bottom of the core and at the top of the core for each selected path during automatic insertion. The position readout devices also furnish an additional stop signal at the preset distance from the bottom after plotting. A set of ten patchboard matrix selector switches (five top-of-core position pins and five bottom-of-core position pins) for each path is provided to preset the bottom-of-core and top-of-core stop signals for normal operation.

   The stop positions are selected by insertion of pins of the correct lengths into the patchboard matrix to make contact as required. Thumbwheel switches are provided for position control settings in Emergency, Common Group, Storage and Calibrate modes of operation. Top-of-core and bottom-of-core position settings are always established on the position control panel of the detector being run.

   Detector position control is accomplished by comparing the encoder binary-coded-decimal (BCD) information with a decimal number created by the patchboard or thumbwheel switches. Each comparator accepts the associated encoder BCD information and compares it with the decimal number presented by the setpoint limits. To make this comparison, the decimal limit setting is converted into a BCD by the comparator.

6. Drive Motor Control - When any operation selector switch is in an ON position and the automatic-manual switch is in the AUTOMATIC position, pushbuttons (INSERT, SCAN, RECORD, WITHDRAW) will control the drive motors. When the automatic-manual switch is in the MANUAL position, the speed switch controls motor speed and the insert-withdraw toggle switch controls motor direction. The drive selector switch (single/multiple) on the common control panel selects either all drives or any single drive.

7. Detector Power Supplies - One power supply is mounted on each detector readout panel. The power supply provides a “floating” dc voltage output continuously variable to 300 volts.

8. Detector Current Readout - A current readout meter, having a range of 0-50 microamperes, is provided in the return circuit from the detector to the power supply. A range switch is provided to shunt the meter so that full scale can also correspond either to 150 or 500 microamperes, or to 1.5 or 5 milliamperes. A 1000-ohm multi turn potentiometer and precision shunts in series with the meter provide outputs to the recorder and plant computer. The full current output can also be supplied temporarily to an external picoammeter for special low current measurements.

9. Recorders - Strip-chart recorders are provided for each detector. The chart speed is synchronized with the low speed of the drive motors so that one inch of chart movement corresponds to 10-inch movements of the detectors. Each recorder is started automatically by the associated SCAN or RECORD pushbuttons, or can also be started at any other time by using the manual start switch.

10. Special Low Signal Level Equipment - A picoammeter is provided for making special low level measurements when the detector currents are less than five microamperes. The external connectors at the rear of all detector readout chassis are connected in parallel by coaxial cables to the input of the picoammeter. Input to the picoammeter is individually selected by switches on the detector readout panels. Also, in case the rectifier power supplies are too noisy for very low level signals, a special low-noise battery supply is provided.

9.2.3.7 Gas Purge System

The gas purge system, as shown in Figure 9.2-10, consists of a source of dry CO_2 gas which is introduced into the thimble runs whenever the movable detectors are being withdrawn from the reactor core. In order to do this, the transfer devices are contained in metallic enclosures and the gas is allowed to flow into these enclosures whenever the detectors are being withdrawn.

A pressure regulator and a throttling valve (a Hoke flow gage) are mounted near the 10-path transfer devices. A normally-closed ac solenoid operated off-on valve is located at the outlet of the throttling valve, which is electrically opened whenever a RECORD or WITHDRAW operation is called for on any of the detector drive motors. Stainless steel tubing connects the gas source to the enclosures through the valves. (The inlet gas tubing is disconnected when the transfer device's assembly is moved aside during refueling.)

These enclosures are designed to withstand an internal pressure of 1.0 psig without damage. The system is sufficiently leak-tight so that with an internal gas pressure of 0.02 inch of water applied, the total gas leakage rate will not exceed 15.0 cubic feet per hour.

9.2.3.8 Leak Detection System

The leak detection system comprises of; a drain header, a liquid level actuated pressure switch, and a 1/4-inch ac solenoid-operated valve, as shown in Figure 9.2-

10. The inlet connection to the drain header is made at the 10-path transfer device enclosure, while the outlet connection is made to the plant drain system.

If water leaks from any of the transfer devices, it enters the leak detection system causing the level to rise. When the level-pressure switch actuates, it energizes the leak alarm and the 1/4-inch solenoid valve. The alarm is acknowledged by pressing the reset pushbutton, which silences the audible alarm and seals in the alarm light. When the water level in the drain header decreases below the level actuating pressure switch setpoint, its contact opens, de-energizing the solenoid drain valve and the alarm light. The drain line is disconnected during refueling preparations.

9.2.3.9 Thermocouples

Sixty-five chromel-alumel thermocouples are provided for a four-loop plant. Each thermocouple is 1/8 inch (nominal) in diameter, stainless steel sheathed, and aluminum oxide insulated, with the trailing end terminated in a male thermocouple connector. Each thermocouple is supplied to the specific length required for its assigned location.

9.2.3.10 Thermocouple Reference Junction Box

Two thermocouple junction boxes are provided to permit transition from chromel-alumel thermocouple extension wiring to copper field wiring. These units provide a controlled 160°F temperature reference for the incore thermocouples. Each reference junction box contains three platinum Resistance Temperature Detectors (RTD). Two of the RTDs from each unit are connected directly to the plant computer for monitoring of reference junction temperature. The third RTD in each unit is an installed spare.

9.2.3.11 Thermocouple Indicator

One indicator is mounted in the flux mapping control console to provide backup readout capability (normal is via the plant computer). This instrument is supplied with a double range measuring circuit which permits measurement within the ranges of 100°F to 400°F or 400°F to 700°F. Selection of a single thermocouple to be indicated is made by nonlocking toggle switches on the front of the indicating panel. The toggle switch must be manually held in position (left or right) to monitor the desired thermocouple. The switch returns to the center position (neutral position) when released. Since the thermocouple input signal to the indicator is in parallel with the plant computer, a contact closure signal is provided to inform the computer when any thermocouple is being monitored by the indicator.

9.2.4 Operation and System Interrelationships

9.2.4.1 Detector Calibration

When using the movable incore detectors, the power supply voltages are set near the predicted centers of the plateau regions. The range switches are set at the expected ranges for on scale readings and the selector switch is in the RECORDER position. The following sequence of operations is typically performed:

1. Select one of the detectors and run it into the calibration path by placing its five-path operation selector switch in the CALIBRATE position and using the INSERT and SCAN pushbuttons. During the scan, set the range switch so that the peak output is between one-third and full scale.
2. After reaching the top-of-core, use manual control to withdraw the detector downward. Stop at or near the point of highest detector output. Take data of voltage versus meter readings for a saturation curve in 10-volt steps from 20 to 160 volts. Plot these readings on linear graph paper or run the strip chart for this plot. Select and set the voltage that will provide operation near the center of the plateau region.
3. Repeat this procedure for the remaining detectors and normalize each detector's output voltage to provide consistent readings from detector to detector.

9.2.4.2 Flux-Mapping Procedure

After detector calibrations are performed, full or partial core flux maps are typically made in the following semiautomatic steps:

1. Turn one or more operation selector switches to the NORMAL position and observe the green light indication. Select the desired individual paths with the ten-path selector switches. During the flux mapping operation, record the reactor core power level to ensure that measurement conditions are stable during the mapping procedure.
2. On the common control panel, turn the mode switch to the AUTO position. In this mode, the speed is determined automatically as described below. (An override can be made by turning the mode switch to MANUAL, which causes all manually controlled movements to be at the speed selected by the speed switch.)
3. Turn the computer switch to the ON position to log the flux-mapping data in the computer. Select the desired operation on the drive selector switch. The ALL position is normally selected to simultaneously insert all detectors. Note that the operation selector switch of the desired drive(s) unit must be in the NORMAL position to obtain flux mapping data from its respective ten-path transfer device.
4. Press the INSERT pushbutton momentarily. The detectors will be driven at high speed to the preselected bottom-of-core position and stopped automatically, as indicated by the position indicator digital displays. When the detectors pass through the path indicator switches, contact-closure signals are fed back to the path display panel.
5. Press the SCAN pushbutton momentarily. The detectors will be driven at slow speed to the top-of-core and stopped automatically as indicated by the digital displays. During this scan, the recorder is automatically started and a continuous readout of the flux profile is obtained as a function of core height. This serves as a permanent record of the measurement. At this time, observe the current level and recorder response and make all necessary scale changes and adjustments.
6. Press the RECORD pushbutton momentarily. The detectors will be withdrawn at slow speed downward through the core and a contact-closure signal will be supplied to the plant computer to indicate that the readouts should be logged. The associated strip-chart recorder automatically starts and again will provide a flux profile as a function of core height. The detectors stop automatically at the bottom of the core. During the record operation, the flux profile data is transmitted to the plant computer further data reduction and evaluation.

7. Press the WITHDRAW pushbutton. The detectors will be withdrawn at high speed back to the withdrawal limit switches as indicated by the digital displays. Repeat the above steps for the other paths to give a full or partial core map, including running all detectors in the calibration path for normalization.

9.2.4.3 Incore-Excore Calibration

The movable incore neutron flux detectors (incore detectors), in conjunction with the plant computer (INCORE Code) present a true representation of the actual neutron flux distribution within the reactor core. Meanwhile, the excore nuclear instruments (excore detectors) rely upon leakage neutrons to determine the flux distribution within the core. Due to the distance and shielding between the reactor core and the excore detectors, these detectors cannot provide a true representation of the flux distribution within the core. Since the excore detectors provide reactor protection signals and also provide the reactor operator with continuously monitored indication of power and flux distributions within the core, it is necessary to calibrate the excore detectors.

Recall from Section 9.1(Excore Nuclear Instrumentation) that the excore power range instruments consist of two six-foot detectors (one upper detector and one lower detector) per power range instrument channel. In theory the upper detector should indicate the power in the upper six feet of the core while the lower detector indicates the power in the lower half of the core. In practice, however, this is not the case, as neutrons leaking from the core do not necessarily leak out of the core at 90 degree angles. Some of the leakage neutrons generated in the lower half of the core will be detected by the upper detector and conversely the lower detector will indicate neutrons that were produced in the upper half of the core. Since the core must be protected from departure from nucleate boiling (DNB) and excessive power generation in both the upper and lower halves of the core, it is essential that the inputs to the protective circuitry be reflective of the actual conditions in the core. This protection is provided by trip signals generated from the overtemperature ΔT trip circuitry (OTΔT) and the overpower ΔT trip circuitry (OPΔT) of which both circuits receive axial flux difference (AFD) inputs from the excore power range detectors.

The outputs of the upper and lower excore detectors are calibrated to the incore detectors at the beginning of each fuel cycle and when the monthly surveillance shows a significant difference between the adjusted excore AFD and the incore AFD. AFD is defined as the flux at the top of the core minus the flux at the bottom of the core divided by the flux at the top of the core plus the flux at the bottom of the core at 100% power. This calibration must demonstrate the linear relationship that should exist between the incore and the excore outputs. Electronically the AFD is expressed in terms of difference in current (ΔI) between the upper and lower excore detectors. The slope of that relationship is used to calibrate the following: the $F_1(\Delta I)$ penalty to the (OTΔT) trip setpoint in the reactor protection system, the $F_2(\Delta I)$ penalty to the (OPΔT) trip setpoint in the reactor protection system, the AFD meters on the control board, the output to the detector current comparators, and the AFD monitor program in the plant computer.

In order to establish the existence of a linear relationship between the incore and excore detector outputs, an adequate number of data points (different flux distributions) must be obtained. This is accomplished by inducing an axial xenon transient, which causes an axial flux oscillation. During this induced transient, incore and excore measurements are obtained. These measurements are used to calculate the equation for the line that best fits the data by using linear regression. The incore measurements are taken by performing full core and quarter core flux maps at various times during the xenon transient. Each time an incore AFD is obtained by a flux map, all power range excore detector currents are recorded.

The current output from the excore detectors is then plotted against the incore AFD. After the linear relationship between the two detector systems is established, the gains of the excore detector isolation amplifiers are adjusted. Adjusting the gain on an isolation amplifier only affects its output signal to the reactor protection system, the detector current comparators, and the various AFD meters and recorders. This adjustment has no effect on the raw current transmitted from the associated excore detector, which in addition to supplying the isolation amplifier also provides an input to the summing and level amplifier. Once made, the adjustment to the isolation amplifier gain is such that when there is an actual 0% incore delta flux, the excore detectors will indicate 0% AFD.

9.2.4.4 Computer

In addition to the strip chart records, on-line computers are installed to provide gross analyses of current core conditions for use on a complementary basis with other on-line monitoring systems.

9.2.4.5 Incore Data Collection

Signal Inputs - A number of active signals are supplied from the flux mapping system to the on-line computer. First, there are analog signals proportional to flux levels as measured by the movable detectors. Second, there are three sets of contact closure signals from each detector position control - one to show selection of detectors, another set to show the group 5-path transfer position, and a third set to show the individual 10-path transfer position. The latter two automatically indicate the flux thimble being measured. Finally, there are three interrupt signals, COMPUTER OFF-ON, SCAN, and RECORD.

SCAN and RECORD Programs - The on-line measurements provide an accurate method of determining a three-dimensional power distribution of the reactor core at periodic intervals in order to evaluate current core performance. The SCAN interrupt is received when the movable detector drive mechanism is energized to drive the selected detectors to the top of the core. However, data collection commences only after the RECORD interrupt is received when the movable detector drive mechanism is energized to withdraw the previously inserted detectors from the top of the core.

The objective of the on-line rapid data collection is to provide a high priority scheme by which all pertinent flux mapping data are collected for later reduction either on an offsite basis or for low priority reduction by the plant computer. Also, on-line priority data reduction provides a gross analysis of current core conditions immediately for use on a comparative basis with other on-line monitoring systems such as incore thermocouples, and excore detectors.

Signal Quality Checks - The program also includes provisions to evaluate the quality of the data as the measurement is taken. Briefly, there are two main quality checks made. For each data point on a pass, three consecutive readings are made (maximum 1/15 second apart). Also, each data point is compared with the preceding and succeeding data points, although relatively large variations are normal at the core grid locations.

Normalization - In order to provide a consistent set of measured relative reaction rates, it is important that all flux mapping data be normalized to one reference condition. Discrepancies which affect measurement results and must be corrected for are:

1. Reactor power drift during the flux mapping period,
2. Dissimilarities between the individual movable detectors,
3. Different readout scale settings, and
4. Leakage current in the detector, normally at low power levels.

During each pass, the total reactor power must be known in order to provide a means of converting each pass to one common reactor power level. This is accomplished by integrating the total output from the excore nuclear power channels during each pass. Changes in subsequent excore readings after the first pass provide correction ratios for subsequent passes.

In order to establish the normalization factors associated with each detector, it is necessary to insert each detector into a common thimble location. Differences between range settings are accounted for by multiplying each detector output by its appropriate range setting. Leakage current correction is made by subtracting from the appropriate detector output.

After the data is collected by the computer, it can be processed to provide a full-core flux map. By using the symmetry of the core (attained by fuel and poison loading), the data from the selected core locations can be extrapolated to include all fuel assemblies in the core. This may be accomplished by the plant computer, or a more powerful offsite computer.

Thermocouple Input - Use of the on-line computer is the normal means for recording thermocouple readings. The thermocouple signals originating above the core pass through reference junctions in the plant containment and then to terminal strips in the flux-mapping console. From there, they are paralleled with one set going to the computer and the other to a precision indicator with manual selector switches. The latter are intended for use in case of a malfunction of the computer.

Computations Based on Thermocouples - The information received from the thermocouples complements the movable detector system by providing periodic on-line checks on reactor core conditions. Calibrations of the thermocouples and the thermocouple reference junctions are made from tests at known thermal core and system conditions.

Computations are made periodically of the enthalpy rise at each thermocouple location, relative fuel assembly powers and core radial tilting factors. Printouts are made of alarm messages when any of the relative fuel assembly power values or incore thermocouple-based radial tilting factors exceeds established limits. A listing of averaged incore thermocouple readings and fuel assembly power values is made for reference usage. Complete core maps and daily thermocouple history are made when requested by the operator.

9.2.5 Summary

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. The detector is welded to the leading end of a helical wrap drive cable and to a sheathed coaxial instrumentation cable. The retractable guide thimbles are closed at their leading ends and serve as the pressure boundary between reactor coolant pressure and atmosphere.

The drive assemblies are motor operated, with a hobbed wheel engaging the helical drive cable, a take-up reel and position encoders. The five-path rotary transfer device is used to select the mode of operation (normal, calibrate, storage, etc.). A five-path rotary transfer device is provided for each detector-drive assembly. A ten-path transfer device is supplied for each detector-drive assembly and is used to route a detector into any one of up to ten preselectable fuel assemblies.

Flux mapping consists of a moving detector scan of each provided core location (Figure 9.2-11). The information obtained is collected by the plant computer, which will either directly analyze the data obtained or record it for analysis by more sophisticated offsite computers.

Thermocouples are provided to give rough approximations of core conditions. They have the advantage of being on-line and are immediately available to the operator. The thermocouples are inserted into guide tubes that penetrate the reactor vessel head and terminate at the flow exits just above the fuel assemblies. Thermocouple readings are monitored by the computer with backup readout at a manual point selection.

Table 9.2-1 Movable Detector Design Parameters

Movable Detectors	
4-loop plants, number	6
3-loop plants, number	5
2-loop plants, number	4
Outside diameter, in.	0.199
Length, in.	2.1
Performance Data	
Cable speed (low), ft/min	12
Cable speed (high), ft/min	72
Position indication, in.	0.5
Flux Thimbles	
4-loop plants, number	58
3-loop plants, number	50
2-loop plants, number	36
Nominal O.D., in.	0.300
Nominal I.D., in.	0.199

Table 9.2-2 Thermocouple Design Parameters

4-loop plants, number	65
3-loop plants, number	51
2-loop plants, number	39
Outside diameter, in.	0.111
Type	Chromel-alumel

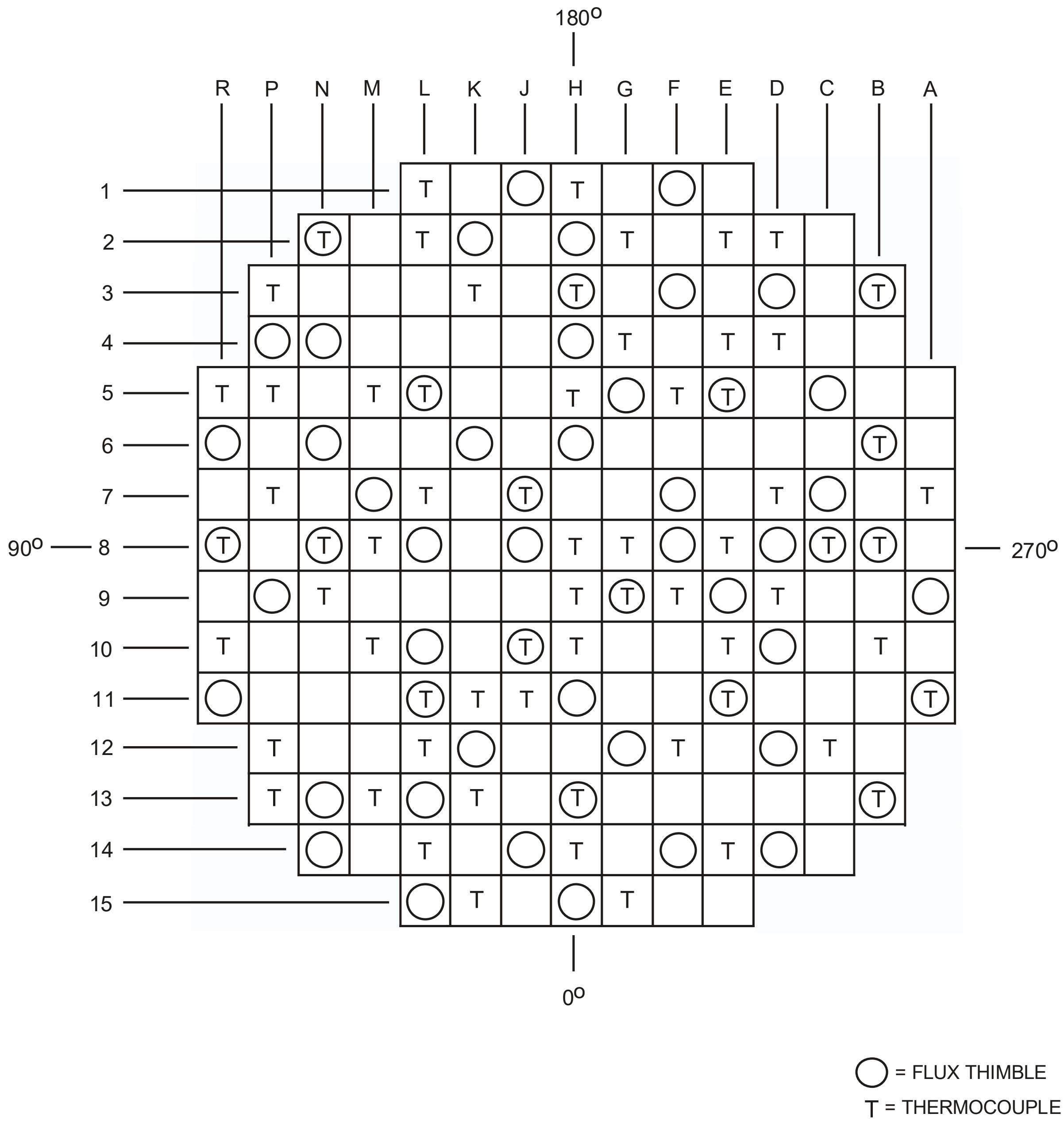

Figure 9.2-1 Thermocouple and Flux Thimble Locations

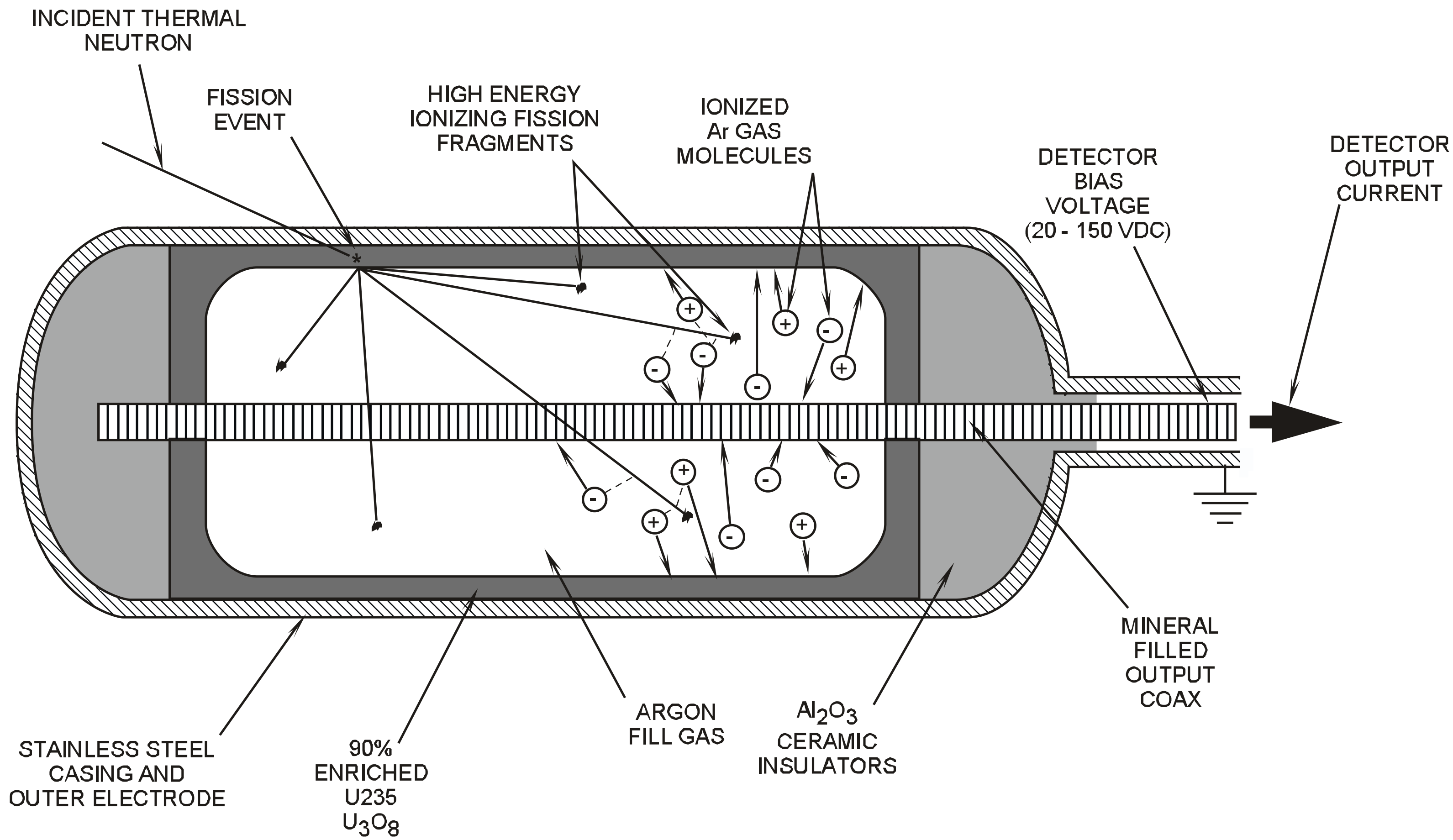

Figure 9.2-2 Incore Fission Chamber

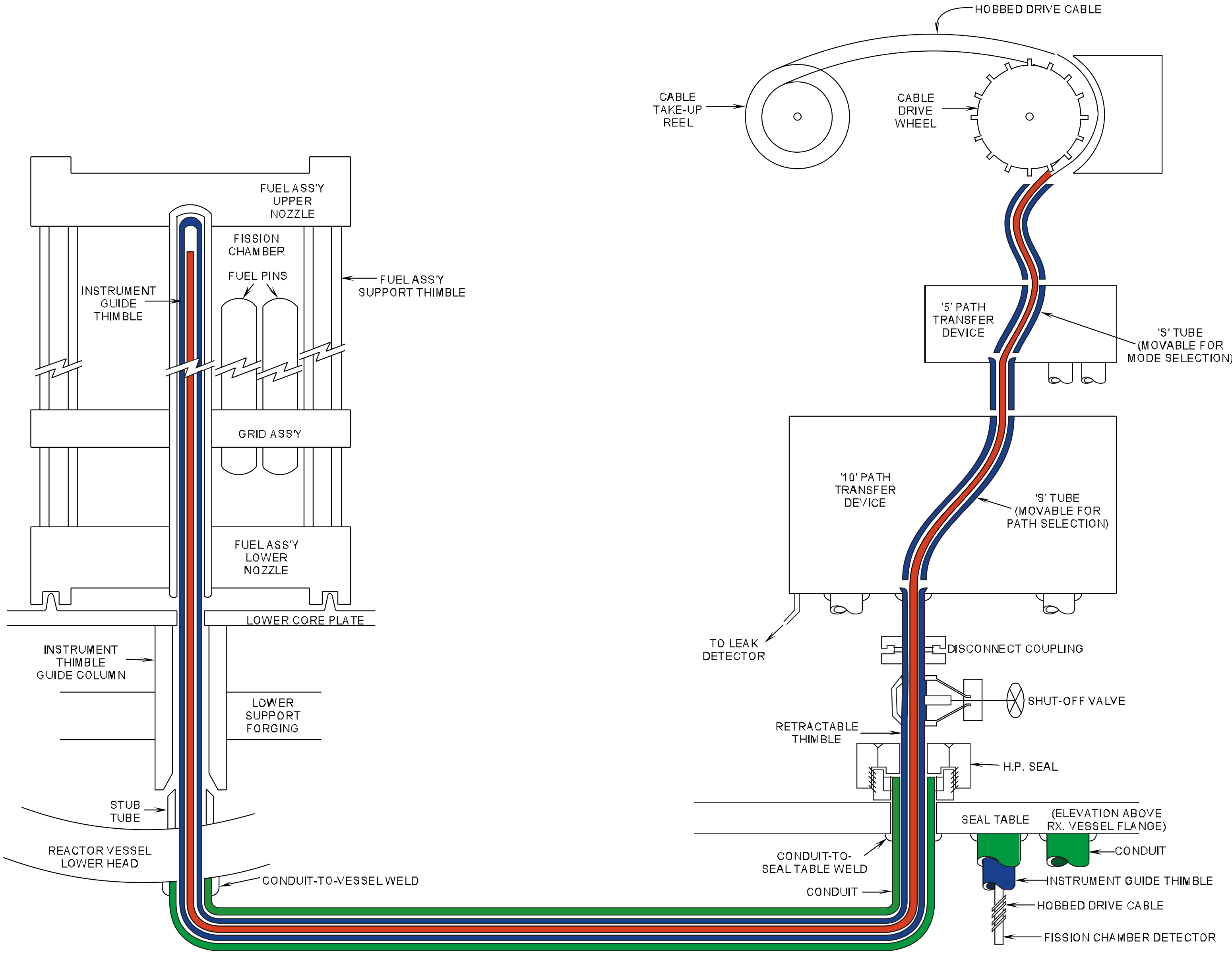

Figure 9.2-3 Movable Detector System

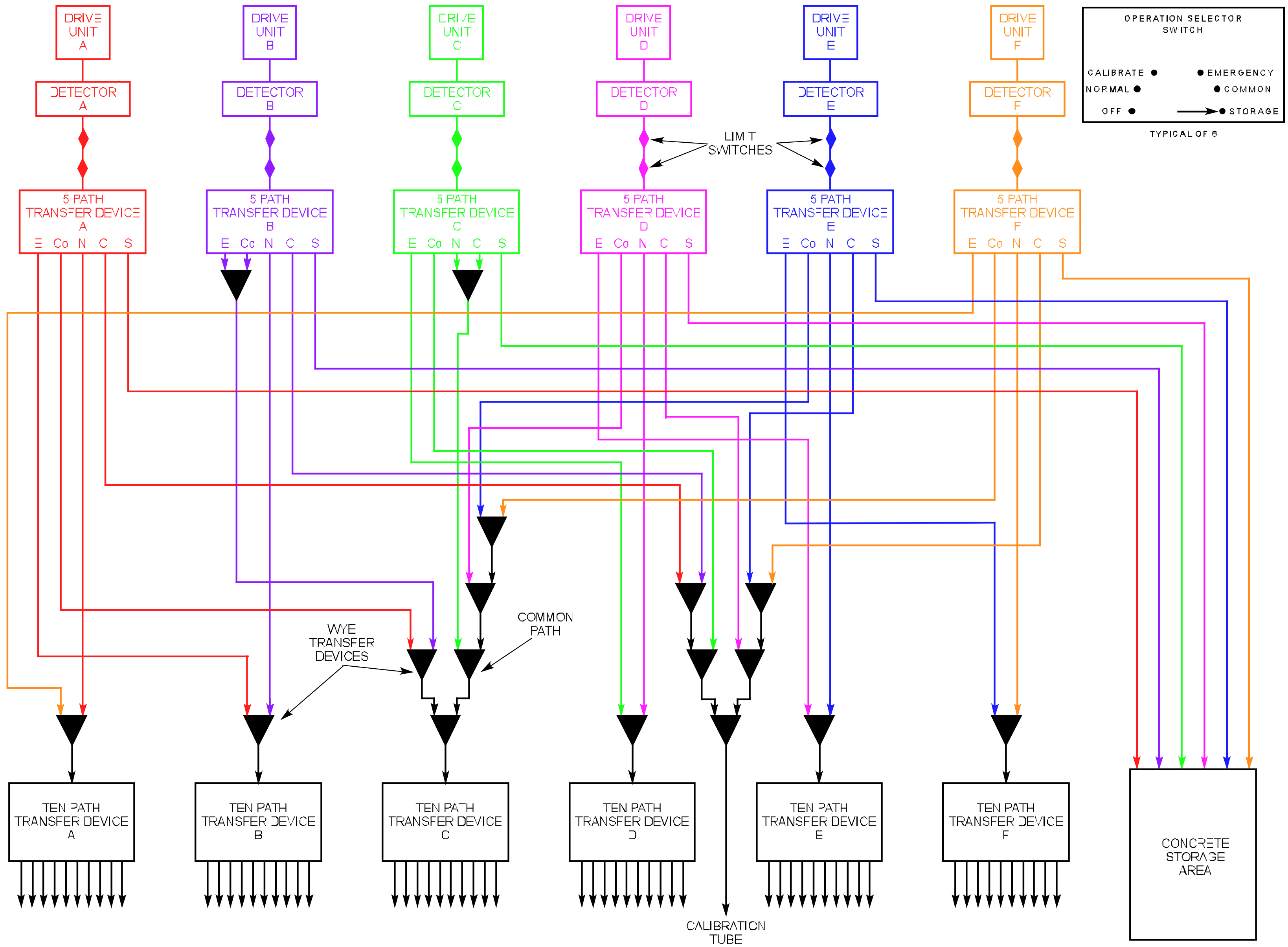

Figure 9.2-4 Incore Nuclear Instrumentation Drive System

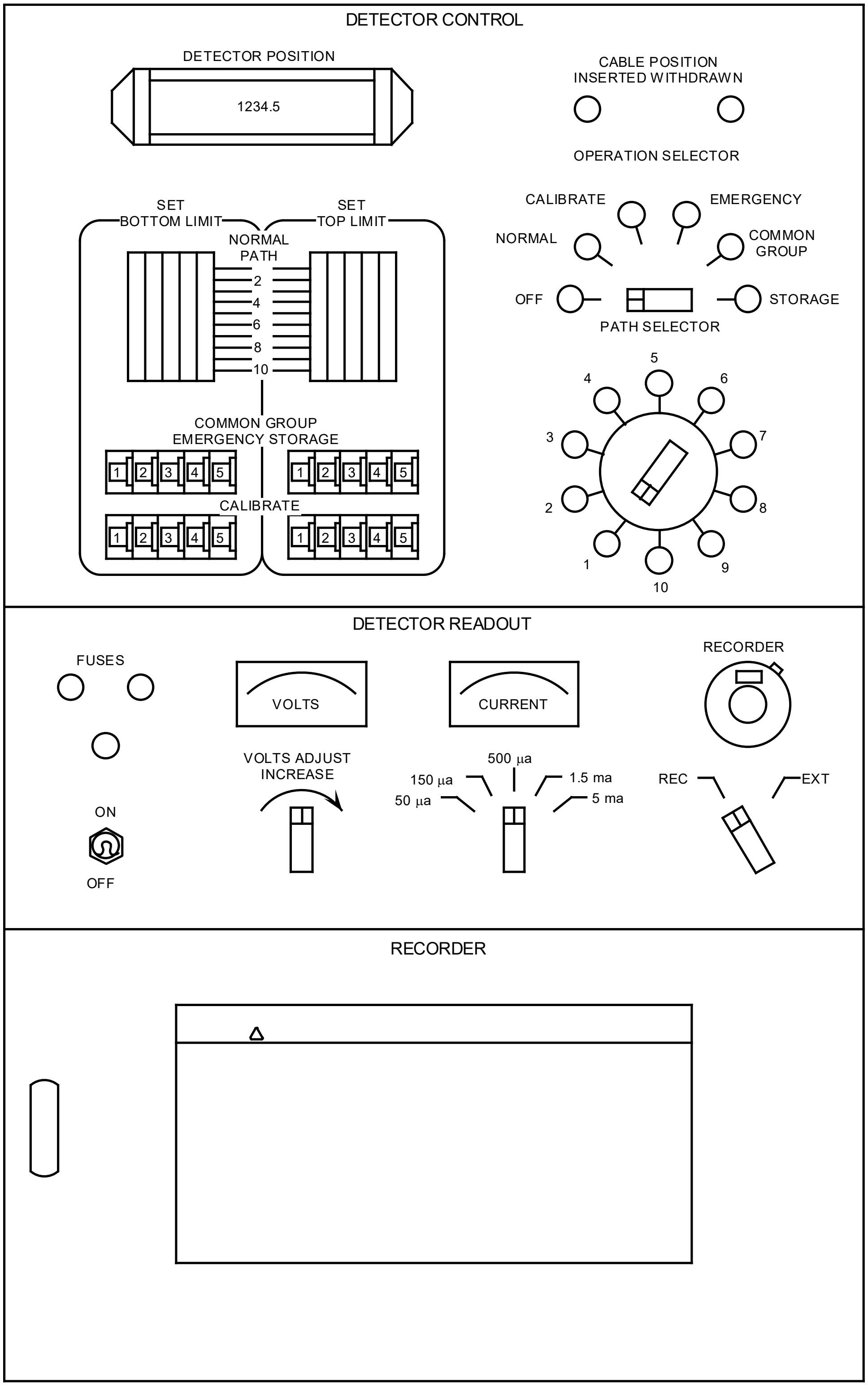

Figure 9.2-5 Incore Detector Control and Readout

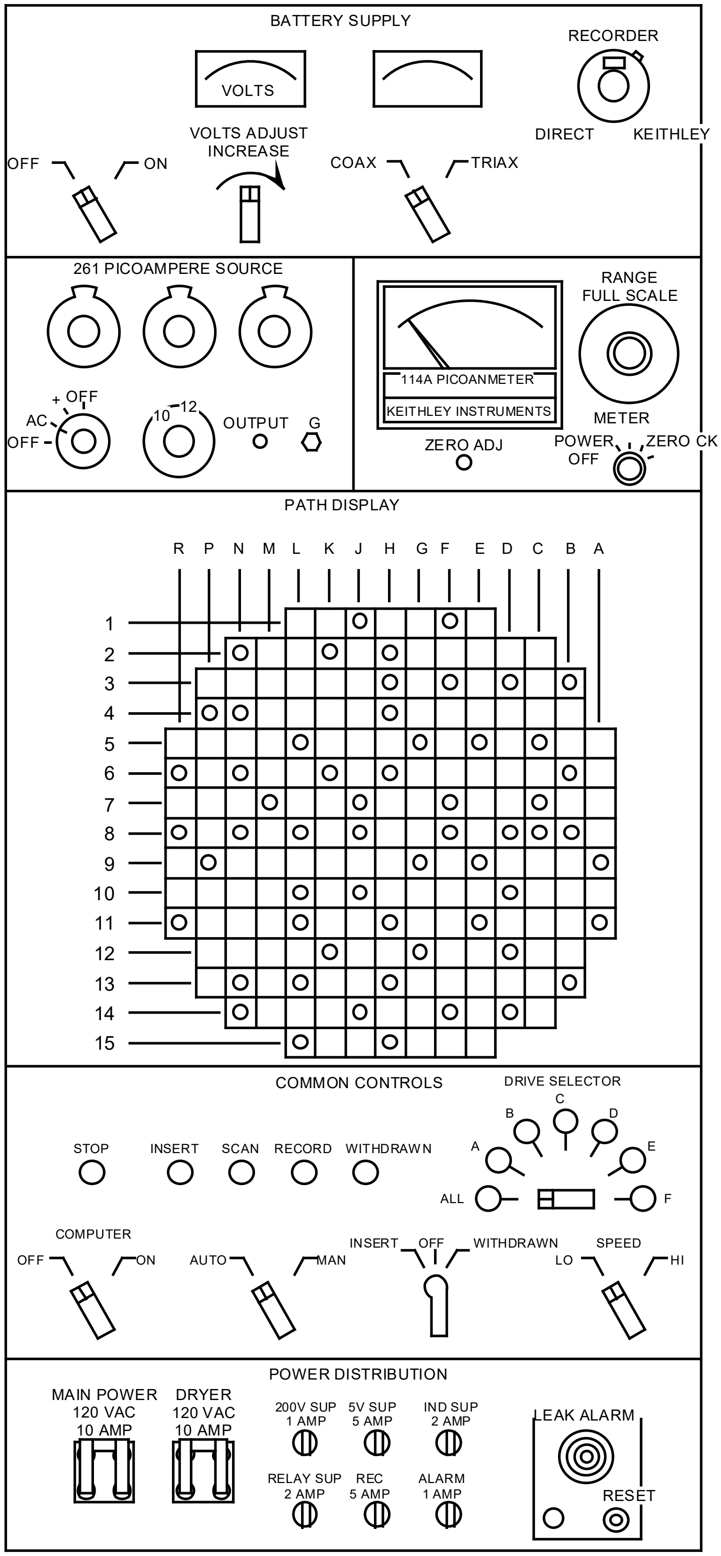

Figure 9.2-6 Incore Common Controls and Display

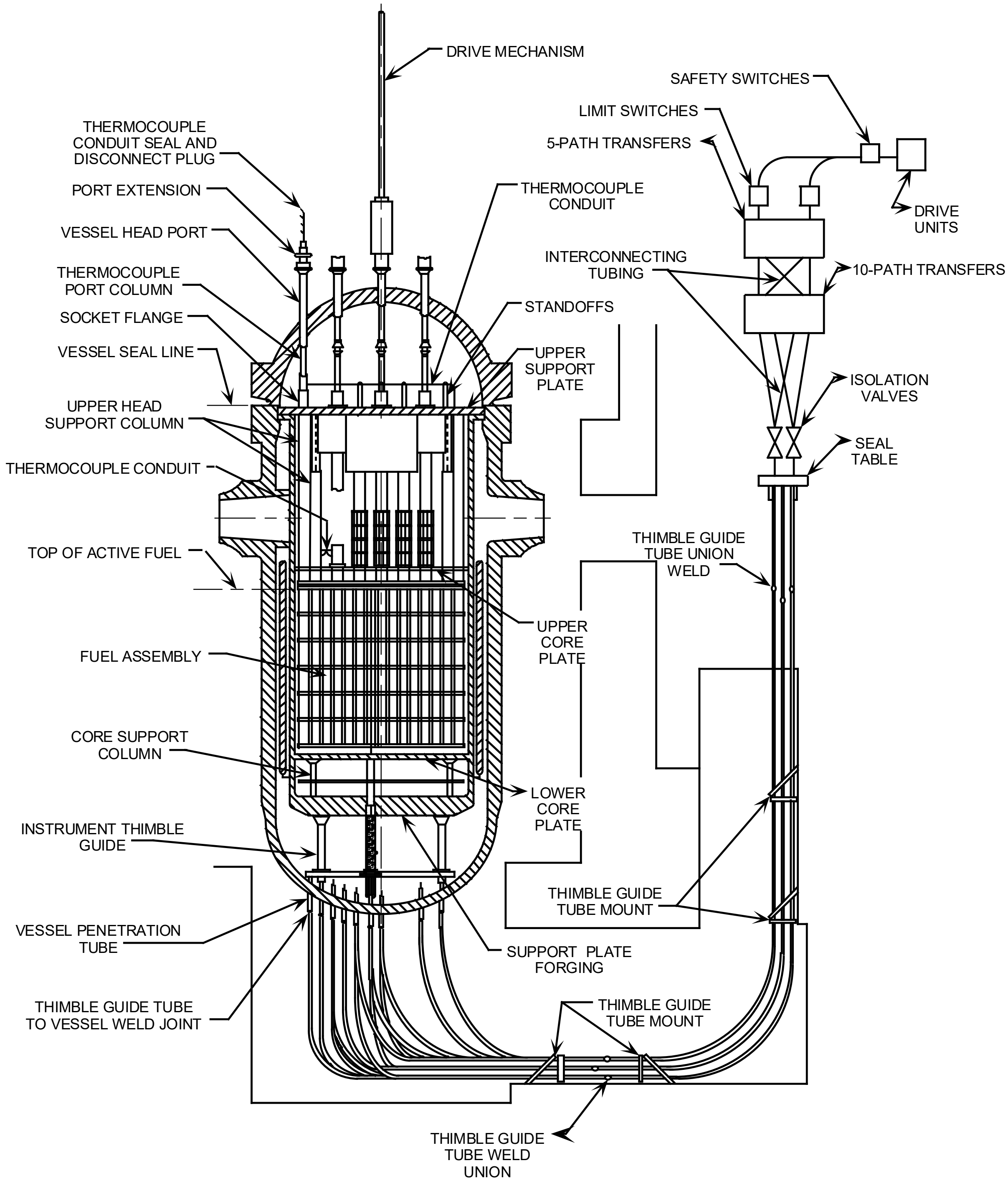

Figure 9.2-7 Incore Instrumentation

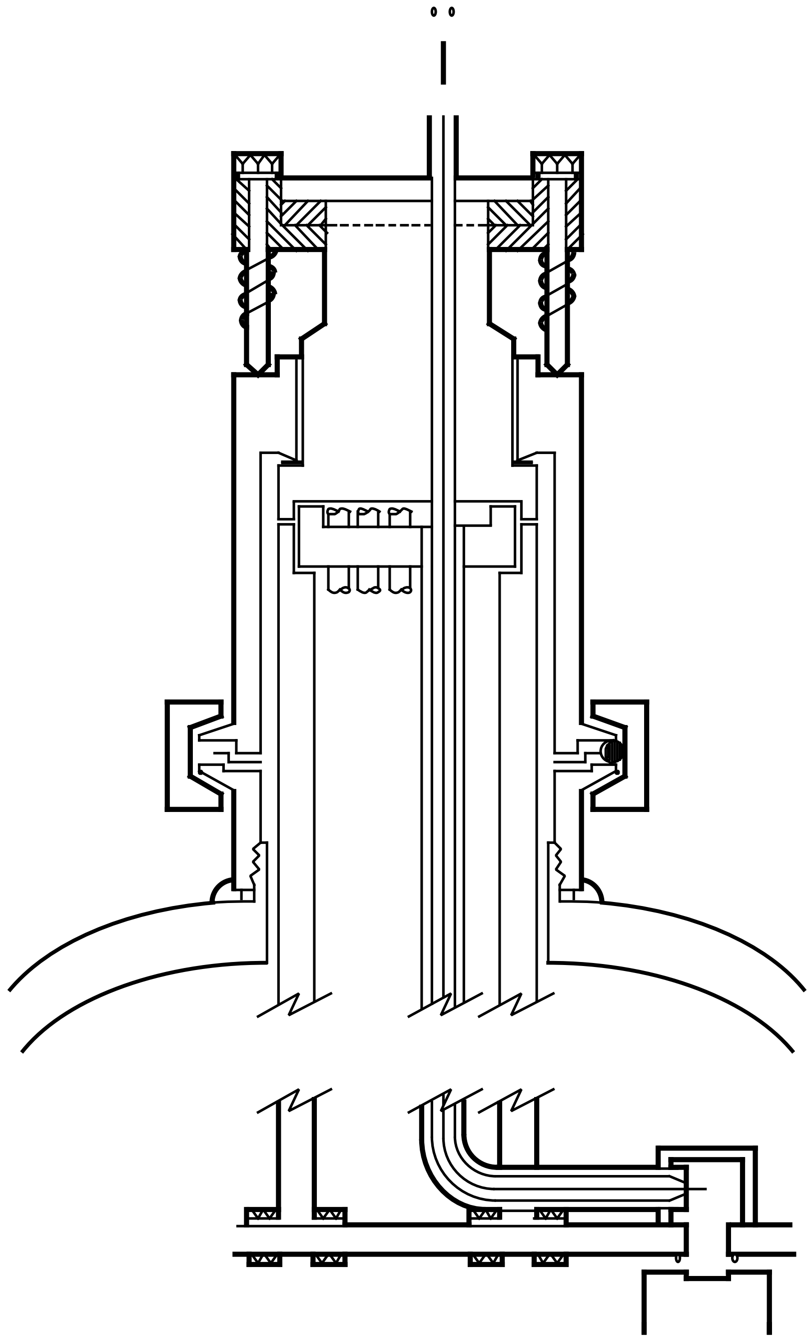

Figure 9.2-8 Incore Thermocouple Arrangement

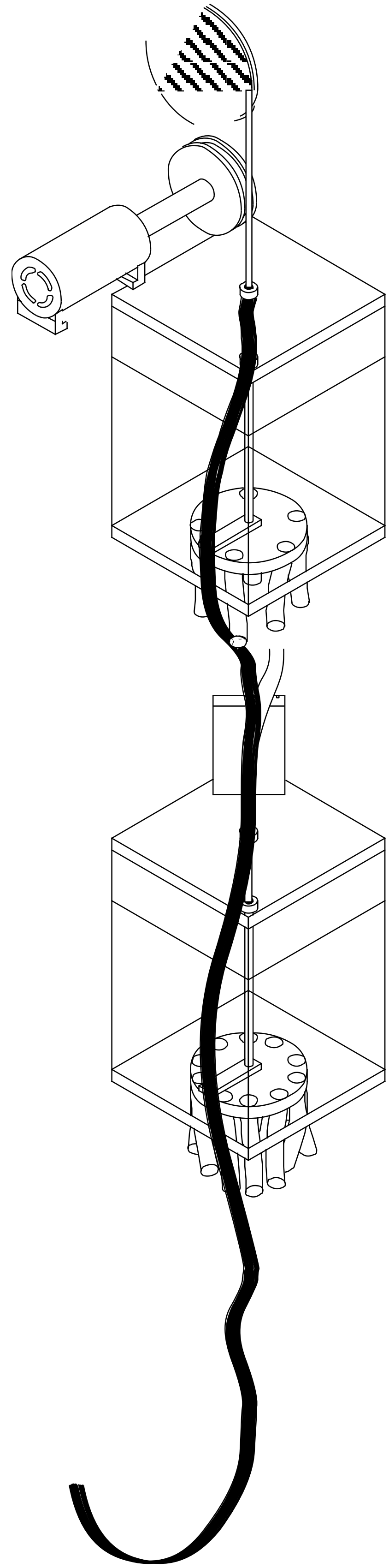

Figure 9.2-9 Drive System for Incore Instrumentation

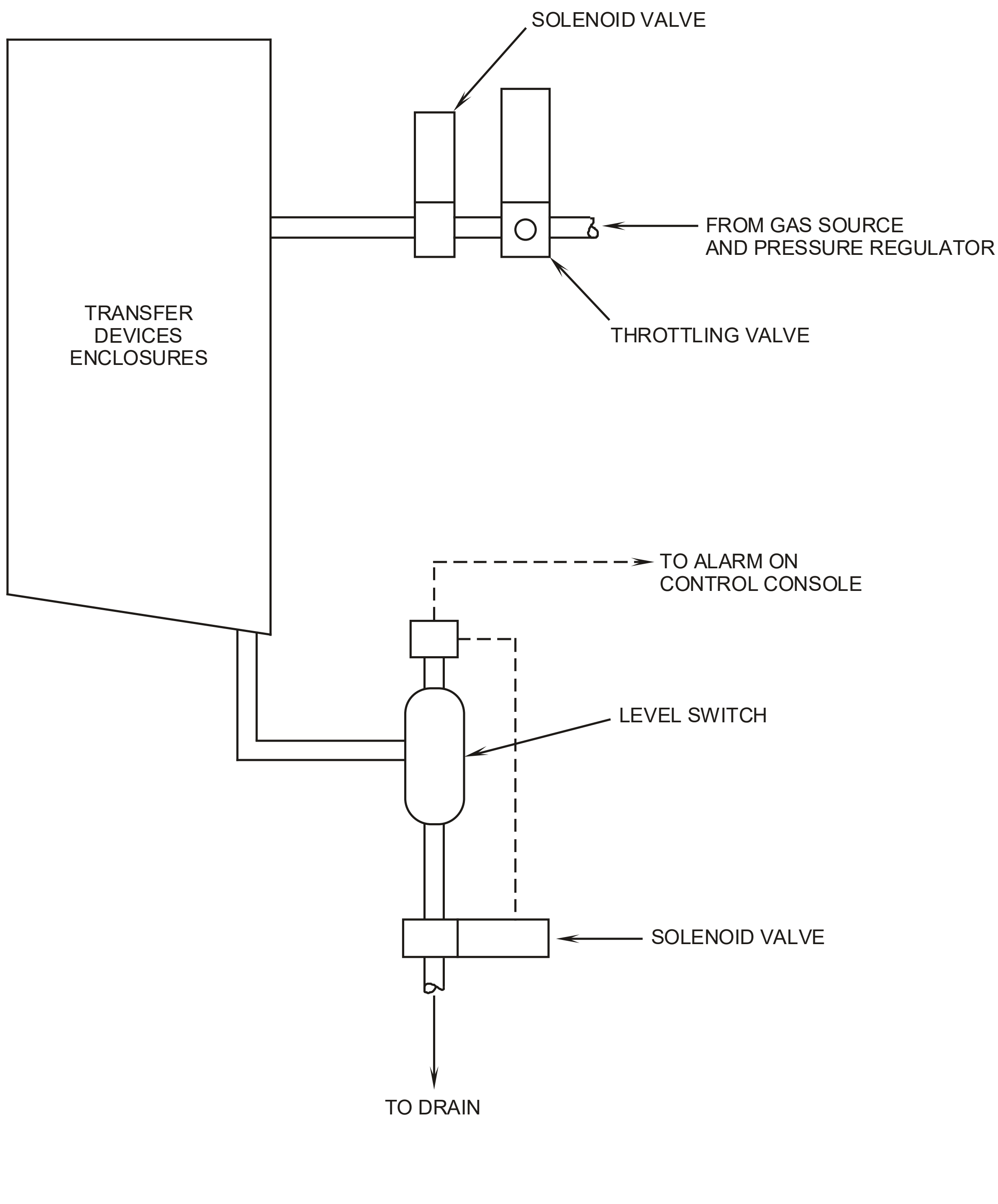

Figure 9.2-10 Gas Purge and Leak Detection System

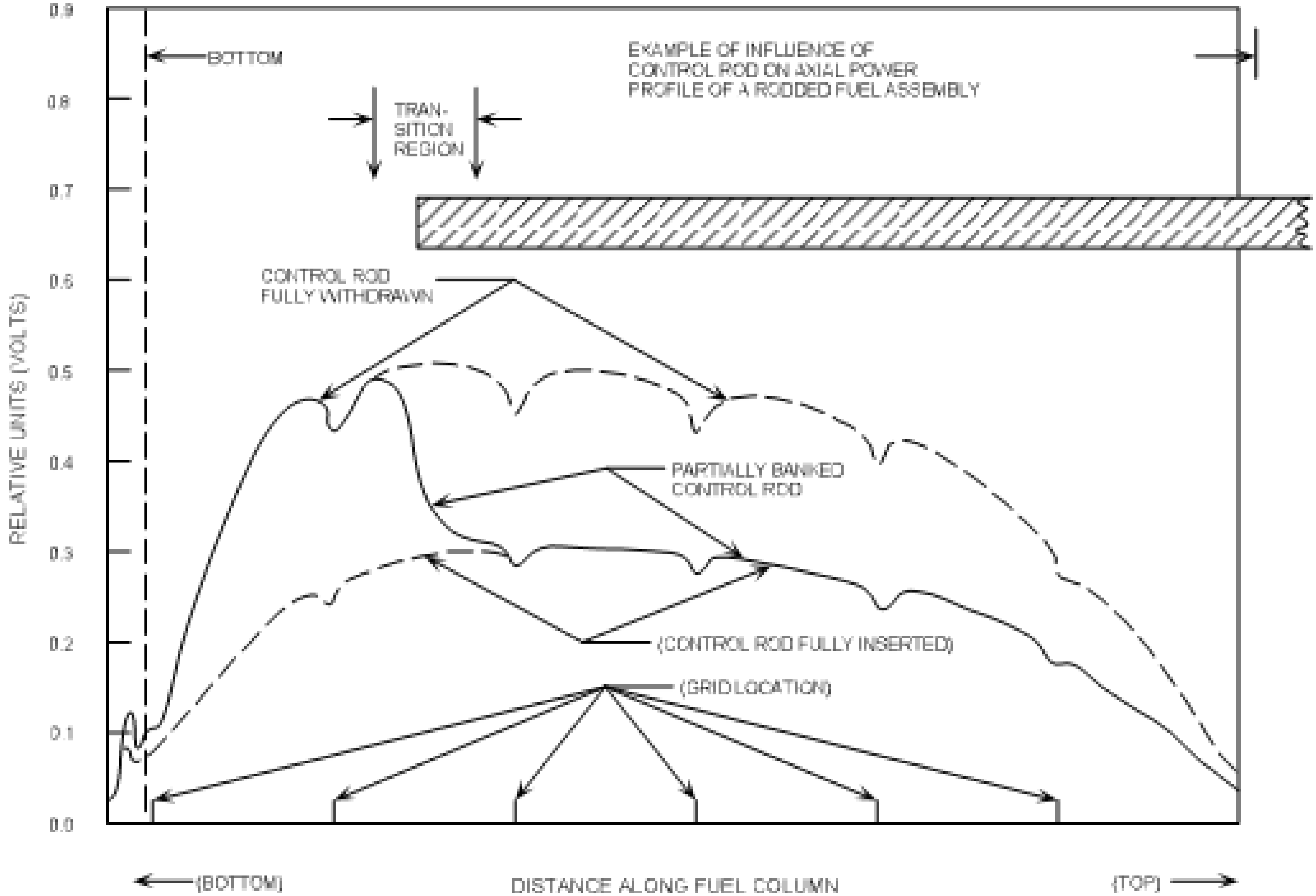

Figure 9.2-11 Flux Profile Curves

Westinghouse Technology Systems Manual

Chapter 10

PRIMARY CONTROL AND INSTRUMENTATION

Section

10.0 PRIMARY SYSTEMS CONTROL AND INSTRUMENTATION

Introduction

The purposes of primary instrumentation are as follows:

1. To monitor reactor coolant system (RCS) temperature, pressure, and flow and pressurizer level.
2. To provide inputs to the reactor protection system (RPS) for reactor trips, engineered safety features actuations, and protection-grade interlocks.
3. To provide inputs to various primary and secondary control systems.

Section 10.1 contains descriptions of instruments which measure the following parameters as well as the uses for their outputs:

- Temperature (10.1.1),
- Pressure (10.1.2),
- Level (10.1.3),
- Flow (10.1.4),
- Reactor vessel level (10.1.5), and
- RCS subcooling (10.1.6).

In addition, pressurizer pressure control (Section 10.2) and pressurizer level control (Section 10.3) are discussed.

Westinghouse Technology Systems Manual

Section 10.1

Reactor Coolant System (RCS) Instrumentation

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LIST OF FIGURES

10.1 REACTOR COOLANT SYSTEM (RCS) INSTRUMENTATION

Learning Objectives:

1. Describe how loop average temperature (T_{avg}) and temperature difference (ΔT) are derived from the coolant loop narrow-range resistance temperature detector (RTD) outputs, and how these signals are used.

2. List the functions of the following temperature monitors:

   a. Reactor coolant system (RCS) wide-range temperature detectors;
   b. Pressurizer, pressurizer surge line, and pressurizer spray line detectors;
   c. Safety and relief valve discharge line detectors;
   d. Pressurizer relief tank (PRT) detector; and
   e. Reactor vessel flange leak-off detector.

3. Explain how the differential pressure (ΔP) cells at RCS piping elbows are used to measure RCS flows.

10.1.1 Temperature

10.1.1.1 Narrow-Range Temperature Detectors

Reactor coolant temperatures are measured by Resistance Temperature Detectors (RTDs) in the hot and cold legs of the Reactor Coolant System (RCS). The outputs of the narrow-range temperature instrumentation (T_h and T_c) are further processed to provide the average temperature (T_{avg}) and the difference between the hot-leg and cold-leg temperatures (ΔT) for each coolant loop. These processed signals are used for control room indication, inputs to various control systems, and inputs to the Reactor Protection System (RPS) for the generation of protection-grade interlocks and reactor trip signals.

Figure 10.1-1 shows the arrangement for measuring narrow-range temperature. Three narrow-range hot-leg RTDs are located 120° apart circumferentially, ensuring that a representative temperature of the hot-leg flow is measured.

A dual-element RTD is inserted into each thermowell. One element provides an electronic signal to a low voltage amplifier. The amplified signals from the three hot-leg RTDs of a particular loop are averaged together to generate a single narrow-range T_h signal (T_h average or T_{have}) for that loop. This averaged signal, along with the T_c signal from that loop, are used to generate a loop T_{avg} and a loop ΔT signal.

The cold-leg narrow-range RTD of each loop, also a dual-element, fast-acting RTD, is inserted into a thermowell directly downstream of the reactor coolant pump. Due to the turbulent flow at the discharge of the Reactor Coolant Pump (RCP), only one narrow-range RTD is required to provide an accurate indication of temperature. One element of the RTD provides the narrow-range T_c signal for its associated loop.

The second element of each fast-acting RTD, at each location, is considered an installed calibrated spare. It is wired directly to the RPS cabinets, but it is not connected to any electronics. In the event of a failure of the in-service temperature element, the spare element is available for use.

The narrow-range cold-leg RTDs are calibrated to provide an output of 510 - 630°F, while the narrow-range hot-leg RTDs are calibrated to provide an output of 530 - 650°F. Figure 10.1-2 illustrates how the hot- and cold-leg RTD temperature signals are combined to calculate a loop T_{avg} with a range of 530°F - 650°F, and a loop ΔT with a range of 0 - 150%. These calculated values provide information to the control room operators concerning plant conditions.

Figure 10.1-2 also shows that the calculated T_{avg} and ΔT for each loop are provided to the RPS for various protective functions. Each loop T_{avg} is provided to an RPS channel for the calculation of the overtemperature ΔT (OT ΔT) and overpower ΔT (OP ΔT) trip setpoints. Each loop ΔT is also provided to an RPS channel, where it is compared to both the OT ΔT and OP ΔT trip setpoints. In addition, the loop T_{avg} signals are used to generate two protection-grade interlocks, low T_{avg} and low-low T_{avg} (permissive P-12). The protection-grade signals are separated from the control-grade signals by isolation amplifiers.

The T_{avg} and ΔT inputs to control systems are provided via auctioneering units, which select the highest of the four input loop values. Auctioneered high T_{avg} is supplied to the rod control system (Section 8.1), the pressurizer level control system (Section 10.3), and the steam dump control system (Section 11.2). In addition, auctioneered high T_{avg} and ΔT are supplied to the rod insertion limit calculators (Section 8.4).

Reactor coolant T_{avg} [$(T_h+T_c)/2$] indicates the condition of the coolant with regard to the margin to saturation, the heat capacity of the reactor coolant, and the deviation from the programmed temperature setpoint (T_{ref}). The rate of change of T_{avg} and its deviation from T_{ref} are indicative of an imbalance between primary and secondary power. The average temperature of the coolant is also an input to the determination of margin to departure from nucleate boiling (DNB).

When the reactor coolant is subcooled, the coolant ΔT (T_h - T_c) is directly proportional to reactor power, and ΔT is used in both control and protection systems as a measure of reactor power.

10.1.1.2 Wide-Range Temperature Detectors

Hot- and cold-leg reactor coolant loop temperatures are also measured by wide-range RTDs (0-700°F) mounted in thermowells in the reactor coolant piping of each loop. These detectors provide indication during heatups and cooldowns and during natural circulation operation. Certain cold-leg and hot-leg wide-range RTDs supply inputs to the subcooled margin monitor (section 10.1.6). The hot-leg wide-range RTDs provide inputs to the reactor vessel level indicating system (RVLIS - section 10.1.5).

10.1.1.3 Pressurizer, Surge Line, and Spray Line Temperature Detectors

There are two temperature detectors on the pressurizer (Figure 10.1-3). One measures steam temperature, and the other measures the water temperature of the pressurizer. Under normal conditions, the pressurizer is a two-phase system in equilibrium, so the water and steam temperatures are equal. When they are not, an abnormal condition is indicated.

The surge line temperature detector provides indication and a low temperature alarm (< 517°F). A low temperature alarm indicates that a large insurge of relatively cold water has entered the pressurizer or that ambient heat losses have lowered the temperature to the alarm setpoint. The temperature in the surge line should remain high due to the constant outflow from the pressurizer which balances the small constant spray bypass flow.

Each spray line has a temperature detector which provides indication and provides a low temperature alarm (< 450°F). Normal detector readings indicate that the spray bypass flows are keeping the spray lines and pressurizer spray nozzle at a temperature near that of the RCS cold legs (see Chapter 3.2). A low temperature alarm could indicate a loss of spray bypass flow, or an incorrectly positioned spray bypass throttle valve. Low spray line temperatures could subject the spray nozzle to thermal shock when pressurizer spray is demanded.

10.1.1.4 Safety and Relief Valve Discharge and Pressurizer Relief Tank Temperature

Figure 10.1-3 shows a temperature detector on the discharge line from each pressurizer safety valve and a single temperature detector on the common discharge line from both Power Operated Relief Valves (PORVs). These temperature detectors provide indication in the control room that a safety or a power-operated relief valve has opened or is leaking.

A high temperature alarm is actuated when the temperature measured by any of these detectors exceeds 160°F. This alarm alerts the control room operator to a discharge through one or more relief lines, or to leakage past one or more valve seats. Since these detectors are located close to each other, any single valve opening causes an increase in the temperature sensed by all of them.

A temperature detector on the Pressurizer Relief Tank (PRT) provides indication and generates a high temperature alarm (> 112.5°F). This detector is shown in Figure 10.1-3. A high temperature in the PRT is an alternate method of alerting the control room operator to a relief valve opening or to possible leakage past a relief valve seat.

10.1.1.5 Reactor Vessel Flange Leakoff Temperature Detector

A temperature detector located between the leakoff line isolation valve and the Reactor Coolant Drain Tank (RCDT) is provided to alert the reactor operator to a leak from the reactor vessel flange O-ring seal. This alarm provides audible annunciation in the control room and is normally set 20°F above the ambient temperature of the containment.

The reactor vessel flange leak detection system may be isolated from the reactor coolant drain tank by closing an air-operated valve (CV-8032) from the main control board. This valve is designed to fail closed upon a loss of instrument air to containment. If the reactor vessel flange inner O-ring starts leaking, the outer O-ring may be placed in service by manually realigning two valves located inside the containment. (See Section 3.1 for additional vessel flange seal details.)

10.1.2 Pressure

10.1.2.1 Pressurizer Pressure Detectors

Four pressurizer pressure transmitters provide indication and control- and protection-grade signals. These signals provide indications in the control room and inputs to the pressurizer pressure control system (Chapter 10.2) and the reactor protection system (Chapter 12.2). The pressure in the pressurizer is maintained by the operation of heaters immersed in the water volume at the bottom of the pressurizer and spray valves in the steam volume at the top. These transmitters are narrow range, with an indication span of 1700 - 2500 psig.

10.1.2.2 Reactor Coolant Loop and Pressurizer Relief Tank Pressure Detectors

Two pressure transmitters (PT-403 and PT-405) are located in the residual heat removal (RHR) system suction line near its penetration into the RCS hot leg (loop 4). These are wide-range transmitters (0-3000 psig) and provide indication during startups and shutdowns. They also provide interlocks to permit manual opening of (pressure < 425 psig) and to automatically close (pressure > 585 psig) the two isolation valves in the RHR suction line from the RCS. The automatic closure of these valves prevents overpressurizing the RHR system piping.

A pressure transmitter on the pressurizer relief tank provides indication in the main control room as well as a high pressure alarm set at eight psig. A high pressure in this tank may be indicative of pressurizer relief valve discharge into the PRT.

10.1.3 Pressurizer Level

Three pressurizer level transmitters provide indication and control- and protection-grade signals. These signals provide indications in the control room and inputs to the pressurizer level control system (Section 10.3) and the reactor protection system (Section 12.2). The level in the pressurizer is a direct measure of reactor coolant inventory. These transmitters are calibrated for the normal pressurizer operating temperature of 650°F. A fourth level transmitter is cold calibrated (80°F) and provides level indication during heatup, refueling, and cold shutdown operations.

10.1.4 Reactor Coolant Flow

As shown in Figure 10.1-1, flow in each reactor coolant loop is measured by three differential pressure (d/P) transmitters located at the first bend (elbow) in the intermediate leg of each reactor coolant loop. The square root of the difference between the pressure at the outside radius and the pressure at the inside radius of the bend is proportional to flow. The developed flow signals provide indications in the control room and inputs into the reactor protection system.

There is one common High Pressure (HP) tap at the outside radius of each intermediate-leg elbow, and there are three separate Low Pressure (LP) taps at the inside radius (see Section 3.2). The pressure at the HP tap is the sum of the static reactor coolant system pressure and the pressure resulting from the centrifugal force exerted by the coolant flow (the force is proportional to the square of the flow velocity). The LP taps sense only the static coolant system pressure. Therefore, the difference in pressure between the outside radius and the inside radius of the intermediate leg is dependent upon flow.

If the HP tap fails (it becomes clogged, or the instrument line ruptures), all three d/P transmitters would fail low (indicating an apparent loss of flow) and a reactor trip would result (all three measured flows would be less than the loop low flow trip setpoint). If the flow indication arrangement were designed with only one LP tap and it failed, then all three d/P transmitters would fail high, which is in the nonconservative direction, and a reactor trip on low flow in this loop could not occur. Therefore, three LP taps are used to provide redundancy and a conservative system response. If one of the three LP taps were to fail, only its corresponding d/P transmitter would be affected (fails high), leaving the remaining two d/P transmitters to provide proper indications of flow, as well as low flow inputs to the RPS if flow is reduced or lost in that loop.

10.1.5 Reactor Vessel Level Indicating System (RVLIS)

The Reactor Vessel Level Indicating System (RVLIS) is designed to provide a reliable method of indicating the water level within the reactor vessel under normal and accident conditions. This instrumentation system is installed in the plant to satisfy a requirement of NUREG-0737. In addition to supplying reactor vessel water level indication during normal operations, the RVLIS also performs the following functions during abnormal operating and accident conditions:

a. Indicates the formation of voids in the reactor coolant system during forced circulation;
b. Detects the approach to inadequate core cooling, and provides information needed for selecting emergency operating procedures associated with inadequate or degraded core cooling;
c. Detects voiding in the reactor vessel head;
d. Provides an accurate measurement of the reactor vessel water level during natural circulation; and
e. Provides information to the operator during operation of the reactor vessel head vent system.

As shown in Figure 10.1-4, the RVLIS utilizes two trains of instrumentation; each train includes three d/P transmitters for three different ranges of vessel level measurement. These transmitters are designed to measure the water level within the reactor vessel or to provide information on the relative void content of the fluid surrounding the core during various operating conditions.

Penetrations for the RVLIS into the reactor coolant system pressure boundary are made through a spare control rod drive mechanism penetration in the vessel head near its center (low pressure tap) and through an incore instrument conduit at the seal table (high pressure tap). In addition, two penetrations (one per hot leg) are made in loops 3 and 4.

Each sensing line extending from an RCS penetration includes a sensor bellows unit in containment. The bellows units provide hydraulic coupling for pressure measurements. From its bellows unit each sensing line extends through a containment penetration to a second hydraulic coupling device, a hydraulic isolator. The hydraulic isolator contains two opposing liquid-filled bellows linked by a connecting rod. Each hydraulic isolator acts as a second isolation valve for the RCS and functions as a containment isolation valve. From the hydraulic isolator, the sensed pressure is applied to the appropriate d/P transmitter(s).

As shown in Figure 10.1-5, the differential pressures for the three measurement ranges are supplied to a microprocessor (one per train). In addition, pressure and temperature inputs to each microprocessor are used for density compensation of the measured fluid pressures. The microprocessor adjusts the measured d/Ps for fluid density variations resulting from environmental conditions inside the containment to generate reactor vessel levels.

Each microprocessor is located in a cabinet in the control room. The RVLIS level outputs are displayed remotely in the control room and are supplied to the plant computer. The RVLIS provides no annunciation in the control room.

The following paragraphs describe the three d/P transmitters and the ranges of level measurement that they provide.

One d/P transmitter is calibrated to measure the level in the reactor vessel with the reactor coolant pumps operating (shown as ΔPc in Figures 10.1-4 and 10.1-5). The output from this transmitter is referred to as the dynamic range, with an indicated range of 0 - 120%. It provides an indication of the differential pressure between the bottom and top of the reactor vessel with forced circulation flow in the RCS. The indicated dynamic range level is typically between 100 and 110%.

The reactor coolant pumps can circulate water and steam as an essentially homogeneous mixture. Therefore, if the reactor coolant pumps are circulating coolant with a void fraction greater than zero, there will not be a distinct water level in the reactor vessel. However, a comparison of the measured d/P across the reactor vessel with the normal single-phase flow d/P provides an approximate indication of the relative void content or density of the circulating fluid.

It should be understood that this instrument is not providing an indication of reactor vessel level per se during forced circulation, but an indication of the relative void fraction of the reactor coolant. In addition, this instrument provides a backup level indication with the reactor coolant pumps turned off; i.e., this instrument is calibrated so that it indicates 40% with the reactor vessel full of water and the reactor coolant pumps turned off. Therefore, during natural circulation a value of less than 40% would be an indication that the reactor vessel is not completely full.

The second d/P transmitter is calibrated to measure the coolant level in the reactor vessel with the reactor coolant pumps secured (ΔPb). This indication is referred to as the full range and spans the total height of the reactor vessel (approximately 40 ft). The full-range level should be 100% (the instrument range is 0-120%) with natural circulation flow and the reactor vessel completely filled with subcooled coolant (See Figure 10.1-6, RVLIS Full Range).

When all reactor coolant pumps are stopped, if any voids exist in the reactor coolant, they separate from the liquid. As a result, the liquid collapses toward the bottom of the reactor vessel and the steam voids rise and fill the upper portion of the reactor vessel. This transmitter's output is an indication of the collapsed water level. The actual water level in the reactor vessel may be slightly higher than that indicated, due to the presence of very small steam bubbles (froth) mixed with the coolant liquid volume. In this instance, the RVLIS provides a conservative indication of coolant level.

With the reactor coolant pumps operating, the pressure sensed at the bottom of the vessel (the high pressure tap) is higher than that during natural circulation. As a result of the higher sensed d/P, the full range indication is off-scale high during forced circulation, and the information provided is invalid.

The third d/P transmitter provides an indication of the water level in the reactor vessel head (ΔPa). This indication is referred to as the upper range and spans the total height from the hot leg to the top of the reactor vessel head (approximately 15 ft). The range of indication is 60-120% with natural circulation flow in the reactor coolant system. The upper-range level should be 100% with natural circulation flow and the reactor vessel completely filled with subcooled coolant. This instrument provides an accurate indication of possible voiding in the upper head region and provides useful information during reactor vessel head venting. This measurement also provides backup confirmation that the level in the RCS is above the hot-leg nozzles.

Because the hot-leg tap is positioned to sense static pressure only, when the reactor coolant pumps are operating, the measured d/P is less than the calibrated span of the upper-range instrument during natural circulation (the indication is off-scale low). Therefore, like the indication from the full-range instrument, the output from this instrument is invalid whenever there is forced flow through the core.

In summary, the RCP operational status has a large influence on the outputs of these d/P transmitters. The dynamic-range transmitter, ΔPc, is calibrated to indicate 100% (or slightly greater) with the reactor coolant pumps operating and 40% without any RCPs operating. The full-range transmitter, ΔPb, and the upper-range transmitter, ΔPa, are calibrated to indicate 100% with the reactor vessel full of water and without any reactor coolant pumps operating. If the reactor coolant pumps are operating, the full-range and upper-range indications are off-scale high and low, respectively. Accordingly, the remote RVLIS panels display the RCP status and the expected levels for each indication range in addition to the actual measured levels.

Because of the relatively long sensing lines, temperature changes in the reactor coolant and changes in the ambient air temperature inside the containment affect the measured levels in the reactor vessel. Each RVLIS microprocessor is supplied with the following inputs to account for the effects of density changes on the measured d/Ps to ensure that the indicated level is as accurate as possible:

- Wide-range T_h (two),
- Wide-range loop pressure (one) and,
- Capillary tube RTD temperatures (seven).

The temperatures of the sensing lines are used to compensate for the density of the fluid. The temperatures are obtained from strap-on RTDs (vertical capillary tube RTDs), which are placed on the vertical portions of various sensing lines. The following are areas through which sensing lines pass and where these strap-on RTDs may be placed:

- Reactor vessel cavity,
- Incore thimble tunnel,
- Hot-leg penetration area, and
- Rise above the seal table.

The capillary tube RTD temperatures, along with the reactor coolant wide-range T_h temperature and reactor coolant system wide-range pressure, are supplied to microprocessor algorithms which automatically compensate the d/P transmitter outputs for density changes.

The remaining inputs into the RVLIS microprocessor are provided by hydraulic isolator limit switches. These switches provide over-travel alarms. An alarm indicates an abnormally large deflection or failure of an isolator bellows, and alerts the operators that a hydraulic isolator is operating in an undesirable condition. An overtravel alarm does not necessarily mean that the information provided by the RVLIS is invalid.

Figure 10.1-6 shows the relationship between indicated RVLIS level and core coverage.

10.1.6 Subcooling Margin Monitoring

At a given plant, the reactor coolant subcooling margin (margin to saturation) can be computed either manually with the aid of steam tables or automatically by a computer-based algorithm. In either case, pressure inputs are supplied by either the RCS wide-range pressure detectors or the pressurizer pressure detectors. In most instances, RCS wide-range pressure inputs are used. The temperature inputs used in the computation are RCS wide-range T_h and T_c and temperatures from the core-exit thermocouples (CETs). The temperature input that ultimately determines the amount of coolant subcooling is typically one of the CET temperatures.

The Subcooled Margin Monitor (SMM) installed in the plant modeled by the TTC Westinghouse simulator is a microprocessor-based instrumentation system which continually displays the margin to saturation of the reactor coolant. This instrument can determine the subcooling margin in terms of RCS pressure or temperature. It serves as a post-accident monitoring instrument in conjunction with the RVLIS and CETs. It quickly and accurately detects the approach to or existence of saturated conditions in the reactor coolant.

As shown in Figure 10.1-7, each train of the SMM receives the following process inputs:

- One RCS wide-range pressure input,
- Two wide-range loop hot-leg temperatures,
- One wide-range loop cold-leg temperature,
- Eight CET temperatures, and
- One cold junction RTD temperature.

The reactor coolant system pressure input is provided by RCS wide-range pressure instruments PT-403 (train A) and PT-405 (train B). Only one pressure input is sent to each train, and there is no designated alternate pressure input.

Wide-range T_h inputs from loops two and four are supplied to the train A SMM, while T_h inputs from loops one and three are supplied to train B. Due to the limit on inputs to the SMM, only one T_c input is provided to each train of the SMM. The wide-range T_c from loop one is input to train A, while the wide-range T_c from loop three is input to train B.

Eight core-exit thermocouple inputs (two per core quadrant) are provided to each SMM train. If a thermocouple fails, an input from a designated alternate thermocouple may be substituted at the respective train's isolator.

Cold reference junction temperature inputs are also provided to the SMM calculator modules. Adjusting the CET inputs as necessary with the reference junction temperature increases accuracy by compensating for temperature effects on the thermocouple cabling.

Two analog outputs are provided by each train of the SMM. One drives a remote temperature display panel (indicating degrees subcooled or superheated) in the control room. The other output is sent to the plant computer and the remote shutdown station. In addition, two alarm signals (annunciated in the main control room) are provided from the SMM to alert the control room operator to an impending loss of core subcooling or to the actual loss of subcooling. The setpoints for these alarms are as follows:

- 15°F for low margin, and
- 0°F for no margin of subcooling.

During normal operation each SMM train supplies a digital display module which displays the margin to saturation in either temperature or pressure units (selectable by the control room operator with a pushbutton on the display panel). The selected mode is indicated by the backlighting of either the “TEMP” or “PRESS” segment of the pushbutton. The displayed value is updated every two seconds.

When the pushbutton indicates that “TEMP” is selected, the subcooling margin is displayed in °F with a resolution of 0.1°F. The indicated temperature margin is the difference between the temperature at which the coolant will boil (saturation temperature) and the measured reactor coolant temperature.

The highest of all the active input temperature values is used to calculate the temperature margin. The high-selected temperature is compared to the saturation temperature calculated from the wide-range pressure input. The calculated result is then the worst-case temperature margin. A negative temperature margin indicates superheated conditions.

When the pushbutton indicates that “PRESS” is selected, the subcooling margin is displayed in psi with a resolution of one psi. The indicated pressure margin is the difference between the measured reactor coolant pressure and the pressure at which the coolant will boil (the saturation pressure). The saturation pressure is calculated from the high-selected temperature input.

The SMM is particularly useful during accident and post-accident conditions when primary coolant temperature and pressure may be rapidly changing. The control room operator is provided with a continuous indication of the margin to saturation and is thus able to devote his attention to mitigating the consequences of the accident or abnormal condition. The possibility of unknowingly changing plant parameters which could lead to uncovering the core is greatly reduced, as the SMM provides automatic alarms at preset subcooling setpoints.

Operability requirements for the SMM trains are contained in the technical specification limiting condition for operation (LCO) for post-accident monitoring instrumentation. The impacts of failed inputs on SMM operability are discussed in the following paragraphs.

The wide-range loop RTDs (T_h and T_c) are input to the SMM only because they were included in the original SMM design. Should an RTD fail, its input can be disabled in accordance with approved procedures at the affected panel, and the associated SMM train is still operable. The RTD inputs are thus "nice to have," but are not required for operability. However, since there is only one pressure input per train, the affected SMM train is inoperable when a wide-range pressure detector fails. There is no immediate recovery from this condition short of repairing the pressure input.

Flexibility was considered in the design of the SMM so that a failure of a CET can be overcome. The outputs of all 65 CETs are routed to two process panels, 32 CET outputs to one panel, and 33 CET outputs to the other panel. Eight operable core-exit thermocouples, two CETs per core quadrant, are required for each SMM train. Eight signals from each process panel are thus transmitted to an SMM train. Any single failed CET input is easily removed from the SMM and replaced by an alternate CET input. The CET which is selected as an alternate must be from the same core quadrant as the failed CET. The operability of the CETs themselves, apart from their impact on SMM operability, is also addressed by the post-accident monitoring LCO.

10.1.7 Summary

RTDs monitor the RCS loop temperatures. These instruments are divided between wide-range (0-700°F) and narrow-range (510 - 630°F or 530 - 650°F) RTDs. The wide-range instruments provide indication in the control room and supply inputs to the RVLIS and the SMM. The signals from the narrow-range RTDs are electronically combined to form T_{avg} and ΔT signals, which are used to provide indication for the control room operator and inputs to control systems and the reactor protection system.

Temperatures in the pressurizer, pressurizer surge and spray lines, pressurizer safety and relief valve discharge lines, the pressurizer relief tank, and the reactor vessel flange leakoff line are also monitored.

Reactor coolant system wide-range pressure (0 - 3000 psig) is monitored by pressure transmitters located on the residual heat removal suction piping, which is attached to loop four of the reactor coolant system. In addition, the pressurizer and pressurizer relief tank are instrumented so that the reactor operator can monitor the pressure and level of these tanks. The pressurizer pressure and level transmitters and their outputs are discussed in Sections 10.2 and 10.3, respectively.

The flow in the reactor coolant system is continuously monitored by loop elbow flow d/P transmitters. The flow in each loop is proportional to the square root of the d/P between the inner and outer radii of the loop elbow. Each reactor coolant loop has three d/P transmitters that provide signals for indication and protection.

The RVLIS monitors the level within the reactor vessel during normal and abnormal plant conditions. This system incorporates a number of d/P transmitters to indicate the water level in the reactor vessel. The validity of the different RVLIS indicating ranges is sensitive to the presence or absence of forced circulation flow. In the event of an accident, the RVLIS aids the operator in selecting the proper emergency procedure for an inadequate or degraded core cooling condition.

The SMM provides an indication of the margin to saturation of the reactor coolant. The SMM and the RVLIS are required by NUREG-0737, and their operability is dictated by the plant's technical specifications.

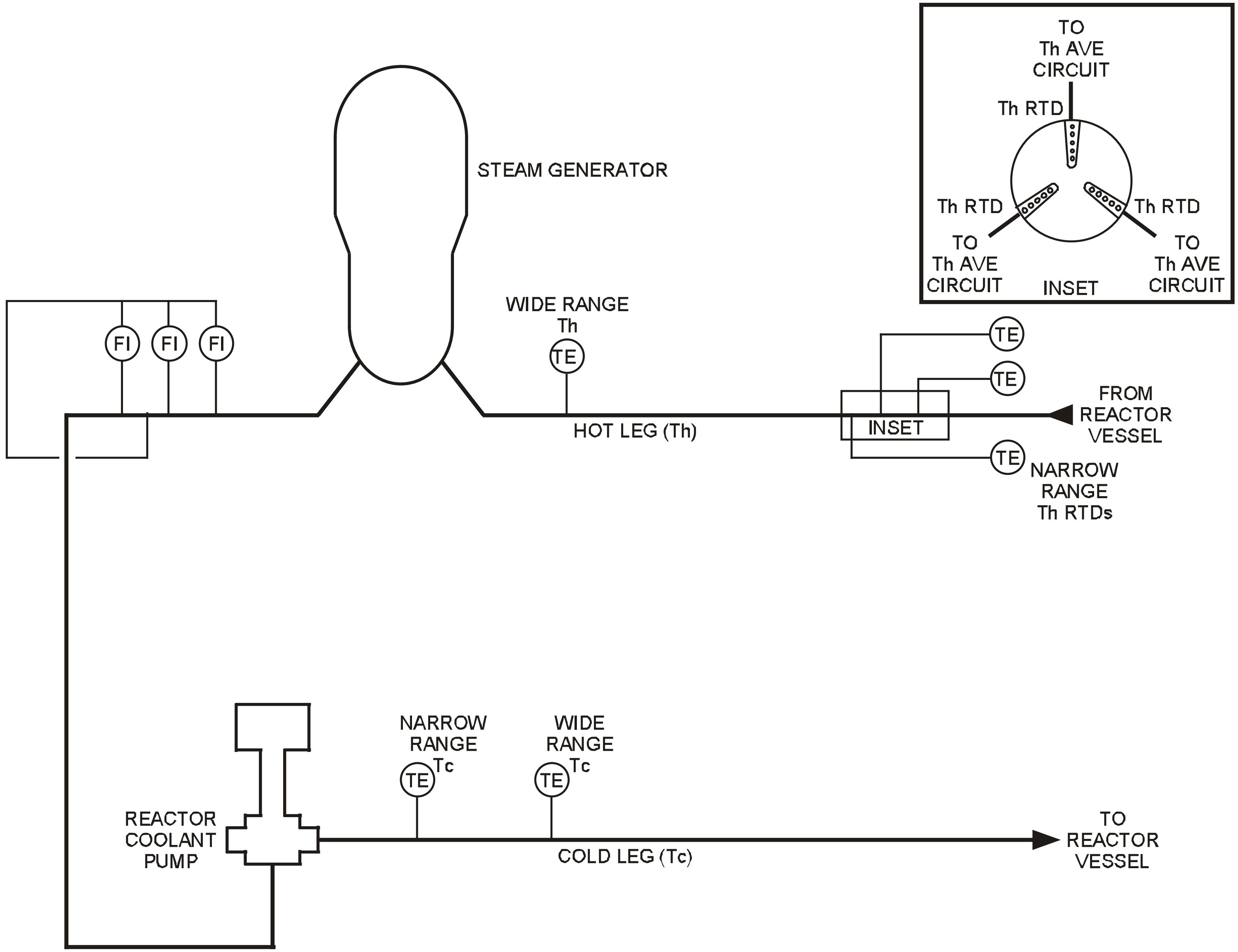


Figure 10.1-1 RCS Loop Instrumentation

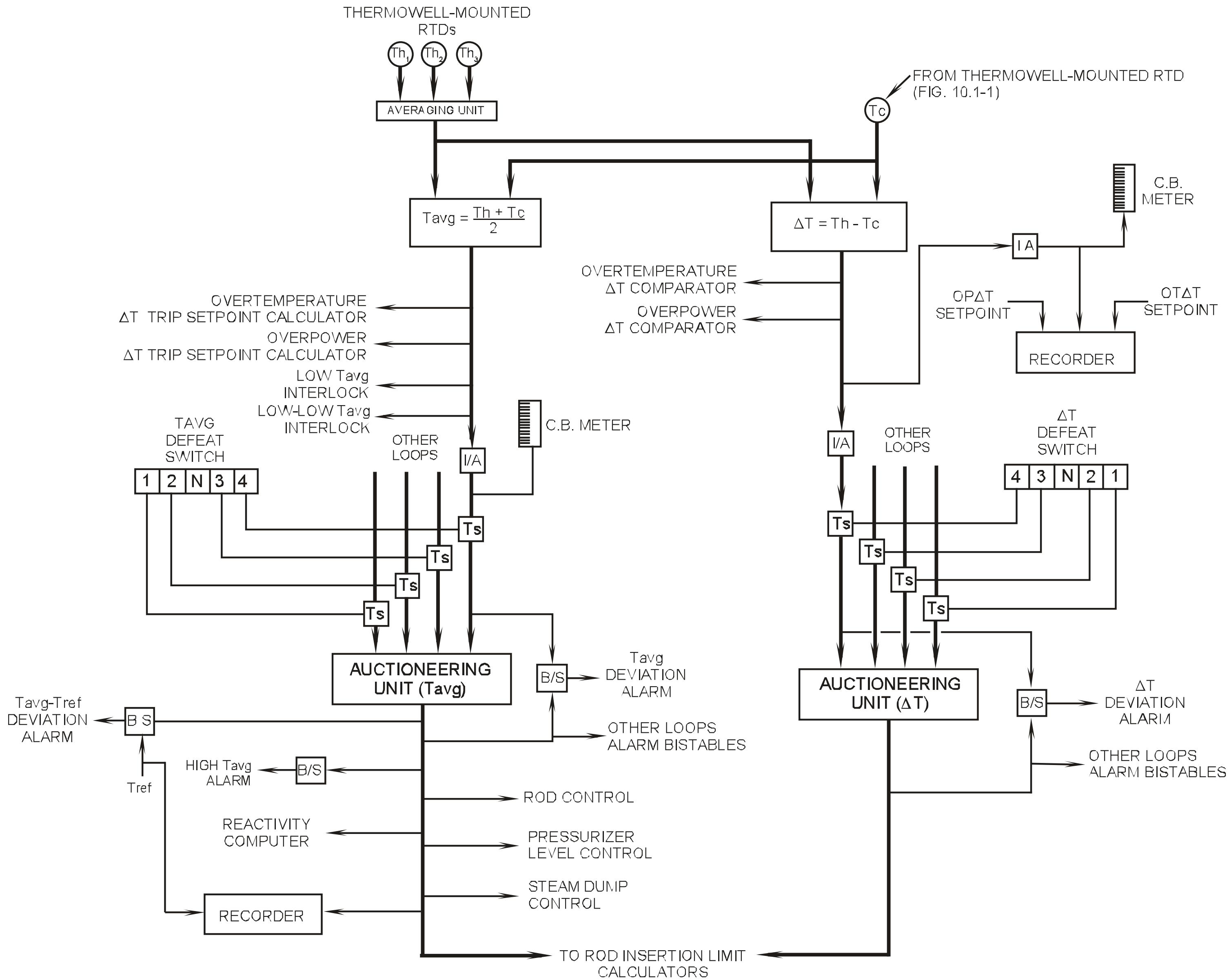


Figure 10.1-2 RCS Temperature Instrumentation

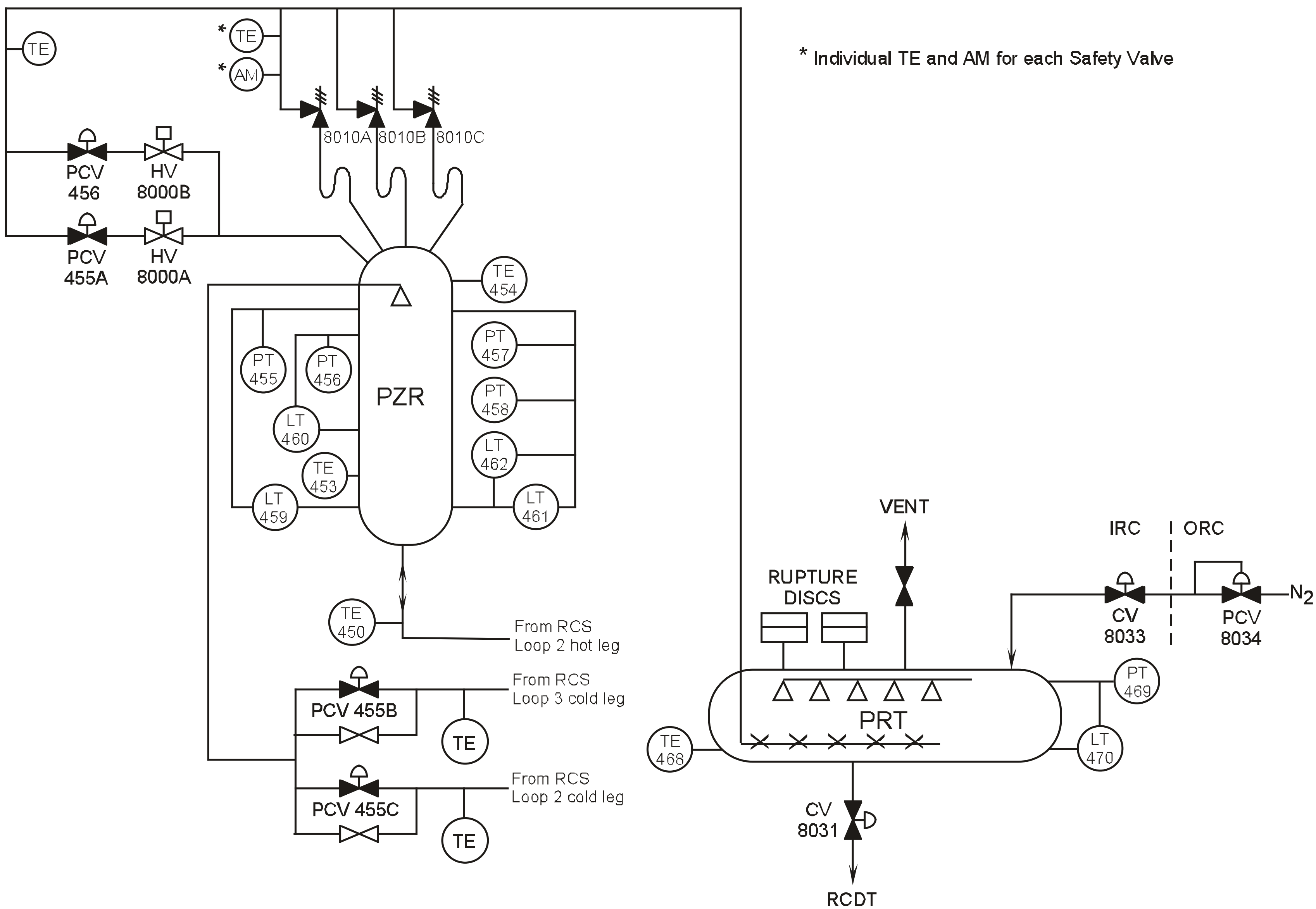


Figure 10.1-3 Pressurizer and Pressurizer Relief Tank

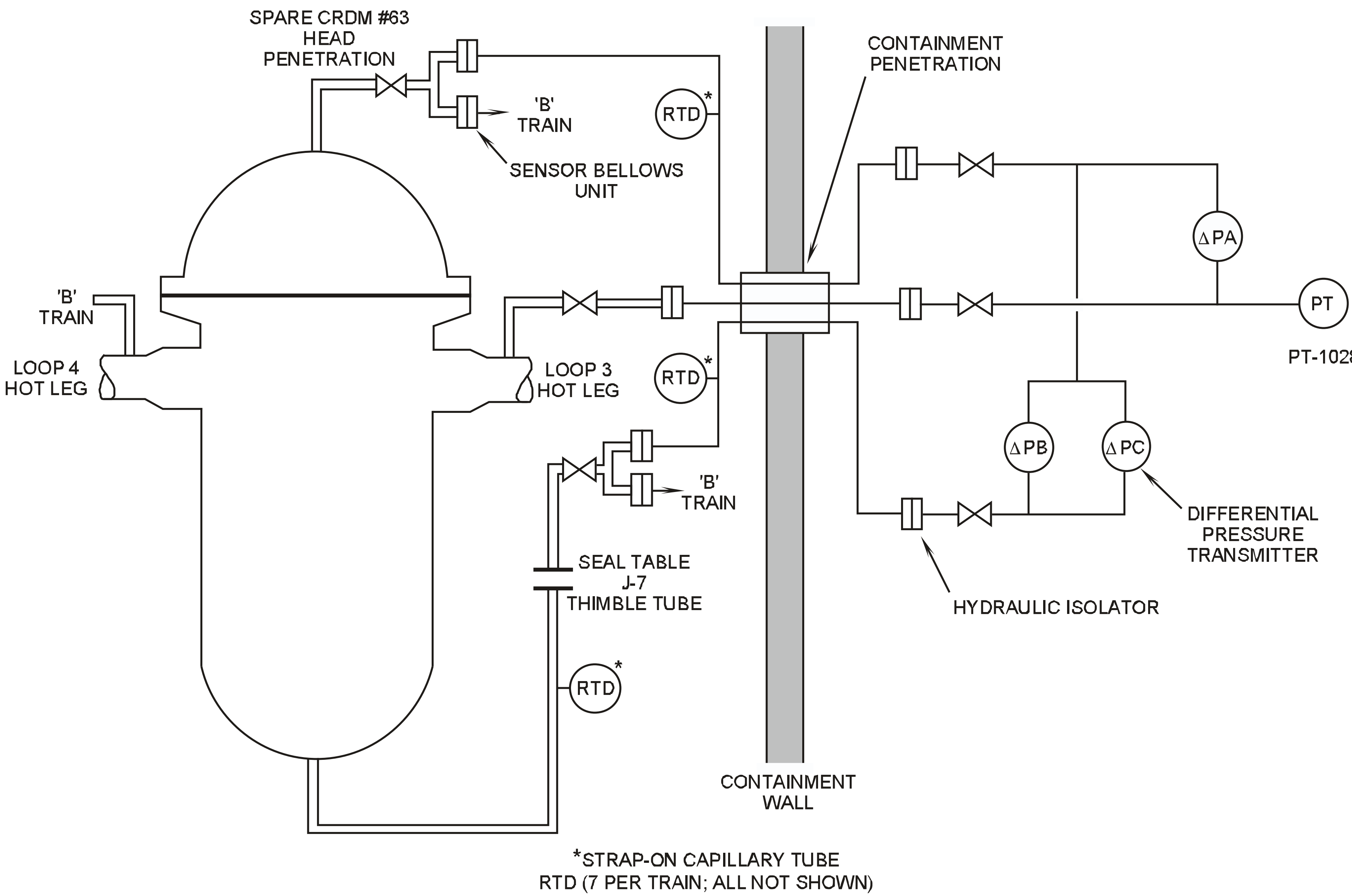


Figure 10.1-4 Reactor Vessel Level Indication System

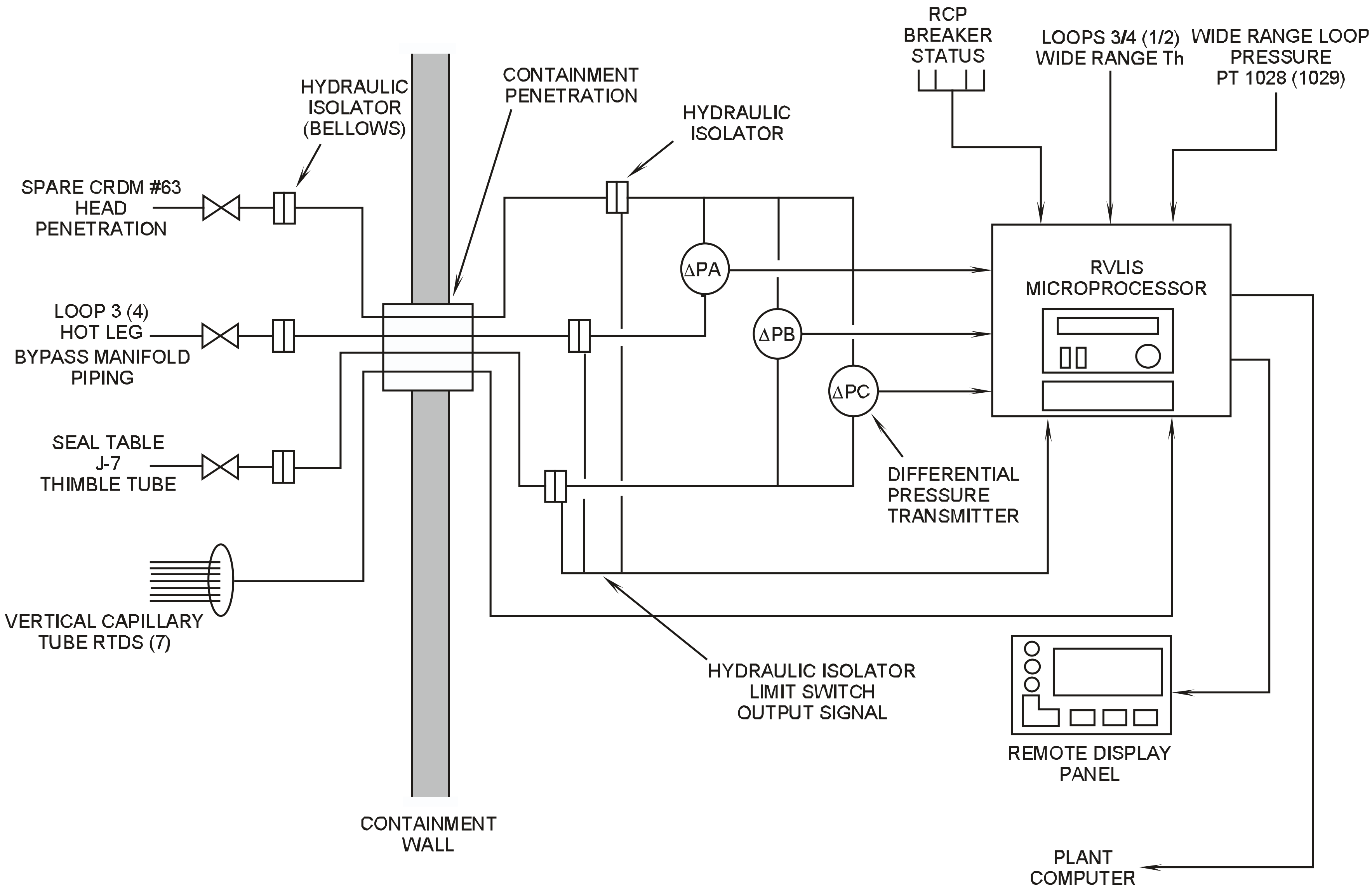
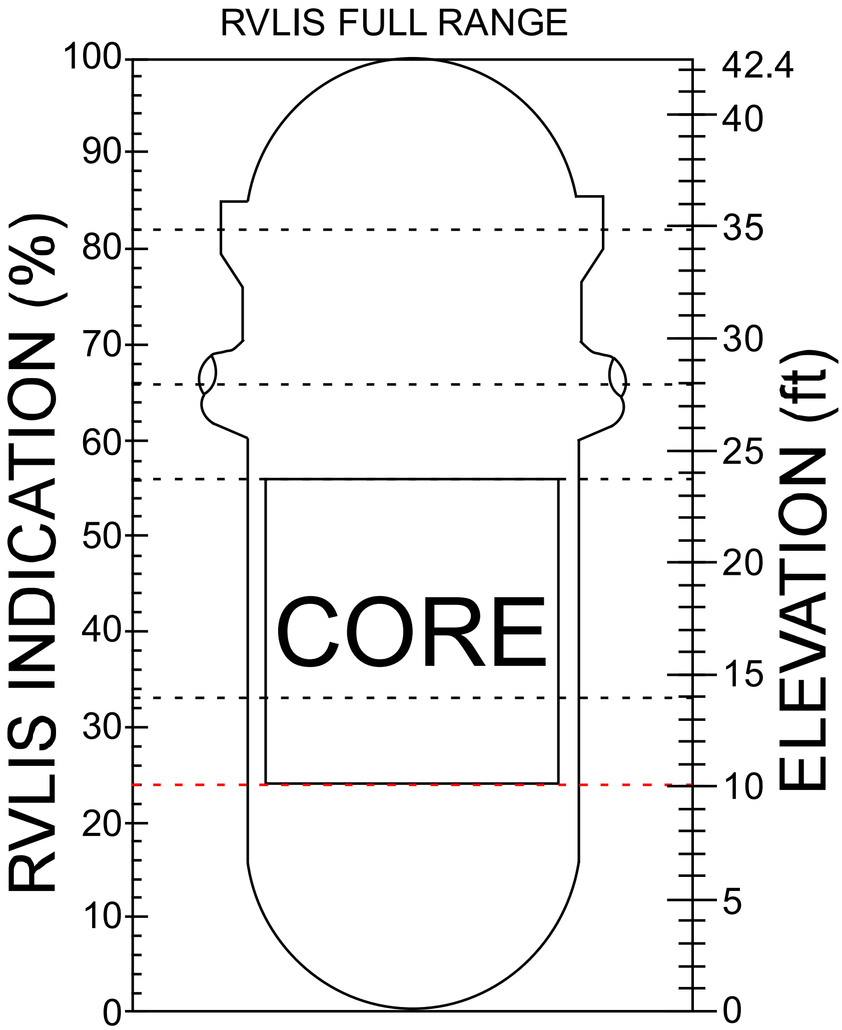


Figure 10.1-5 RVLIS Microprocessor Block Diagram



RVLIS Indication*	Approximate Vessel Water Level
100%	Top of Vessel
82%	Vessel Flange
66%	Inlet/Outlet Nozzles
56%	Top of Core
33%	3.5 ft. from Bottom of Core
24%	Bottom of Core
0%	Bottom of Vessel

*These values do not reflect uncertainty of 6%
(e.g. EOPs use 39% for 3.5 ft. from Bottom of Core)

Figure 10.1-6 RVLIS Full Range

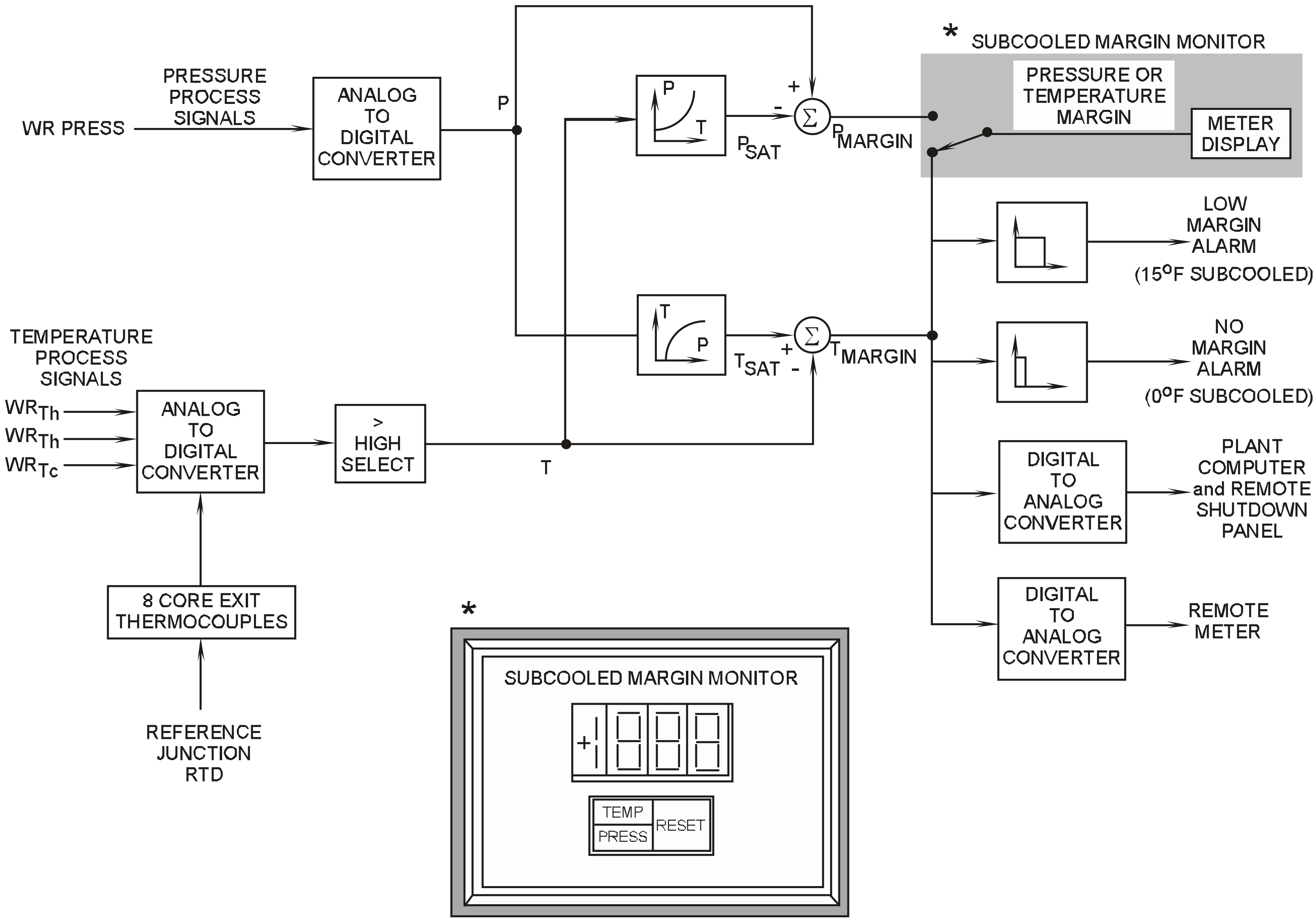


Figure 10.1-7 Subcooling Margin Monitor

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Section 10.2

Pressurizer Pressure Control (PPC) System

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10.2 PRESSURIZER PRESSURE CONTROL (PPC) SYSTEM

Learning Objectives:

1. List and describe the purposes (bases) of the protective signals provided by the pressurizer pressure transmitters.

2. List and describe the purposes of the permissives and interlocks provided by the pressurizer pressure transmitters.

3. List in sequence the actions performed by the pressurizer pressure control system during:

   a. A continuous pressure increase above the normal pressure setpoint (2235 psig), and
   b. A continuous pressure decrease below 2235 psig.

4. Explain the effect of changing the pressure control setpoint on both control and protective functions.

5. List the inputs to the cold overpressure protection system, and explain the operation of the system.

10.2.1 Introduction

The pressurizer pressure control system maintains Reactor Coolant System (RCS) pressure within a narrow band around an operator selectable setpoint. The setpoint span is 1700 psig to 2500 psig, and the setpoint is normally set to 2235 psig.

The input to the master pressurizer pressure controller is the error between actual pressurizer pressure and the setpoint. The output of the master controller controls the operation of electrical heater banks, pressurizer spray valves, and one Power Operated Relief Valve (PORV). Separate control system inputs trigger operation of the second PORV. When these components are actuated at the proper times, under- and overpressurization events are minimized.

10.2.2 System Description

The pressurizer heaters are divided into four banks: one bank of proportional heaters (heater bank C) and three banks of backup heaters (heater banks A, B, and D). The proportional heaters are controlled by varying the percentage of time during which they are energized. The backup heaters are either constantly energized or constantly de-energized.

If the pressure in the pressurizer decreases from the desired pressure of 2235 psig, the master controller increases the output of the proportional heaters (increases the percentage of time that they are energized). If the pressure continues to decrease, all banks of backup heaters are turned on. As the heaters add energy to the water in the pressurizer, more water flashes to steam, thereby increasing the pressure to the desired setpoint.

As the pressure in the pressurizer increases above its normal setpoint, the master controller decreases the output of the proportional heaters. If the pressure continues to increase, the master controller output modulates the spray valves open. Opening the spray valves allows reactor coolant to flow from the RCS cold legs (loop B and loop C) through the spray nozzle into the pressurizer. The relatively cool water spraying into the steam space of the pressurizer condenses some of the steam, which in turn lowers pressurizer pressure.

If the spray valves are not capable of controlling the pressure increase for a large overpressure transient, the two PORVs, mounted on the pressurizer, open to aid the spray valves in minimizing the pressure excursion. The PORVs discharge steam into the Pressurizer Relief Tank (PRT).

For transients that exceed the capability of the control system, appropriate high- and low-pressure reactor trips and a low pressure engineered safety features actuation are actuated by the Reactor Protection System (RPS). If the high-pressure reactor trip is inoperable or an overpressure transient is of such a magnitude that the pressure in the RCS continues to increase beyond the trip setpoint, three code safety valves open to protect the integrity of the reactor coolant pressure boundary.

Figure 10.2-1 shows the pressurizer, its associated instrumentation, and the components used to control pressure. Figure 10.2-2 is a functional block diagram of the pressurizer pressure control system. The sequence of component operation and protective actions is shown in Figure 10.2-3.

The pressure from the selected pressurizer pressure channel (usually channel I, as shown in Figure 10.2-2) is compared to a variable pressure setpoint (normally 2235 psig). The resulting pressure error is the input to the master pressure controller, which is a Proportional + Integral + Derivative (PID) controller (reviewed in PPE and section 1.3). The integral action of the controller causes the controller output to vary with the duration of the pressure error and thus serves to return pressurizer pressure to setpoint. The derivative action causes the controller output to vary with the rate of change (derivative) of the pressure error and thus makes the controller responsive to rapid pressure changes.

The output from the master pressure controller provides input signals to the controllers for the proportional heaters and the spray valves (one controller for each spray valve). The master controller also provides inputs to the bistable that energizes the backup heaters, to the bistables for the high- and low-pressure alarms, and to the opening logic for one of the two PORVs.

Figure 10.2-3 shows the nominal master controller pressure setpoints for component actuation and modulation. These setpoints correspond to the proportional output of the controller only. The integral and derivative features of the controller could cause heater or spray operation at different pressures than those indicated in Figure 10.2-3. For instance, if pressurizer pressure were to remain at exactly 2250 psig (above the normal setpoint) for a significant period of time, the integrated pressure error would gradually add to the output of the controller, which would eventually modulate open the spray valves. In summary, the master pressure controller decreases the output of the variable heaters and then increasingly opens the spray valves in response to an increasing or persistently above-setpoint pressure, and it increases the output of the variable heaters and then energizes the backup heaters in response to a decreasing or persistently below-setpoint pressure. In either case, the controlled components should bring the pressure back to setpoint.

In accordance with the design of the pressurizer pressure control system, during normal operation the heaters and spray valves are placed in automatic, ready to respond to outputs from the master pressure controller. During steady-state operation, the controller energizes the proportional heaters to compensate for minor pressure fluctuations. The proportional heaters are energized for a small percentage of the time (a portion of each 10-sec interval) to compensate for the continuous bypass spray flow (approximately one gpm) and to compensate for heat losses from the pressurizer to ambient.

By contrast, at present many plants normally operate with some banks of backup heaters manually energized to promote spray flow so that water chemistry (boron concentration) in the pressurizer is maintained equivalent to that of the RCS. When the heaters are first energized, the additional steam formation in the pressurizer increases the pressure above the setpoint. The output of the master pressure controller increases until the spray valves partially open, and the spray flow reduces the pressure back to setpoint. The integrated pressure error over the duration when pressure exceeded setpoint generates sufficient controller output to keep the spray valves partially open. When steady-state conditions are reached, pressurizer pressure is maintained at the normal setpoint with the spray valves open just enough to counteract the effect of the energized backup heaters.

For sufficiently low pressurizer pressures, a low-pressure alarm is actuated in the main control room. This annunciator alerts the control room operators that a technical specification action requirement associated with the limiting condition for operation for Departure from Nucleate Boiling (DNB) may be in effect as a result of low pressurizer pressure.

The purpose of the two PORVs is to maintain RCS pressure below the high pressurizer pressure reactor trip setpoint during transients that cause pressure in the RCS to increase. In addition, if these valves operate as designed, they prevent or minimize the number of times the spring-loaded, self-actuating code safety valves lift. One PORV opens automatically at a fixed bistable setpoint of 2335 psig as sensed by the selected pressurizer pressure transmitter (usually channel II). The second PORV opens automatically with a sufficiently large master controller output (nominal 100-psi pressure error). The automatic opening of each PORV also requires the correct status of an interlocking bistable, which is supplied by a separate pressure transmitter. (See section 10.2.4.2 for relief valve interlock details.)

10.2.3 Reactor Protection Signals (RPS)

Four pressure transmitters are used to generate the required coincidence for the protective functions. These four channels also provide control functions through a channel selector switch which allows for testing an individual channel and, in the event of a failed transmitter, for substituting the output of a non-faulted detector into the control circuitry. The control functions of this system are physically separated from the protective features via isolation amplifiers. The protective functions of these pressure transmitters are discussed below and in detail in Chapter 12.

10.2.3.1 High Pressure Reactor Trip

The high-pressure trip is generated when pressure in the pressurizer exceeds 2385 psig, as sensed by at least two of four transmitters. It provides protection for the reactor coolant pressure boundary. This trip cannot be blocked by the operator.

10.2.3.2 Low Pressure Reactor Trip

The low pressure trip is generated when pressurizer pressure decreases to 1865 psig, as sensed by at least two of four transmitters. The low pressure reactor trip is functional whenever the power of the reactor or the turbine is greater than 10%. This trip is rate sensitive and protects against DNB (see Section 2.2).

10.2.3.3 Overtemperature ΔT Trip (OTΔT)

There are four separate OverTemperature ΔT (OTΔT) trip setpoint calculators (see Section 12.2). Each reactor protection system (RPS) channel has its own dedicated calculator. Each of the four pressurizer pressure transmitters supplies an analog pressure signal to its respective channel's calculator (e.g., pressurizer pressure channel I supplies an input to the RPS channel I OTΔT trip setpoint calculator). The pressure input is thus one of the DNB-related parameters used in the computation of the OTΔT trip setpoint. This trip provides protection against DNB.

10.2.3.4 Safety Injection Actuation

Three of the four pressurizer pressure transmitters (channels I, II, & III) supply the logic for generating a Safety Injection (SI) actuation signal for Loss Of Coolant Accident (LOCA) protection. This signal is generated when at least two of the three pressure transmitters sense a pressure of 1807 psig or less. In later generation Westinghouse units, the coincidence logic for this actuation signal is two out of four.

10.2.4 Permissives and Interlocks

10.2.4.1 Engineered Safety Feature (ESF) Actuation Block

The pressurizer safety injection block permissive (P-11) is generated when at least two of three pressure transmitters sense a pressurizer pressure of less than 1915 psig. This permissive allows the operator to manually block the low pressurizer pressure engineered safety features actuation and thereby enables a normal plant cooldown and depressurization without an engineered safety features actuation.

In accordance with IEEE Standard 279-1979, if a protective feature is removed from service it must automatically be reinstated if the plant state requires that protective feature. Therefore, when at least two of the three pressure transmitters sense a pressure of 1915 psig or greater, the P-11 permissive is automatically removed, and the low pressure ESF actuation signal is reinstated within the logic portion of the RPS.

10.2.4.2 Relief Valve Interlocks and Cold Overpressure Protection

Each PORV attached to the pressurizer is provided with an interlock to prevent its inadvertent opening if pressurizer pressure is less than 2335 psig. This interlock prevents the failure of either a single pressure transmitter or the master pressure controller from inadvertently opening a PORV. Accidental opening of a PORV is in effect a small-break LOCA through the top of the pressurizer, which causes a depressurization of the RCS. The interlock is the status of a second bistable in the PORV opening logic; the bistable receives an input from a separate independent pressure transmitter. The second bistable's setpoint is established at 2335 psig. With this configuration, as shown in Figure 10.2-2, automatic opening of PORV PCV-456 requires two pressurizer pressure channels sensing a pressure ≥ 2335 psig, in conjunction with the valve operating switch being in the AUTO position. Automatic opening of PORV PCV-455A requires one pressurizer pressure channel sensing a pressure ≥ 2335 psig, the output of the master pressure controller calling for the valve to open, and the valve operating switch being in the AUTO position.

Technical Specifications require that the cold overpressure protection system (consisting of either two PORVs, a combination of other relief valves of sufficient capacity, or a suitably large RCS vent) be operable whenever the RCS cold-leg temperature is less than a predetermined value. During at-power operation the cold overpressure protection switches (one per PORV, as shown in Figure 10.2-2) are in the block position. When the RCS pressure, as indicated by the wide-range pressure detectors, is ≤ 375 psig, the operator is directed by the plant's operating procedures to place these switches in the unblocked positions. This action arms the overpressure protection circuitry, and all that is needed for the opening of a PORV is for the pressure in the RCS, as sensed by the associated wide-range pressure detector, to increase to a value greater than its cold overpressure bistable setpoint.

If the pressure in the RCS increases to 400 psig or greater with the cold overpressure protection system unblocked, an alarm is annunciated in the control room alerting the operator to an overpressure condition. If the control room operator takes no corrective action and pressure continues to increase, one PORV (PCV-455A) opens when RCS pressure exceeds 425 psig (as sensed by pressure transmitter PT-403). If the magnitude of the pressure surge into the RCS is greater than the capacity of a single PORV, the second PORV (PCV-456) opens when the pressure in the RCS exceeds 475 psig (as sensed by PT-405). The PORVs close in reverse order as the pressure in the RCS decreases below the opening setpoints.

The control room operator can manually open or close either PORV. The PORV opening logic shown in Figure 10.2-2 shows that manual opening is independent of both the plant pressure and the status of the cold overpressure protection system.

10.2.5 System Controls

10.2.5.1 Channel Selector Switch

A three-position selector switch mounted on the control board allows the control room operator to select different pressure transmitters for pressure control and relief valve actuation during channel testing and in the event of a transmitter failure. This switch allows the pressure from channel I or III to generate the pressure error used as the input to the master pressure controller, while channel II or IV can supply one input to the opening logic for PORV PCV-456, the PORV not controlled by the master controller. Note that channel III always provides the interlock function for PCV-456, and that channel IV always provides the interlock function for PCV-455A.

10.2.5.2 Master Pressure Controller

The master pressure (PID) controller develops an output control signal in response to the error resulting from the comparison of actual pressure to an adjustable pressure setpoint normally set at 2235. This setpoint adjustment (1700 psig to 2500 psig) is accessible to the operator via a potentiometer knob on the controller.

As shown in Figure 10.2-2, the master controller is "downstream" of the isolation amplifiers which separate protective features from pressure control functions. If the control room operator changes the setpoint of this controller, the pressures at which pressure control components actuate change accordingly, and pressurizer pressure ultimately stabilizes at the new setpoint. The setpoint adjustment has no impact on the inputs to the protection system bistables, which are "upstream" of the isolation amplifiers, and the bistable setpoints remain unchanged.

10.2.5.3 Relief Valve Controls

Each PORV has a three-position switch located adjacent to each other on the main control board. These switches allow the control room operator to manually open or close the valves, or to place them in the automatic mode of operation.

10.2.5.4 Spray Valve Controls

Each spray valve has an automatic/manual controller on the main control board. These controllers allow the operator to manually open or close the spray valves, or to place them in the automatic mode of control and allow the master pressure controller to modulate their positions. The amount of modulation, when the valve controllers are in automatic, is dependent on the output of the master controller. The nominal setpoints (corresponding to the proportional output of the controller only) are 2260 psig (25 psig above setpoint) for spray valves to start opening and 2310 psig (75 psig above setpoint) for spray valves to fully open. The amount of valve opening varies linearly between the full-closed and full-open setpoints.

10.2.5.5 Heater Controls

The proportional heaters have an on-off switch, mounted on the control board, which either places them in automatic control or de-energizes them. When the proportional heaters are operated in automatic, they are energized for a percentage of each successive 10-sec interval; that percentage is proportional to the output of the master pressure controller. The nominal setpoints (corresponding to the proportional output of the controller only) are 2220 psig (15 psig below setpoint) for the proportional heaters to be constantly energized and 2250 psig (15 psig above setpoint) for the proportional heaters to be constantly de-energized. The percentage of time that the proportional heaters are energized varies linearly between the constantly energized and constantly de-energized setpoints.

Each of the three backup heater banks has an off-on-automatic control switch mounted on the main control board which allows the operator to manually control the heaters or to place them in automatic control. In automatic control, the actuation of the backup heaters is dependent on the output of the master controller. The nominal setpoints (corresponding to the proportional output of the controller only) are 2210 psig (25 psig below setpoint) for the heaters to energize and 2217 psig (18 psig below setpoint) for the heaters to de-energize.

In addition, there are local-remote, on-off switches for the backup heater banks which are located on the remote shutdown panel in the auxiliary building. These switches allow limited remote control of pressurizer pressure in the event of a control room emergency.

10.2.6 Summary

The pressurizer pressure control system maintains the RCS pressure at or near a desired adjustable setpoint. This setpoint may be changed by the control room operator; it is normally selected to 2235 psig. The pressurizer pressure control system maintains the RCS at the desired pressure by operating proportional and backup heaters, spray valves, and power-operated relief valves. The master pressure controller calls for actuation of pressure control components in accordance with how much, how long, and how quickly actual pressurizer pressure deviates from the pressure setpoint.

The pressure transmitters also provide the RPS with input signals for reactor trips which provide reactor coolant pressure boundary protection and protection against Departure from Nucleate Boiling (DNB). These transmitters also supply inputs to the low pressurizer pressure safety injection actuation for the mitigation of a potential LOCA.

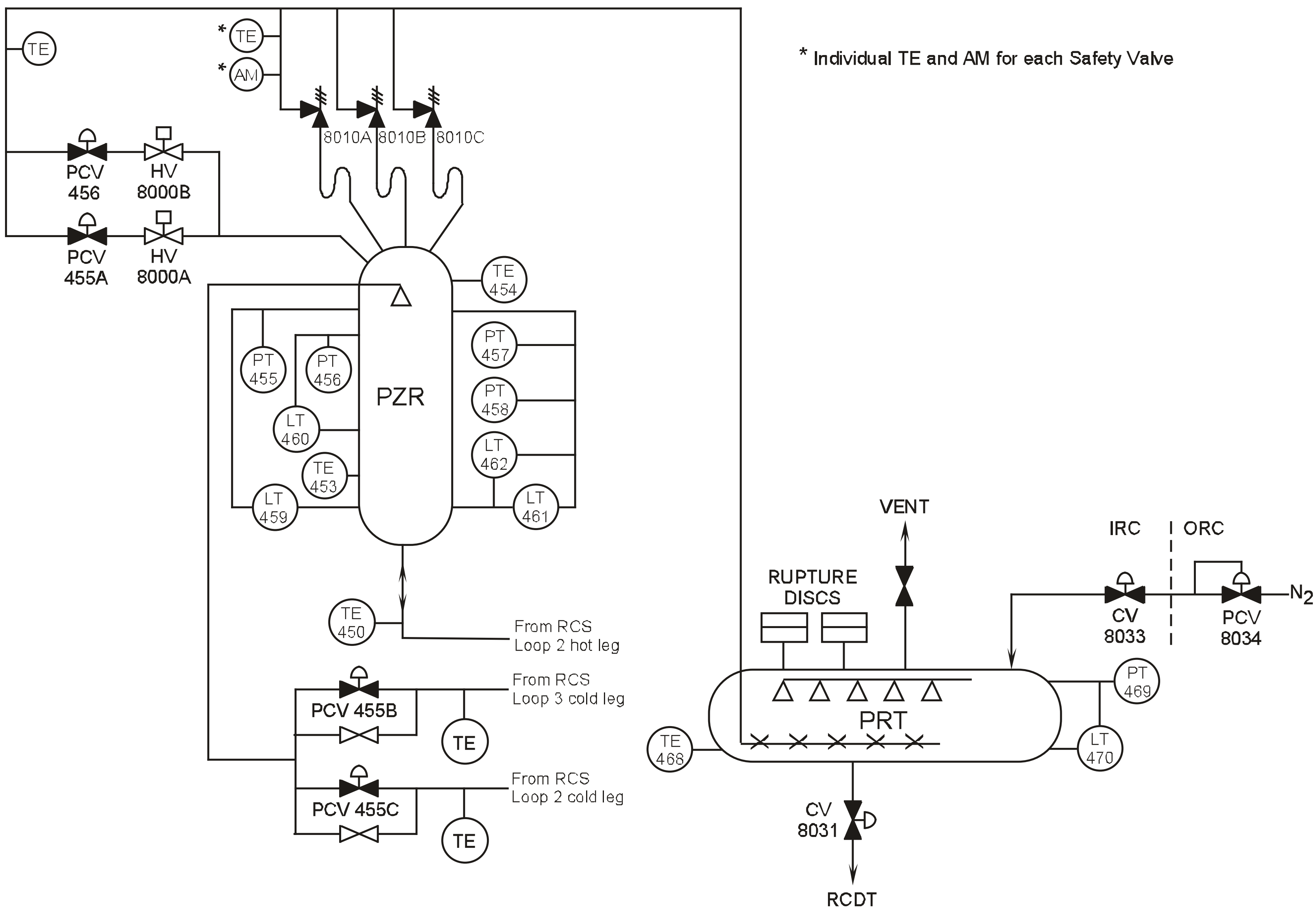

Figure 10.2-1 Pressurizer and Pressurizer Relief Tank

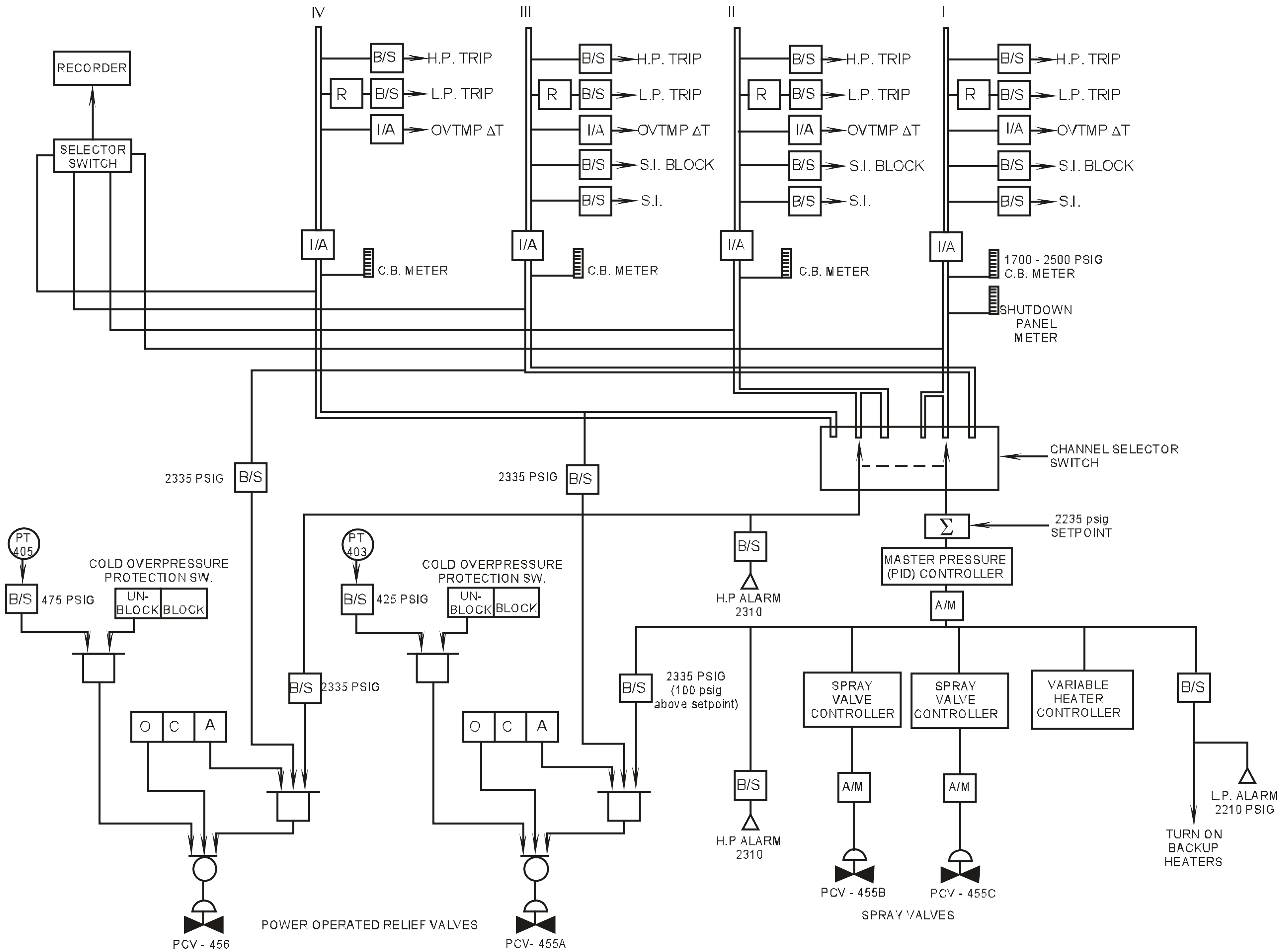

Figure 10.2-2 Pressurizer Pressure Control

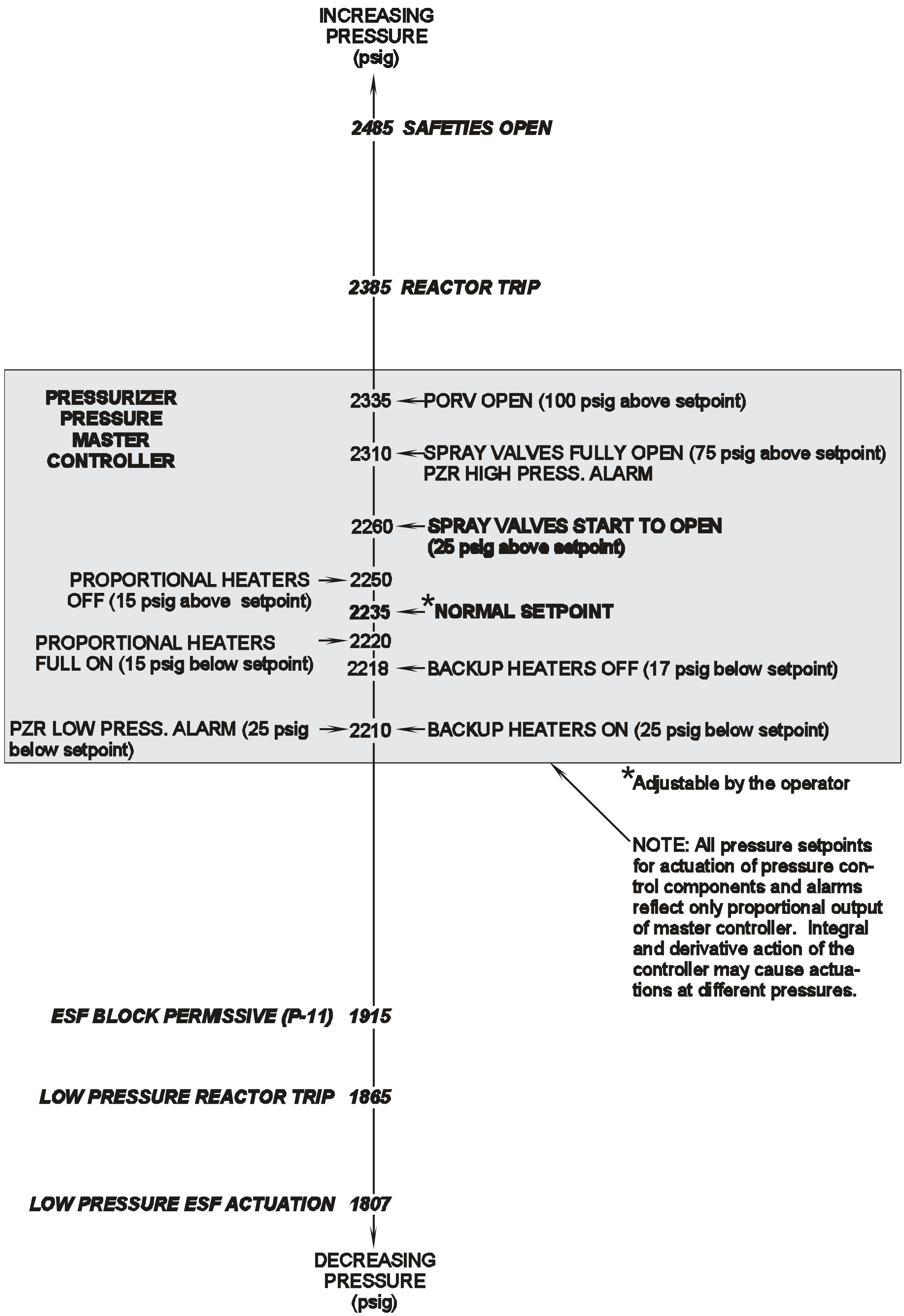

Figure 10.2-3 RCS Pressure Setpoint Diagram

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Section 10.3

Pressurizer Level Control (PLC) System

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10.3 PRESSURIZER LEVEL CONTROL (PLC) SYSTEM

Learning Objectives:

1. State the purposes of the pressurizer level control system.

2. List and describe the purposes (bases) of the protective signal provided by pressurizer level instrumentation.

3. Identify the instrumentation signal that is used to generate the pressurizer level program, and explain why level is programmed.

4. Explain how charging flow is controlled in response to pressurizer level error signals during the following:

   a. Centrifugal charging pump operation, and
   b. Positive displacement charging pump operation.

5. Explain the purposes of the pressurizer low level interlocks.

10.3.1 Introduction

The purposes of the Pressurizer Level Control (PLC) system are to:

1. Control charging flow to maintain a programmed level in the pressurizer, and
2. Provide inputs to pressurizer heater control and letdown isolation valves for certain pressurizer level conditions.

10.3.2 System Description

During steady-state operation, an unchanging pressurizer level indicates that a balance exists between the charging flow into the reactor coolant system and the letdown flow from the reactor coolant system into the chemical and volume control system. During transients the level in the pressurizer changes because the reactor coolant expands or contracts as the average temperature of the coolant increases or decreases.

Designing a control system to maintain a constant pressurizer level, as reactor power and reactor coolant temperatures change, is a relatively simple matter. However, a major disadvantage of such a system is that, as the temperature of the reactor coolant increases, the coolant expands. The expansion of coolant is seen as an increase in pressurizer level. When the level in the pressurizer increases above the programmed setpoint, the pressurizer level control system decreases the charging flow.

Recall from the description of the chemical and volume control system (Section 4.1) that the letdown flow from the reactor coolant system is constant (75 gpm). With constant letdown and decreasing charging as described in the previous paragraph, the rate of coolant letdown is greater than the rate of coolant return to the reactor coolant system via the charging pumps. With this imbalance of flow, the level in the volume control tank increases. When the level in the volume control tank reaches a high level, coolant is diverted to the holdup tanks.

Once the water is diverted, it is treated as liquid waste and is processed for reuse or discarded. This places a large burden on the liquid radioactive waste processing systems.

On the other hand, a decrease in the temperature of the reactor coolant causes the coolant to contract and places a large demand on the makeup system. To minimize the demands on the liquid waste system and the chemical and volume control system, the level in the pressurizer is programmed to follow the natural expansion or contraction of the reactor coolant as the temperature of the coolant increases or decreases.

The pressurizer level control system is shown in Figure 10.3-1, while the functional system parameters are displayed in Figure 10.3-2.

10.3.3 Component Descriptions

10.3.3.1. Level Transmitters

The level in the pressurizer is determined by the measuring the difference in pressure between an external column of water of a known height (reference leg) and a variable column of unknown height inside the pressurizer (variable leg). The differential pressure between these two columns of water is converted into a pressurizer level signal.

Four differential pressure transmitters (d/P cells) are mounted on the pressurizer. Each d/P cell converts the sensed d/P into an electrical current that corresponds to a level varying from 0 to 100%. Each transmitter has an external, bellows-type, sealed reference leg, with a condensate pot attached at the top of the leg, to generate the static pressure head of the reference leg. The actual water level inside the pressurizer constitutes the dynamic or variable leg. Since the density of water varies with temperature, any temperature change of the coolant inside the pressurizer affects its indicated level. Therefore, the pressurizer level instruments are calibrated based upon pressurizer temperature.

Three of the four level transmitters are calibrated for normal operating temperatures and are used for indication, control and protection. The remaining level transmitter is calibrated for cold conditions and is used only for indication with the plant in cold shutdown or when a steam bubble is drawn in the pressurizer. The cold-calibrated transmitter does not provide an input to the pressurizer level circuitry or an input into the reactor protection system.

The output of each level transmitter indicates a level of 0 to 100% for the water volume inside the pressurizer. A selector switch, located on the main control board, allows the control room operator to select two of the three transmitters used for control. One channel is used for level control, letdown isolation, and pressurizer heater cutoff, while the other channel is used for backup letdown isolation and heater cutoff. The third channel can be selected to replace either of the two controlling channels during testing or failures. An additional selector switch is provided on the main control board that allows the operator to select any one of the three transmitters for recording.

10.3.4 System Interrelationships

10.3.4.1. Control Channel

The difference between the actual pressurizer level and the programmed reference level signal is supplied to the master pressurizer level controller. If an error signal exists, this PI (proportional plus integral) controller varies the chemical and volume control system charging flow. This controller prevents the charging flow from reacting to small temporary level perturbations while eliminating steady-state level errors. Since the letdown flow is fixed, the inventory of the reactor coolant system is maintained by varying the charging flow. This is accomplished by one of two different methods:

1. If the positive displacement charging pump is operating, charging flow is controlled by varying the speed of the positive displacement charging pump. For this method of control, the output of the master level controller is supplied to a proportional (P) pump speed controller.
2. If a centrifugal charging pump is operating, charging flow is controlled by varying the position of the flow control valve (FCV-121), located in the common discharge header downstream of the centrifugal charging pumps. For this method of control, the output of the master pressurizer level controller serves as the flow setpoint; the setpoint is compared to the actual charging flow measured by flow transmitter FT-121, located just downstream of FCV-121. The difference is supplied to the PI charging flow controller, which controls the air pressure to the operator for FCV-121 and thus regulates its position. As FCV-121 is an air-to-close valve, an increasing output from the charging flow controller (meaning that charging flow exceeds the demand from the master level controller) repositions the valve in the closed direction.

When the plant is operating and the power in the reactor is changed, the average temperature of the reactor coolant system is programmed to change. This change in temperature causes a corresponding change in the level of the pressurizer. To reduce the effect on the charging system, the level in the pressurizer is programmed (shown in Figure 10.3-2) as a function of auctioneered high T_{avg}, so that it follows the natural expansion characteristics of the reactor coolant. However, a rapid transient causes an increase or decrease in the water level of the pressurizer and a corresponding response by charging flow. For this reason, both minimum and maximum level limitations are placed on the level program in order to satisfy the following:

1. The pressurizer low level setpoint of 25% is selected to prevent the pressurizer from emptying following a reactor trip. In addition, this level ensures that a step load increase of 10% power does not uncover the heaters.
2. The pressurizer high level setpoint of 61.5% is derived from the natural expansion of the reactor coolant when the coolant is heated up from the no-load

to the full power T_{avg} (557°F to 585°F), with the assumption that the level in the pressurizer is 25% when the heatup begins.

This high level setpoint (61.5%) is low enough to ensure that the pressurizer does not go solid following a turbine trip from 100% power without a direct reactor trip, assuming no operator action and no response by the automatic control systems (the rod control and steam dump control systems).

In addition, this level (61.5%) is low enough that the insurge from a step load reduction of 50% does not cause the level in the pressurizer to reach the high-level reactor trip setpoint, assuming that the automatic rod control system and the steam dump control system respond to the transient properly.

In general, an outsurge of water from the pressurizer results in a system pressure decrease, and an insurge of water from the Reactor Coolant System (RCS) results in a pressure increase. However, if the insurge is large, it ultimately results in a system pressure decrease because the insurge water is cooler than the water initially in the pressurizer. Therefore, if the level in the pressurizer increases above the program level setpoint by 5%, the control system automatically energizes the backup heaters in an effort to offset that effect.

An insurge into the pressurizer is observed during a step load decrease (RCS temperature increases due to reactor power being higher than the secondary load); over time the cooler water that has entered the pressurizer would cause a pressure reduction. This insurge is followed by a larger outsurge as the rod control system brings T_{avg} to program for the lower power level; this control response also tends to reduce pressure. Therefore, the 5% deviation above level setpoint serves as an anticipatory signal to limit the pressure reduction in the reactor coolant system upon a load decrease.

The same level signal which is compared to the reference level in the level controller is also sent to a bistable. This bistable provides a low level interlock at 17% level in the pressurizer. In addition to providing a low level alarm, this interlock isolates the letdown from the chemical and volume control system by closing one letdown isolation valve and all orifice isolation valves, and turns off all pressurizer heaters. Isolating the letdown prevents further lowering of the pressurizer level, and the heater cutoff protects the heaters which would be damaged if operated in a steam environment.

10.3.4.2. Redundant Isolation Channel

This channel consists of an actual level signal sent through the channel selector switch and then to two bistables. One of these bistables functions to provide a high level alarm at 70% level. The other bistable closes the second letdown isolation valve, provides a redundant signal to close all orifice isolation valves, and turns off all heaters.

10.3.4.3. Pressurizer High Level Reactor Trip

If two out of the three level transmitters sense a level greater than 92%, a reactor trip signal is generated. This trip is provided to protect the RCS pressure boundary by tripping the reactor before the pressurizer completely fills with water, or “goes solid.” It thus functions as a backup to the high pressurizer pressure reactor trip.

The high-level trip setpoint is selected at a value low enough to prevent the discharge of water through the pressurizer safety valves. Discharges of water could mechanically damage the pressurizer safety valves. This trip is an “at-power” trip and is only active if either reactor power or turbine power is 10% or greater ("at-power permissive" P-7). This reactor trip is discussed in detail in Chapter 12.

10.3.5 Summary

The pressurizer level control system maintains the water inventory of the reactor coolant system by varying the charging rate from the chemical and volume control system. In addition, provisions are made to isolate letdown and turn off the pressurizer heaters on a pressurizer low level. This feature minimizes the effects of a loss of coolant and protects the pressurizer heaters.

The system also turns on the pressurizer heaters if the level in the pressurizer is higher than the program level. Turning on the heaters is performed in anticipation of a pressure decrease following a loss of load transient.

A pressurizer high level reactor trip is provided to prevent operation with a “solid” pressurizer and thus provides RCS boundary protection.

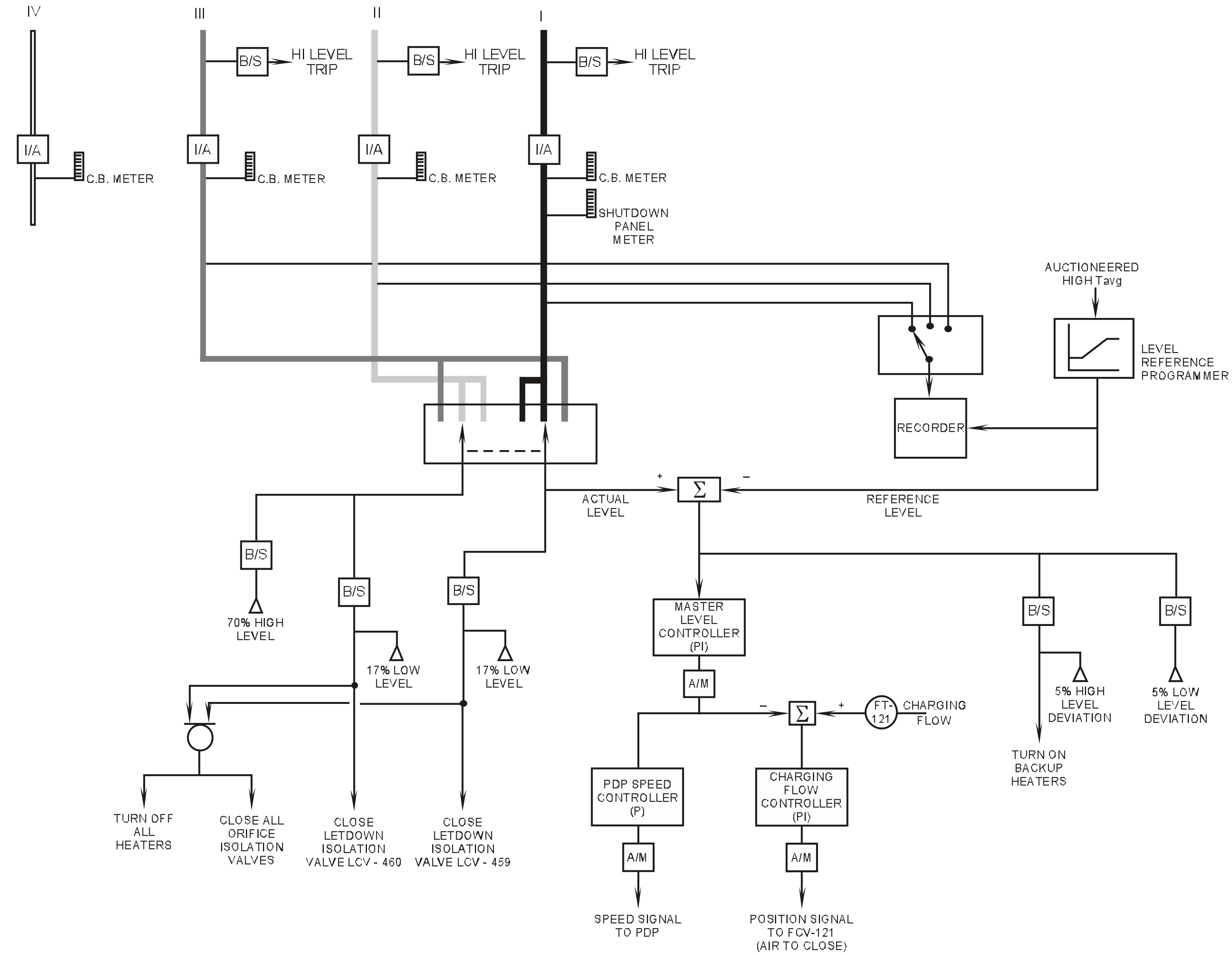

Figure 10.3-1 Pressurizer Level Control

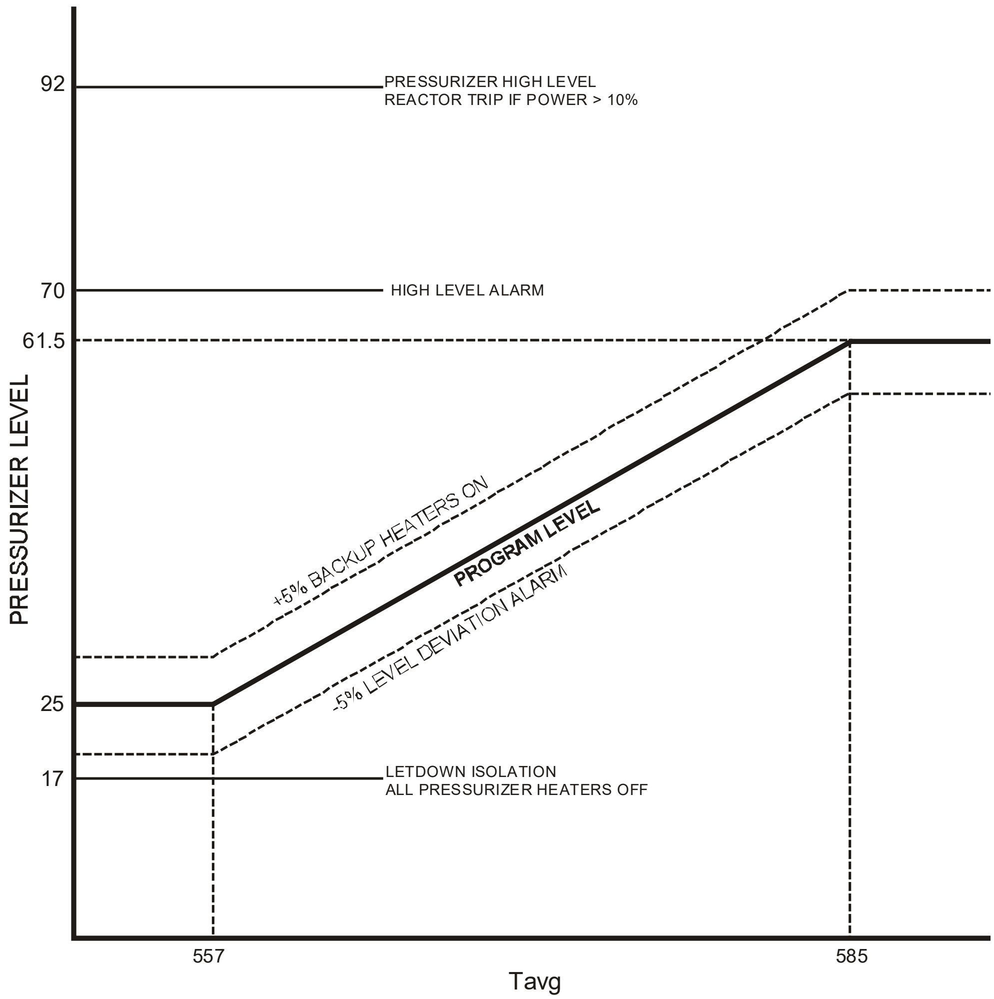

Figure 10.3-2 Pressurizer Level Program

Westinghouse Technology Systems Manual

Chapter 11

SECONDARY CONTROL SYSTEMS

Section

Westinghouse Technology Systems Manual

Section 11.1

<u>Steam Generator Water Level Control (SGWLC) System</u>

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11.1 STEAM GENERATOR WATER LEVEL CONTROL (SGWLC) SYSTEM

Learning Objectives:

1. State the purposes of the Steam Generator Water Level Control System.

2. List the Reactor Protection System and turbine trip inputs provided by steam generator instrumentation, and state the purpose of each trip.

3. List the inputs used in the feedwater control system. Describe how and why each input is used.

4. List the inputs used in the main feed pump speed control system. Describe how and why each input is used.

11.1.1 Introduction

The purposes of the steam generator water level control system are as follows:

1. To control feedwater flow to maintain the programmed levels in the steam generators, and
2. To control the main feed pump speed to maintain the programmed main feed regulating valve differential pressure.

Additionally, the steam generator instrumentation provides inputs into the reactor protection system for loss of heat sink protection and inputs into the turbine trip system for equipment protection.

The Steam Generator Water Level Control (SGWLC) System involves two separate control systems for regulating feedwater flow to the Steam Generators (SGs). The feedwater control system, which controls steam generator level from 20% to 100% power, modulates the positions of the 14-inch main feed regulating valves. This control system is provided with inputs of main steam flow, main feedwater flow, actual level, and reference level (programmed as a function of turbine impulse pressure). Below 20% power, feedwater flow is controlled through manual operation of the 6-inch feed regulating bypass valves.

The Main Feed Pump (MFP) speed control system is utilized above 20% power to control the speed of the main feed pumps. Appropriate control of feed pump speed maintains each feed regulating valve near the midpoint of its travel. The feed pump speed control system does not directly control the levels of the steam generators. The inputs provided for feed pump speed control are main steam header pressure, main feed header pressure, and a programmed reference differential pressure (ΔP).

The Reactor Protection System (RPS) is provided with several inputs from the detectors used in the steam generator water level control system. The inputs are used for the generation of reactor trips and engineered safety features actuations. The reactor protection system also generates feedwater isolation signals, which affect the operation of feedwater system components. Inputs from steam generator instrumentation are also provided to the turbine trip system for turbine protection.

11.1.2 System Description

The steam generator water level control system utilizes the inputs from various detectors to control the feedwater flow to maintain programmed levels in the steam generators. The following sections provide a detailed discussion of each of the control systems involved.

11.1.2.1 Feedwater Control System

The feedwater control system for one steam generator is shown in Figure 11.1-1. Each steam generator has an identical system. The feedwater control system utilizes the following inputs for controlling the position of the main feed regulating valve:

- One of two pressure-compensated steam flow channels (selectable),
- One of two feedwater flow channels (selectable),
- An actual steam generator level channel (median signal selected), and
- A programmed level generated by one of the turbine first-stage pressure channels.

For an accurate measure of the steam flow rate, a pressure-compensated steam flow signal is required. The mass flow rate of the steam is dependent on the density of the steam. Since steam is a compressible fluid, the density is a function of the steam pressure. Feedwater flow does not require density compensation because water is an incompressible fluid. These two flow signals are compared to produce a flow error signal, which is combined with the level error signal as the input to the feed regulating valve controller. The flow signals are also compared to provide steam flow/feed flow mismatch alarms.

The level error signal is derived from the comparison of the actual level signal with the programmed level. The programmed level is generated by turbine first-stage (impulse) pressure. Since impulse pressure is proportional to power, the steam generator levels are effectively programmed with power level.

The programmed level varies linearly from hot zero power (33% narrow-range level indication) to 20% power (44% narrow-range level indication), then remains at 44% above 20% power. The lower programmed level at low power levels minimizes the consequences of a steam line break inside the containment. The mass in the Steam Generators is greatest at low power levels. The 44% maximum program level satisfies the following considerations:

- The “shrink” in steam generator water level during a 50% (maximum design) load reduction will not cause a reactor trip on low-low steam generator level,

- The “swell” in steam generator water level during a 10% step load increase will not cause water in the steam generator downcomer to back up into the moisture separators, and
- The peak containment pressure resulting from the blowdown of one steam generator’s entire inventory during a steam line break is limited.

A median select circuit eliminates the possibility of adverse control/protection interaction. It does this by automatically discriminating against a high or low instrument failure by throwing out both the high and low inputs and selecting a middle or "median" value as the output. The selected level signal is then conditioned by a lag unit to delay the input of level error to level control during the initial stages of a transient. Lagging the actual level signal prevents shrink and swell effects from masking actual steam generator inventory changes and thus allows the flow error to initially control the feed regulating valve position during a transient. The actual level is then subtracted from the programmed level to generate the level error.

The level error is the input signal to a Proportional-plus-Integral (PI) controller. The proportional section amplifies the error signal. The integral portion adds to the controller’s output as long as a level error persists, thereby making level error increasingly dominant. The time constant associated with the integral portion of the controller is two minutes, which allows the flow error to initially control water level and prevents rapid responses to level errors. The integrated level error also prevents an offset in level that could result from calibration errors in steam or feed flow detectors.

The output of the PI level controller is sent to the total error controller, where it is combined with the flow error. The flow error is generated by subtracting feed flow from steam flow. The output of the total error controller (also a PI controller) is used to position the main feed regulating valve. An opening signal to the valve results when either (1) the actual level is less than the programmed level or (2) feed flow is less than steam flow. A closing signal results from one of the converse conditions.

A load change affects steam flow and steam generator level. However, the control action caused by the level change would initially be in the wrong direction. For example, using Figure 11.1-2, during a load increase, steam flow increases; this action by itself produces a corresponding increase in feedwater flow. However, a load increase also causes an increase in steam generator level. This increase in level is called a swell (a temporary effect due to the measurement of level in the downcomer). This increase in level by itself would produce a decrease in feedwater flow (an undesirable effect). To prevent this undesired action, the lagged actual level signal and the large time constant of the PI level controller limit the effect of the momentary swell on the SG level control output. Therefore, the flow error increases feed flow, which is the desired response. A continuing level error will be amplified by the integral function of the level controller, and actual level will be returned to the programmed level setpoint.

During a load decrease the opposite of the load increase occurs; in a load decrease case, the indicated level in the steam generator level decreases for a short period of time. This phenomenon is called ‘shrink’. Once again, the control system features allow the flow error to produce the initial desired response of reducing feedwater flow before the lagged and integrated level error input returns the actual level to the programmed level setpoint.

11.1.2.2 Main Feedwater Pump Speed Control System

Each main feed regulating valve is a throttling valve with linear flow characteristics throughout its travel. However, the best characteristics for flow control result when the valve position is somewhat near the midpoint of valve travel, or from about 25% open to 75% open. To maintain the valve position in this optimal range for all power levels, the speed of the main feed pumps is controlled to overcome the feedwater system dynamic losses (head losses), which vary with the feedwater flow and valve position. As a result, the pressure at the discharge of the pumps varies, and the differential pressure across the feedwater regulating valves changes. Controlling the feed pump speed also reduces regulating valve wear by allowing the valves to be further open with low feedwater flow rates and increases pump efficiency by reducing pump power requirements. The main feed pump speed control system is shown in Figure 11.1-3.

The feed pump speed is controlled by the differential pressure error generated through a comparison of programmed differential pressure and actual differential pressure. The programmed differential pressure is generated by summing the pressure-compensated steam flows from all four steam generators and sending them to a setpoint generator, which has a no-load setpoint as a starting point. The output of the setpoint generator is the programmed differential pressure, which has a range of 45 -195 psid from no load to full power. The programmed differential pressure is then compared to the actual differential pressure. The lag unit on the output of the steam flow summer slows the system response to rapid changes in steam flow. This feature allows the main feed regulating valves, not the feed pumps, to be the primary components controlling steam generator level.

The actual differential pressure is the difference between steam header pressure and feed header pressure. The steam header pressure is sensed in the bypass header of the main steam system. The feed header pressure is measured in the combined header downstream of the high pressure heaters. The programmed differential pressure and the actual differential pressure are compared in a summer to produce the differential pressure error. A positive error (actual differential pressure less than programmed differential pressure) would call for an increase in feed pump speed. This error is sent to the master pump speed (PI) controller, which eliminates steady-state errors and sends an output to the individual feed pump speed controllers.

11.1.3 Instrumentation

11.1.3.1 Level Channels

There are four level detectors for each steam generator (see Figure 11.1-4), three protection-grade narrow-range transmitters and one wide-range transmitter. The span of each narrow-range detector is the top 12 ft of the wide-range span. Each narrow-range detector's upper tap (100% narrow-range level) is located just belowan upper manway, and the lower tap (0% narrow-range level) is located 26 in. above the top of the U-tube bundle. Each detector supplies control board indication and level alarms.

The narrow-range detectors generate a reactor trip for loss of heat sink protection when at least two out of the three channels indicate a low-low level (11.5%) in any steam generator. In addition, the low-low level condition starts the auxiliary feedwater pumps.

The narrow-range detectors also generate a turbine trip if two out of the three channels exceed the high-high level setpoint (69%) in any steam generator. This condition also generates a main feedwater isolation signal and trips the main feed pumps. The purpose of this turbine trip is for protection of the turbine blades from excessive moisture carryover.

The fourth level detector for each steam generator is the wide-range channel (not shown in Figure 11.1-1). This instrument provides indication of wide range level and is recorded in the main control room. The location of the lower tap of this detector is one foot above the steam generator tube sheet. The span of the detector is 48 ft. The wide-range level detectors are addressed by the Westinghouse Emergency Operating Procedures (EOPs) and are used by the operator for verification of a loss of heat sink.

11.1.3.2 Turbine First-Stage Pressure

One of the two turbine first-stage (impulse) pressure transmitters is used to generate the reference steam generator level. Since this pressure is proportional to power, steam generator level is effectively programmed as a function of power.

11.1.3.3 Steam Flow Channels

Two steam flow channels for each steam generator can provide an input to the feedwater control system; the operator selects one with a switch on the main control board. Each detector's flow signal is developed from the ΔP sensed across the flow restrictor at the outlet of the steam generator. Because steam is a compressible fluid and its density varies with pressure, the steam flows are pressure compensated to account for density variations. Each steam flow channel is compensated by a separate steam pressure channel.

In addition to providing an input to the feedwater control system, each steam flow detector provides an input to the high steam flow safety injection actuation and steam line isolation logic. Each steam flow channel also supplies control board indication and a steam flow/feed flow mismatch alarm.

11.1.3.4 Feedwater Flow Channels

Two feedwater flow channels for each steam generator can provide an input to the feedwater control system; the operator selects one with a switch on the main control board. Each detector's flow signal is developed from the ΔP sensed across the venturi downstream of the feedwater regulating valve.

In addition to providing an input to the feedwater control system, each feed flow channel also supplies control board indication and a steam flow/feed flow mismatch alarm.

11.1.3.5 Steam Pressure Channels

Four steam pressure detectors per steam generator are located on the steam line just outside containment and upstream of the main steam isolation valve. One of these detectors is dedicated solely to the control of the steam generator atmospheric relief valve. The other three channels are protection-grade channels. They provide inputs to the protection logic for the high steam line differential pressure safety injection actuation. Two of the protection-grade channels provide density compensation for separate steam flow channels. All protection-grade steam line pressure channels provide control board indication.

A steam pressure detector on the common bypass header which cross-connects the four main steam lines provides inputs to the feed pump speed control system and the steam dump control system. This detector provides indication on the control board.

11.1.3.6 Feedwater Pressure Channel

A pressure transmitter on the common feedwater header downstream of the high pressure heaters provides an input to the feed pump speed control system. This detector also provides indication on the control board.

11.1.4 System Interrelationships

Four inputs override the steam generator water level control system:

- Manual control by the operator,
- Reactor Trip (P-4) coincident with low T_{avg},
- Steam Generator high level (P-14 Table 12.2-2), and
- Safety Injection Actuation Signal (SIAS).

Each of the last three conditions listed above generates a Feed Water Isolation Signal (FWIS Table 12.3-1), which trips the main feed pumps and causes automatic closure of all feed regulating and bypass valves, and main feedwater isolation valves.

11.1.5 Summary

Steam generator water level is controlled through the automatic or manual operation of the main feed regulating valves (at high powers), or through the manual operation of the main feed regulating valve bypass valves (at low powers). In addition, the speed of the main feed pumps is controlled through the maintenance of a programmed differential pressure across the steam generators to maintain efficient operation of the main feed regulating valves. The detectors used in the control systems provide signals for control, protection, and indication.

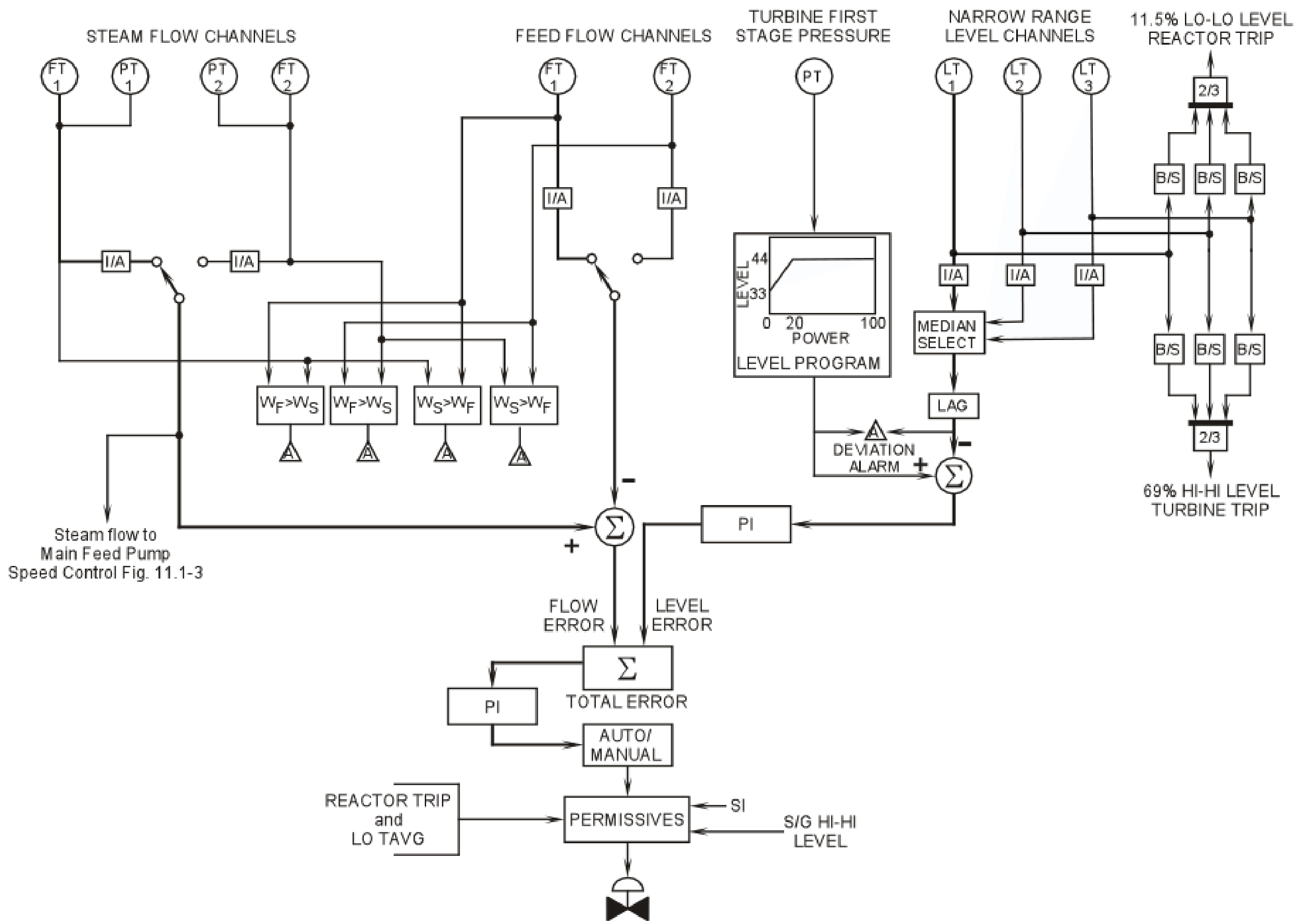


Figure 11.1-1 Feedwater Control System

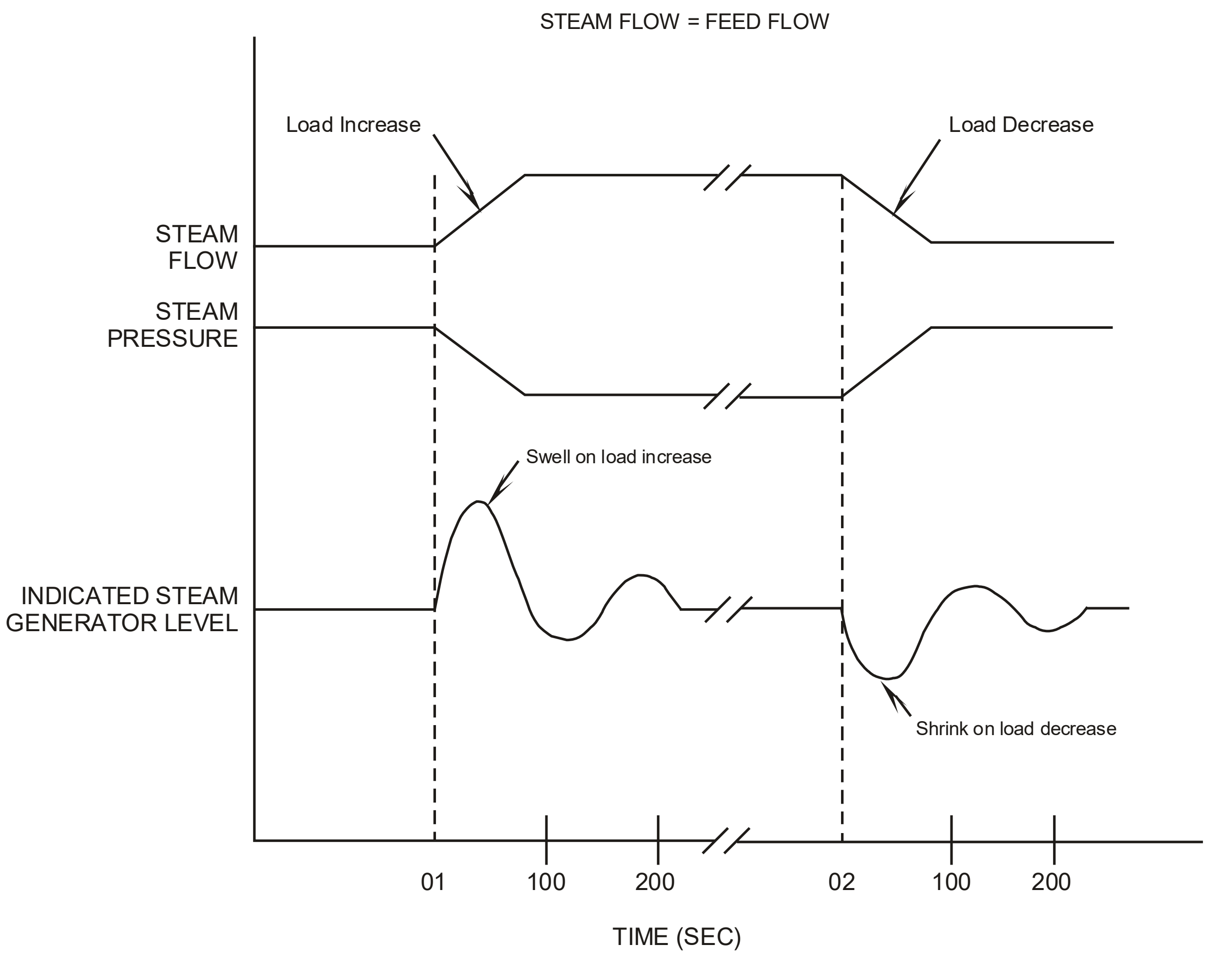


Figure 11.1-2 Steam Generator Shrink and Swell

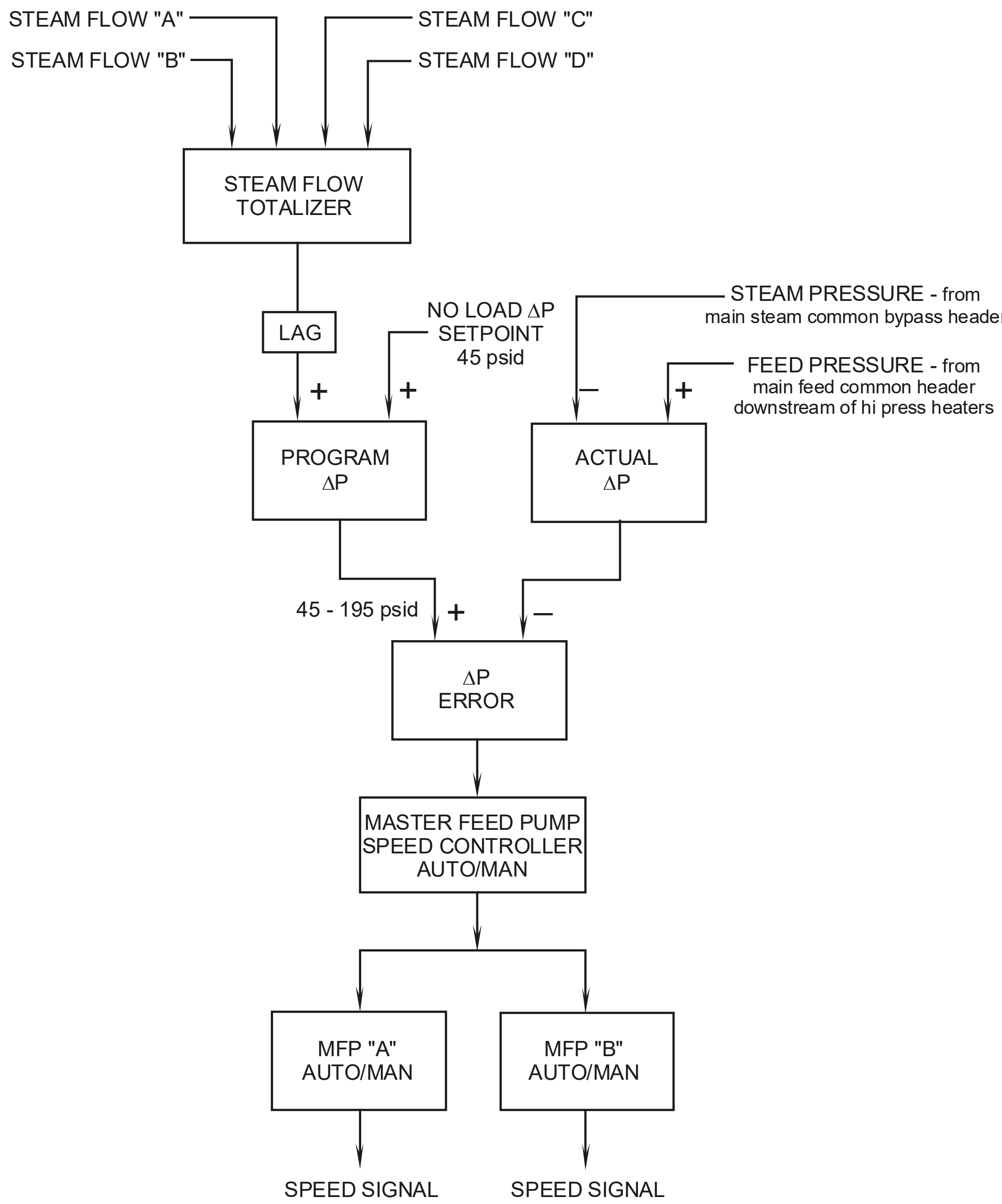
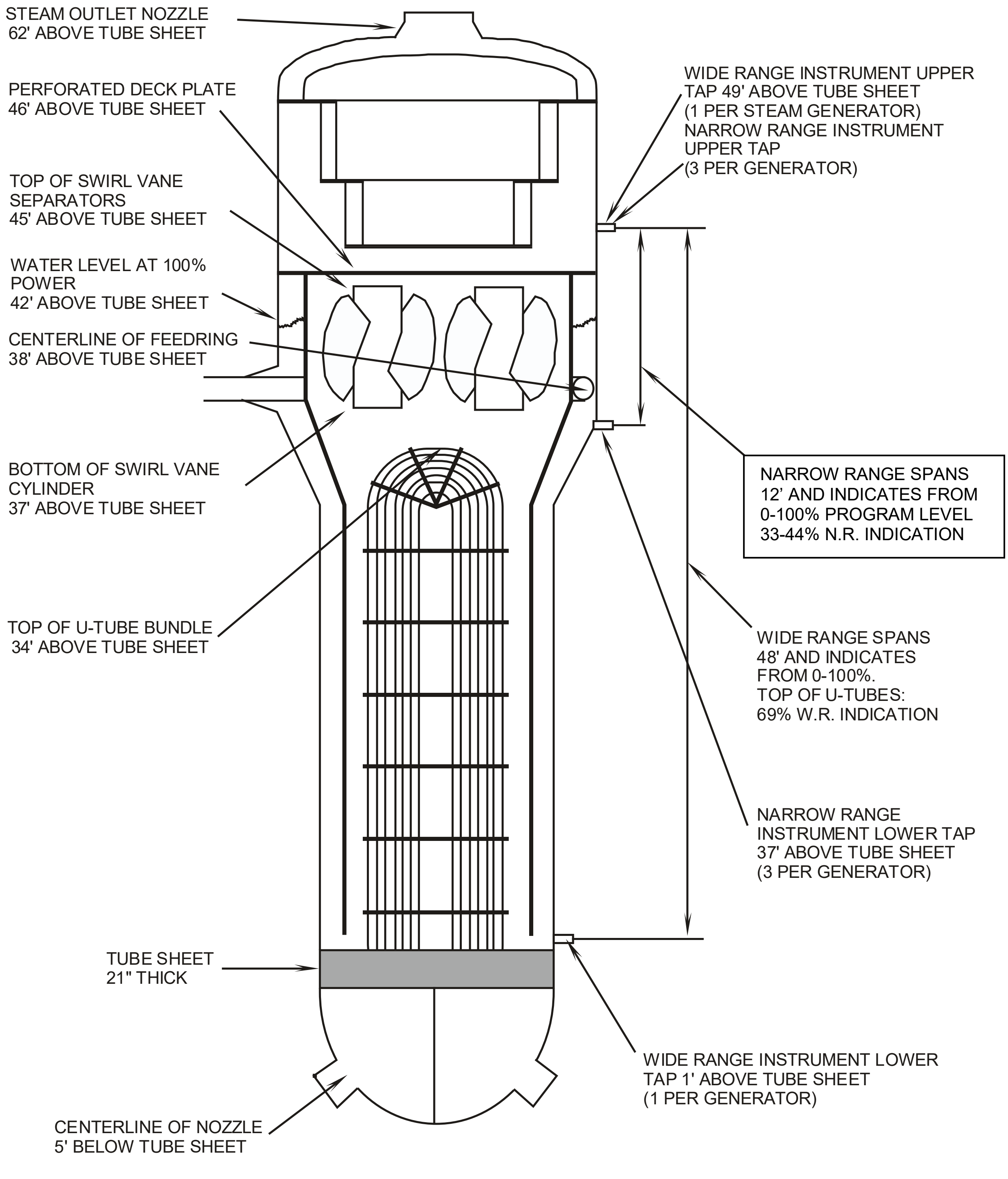


Figure 11.1-3 Main Feedwater Pump Speed Control



NOTE: MEASUREMENTS ROUNDED TO THE NEAREST FOOT

Figure 11.1-4 Steam Generator Level Data

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Section 11.2

Steam Dump (SD) Control System

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11.2 STEAM DUMP (SD) CONTROL SYSTEM

Learning Objectives:

1. List the purposes of the steam dump control system.

2. Briefly describe how each of the purposes is accomplished.

3. Discuss the inputs to the steam dump control system.

4. List and explain the purposes of the steam dump control arming signals and interlocks.

11.2.1 Introduction

The function of the Steam Dump (SD) system is to remove excess energy from the reactor coolant system. The plant's rod control system in the automatic mode is designed to handle a 5%/min ramp or 10% step decrease in power, from steady-state conditions, without a resultant reactor trip or pressurizer relief valve actuation. However, during a turbine load reduction in excess of these design load changes, the automatic rod control system cannot reduce reactor power as fast as the secondary power is decreasing. Under these conditions, a power imbalance results, with reactor power greater than the secondary system load (i.e., more heat is being added to the reactor coolant than that removed by the secondary via the steam generators). This power imbalance causes the temperature of the reactor coolant to increase. The steam dump system is designed to limit this unwanted temperature increase.

Following a reduction in load, the steam dump system limits the temperature rise of the reactor coolant and aids the rod control system in reducing the temperature of the reactor coolant to the programmed T_{avg} for the new turbine load. During operation of the steam dump system, steam from the main steam system bypasses the main turbine and flows directly to the main condenser. The increased steam flow from the steam generators dissipates the excess energy of the reactor coolant until the power in the reactor is reduced to the same value as the secondary load.

The capacity of the steam dump system depends on the individual plant's load rejection capability. In most Westinghouse units the capacity of the steam dump system is 40%.

In a 40% steam dump system, the steam dump valves are designed to pass 40% of the full-power steam flow at some maximum defined steam pressure. This steam dump capacity allows for a 50% turbine load reduction without a reactor trip. The 50% loss of load is accommodated by the steam dump capacity of 40% and by the 10% step change capability of the rod control system. In addition, this dump capacity avoids the lifting of steam generator safety valves following a turbine trip and reactor trip from 100% power.

This section discusses the control system for a 40% steam dump system, which consists of 12 steam dump valves and the associated piping between the main steam system and the main condenser. For accident analysis considerations with regard to an accidental overcooling of the reactor coolant due to a small steam break, the opening of any single steam dump valve is designed to pass not more than 895,000 lbm/hr of steam at 1106 psia. The steam dump system is a control-grade system and is not required for the safe shutdown of the reactor.

The modes of operation of the steam dump system and the purposes of each mode are as follows:

1. T_{avg} mode: Enables the nuclear steam supply system to accept a 50% loss of load without incurring a reactor trip.
2. T_{avg} mode: Removes stored energy and decay heat from the reactor coolant following a turbine trip and returns the plant to no-load conditions without actuation of the steam generator safety valves.
3. Steam pressure mode: Controls steam pressure at low- or no-load conditions and provides for a manually controlled cooldown of the reactor coolant system.
4. Steam pressure mode: Provides a constant steam flow during turbine startup and synchronization to facilitate manual feedwater control.

11.2.2 System Description

Figures 11.2-1, -2, and -3 are simplified diagrams of the steam dump control system. They are intended as "building blocks" for the more complete system diagram of Figure 11.2-4.

There are two modes of steam dump control, selectable by the control room operator. One mode is the T_{avg} mode, which includes both the loss-of-load controller and the turbine-trip controller. The other mode of control is the steam pressure mode, which involves the steam pressure controller. The position of the mode selector switch and the plant conditions determine which of the three controllers is in service. These controllers are described in detail in sections 11.2.2.1 and 11.2.2.2.

The 12 steam dump valves are air operated and divided into four different valve groups. Each valve group consists of three valves; each valve within a group discharges to a different condenser shell. The groups are operated sequentially. The first group (which contains the three cooldown valves) modulates to the fully open position before the second group of valves begins to open. After the second group has fully opened, the third group begins to open, and the fourth group begins to open after the third group has fully opened. When the valves close, they do so in the reverse order; that is, the group four valves close fully before the group three valves begin to close, etc.

As shown in Figure 11.2-1, each steam dump valve has a valve positioner which regulates the control air pressure, through two solenoid valves in series, to a diaphragm operator located on the valve. The diaphragm varies the position of the steam dump valve based on the control air pressure developed by its valve positioner. The valve positioner varies the control air pressure in accordance with a variable instrument air signal from its associated current-to-pneumatic (I/P) converter. The I/P converter (one for each steam dump valve) receives an electrical current input from one of three electronic controllers.

In addition to the features already mentioned, the steam dump control system incorporates (1) arming signals, which align the steam dumps for operation during the appropriate plant operating conditions, and (2) interlocks, which prevent or halt operation of the steam dumps when they are not needed or desired. The arming signals are discussed in the next three sections, while the individual interlocks are explained in section 11.2.2.4.

11.2.2.1 Steam Pressure Mode

During a plant startup or cooldown, the steam dump system is operated in the steam pressure mode. As shown in Figure 11.2-1, when the steam dump mode selector switch is placed in the steam pressure position, the relay associated with the mode selector switch energizes and closes two contacts. Closing the contact shown to the right of the steam pressure controller places the steam pressure controller in service, while closing the middle contact in the set of three parallel contacts completes the electrical circuit which "arms" the steam dumps. This arming contact, once closed, allows dc power to be applied to the two solenoid valves in series. The inputs to the steam pressure controller are steam header pressure (measured at the main steam bypass header) and a variable setpoint which is selected by the control room operator. The steam pressure controller is a proportional-plus-integral controller.

The steam pressure mode is selected during hot standby operation, reactor startup, and initial loading of the turbine. The steam dump valves act as a load on the primary system by removing heat from the Reactor Coolant System (RCS). As the steam press is maintained by the steam dumps at the selected setpoint, the temp of the main steam header is maintained at a value corresponding to the saturation temp for the setpoint press. For example, if the steam press setpoint is selected to 1092 psig, the temperature of the steam header will be maintained at approximately 557°F. The RCS temperature will be a function of Q=UAΔT where the ΔT is equal to Tavg minus Tsteam. At zero load, since Q (power) is only RCP pump heat, the ΔT is almost zero and Tavg and Tstm are about the same (557°F). As reactor power is increased, if steam header pressure and temperature is maintained constant by the Steam Dump Pressure Mode Controller, then Tavg has to increase to transfer the increased heat energy from the RCS to the SG. The full load primary to secondary ΔT is approximately 50°F. Since the ΔT for heat transfer is linearly related to reactor power (Q), when reactor power is 10%, the primary to secondary ΔT is approximately 5°F, and Tavg is 562°F (557°F [Tstm] plus 5°F [ΔT]).

At the end of a plant heat-up, the heat added to the reactor coolant by the reactor coolant pumps is transferred to the steam generators and removed by the steam dump system to maintain the reactor coolant at 557°F (no-load T_{avg}). During the subsequent reactor startup and low power operation, withdrawing the control rods causes reactor power to increase, which in turn causes the reactor coolant temperature and the pressure in the steam system to increase. The increasing steam pressure inputs an error signal (the actual steam pressure is greater than the setpoint) into the steam pressure controller. The controller converts this error signal into a valve positioning demand that, once converted to control air pressures by the individual valve positioners, modulates open the steam dump valves. The integral action of the controller will increase the valve opening demand if the steam pressure error persists for an extended period. The number of open valves and the degree of modulation are determined by the magnitude of the controller output. A steam pressure error, after integration, equivalent to 100 psid results in the full opening of all four valve groups.

When the reactor power is approximately 10 - 15%, the turbine is placed in service. The steam dump system is still selected to the steam pressure mode, and the dump valves are passing approximately 10 - 15% of full-power steam flow. During the initial turbine startup, the steam dump system maintains a relatively constant total steam flow in the main steam system. The steam dump valves are open and dumping steam to the main condenser to maintain the desired pressure in the main steam system.

As the turbine governor valves open, steam is admitted to the high-pressure turbine, which causes the steam pressure in the main steam header to decrease. This reduces the magnitude of the pressure error generated by the steam pressure controller, and the controller's decreasing output causes the steam dump valves to modulate closed. The net result of this evolution is that the total steam flow remains relatively constant. This process of transferring the main steam flow from the steam dumps to the turbine governor valves continues as the turbine generator is loaded until the steam dump valves are fully closed and the turbine governor valves are passing the entire 10 - 15% main steam flow.

Since the total steam flow is not affected (i.e., the heat removal from the reactor coolant does not change), the temperature of the reactor coolant does not change significantly, which reduces the need to move control rods. Also, the heat transfer in the steam generators remains unchanged, which allows for a constant feed flow rate to the steam generators, making feedwater control easier for the feed station operator.

After a reactor trip or a controlled reactor shutdown, the steam dump system may be placed in the steam pressure mode of control to perform a plant cooldown. With the steam pressure controller in automatic, the control room operator can lower the steam pressure setpoint to cause the steam dump valves to open, which lowers the steam pressure and T_{avg}. With the controller in manual, the operator inputs a signal to modulate the steam dump valves open to maintain the desired cooldown rate.

11.2.2.2 T_{avg} Mode

During normal power operations, generally greater than 15% of rated thermal power, the steam dump system is placed in the T_{avg} mode. As shown in Figure 11.2-2, there are two controllers in the T_{avg} mode of control. The upper controller, the loss-of-load controller, is provided with auctioneered high T_{avg} and T_{ref} as inputs. T_{ref} which is generated from turbine impulse pressure, is the desired T_{avg}. The lower controller, the turbine-trip controller, is provided with auctioneered high T_{avg} and no-load T_{avg} as inputs. These two controllers differ according to their functions.

(Note: Unless stated otherwise, the relay and contact locations indicated in the following paragraphs of this section refer to their locations in Figure 11.2-2.)

When the control room operator places the steam dump mode selector switch in the T_{avg} position, as shown in Figure 11.2-2, the relay associated with the mode selector switch de-energizes. De-energizing this relay causes the following:

1. The contact directly to the right of the steam pressure controller opens (this contact is shown in Figure 11.2-1 and is not shown in Figure 11.2-2),
2. The second contact to the right of the loss-of-load controller closes,
3. The second contact to the right of the turbine-trip controller closes, and
4. The middle contact in the set of three parallel contacts opens and disarms the steam dumps.

With the turbine-trip signal relay de-energized as shown, the contact directly to the right of the loss-of-load controller is closed, while the contact directly to the right of the turbine-trip controller is open. Therefore, if no turbine-trip signal is present, the loss-of-load controller is automatically selected whenever the mode selector switch is placed in the T_{avg} mode of control.

In accordance with this relay/contact arrangement, if a turbine trip occurs, the turbine-trip signal relay energizes, causing the contact at the output of the loss-of-load controller to open and the contact at the output of the turbine-trip controller to close. The actuation of this relay also arms the steam dumps by closing the top contact in the set of three parallel contacts. The turbine-trip controller is thus automatically selected when a turbine-trip signal is present.

The loss-of-load controller has a 5°F dead band to allow the rod control system to respond to a T_{avg} / T_{ref} difference first. If a difference greater than 5°F between T_{avg} and T_{ref} exists, then the loss of load is in excess of the designed capability of the rod control system. The output of the loss-of-load controller (valve opening demand) is proportional to the portion of the T_{avg} / T_{ref} difference in excess of 5°F. The steam dump valves will open in response to this demand provided that the dumps are armed by a loss-of-load signal (the bottom contact in the set of three parallel contacts is closed). Therefore, for any load reduction that is greater than the design limitations of the rod control system, the steam dumps act as an alternate heat sink (load) until the rod control system returns T_{avg} to within 5°F of T_{ref}.

With a turbine trip, the function of the steam dump system is different. When a turbine trip occurs, the turbine-trip controller is automatically placed in service and the steam dumps are armed, as previously described. The output of the turbine-trip controller (valve opening demand) is proportional to the difference between T_{avg} and the no-load T_{avg} setpoint. The steam dump system thus actuates to remove stored energy and decay heat to return T_{avg} to its no-load value (normally selected to 557°F). There is no dead band associated with the turbine-trip controller.

11.2.2.3 Arming Signals

To ensure that the steam dumps operate only during specific plant conditions, arming signals are provided. A control signal opens the steam dump valves only if an arming signal has energized their associated arming solenoid valves. The solenoid valves for each steam dump valve are positioned in series in the air line between the valve positioner and the dump valve. Control power is required to energize the solenoids to port air to the dump valves. The arming signal allows dc power to reach these solenoids by closing a contact in the power supply to the solenoids. There are three arming signals: one for the steam pressure mode of control and two for the T_{avg} mode of control. The arming signals and their relationships with the three steam dump controllers are illustrated in Figure 11.2-3.

When the steam dump mode selector switch is placed in the steam pressure mode of control, the steam dumps are armed. The two T_{avg} mode arming signals are the loss-of-load signal and the turbine-trip signal. The loss-of-load signal (C-7 interlock) is generated by either of the following: a ramp load decrease at a rate greater than 5%/min, or a step load decrease of greater than 10%. Either of these load reduction indications is sensed from turbine impulse pressure. The turbine-trip signal (C-8 interlock) is generated whenever all four turbine stop valves are shut or low pressure is indicated by at least two out of three pressure switches located on the emergency trip system header. (The turbine trip input from the emergency trip system header applies to plants with General Electric turbines and electrohydraulic control [EHC] systems. For plants with Westinghouse turbines and EHC systems, a turbine trip signal is generated when low pressure is indicated by at least two out of three pressure switches located in the auto-stop oil system. See Sections 11.3 and 11.5.)

If the steam dump system is armed by a loss of load, the system remains armed until the loss-of-load signal is manually reset by a control room operator. As shown in Figure 11.2-4, this reset is accomplished by placing the mode selector switch to the reset position and then allowing it to spring return to the T_{avg} position. If the steam dump system is armed by a turbine trip, it remains armed until the turbine is latched.

11.2.2.4 Interlocks

As previously mentioned, dc control power must be supplied to the solenoid valves to allow actuation of the steam dumps. An arming signal is required to shut one of three parallel contacts which supply this dc power. In addition, three interlocks must be satisfied to allow operation of the steam dump system. The failure to satisfy any of these interlocks interrupts dc control power, via an open contact, to the series solenoid valves in the air supplies to the dump valves.

The first interlock, the condenser available (C-9) interlock, is provided for condenser protection. As shown in Figure 11.2-4, a sufficient vacuum in the condenser (as sensed by each of two condenser pressure detectors) and at least one operating condenser circulating water pump (for steam condensing) are required to satisfy this interlock and thereby allow the steam dump valves to actuate.

The second interlock, the low-low T_{avg} (P-12) interlock, is provided to prevent an inadvertent cooldown of the reactor coolant due to an instrument failure. If T_{avg} is less than 553°F in two of the four reactor coolant loops, the steam dumps will be interlocked off.

To use the steam dumps for a normal cooldown below 553°F, it is necessary to bypass the low-low T_{avg} interlock. As illustrated in Figure 11.2-4, bypassing this interlock allows the operator to use the first group of three steam dump valves, the cooldown valves, to cool down the plant. The other three groups remain shut below the P-12 interlock setpoint. Since this interlock signal is generated in the reactor protection system, there are actually two signals, one from each protection system train. Therefore, there are two bypass interlock switches located on the main control board. Each bypass interlock switch (only one switch is shown in Figure 11.2-4) has three positions: off/reset, on, and bypass interlock. Bypassing the P-12 interlock is accomplished by placing the switch in the bypass interlock position and allowing the switch to spring return to the on position. Placing the switch in the off/reset position disables the dumps by de-energizing the solenoid valves in the air supplies to the steam dump valves.

The third interlock, the low-low steam generator water level interlock, is provided to conserve secondary inventory for steaming the turbine-driven auxiliary feedwater pump following a reactor trip from a high-power level. If any of the steam generator levels falls below the low-low level setpoint of 10.7% in two of three channels, dc control power will be interrupted to nine steam dump valves (all except the cooldown valve group). The interlock has a time delay of five minutes to allow for transient conditions.

In summary, all of the following conditions must be satisfied to complete the dc arming circuits for the steam dump solenoid valves:

1. One of the three arming signals discussed in section 11.2.2.3 has been developed,
2. The condenser available interlock logic is satisfied,
3. The reactor coolant temperature is greater than the low-low T_{avg} setpoint, or the operator has bypassed this interlock (three cooldown valves only), and
4. All four steam generator levels exceed the low-low level setpoint (all steam dump valves except the cooldown group).

11.2.2.5 Steam Dump Trip-Open Bistables and Valves

As shown in Figure 11.2-4, in addition to the solenoid valves which are energized by the arming signals, there is a third solenoid valve associated with each steam dump valve. This solenoid valve, located upstream of the arming solenoid valves, is actuated by one of the bistables known as the trip-open or blast-open bistables. These bistables are effective only in the T_{avg} mode of control. When energized, this trip-open solenoid valve directs high pressure air around its associated valve positioner.

Normally, 100-psig air is routed from the service air header through each valve positioner, which regulates the air pressure to its associated steam dump valve. Each valve positioner varies the control air pressure based on a variable instrument air signal from its associated I/P converter. The flow of control air from the valve positioner, now at a reduced pressure, passes into the right-hand port and out the bottom port of the three-way trip-open solenoid valve. (The valve port orientation discussed here corresponds to that shown in Figure 11.2-4.) This control air passes through the two series arming solenoid valves to the diaphragm operator located on the steam dump valve. As the control air pressure from the valve positioner varies, the steam dump valve position will change (i.e., modulate open or closed). However, if the trip-open solenoid is energized, the solenoid valve is repositioned so that the top and bottom ports are open and the right-hand port is closed. With the solenoid valve in this position, 100-psig control air is immediately applied to the valve actuator of the associated steam dump valve. This action allows quick opening of the steam dump valve for large load rejections.

The four trip-open bistables and their associated contacts are shown in Figure 11.2-4 between and to the right of the loss-of-load and turbine-trip controllers. The input to two of the bistables is the temperature error (T_{avg} - T_{ref}) supplied to the loss-of-load controller, and the input to the other two bistables is the temperature error (T_{avg} - [no-load T_{avg}]) supplied to the turbine-trip controller. When the steam dump mode selector switch is selected to the T_{avg} mode of control (as shown in the figure), the contacts in the circuits from the two upper (loss-of-load) bistables are closed. If a turbine trip occurs, then the contacts directly to the right of the two upper bistables open, and the contacts directly to the right of the two lower (turbine-trip) bistables close. (The locations of the bistables and contacts discussed above refer to their locations in Figure 11.2-4.)

The normal setpoints for these bistables are as follows. For the loss-of-load bistables, the high bistable setpoint is 10.7°F (T_{avg} - T_{ref}), and the high-high bistable setpoint is 16.4°F. For the turbine-trip bistables, the high bistable setpoint is 13.8°F (T_{avg} - [no-load T_{avg}]), and the high-high bistable setpoint is 27.7°F. The large temperature errors are indicative of the large imbalances between primary and secondary power that would result from large load rejections.

When a high bistable setpoint is exceeded, the trip-open solenoid valves for the first two groups of valves (six valves total) reposition to supply 100-psig air directly to the steam dump valve operators. The steam dump valves then open fully within two to three seconds. When the bistable resets, the solenoid valves are de-energized and repositioned so that the air signals from the valve positioners will modulate the steam dump valves closed. A high-high bistable, if actuated, opens the remaining two groups of three valves (six valves total).

11.2.3 Summary

The steam dump system provides:

1. A heat sink for the primary system on a load reduction to prevent a reactor trip,
2. A method of returning the plant to no-load conditions following a turbine trip, and
3. A method of maintaining and varying reactor coolant temperature during startups and cooldowns.

The control system for the steam dumps accomplishes the first two functions by automatically opening the steam dump valves in response to temperature errors resulting from load rejections (loss of load or turbine trip). The control system accomplishes the third function by controlling steam pressure and thus reactor coolant T_{avg} at a selected setpoint.

The steam dump control system is provided with arming signals and interlocks. The purpose of the arming signals is to ensure that plant conditions requiring steam dump actuation actually exist. The purpose of the interlocks is to provide equipment protection and, in the event of an instrument failure after the steam dumps have been armed, to prevent the reactor coolant system from being overcooled.

In the event of a large loss of load or a turbine trip, trip-open bistables rapidly open the steam dump valves. This action helps limit the increase in T_{avg} for these transients and returns the temperature of the reactor coolant to program faster than if the transients were handled only by the rod control system.

The steam dump system is not a safety-related system, it is supplied with nonvital power, and its operation is not considered by the plant's Final Safety Analysis Report (FSAR) for mitigation of any accident. In addition, the operation of the steam dump system is not required for the safe shutdown of the reactor.

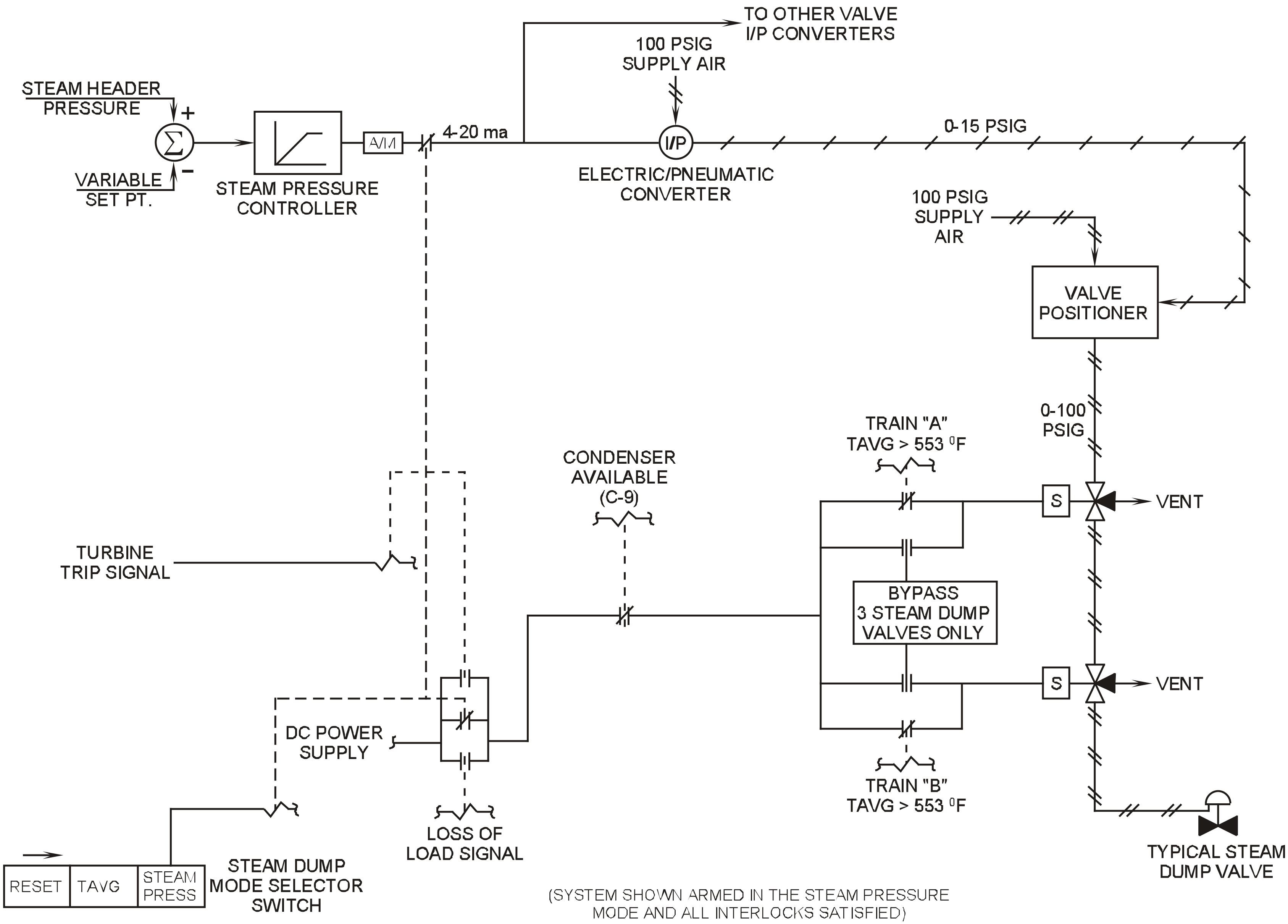


Figure 11.2-1 Steam Pressure Control Mode

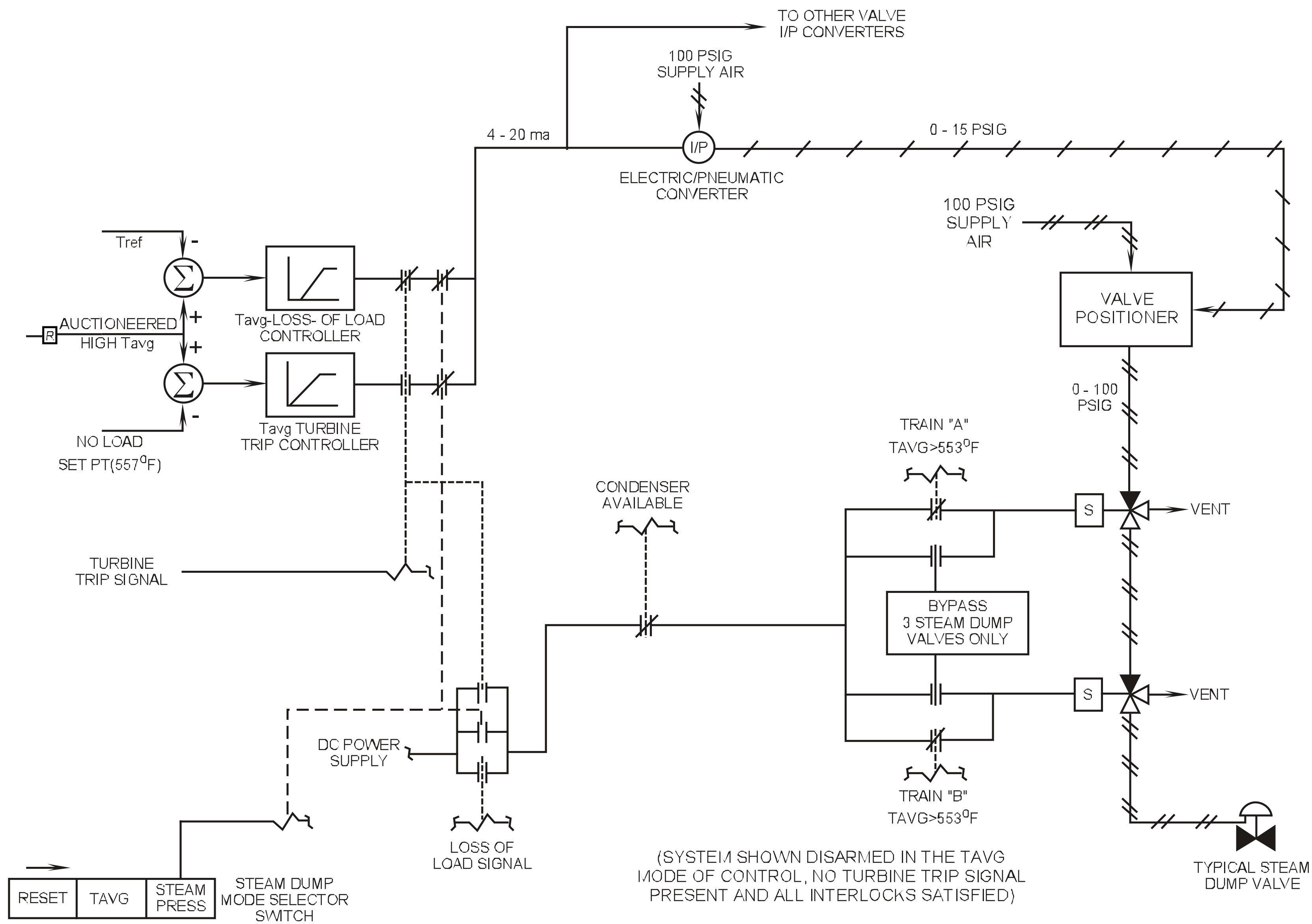


Figure 11.2-2 T_{AVG} Control Mode

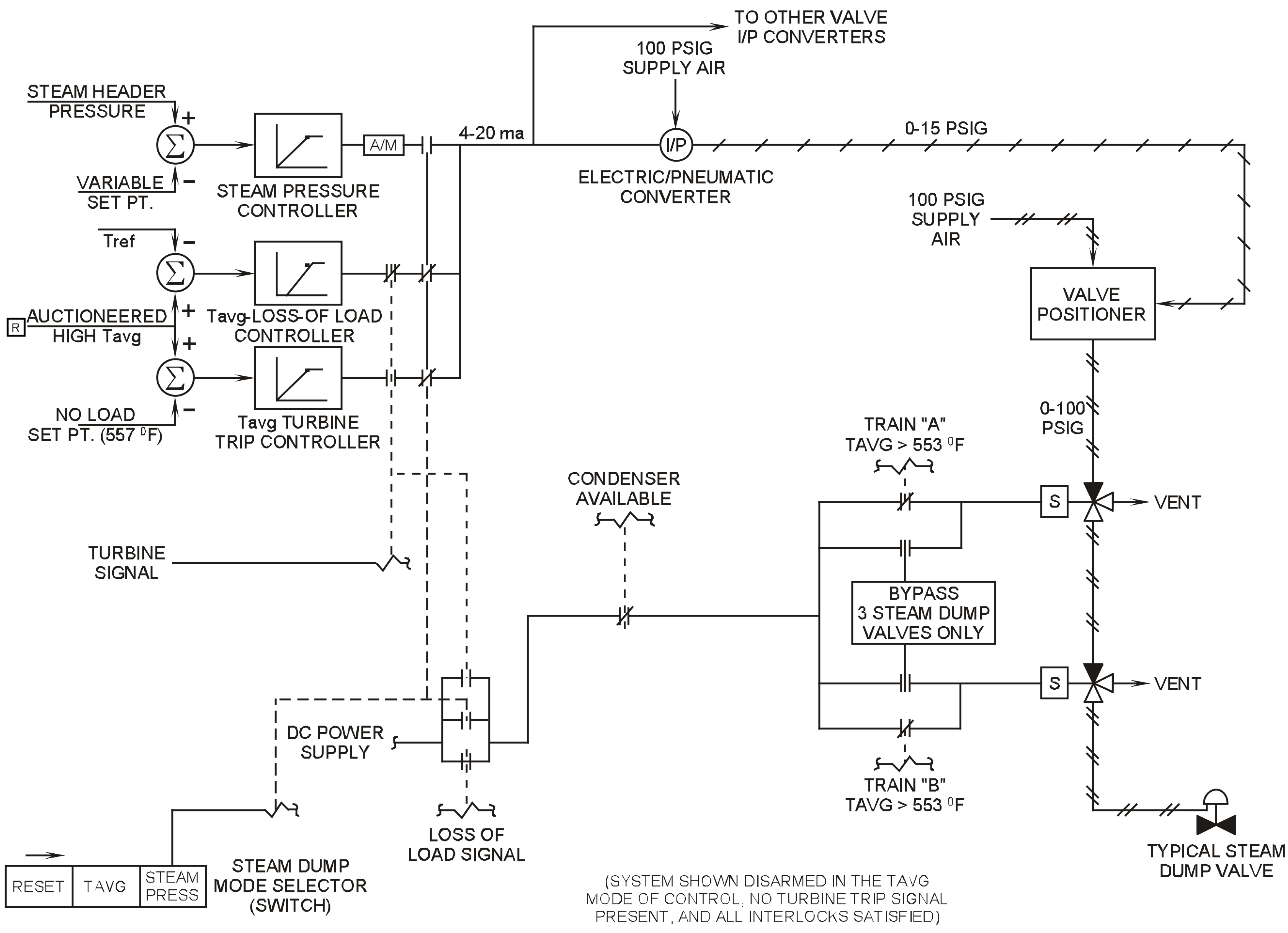


Figure 11.2-3 Steam Dump Control System

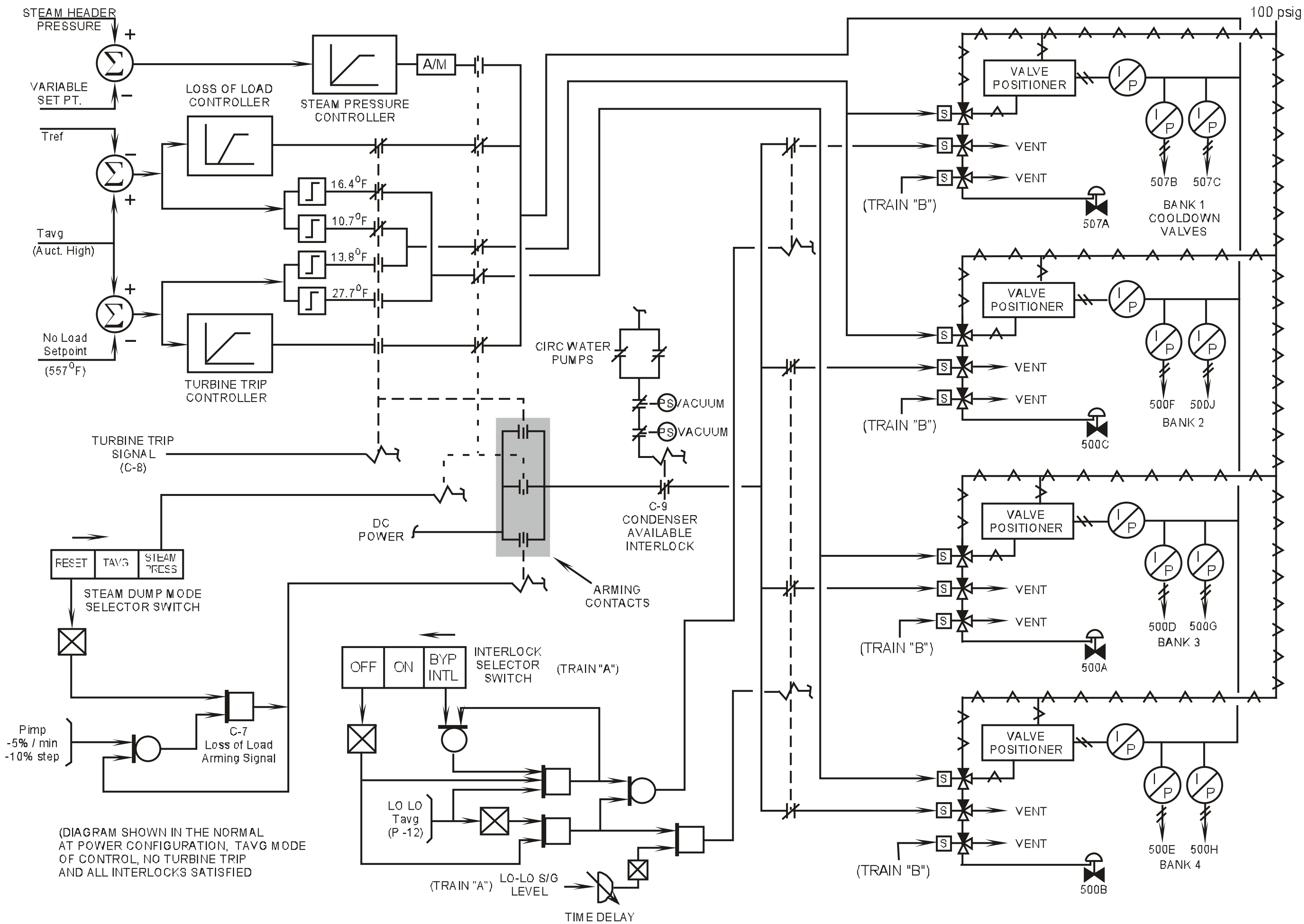


Figure 11.2-4 Steam Dump Control

Westinghouse Technology Systems Manual

Section 11.3

Westinghouse Electro Hydraulic Control (EHC) System

“READ ONLY SELF STUDY MATERIAL”

TABLE OF CONTENTS

LIST OF FIGURES

11.3 WESTINGHOUSE ELECTRO HYDRAULIC CONTROL (EHC) SYSTEM

Learning Objectives:

1. State the purposes of the turbine Electro Hydraulic Control (EHC) System.
2. Describe the sequence of events which results in a turbine trip when initiated by:
   a. Mechanical input (example: low condenser vacuum), and
   b. Electrical input (example: reactor protection signal).
3. Explain what function the following components perform in initiating a turbine trip:
   a. Solenoid trip mechanism,
   b. Interface valve, and
   c. Emergency trip valve.
4. List the input parameters to the control systems used for the following turbine operational modes:
   a. Speed control, and
   b. Load control.
5. Explain the difference between “impulse in” and “impulse out” during turbine load control operations.
6. Briefly describe the actions initiated by the overspeed protection controller (OPC) for the following conditions:
   a. 103% turbine overspeed, and
   b. Opening of the generator output breakers at high loads.
7. Explain how the following types of turbine runbacks are accomplished:
   a. Secondary system initiated, and
   b. Reactor protection system initiated.
8. List the turbine trip indication inputs to the reactor protection system.

11.3.1 Introduction

The purposes of the Electro Hydraulic Control (EHC) system are as follows:

1. To control the speed of the turbine-generator from turning gear operation to synchronous speed (60 Hz),
2. To control the load of the generator from synchronization to 100 percent load,
3. To provide rapid shutdown capability (trip) to protect the turbine-generator, and
4. To limit turbine overspeed on partial load rejections.

The EHC system uses high pressure hydraulic fluid to open and position the steam inlet valves to the high- and low-pressure turbines in response to commands from an electronic controller. An auto-stop oil system interfaces with the high pressure hydraulic system to generate a quick closure of all steam inlet valves if an abnormal condition is sensed by one or more of the turbine protective devices.

11.3.2 System Description

A simplified diagram of the EHC system is shown in Figure 11.3-1. As shown on this figure, the EHC system can be divided into three subsystems. The three subsystems are as follows:

1. The electronic controller and the operator's panel are shown on the lower left side of Figure 11.3-1. The controller cabinet receives inputs from: the operator's panel located in the main control room, a speed transducer located on the high pressure turbine rotor, a pressure signal from the impulse chamber of the high pressure turbine, and finally governor valve position (not shown on this figure). The electronic controller sends signals to servo valves for the throttle and control valves.
2. The electrohydraulic (EH) fluid system, a high-pressure hydraulic oil system, is shown in the right center of Figure 11.3-1. High pressure hydraulic fluid is supplied to the valve actuators for the throttle, governor, reheat stop, and interceptor valves. A drain path from the valve actuators returns the hydraulic fluid to the EH fluid sump via an emergency trip device. With the trip device closed, a high pressure is maintained at the valve actuators which keeps the steam supply valves open.
3. The final subsystem is a combination auto-stop and lubricating oil system. It is shown in the bottom right portion of Figure 11.3-1. This system provides lubricating oil to the turbine bearings and acts as a hydraulic fluid in the auto-stop oil system. This hydraulic system keeps the emergency trip device closed during normal operations. Should an unsafe condition exist, the auto-stop oil system pressure decreases, allowing the emergency trip device to open.

11.2.2.1 Electro Hydraulic (EH) Fluid System

The valves that admit and control the steam flow to the high and low pressure turbines are opened by high pressure hydraulic fluid acting upon the valves' hydraulic actuators. This high pressure hydraulic fluid is supplied by the EH fluid system, which is shown in Figure 11.3-2. Each steam valve has an actuator (for opening) and a dump valve (for closing). When the EH fluid system is pressurized, the dump valves are kept closed. With the dump valves closed hydraulic fluid pressure is applied to the valve actuator; the force exerted by the EH fluid overcomes the spring force (used to close the steam valve) and opens its associated steam admission valve. When the EH fluid pressure is decreased by opening the interface valve or the emergency trip solenoid, the dump valves open and bleed the hydraulic fluid in the valve actuator to the EH fluid sump. Spring force closes the steam admission valves, blocking steam to the high and low pressure turbines. When all turbine steam valves are closed in this manner, the turbine is said to be tripped.

Electro Hydraulic (EH) fluid system pressure is maintained by the operation of one of the two positive displacement EH pumps. The idle EH pump is placed in standby. If the pressure in this system drops below 1500 psig, the standby pump automatically starts. The system contains two unloader valves and one relief valve. The unloader valves maintain a desired pressure, while the relief valve prevents the over-pressurization of the system. The unloader valves regulate the hydraulic pressure by unloading (opening) at 2150 psig and closing at 1800 psig, while the relief valve opens at 2350 psig. Accumulators, which are not shown in this figure, are provided to smooth out pressure variations. Orifices are installed in the supply lines to the actuators and the dump valves to prevent repressurizing the system when the interface or the emergency trip valve opens.

The reheat stop valves and the intercept valves supply steam to the low-pressure turbines. These valves are either fully open or fully closed (never modulated). EH fluid is supplied through orifices (O-1 & O-2 as shown on Figure 11.3-2) directly to the valve actuators for these steam valves. The throttle (stop) valves supply steam to the high-pressure turbine through the governor valves. The throttle valves are generally fully open or fully closed. However, they do have a throttling feature, which is used during turbine acceleration from 0 to 1700 rpm. The governor (control) valves supply steam to the high-pressure turbine and are modulated to produce the desired generator output. Because the throttle valves and the governor valves must be capable of modulation, EH fluid is supplied to their respective valve actuators via servo valves. Each servo valve receives a command from the electronic controller and increases or decreases the hydraulic pressure in its actuator, to either open or close its associated valve.

All turbine steam supply valves are testable to ensure that they close upon a turbine trip signal. The throttle valves and the governor valves are tested one at a time. The test is accomplished by closing and opening the valves individually with their respective servos. The reheat stop valves and the intercept valves have solenoid valves that open the dump valves associated with the valve being tested. The reheat stop valves and intercept valves are tested in pairs; the valves in each steam line from one moisture separator reheater to one low pressure turbine are closed simultaneously and then reopened. Turbine load, hence reactor power, is lowered to about 75% during valve testing so that the generator output can be maintained constant by the control system.

Overspeed Protection Controller (OPC)

The purpose of the OPC is to prevent an overspeed trip of the main turbine. This function is accomplished by securing steam to the turbine for a short period; or securing steam to the turbine until the condition that is generating the potential overspeed condition clears. Three conditions could cause the OPC to actuate.

First, the OPC is provided with a speed signal from a shaft-mounted speed transducer. If 103% of normal speed is sensed, the OPC solenoid valves open. When these valves open, EH trip fluid is dumped into the EH fluid sump. This action closes the governor and intercept valves. A check valve, installed in the EH trip fluid line, prevents dumping EH trip fluid from the throttle and reheat stop valves. When the overspeed condition clears, the solenoid valves close and the governor and intercept valves reopen.

Secondly, if the generator output breakers open when the power is above a preset value, the OPC solenoids energize, as discussed above, closing the governor and intercept valves. This signal resets after a preselected time delay.

Finally, if the difference between the main generator output and the low-pressure turbine inlet pressure is greater than a preset value, the test solenoids of the intercept valves are energized to close the intercept valves. The intercept valves reopen when the difference clears. This circuit senses a loss-of-load and shuts these valves to prevent overspeeding the turbine-generator.

Emergency Trip Solenoid Valve

An emergency trip solenoid valve in the EH fluid system provides a backup for the interface valve (see Section 11.3.2.2). Opening of the emergency trip solenoid valve dumps EH fluid from the turbine valve actuators. The emergency trip solenoid valve is opened on any of the following signals:

- $ Manual turbine trip (from the control board),
- $ Reactor trip signal (train B),
- $ High-high level in any steam generator, and
- $ Low auto-stop oil pressure.

11.2.2.2 Auto-Stop Oil System

A combined lubricating and auto-stop oil system supplies lubricating oil to the turbine and generator bearings and keeps the interface valve closed during normal operation. Figure 11.3-2 shows this combination system. The EH fluid and auto-stop oil never come into contact with each other. The interface valve is the only component common to both systems, with EH fluid flowing through the valve upon a turbine trip, and auto-stop oil applied to the valve operator to close it against spring force. Low pressure in the auto-stop oil system allows the interface valve to open and trip the turbine.

Oil for the auto-stop system is normally supplied by a shaft-mounted centrifugal pump. When the turbine is not at rated speed, oil is supplied by the seal oil backup pump.

There are five protective trips for the main turbine generated via the auto-stop oil system:

- Low bearing oil pressure,
- Thrust bearing excessive movement,
- Low condenser vacuum,
- Solenoid (remote) trip, and
- Mechanical overspeed.

All five trips cause a low pressure in the auto-stop oil system, thereby opening the interface valve. The devices for the first four trips are located on one assembly, the protective trip block, as shown in Figure 11.3-2.

Low Bearing Oil Pressure Trip

Bearing oil is supplied to a spring-loaded diaphragm on the protective trip block. If pressure decreases to five to seven psig, the spring force lowers the diaphragm and raises the dump valve on the opposite end of the protective trip block. This set of events lowers the auto-stop oil pressure, which in turn opens the interface valve and trips the turbine.

Thrust Bearing Trip

This device warns the operator of excessive rotor movement in the axial direction and trips the turbine before such movement is enough to cause serious damage. The device consists of two small nozzles which discharge close to the thrust collar faces. Oil is supplied to the nozzles and through check valves to a spring-loaded diaphragm on the protective trip block. If the rotor moves toward either nozzle, pressure in that line increases. When pressure reaches 35 psig, a pressure switch actuates an alarm. When pressure increases to 75 - 80 psig, the diaphragm will move up and open the dump valve, causing the interface valve to open and trip the turbine.

Low Condenser Vacuum Trip

This trip also involves a spring-loaded diaphragm on the protective trip block. The diaphragm is subjected to the condenser vacuum. When the vacuum decreases (pressure increases) to 19 - 22 inches Hg, the diaphragm moves up and opens the dump valve. A vacuum trip latch is provided to permit starting the turbine with a low vacuum; it is engaged when the turbine is latched. The vacuum trip latch automatically disengages when the condenser vacuum reaches 23 - 25 inches Hg. Even if this latch is engaged it will not prevent a trip if the condenser pressure reaches 2.5 - 4.5 psig.

Solenoid

This feature allows the initiation of a turbine trip from a remote point through the energizing of a solenoid on the protective trip block, which causes the dump valve to open. Solenoid trips include the following:

- Manual turbine trip (from the control board),
- Reactor trip signal (train A),
- Electrical overspeed (approximately 111%),
- High-high level in any steam generator,
- Failure of DC control power to the EHC system,
- Low lubricating oil level,
- Low EH fluid level,
- Low EH fluid pressure,
- Failure of cooling water to the main generator,
- High vibration,
- Loss of both main feedwater pumps,
- Generator reverse power (with a 30-sec delay), and
- Trips initiated by main output transformer protective relays.

Mechanical Overspeed Trip

The overspeed trip mechanism consists of an eccentric weight mounted inside a transverse hole in the high-pressure turbine rotor shaft. The weight is held in place by a spring; but because the weight is off-center, it moves outward, away from the center of the rotor, against spring force, when the turbine overspeeds. When the weight moves outward, it strikes a trigger which opens the overspeed trip valve, causing auto-stop oil to drain from the system and the turbine to trip. The setpoint for the mechanical overspeed trip is higher than the trip setpoint of the electric overspeed trip.

The overspeed trip mechanism also seals in any turbine trip developed at the protective trip block. When the dump valve opens in response to any of those trips, the auto-stop oil pressure decreases throughout the system. The absence of oil pressure at the overspeed trip valve allows a spring to deflect the overspeed trip trigger, opening the overspeed trip valve, which maintains an open drain path for the auto-stop oil. This feature seals in the trip, even if the initial condition clears and closes the protective trip block dump valve. The control room operator must reset the overspeed trip mechanism either locally or remotely to repressurize the auto-stop oil system.

The overspeed trip mechanism can be tested by injecting oil under the weight to move it into the trigger. To prevent an actual turbine trip during testing, the trip test handle must be manually held to prevent depressurizing the portion of the system containing the interface valve. The trip test handle must be held in the test position until the overspeed trip mechanism is reset and the auto-stop oil pressure is restored. The trips on the protective trip block are also tested while the trip test handle is held in the test position. Each trip tested trips the overspeed trip mechanism.

11.2.2.3 Electronic Control System

The electronic control system calculates deviations between reference signals and turbine speed, valve position, or turbine first-stage pressure (Imp In only). If the turbine is latched (not tripped), it is controlled in one of two operational modes: speed control or load control. Speed control is used to roll the turbine from turning gear speed (about 1 rpm) to synchronous speed (1800 rpm). When the generator output breakers are closed, the EHC system automatically shifts from speed control to load control. In load control, the EHC system controls the turbine’s power output.

Speed Control

Figure 11.3-3 illustrates the speed control circuit, which contains two modes of speed control: throttle valve control and governor valve control. Latching the turbine automatically places the speed control circuit in throttle valve control. When operating in this mode, steam passes through one throttle valve via an internal poppet. From this poppet steam is directed through all four, fully open, governor valves, into the steam chest of the high-pressure turbine and is called “full arc admission.”

Initially, after latching the turbine, the throttle valves and the governor valves are closed. Rolling the turbine for chest warming requires opening the governor valves. To accomplish this, the control room turbine operator depresses the valve position limit increase push button. Increasing the output of the valve position limit, forces the governor valves open due to the 100-rpm open bias input into the low value gate from the PI amplifier. The control room operator continues increasing the setting of the valve position limiter until it indicates 100% and the governor valves are full open. Applying a constant 100-rpm open bias with the integral action of the Proportional Integral (PI) amplifier keeps the governor valves open.

To roll the turbine off its turning gear, warm up the turbine, and increase its speed to 1700 rpm, throttle valve control is used. The control room turbine operator selects a speed and an acceleration rate on the EHC panel (according to the turbine heatup and loading curves) and depresses the “GO” push-button. The proportion amplifier receives a speed error signal, without the 100-rpm open bias, and sends a proportional output signal to the throttle valve servos (Note: the contact from the 100-rpm open bias is open).

When the turbine attains a speed of 1700 rpm, the control room turbine operator depresses the “TV/GV” transfer push-button to execute the shift-over from throttle valve control to governor valve control. During the shift-over, the “TV/GV” pushbutton flashes alerting the control room turbine operator that the shift over is in progress. After the shift-over is complete, the “TV/GV” pushbutton stops flashing. The throttle valves receive a continuous 100-rpm open bias via a PI amplifier, which keeps the throttle valves fully open, and the speed error signal modulates the governor valves to maintain a speed of 1700 rpm. After completing the transfer, the turbine is increased to synchronous speed (1800 rpm) in preparation of paralleling the generator to the grid.

Load Control (Imp Out)

Two modes of automatic load control are incorporated into the design of the EHC system: impulse pressure out of service (Imp Out) and impulse pressure in service (Imp In). Imp Out is described first.

Referring to Figure 11.3-4, the input signals to this circuitry are two reference signals; speed and load reference, and two measured parameters; turbine speed and turbine impulse pressure. In addition, the governor valve servo circuit receives a feedback signal from governor valve position.

As discussed earlier, speed control is used to warm up the turbine and bring it to synchronous speed. After synchronizing the turbine to the grid, the turbine operator in the control room closes the main generator output breaker. This action automatically shifts the EHC system from speed control to load control. Imp Out is the default mode of operation when the shift-over takes place. The electronic controller sets the reference load at 5%, with a load rate of 1%/min. Increasing the load of the turbine to 5% ensures that the generator does not motorize.

Besides reference load, the control system is provided with a speed error signal developed by comparing a fixed reference speed (1800 rpm) with the actual turbine speed transmitted from a shaft-mounted speed transducer. Normally the output from this part of the circuit is zero. Supplying a speed error signal to this electronic control system allows the turbine-generator to assist the other generating units to maintain the stability of the offsite electrical system (the grid). If the demand load on the grid is greater than the supplied generating capacity, electrical frequency on the grid decreases. This decrease in frequency generates a speed error signal, which is added to the reference load. The increased demand opens the governor valves increasing the power output from the turbine. The electrical loads from the other turbine-generators tied to the grid are similarly increased. The combined effect should match the total plant power output to the total system power demand, returning and maintaining grid frequency at 60 Hz.

A proportional amplifier receives the combined reference load and speed error signal. A low value gate receives this proportionally amplified signal along with a valve position limit setpoint. The valve position limit is adjusted by the turbine operator to prevent the turbine governor valves' form opening beyond a preselected limit, i.e., prevents the secondary load from exceeding a preselected maximum value. As long as the demanded reference signal is less than the valve position limit, the governor valve servo circuit receives the reference load signal. If the load reference demand is greater than the valve position limit setpoint, the low value gate clamps the governor valves at a position demanded by the valve position limiter. If the governor valves are clamped, the reference window continues to increase at the rate input by the turbine operator. This action, reference window display increase, continues until the displayed value in the "Reference" window equals the value in the "Setter" window.

The function generator in each servo circuit [F(X)] accounts for the nonlinear effect of valve position on steam flow and provides a bias to open the governor valves in a sequence if desired. The output of F(X) is compared with the actual valve position provided by a Linear Variable Differential Transmitter (LVDT). Any error between the demanded valve position and the actual valve position is amplified and integrated over time to ensure that the valve reaches its demanded position. Only when the valve position feedback equals the demanded position will the Proportional-plus-Integral (PI) amplifier stop integrating. In the Imp Out mode valve position is the only feedback other than the speed signal.

Finally, if the turbine-generator is operating at 50% power, and the turbine operator is directed to increase power to 100% at 1%/min, the turbine operator, using the reference control increase push-button increases the target load to 100% (displayed in the "Setter" window). The operator also selects 1%/min on the load rate thumb-wheel. To start the load increase the operator depresses the "go" push-button. The system electronically changes the reference load from 50% to 100% at 1%/min. As the reference load increases, as indicated in the "Reference" window, the governor valve servo circuits receive a steadily increasing signal, which results in the governor valves opening farther increasing steam flow to the turbine. The system opens or closes the governor valves to a position that is equivalent to the demanded power level.

Load Control (Imp In)

At 15% to 20% turbine-generator load, the operator may select impulse pressure (Imp In) as a feedback input into the load reference circuitry. Impulse pressure is an indication of actual turbine load. After switching the EHC system to Imp In, the load reference, as shown in Figure 11.3-4, becomes a combination of speed error, reference load and impulse pressure. A proportional-integral (PI) amplifier receives the reference load instead of a proportional-only amplifier. The PI amplifier provides a proportional output dependant upon the magnitude of the input error signal. The integral function increases the proportional gain to ensure that the governor valves open far enough to increase turbine load (as indicated by impulse pressure) to a value that is equal to the desired load.

The electronic control system receives two feedback signals: impulse pressure and valve position. To reach an equilibrium condition, the valve position feedback from each governor valve must be equal to the output of F(X), and the impulse pressure feedback must equal the reference load. There could be some “hunting” of the system while the outputs of the PI amplifiers decrease to zero. Although the design of the function generators is to linearize the load reference with respect to actual load (a function of governor valve position), linearity can only be achieved in the Imp In mode. Figure 11.3-5 illustrates the difference between the two modes of load control (Imp In vs. Imp Out).

Curve A represents operation with impulse pressure out of service. This curve shows the non-linear relationship between load reference (vertical axis) and generator output (horizontal axis). The non-linearity of this curve is due to the variable steam flow characteristics of the governor valves. This non-linearity is illustrated by the reference loads labeled r'= and r", where r'= is at a lower value than r". As the load reference changes from r'= to r", actual generated load remains constant (P2) and is indicated by “c” on Curve A.

Curve B represents operation with impulse pressure in service. With Imp In selected, the control system changes governor valve position(s) until impulse pressure equals the load reference. Since impulse pressure is linear with respect to power, load reference becomes a linear function of power.

These curves also show how the load reference changes as a result of changing modes of operation. Assume that the system is operating in Imp Out, with power at P1 and load reference at R1. The operating point is “a” on curve A. During the shift-over to Imp In, the governor valves do not move. Meanwhile the load reference changes from R1 to R2; i.e., the reference window indication increases to equal the value at P1. The new operating point is “b” on curve B and the reference and setter window indication should be equal. Note the actual load (P1) has not changed, but the load reference has changed. Changing from Imp In to Imp Out results in a similar load reference change.

11.3.3 System Features and Interrelationships

Reactor Protection System

Two different signals from the turbine are sent to the reactor protection system to indicate that the turbine is tripped. One signal is four-out-of-four throttle (stop) valves fully closed, as indicated by the limit switches on the throttle valve stems. The other signal is low auto-stop oil pressure, as indicated by two-out-of-three pressure transmitters located in the auto-stop oil system.

Turbine Runbacks

Turbine runbacks are automatic reductions in turbine load. These runbacks are actuated based upon present plant conditions, if left unattended, could cause a plant trip. The runback signals can be initiated from either the primary or the secondary.

Two turbine runbacks are initiated by the reactor protection system. A runback signal is developed when the ΔT in two out of four reactor coolant loops is within three percent of the Over Temperature Differential Temperature (OTΔT) or Over Power Differential Temperature (OPΔT) trip setpoint. These trips are discussed in Chapter 12. If either of these runbacks is in effect, the EHC system reduces load at 200%/min for 1.5 sec (a 5% load change), then holds the load constant for 28.5 sec. If the runback condition has not cleared, the load will be reduced by another 5% in the next 30-sec interval.

The other turbine runbacks are initiated by secondary system conditions. Secondary system runbacks are accomplished via reductions of the governor valve position limit setpoint. Possible conditions that may cause a turbine runback include:

1. A combination of a main feed pump trip and turbine load greater than 80% (the turbine runs back to 75% power), and
2. Directing heater drains from the heater drain tank to the condenser instead of the suction of the main feed pump (the turbine runs back to 85% power).

11.3.4 Summary

The EHC system is made up of three main subsystems:

- EH fluid system,
- Auto-stop oil system, and
- Electronic control system.

High pressure electrohydraulic fluid opens the steam admission valves to the high- and low-pressure turbines. Pressure in this system is maintained by, EH control pumps, unloader valves, and an interface valve. The unloader valves maintain the pressure within design values, while the interface valve allows the system to be pressurized.

Auto-stop oil keeps the interface valve closed. If the interface valve is shut the EH fluid high pressure will be maintained at its design value. Opening the interface valve by dumping the auto-stop oil causes a turbine trip.

The electronic control system computes deviations between operator-initiated reference values and turbine speed and load. Deviations are transmitted to servo valves to reposition governor or throttle valves.

The turbine is operated in either speed control or load control. With the system in speed control, the throttle valves control the speed until a preselected speed is achieved and then speed control is shifted to the governor valves.

After the generator output breakers are closed, the system automatically shifts to load control with impulse pressure out of service. When operating in this mode, Imp Out, governor valve position is used as a feedback signal. The operator may select impulse pressure in service after power has exceeded some nominal power level. Once this action has taken place, turbine impulse pressure along with governor valve position are used as feedback signals.

Runbacks are provided to prevent either a reactor trip or a turbine trip. Runbacks may be initiated either from the primary protection system, or from the secondary system. Primary runbacks decrease the turbine load via a decrease in the reference load, while the secondary runbacks decrease the setting of the valve position limiter.

Finally, various protective signals are provided to trip the turbine. Whenever a turbine trip occurs, the overspeed trip device is actuated to seal in the trip. To prevent a turbine overspeed, an overspeed protection circuit is provided. This circuit momentarily closes the governor and the intercept valves. When the overspeed condition clears, the governor and intercept valves return to their open positions.

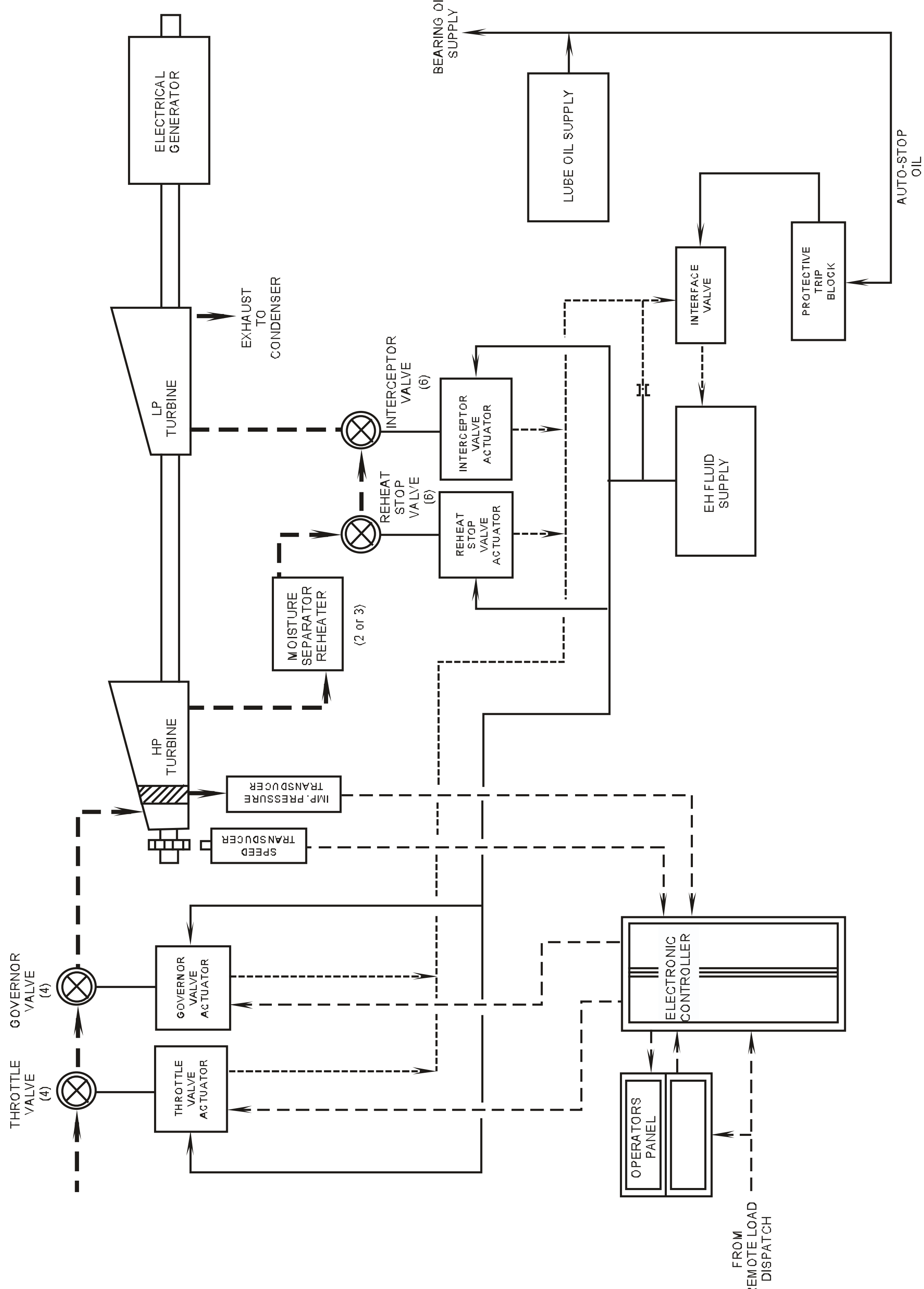


Figure 11.3-1   Simplified EHC System

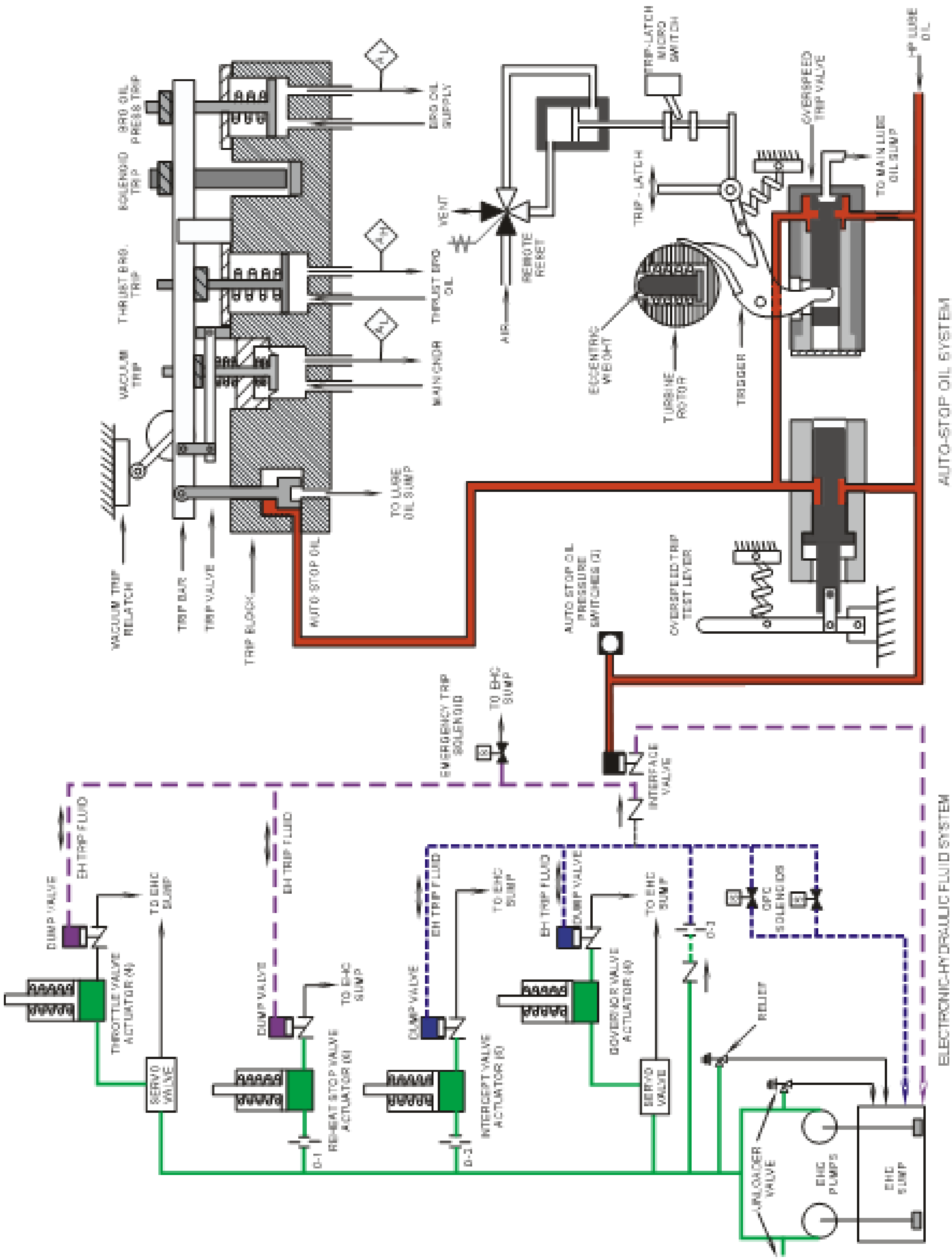


Figure 11.3-2 EH Fluid and Auto – Stop Oil System

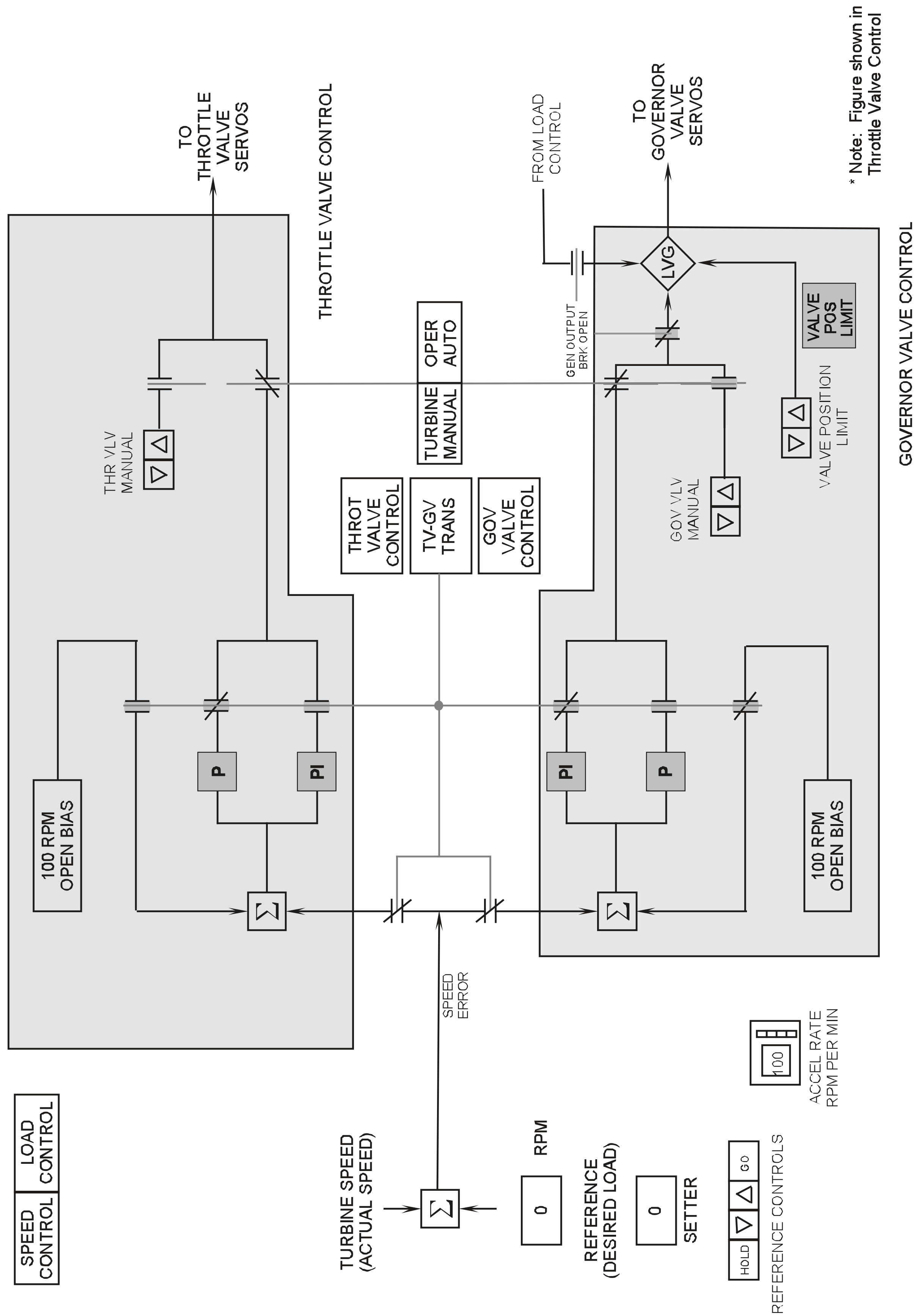


Figure 11.3-3 Speed Control

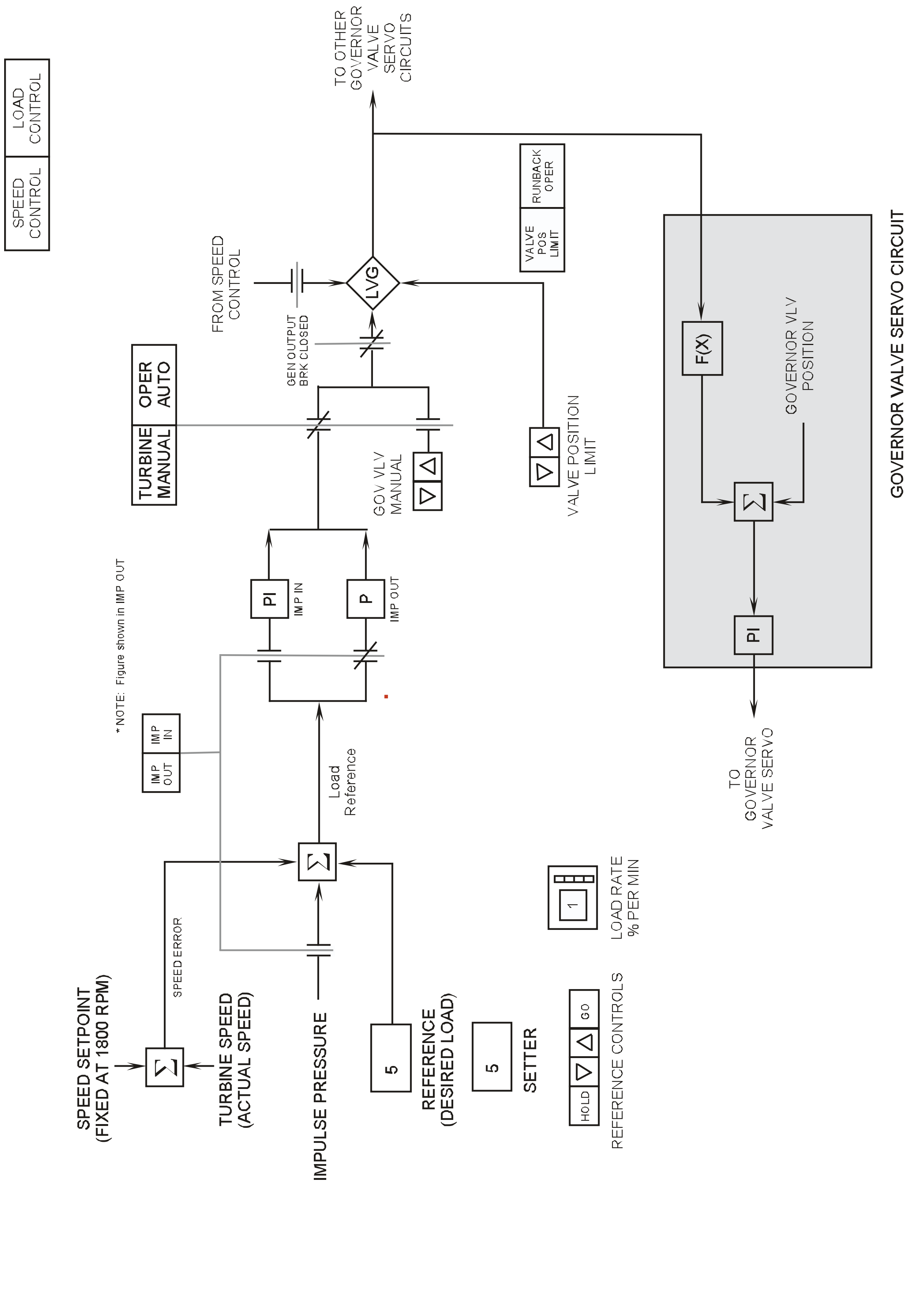
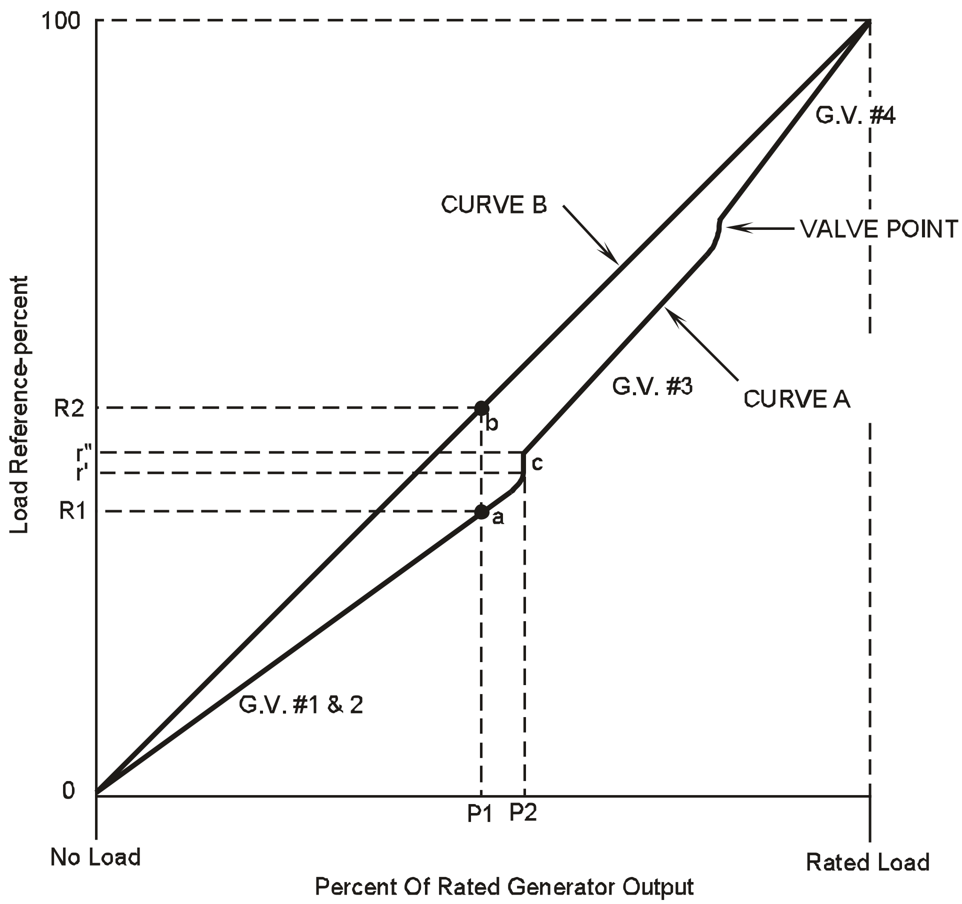


Figure 11.3-4 Load Control



Curve A -- Impulse Chamber
Pressure Feedback Out-of-Service
(IMP OUT)

Curve B -- Impulse Chamber
Pressure Feedback In-Service
(IMP IN)

Figure 11.3-5 Impulse Chamber Pressure vs. Load Reference

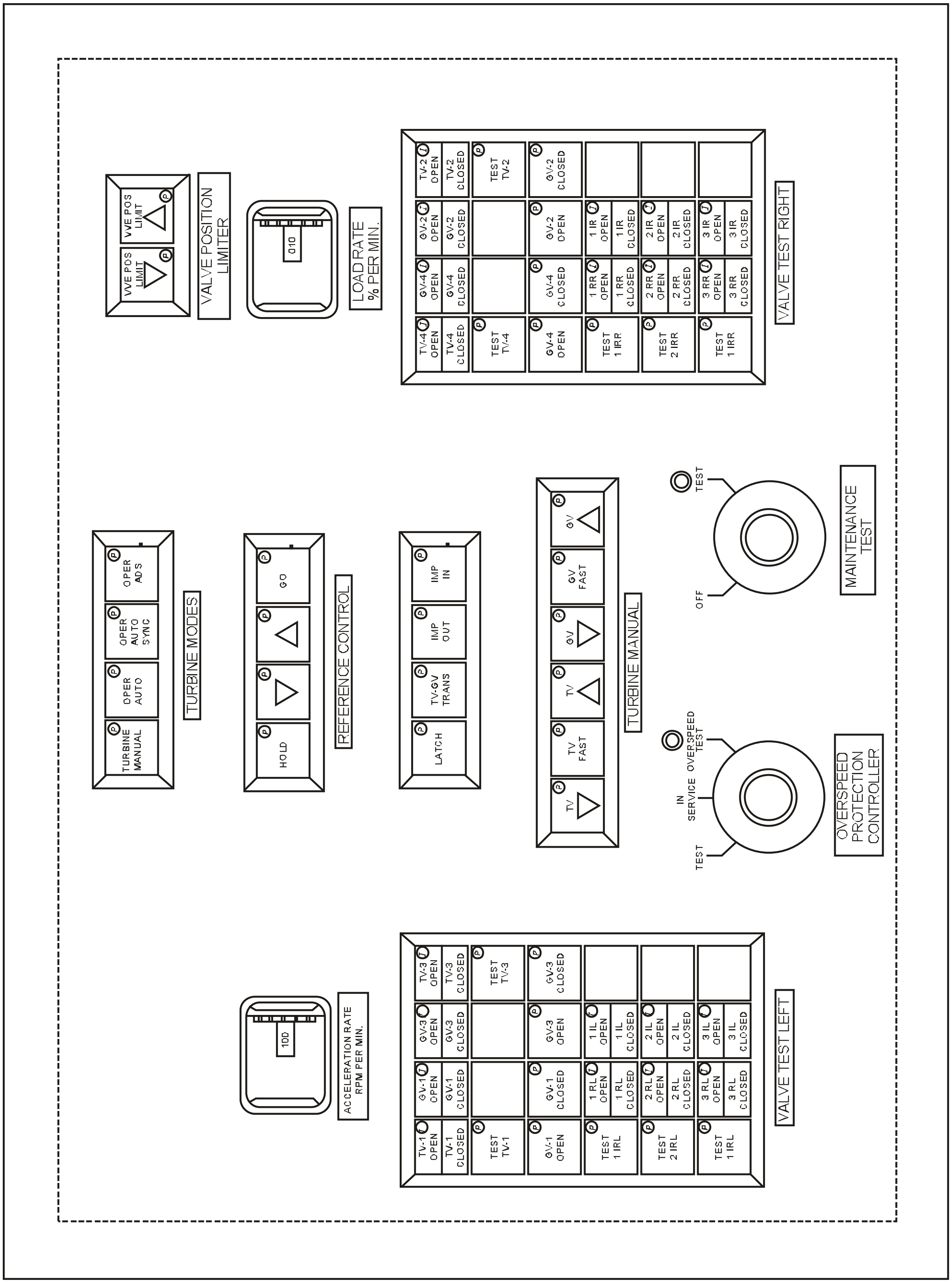


Figure 11.3-6 EH Control Panel

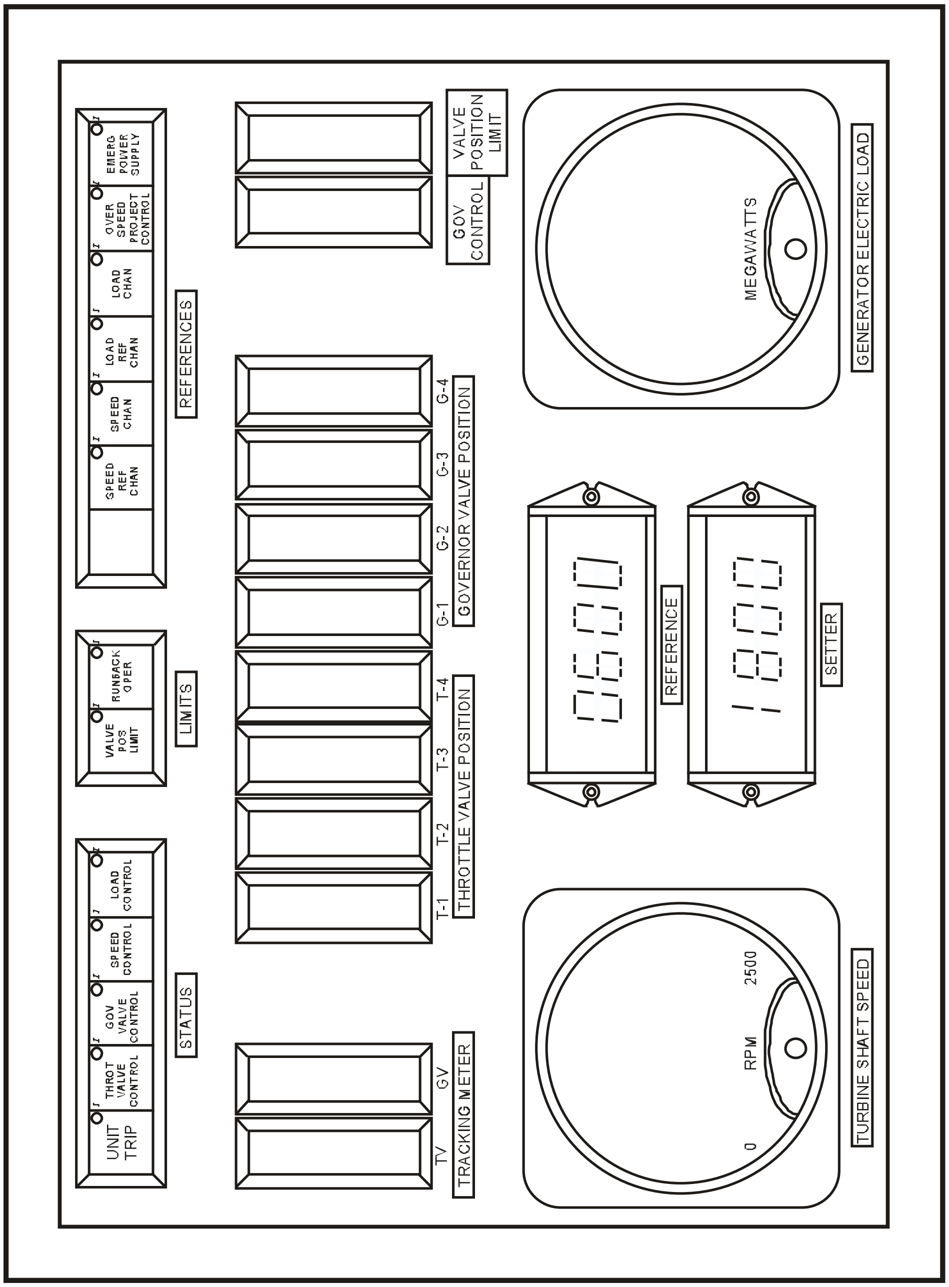


Figure 11.3-7 EH Indicating Panel

Westinghouse Technology Systems Manual

Section 11.4

Moisture Separator Reheater (MSR) Control

"READ ONLY SELF STUDY MATERIAL"

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11.4 MOISTURE SEPARATOR REHEATER (MSR) CONTROL

Learning Objectives:

1. State the purposes of the Moisture Separator Reheater (MSR) Control system.

11.4.1 Introduction

The Moisture Separator Reheater (MSR) control system ensures proper heating of the low-pressure turbine during cold startups, ensures a minimum differential between the inlet steam and low-pressure turbine metal temperatures during hot startups, and provides a smooth decrease in low pressure turbine inlet steam temperature to 400°F after a large load shed from a high-power level. These functions are accomplished through the control of the MSR outlet steam temperature.

11.4.2 System Description

After the exhaust steam from the high pressure turbine passes through the moisture separator section of an MSR, the steam enters a two-stage heater section for the addition of superheat. The first-stage heating medium is extraction steam from the high pressure turbine. This steam supply is not regulated. The second-stage heating medium is high pressure steam from the main steam header. This steam supply is regulated by flow control valves to control the temperature of the steam at the outlet of the MSRs.

Figure 11.4-1 shows the operator's panel for the MSR controls. The top of the panel has a row of pushbuttons. Below that is a row of valve status lights for the flow control valves that regulate the main steam flow to the second-stage heater bundles of the MSRs. At the bottom of the panel are three meters, one meter for each low pressure turbine. Each meter indicates the steam inlet temperature supplied to its associated turbine. A status light illuminates when a preset temperature limit has been exceeded and a knob located in the lower right of the panel is provided for manual control.

The POWER ON pushbutton turns the controller on and off. During the performance of a cold startup, the RAMP pushbutton is pushed at 35% of rated power. After this the ramp pushbutton is depressed the flow control valves are opened over a one-hour period. This provides a uniform temperature increase. For a hot startup, the HOT START pushbutton is pushed; the valves are opened quickly, and maintain a low pressure turbine inlet temperature of 400°F to prevent cooling of the low pressure turbine inlet. The 400°F pushbutton is also used during extended low power operations to prevent overheating of the low pressure turbine exhaust sections. MANUAL transfers control to the knob at the bottom of the panel. RESET clears the controller.

After a large load reduction to 10% power or below, the MSR control system automatically positions the second-stage heating flow control valves to maintain a steam temperature of 400°F at the low-pressure turbine inlet.

11.4.3 Summary

The inlet temperature to the low pressure turbines is controlled by regulating the flow of high pressure heating steam to the second-stage heater bundles of the MSRs. Steam flow is controlled by flow control valves. The control system will ramp open the valves automatically or maintain a low pressure turbine inlet temperature of 400°F. The valves can also be controlled manually.

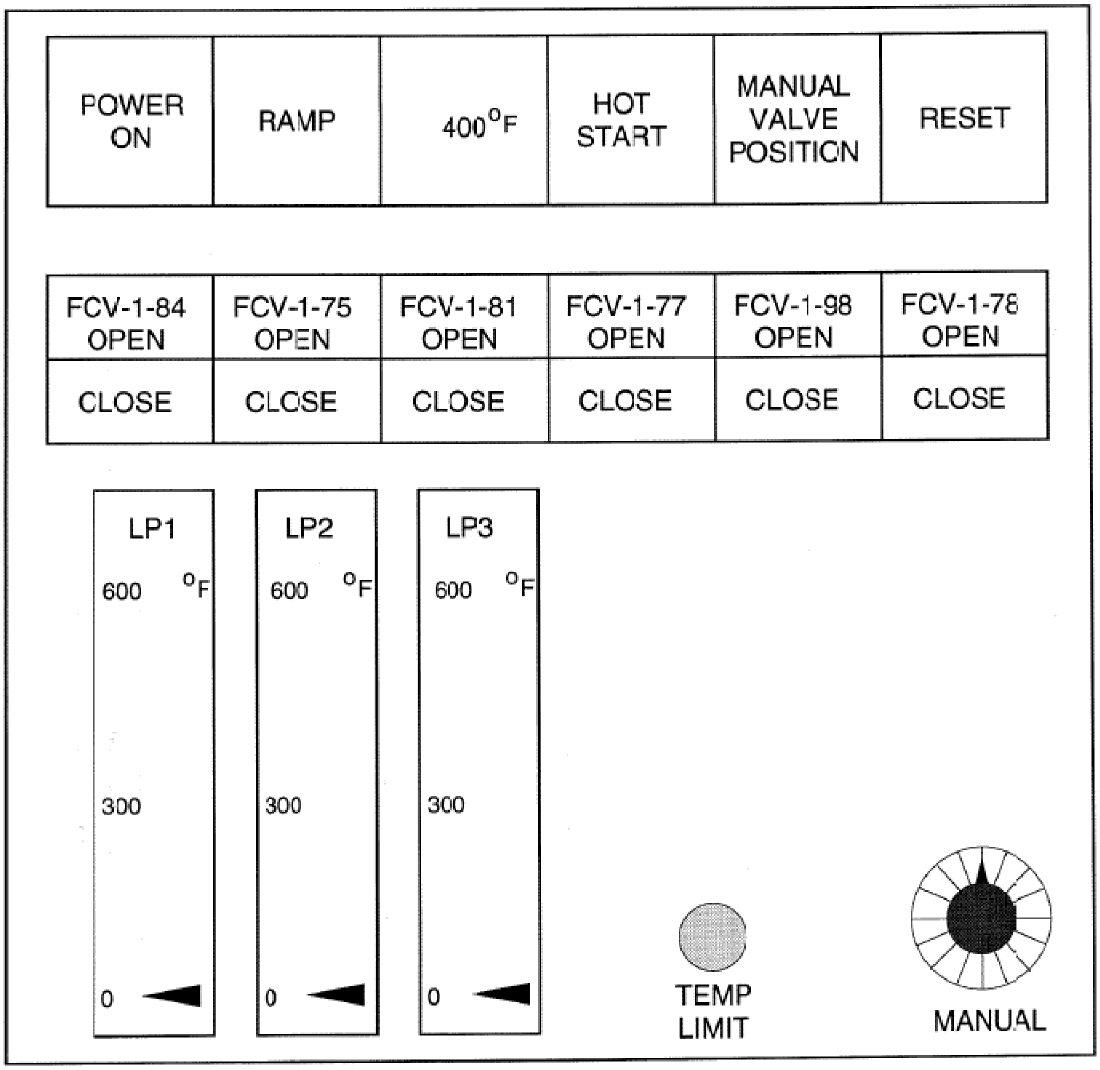

Figure 11.4-1 Reheater Control Panel

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Section 11.5

<u>General Electric Electro Hydraulic Control (EHC) System</u>

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11.5 GENERAL ELECTRIC ELECTROHYDRAULIC CONTROL (EHC) SYSTEM

Learning Objectives:

1. State the purposes of the turbine Electro Hydraulic Control (EHC) system.

2. Describe the sequence of events that results when a turbine trip is initiated mechanically or electrically.

3. Explain the functions of the following emergency trip system components:

   a. Mechanical trip valve,
   b. Lockout valve,
   c. Master trip solenoid valve,
   d. Relay trip valve, and
   e. Extraction relay dump valve.

4. Describe the generation of turbine valve positioning signals in the following components of the electrical control system:

   a. Speed control unit,
   b. Load control unit, and
   c. Flow control unit.

11.5.1 Introduction

The purposes of the Electro Hydraulic Control (EHC) system are as follows:

1. To govern the warming of the turbine steam chest and high pressure turbine shell,
2. To control the speed of the turbine-generator from turning gear operation to synchronous speed (60 Hz),
3. To control the load of the turbine-generator during normal and abnormal operations, and
4. To provide a rapid shutdown capability (trip) for the protection of the turbine-generator.

The EHC system uses high pressure hydraulic fluid to open and position the steam inlet valves to the high and low pressure turbines in response to commands from an electrical controller. High pressure hydraulic fluid is also supplied to the emergency trip system, which maintains shut the disk dump valves incorporated within the steam inlet valve operators. When the hydraulic pressure in the emergency trip system is relieved, the disk dump valves open, allowing springs to close all steam inlet valves and thereby trip the turbine. A simplified diagram of the EHC system is shown in Figure 11.5-1.

11.5.2 System Description

The EHC system can be divided into three subsystems:

a. The EHC fluid system (high pressure hydraulic fluid),
b. The emergency trip system, and
c. The electrical control system.

11.5.2.1 EHC Fluid System

The valves that admit and control the steam to the high and low pressure turbines are opened by high pressure hydraulic fluid acting on the valves' actuators or operators, which are mechanically linked to the valve stems. This high pressure fluid is supplied by the EHC fluid system, as shown in Figure 11.5-2. Each valve has an operator and a disk dump valve. The application of EHC fluid pressure to the piston in a steam inlet valve's operator overcomes the force exerted by the operator's spring assembly and opens the valve. When a valve operator's disk dump valve opens, EHC fluid is dumped to the EHC fluid reservoir, allowing the spring force to rapidly close the valve. Each disk dump valve is normally maintained in the closed position by the hydraulic fluid pressure applied by the emergency trip system. The means by which emergency trip system pressure is removed are discussed in section 11.5.2.2. When all disk dump valves have opened and the valve operator springs have closed all steam inlet valves to the high and low pressure turbines, the turbine is said to be tripped.

EHC fluid at 1600 psig is supplied to the turbine valve operators by an operating EHC pump, which takes suction on the EHC fluid reservoir. The second (standby) EHC pump starts if the EHC fluid pressure falls to 1300 psig. The system contains relief valves for overpressure protection, nitrogen-charged accumulators for dampening system pressure variations, and strainers and filters for the removal of contaminants. EHC fluid from the turbine valve operators and from the emergency trip system is returned to the EHC fluid reservoir via two EHC fluid coolers, which are cooled by the bearing cooling water system. The EHC fluid is a synthetic, fire-retardant phosphate ester.

EHC fluid is supplied through servo valves to the operators for the control valves and the #2 stop valve of the high pressure turbine and for three of the six intercept valves of the low pressure turbines. Within a servo valve, commands from the electrical control system result in the movement of an internal spool, which ports more or less EHC fluid to the associated turbine valve operator and thereby causes the turbine valve to open or close further. Once the turbine valve has attained the desired new position, the internal spool returns to its neutral position, which bottles up the EHC fluid between the servo valve and the valve operator in a "hydraulic lock" and maintains the valve position. The turbine valve operators equipped with servo valves are thus capable of modulation.

The remaining turbine valves (high pressure turbine stop valves #1, #3, and #4; three of the six intercept valves; and all six of the intermediate stop valves) are either completely open or completely shut, not modulated. The operator for each of these valves is supplied with EHC fluid through a solenoid-operated valve. With the solenoid de-energized, an internal spool is positioned to admit EHC fluid to the associated valve operator; with the solenoid energized, the spool is positioned to bleed fluid from the operator. Information concerning the positioning of turbine valves during operation is provided in section 11.5.2.3.

11.5.2.2 Emergency Trip System

The EHC pumps supply high pressure EHC fluid to the emergency trip system as well as the turbine valve operators. The emergency trip system, shown in Figure 11.5-3, supplies EHC fluid to the disk dump valves associated with all 20 turbine valves, the relay trip valve, and the extraction relay dump valve (the disk dump valves associated with the control valves and intercept valves are supplied via the relay trip valve). All of the valves listed above are supplied through the mechanical trip valve, the lockout valve, and the master trip solenoid valve. Turbine trip signals act through these latter three valves to dump EHC fluid from the turbine valve operators.

The mechanical trip valve, as its name implies, provides a means of mechanically tripping the turbine. Under normal operating conditions (i.e., a trip condition is not present), the valve aligns the emergency trip system fluid to the lockout valve. In the tripped position, the valve blocks the incoming supply of emergency trip system fluid and opens a drain to the EHC fluid reservoir, allowing emergency trip system fluid to drain from the lockout valve and all downstream components. The mechanical trip valve's incoming and outgoing paths for hydraulic fluid are controlled by the position of an internal spool, which in turn is controlled through mechanical linkages by the overspeed trip device, the manual trip lever, and the mechanical trip solenoid.

The overspeed trip device is an unbalanced ring attached to the turbine shaft; the ring is maintained concentric with the shaft at normal turbine speeds by spring force. At 110% of rated turbine speed (1980 rpm), the ring moves to an eccentric position and strikes the trip finger, which through mechanical linkages places the mechanical trip valve in the tripped position. The overspeed trip device can be tested at normal operating speeds by admitting main turbine lubricating oil inside the ring and thereby causing it to assume its eccentric position (the lockout valve must first be placed in the locked out position; see below).

Pulling the manual trip lever, located on the turbine front standard, to the trip position results in a mechanical linkage striking the overspeed trip finger. From that point, the development of a mechanical trip is identical to that caused by an overspeed condition. Energizing the mechanical trip solenoid causes the same linkage to strike the overspeed trip finger and also results in a mechanical trip. The mechanical trip solenoid is energized when the turbine trip pushbutton in the control room is depressed or when any electrical trip signal is present. The mechanical trip solenoid thus serves as a redundant tripping device to the master trip solenoid valve.

The lockout valve is a three-way solenoid valve located on the turbine front standard. It does not process turbine trips but allows testing of the overspeed trip device (described above) without tripping the turbine. Under normal conditions (i.e., an overspeed trip test is not being conducted), the valve aligns the emergency trip system fluid from the mechanical trip valve to the master trip solenoid valve. In the locked out position, the valve blocks the fluid supply from the mechanical trip valve and aligns a separate emergency trip system fluid supply to the master trip solenoid valve. The lockout valve's alignment is controlled by the position of an internal spool, which is controlled by the lockout solenoid. Energizing the lockout solenoid places the valve in the locked out position.

To conduct a test of the mechanical overspeed trip device, the lockout solenoid is energized. Placing the lockout valve in the locked out position satisfies an interlock which permits the operator to supply lubricating oil to the overspeed trip device. When the overspeed trip is developed, the mechanical trip valve will realign to drain emergency trip system fluid to the EHC fluid reservoir, but the lockout valve will maintain a supply of emergency trip system fluid to the master trip solenoid valve and all downstream components. Pulling the manual trip lever or energizing the mechanical trip solenoid opens an interlock switch through mechanical linkages; the switch in turn de-energizes the lockout solenoid and places the lockout valve in its normal position. Thus, the lockout valve remains in the locked out position only for a mechanical overspeed trip (testing-induced or actual) and allows normal functioning of the emergency trip system for all other turbine trips.

The last of the three valves in the emergency trip system supply line is the master trip solenoid valve. Under normal operating conditions, the valve aligns the emergency trip system fluid from the lockout valve to the downstream emergency trip system components (disk dump valves, relay trip valve, and extraction relay dump valve). In the tripped position, the valve blocks the fluid supply from the lockout valve and opens a drain to the EHC fluid reservoir, allowing fluid to drain from all downstream components. The master trip solenoid valve's alignment is controlled by the position of an internal spool, which in turn is controlled by two solenoids. De-energizing both solenoids places the valve in the tripped position. The valve maintains the fluid supply to the downstream components if either solenoid remains energized; this feature allows either solenoid to be tested (i.e., de-energized) during turbine operation.

When a turbine trip setpoint is reached, a contact or contacts close in the power supply to the master trip bus. The master trip bus then energizes the master trip relays, which open contacts in the power supply to the solenoids of the master trip solenoid valve. De-energizing the solenoids of the master trip solenoid valve causes the valve to assume its tripped position and thereby dump hydraulic fluid from the emergency trip system, causing a turbine trip. The following conditions will cause the master trip bus to be energized:

- Excessive thrust bearing wear and low bearing oil pressure,
- Low EHC fluid pressure,
- High moisture separator reheater (MSR) water level,
- High turbine shaft vibration,
- Loss of stator cooling water,
- Low shaft-driven lubricating oil pump discharge pressure,
- Loss of EHC system power,
- Loss of turbine speed signal feedback,
- High turbine exhaust hood temperature,
- Loss of condenser vacuum,
- Backup overspeed (111.5% of rated speed, as sensed by a speed transducer),
- Generator trip,
- Reactor trip,

- Safety injection actuation,
- High steam generator water level,
- Low generator output frequency, and
- Satisfaction of ATWS (anticipated transient without scram) mitigation system actuation circuitry (AMSAC) logic.

Any of the above conditions redundantly initiates a turbine trip through the mechanical trip solenoid and the mechanical trip valve. When the master trip bus is energized, the master trip relays also close contacts in the power supply to the mechanical trip solenoid. As explained above, energizing this solenoid causes the mechanical trip valve to assume its tripped position.

Downstream of the master trip solenoid valve in the emergency trip system are the disk dump valves for the high pressure turbine stop valves and for the intermediate stop valves, the relay trip valve, and the extraction relay dump valve. Under normal operating conditions, the relay trip valve aligns a separate hydraulic fluid supply (not from the main emergency trip system header) to the disk dump valves for the control valves and for the intercept valves. Emergency trip system fluid pressure is applied to the relay trip valve’s internal spool to maintain the valve in its normal position. When the fluid pressure is removed from the spool, the new (tripped) valve alignment blocks the incoming fluid supply and opens a drain to the EHC fluid reservoir, allowing fluid to drain from the downstream disk dump valves.

The extraction relay dump valve serves a purpose similar to that of the relay trip valve. Under normal operating conditions, the extraction relay dump valve aligns the incoming air supply to the operators for the extraction steam bleeder trip valves and for the extraction drain valves. This alignment keeps the bleeder trip valves open (supplying extraction steam to the feedwater heaters) and the extraction drain valves closed (isolating the extraction steam drain lines to the main condenser). Emergency trip system fluid pressure is applied to the relay dump valve’s piston to maintain the valve in its normal position. When the fluid pressure is removed from the piston, the new (tripped) valve alignment blocks the incoming air supply and opens an exhaust port which vents the operators of the extraction steam system valves. The loss of air pressure closes the bleeder trip valves and opens the extraction drain valves. Closing the bleeder trip valves prevents the reverse flow of steam from the feedwater heaters to the turbine and possible turbine overspeeding (a great deal of energy remains stored in the extraction steam system immediately following a turbine trip). Opening the extraction drain valves allows the extraction steam to exhaust to the main condenser.

Five pressure switches, physically located on the turbine front standard, are connected to the emergency trip system header downstream of the master trip solenoid valve. The pressure in the header will drop rapidly when either the mechanical trip valve or the master trip solenoid valve dumps hydraulic fluid in response to a turbine trip condition. These pressure switches, set to close at 800 psig, thus indicate whether the turbine has tripped.

Three of the pressure switches supply the reactor protection system logic. A reactor trip is initiated when at least two of these switches are closed with plant power greater than the P-7 permissive setpoint (10%). The remaining two pressure switches provide turbine trip inputs to the turbine electrical control system. When closed, the pressure switches (1) lock in the CLOSE VALVES turbine speed reference and SLOW acceleration setpoint (in this chapter, capitalized terms refer to indications, pushbuttons, and switches on the turbine control panel), and (2) close contacts which apply large closing inputs to the control valve and intercept valve positioning circuits (see section 11.5.2.3 for a detailed discussion of the electrical control system). These last two pressure switches also serve to lock in a turbine trip by closing contacts in series with the master trip reset pushbutton in the power supply to the master trip bus.

To summarize the action of the emergency trip system, consider the following sequence of events initiated by high turbine shaft vibration:

1. The initiating condition closes contacts in the power supply to the master trip bus, thereby energizing the master trip relays.

2. The energized master trip relays close contacts in the power supply to the mechanical trip solenoid and open contacts in the power supply to both solenoids of the master trip solenoid valve.

3. The mechanical trip valve and the master trip solenoid valve assume their tripped positions, opening drain ports which dump hydraulic fluid from the emergency trip system.

4. With the decreasing emergency trip system header pressure:

    a. The disk dump valves for the high pressure turbine stop valves and for the intermediate stop valves are no longer held in the closed position. EHC fluid is dumped from the turbine valves’ operators, allowing springs to close the valves.

    b. The relay trip valve assumes its tripped position, opening a drain port which dumps hydraulic fluid from the disk dump valves for the high pressure turbine control valves and for the intercept valves. The disk dump valves open. EHC fluid is dumped from the turbine valves’ operators, allowing springs to close the valves.

    c. The extraction relay dump valve assumes its tripped position, opening an exhaust port which vents air from the operators for the bleeder trip valves and for the extraction drain valves. The bleeder trip valves close, and the extraction drain valves open.

    d. The pressure switches connected to the emergency trip system header close when the header pressure decreases to 800 psig. They provide turbine trip inputs to the reactor protection system and to the turbine electrical control system.

11.5.2.3 Electrical Control System

The major components of the turbine electrical control system are the speed control unit, the load control unit, and the flow control unit. These units are illustrated in Figure 11.5-4. The speed control unit controls turbine speed in response to operator commands or maintains the normal rated speed of the turbine-generator. In the load control unit, electrical signals are generated to position the turbine steam valves to maintain the desired load. The flow control unit receives the valve positioning signals, accounts for the steam flow control characteristics of the valves, and positions the valves accordingly. The flow control unit supplies valve positioning signals only to the servo valves associated with the control valves and with intercept valves #1, #2, and #3. The turbine chest and shell warming circuits supply positioning signals to the servo valve associated with stop valve #2. The remaining turbine valves are not modulated. They are either completely open or completely shut in accordance with the turbine operating status and the positions of limit switches associated with the modulated valves.

Speed Control Unit

In the speed control unit, the actual turbine speed is compared to the reference speed, and the actual turbine acceleration is compared to the acceleration setpoint. Either the speed error or the integrated acceleration error is chosen as the unit output and supplied to the load control unit. Normally, the speed error dominates the circuit, but when the reference speed is changed, the integrated acceleration error dominates until the turbine nears the new reference speed. During steady-state operation, the turbine speed is maintained constant at rated speed, and the output of the speed control unit is zero. Refer to Figure 11.5-5.

Turbine speed signals from two speed transducers are provided to separate circuits for redundancy and reliability. In each circuit, the actual speed signal is subtracted from the reference speed to produce a speed error. In addition, each speed signal is provided to a differentiator, which converts the speed signal into an acceleration signal. In each circuit of the speed control unit, the acceleration signal is subtracted from the acceleration setpoint to produce an acceleration error; the error is then integrated. The integrated acceleration error and speed error of each circuit are provided to a low value gate, which selects the signal of lowest value. The outputs of the low value gates of both circuits are provided to another low value gate, which again selects the lowest signal and provides it as the speed control unit output to the load control unit.

The reference speed is selected by the operator at the turbine control panel. The available setpoints are CLOSE VALVES, 100 RPM, 800 RPM, 1500 RPM, 1800 RPM, and OVERSPEED TEST. The normal turbine speed is 1800 rpm; the other discrete speed setpoints can be selected as intermediate stopping points when the turbine is being accelerated to synchronous speed. The CLOSE VALVES reference can be selected to stop a turbine startup in lieu of a manual turbine trip. The OVERSPEED TEST reference is used to develop actual overspeed conditions during overspeed trip testing. The CLOSE VALVES reference is automatically selected when the turbine trips.

The available acceleration setpoints are SLOW (60 rpm/min), MEDIUM (90 rpm/min), and FAST (180 rpm/min). The selected setpoint is governed by the turbine first-stage shell temperature during a turbine acceleration to synchronous speed if shell warming has not been performed first (the higher the temperature, the greater the allowable acceleration). The SLOW reference is automatically selected when the turbine trips.

The relative effects of the speed and integrated acceleration errors are illustrated in Figure 11.5-6 for a turbine speed increase. When the new speed reference is first selected, the speed error is large. The relatively smaller integrated acceleration error dominates initially as the turbine speed increases. Once the turbine has accelerated to the acceleration setpoint, the integrated acceleration error stops increasing and remains constant (at a lower value than the speed error) during much of the remaining speed increase. As the turbine speed approaches the reference speed, the speed error decreases until it becomes smaller than the integrated acceleration error. The speed error is then selected by the low value gates. Hence, the integrated acceleration error ensures that the turbine accelerates at the selected rate during a speed change, and the small or negligible speed error ensures that the steady-state turbine speed matches the selected reference speed.

Load Control Unit

The output of the speed control unit is supplied to the control valve and intercept valve amplifiers in the load control unit, shown in the center portion of Figure 11.5-4. This signal is first conditioned by the control valve and intercept valve regulation circuits. The regulation circuits ensure that the affected valves are modulated closed in response to turbine overspeed conditions.

In the control valve regulation circuit, any incoming speed error from the speed control unit is multiplied by an adjustable gain and then supplied to the control valve amplifier (summer), where it is added to the load reference signal. The gain is adjusted in the EHC control cabinets and usually selected such that the degree of valve regulation is 5%. What this term denotes is that an overspeed condition of 5% greater than normal rated speed (1890 rpm) is required to cause the control valves to close fully from their initial full-open positions when the turbine reference load is 100%. In other words, a 5% speed error (actual greater than reference) is multiplied by a gain of 20 (divided by 0.05 or 5%) in the control valve regulation circuit and supplied as a -100% input to the control valve amplifier, where it completely negates a 100% load reference signal and results in a 0% (close completely) signal to the control valves. Note that with a load reference of 100%, the control valves will receive partial-close signals for degrees of overspeed less than 5%, and that lesser degrees of overspeed are required to close the control valves fully for reference loads of less than 100%.

In the intercept valve regulation circuit, the incoming speed error is similarly multiplied by an adjustable gain, except that the selected degree of valve regulation is typically 2% (i.e., a gain of 50). However, the intercept valves do not fully close with a 2% overspeed condition (and a reference load of 100%) because of the “C.V. Reg./I.V. Reg.” conditioning applied to the load reference signal. The load reference signal is multiplied by a gain equivalent to the ratio of the control valve and intercept valve regulations (in this case, 5% divided by 2%, or 2.5) and supplied as an additional positive signal to the intercept valve amplifier. A 100% load reference signal is thus supplied as a 250% input to the intercept valve amplifier, where it is added to the always present 100% opening bias (the intercept valves are fully open during turbine operation except for overspeed conditions). To completely overcome this 350% valve opening input to the intercept valve amplifier (i.e., to fully close the intercept valves), a -350% input from the intercept valve regulation circuit, or a 7% overspeed condition (1926 rpm), is required. Also, with these values for intercept valve regulation and load reference conditioning and with a 100% reference load, any overspeed condition between 5% and 7% above rated speed causes partial closing of the intercept valves.

The conditioned load reference signal supplied to the intercept valve amplifier ensures that the amount of overspeed that causes the control valves to close completely also causes the intercept valves to begin to close. The higher turbine speed required to close the intercept valves enables them to continue blowing down the MSR steam inventory after the control valves have closed. Figure 11.5-7 illustrates the relationship between control valve and intercept valve regulation for overspeed conditions with reference loads of 50% and 100%.

In addition to the regulated speed control unit output, the load reference signal is supplied to the control valve amplifier. The operator varies the load reference signal to control the turbine-generator load once the generator output breakers have been closed. This signal is developed by the bi-directional load reference drive motor, which drives a differential transformer. The output of the transformer is provided via the load reference amplifier. Refer to Figure 11.5-8.

Normally, the load reference drive motor is operated by the INCREASE and DECREASE pushbuttons on the turbine control panel. Depressing one of these pushbuttons changes the reference load at a rate of 133%/min, which is reflected on the LOAD SET meter. For an increasing reference load, the rate of change of the reference signal is limited by the load reference amplifier in accordance with the loading rate selected by the operator. The available rates are 0.5%/MIN, 1%/MIN, 3%/MIN, and 5%/MIN. There is no rate-limiting capability for a decreasing reference load.

The load reference drive motor can also be operated by the following inputs:

1. Line speed matcher
2. Runbacks
    a. Overpower ΔT (OPΔT)
    b. Overtemperature ΔT (OTΔT)
    c. Loss of stator cooling water
3. Power-to-load unbalance circuit.

The line speed matcher can both increase and decrease the reference load, while the other inputs can only decrease it.

The line speed matcher is used to automatically match the turbine speed with the grid frequency during the synchronization process. The line speed matcher is removed from the load reference circuit whenever the generator output breakers are closed.

The turbine runback signals reduce the reference load in response to abnormal conditions. An OPΔT or OTΔT runback signal is generated whenever the reactor coolant loop ΔT is within three percent of the respective reactor trip setpoint (see Section 12.2). Either of these runback signals is applied to the load reference drive motor in an on/off cycle such that the reference load is decreased at the rate of 133%/min for 2.3 sec and then held constant for the next 27.7 sec. This cycle imposes an overall 10.2%/min runback rate. The runback initiated by the loss of stator cooling water (indicated by low stator cooling water flow, low pressure, or high outlet temperature) is provided in a one-sec-on, five-sec-off cycle, for an overall runback rate of 22%/min. For any runback, the on/off cycle repeats as long as the runback condition persists and ends when the condition has cleared. The loss-of-stator-cooling-water runback is effective for loads greater than 23%.

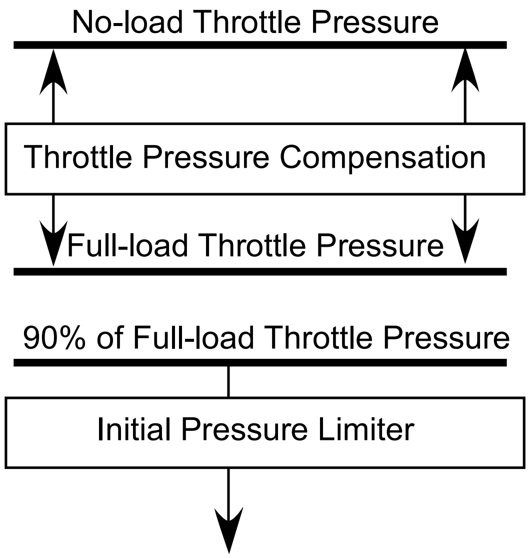
The last input to the load reference circuit, the power-to-load unbalance circuit, is designed to prevent an overspeed condition in response to a sudden load rejection by immediately closing the control valves and by rapidly reducing the load reference signal. The power-to-load unbalance setpoint is a mismatch of 40% between turbine power (measured in terms of high pressure turbine exhaust pressure) and generator load (measured in terms of generator output current). When the unbalance condition is sensed, the reference load is driven toward zero, and the output of the load reference circuit is removed from the control valve and intercept valve amplifiers. Outside the load reference circuit, the power-to-load unbalance circuit energizes solenoid-operated valves (not shown in any figure in this section) which dump the hydraulic fluid from the control valve disk dump valves, causing the control valves to shut. When the unbalance condition clears, the control valves reopen, the load reference circuit output is restored, and the new reference load corresponds to the endpoint of the reference load decrease which occurred while the unbalance condition was in effect.

The last input to the control valve amplifier is first-stage pressure feedback. This input is provided only during control valve testing; it compensates for the closure of one control valve by providing an additional opening signal to the other three. The first-stage pressure feedback circuit provides a signal proportional to the difference between the desired load and turbine power (as derived from first-stage pressure in the high pressure turbine). As the first-stage pressure drops in response to the closure of the tested control valve, the feedback circuit provides an additional opening signal to the other three control valves in order to maintain the desired load. (Note: At some plants the first-stage pressure feedback circuit provides true load feedback in the load control unit.)

The output of the control valve amplifier is supplied to a low value gate. The other potential input to the gate is a minimum signal supplied from the emergency trip system header pressure switches. This input provides a large closing signal to the control valves when the turbine trips. This closing signal is a backup to the mechanical tripping of the valves initiated by the emergency trip system.

The output of the low value gate proceeds to the throttle pressure compensator. Throttle pressure compensation is necessary because of the inherent decrease in steam pressure that accompanies an increasing steaming rate from a U-tube steam generator. The compensator corrects for the variation of throttle pressure with load to maintain a nearly linear relationship between steam flow and turbine load demand. The compensator multiplies the input signal by a gain equal to the ratio between the throttle pressure at rated load and actual throttle pressure (measured from the steam chest between the stop and control valves). During power changes where T_{avg} is kept on program, the action of throttle pressure compensation is transparent to the operator. However, if T_{AVG} deviates from program but remains in the operating band, the resulting change in steam pressure will cause the control valves to move in a way that maintains generator load fairly constant. For example, a 5°F cooldown with the plant at 50% power will result in very little change in generator load because throttle pressure compensation will open turbine control valves in response to the drop in throttle pressure. But if the same 5°F cooldown occurs with the plant at 100% power, generator load will noticeably drop because the control valves will not open to respond to the drop in throttle pressure. When the plant is at 100% power, throttle pressure is already at the bottom of the operating band of throttle pressure compensation. The output of the throttle pressure compensator is supplied to another low value gate. The other inputs to the gate are the initial pressure limiter and the load limit circuit.

The initial pressure limiter compares the actual throttle pressure (measured by a different instrument from the one that supplies the throttle pressure compensator) to an adjustable setpoint. The operator selects the setpoint with a potentiometer on the turbine control panel. The range of the potentiometer is 0 to 100% of rated throttle pressure; it is normally adjusted to 90%. If the throttle pressure decreases below the setpoint, the initial pressure limit begins to drop. There is usually some margin between the initial pressure limit and current valve position, so the initial action of the initial pressure limiter is transparent. However, if throttle pressure drops enough, the initial pressure limit becomes limiting (is selected by the low value gate) and begins to close the control valves. The control valves close completely if the throttle pressure drops to 10% below the setpoint. The limiter protects the turbine against an excessive decrease in inlet steam pressure (and potential moisture carryover) when the steam generation rate of the steam generators falls below the turbine steam demand.



In summary, the throttle pressure compensation circuit acts between no-load and full-load throttle pressure to maintain generator load fairly constant over changing steam pressure conditions. Throttle pressure compensation can act to either open or close control valves within this range. For this scenario, assume that the initial pressure limiter is set at 90%. The initial pressure limiter only acts if throttle pressure drops to less than 90% of full-load throttle pressure, and then will move control valves in the closed direction as pressure drops. If a cooldown begins with the plant at 50% power, the control valves would initially open because of the action of the throttle pressure compensation. When throttle pressure drops to full-load throttle pressure, throttle pressure compensation has reached the end of its program band and cannot act further. As throttle pressure drops below < 90% of full-load throttle pressure, the control valves will eventually begin to close. At about 80% of full-load throttle pressure, the control valves will be fully closed.

The load limit input to the low value gate is supplied by a potentiometer on the turbine control panel. The potentiometer setting, acting through the low value gate, acts as a clamp on valve opening; that is, the valves cannot respond to an opening signal larger than that called for by the potentiometer. Adjusting the load limit potentiometer allows the operator to prevent inadvertent load increases above some limit associated with equipment operation. For instance, if the plant is limited to 60% power with one operating main feed pump, a load limit setting of 60% prevents load increases above this value. In addition, at some plants setback signals are generated through the load limit circuit. A turbine setback automatically inserts a control valve opening limit into the load limit circuit in response to the loss of some necessary power conversion system component, such as a main feed pump or circulating water pump. If the reference load demand exceeds the limit when the setback condition arises, the low value gate accepts the setback input, and an immediate reduction in control valve position results.

To summarize, the last low value gate in the control valve load control circuitry is supplied with a reference load input from the control valve amplifier (via the throttle pressure compensator) and with inputs from the initial pressure limiter and the load limit circuit. The reference load is selected unless some limit is imposed by the other two inputs. The output of the low value gate is supplied to the control valve positioning units in the flow control unit.
The intercept valve amplifier receives the following inputs: the regulated output of the speed control unit (described previously in this section), the modified output of the load reference circuit (also described previously), and a 100% opening bias. During normal operation the opening bias provides a fully open signal to the intercept valves. The intercept valve amplifier would provide a less-than-full-open demand only during an overspeed event of sufficient severity. The output of the intercept valve amplifier is supplied to a low value gate. The other potential input to

the gate is a minimum signal supplied from the emergency trip system header pressure switches. This input provides a large closing signal to the intercept valves when the turbine trips. This closing signal is a backup to the mechanical tripping of the valves initiated by the emergency trip system. The output of the low value gate is supplied to the valve positioning units for intercept valves #1, #2, and #3 in the flow control unit. These are the intercept valves capable of modulation; the other three intercept valves are slaved to the modulated valves.

Flow Control Unit

The flow control unit receives the valve positioning signals for the control valves and for three of the intercept valves from the load control unit and positions the valves accordingly. The flow control unit contains seven valve positioning units, one for each of the modulated turbine valves. A typical valve positioning unit is illustrated in Figure 11.5-9.

The output from the load control unit (control valve or intercept valve position demand) is supplied to a summing amplifier, along with the actual valve position from the feedback circuit. For a control valve, a sequencing bias would also be applied to the summing amplifier if the control valves do not open and close in concert. The output from the summing amplifier is supplied via a servo amplifier to the servo valve, which controls the position of the associated turbine valve.

When a new valve position is demanded by the load control unit, the servo amplifier at first receives a large (in magnitude) signal from the summing amplifier due to the large error between demanded and actual valve position, and then a gradually decreasing (in magnitude) signal as the actual position approaches the demanded position. When the valve has attained the desired new position, zero current is applied to the servo valve, the servo valve's internal spool is again in the neutral position, and the hydraulic lock applied to the valve operator maintains the valve position until the next new position demand is received.

Actual valve position is relayed to the feedback circuit by a linear variable differential transformer mounted on the valve. The transformer's output is varied by a stroke transducer which follows the motion of the valve's operating piston. A diode function generator compensates the actual valve signal in the feedback circuit to account for the nonlinear relationship between valve position and steam flow. What has been termed a "valve positioning signal" in this section might be better described as a "steam flow demand signal"; the function generator ensures that the valve is positioned such that the demanded steam flow is obtained.

Chest and Shell Warming

Prior to rolling the turbine, the steam valve chests (the chambers between the stop and control valves) and the high pressure turbine shell must be heated slowly to minimize the development of thermal stresses. In addition, shell warming minimizes differential expansion between the turbine rotor and the high pressure turbine casing. A slow heatup capability for these turbine regions is provided by the internal bypass valve of stop valve #2 (see Section 7.4) and its associated control circuit. Refer to Figure 11.5-10.

To initiate chest warming, the turbine must be reset and the CLOSE VALVES reference speed must be selected. The operator depresses the CHEST WARM pushbutton and adjusts the position of the #2 stop valve internal bypass by manipulating a potentiometer on the turbine control panel. The potentiometer output and valve position feedback signal are supplied as inputs to a summing amplifier; the amplifier's output is supplied to the #2 stop valve's servo valve. This positioning circuit is similar to the control valve and intercept valve positioning units described above. A maximum limit is incorporated in the positioning circuit to ensure that the main disk of the #2 stop valve is not lifted.

The operator adjusts the potentiometer to obtain the desired warming rate in accordance with the steam chest temperature limits. The steam chests associated with all stop and control valve pairs are warmed through the steam chest cross-connections. The steam chest warming process also equalizes the pressures across the stop valve main disks in preparation for subsequent opening.

Turbine shell warming is conducted in a similar fashion. (Note: At some plants, a separate shell warming procedure is not implemented, and the turbine shell is warmed as the turbine is accelerated to synchronous speed.) To initiate shell warming, the operator depresses the SHELL WARM pushbutton and again manipulates the potentiometer to obtain the desired heating rate. The initiation of shell warming automatically opens the control valves and closes the intermediate stop valves. Heating steam is admitted to the high pressure turbine shell via the #2 stop valve internal bypass and the open control valves. The steam condenses within the shell and exits the turbine via the shell drains.

Positioning of Unmodulated Turbine Valves

The unmodulated turbine valves are operated in accordance with the turbine operating status or the positions of limit switches associated with the modulated valves.

The #2 stop valve receives a full-open signal whenever a reference speed other than CLOSE VALVES is selected. The #1, #3, and #4 stop valves receive full-open signals when the #2 stop valve open limit switch opens; they receive full-close signals when the limit switch closes (indicating that the #2 stop valve is not fully open). The limit switch is operated by a rod mechanically linked to the #2 stop valve's operator piston. Hence, the other three stop valves are slaved to the #2 stop valve.

The #1, #2, and #3 intercept valves also receive a full-open signal whenever a reference speed other than CLOSE VALVES is selected. Each of the #4, #5, and #6 intercept valves is slaved to one of the modulated intercept valves. The slaved valves open or close in accordance with the positions of limit switches associated with the modulated valves. When a modulated valve is opened and reaches the full-open position, the associated slaved valve opens. When a modulated valve reaches the 50% open position as it closes, the associated slaved valve closes.

All intermediate stop valves open when the master trip reset pushbutton is depressed. They are open for all turbine operations except for shell warming.

11.5.3 System Operation

The following paragraphs describe the warming, acceleration, and loading of the turbine in terms of operator actions at the turbine control panel. Refer to Figures 11.5-11 and 11.5-12 for the locations of panel indications and pushbuttons.

Prior to a turbine startup, the operator verifies the following EHC system indications at the turbine control panel:

- The turbine is tripped, as indicated by the illuminated mechanical trip TRIPPED light and emergency trip system TRIPPED light.
- The SLOW starting rate and CLOSE VALVES speed set pushbuttons are backlit.
- The chest/shell warming OFF pushbutton is backlit and the chest/shell warming potentiometer is set at zero.
- The load set megawatt meter is set at zero and the load limit set potentiometer is set at 10%. The LOAD LIMIT LIMITING light is extinguished.
- The initial pressure limit ON pushbutton is backlit and the limiting pressure potentiometer is set at 90%.
- The throttle pressure indicator reads zero.
- All servo valve current indications are negative.

To initiate the turbine startup, the operator depresses and holds the RESET pushbutton. The mechanical trip RESETTING light is illuminated until the mechanical trip valve is reset, at which time the RESETTING and TRIPPED lights extinguish and the RESET light illuminates. When the master trip solenoid valve resets, the emergency trip system TRIPPED light extinguishes and the RESET light illuminates. Now that the turbine has been reset, the intermediate stop valves open fully.

Next, the chest warming controls are used to warm the turbine steam chests. The operator depresses the CHEST WARM pushbutton and uses the chest/shell warming potentiometer to admit steam to the chests via the #2 stop valve bypass. When the chest metal temperature is within 50°F of main steam temperature, chest warming is terminated by closing the #2 stop valve bypass with the potentiometer.

Following chest warming, the turbine is rolled to synchronous speed (assume that shell warming is conducted in conjunction with turbine acceleration). The operator selects the 100 RPM speed set. The #2 stop valve opens fully, after which the remaining three stop valves open fully. Also, the modulated intercept valves open fully, after which the slaved intercept valves open fully. The speed control unit controls the turbine acceleration in accordance with the starting rate (SLOW, MEDIUM, or FAST) selected by the operator. As the turbine accelerates, the SPEED INCREASING light is illuminated. When the turbine speed reaches 100 rpm, the SPEED INCREASING light extinguishes, and the AT SET SPEED light illuminates.

At 100 rpm, proper turbine operation and control are verified. The operator then selects the 1800 RPM speed set and accelerates the turbine to synchronous speed. With the SLOW starting rate selected, the turbine takes about 30 min to reach 1800 rpm. At 1800 rpm, the AT SET SPEED light is again illuminated. If an abnormal condition develops during the turbine speed increase, the CLOSE VALVES speed set may be selected to interrupt steam admission to the turbine. If turbine control is erratic, or if excessive rotor/casing differential expansion or vibration develops, the operator trips the turbine by depressing the TRIP pushbutton.

With a turbine speed of 1800 rpm, the generator is ready for synchronization with the electrical grid. (At this point, the reactor will have been made critical, and reactor power will have been increased to 10-15%. The steam dump system is in operation.) The load selector INCREASE and DECREASE pushbuttons or the line speed matcher are used to match generator and grid frequencies. Once the generator output breakers are closed, the operator immediately increases the load setpoint with the INCREASE pushbutton to a value high enough to clear any potential generator motoring alarms.

During the power ascension, load setpoints and loading rates are selected in accordance with applicable turbine temperature limits, the status of other plant equipment, and load dispatcher instructions.

11.5.4 Summary

The EHC system is made up of three main subsystems:

a. The EHC fluid system,
b. The emergency trip system, and
c. The electrical control system.

The EHC fluid system supplies high pressure hydraulic fluid to the operators of the steam inlet valves of the high and low pressure turbines. The emergency trip system provides the means by which the hydraulic fluid is dumped from the valve operators, allowing springs in the operator assemblies to rapidly close the valves. The electrical control system provides signals for turbine valve positioning to control the turbine-generator's speed and loading in accordance with operator commands.

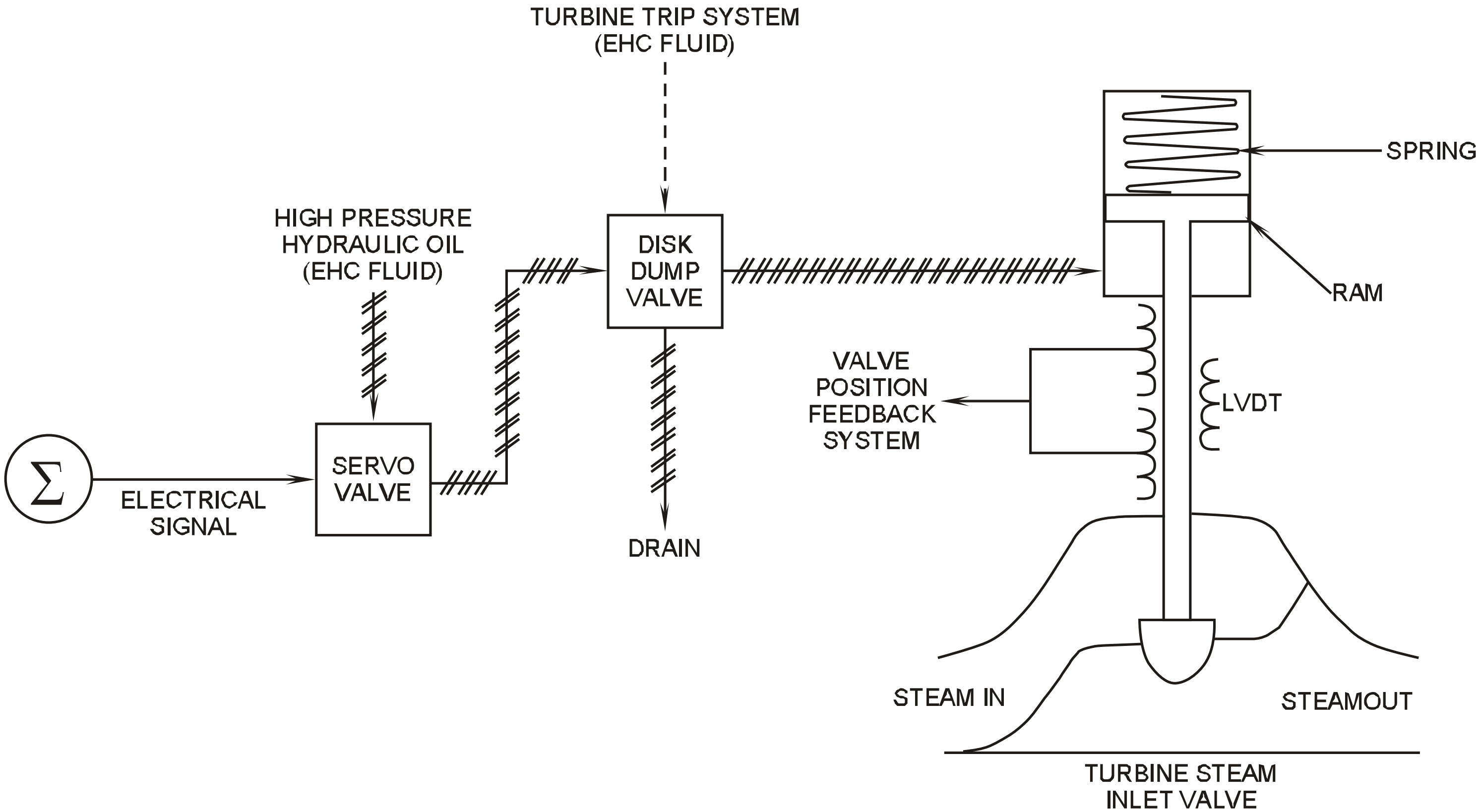


Figure 11.5-1 Simplified EHC System

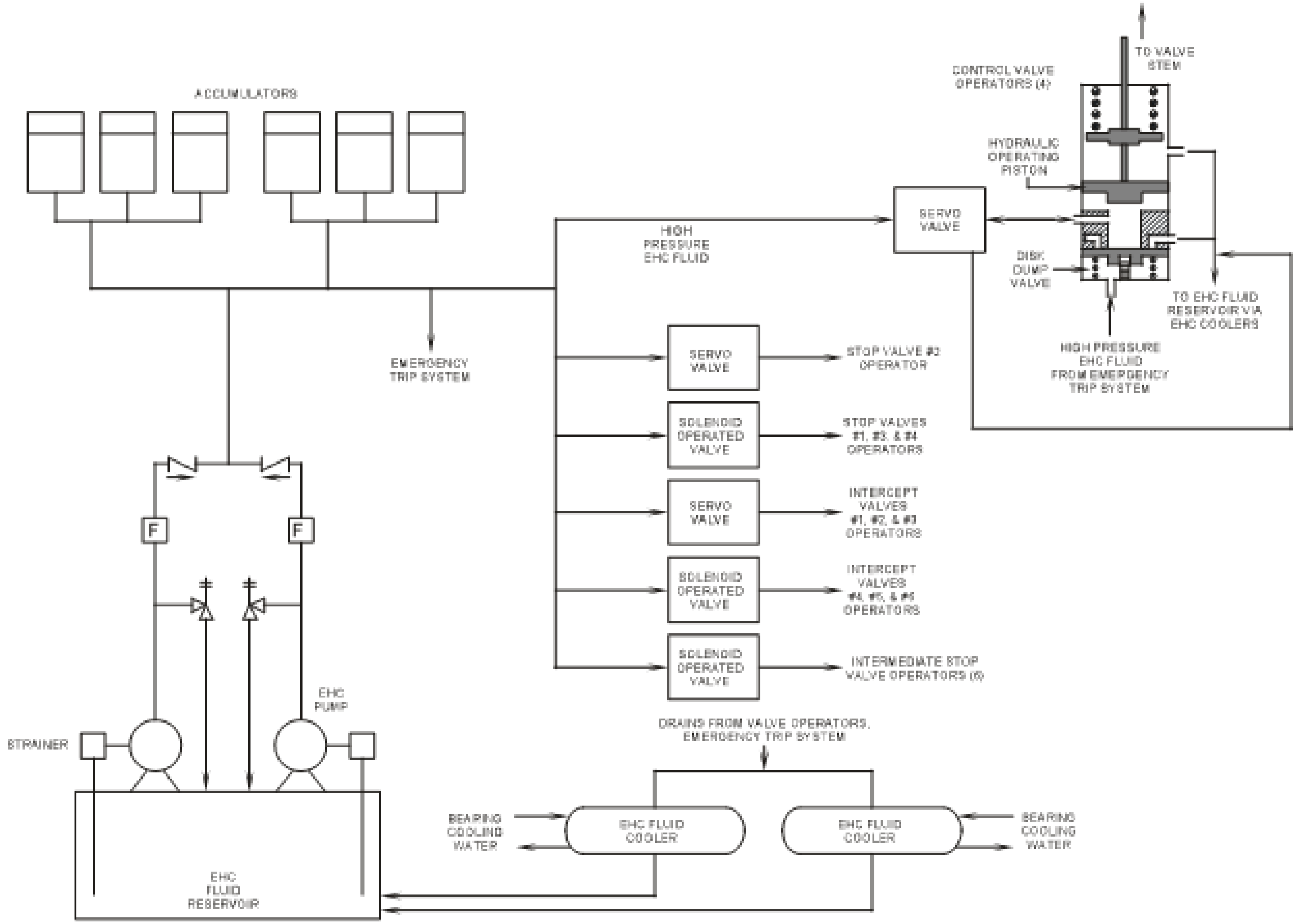


Figure 11.5-2 EHC Fluid System

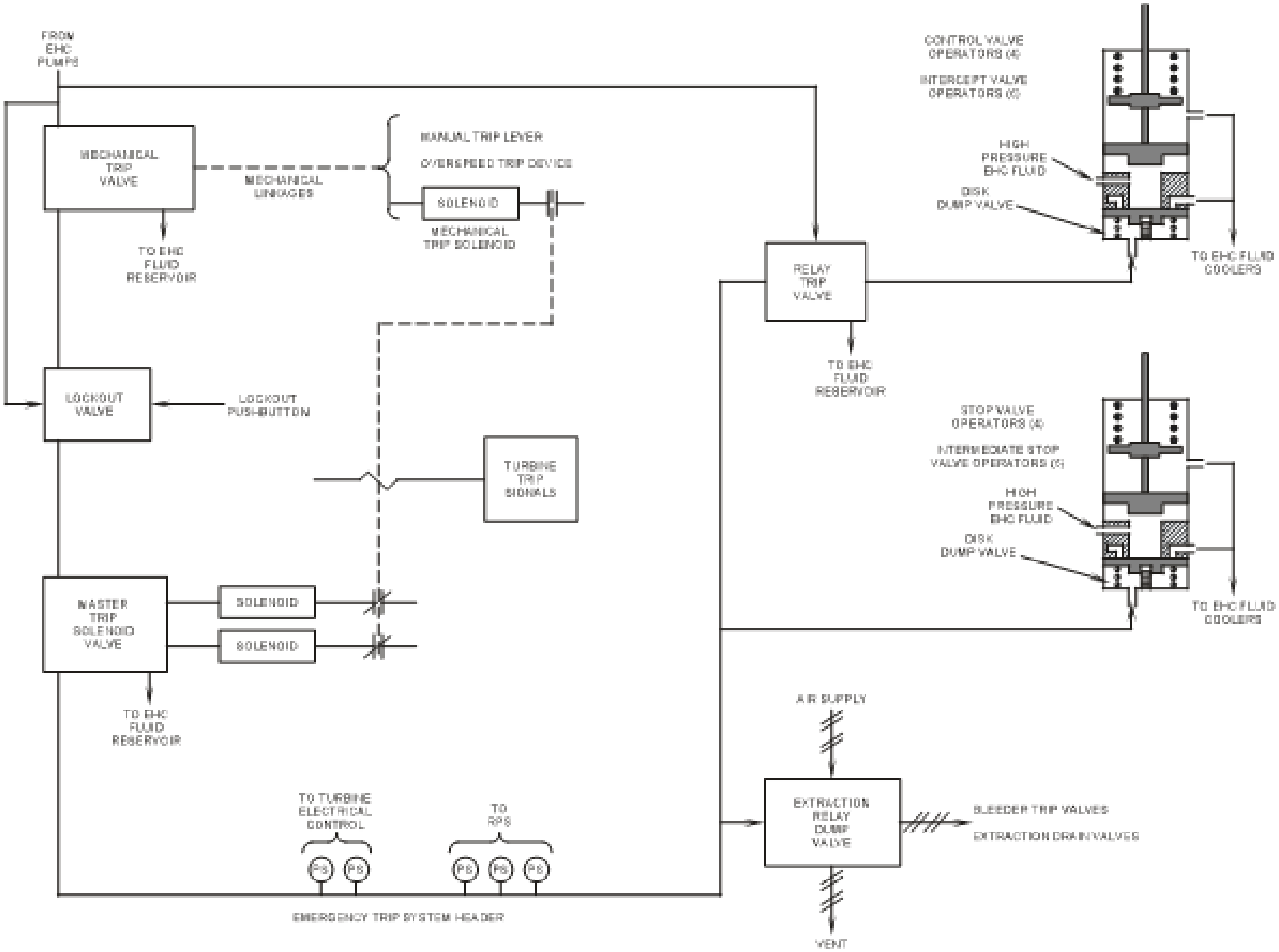


Figure 11.5-3 Emergency Trip System

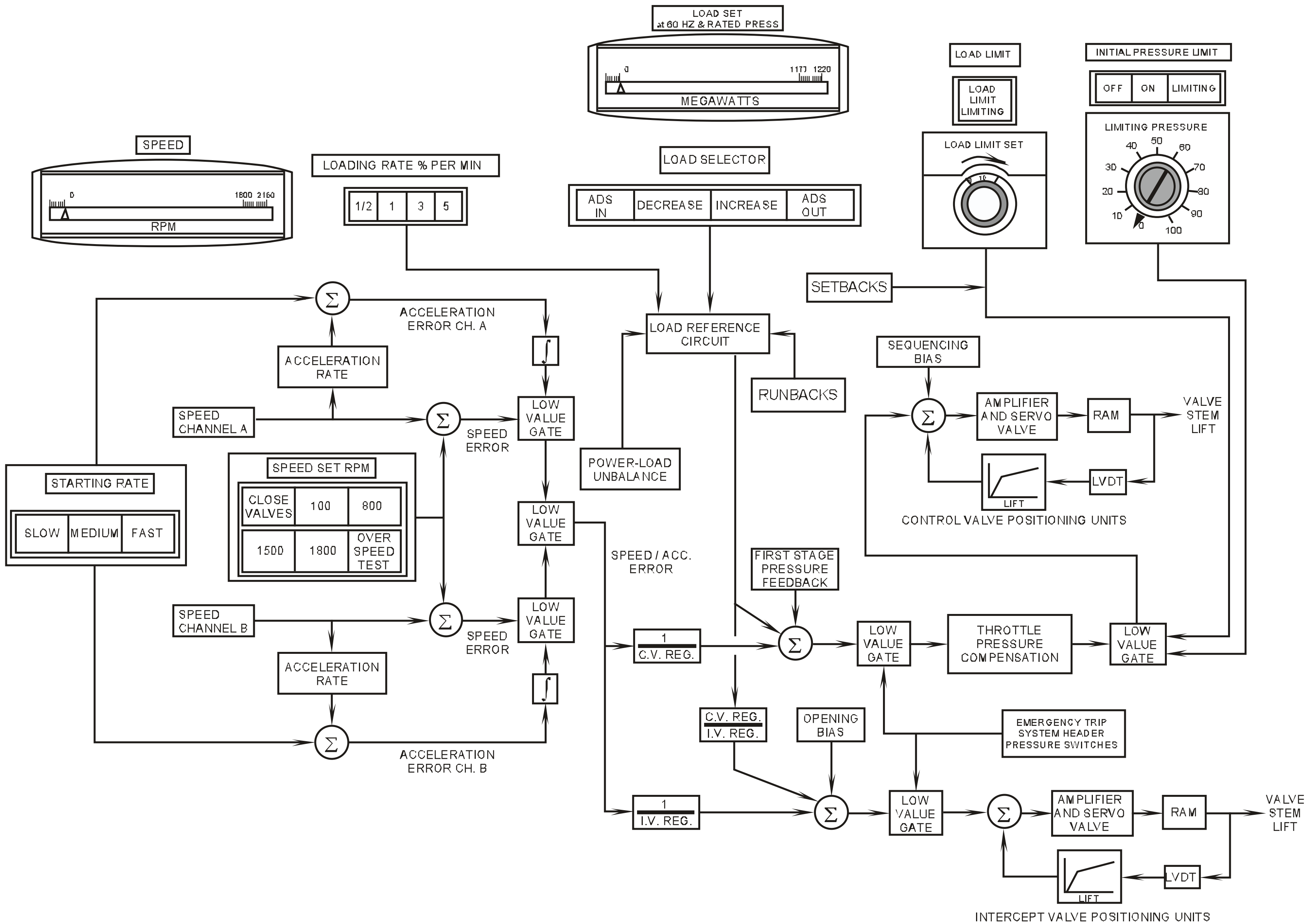


Figure 11.5-4 Turbine Electrical Control System

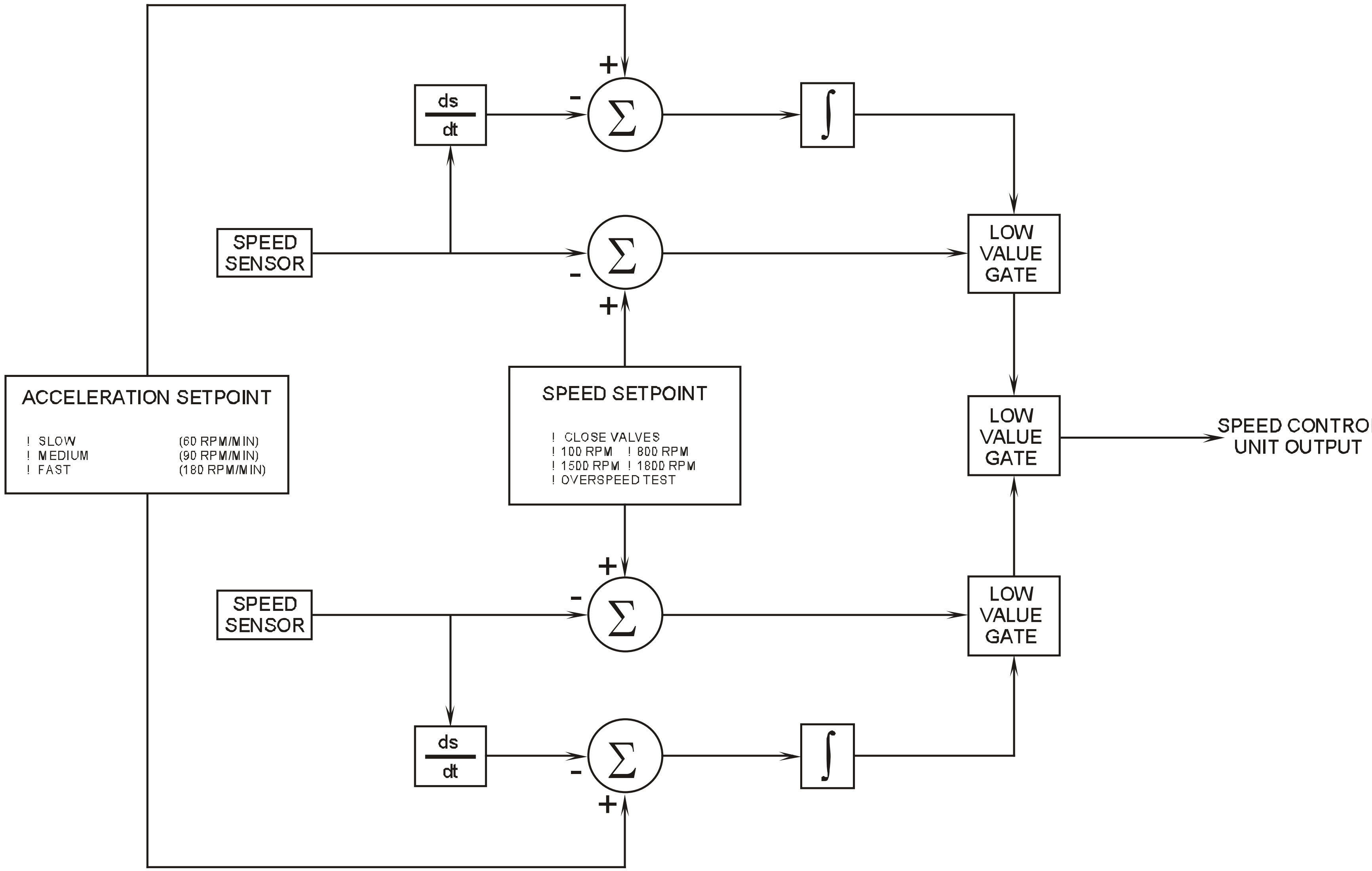
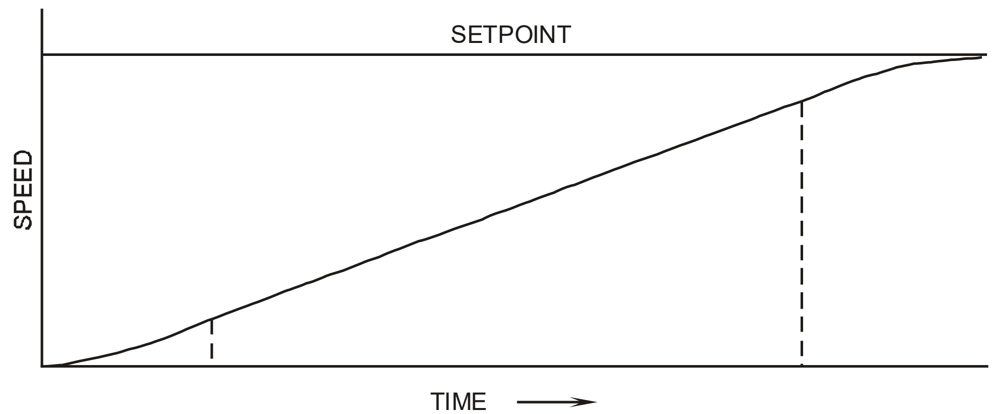
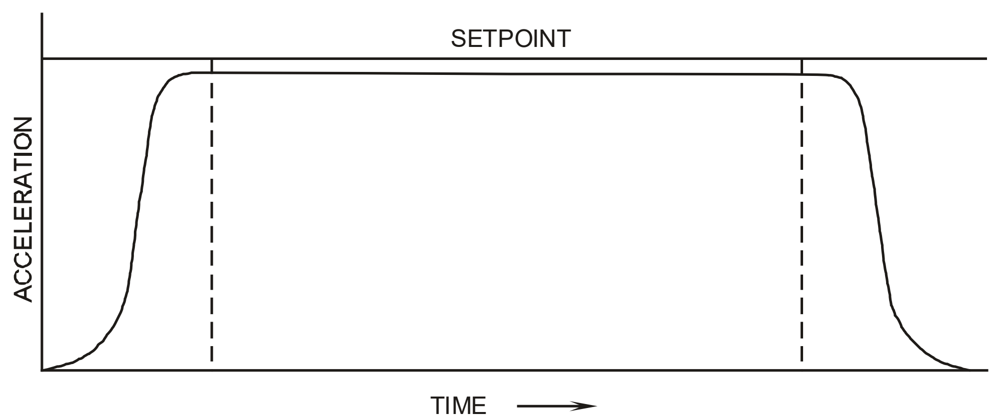


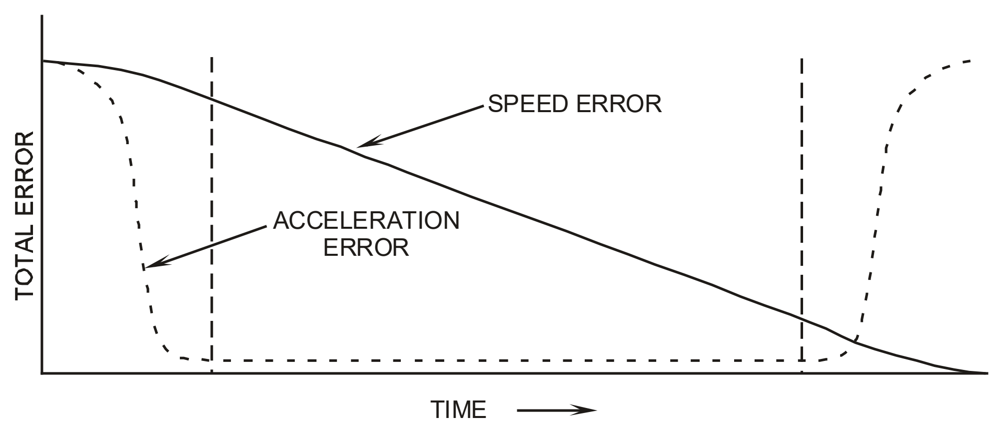
Figure 11.5-5 Speed Control Unit



(A) SPEED SETPOINT vs. ACTUAL SPEED



(B) ACCELERATION SETPOINT vs. ACTUAL ACCELERATION



(C) SPEED AND ACCELERATION ERROR SIGNALS

Figure 11.5-6 Speed Control Operating Characteristics

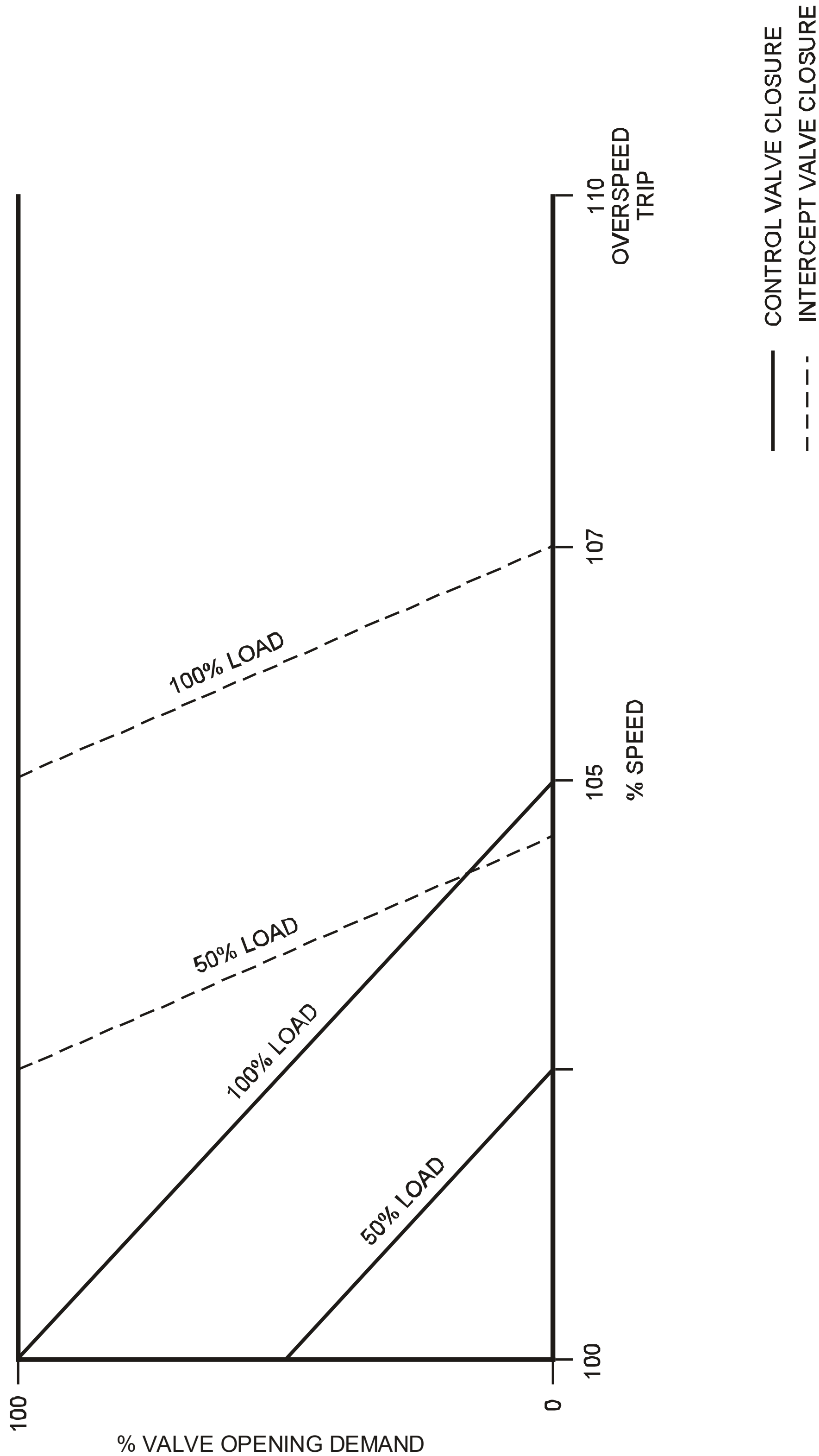


Figure 11.5-7 Control and Intercept Valve Regulation

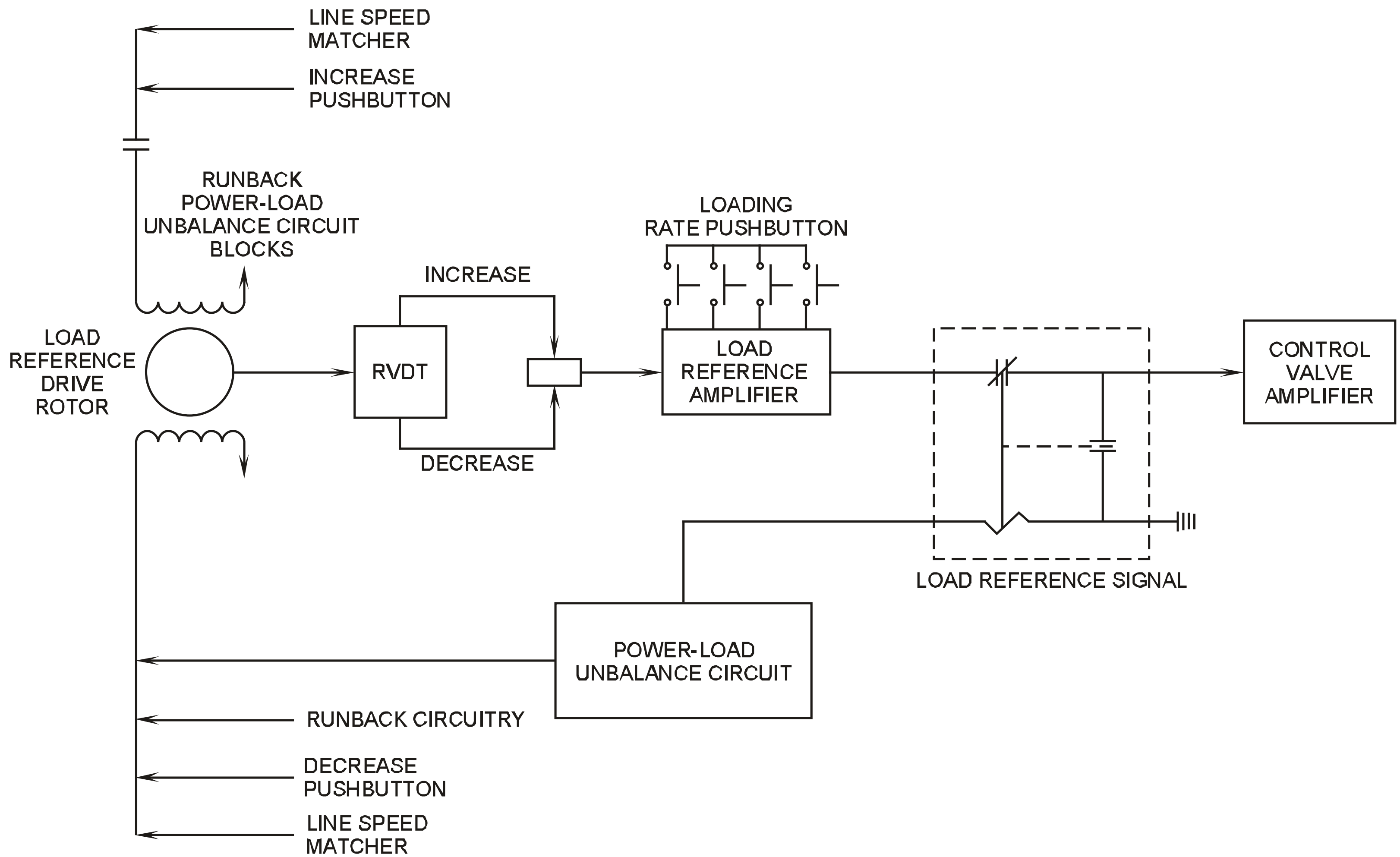


Figure 11.5-8 Load Reference Signal Generation

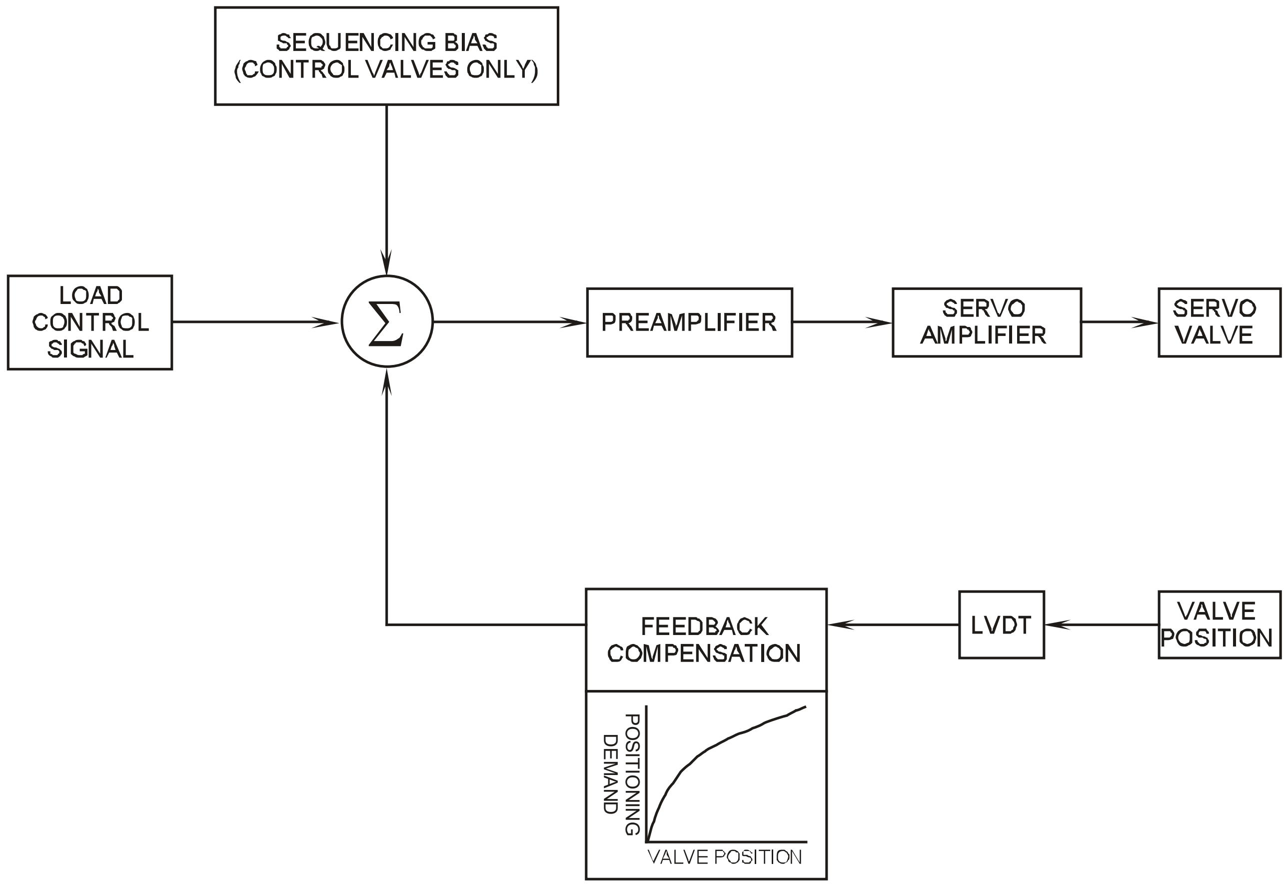


Figure 11.5-9 Typical Valve Positioning Unit

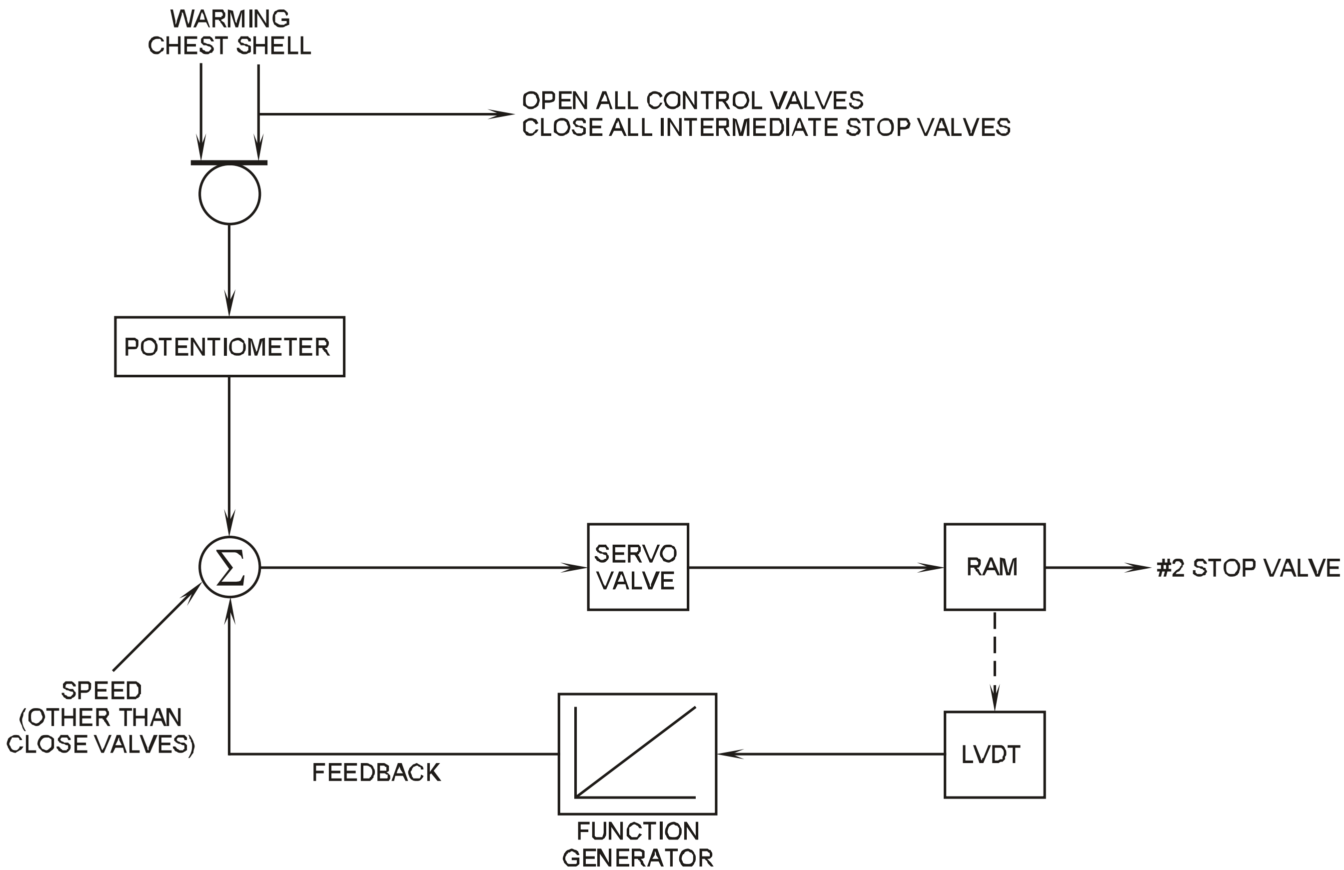


Figure 11.5-10 Chest / Shell Warming

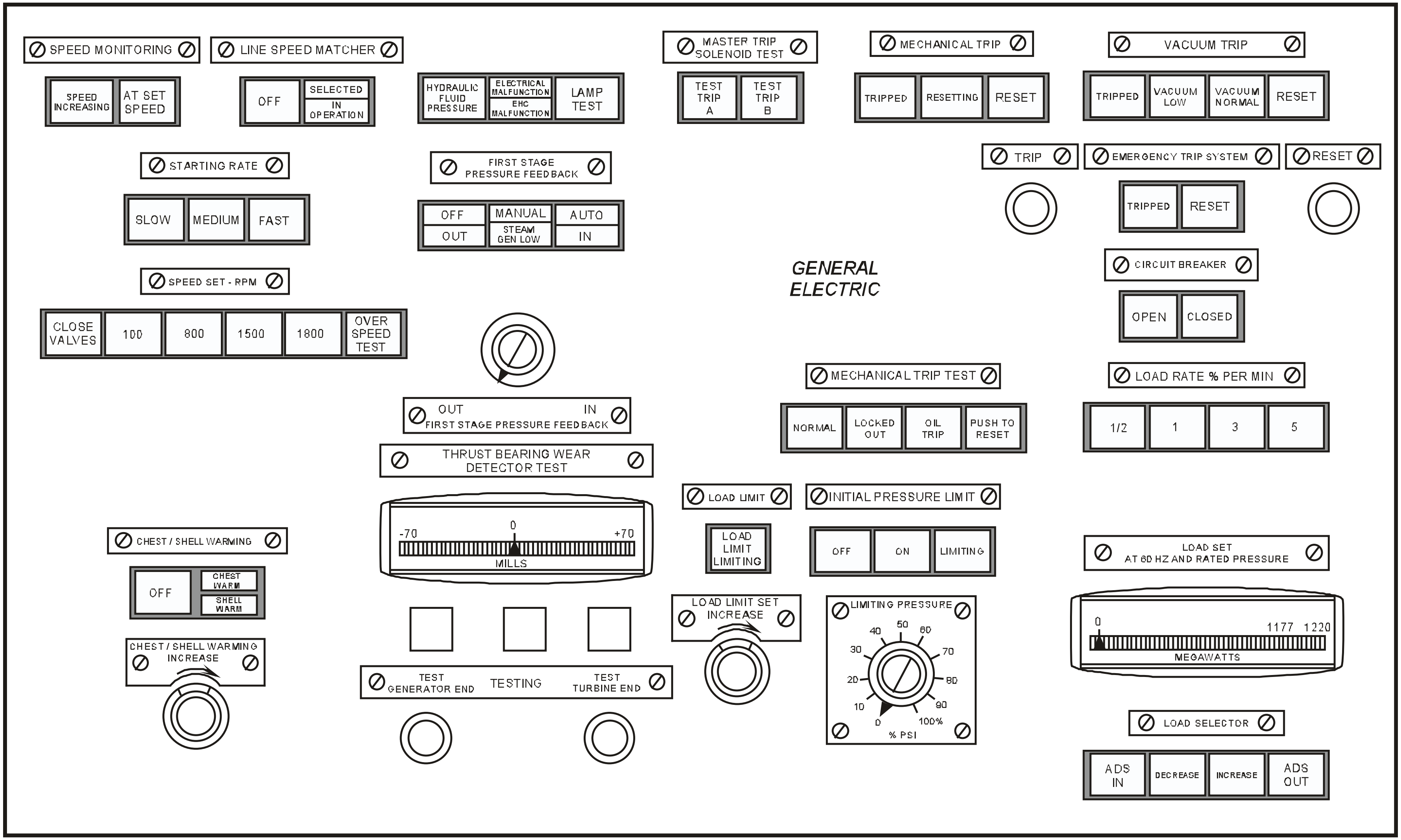


Figure 11.5-11 Turbine Control Panel

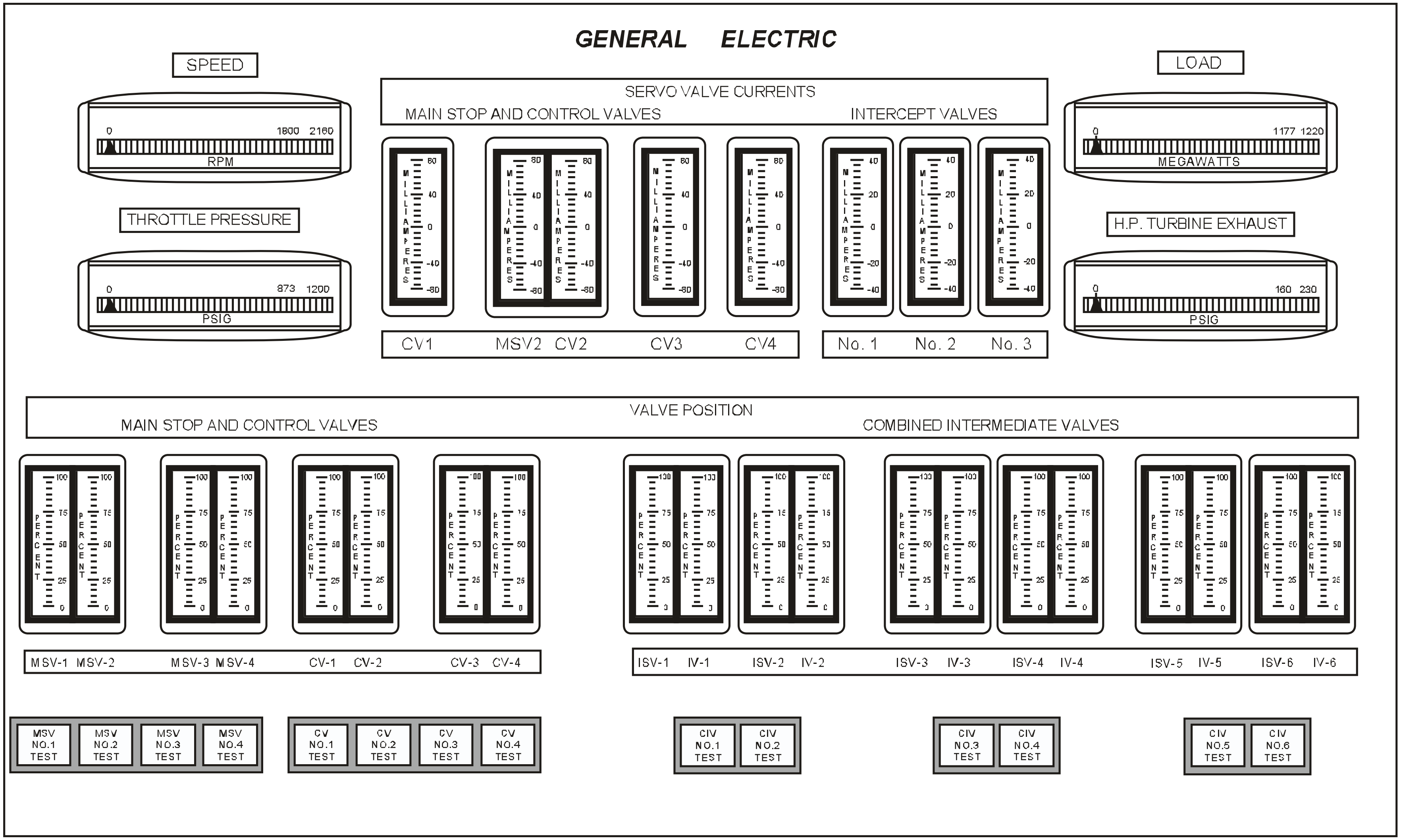


Figure 11.5-12 Turbine Instrument Panel

Westinghouse Technology Systems Manual

Chapter 12

REACTOR PROTECTION and ENGINEERED SAFETY FEATURES SIGNALS

Section

Westinghouse Technology Systems Manual

Section 12.1

Reactor Protection System (RPS)

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12.1 REACTOR PROTECTION SYSTEM (RPS)

Learning Objectives:

1. State the purposes of the Reactor Protection System (RPS).

2. Explain how the following design features are incorporated into the RPS:

   a. Single failure criterion,
   b. Testability,
   c. Equipment qualification,
   d. Independence,
   e. Diversity, and
   f. Prevention of control and protection system interaction.

3. Describe the sequence of events (flowpath) beginning at the sensor up to and including the starting of an Engineered Safety Feature (ESF) component and/or the opening of a reactor trip breaker.

4. Explain how failures in the rod control system are prevented from affecting reactor trip capability.

12.1.1 Introduction

The purposes of the reactor protection system are as follows:

1. To initiate a reactor trip if safe operating limits are exceeded, and
2. To initiate engineered safety features actuation(s) if an accident occurs.

The overall purpose of the Reactor Protection System (RPS) is to prevent the release of radioactivity to the environment. To meet this objective, the RPS acts to prevent the unsafe operation of the reactor. The initiation of a reactor trip by the RPS prevents the core from operating in a condition that could cause damage to the core. Also, if an accident occurs, the RPS trips the reactor and actuates the engineered safety features. These safety features mitigate the consequences of the accident.

The reactor plant operating limits are determined and set by the utility's Final Safety Analysis Report (FSAR). The plant incorporates these limits into its Technical Specifications (TS or Tech Specs), and the NRC appends the technical specifications to the plant's operating license. To keep plant conditions within these operating limits, local sensors monitor various processes; these sensors are capable of detecting a condition that would require a reactor trip or an engineered safety features actuation.

Bistables in the analog circuitry (located within the analog cabinets) compare analog input signals, supplied by process sensors, to preselected trip or actuation setpoints. If a process signal exceeds a setpoint, the output of the associated bistable is changed. The bistable thus converts the analog signal into a digital output (on or off, energized or de-energized) which is monitored by the trip logic matrix. Based on the status of the inputs from the bistables, the logic matrices (located within the logic cabinets) determine whether the RPS should generate a reactor trip or initiate an engineered safety features actuation.

12.1.2 System Description

12.1.2.1 Reactor Protection System Design

To guarantee the integrity of the reactor and to avoid an undue risk to the public health and safety, the plant design incorporates a reactor protection system. This system is capable of supplying reactor and component trip signals and initiates the engineered safety features, which provide protection for normal operating, transient, and accident conditions.

The reactor protection system contains two complete and independent trains of analog and logic circuits. If an analog circuit senses an unsafe condition, signals are sent to the protection system logic cabinets, where the appropriate logic contacts open. The logic matrices (circuits) determine whether the coincidence for a reactor trip function is satisfied. If so, the protection system opens the reactor trip breakers. Opening these breakers removes power from the control rod drive mechanisms, allowing the rods to fall into the reactor core. If an accident occurs and an engineered safety features actuation is required, the protection system actuates the appropriate safety equipment. In addition, the logic trains automatically enable or remove permissives (protection-grade interlocks).

12.1.2.2 Compliance with General Design Criteria (GDC)

The reactor protection system designed by Westinghouse meets the General Design Criteria (GDC) of 10 CFR Part 50. In addition, the protection system complies with various Regulatory Guides (RG) and several different IEEE Standards. These documents include:

1. “General Design Criteria for Nuclear Power Plants,” Appendix A to Title 10 CFR 50,
2. United States Nuclear Regulatory Commission Regulatory Guides,
3. “Criteria for Protection Systems for Nuclear Power Generating Stations,” IEEE 279-1971,
4. “Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations,” IEEE 308-1971, and
5. “Trial-Use Criteria for Periodic Testing of Nuclear Power Generating Station Protection Systems,” IEEE 338-1971.

12.1.2.3 Single-Failure Criterion

The reactor protection system contains redundant instrumentation channels (two to four instruments) for each protective function. These process instruments provide signals to a one-out-of-two logic train scheme and are electrically isolated and physically separated from each other. Either logic train sensing the required coincidence can provide the required protective actions (either a reactor trip or an Engineered Safety Features Actuation ESFAS). Any single failure within a channel or train does not prevent a protective action when required. The RPS is testable, with the reactor operating, without reducing its reliability of operation. These features meet the requirements of General Design Criteria 21 and 22 and Regulatory Guide 1.53. A loss of input power (the most likely mode of failure) to the protection system results in the system failing to a safe state or into a state demonstrated to be acceptable. This feature meets the requirements of GDC 23.

12.1.2.4 Testability

The RPS is testable during all plant conditions. The RPS is tested in a segmented fashion, in which each test section overlaps an adjacent test section. Such testing ensures both the availability and the accuracy of the system from the process sensors to the final devices (trip breakers, ESF equipment, etc.).

12.1.2.5 Equipment Qualification

Following an accident, a Loss Of Coolant Accident (LOCA) or some other high energy line break, the environmental conditions inside the containment degrade (i.e., temperature, pressure and radiation levels increase). All safety systems, components and instruments important to safety must remain functional in order to provide their intended safety functions. Therefore, a wide range of environmental qualification tests and functional performance tests is employed to ensure equipment survivability. These test results demonstrate that the safety equipment meets the requirements of GDC 22.

12.1.2.6 Independence

Each process instrument is assigned to one of the four protection channels (Channels I, II, III, and IV). Channel independence is maintained throughout the system. This independence extends from the sensor to the device which actuates the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved by using separate wireways, cable trays, conduit runs, and containment penetrations for redundant channels. Redundant analog equipment is separated by locating modules in different protection racks. Finally, each redundant channel is powered from a separate vital ac power source. These features meet the requirements of GDC 22.

There are two reactor trip breakers, each of which is automatically opened (tripped) by its own dedicated logic matrix. The series-connected reactor trip breakers supply power to the rod drive mechanisms. Opening either breaker interrupts power to all rod drive mechanisms, allowing the rods to fall freely into the core.

12.1.2.7 Diversity

To ensure the safe operation of the reactor core and to protect the reactor coolant system pressure boundary, the RPS continuously monitors numerous diverse process system variables. The extent of this diversity has been evaluated for a great number of postulated accidents. Generally, one or more diverse protection functions would generate a reactor trip or mitigate an accident before intolerable consequences could occur. This feature meets the requirements of GDC 21 and GDC 22.

12.1.2.8 Control and Protection System Interaction

The reactor protection system is designed to be independent of all process control systems. However, in certain applications, some control signals and other nonprotective functions are derived from individual protection channels through isolation amplifiers. The isolation amplifiers are classified as part of the protection system and are most often located within the reactor protection analog racks. The isolation amplifier is designed so that a short circuit or open circuit in, or a voltage (ac or dc) applied to, the isolated output portion of the amplifier (the control side of the circuit) does not affect the input (protective) side of the circuit. Any signal passed through an isolation amplifier is never returned to the protection racks. This feature meets the requirements of GDC 24.

If the failure of a protection system process instrument or component causes a plant transient which requires a protective action (e.g., a reactor trip), the protection system is designed to withstand another, independent failure without the loss of the protective function.

12.1.3 Component Descriptions

The Westinghouse protection system may be one of several different designs. The common designs are the relay protection system and the solid-state protection system. Either of these systems performs the same functions as stated in the system description, with the solid-state protection system being a more recent design. Descriptions of both systems are included, with specific differences explained. This section also provides descriptions of the reactor trip breakers and their protection system interfaces.

Some facilities have upgraded portions of their solid-state protection systems to the Eagle-21 protection system sold by Westinghouse. This section does not discuss the Eagle-21 system. The innovative feature of the Eagle-21 system is that it is an on-line, self-testing protection system. Using solid-state devices, this system checks the entire protection system regardless of the operational condition of the reactor, and it performs these functional tests continuously.

12.1.3.1 Relay Protection System

The relay protection system is explained by describing the features shown on Figure 12.1-1.

1. Red, White, Blue, Yellow - Redundant analog protection channels originate at the process sensors. Each channel is powered from an independent vital power supply.
2. Isolation Amplifier - The control systems are separate and distinct from the protection system. The control systems are, however, dependent upon signals derived from the protection system through these isolation amplifiers.

3. External Signal Input - The signal conditioning equipment of each protection channel in service during normal operations is capable of being calibrated and tested independently. This is accomplished by inserting analog signals to verify proper operation without tripping the reactor. This allows testing throughout the channel to the protection bistable output.
4. Channel Test Switch – This switch provides the path for the application of an external signal input to the protection bistable, and it also provides a path to an alarm which alerts the operator that the proper testing sequence has not been followed (see item 6 below).
5. Protection Bistable – The bistable is an electronic switch with an adjustable on-off setpoint. It is designed to interrupt control power to both the train A and train B logic cabinet input relays.

   Within the bistable, a signal from the process sensor is compared to a preset, adjustable setpoint. When the process signal equals or exceeds the setpoint value, the bistable's output is turned off (de-energized), and its output voltage goes to zero (the bistable is tripped). This electronic device or switch thus converts the analog (variable) input signal into a digital (on-off) output signal. The input relays (item 7 below) of the logic cabinet receive this digital signal.

6. Bistable Output Trip Switch – This switch permits verification of the bistable's operability by providing continuity through the "Proving Lamp." When this switch is placed in the trip position, the bistable's output is no longer connected to the logic matrices. To the logic matrices, removing the bistable's output by placing the bistable output trip switch in trip is indistinguishable from the bistable actually tripping as described in item 5 above. Hence, placing the output trip switch in trip is somewhat confusingly referred to as "tripping the bistable."

   With the switch in trip, the technician varies a test input signal via a signal generator as described in items 3 and 4 above. When the test signal equals the trip setpoint, the bistable trips (the output is de-energized), and so the proving lamp de-energizes. This process provides verification of the bistable's setpoint.

   In addition, an alarm sequence violation circuit is provided to ensure that the technician places the bistable output trip switch in trip prior to performing any testing on the analog section of the protection system. If this alarm actuates, it alerts the control room operator that the technician performing the surveillance is not following the proper procedural steps for testing. When this switch is in the normal position (not tripped), power is supplied through the bistable to both the train A and the train B logic cabinets.

7. Input Relays - The input relays are operated by the output of the bistable described in item 5 above. When energized (the bistable is not tripped), each input relay holds closed a contact in one of the logic matrices, providing circuit continuity to reactor trip breaker undervoltage coils. When the protection bistable trips, its associated input relays de-energize, opening their corresponding contacts in the logic matrices.

   In Figure 12.1-1, the red channel is shown from the sensor of some parameter to the inputs to the logic cabinets. For this discussion assume that the red channel is an analog process signal corresponding to pressurizer pressure. If this channel senses a pressure in excess of 2385 psig, its associated bistable trips, causing the bistable's output voltage to go to zero.

With the bistable output at zero, the red input relays de-energize in both the train A and train B logic cabinets. When the input relays de-energize, the contact labeled "1" opens in the logic matrix of train A, and the contact labeled "A" opens in the train B logic matrix. The logic coincidence for this particular trip function is two out of four (2/4). Therefore, two channels must de-energize to produce a reactor trip. Note that even with the 1 and A contacts open, power is still delivered from the 125-Vdc battery buses to the undervoltage (UV) coils for the reactor trip and reactor trip bypass breakers.

A reactor trip does not occur unless at least one of the other three channels also senses a high-pressure condition, its associated bistable trips, and the associated input relays de-energize. With any two sets of logic matrix contacts open, power is interrupted to the undervoltage coils of the reactor trip breakers, causing them to open.

8. Logic Cabinets – The logic cabinets receive the signal inputs from the protection bistables (either on or off). The bistable output signals provide the protection system inputs for all reactor trips and ESF actuations. Energized input relays 1, 2, 3, and 4, (for train A) or A, B, C, and D, (for train B) hold their associated contacts closed, thereby maintaining continuity of power to the undervoltage coils of the reactor trip breakers. If an undervoltage coil de-energizes as the result of bistable trips, incorrect testing, or any other cause, one of the series-connected reactor trip breakers opens, allowing all shutdown and control rods to fall into the core.

9. Pushbuttons 1, 2, 3, and 4 (A, B, C, and D) – These buttons allow complete logic testing, which ensures the correct reactor trip breaker status when different combinations of channel trips are established. When an electronics technician depresses one of these pushbuttons, its associated test relay energizes, opening its associated test contact (shown beneath an input relay in Figure 12.1-1). When the test contact opens, the associated input relay de-energizes, causing its associated logic contact in the logic matrix to open. Using this process to satisfy the necessary trip coincidence (at least two input relays de-energized) ultimately interrupts power to a reactor trip breaker undervoltage coil. During this test, a reactor trip bypass breaker must be closed to prevent a reactor trip. The reactor trip breakers and their associated bypass breakers are described in section 12.1.3.3.

12.1.3.2 Solid-State Protection System

Applying solid-state techniques to the design of the reactor protection system has provided significant improvements over previous designs utilizing relays and contacts. Approximately 750 relays with 4000 contacts connected in various matrices are contained in a relay protection system for a Westinghouse-designed four-loop plant. This vast quantity of relays and contacts requires fourteen 30-in.

wide by 30 in. deep cabinets, contrasted with six cabinets of the same size supplied with the solid-state system.

The addition of a semiautomatic fast pulse test circuit reduces the test time for the logic section of the protection system from four hours per train for the relay system to approximately one hour per train for the solid-state system. Fast pulse testing also eliminates the need to bypass the reactor trip breakers each time the logic section is tested. The duration of the logic test pulse is so short that the undervoltage driver card output is not interrupted. Therefore, the reactor trip breaker for the train undergoing this surveillance test is unaffected.

Figure 12.1-2 shows a simplified diagram of the solid-state reactor protection system. This system, like the analog reactor protection system, is comprised of two redundant, identical trains (A and B) that are physically and electrically independent. Inputs into this system are derived from various nuclear and nonnuclear sensors located both inside and outside of the containment building. Most of these signals are processed in the analog cabinets and result in bistable outputs (128 volts ac normal or zero volts when tripped) to the solid-state logic cabinets. Other protection signals are derived directly from the status of contacts at sensors or components (examples are oil pressure switches on the turbine, auxiliary contacts on circuit breakers, and limit switches on valves).

The physical arrangement of the input relay contacts within the logic portion of this system determines the coincidence logic (i.e., 2/3, 2/4, etc.). Additional inputs, which carry the train designation, enter the logic directly from control board switches and pushbuttons.

Information concerning the status of this system is transmitted to the control board status lamps and annunciators via a control board demultiplexing circuit and to the computer via a computer demultiplexing circuit. The purpose of these multiplexing systems is to transmit a large amount of status information over a small number of conductors, thereby simplifying and reducing field wiring requirements. About 200 status lamps and 100 annunciators are operated by the control board demultiplexer and about 200 signals are recorded by the plant computer by its demultiplexer.

Status information taken from the solid-state logic is transmitted to the demultiplexers through isolation devices in the trains (light transmission is used to achieve this isolation). The purpose of the isolation is to separate the monitoring circuit (which is considered to be a nonprotective function) from the protection circuitry. By design there is no possibility of short circuits, open circuits, or high voltage connections on the multiplexing line affecting operation of the protection circuits. The multiplexed outputs of the two trains are designed so that a status lamp or annunciator is actuated by either train A or train B. Normally both trains actuate the devices simultaneously. A flashing lamp or annunciator indicates status disagreement between train A and train B.

The solid-state logic circuitry can be tested with the plant either shutdown or at power. Each train contains an identical semiautomatic test panel with the necessary controls for testing. During the logic matrix surveillance, all reactor trips and engineered safety features actuations for the train under test are inhibited (prevented from actuating). In addition, all information transmitted to the control board status lamps and annunciators, and to the plant computer from that same train, is inhibited. To perform this surveillance, the operator needs only to select the process to be tested using a rotary selector switch, press a “start test” pushbutton, and wait for either a green “good” lamp or a red “bad” lamp to illuminate. During the test sequence all possible combinations of nontrip and trip conditions for that process logic are checked.

The semiautomatic testing of the solid-state logic includes checking the continuity of power to the undervoltage coils of the reactor trip breakers and to the master relay coils but excludes testing the input relays and contacts. The input relays and contacts are checked during testing of the analog portion of the protection system by tripping bistables while monitoring the control board status lamps for the specific tprotective functions. Since the lamps are operated through the multiplexing system, they cannot light unless appropriate input relays are affected.

12.1.3.3 Reactor Trip Breakers

Two series-connected reactor trip breakers, Figure 12.1-2, deliver power from the rod control motor-generator sets to the rod control power cabinets. A loss of power to these cabinets causes all rods to drop into the core.

Undervoltage coils keep the reactor trip breakers closed. In the untripped state, the reactor protection system logic matrices provide current flow paths to these coils. If a reactor trip coincidence is satisfied, contacts within the logic matrices open, breaking the continuity of these circuits, and the undervoltage coils de-energize. Removing power to these coils opens the reactor trip breakers.

Installed in parallel with each reactor trip breaker is a reactor trip bypass breaker. This presence of this breaker allows on-line testing of the associated reactor trip breaker without interrupting power to the rod drive mechanisms. The train A logic section supplies power to the undervoltage coils for the train A reactor trip breaker and for the train B bypass breaker. Similarly, the train B logic section supplies power to the undervoltage coils for the train B reactor trip breaker and for the train A bypass breaker. Whenever a reactor trip breaker is bypassed, the protection train associated with that breaker is considered to be inoperable.

The bypass breakers are interlocked so that if an attempt is made to close a bypass breaker with one reactor trip bypass breaker already closed, both bypass breakers trip open. This interlock prevents bypassing both protection trains simultaneously.

12.1.3.4 Output Cabinets

Engineered Safety Feature (ESF) functions are generated from the protection system output cabinets (one for each protection train). Each output cabinet contains approximately 20 master relays and 40 slave relays. The logic section initiates an engineered safety features actuation by energizing master relay(s). Each master relay, in turn, operates contacts which energize up to four slave relays (see Figure 12.1-3). The slave relays close contacts in pump starting circuits, close contacts to open or close valves, or actuate solenoids for air-operated equipment.

Test cabinets for both the slave and master relays allow periodic testing. Testing of this circuitry consists of introducing a low voltage electrical signal to each coil. This low voltage is not strong enough to actuate the relay but is sufficient to demonstrate continuity through the coil.

Integrated full-scale operability testing requires the actuation of the engineered safety features equipment (final device testing). Testing of this nature can only be accomplished during plant shutdown and requires extensive preparation and system realignments. Generally, one entire train (either train A or train B) is alternately tested every 18 months.

12.1.4 System Interrelationships

12.1.4.1 Protection System Testing

While only portions of this system are tested at any given time, the testing sequence provides an overlap to assure complete system operability. Testing the analog portion of the protection system at power is accomplished without initiating a protective action unless a trip condition actually exists. A trip does not occur because of the two-out-of-three or the two-out-of-four coincidence logic usually required for a reactor trip. Exceptions are the source and intermediate range high flux trip functions, which have one-out-of-two logic schemes. Therefore, placing one of these channels in test would generate a reactor trip. To prevent this action, these instruments have local bypass switches. However, placing one channel in bypass reduces the remaining function coincidence to one out of one.

Technicians verify the proper operation of process sensors by performing what is known as a channel check, which involves comparing redundant channels monitoring the same process variable to each other. Calibration of the sensors is normally accomplished during plant shutdown. The voltage and current of a channel from the sensor to the bistable is variable in magnitude and is referred to as the analog signal. From the bistable to the input relays, only ON-OFF signals are found. This portion of the channel is referred to as digital. Analog testing is performed at the analog instrumentation rack by individually introducing test signals into the instrumentation channels and observing the bistable outputs.

Each power range channel of the nuclear instrumentation system is tested by superimposing a test signal on the actual detector signal at the time of testing. The output of the bistable is not placed in a tripped condition prior to testing. Also, since the coincidence logic for power range trip functions is two out of four, bypassing these functions is not required.

The logic trains of the reactor protection system are designed to be capable of complete testing at power, except for those trips listed below. Annunciation is provided in the control room to indicate when a train is in test, a reactor trip function is bypassed, or a reactor trip bypass breaker is racked in and closed.

The reactor coolant pump breakers cannot be tripped at power without causing a reactor trip. However, the reactor coolant pump breaker open trip logic and continuity through the shunt trip coil can be tested at power. The manual reactor trip switches cannot be tested at power without causing a reactor trip, since operation of either manual trip switch actuates both trains of the protection system. Initiating a safety injection actuation or a turbine trip cannot be performed at power without upsetting normal plant operations. However, the logic for these trips is testable at power.

All trip function channels, logic trains, and trip breakers of the RPS are normally required to be in service. However, to permit on-line testing of the various system portions or to permit continued operation in the event of a failure, the Technical Specifications allow continued plant operation with limited RPS inoperabilities. The Technical Specifications also define the required restrictions on operation in the event that the full system operability is not met.

The RPS is designed so that response-time tests can only be performed during shutdown. However, the safety analysis includes conservative numbers for trip channel response times. The measured channel response times are compared with those used in the safety evaluations. On the basis of startup tests conducted at several plants, the actual response times measured are less than the times used in the safety analyses.

12.1.4.2 Testing Input Relays

Testing the logic trains of the reactor protection system includes a check of the input relays and a logic matrix check. During a process instrumentation system test, the technician trips each bistable. Each tripped bistable de-energizes one input relay in logic train A and one input relay in train B. A contact from each relay is connected to a universal logic printed circuit card. This printed circuit card performs both trip and monitoring functions. The contact that creates the channel trip signal also actuates a status lamp and an annunciator on the control board. Operation of the input relay from either train lights the status lamp and the annunciator.

Each train contains a multiplexing test switch. At the start of a process or nuclear instrumentation system test, this switch (in either train) is placed in the A+B position. The A+B position alternately transmits information from the two trains to the control board. A steady status lamp and annunciator indicates that the input relays in both trains have been de-energized. A flashing lamp means that the input relays in the two trains have not both de-energized. Contact inputs to the protection system logic, such as reactor coolant pump bus under-frequency relays, operate input relays which are tested by operating the remote contacts and using the same type of indications as those provided for bistable input relays.

Actuation of the input relays provides the overlap between testing the logic portion of the protection system and testing those systems supplying the inputs to the logic section. Inputs to the logic section are checked one channel at a time, leaving the other channels in service. For example, a function that trips the reactor when two out of four channels trip effectively becomes a one-out-of-three trip when the channel in test is placed in the trip mode. Both trains of the logic section remain in service during this portion of the test.

12.1.4.3 Testing Logic Matrices

Logic matrices are checked one train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train under test are inhibited by the input error inhibit switch on the semiautomatic test panel in the train. At the completion of the logic matrix tests, one bistable in each channel of process instrumentation or nuclear instrumentation is tripped to check closure of the input error inhibit switch.

The logic test scheme uses short duration pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same terminals that connect the input relay contacts. Thus, there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage coil to the tester. These pulses are of such short duration that the reactor trip breaker undervoltage coil armature cannot respond mechanically.

12.1.4.4 Testing Reactor Trip Breakers

Normally, reactor trip breakers A and B are in service, and their associated reactor trip bypass breakers A and B are open and racked out (out of service). The following procedure briefly describes the method used for testing the reactor trip breakers:

1. With reactor trip bypass breaker, A racked out, manually close and trip this breaker to verify its operability.
2. Rack in and close reactor trip bypass breaker A. Trip reactor trip breaker A using the protection system logic matrix.
3. Re-close reactor trip breaker A.
4. Trip (open) and rack out reactor trip bypass breaker A.
5. Repeat the above steps to test reactor trip breaker B.

Auxiliary contacts of the reactor trip bypass breakers supply a protective function designed to prevent both bypass breakers from being closed simultaneously. If either train is placed in test while the reactor trip bypass breaker of the other train is closed, both reactor trip breakers and both reactor trip bypass breakers automatically trip.

12.1.4.5 Testing Bypasses

Where operating requirements necessitate automatic or manual bypass of a protective function, the system is designed so that any actuated bypass is automatically removed whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are considered part of the protection system and are tested much as other RPS components are tested. Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

12.1.5 PRA Insights

The purpose of the reactor protection system is to initiate reactor trips to prevent the plant from exceeding a safety limit and to actuate engineered safety features to mitigate the consequences of an accident. A failure of the reactor protection system would allow core heat production to continue and prevent the initiation of safety-related heat removal systems. Therefore, the failure of the RPS could lead to significant core damage.

The failure of the reactor protection system is not a significant contributor to sequences which lead to core damage (6.3% at Surry, 1.3% at Sequoyah). However, the failure of the reactor protection system to perform its function has a major impact on importance measures. The risk achievement factor is 1300 for Surry and 450 for Sequoyah.

12.1.6 Summary

Due to its importance to safety, the RPS is designed, constructed, and tested to the highest standards. These include requirements for the ability to withstand single failures and still provide full protection, for the independence of separate trains, and for testability to insure continued reliability.

The RPS contains process sensors (multiple sensors for each parameter) which produce variable outputs provided to comparators (bistables). The variable signal from a sensor is compared to a preset bistable trip setpoint. If the process variable exceeds the setpoint value, the bistable changes state and de-energizes (its output voltage goes to zero). The bistables's output is sensed by both the train A and train B logic cabinets.

The logic cabinets continuously monitor the status of the bistables and produce a protective action (reactor trip or ESF actuation) when the coincidence of tripped bistables indicates the need for it. Either logic train, by itself, is sufficient to fully initiate necessary protective actions independent of the other logic train.

Testing the RPS at power is necessary to ensure the continued reliability and integrity of the RPS. Testing is performed by overlapping individual tests of system portions to ensure that nothing is missed. Sensor calibration and final device testing is normally performed when the plant is shutdown.

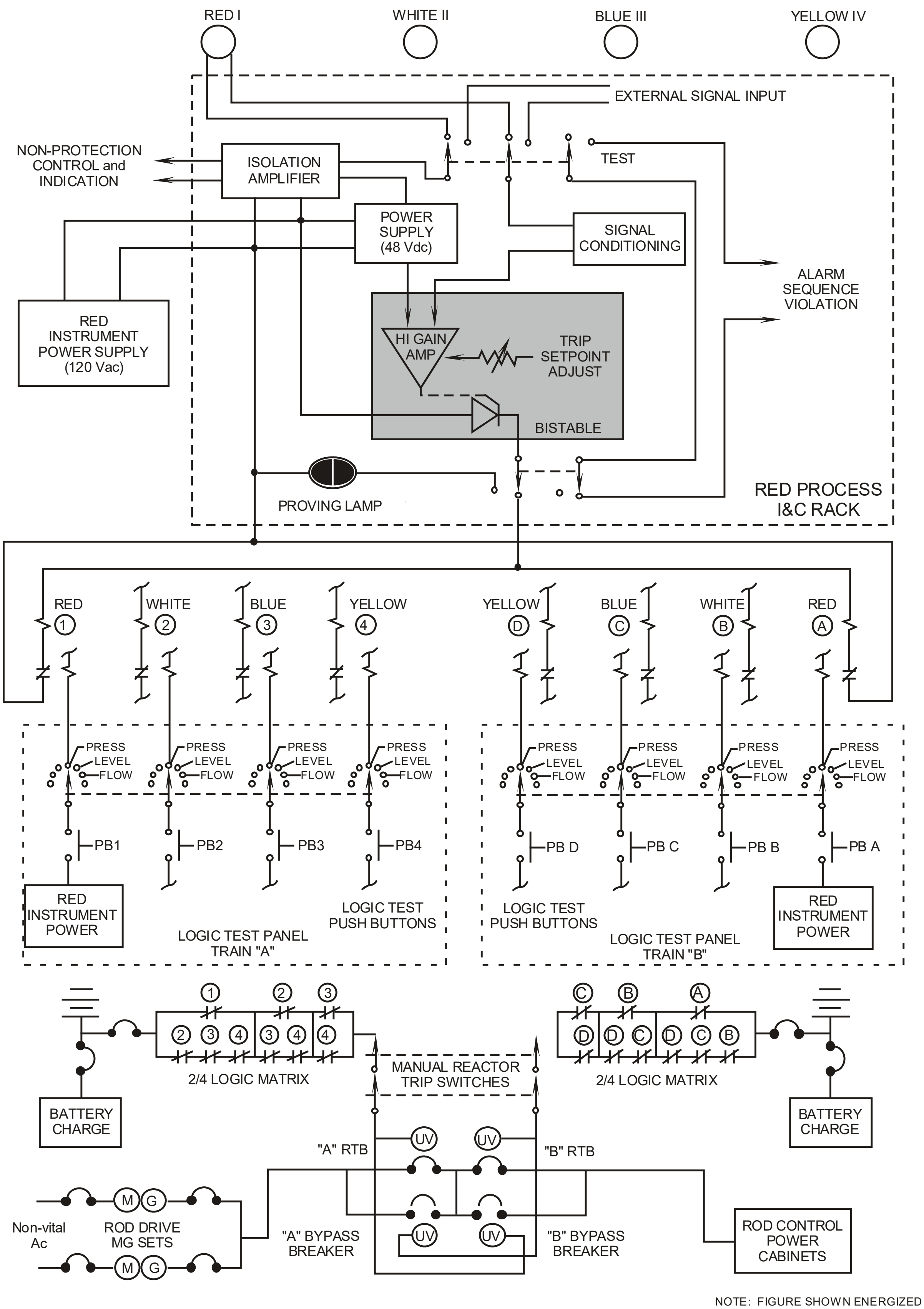

Figure 12.1-1 Relay Protection System

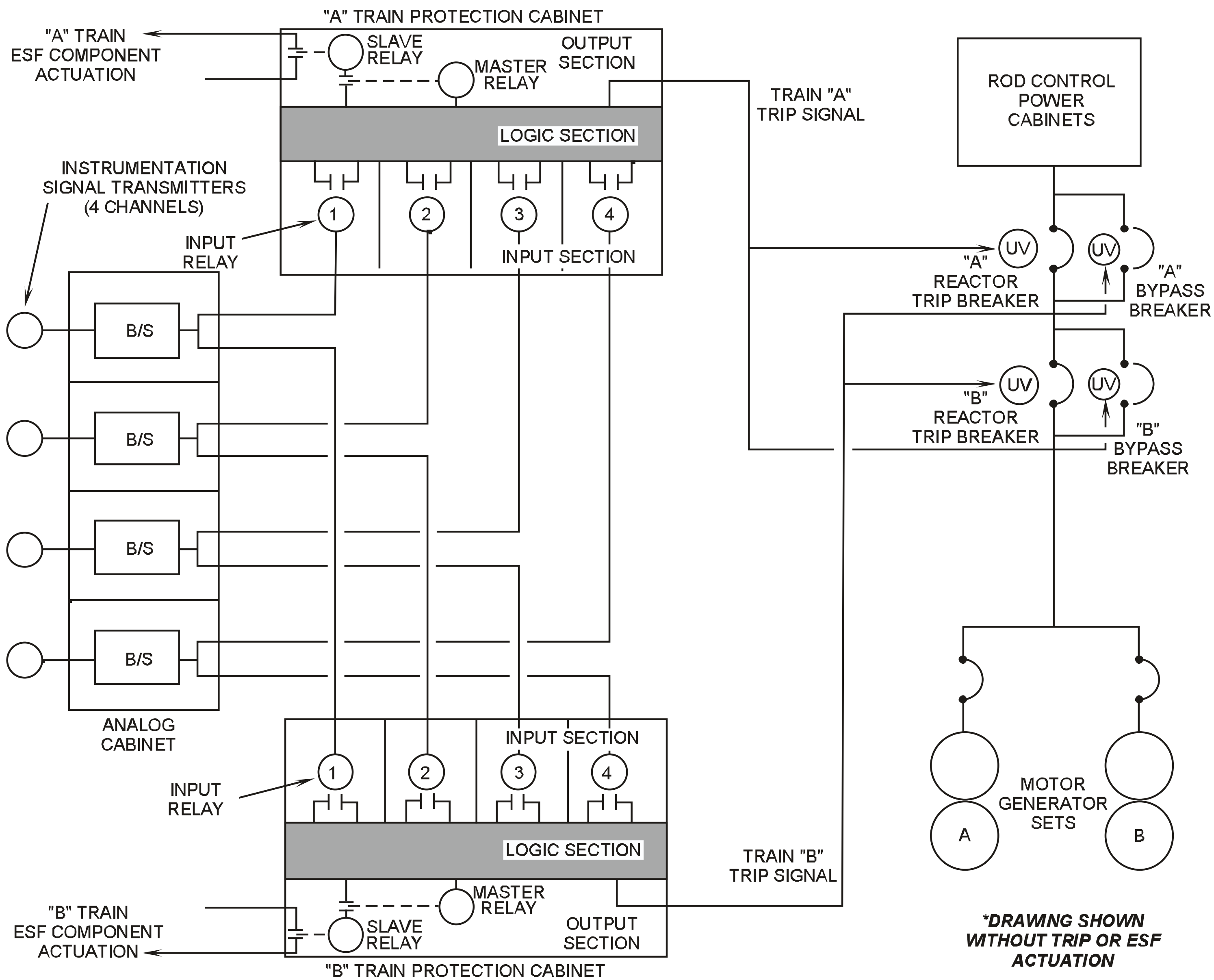

Figure 12.1-2 Solid State Protection System

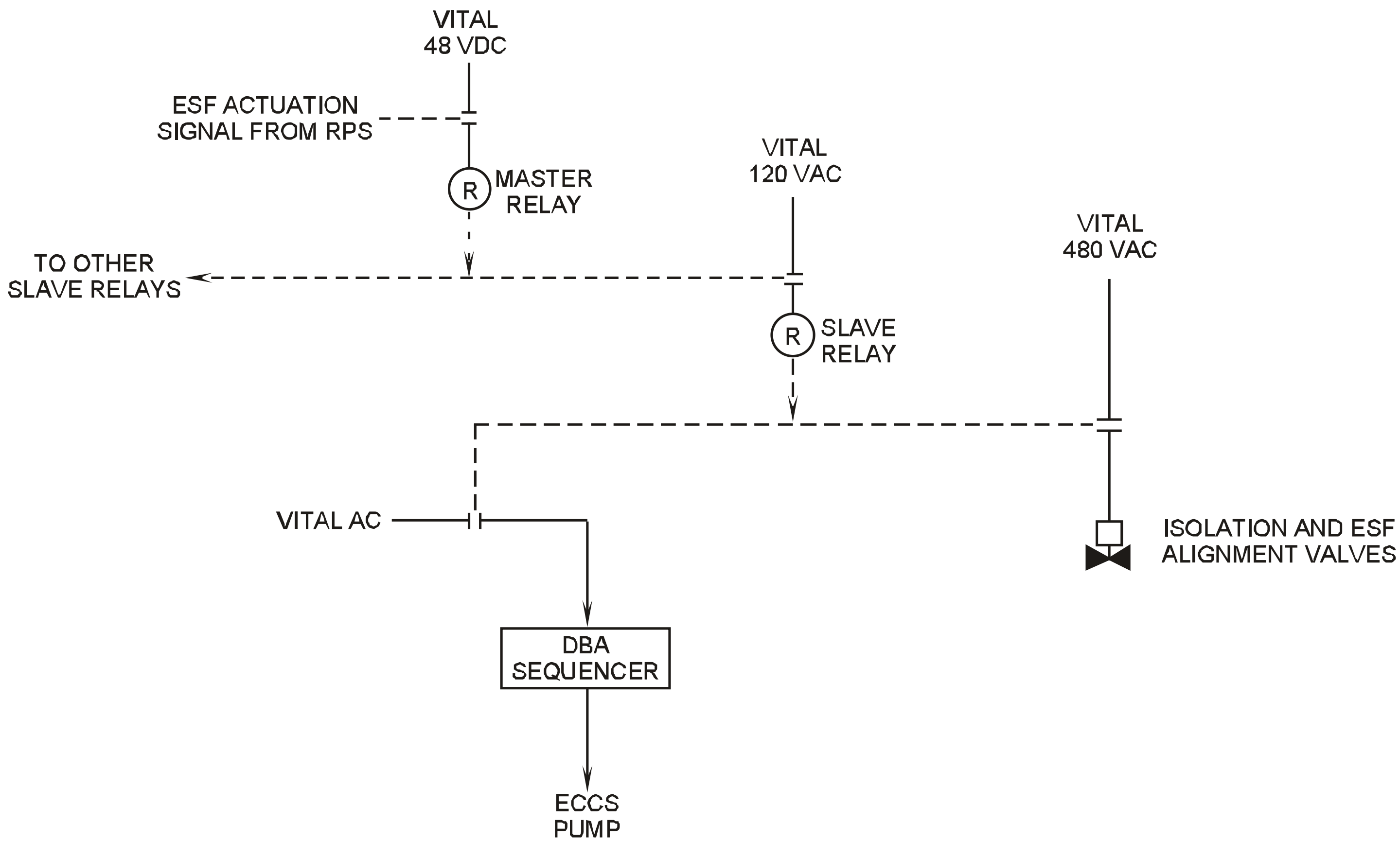

Figure 12.1-3 ESF Actuation Output Relay Operation

Westinghouse Technology Systems Manual

Section 12.2

<u>Reactor Protection System (RPS) –</u>
<u>Reactor Trip Signals</u>

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12.2 REACTOR PROTECTION SYSTEM (RPS) - REACTOR TRIP SIGNALS

Learning Objectives:

1. Given a list of reactor trips, explain the purpose (basis) of each.
2. Given a list of Reactor Protection System (RPS) interlocks, explain the purpose of each.
3. Given a list of control-grade interlocks, explain the purpose of each.

12.2.1 Introduction

The purposes of the reactor trip signals are to initiate a reactor trip if safe operating limits are exceeded. The safe operating limits bounded by these trips are monitored by sensors and are compared to preselected bistable setpoints. If a processed parameter exceeds its associated setpoint, a reactor trip occurs. The specific functions of all reactor trips are discussed in the following sections.

12.2.2 Reactor Trip Functions

The philosophy of the reactor protection system is to define an area of permissible operation in terms of power, flow, axial power distribution, and primary coolant temperature and pressure, so that the reactor is tripped when the limits of a selected area of concern are approached. When the protection system receives signals indicative of an approach to an unsafe operating condition, the system actuates alarms, prevents control rod withdrawal (if applicable), initiates a turbine runback (if applicable), and/or opens the reactor trip breakers. The Over-Power ΔT (OPΔT) and Over-Temperature ΔT (OTΔT) reactor trips provide core protection for situations in which:

- The transient is slow with respect to coolant piping delays from the core to the temperature sensors, and
- Pressure is within the range between the high- and low-pressure reactor trips.

Other reactor trips shown in Figure 12.2-1, such as the low coolant flow and high nuclear flux trips, provide core protection for accidents in which the loop ΔT signal does not respond quickly enough. Additional reactor trips, such as the high pressurizer water level and low feedwater flow trips, are provided primarily for equipment protection. Finally, some reactor trips, such as those produced by a turbine trip or reactor coolant pump circuit breaker opening, are provided to anticipate probable plant transients and to minimize the resulting thermal transient on the Reactor Coolant System (RCS). Descriptions of the reactor trips are provided in section 12.2.3 and in Table 12.2-1.

Protection-grade interlocks (designated as P-n), also known as permissives, and control-grade interlocks (designated as C-n) are also described in this section. An interlock blocks certain actions and permits others. Rod withdrawal stops are examples of control-grade interlocks; they are provided to prevent abnormal conditions which could result in a trip in response to excessive control rod withdrawal initiated by either a control system malfunction or a violation of administrative procedures by the operator. Descriptions of interlocks are provided in sections 12.2.3 and12.2.4 and in Tables 12.2-2 and 12.2-3.

A reactor trip is initiated by interrupting power to the Rod Cluster Control Assemblies (RCCAs). Power is delivered to the RCCAs from the rod drive motor generator sets through two series-connected trip breakers. Opening either trip breaker removes power to the rods. Each breaker is designed to trip open by spring action when a small undervoltage coil in the breaker assembly is de-energized. When this coil is de-energized, it allows a mechanical latch to move, allowing the spring to open the trip breaker. The undervoltage coil to Reactor Trip Breaker (RTB) “A” is powered by protection train “A,” and that of RTB “B” is supplied by protection train “B.” Therefore, either protection train is capable of initiating a reactor trip, regardless of the action by the opposite train.

12.2.3 Trip Signal Functions

Reactor trip signals are provided by the RPS to protect the plant during various analyzed transients or accidents. The reliability of the RPS is assured by providing more than one trip function to protect the plant against the same event. The following provides a brief description of each of the various reactor trip signals.

12.2.3.1 Manual Trip

The manual actuating devices (reactor trip switches) are independent of the automatic trip circuitry and are not subject to the types of failures which may render a portion of the automatic circuitry inoperable. Actuating either of the two manual reactor trip switches located in the control room initiates a reactor trip and a turbine trip.

12.2.3.2 High Neutron Flux Trip - Source Range (SR)

This trip, Figure 12.2-2, occurs when at least one of the two source range channels indicates greater than 10^5 cps. The source range trip provides protection against reactivity excursions and startup accidents. This trip may be manually blocked when at least one of the two intermediate range channels exceeds the P-6 setpoint value of 10^{-10} amps, and the trip function is automatically reinstated when both intermediate range channels decrease below the P-6 setpoint.

When this trip is manually blocked, power is removed from the source range neutron detectors, de-energizing both channels. The operator can manually restore power to the source range detectors by momentarily placing the BLOCK-RESET switches to reset. When the P-10 permissive setpoint (10% power on the power range instruments) is exceeded, the altered reset logic prevents the operator from inadvertently energizing the source range detectors. Applying a high voltage to these detectors in the presence of a high neutron flux could damage the detectors.

12.2.3.3 High Neutron Flux Trip - Intermediate Range (IR)

This trip, Figure 12.2-3, occurs when the current output from at least one of the two intermediate range channels indicates greater than the equivalent of 25% power. The intermediate range trip, which provides protection against reactivity excursions and startup accidents, can be manually blocked if at least two of the four power range channels exceed 10% of full power (P-10). If at least three of four (3/4) power range channels fall below the P-10 setpoint value, the trip function is automatically reinstated.

12.2.3.4 High Neutron Flux Trip - Power Range (PR)

This trip, Figure 12.2-4, occurs when at least two of the four (2/4) power range channels indicate greater than the trip setpoint. Two independent trips are provided: a high setting at 109% and a low setting at 25%. The high trip setting provides protection against overpower during normal power operations. The low setting, which provides protection against reactivity excursions and startup accidents, can be manually blocked when at least two of the four power range channels indicate greater than 10 percent of full power (P-10).

If at least three of the four power range channels drop below 10 percent power, the low power trip function is automatically reinstated. The high trip setting is always active (cannot be blocked). Before reactor power reaches the 109% trip setpoint, a signal is generated to block automatic and manual rod withdrawal. This action occurs if at least one of the four power range channels exceeds 103% power (the C-2 interlock).

12.2.3.5 Positive Neutron Flux Rate Trip - Power Range

This trip, Figure 12.2-5, occurs when an abnormal rate of increase in nuclear power (+5% with a 2 second time constant) occurs in at least two of the four power range channels. This trip provides protection for rod ejection accidents and cannot be bypassed or blocked. A rate trip in a particular RPS channel “seals in”; it remains in effect until the operator resets the trip at the appropriate nuclear instrument drawer.

12.2.3.6 Negative Neutron Flux Rate Trip - Power Range

This trip, Figure 12.2-5, occurs when an abnormal rate of decrease in nuclear power (-5% with a 2 second time constant) occurs in at least two of the four power range channels. This trip provides protection against dropped rod accidents and cannot be bypassed or blocked. A rate trip in a particular RPS channel “seals in”; it remains in effect until the operator resets the trip at the appropriate nuclear instrument drawer.

12.2.3.7 Over-Temperature ΔT (OTΔT) Reactor Trip

The OTΔT trip, Figure 12.2-6, is designed to protect against Departure from Nucleate Boiling (DNB), which causes a large decrease in the heat transfer coefficient between the fuel rods and the reactor coolant, resulting in high fuel clad temperatures. In each of the four reactor protection channels, the calculated loop ΔT, a measure of reactor power, is compared with a continuously calculated trip setpoint. This setpoint is a function of T_{avg}, pressurizer pressure, and axial flux difference. (Separate inputs of T_{avg}, pressurizer pressure, and axial flux difference are used in each reactor protection channel.) If the calculated ΔT equals the calculated trip setpoint, the affected channel is tripped. If two or more channels are simultaneously tripped, the reactor is automatically tripped. The equation for the calculation of the OTΔT setpoint is:

$$\text{OT}\Delta\text{T setpoint} = \Delta T_0 \left[K_1 - K_2 \frac{(1 + \tau_1 S)}{1 + \tau_2 S}(T - T') + K_3(P - P') - f_1(\Delta I)\right]$$

where:

ΔT_0 = indicated ΔT at rated thermal power, in terms of percent reactor power.

T = measured RCS average temperature (T_{avg}), °F.

T' = nominal T_{avg} at rated thermal power, 585°F.

P = pressurizer pressure, psig.

P' = nominal RCS operating pressure, 2235 psig.

S = Laplace transform operator, sec^{-1}.

$\frac{1 + \tau_1 S}{1 + \tau_2 S}$ = function generated by the lead-lag controller for T_{avg} dynamic compensation.

τ_1 = lead time constant, sec.

τ_2 = lag time constant, sec.

K_1 = manually adjusted preset bias that sets the steady-state trip setpoint when other parameters are at their rated values.

K_2, K_3 = manually adjusted preset gains.

$f_1(\Delta I)$ = function of axial flux difference.

The T_{avg} term in the equation acts to lower the trip point when T_{avg} is greater than the normal full power T_{avg}. This correction is necessary because the increased average temperature reduces the margin to DNB. The pressure signal reduces the ΔT setpoint when pressure is lower than rated, since this condition also reduces the margin to DNB. The $f_1(\Delta I)$ term reduces the value of the trip setpoint to reflect an increase in the hot channel factors which could result in localized DNB. Generally, the ΔI function does not affect the OTΔT trip setpoint (the function value is set to 0) when core power is evenly or fairly evenly distributed axially; it dramatically reduces the OTΔT trip setpoint for very large positive or negative values of axial flux difference. This correction ensures that DNB is not approached even for highly skewed power distributions. The OTΔT trip ensures a DNBR of not less than 1.30 at the time of the reactor trip if:

- The transient is slow with respect to piping transient delays from the core to the temperature detectors and
- The reactor coolant pressure is within the bounds set by the high- and low-pressure trips.

Prior to the actual ΔT reaching the OTΔT trip setpoint, both automatic and manual control rod withdrawal is inhibited, and a cyclic turbine runback is initiated, as long as the overtemperature condition exists. This action occurs if the calculated ΔT values in at least two of the four protection channels are within 3% of the trip setpoint.

12.2.3.8 Over-Power ΔT (OPΔT) Reactor Trip

The OPΔT trip, Figure 12.2-7, is designed to protect against a high fuel rod power density (excessive kw/ft) and subsequent fuel melt and fuel rod cladding failure. Fuel melt is avoided by limiting the fuel centerline temperature to less than 4700°F, which is significantly below the actual UO_2 melting temperature. In each of the four reactor protection channels, the calculated loop ΔT, a measure of reactor power, is compared with a continuously calculated trip setpoint that is automatically calculated as a function of T_{avg} and axial flux difference. (Separate inputs of T_{avg} and axial flux difference are used in each reactor protection channel.) If the ΔT signal exceeds the calculated setpoint, the affected channel is tripped. If two or more channels are simultaneously tripped, the reactor is automatically tripped. A turbine runback occurs, and automatic and manual rod withdrawal is inhibited when, in at least two protection channels, the ΔT value reaches 3% below the trip setpoint. Since core thermal power is not precisely proportional to ΔT due to the effects of changes in coolant density and heat capacity, a compensating term, a function of average temperature, is used. Similarly, since the prescribed overpower limit may not be adequate for highly skewed axial power distributions, a compensating term related to ΔI is used. The setpoint equation is:

$$\text{OP}\Delta\text{T setpoint} = \Delta T_0 \left[K_4 - K_5\left(\frac{\tau_3 S}{1 + \tau_3 S}\right)T + K_6(T - T') - f_2(\Delta I)\right]$$

where:

ΔT_0 = indicated ΔT at rated thermal power, in terms of percent reactor power.

T = measured RCS average temperature (T_{avg}), °F.

T' = nominal T_{avg} at rated thermal power, 585°F.

S = Laplace transform operator, sec^{-1}.

$\frac{\tau_3 S}{}$ = function generated by the rate-lag controller for T_{avg} dynamic

$1 + \tau_3 S$ compensation.

τ_3 = rate-lag time constant, sec.

K_4 = manually adjusted preset bias that sets the steady-state trip setpoint when other parameters are at their rated values.

K_5, K_6 = manually adjusted preset gains.

$f_2(\Delta I)$ = function of axial flux difference.

The (T - T') term effectively imposes an upper limit for the setpoint based on full power. Since it is possible for the average temperature to exceed the programmed full power average temperature, the setpoint must be reduced to take into account the increase in the heat capacity of the reactor coolant at higher temperatures. This term can only decrease the OPΔT trip setpoint from its normal full power value.

Prior to the actual ΔT reaching the OPΔT trip setpoint, both automatic and manual control rod withdrawal is inhibited, and a cyclic turbine runback is initiated, as long as the overpower condition exists. This action occurs if the calculated ΔT values in at least two of the four protection channels are within 3% of the trip setpoint.

12.2.3.9 Pressurizer Low Pressure Trip

The pressurizer low pressure trip, Figure 12.2-8, protects against excessive core steam voids and limits the range of required protection afforded by the OTΔT trip. The reactor trips when at least two of four pressurizer pressure signals fall below 1865 psig. This trip is automatically blocked when turbine first-stage pressure or reactor power is less than 10 percent power (P-7 permissive).

12.2.3.10 Pressurizer High Pressure Trip

The pressurizer high pressure trip protects against reactor coolant system overpressure, thereby protecting the RCS pressure boundary. As shown in Figure 12.2-9, the reactor trips when two of four high pressurizer pressure signals exceed 2385 psig. This trip is always in service and cannot be bypassed or blocked.

12.2.3.11 Pressurizer High Water Level Trip

The pressurizer high water level trip, shown in Figure 12.2-10, protects against overpressurization of the RCS resulting from rapid thermal expansions of reactor coolant which fill the pressurizer. In addition, if the pressurizer fills completely with water, relieving water instead of steam could be damaging to the relief and safety valves. The reactor is tripped when two of three pressurizer water level signals exceed 92%. This trip is automatically blocked below 10 percent power (P-7).

12.2.3.12 Low Reactor Coolant Flow Trips

The low flow reactor coolant flow trips protect the core from DNB following a loss of coolant flow. The means of generating a low flow are shown in Figure 12.2-11 and described below:

1. Low primary coolant flow trip: A low loop flow signal is generated by two-out-of-three low flow signals per loop. Above the P-7 setpoint (approximately 10% of full power), a low flow in two or more loops results in a reactor trip. Above the P-8 setpoint (39% of full power) low flow in any single loop results in a direct reactor trip.
2. Reactor coolant pump breaker position trip: A contact associated with each reactor coolant pump power supply breaker supplies a signal to the logic section of the reactor protection system. The reactor trips if at least two reactor coolant pump breakers open.
3. RCP bus under-voltage trip: The RCP under-voltage trip anticipates, and improves the response of the RPS to, a complete loss of reactor coolant flow. Each of the two RCP busses is equipped with two under-voltage sensors. An under-voltage condition, as sensed by one of two (1/2) devices on an individual bus, must exist on two of two (2/2) RCP busses to produce a reactor trip.
4. RCP bus under-frequency trip: An under-frequency condition on the RCP busses reduces the speed of the pumps (with a subsequent reduction in flow). This is undesirable because it reduces the coastdown time of the pumps if power is lost to the busses. Each of the two RCP busses is equipped with two under-frequency sensors. An under-frequency condition, as sensed by one of two devices on an individual bus, must exist on two of two RCP busses to produce a reactor trip. In addition to tripping the reactor, satisfaction of the under-frequency trip logic also trips the RCPs.

All the reactor coolant low flow trips are automatically blocked below the P-7 setpoint (10% power).

12.2.3.13 Low-Low Steam Generator Water Level Trip

This trip (Figure 12.2-12) protects the reactor against a loss of heat sink. The setpoint of this trip is 11.5%, as indicated by the narrow-range steam generator level instruments. The trip logic is satisfied by two of three (2/3) levels below the low-low setpoint in at least one steam generator.

12.2.3.14 Safety Injection (SI) Actuation Trip

If a reactor trip has not already been generated by any other trip signal, the Safety Injection (SI) actuation signal initiates a trip when the RPS senses any condition which initiates safety injection. The SI actuation trip protects the core in the event of a loss of coolant accident or a steam line break accident.

The safety injection actuation signals are discussed in Section 12.3.

12.2.3.15 Reactor Trip on Turbine Trip

The turbine trip - reactor trip signal, Figure 12.2-13, protects the reactor coolant system from a thermal transient (overpressure or overtemperature) when the energy removal from the coolant abruptly diminishes. This trip occurs for power levels greater than 10% (P-7), or in plants with the P-9 permissive, for levels greater than 50%. The signals used to sense that the turbine has tripped are:

1. Four of four (4/4) turbine throttle (stop) valves fully closed, or
2. Two of three low turbine electrohydraulic control system trip header fluid pressures (setpoint: 800 psig) for a General Electric turbine, or two of three low auto-stop oil pressures (setpoint: 45 psig) for a Westinghouse turbine.

See Sections 11.3 and 11.5 for additional details.

12.2.4 Interlocks

Various signals are generated throughout the plant for the purpose of:

1. Automatically prohibiting and/or allowing the actuation of certain protective functions and the operation of certain control systems, and
2. Allowing the operator to manually prohibit certain protective actions.

The interlocks are divided into two broad categories, designated as protection-grade (P) interlocks (permissives) and control-grade (C) interlocks. Protection-grade interlocks are developed within the solid-state protection system. Control-grade interlocks are developed within the process instrumentation racks (with the exception of C-8). Although not part of the protection system, the control-grade interlocks are discussed here for the sake of completeness.

12.2.4.1 Control-Grade Interlocks

An interlock is a signal or equipment status that prevents or allows an action or a function when a certain set of conditions exist. Listed below are the control-grade interlocks (designated by the C-n convention) employed in most Westinghouse reactor plants. The “C” designation differentiates them from RPS permissives (“P” designation), as previously discussed.

C-1: High Neutron Flux Rod Stop Interlock

At least one of two intermediate range detector currents exceeding the equivalent of 20% power generates a rod withdrawal stop for both automatic and manual rod control. The rod stop may be blocked with reactor power (power range) at or above the P-10 setpoint (2/4 coincidence), but it is automatically reinstated when power drops below the P-10 setpoint (3/4 coincidence).

C-2: Overpower Rod Stop Interlock

If at least one of the four excore power range flux detectors indicates a power output of greater than 103%, an automatic and manual rod withdrawal stop is actuated.

This interlock may be bypassed by the operator to allow for continued operation with one inoperable power range channel.

C-3: OTΔT Rod Stop and Turbine Runback Interlock

When the calculated loop ΔT in at least two of four protection channels is within three percent of the OTΔT trip setpoint, automatic and manual rod withdrawal is blocked, and a turbine runback is initiated.

C-4: OPΔT Rod Stop and Turbine Runback Interlock

When the calculated loop ΔT in at least two of four protection channels is within three percent of the OPΔT trip setpoint, automatic and manual rod withdrawal is blocked, and a turbine runback is initiated.

C-5: Low Power Interlock

The setpoint for this interlock is 15% load, as sensed by turbine impulse pressure. If load drops below 15%, automatic rod withdrawal is inhibited. The C-5 interlock is supplied by a particular turbine impulse pressure sensor that cannot be changed by the operator.

C-7: Loss of Load Interlock

This interlock is actuated by a reduction in turbine load of sufficient severity; it arms the steam dump control system (allows steam dump valves to open if an open demand exists). C-7 senses must be manually reset. It is actuated by a turbine load decrease larger in magnitude than a 10% step drop or a 5%/min ramp decrease.

C-8: Turbine Tripped Interlock

When the C-8 interlock is actuated, the steam dump control system (if in the T_{avg} mode of control) shifts from the load-rejection controller to the turbine-trip controller. Permissive C-8 requires:

1. Four of four (4/4) turbine throttle (stop) valves fully closed, or
2. Two of three low turbine electrohydraulic control system trip header fluid pressures (setpoint: 800 psig) for a General Electric turbine, or two of three low auto-stop oil pressures (setpoint: 45 psig) for a Westinghouse turbine.

In addition, C-8 arms the steam dumps. The C-8 interlock is not installed in Westinghouse-designed units that have the P-9 permissive.

C-9: Condenser Available Interlock

The condenser must be available in order to allow steam dump operation. To actuate C-9, one of two (1/2) circulating water pump breakers must be shut AND two of two condenser vacuum switches must be shut (< 5 in. Hg backpressure). If backpressure in the condenser increases to 7.6 in. Hg, then the C-9 interlock is removed.

C-11: Control Bank D Rod Withdrawal Limit Interlock

This signal prevents misalignment of rod position step counters by blocking automatic withdrawal of control bank D when the bank D position has reached 223 steps.

12.2.4.2 Protection-Grade Interlocks

During controlled plant evolutions, certain protection signals are not required for plant safety and may be blocked to prevent inadvertent reactor trips or engineered safety features (ESF) actuations. These signals are disabled automatically by the RPS or manually by the operator. The mechanisms for blocking these trips are the protection-grade interlocks, or permissives. The protection system is designed so that any signal which had been blocked is automatically reinstated whenever the conditions allowing that block (a satisfied permissive) are no longer met (This design convention is required by IEEE Std. 279-1971). The following provides brief descriptions of the various permissives.

P-4: Reactor Trip Permissive

This permissive is derived from the status of "b" contacts on the reactor trip breakers (RTBs). (Each contact is closed when the associated RTB is open, and open when the RTB is closed). The permissive is satisfied whenever an RTB is open. It performs the following functions:

1. Actuates a turbine trip,
2. Initiates main feedwater isolation with RCS temperature below 564°F,
3. Inputs to the SI actuation block-reset logic, and
4. Prevents opening of the main feedwater isolation valves which had been closed by an SI actuation signal or high-high steam generator level (P-14).

Permissive P-4 (and P-14, as discussed below) is not a permissive signal in the classic sense, in that it does not enable or reinstate some switch or function. It does not have associated status lights on protection system bistable status panels in the control room.

P-6: Source Range Block Permissive

Permissive P-6 enables the source range block-reset switches on the main control board. The operator can then place the switches in the “block” position to remove power from the source range detectors, thereby blocking the source range high flux trip. During a power increase when at least one of two intermediate range channels is greater than 10^{-10} amps, permissive P-6 is in effect. During a power decrease when BOTH intermediate range channel outputs drop below 10^{-10} amps, permissive P-6 is removed.

P-7: At-Power Permissive

At-power permissive P-7 is in effect below 10% power and automatically blocks the at-power trips listed below:

- Two-loop low reactor coolant flow trip,
- RCP power supply breaker trip,
- RCP bus under-voltage trip,
- RCP bus under-frequency trip,
- Pressurizer low pressure trip,
- Pressurizer high level trip, and
- Reactor trip on turbine trip (except at plants with P-9).

During a power increase, when either the turbine load (P-13) or the reactor power (P-10) is greater than 10%, permissive P-7 is removed, and the at-power trips are automatically enabled. During a power decrease, both the turbine load (2/2) and the reactor power (3/4, power range) must be below 10% to enable permissive P-7 and disable the at-power trips.

P-8: Three Loop Flow Permissive

Permissive P-8 is in effect below 39% reactor power. The permissive allows the loss of flow in one reactor coolant loop without generating a direct reactor trip signal. When at least two of four power range channels indicate that reactor power is greater than 39%, a loss-of-flow signal in any single loop initiates a reactor trip signal.

P-9: Turbine Trip/Reactor Trip Permissive

Permissive P-9 is in effect below 50% power (note: not all Westinghouse units use this permissive). This permissive allows the reactor to remain in operation if the turbine trips. Facilities with this permissive have demonstrated that, for turbine trips from 50% power or less, sufficient steam dump capacity is available for excess energy removal until the plant is brought to no-load conditions.

P-10: Nuclear At-Power Permissive

Inputs to the P-10 permissive circuit are from each of the four power range channels. The P-10 setpoint is 10%. When at least two of the channels indicate greater than or equal to this setpoint, the operator may block the intermediate high flux trip, the power range low setpoint high flux trip, and the high neutron flux rod stop (C-1). When 3/4 power range channels drop below the P-10 setpoint, the functions previously mentioned are automatically reinstated. The following is a list of functions provided by P-10:

1. Allows the operator to manually block the intermediate range high flux trip and the C-1 rod stop,
2. Allows the operator to manually block the low setpoint power range high flux trip,
3. Automatically restores intermediate range trip and C-1 rod stop when power falls below the P-10 setpoint,
4. Automatically restores the low setpoint power range high flux trip when power falls below the P-10 setpoint,
5. Provides an input to the P-7 circuit, and

6. Serves as a backup to P-6 by preventing the operator from inadvertently re-energizing the source range high voltage.

P-11: Low Pressurizer Pressure SI Block Permissive

Permissive P-11 is in effect below 1915 psig. When two of three pressurizer pressure channels indicate less than 1915 psig, the block switches for the low pressurizer pressure safety injection actuation signal are enabled, and the operator may block the actuation signal before the low-pressure SI setpoint of 1807 psig is reached.

With pressure increasing, when two of three channels indicate greater than 1915 psig, the block is automatically removed. In addition, the removal of this permissive (pressurizer pressure greater than the permissive setpoint) provides a confirmatory open signal to all cold-leg accumulator motor-driven isolation valves. (The accumulator isolation valves are unlikely to open automatically; power to the valves is removed except when operators are manually opening or closing them.)

P-12: High Steam Flow SI Block Permissive

Permissive P-12 is in effect below 553°F. If two of four loop T_{avg} signals are below the low-low Tavg value of 553°F, the block switches for the high steam line flow safety injection actuation is enabled, and the operator can block this signal. This signal is blocked during a controlled plant cooldown to prevent an automatic initiation of the ESF equipment. Permissive P-12 also automatically blocks steam dump operation and thereby prevents an uncontrolled cooldown caused by an instrumentation malfunction. Operators can bypass the block for only one bank of three steam dump valves. This permissive is automatically removed when three of four (3/4) T_{avg} channels indicate greater than 553°F. The removal automatically makes the remaining nine steam dump valves available for operation and removes the block of the high steam line flow SI actuation signal.

P-13: Turbine At-Power Permissive

Permissive P-13 is enabled when both turbine impulse chamber pressures indicate that turbine load is less than 10%. P-13 and P-10 are the two inputs to at-power permissive P-7.

P-14: Steam Generator High Level Override

The P-14 setpoint is enabled when at least two of three steam generator narrow-range levels exceed 69% for at least one steam generator. When this permissive is actuated the following actions occur:

1. The turbine trips,
2. All main feedwater pumps trip,
3. All main feedwater regulating, and bypass valves shut, and
4. All main feedwater isolation valves shut.

Permissive P-14, like P-4, is not a permissive signal in the classic sense, in that it does not enable or reinstate some switch or function. Individual bistable lights for the high-high level turbine trip function are on the reactor trip bistable status panel.

12.2.5 Summary

Many reactor trip signals are generated to ensure that the reactor is operated within safe limits. Some trip functions are enabled or blocked in accordance with the status of associated permissives (protection-grade interlocks). Control-grade interlocks, discussed in this section for completeness, are also provided for certain plant control functions.

Table 12.2-1 Summary of Reactor Trips

Trip	Coinc.	Setpoint	Interlocks	Purpose	Accident/Event
1. Source Range High Neutron Flux	1/2	10^5 cps	Manual block permitted by P-6; power to source range detectors is removed when manual block is initiated. Power to detectors cannot be turned on when power is above P-10.	Prevents an inadvertent power rise (excursion). A trip will occur unless the operator deliberately blocks the trip.	Reactivity addition accidents such as: a. Uncontrolled rod withdrawal from subcritical or low power condition, b. Inadvertent boron dilution, or c. Excessive heat removal caused by steamline break or feedwater addition accident
2. Intermediate Range High Neutron Flux	1/2	Current equiva-lent to 25% power level	Manual block permitted by P-10.	Prevents an inadvertent power rise (excursion). A trip will occur unless the operator deliberately blocks the trip.	Reactivity addition accidents such as: a. Uncontrolled rod withdrawal from subcritical or low power condition, b. Inadvertent boron dilution, or c. Excessive heat removal caused by steamline break or feedwater addition accident
3. Power Range High Neutron Flux - low setpoint	2/4	25%	Manual block permitted by P-10.	Prevents an inadvertent power rise (excursion). A trip will occur unless the operator deliberately blocks the trip.	Reactivity addition accidents such as: a. Uncontrolled rod withdrawal from subcritical or low power condition, b. Inadvertent boron dilution, or c. Excessive heat removal caused by steamline break or feedwater addition accident

Table 12.2-1 (cont'd)
Summary of Reactor Trips

Trip	Coinc.	Setpoint	Interlocks	Purpose	Accident/Event
4. Power Range High Flux - high setpoint	2/4	109%	No Interlocks	Limits maximum power level to prevent damage to fuel clad and to protect against centerline melting.	Inadvertent power excursions such as: a. Excessive load increase, b. Excessive heat removal, c. Boron dilution accident, d. Inadvertent rod withdrawal, or e. Rod ejection accident
5. High Positive Rate Neutron Flux	2/4	+5% change with a 2-sec time constant	No Interlocks	Limits power excursions. Prevents unacceptable power distribution.	Rod Ejection Accident
6. High Negative Rate Neutron Flux	2/4	-5% change with a 2-sec time constant	No Interlocks	Prevents unacceptable power distribution. Limits power overshoot from rod withdrawal in response to a dropped rod.	Dropped Rod
7. OTΔT	2/4	Variable (calculated)	No Interlocks	Prevents operation with DNBR <1.30.	Relatively slow transients such as: a. Uncontrolled rod withdrawal at power, b. Uncontrolled boron dilution, c. Excessive load increase, or d. Depressurization of the RCS

Table 12.2-1 (cont'd)
Summary of Reactor Trips

Trip	Coinc.	Setpoint	Interlocks	Purpose	Accident/Event
8. OPΔT	2/4	Variable (calculated)	No Interlocks	Prevents excessive power density (kw/ft).	Relatively slow transients such as: a. Uncontrolled rod withdrawal at power, b. Uncontrolled boron dilution, c. Excessive load increase, or d. Steamline break
9. Pressurizer Low Pressure	2/4	1865 psig (rate compensated)	Disabled below P-7 (10%)	Prevents operation with DNBR <1.30. Limits required range of OTΔT trip.	Depressurization of RCS due to: a. LOCA, b. Steamline break, or c. SG tube rupture
10. Pressurizer High Pressure	2/4	2385 psig	No Interlocks	Protects integrity of RCS pressure boundary.	Uncontrolled rod withdrawal at power, loss of electrical load, or turbine trip
11. Pressurizer High Water Level	2/3	92%	Disabled below P-7 (10%)	Prevents "solid-water" operations, prevents discharge of high energy water through relief and safety valves.	Uncontrolled rod withdrawal at power, loss of electrical load, or turbine trip
12. Low Reactor Coolant Flow	2/3 per loop	<90% of rated flow	<P-8 (39%): loss of flow in one loop, no direct trip. <P-7 (10%): loss of flow in two or more loops, no direct trip.	Ensures adequate loop flow to remove core heat. DNBR considerations.	Loss of coolant flow events such as: a. Partial loss of RCS flow, b. Complete loss of forced RCS flow, or c. Loss of off-site power to station auxiliaries.
13. Reactor Coolant Pump Bus Under-Voltage	1/2 on 2/2 buses	68.6% of nominal bus voltage	Disabled below P-7 (10%)	Redundant to low flow trip	Redundant to low flow trip

Table 12.2-1 (cont'd)
Summary of Reactor Trips

Trip	Coinc.	Setpoint	Interlocks	Purpose	Accident/Event
14. Reactor Coolant Pump Bus Under-Frequency	1/2 on 2/2 buses	57.7 Hz	Disabled below P-7 (10%); trips open the pump motor breakers when actuated to preserve pump coastdown time.	Redundant to low flow trip	Redundant to low flow trip
15. Reactor Coolant Pump Breaker	1/1 on 2/4 RCPs	Breaker open	Disabled below P-7 (10%)	Redundant to low flow trip	Redundant to low flow trip
16. Steam Generator Low-Low Level	2/3 on 1/4 SGs	11.5%	No Interlocks	Prevents loss of heat sink.	Loss of normal feedwater
17. Turbine Trip	2/3 low pres-sure or 4/4 trip valves closed	Westing-house: 45 psig auto-stop oil press. GE: 800 psig trip header press.	Disabled below P-7 (10%)	Removes heat source if steam load is lost to SGs.	Turbine trip, loss of load

Table 12.2-1 (cont'd)
Summary of Reactor Trips

Trip	Coinc.	Setpoint	Interlocks	Purpose	Accident/Event
18. SI Actuation	1/2 trains		No Interlocks		Any accident requiring a safety injection actuation signal
19. Manual	1/2 manual push-buttons		No Interlocks	Operator initiated backup to all trips	Any condition requiring a reactor trip
20. SSPS General Warning	2/2	General Warning		The SSPS has a self-check feature that will trip the reactor if both protection trains develop trouble.	

Table 12.2-2 Summary of Protection-Grade Interlocks

Number	Name	Setpoint	Coincidence	Functions
P-4	Reactor Trip Breaker Contact	Open if trip breaker is closed. Closed if trip breaker is open.	Trip breaker and its bypass breaker both open	1. Trips main turbine. 2. Isolates main feedwater with T_{avg} <564°F in 2/4 loops. 3. Input to SI block and reset logic. 4. If main feed regulating and bypass valves are closed by SI or SG high level, P-4 seals in the isolation.
P-6	Source Range Block Permissive	Intermediate range power > 10^{-10} amps.	1/2	Enables BLOCK/RESET switches to allow the operator to block SR high flux trip.
P-7	At-Power Permissive	Power < 10%	Power range power <10% (P-10 cleared) and turbine power (impulse pressure) <10% (P-13)	Automatically blocks the "at-power" trips: 1. Pressurizer low pressure, 2. Pressurizer high level, 3. All RCS low flow, and 4. Turbine tripped
P-8	3-Loop Flow Permissive	Power range power < 39%	3/4	Automatically blocks the single loop low flow reactor trip.
P-9 (Not on all plants)	Turbine Trip/Reactor Trip Permissive	Power range power < 50%	3/4	Blocks reactor trip on turbine trip below 50%.
P-10	Nuclear At-Power Block Permissive	Power range power > 10%	2/4	1. Opens contacts to SR high voltage power supply. 2. Enables BLOCK switches to allow the operator to block IR high flux trip and rod stop. 3. Enables BLOCK switches to allow the operator to block PR high flux - low setpoint trip. 4. Input to P-7.

Table 12.2-2 (cont'd)
Summary of Protection-Grade Interlocks

Number	Name	Setpoint	Coincidence	Functions
P-11	Low Pressurizer Pressure SI Block Permissive	Pressurizer pressure < 1915 psig	2/3	Enables BLOCK switches to allow the operator to block low pressurizer pressure ESF actuation. Removal of permissive provides open signal to accumulator isolation valves.
P-12	High Steam Flow SI Permissive	T_{avg} < 553°F	2/4	1. Enables BLOCK switches to allow the operator to block high steam flow ESF actuation. 2. Input to high steam flow ESF actuation logic. 3. Removes arming signal for steam dump operation. Operator may bypass the interlock on the three cooldown valves.
P-13	Turbine At-Power Permissive	Turbine power (impulse pressure) < 10%	2/2	Input to P-7
P-14	SG High Level Override	Steam generator narrow-range level > 69%	2/3 per SG on 1/4 SGs	1. Closes main feedwater regulating and bypass valves. 2. Trips all main feed pumps. 3. Trips main turbine. 4. Closes all main feedwater isolation valves.

Table 12.2-3 Summary of Control-Grade Interlocks

Number	Name	Setpoint	Coincidence	Interlocks	Functions
C-1	Intermediate Range High Flux Rod Stop	Intermediate range power > current equivalent to 20% power	1/2	Blocked when IR trip is blocked. Bypassed when IR trip is bypassed.	Stops control rod outward motion (manual & automatic).
C-2	Power Range High Flux Rod Stop	Power range power > 103%	1/4	Individual channel can be bypassed at local cabinet.	Stops control rod outward motion (manual & automatic).
C-3	OTΔT Rod Stop & Runback	Loop ΔT > (OTΔT reactor trip setpoint - 3%)	2/4	None	Stops control rod outward motion (manual & automatic) and initiates a turbine runback.
C-4	OPΔT Rod Stop & Runback	Loop ΔT > (OPΔT reactor trip setpoint - 3%)	2/4	None	Stops control rod outward motion (manual & automatic) and initiates a turbine runback.
C-5	Low Power Interlock	Turbine power (impulse pressure) < 15%	1/1 (one channel assigned)	None	Stops control rod outward motion in automatic only.
C-7	Loss of Load	Turbine power (impulse pressure) reduction > 10% step or 5%/min ramp	1/1 (one channel assigned)	Seals in. Must be reset.	Arms steam dumps in T_{avg} mode (loss-of-load controller).
C-8 (Plant with P-9 does not have)	Turbine Tripped	Trip valves closed, or Westinghouse: auto-stop oil pressure <45 psig GE: trip header pressure < 800 psig	1. 4/4 2.a, b 2/3	Reactor trip (see function 2) disabled if P-7 satisfied.	Arms steam dumps in T_{avg} mode (turbine-trip controller) and Trips the reactor.

Table 12.2-3 (cont'd)
Summary of Control-Grade Interlocks

Number	Name	Setpoint	Coincidence	Interlocks	Functions
C-9	Condenser Available Interlock	1. Condenser vacuum > 22 in. Hg, and 2. Condenser circulating water pump breaker closed	1. 2/2 2. 1/2	None	Ensures condenser is available for steam dump operation.
C-11	Control Bank D Withdrawal Interlock	Control bank D pulse-to-analog converter output >223 steps	1/1	None	Stops outward rod motion in automatic only.

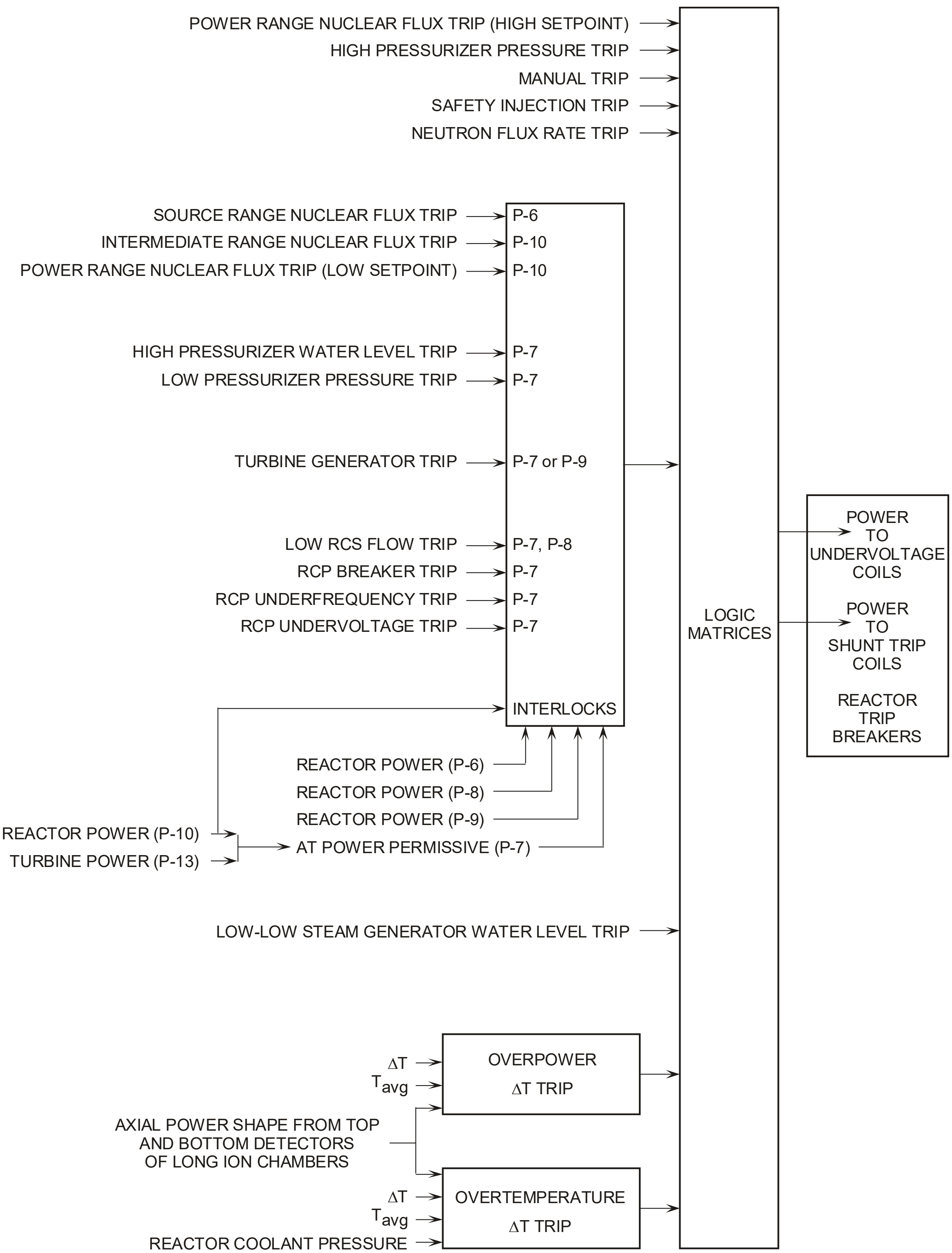


Figure 12.2-1 Reactor Protection System Block Diagram

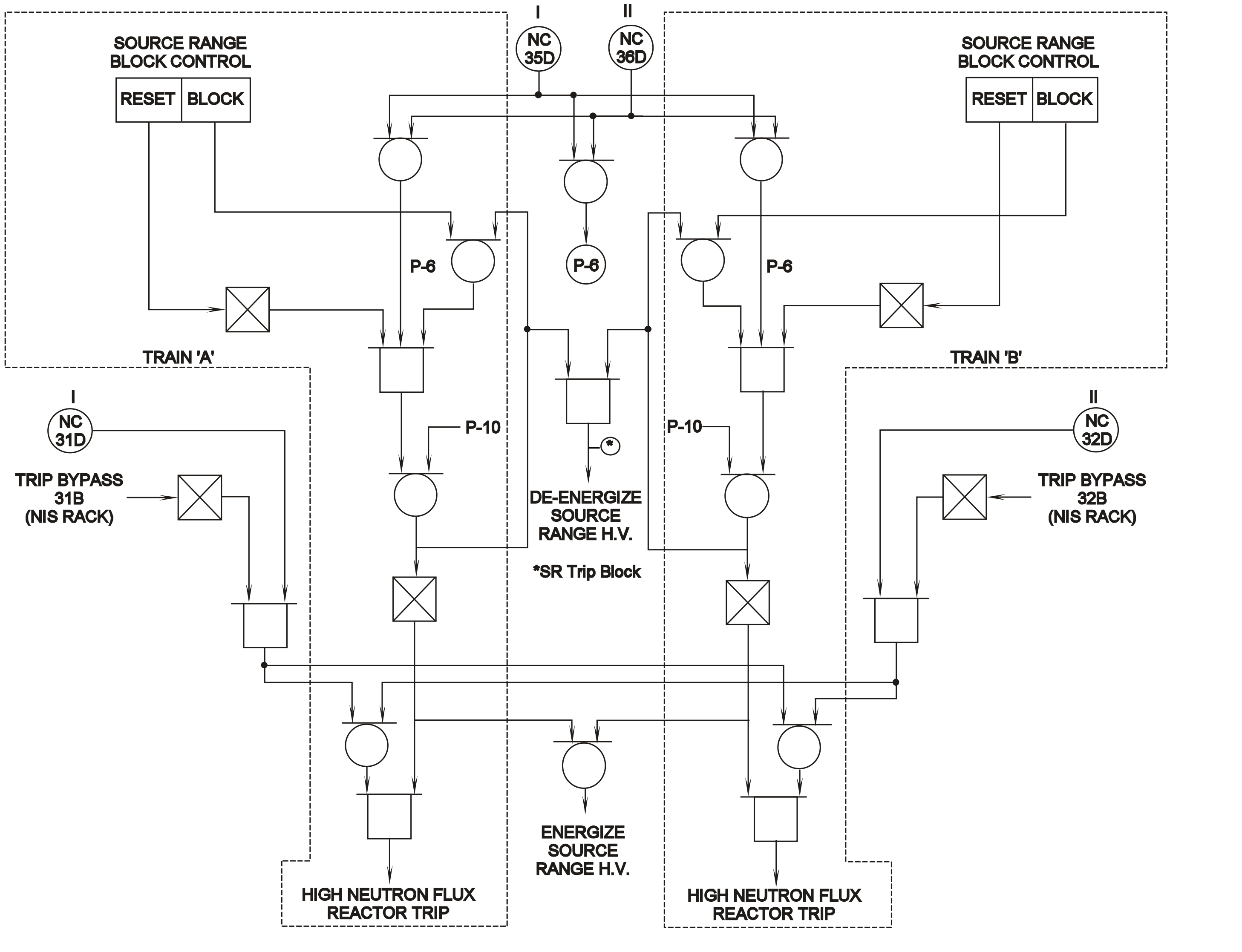
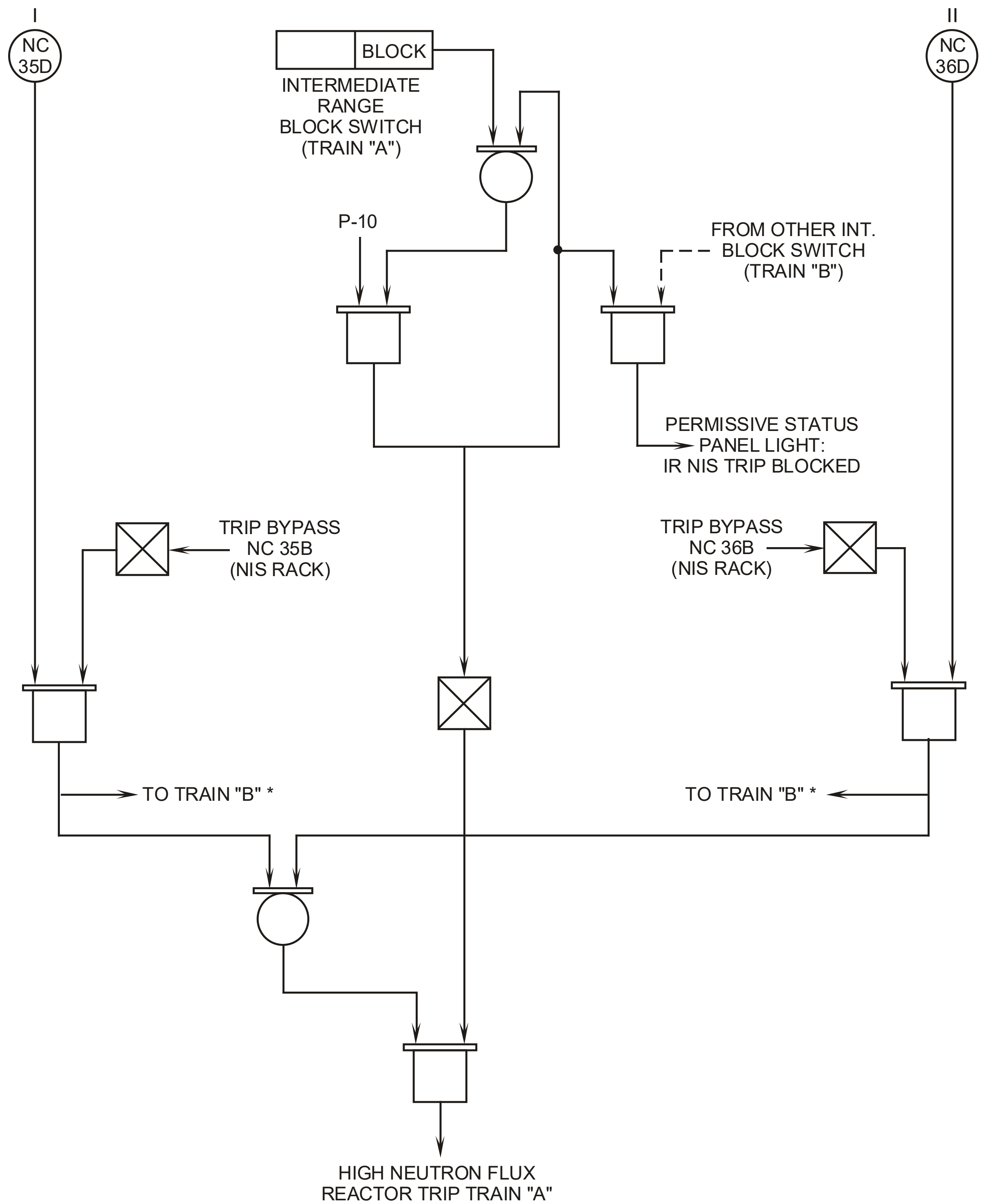


Figure 12.2-2 Source Range Reactor Trip Logic



* TRIP LOGIC DEVELOPMENT SIMILAR TO FIGURE 12.2-2

Figure 12.2-3   Intermediate Range Reactor Trip Logic

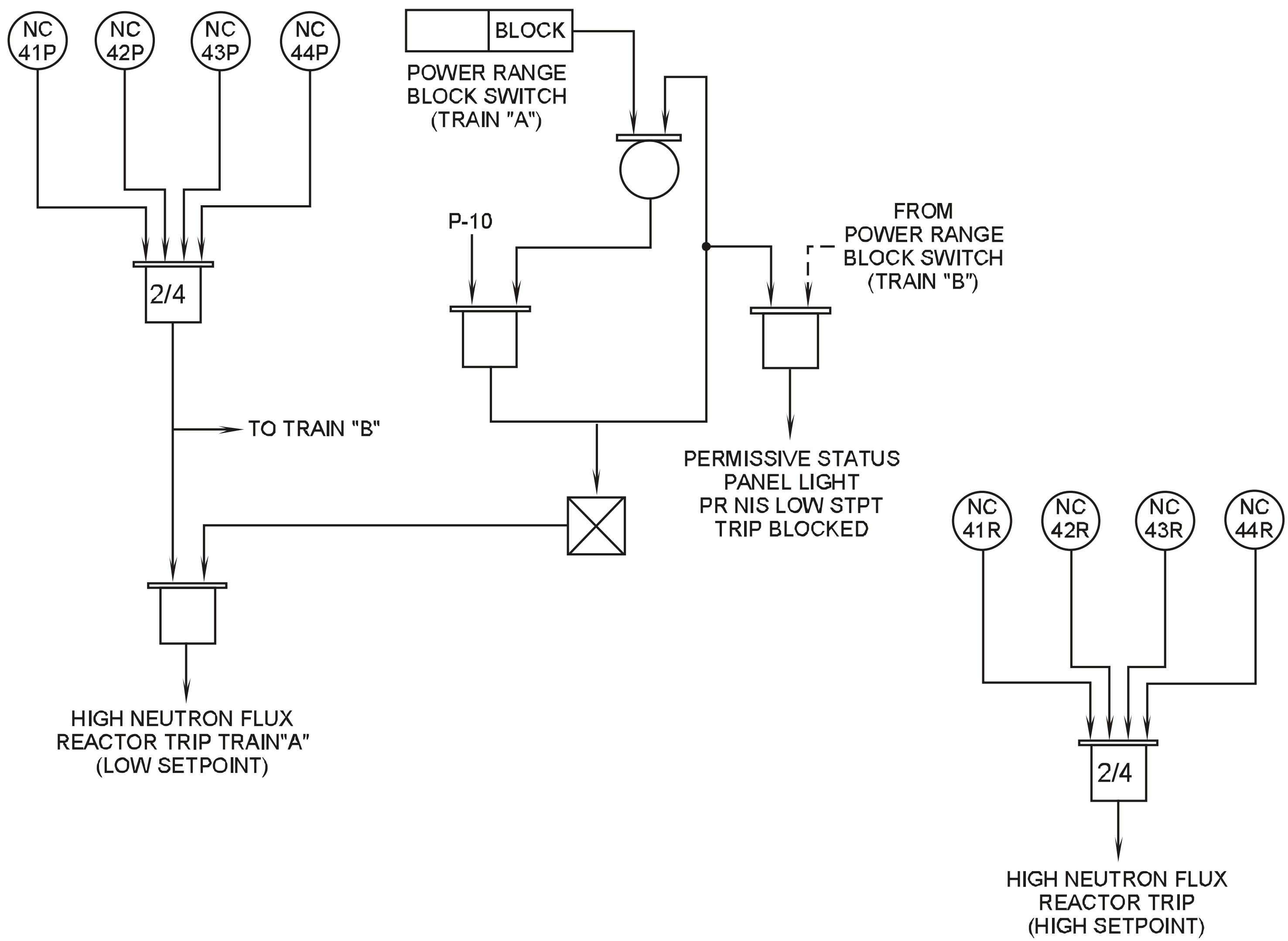


Figure 12.2-4 Power Range Reactor Trip Logic

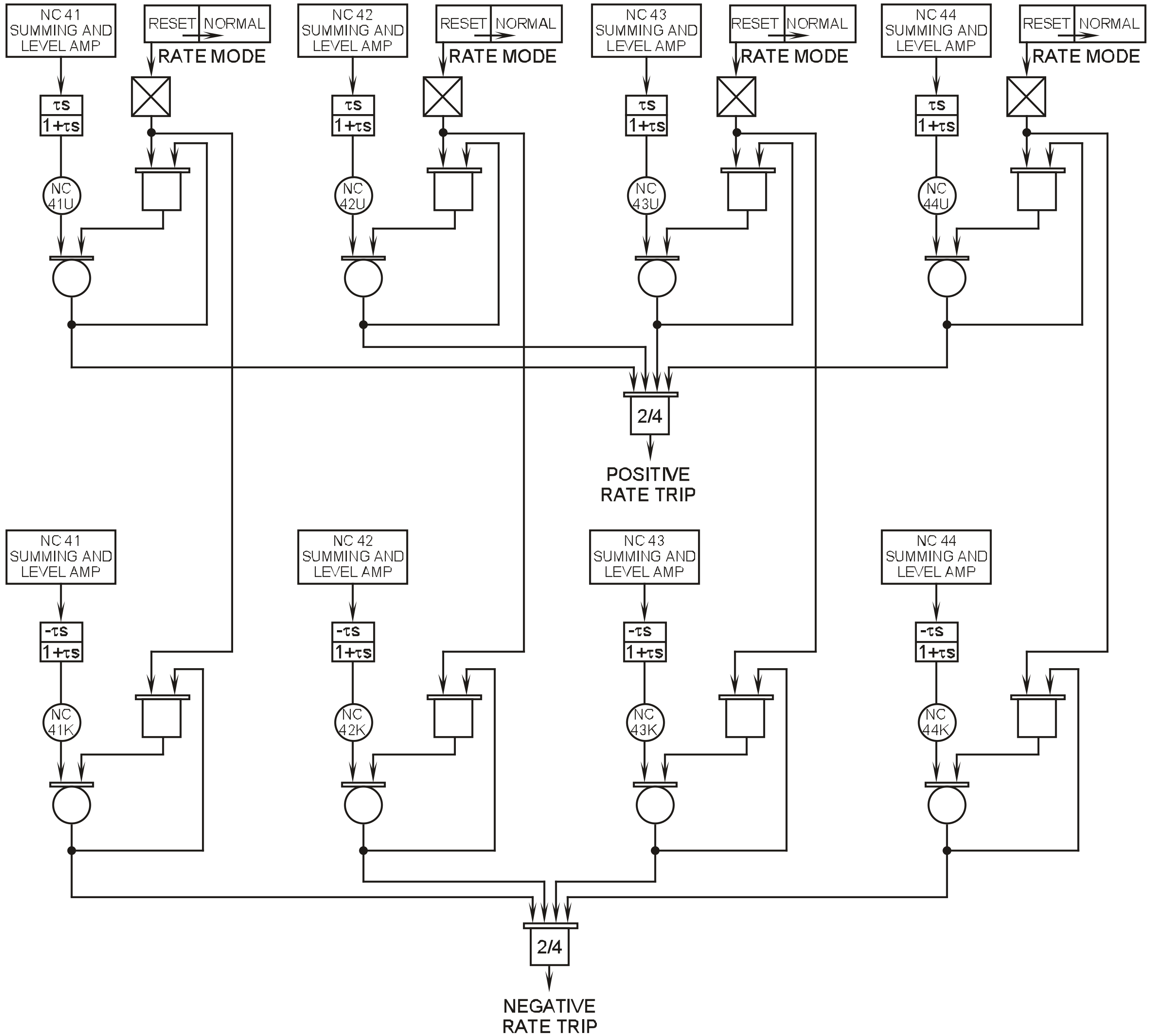


Figure 12.2-5 Power Range Flux Rate Trips

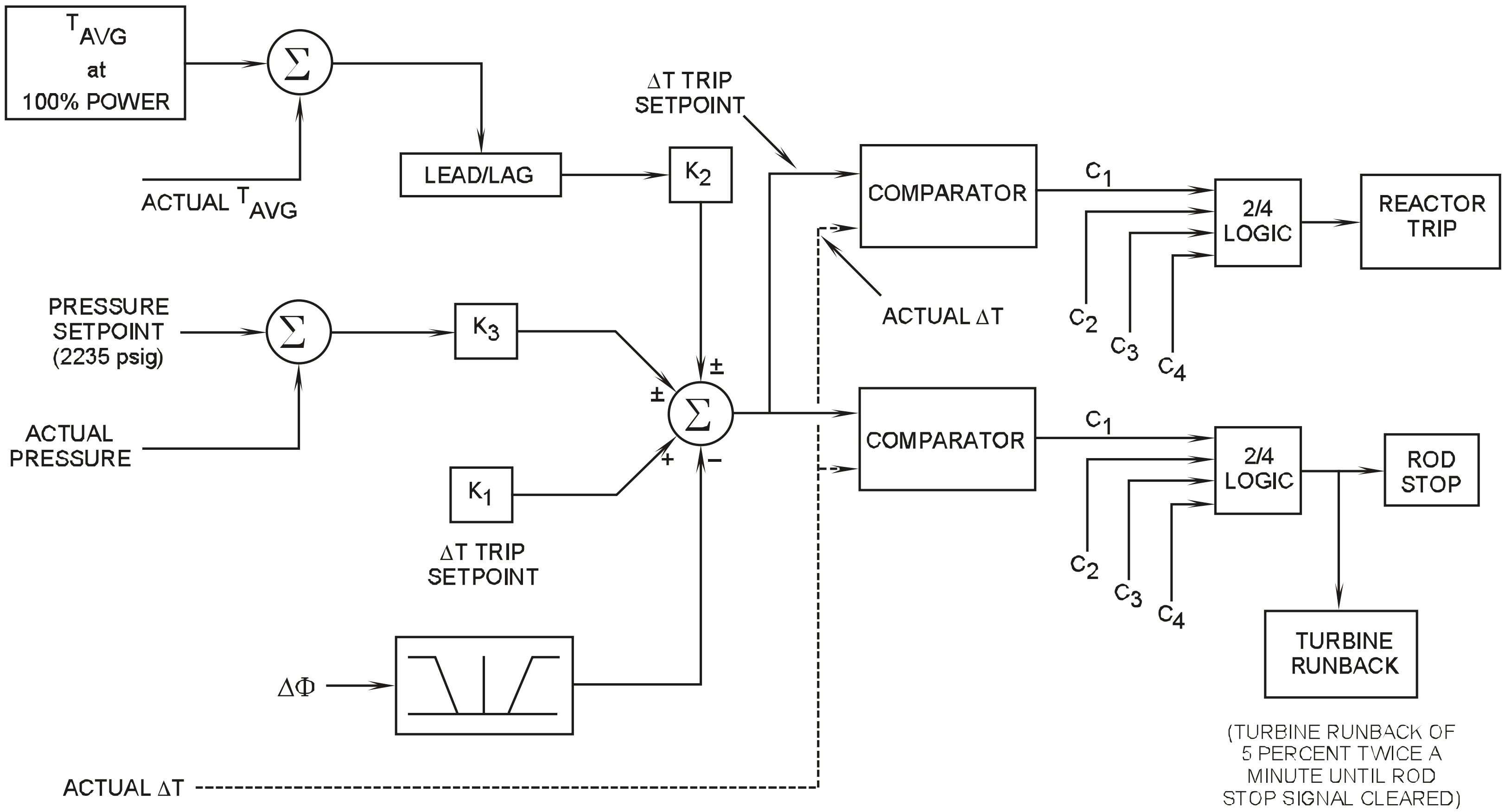


Figure 12.2-6 Overtemperature ΔT Channel Block Diagram

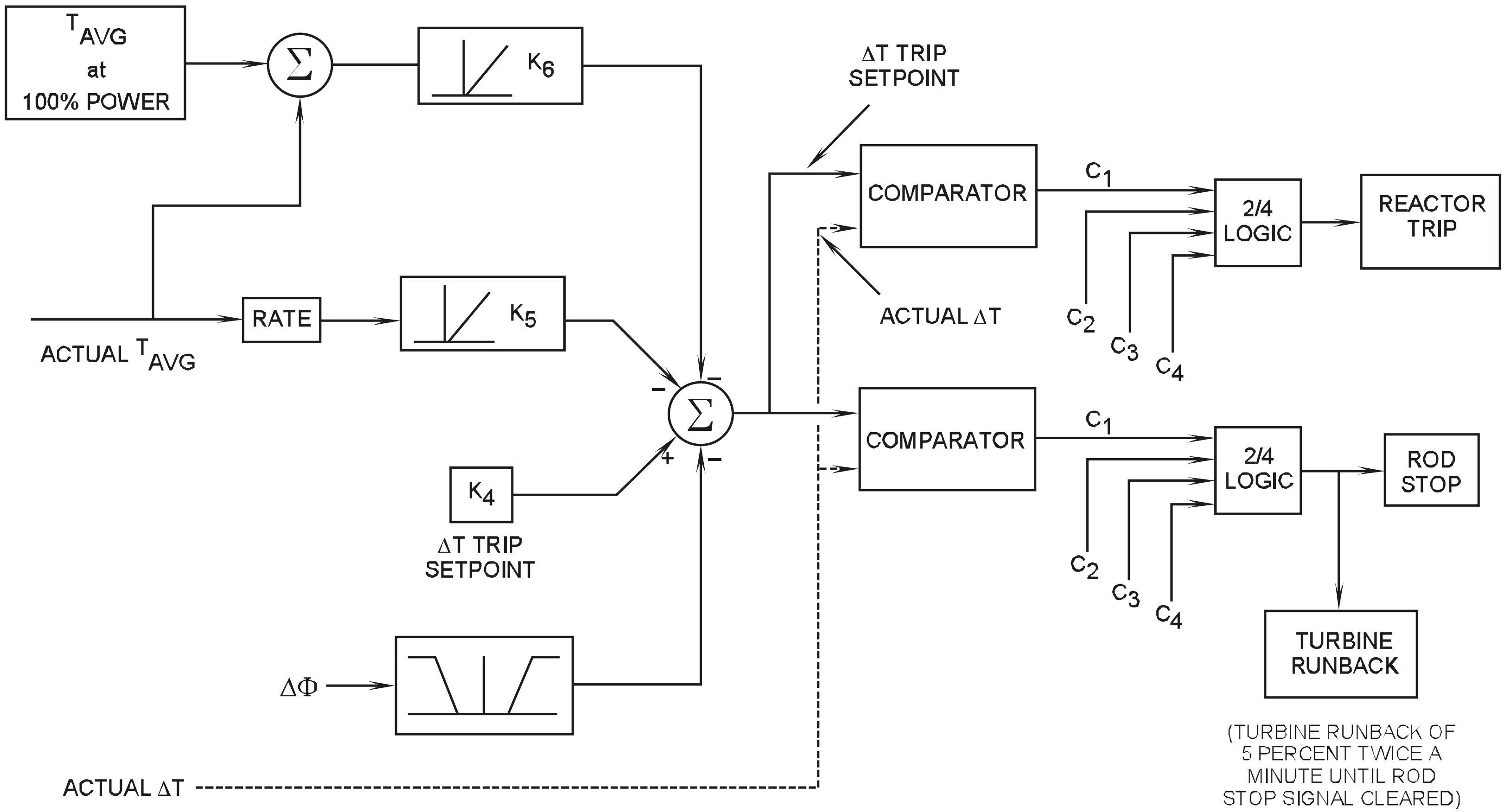


Figure 12.2-7 Overpower ΔT Channel Block Diagram

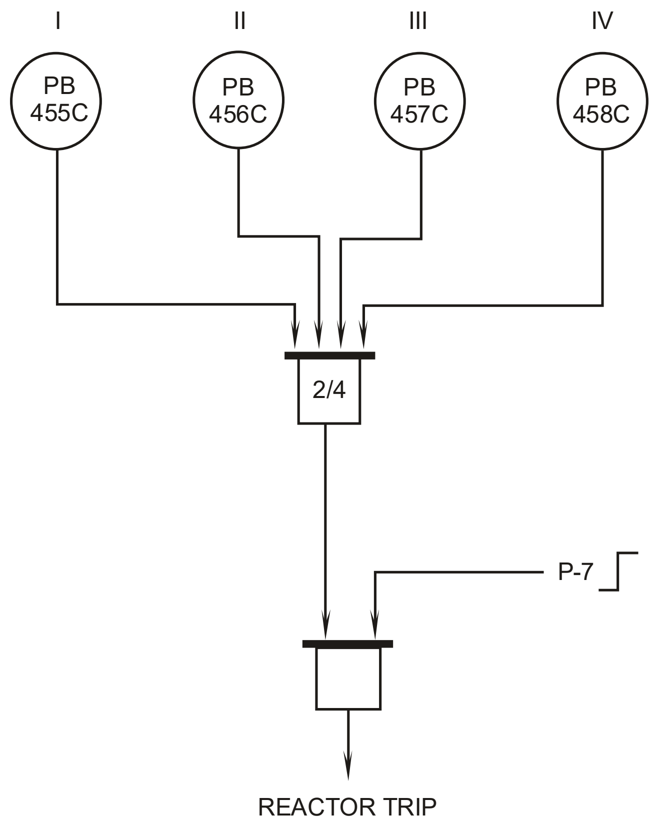


Figure 12.2-8 Pressurizer Low Pressure Reactor Trip

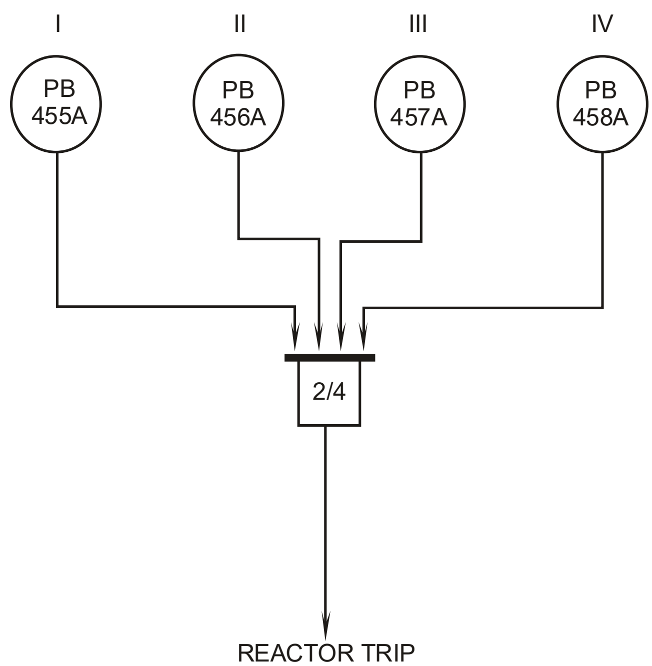


Figure 12.2-9 Pressurizer High Pressure Reactor Trip

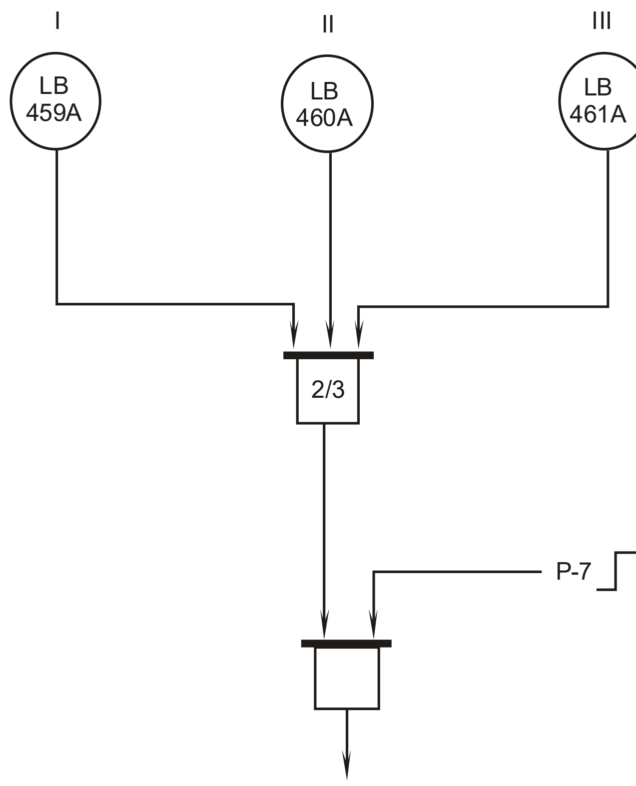


Figure 12.2-10 Pressurizer High Water Level Reactor Trip

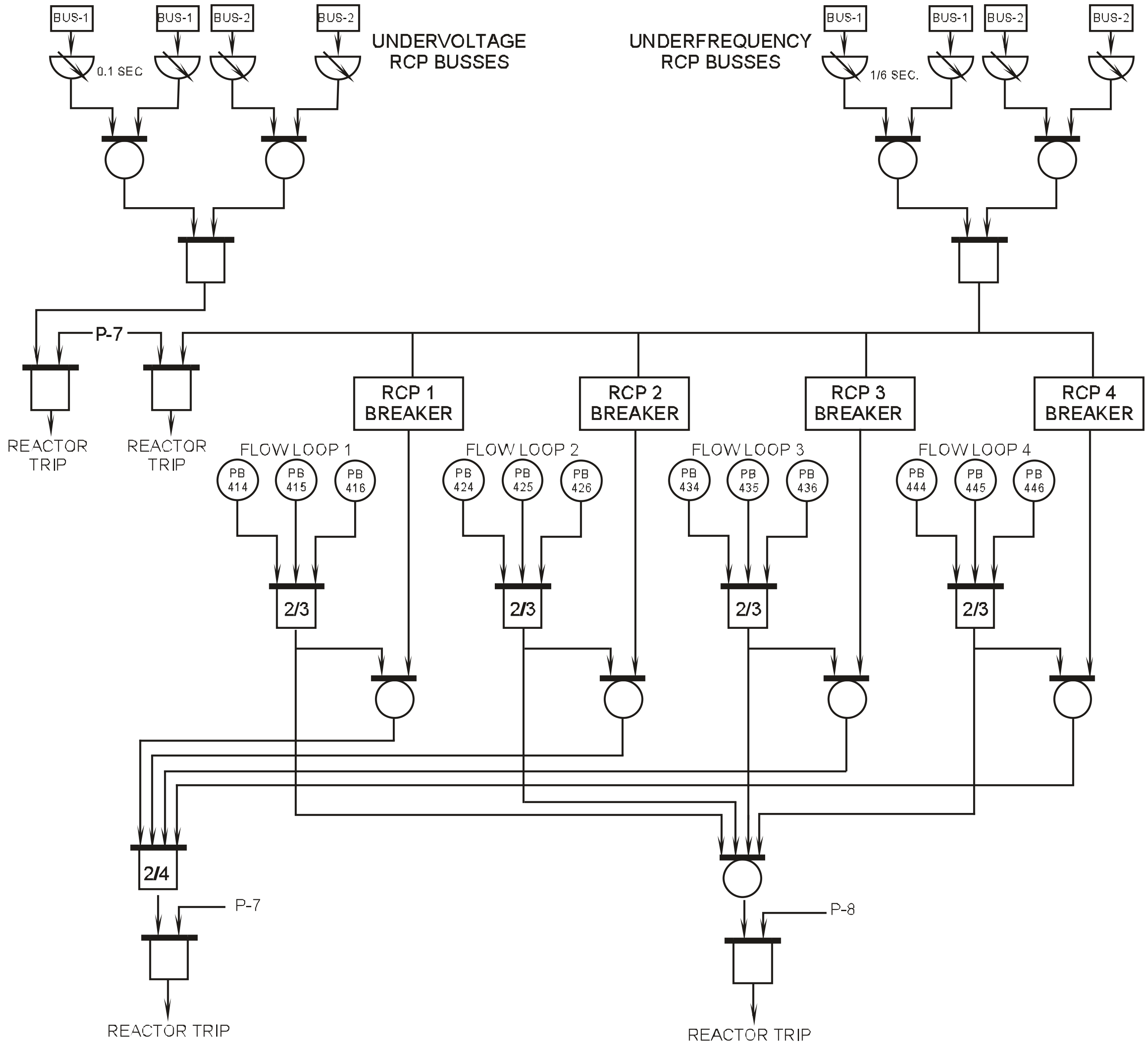


Figure 12.2-11 Low Flow Trips

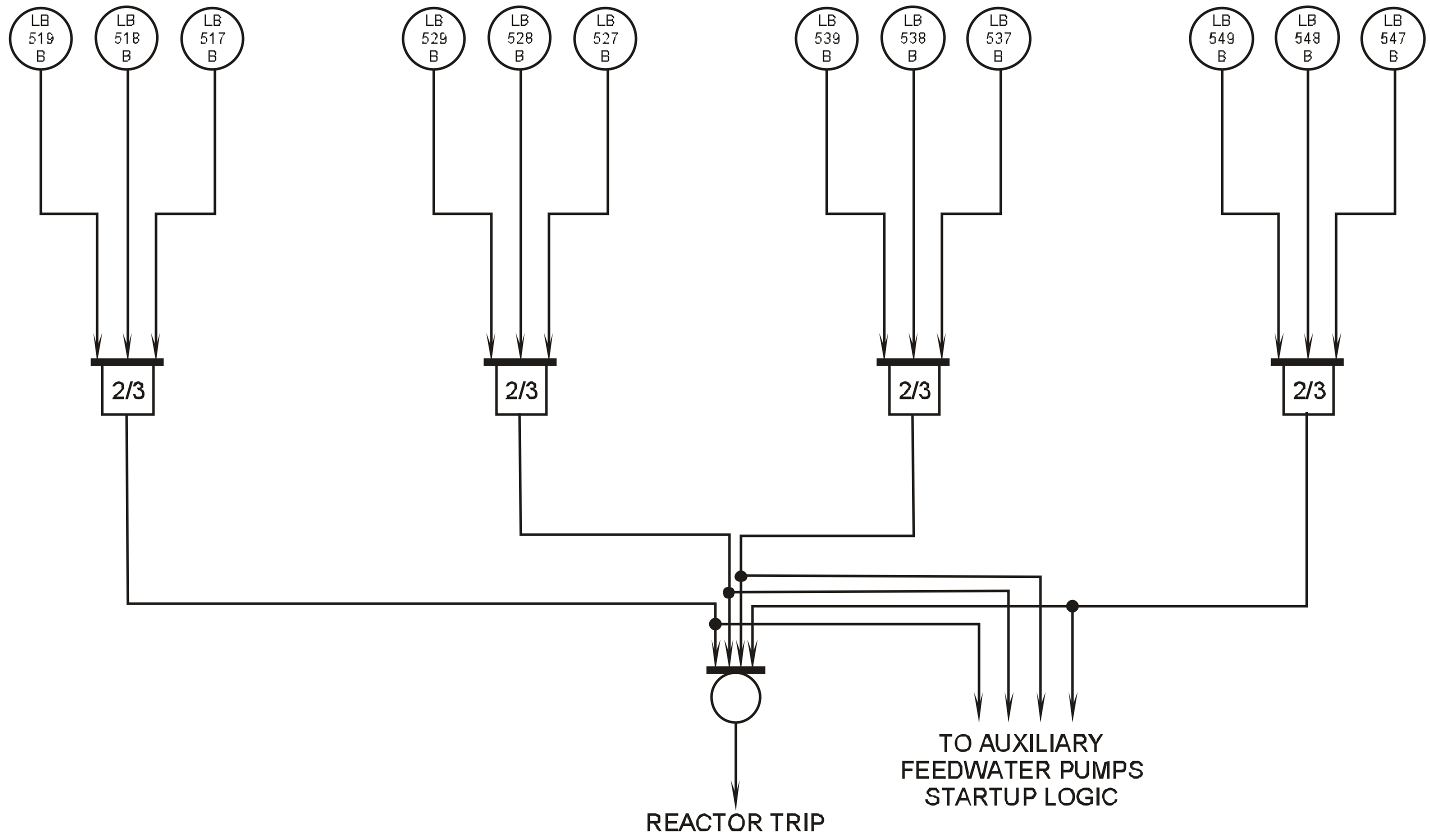


Figure 12.2-12 Steam Generator Low-Low Water Level Reactor Trip

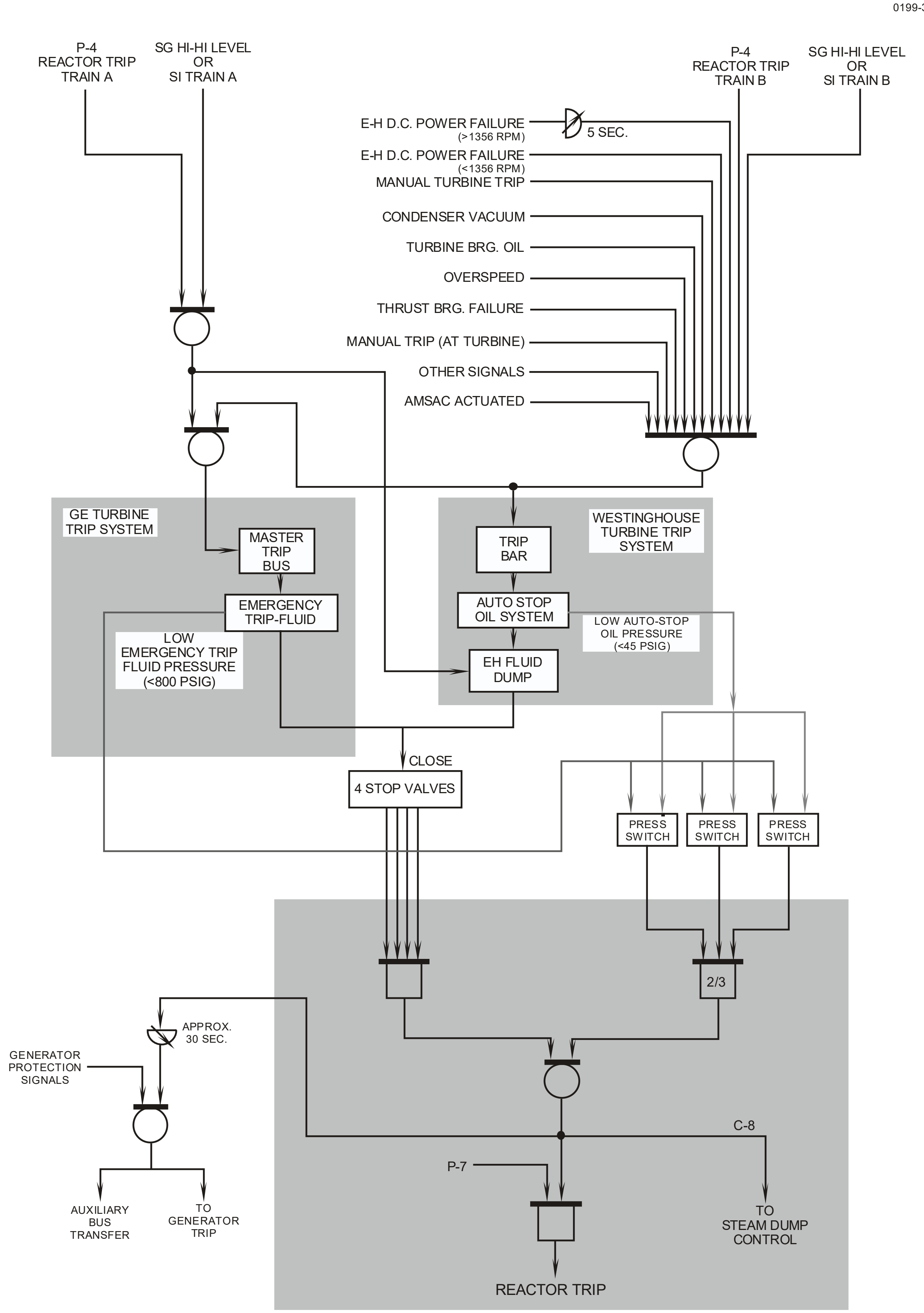


Figure 12.2.13 Turbine Trip – Reactor Trip

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Section 12.3

<u>Reactor Protection System (RPS)–</u>
<u>Engineered Safety Features Actuation Signals (ESFAS)</u>

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12.3 REACTOR PROTECTION SYSTEM (RPS) - ENGINEERED SAFETY FEATURES ACTUATION SIGNALS (ESFAS)

Learning Objectives:

1. List the engineered safety features (ESF) actuation signals and the accident(s) or conditions which will initiate each one.
2. List the systems or components that are actuated or realigned by each engineered safety features actuation signal.
3. Describe the effects of resetting a safety injection actuation signal and how the reset signal is removed.

12.3.1 Introduction

The Engineered Safety Features Actuation Signals (ESFAS) actuate or realign safety-related systems, equipment, and/or components and to isolate nonsafety-related systems in response to accidents. Various parameters are monitored by plant instrumentation to determine whether an accident or other condition requiring protective action has occurred. In the Reactor Protection System (RPS), multiple analog signals for each monitored parameter are compared to bistable setpoints. When enough signals in an appropriate combination have exceeded their respective setpoints, the RPS generates the necessary protective actions.

Each ESF protective function discussed in this section has a set of actuating signals and a set of plant equipment responses. The ESF functions include:

- Safety Injection Actuation (SIAS),
- Containment Spray Actuation (CSAS),
- Containment Isolation (CIS),
- Main Steam Line Isolation (MSLIS),
- Feedwater Isolation (FWIS), and
- Auxiliary FeedWater Actuation (AFAS).

When the RPS senses a condition requiring an ESF actuation, it energizes the appropriate master relay(s), as shown in Figure 12.3-2. Each ESF protective function has an associated master relay or set of master relays. Each master relay operates contacts which energize up to four slave relays. The slave relays actuate ESF equipment through control devices such as valve positioners and motor controllers.

An important feature of the ESF actuation circuitry is the maintenance of independence and redundancy. These features are accomplished by having each separate, independent protection train actuate only those systems and components associated with that train. That is, protection train “A” controls the “A” train ESF equipment such as the “A” train diesel generator, the “A” train residual heat removal (RHR) pump, the “A” train Safety Injection (SI) pump, and the “A” train isolation and flow control valves. Protection train “B” controls all the train “B” equipment. Since all the safety equipment is fully redundant, a single operable train is required to mitigate the consequences of an accident and to provide protection for the public health and safety. Either protection train may operate a component when it is not assigned to either train.

12.3.2 Safety Injection (SI) Actuation

The RPS automatically initiates a Safety Injection (SI) actuation to limit the consequences of infrequent faults (Condition III events) and limiting faults (Condition IV events) to reduce the potential for a significant release of radioactive material to the environment.

The SI actuation functions to shut down the reactor if it is still operating, to maintain the reactor in a shutdown condition, to provide sufficient core cooling to limit possible cladding and fuel damage, to ensure the integrity of the containment, and to place plant support systems in appropriate post-accident alignments. Figure 12.3-1 illustrates the SI actuation signals and the ESF systems affected by the SI actuation. Each actuation signal and the accidents to which each signal is designed to respond are discussed in section 12.3.2.1.

If the RPS senses conditions associated with either a Loss Of Coolant Accident (LOCA) or a secondary system (steam line or feed line) break, it initiates an SI actuation. Either of these accidents requires the operation of various safety features to ensure the safety of the public and to limit core damage. Regardless of the accident, the response of plant equipment to the SI actuation includes:

1. Placing the plant in a safe shutdown configuration, including tripping the reactor and injecting borated water into the reactor coolant system,
2. Providing cool, borated water at a rate sufficient to prevent excessive core damage following a LOCA,
3. Isolating the containment from the outside environment to limit the amount of radioactive effluent releases.
4. Providing a heat sink to remove the residual heat of the reactor core during the injection phase of the accident and to remove decay heat for the long term, and
5. Providing a reliable source of emergency power (running diesel generators) in the event that the preferred source of power is lost.

12.3.2.1 Safety Injection Actuation Signals (SIAS)

The SI actuation signals are discussed in the following paragraphs. The signals are summarized in Table 12.3-1.

Low Pressurizer Pressure

The logic for the low pressurizer pressure SI actuation is shown in Figure 12.3-4. The actuation setpoint is 1807 psig, with a coincidence of two-out-of-three channels. This SI actuation signal is designed to respond to the drop in reactor coolant pressure which accompanies inventory loss during a LOCA. A steam line break could also trigger this actuation signal due to the decrease in primary pressure resulting from coolant contraction. During a normal cooldown and depressurization of the plant, this signal is manually blocked when pressurizer pressure drops below 1915 psig on two-out-of-three channels (the P-11 permissive).

High Containment Pressure

The high containment pressure SI actuation signal, shown in Figure 12.3-5, is designed to serve as a backup protection signal in response to any High Energy Line Break (HELB), primary or secondary, inside the containment. Also, the high containment pressure signal would initiate an SI actuation if the break is large enough to cause a sufficient increase in containment pressure, but not large enough to trigger an SI actuation from any other signal. The setpoint for this protection signal is 3.5 psig. This SI actuation signal cannot be blocked by the operator.

High Steam Line Flow Coincident with Either Low Steam Line Pressure or Low-Low T_{avg}

The combination of high steam line flow in conjunction with either low steam pressure or low-low T_{avg} arises when a steam line break occurs downstream of the Main Steam Line Isolation Valves (MSIVs) and check valves. A steam line break at this location is common to all steam generators. It causes a steam flow increase and a steam pressure decrease in each main steam line. The increased steam flow increases the heat removal from the reactor coolant and thus reduces the reactor coolant temperature (T_{avg}). As shown in Figure 12.3-6, the high steam flow setpoint is a function of turbine impulse pressure, allowing it to vary with plant power. In addition to initiating an SI actuation, this signal initiates isolation of the steam lines (see section 12.3.5).

The control room operator may manually block the portion of the actuation signal that inputs to the Safety Injection actuation logic, as shown in Figure 12.3-6. Permissive P-12 (T_{avg} < 553°F) provides an input into the logic that allows the control room operator to block this signal. Blocking this signal allows the operating staff to cool down and depressurize the plant without inadvertently actuating an SI. It should be noted that ONLY the SI actuation portion of the logic can be blocked and that the Main Steam Line Isolation function remains unaffected by the block signal. As stated, the block function allows for plant cooldown while recognizing that a Main Steam Line break can occur at reduced pressures/temperatures and that the Steam Line Isolation function remains needed for steam line break protection.

High Steam Line Differential Pressure

This actuation signal is indicative of a steam line break upstream of the MSIVs and main steam check valves. With this break location, the pressure in the affected steam line pressure drops to a value significantly lower than the pressures of the other steam lines when the affected steam line's check valve seats. If the pressure in the affected steam line is 100 psi lower than the pressure in at least two of the remaining three steam lines, as shown in Figure 12.3-7, the necessary coincidence for this actuating signal is satisfied. This SI actuation signal cannot be blocked by the operator.

Manual

The manual function allows the operator to initiate an SI actuation (from either of two main control board locations) at any time.

12.3.2.2 Safety Injection (SI) Functions

When an SI actuation is initiated, as shown in Figure 12.3-1, by any of the previously described signals, various actions are completed to place the plant in a safe shut-down configuration. The specific actions that occur are as follows:

1. Reactor Trip: A trip shuts down the reactor if one has not already occurred.
2. Emergency Core Cooling System (ECCS) actuation: The discharge of the centrifugal charging pumps is realigned from the normal charging path of the chemical and volume control system to the high head cold-leg injection path. The suctions of the charging pumps are realigned from the volume control tank to the Refueling Water Storage Tank (RWST). In addition, the SI actuation starts the Centrifugal Charging Pumps (CCPs) (one may already have been running), the Safety Injection Pumps (SIPs), and the Residual Heat Removal (RHR) pumps. The RHR and SI systems are normally aligned to inject borated water from the RWST into the reactor coolant system cold legs. Refer to Section 5.2 for detailed descriptions of these systems.
3. Containment Isolation Phase A: Refer to section 12.3.4.1.
4. Auxiliary FeedWater (AFW) Actuation: The AFW system provides a reliable, safety-grade source of water to the steam generators to ensure that a reactor heat sink is available.
5. Main FeedWater (MFW) Isolation: Refer to section 12.3.6.
6. Emergency Diesel Generator (EDG) startup: The diesel generators are the emergency power source for the engineered safety features. They are started by any SI actuation, regardless of the status of offsite power. The diesel generators run unloaded if offsite power is maintained. If the preferred power source (offsite power) is lost, the diesel generator output breakers automatically close onto the dead class IE buses.
7. Auxiliary cooling system alignment: The Service Water System (SWS) and the Component Cooling Water (CCW) system automatically realign to their emergency configurations. In addition, start signals are sent to pumps in each system.
8. Control Room Ventilation Isolation (CRVIS): The normal ventilation supply to the control room is isolated to prevent the entry of smoke or radioactivity from the auxiliary building. In addition, the control room emergency ventilation system, which recirculates control room air through filters and charcoal adsorbers, is actuated.
9. Containment ventilation isolation: The containment purge supply and exhaust systems and the hydrogen vent system, if operating, are isolated by the SI actuation as part of isolating the containment from the environment.

12.3.2.3 SI Actuation Reset

As shown in Figure 12.3-3, an automatic SI actuation places a retentive memory device in the “ON” position. In the “ON” position, energized relay K1 closes two K1 contacts in the retentive memory circuit. One K1 contact provides power to the output relays, and the other K1 contact completes an alternate power-supply circuit for relay K1. This means that the protective functions described above continue to receive an actuation signal even if the original SI signal clears.

The control room operator cannot interrupt any of the SI-initiated functions until the reset logic is satisfied. This “locking out” of the operator prevents the interruption of a valid SI actuation. Additionally, the Design Basis Accident (DBA) sequencers initiate many of the SI functions; interrupting the start sequence before it is finished could leave some systems incorrectly aligned.

To prevent the interruption of any SI actuation, the reset logic must be satisfied before the reactor operator can manually reset (turn off) the SI actuation signal. When the retentive memory is turned on (relay K1 in Figure 12.3-3 energizes), the K1 contact in the reset circuit closes, thus starting the energizing sequence for the time delay relay (relay TD). The time delay relay produces an output (energizes) some time after it is started (usually 45 - 60 sec). After the time delay relay times out, it energizes and closes the TD contact in the reset circuit. This action, along with the P4 contact being closed by the reactor trip (permissive P-4 is described in Section 12.2), allows the operator to reset (turn off) the SI actuation signal by depressing the control room reset pushbutton. The time delay ensures that all system and component realignments are complete prior to the SI reset.

As shown in Figure 12.3-3, closing the TD contact and depressing the reset pushbutton energize relay R1 and thus close an “a” contact (labeled R1), which is located in the reset circuit in parallel with the reset pushbutton. After this contact closes, the control room operator can release the reset pushbutton without de-energizing the R1 relay. The reset signal is thus maintained.

Relay R1 also opens two “b” contacts. One of these “b” contacts is located in the time delay circuit. Opening this contact (labeled R1) de-energizes the TD relay. Simultaneously opening the other “b” contact (also labeled R1) in the retentive memory portion of the circuit de-energizes relay K1, thereby removing power from the output relays. As long as the R1 relay remains energized, the retentive memory is in the “OFF” position, and all automatic SI actuation signals are blocked.

As described in the preceding paragraphs, resetting the SI actuation places the retentive memory device in the “OFF” position. Removing the “ON” signal from the SI actuation circuitry does not turn off any ESF equipment, realign any valves, or change any functions initiated by the SI actuation. When the operator depresses the reset pushbutton, the only response is the removal of the start signal. However, after turning off the actuation circuitry the control room operators can change system alignments, start or stop equipment as needed, and control the plant as required by the plant’s emergency operating procedures to recover from the accident (or SI actuation conditions).

As mentioned above, a significant feature of the SI actuation reset is that the reset blocks any further automatic SI actuations. However, a manual SI actuation is still available. If the control room operator depresses either of the two manual SI actuation pushbuttons located in the main control room, relay K2 energizes. When this relay energizes, it closes contact K2 in the “ON” side of the retentive memory and thus energizes relay K1. This action provides power to the output relays (actuates the ESF loads). Meanwhile, “b” contact K2 opens in the “OFF” side of the retentive memory. When it opens, it de-energizes relay R1, which closes “b” contact

R1 in the “ON” side of the retentive memory. With this contact closed, relay K1 remains energized after the operator releases the manual SI actuation pushbutton.

De-energizing the R1 relay also simultaneously opens the R1 contact in parallel with the reset pushbutton and closes the R1 contact in the time delay relay circuit. The operator is again prevented from resetting the actuation until the time delay relay times out.

After the control room operator resets the SI actuation, all automatic SI actuation signals are disabled until the control room operator manually initiates an SI actuation or until the reactor trip input to the reset circuit (permissive P-4) is cleared by closing the reactor trip breakers. Before closing the reactor trip breakers, the operator should ensure that all SI actuation signals have cleared. Otherwise, when the control room operator closes the reactor trip breakers and removes the reset signal, the actuation sequence restarts.

12.3.3 Containment Spray (CS) Actuation

12.3.3.1 Containment Spray Actuation Signals (CSAS)

The Containment Spray (CS) system is automatically actuated by a high-high containment pressure signal, as shown in Figure 12.3-5. The setpoint is 30 psig. A very high containment pressure is indicative of a large line break; operation of the containment spray system is needed to reduce the containment temperature and pressure. The containment spray system can also be manually actuated. The actuation signals are summarized in Table 12.3-1.

12.3.3.2 Containment Spray Actuation Functions

A Containment Spray Actuation Signal starts the Containment Spray Pumps (CSPs), opens the spray header isolation valves, and aligns the spray additive tank to the suctions of the pumps. Starting the spray pumps also requires initiation of the DBA sequencers by an SI actuation. Refer to Section 5.4 for additional details concerning the containment spray system.

12.3.4 Containment Isolation Signals (CIS)

12.3.4.1 Containment Isolation Signal Phase A (CIS A)

Phase A Actuation Signals

Containment Isolation Phase A is automatically actuated by a Safety Injection actuation. Most containment penetrations are thus isolated when there is evidence of an accident in progress, so that the potential release of radioactivity to the environment is minimized. A Phase A isolation can also be manually actuated. The actuation signals are summarized in Table 12.3-1.

Phase A Functions

Redundant isolation valves and dampers (one inside containment, one outside containment) are shut in all non-essential lines which penetrate the containment. The containment penetrations which remain unisolated are the CCW supply and return lines for the Reactor Coolant Pumps (RCPs) and the main steam lines.

Continued forced circulation of coolant by the RCPs, although not essential for safe shutdown of the plant, is the preferred method of decay heat removal. CCW flow to the RCP heat exchangers is thus maintained even during an accident, unless the CCW isolation valves are closed by a containment isolation Phase B signal (see Section 12.3.4.2).

The Main Steam Isolation Valves (MSIVs) are not closed by a Phase A isolation so that steam flow to the steam dump system is available for core decay heat removal. The MSIVs are automatically closed by a Main Steam Line Isolation actuation (MLIS) (see Section 12.3.5).

12.3.4.2 Containment Isolation Signal Phase B (CIS B)

Phase B Actuation Signals

Containment Isolation Phase B is automatically actuated by a high-high containment pressure signal. Phase B isolation should be simultaneous with containment spray actuation. Phase B isolation is manually actuated when Containment Spray (CS) is manually actuated. The actuation signals are summarized in Table 12.3-1.

Phase B Functions

A Phase B isolation shuts the isolation valves in the CCW supply and return lines to the RCPs. Together with isolation of the main steam lines (see Section 12.3.5), a Phase B isolation completes isolation of containment penetrations when there is a large break inside containment.

12.3.5 Main Steam Line Isolation

12.3.5.1 Main Steam Line Isolation Signals (MSLIS)

The main steam lines are isolated by (1) a high-high containment pressure signal or (2) high steam flow coincident with low-low T_{avg} or low steam pressure. Together with a containment isolation Phase B (see Section 12.3.4.2), the first main steam line isolation signal completes isolation of containment penetrations when there is a large break inside containment. The second signal isolates the steam lines when there is evidence of a steam line break downstream of the MSIVs; this action should isolate the break from the steam generators and end its effects on the plant. Note that, as shown in Figure 12.3-6, manually blocking the high steam flow SI actuation does not block the high steam flow steam line isolation. The actuation signals are summarized in Table 12.3-1.

12.3.5.2 Main Steam Line Isolation Functions

A steam line isolation actuation closes all Main Steam Line Isolation Valves (MSIVs), all MSIV bypass valves, and all main steam line high pressure drain valves.

12.3.6 Main Feedwater (MFW) Isolation

12.3.6.1 Feedwater Isolation Signals (FWIS)

Main FeedWater (MFW) to the steam generators is automatically isolated by each of the following signals:

- Low T_{avg} (564°F) coincident with a reactor trip (permissive P-4),
- High steam generator water level (permissive P-14) in any generator, and
- SI actuation.

Isolating MFW in response to these signals provides the following benefits:

1. Overcooling of the reactor coolant by excessive MFW to the Steam Generators (SGs) should be avoided. In response to the large prolonged “shrink” in steam generator levels following a reactor trip, the Steam Generator Water Level Control (SGWLC) system develops large feed flow demands; without MFW isolation the main feedwater regulating valves would supply relatively cold feedwater to the generators at a very high rate.
2. Completely filling the steam generators and introducing water into the steam piping should be avoided.
3. The non-Seismic Category I portion of the feedwater piping is isolated from seismically qualified equipment needed for decay heat removal during an accident.

The actuation signals are summarized in Table 12.3-1.

Figure 12.3-8, Feedwater Isolation Signal Logic, shows the signals which will initiate a Feedwater Isolation. Note that the FW Isolation Signa (FWIS)l can be reset as long no SI signal is present or SI is blocked (SI Reset and P4, Figure 12.3-1) and no Hi/Hi SG level is present. If a Reactor Trip (P4) and Low Tavg Signal are present, depressing the FW Isolation Reset Pushbutton will reset the retentive memory, block the P4 and Low Tavg Signal, and seal in the reset circuit. If the Reactor Trip Breakers are closed (even momentarily), then the seal-in circuit will clear and the P4 and Low Tavg Signal can cause a subsequent isolation of feedwater.

12.3.6.2 Feedwater Isolation Functions

Any feedwater isolation signal trips both MFPs, closes all four main feedwater regulating valves, all four bypass regulating valves, and all eight feedwater isolation valves. The high steam generator water level and SI actuation signals also directly trip the main turbine.

12.3.7 Auxiliary Feedwater (AFW) Actuation

12.3.7.1 Auxiliary Feedwater Actuation Signals (AFAS)

The AFW system is automatically actuated by the following signals:

- SI actuation,
- Low-low steam generator water level in any generator,
- ESF bus undervoltage (train dependent - undervoltage on bus A1 starts the "A" train AFW pump; undervoltage on bus A2 starts the "B" train pump), and
- Trip of all main feed pumps.

(Note: Automatic AFW actuation by the ATWS mitigation system actuation circuitry is not listed here because that actuation signal is not generated by the RPS.) The above list indicates that the AFW system is actuated when the MFW system is not available or is not maintaining a sufficient heat sink, and to provide a safety-grade source of water for heat sink maintenance during an accident. The actuation signals are summarized in Table 12.3-1.

12.3.7.2 Auxiliary Feedwater Actuation Functions

An actuation signal to the "A" train (steam-driven) AFW pump opens all four steam supply valves (one from each main steam line) to the pump turbine and opens the turbine trip and throttle valve. An actuation signal to the "B" train (diesel-driven) pump starts the diesel engine and unisolates the service water line which provides cooling for several engine and pump heat loads. Any actuation signal to either AFW train closes all isolation valves in the steam generator blowdown and sampling lines.

12.3.8 Summary

The reactor protection system acts to limit the consequences of postulated accidents by actuating engineered safety features. These systems and components are actuated to place the plant in the most stable, safe shutdown condition possible following an accident. The ESF functions discussed in this section are safety injection actuation, containment spray actuation, containment isolation, steam line isolation, feedwater isolation, and AFW actuation.

TABLE 12.3-1 SUMMARY OF ESF ACTUATION SIGNALS

Signal	Coincidence	Setpoint	Interlocks	Accident/Condition
Safety Injection Actuation				
Low Pressurizer Pressure	2/3	1807 psig	Manual block; block enabled when pressurizer pressure < 1915 psig (P-11)	Loss-of-coolant accident (LOCA)
High Differential Pressure Between Steam lines	Any steam line 100 psi lower than at least two of the remaining three steam lines	100 psi ΔP	No Interlocks	Steam line break (SLB) upstream of the main steam line isolation valves (MSIVs)
High Steam Flow COINCIDENT WITH Low Steam Pressure OR Low-Low T_{avg}	1/2 flows on 2/4 steam lines 2/4 steam lines 2/4 RCS loops	Setpoint varies with turbine load (impulse pressure) 600 psig (Rate sensitive) 553°F	Manual block; block enabled when T_{avg} < 553°F (P-12)	SLB downstream of the MSIVs (common to all steam generators)
High Containment Pressure	2/3	3.5 psig	No Interlocks	High energy line break inside containment (LOCA or secondary pipe break)
Manual	1/2 actuation switches on main control board		No Interlocks	Operator backup to automatic actuation

TABLE 12.3-1 (cont'd)
SUMMARY OF ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Signal	Coincidence	Setpoint	Interlocks	Accident/Condition
Containment Spray Actuation Signal (SIAS)				
High-High Containment Pressure	2/4	30 psig	No Interlocks	Large high energy line break inside containment (LOCA or secondary pipe break)
Manual	Simultaneous 2/2 actuation switches on main control board		No Interlocks	Operator backup to automatic actuation
Containment Isolation Signal Phase A (CIS A)				
Any Safety Injection Actuation	Refer to Safety Injection Actuation portion of this table.			
Manual	1/2 actuation switches on main control board		No Interlocks	Operator backup to automatic actuation
Containment Isolation Signal Phase B (CIS B)				
High-High Containment Pressure	2/4	30 psig	No Interlocks	Large high energy line break inside containment (LOCA or secondary pipe break)
Manual	Actuated with manual actuation of containment spray		No Interlocks	Operator backup to automatic actuation

TABLE 12.3-1 (cont'd)
SUMMARY OF ENGINEERED SAFETY FEATURES ACTUATION SIGNALS

Signal	Coincidence	Setpoint	Interlocks	Accident/Condition
Main Steam Line Isolation Signal (MSLIS)				
High-High containment pressure	2/4	30 psig	No Interlocks	Large high energy line break inside containment (LOCA or secondary pipe break)
High Steam Flow COINCIDENT WITH Low Steam Pressure OR Low-Low T_{avg}	1/2 flows on 2/4 steam lines 2/4 steam lines 2/4 RCS loops	Setpoint varies with turbine load (impulse pressure) 600 psig 553°F	No interlocks	SLB downstream of the MSIVs (common to all steam generators)
Feed Water Isolation Signal (FWIS)				
Low T_{avg} COINCIDENT WITH Reactor Trip	2/4 RCS loops	564°F	P-4	Overcooling of reactor coolant following a reactor trip
High SG Water Level	2/3 levels on 1/4 SGs	69%	No Interlocks	SG overfill
Any Safety Injection Actuation	Refer to Safety Injection Actuation portion of this table.			
Auxiliary Feedwater Actuation Signal (AFAS)				
Low-Low SG Water Level	2/3 levels on 1/4 SGs	11.5%	Can be defeated at RPS cabinets	Loss of heat sink
Trip of All Main Feed Pumps	2/2		Can be defeated using switches on main control board	Loss of heat sink
ESF Bus Undervoltage	1/2 taken twice on either ESF bus	2560 V with 1.1-sec delay	No Interlocks	Need for decay heat removal without offsite power
Any Safety Injection Actuation	Refer to Safety Injection Actuation portion of this table.			

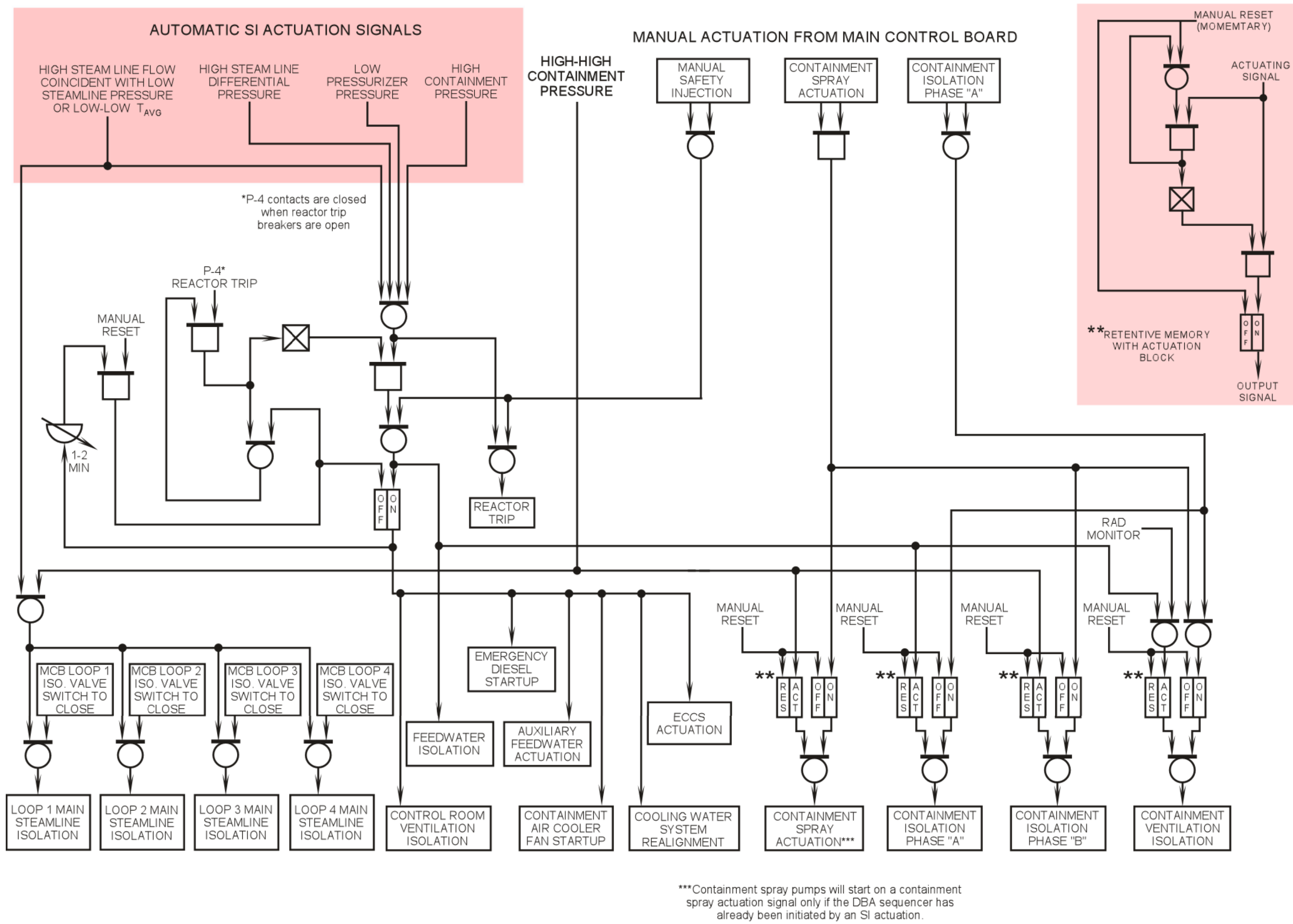


Figure 12.3-1 Engineered Safety Features Actuation Logic

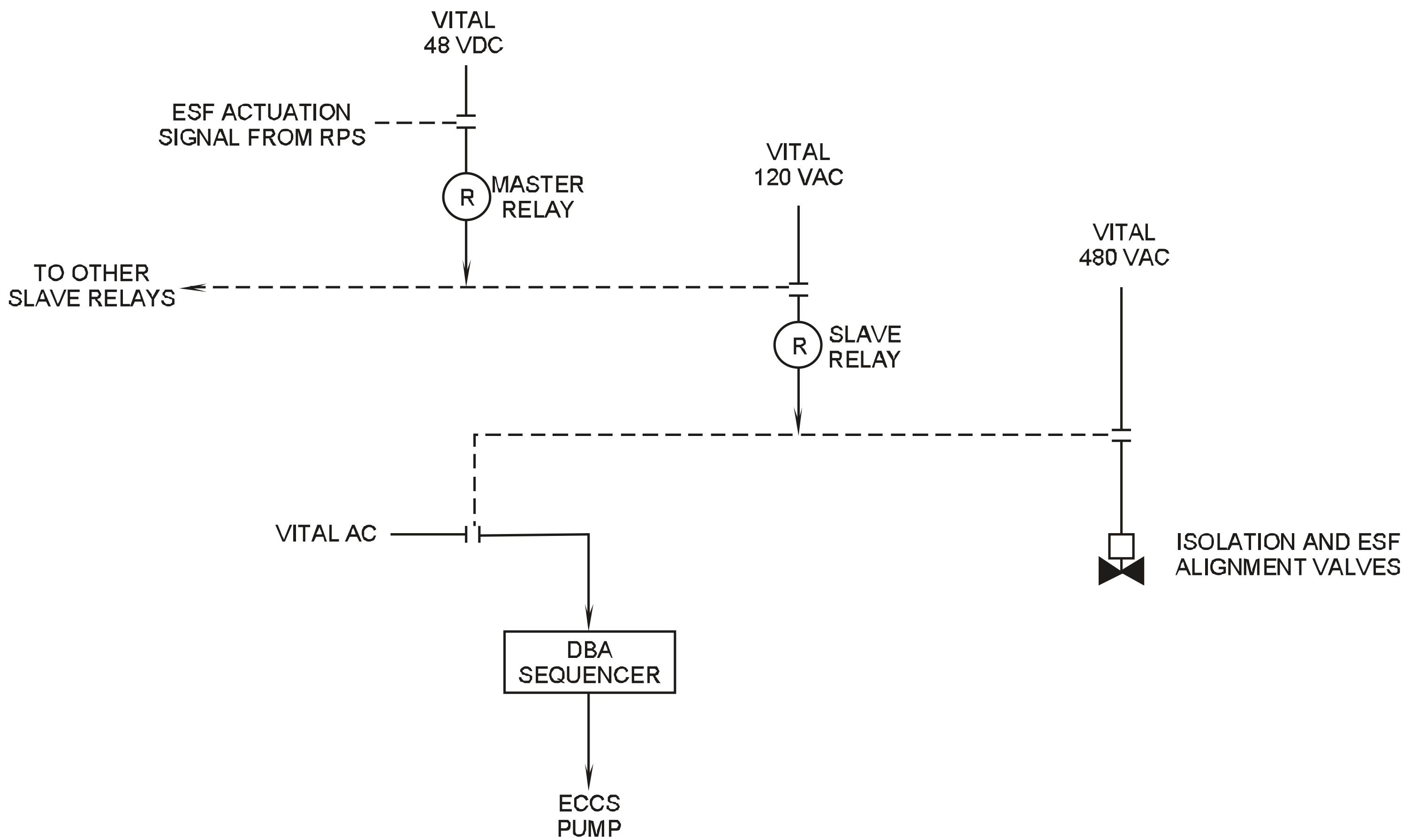


Figure 12.3-2 ESF Actuation Output Relay Operation

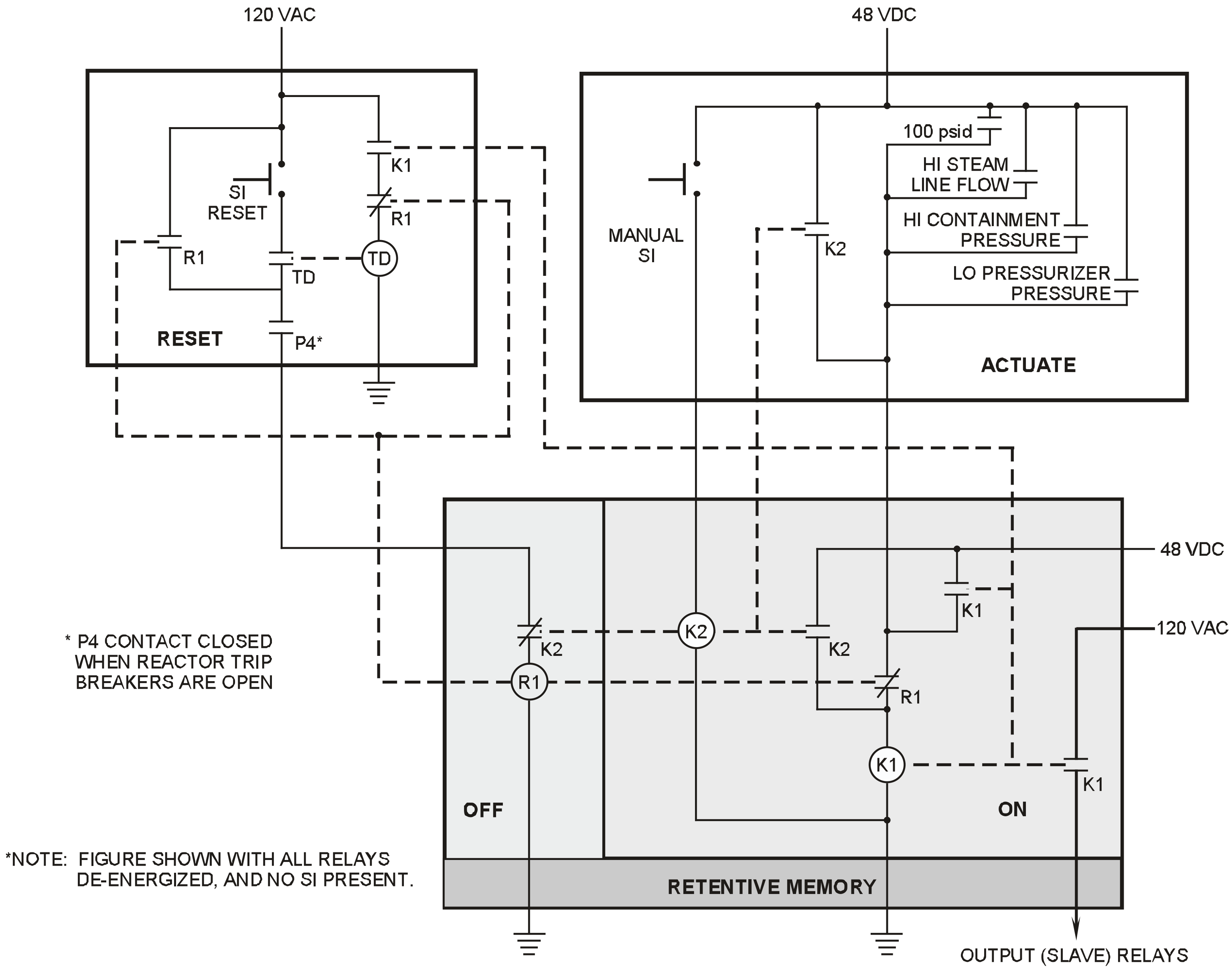


Figure 12.3-3 SI Actuation Retentive Memory and Reset Circuit

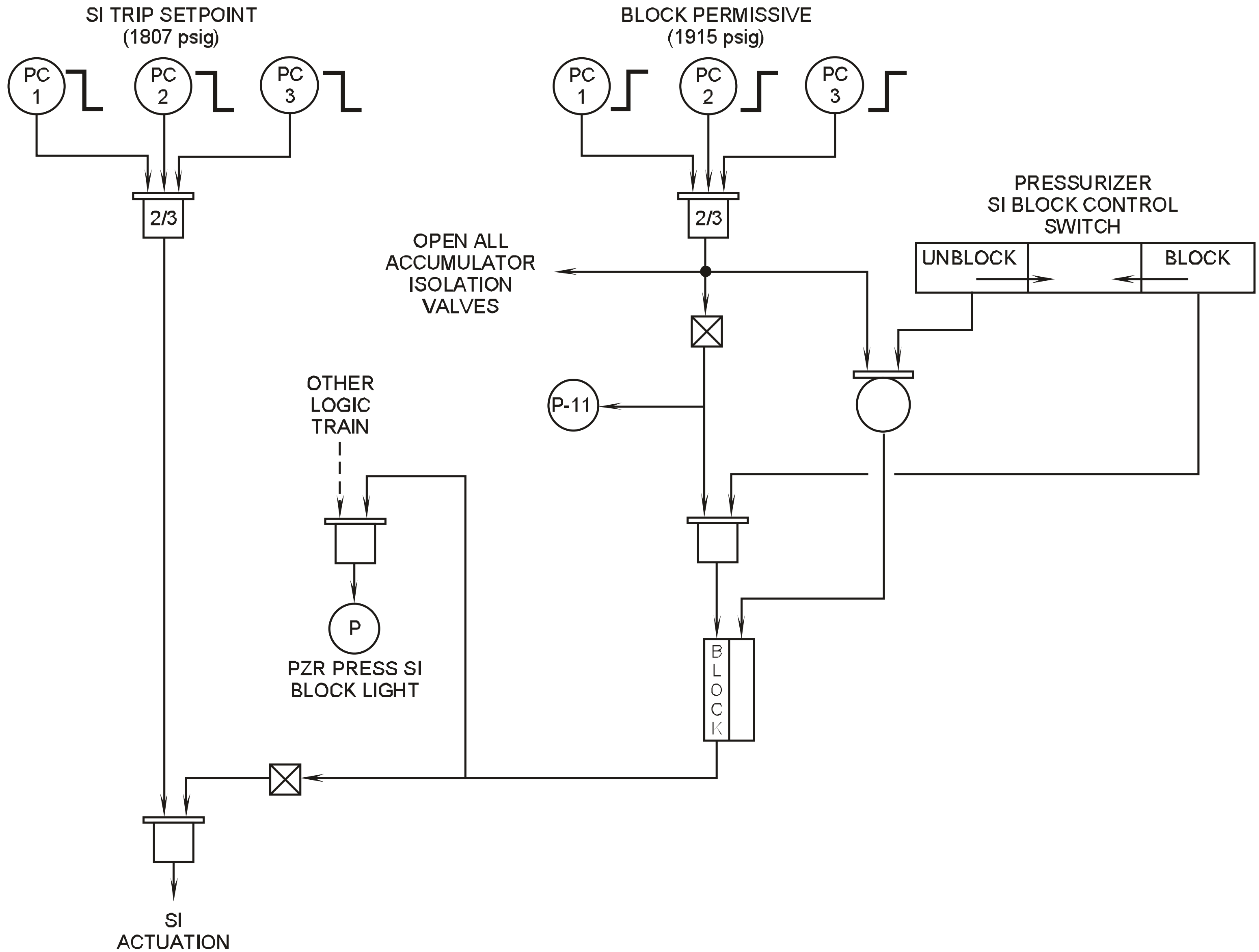
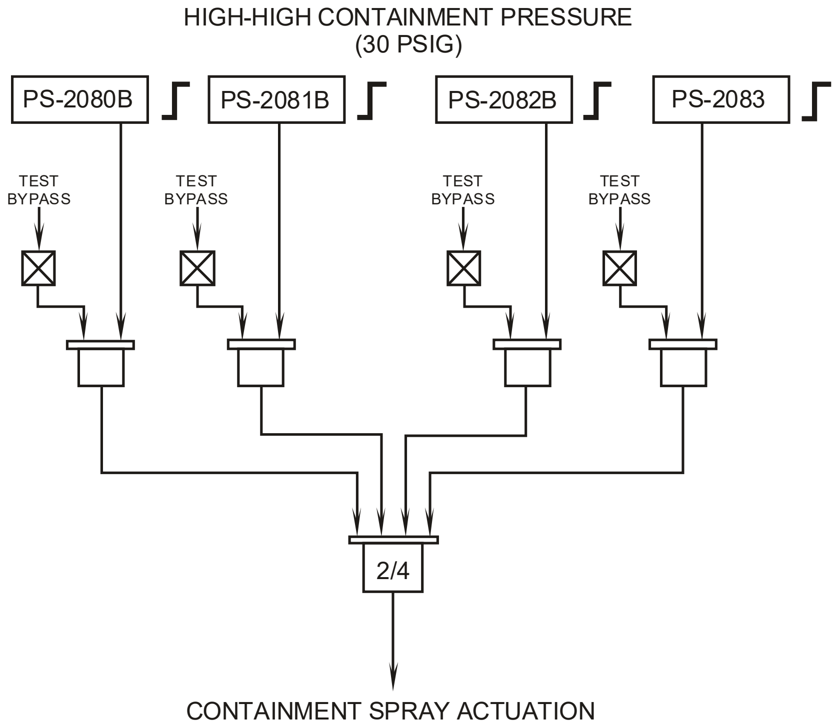


Figure 12.3-4 Low Pzr Pressure SI Actuation Logic



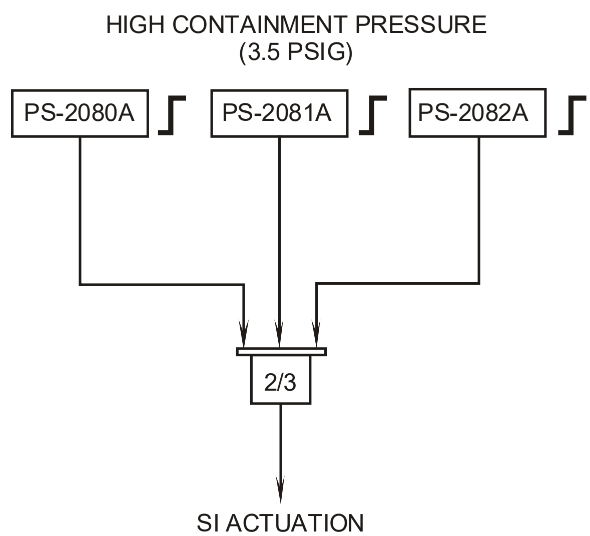


Figure 12.3-5 Containment Pressure ESF Actuation Logic

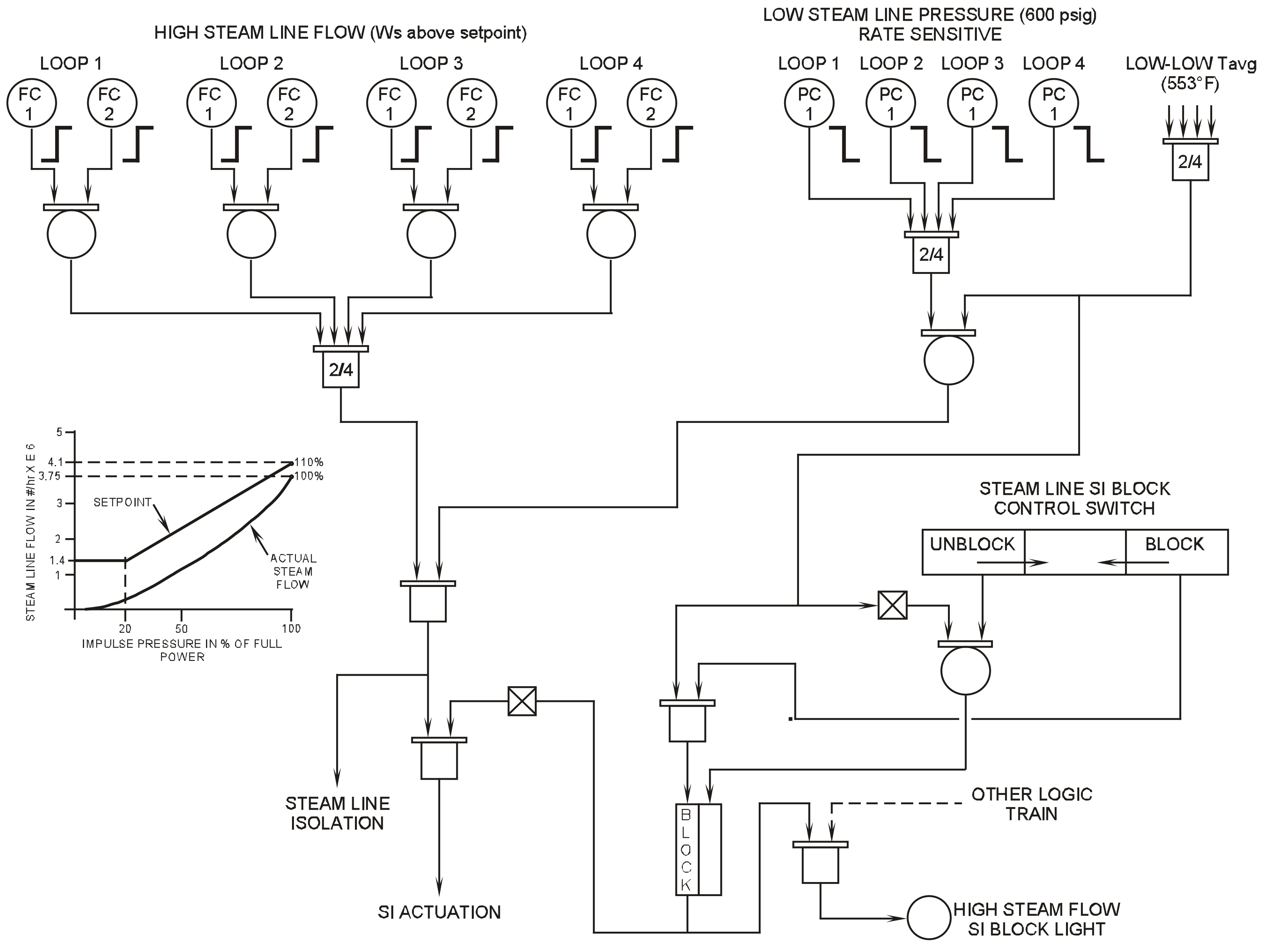


Figure 12.3-6 High Steam Line Flow ESF Actuation Logic

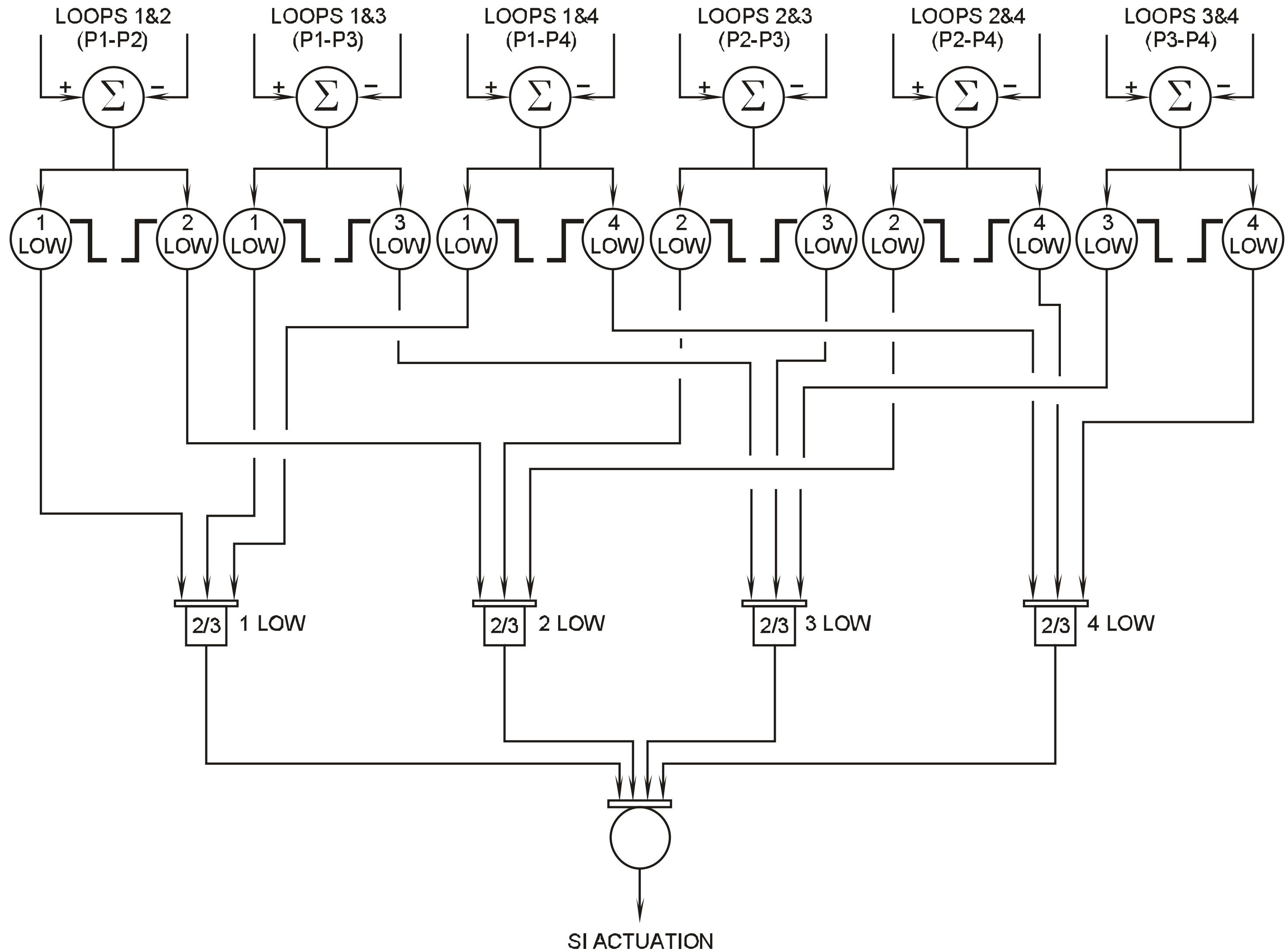


Figure 12.3-7 High Steamline ΔP SI Actuation Logic

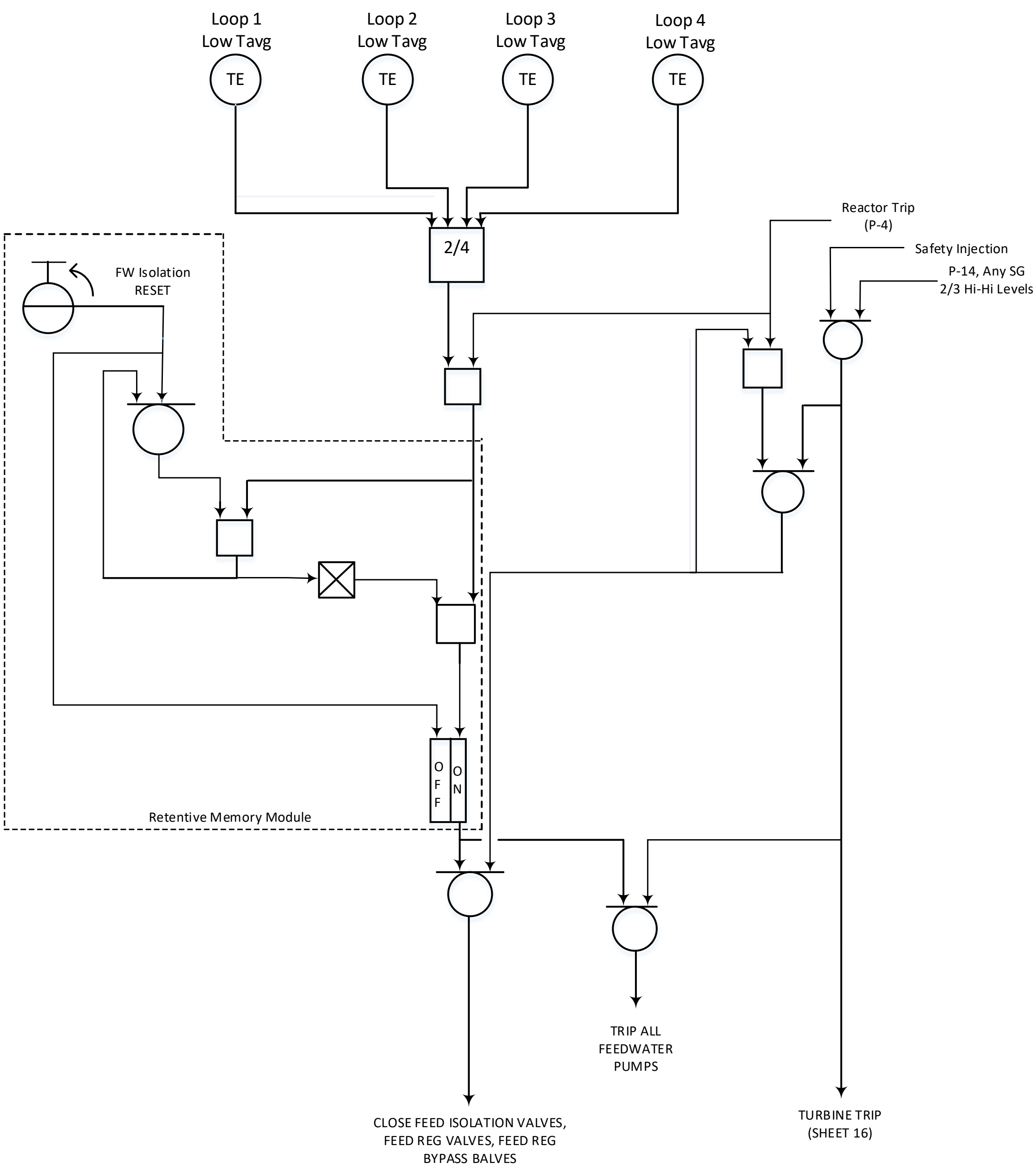


Figure 12.3-8 Feedwater Isolation Logic

Westinghouse Technology Systems Manual

Section 13.0

Instrument and Service Air System

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13.0 INSTRUMENT AND SERVICE AIR SYSTEM

Learning Objectives:

1. Explain the purpose of the instrument and service air system.

2. Describe the normal operation of the instrument and service air system.

3. Describe the plant response to, and how certain pneumatic components remain operable following, a loss of instrument air.

4. Describe the consequences of a loss of offsite power on the instrument and service air system.

13.1 Introduction

The compressed air system supplies compressed air requirements for pneumatic instruments, valves, and service air outlets throughout the plant. The compressed air system is not required for safe shutdown of the plant. The availability of compressed air is necessary for plant startup and normal operations at power, but following a loss of air pressure, pneumatically operated components should assume fail-safe positions which ensure the safe shutdown of the plant. Because the system supplies compressed air to many plant systems, a loss-of-air event can have severe consequences. Therefore, the system is designed with a high degree of reliability.

The compressed air system or instrument and service air system consists of three sections: air supply, instrument air distribution, and service air distribution. See Figure 13-1. In the air supply section of the system, the air compressors supply compressed air via aftercoolers to air receivers, where the air is stored before it is filtered and distributed throughout the plant. In the instrument air distribution section, the compressed air is filtered, dried, and supplied to the instrument air header, from which the dried air is provided to various loads throughout the plant. As illustrated in Figure 13-1, there are two trains of filters and air dryers; the in-service train continually dries the instrument air supply simultaneous with regeneration of the other train's dryer desiccant media. In the service air distribution section, the compressed air from the air supply section is supplied to the service air header, from which it is distributed to the service air loads throughout the plant.

13.2 System Description

The instrument and service air system takes air at atmospheric pressure and compresses it to 125 psig. The air is filtered and then supplied to the instrument and service air headers, from which it is directed to the plant loads. Each of the four air compressors provided in the system is sized to furnish the total average instrument air requirements plus an allowance for service air use.

The air supply section includes four air compressors, four aftercoolers, four air receivers, a dual train instrument filtering and drying unit, and one common alarm and control panel all located in the 45 ft elevation of the Turbine Building. Each air compressor takes suction on the turbine building atmosphere through its intake filter and compresses the air to 125 psig. The 100% capacity Sullair compressor is normally in service, with the three 50% capacity Joy air compressors in standby. The Joy air compressors start automatically on lowering air pressure, as measured by pressure switches downstream of the air receivers. Each operating compressor supplies air through an aftercooler, where the compressed air is cooled and entrained moisture is condensed and removed, to its associated air receiver. The air receiver acts as a storage tank for the air. As air is required by the loads, the air flows through the two filters. These filters remove particulates and aerosols entrained in the air. The filtered high pressure air is available for use by the instrument air and service air distribution sections.

The air supply section of the system also includes a diesel-driven air compressor, which serves as a backup to the motor-driven Sullair and Joy air compressors in the event of a loss of offsite power. The diesel-driven compressor can be manually aligned to two of the four air receivers.

Due to the delicate nature of the pneumatic devices supplied by the instrument air header, instrument air must be of a higher quality than that supplied to the service air loads. The instrument air distribution section thus provides additional filtering and drying of the compressed air via redundant trains of prefilters, air dryers, and afterfilters. A single train consisting of one prefilter, air dryer, and afterfilter is capable of handling the maximum air demand. Each of the two trains of instrument air filtering and drying components provided is sized to treat the normal maximum quantity of air required for instrument air requirements and deliver dry air having a dew point of -40°F or less at 125 psig.

The loads supplied by the service air distribution section (such as breathing air) are not as delicate as those supplied by the instrument air header, so service air does not require additional filtering and drying. High pressure air is supplied to the service air header through an inlet control valve (CV-4467). Pressure switch PS-4467 is installed in the instrument air header and is interlocked to close off the service header when the pressure in the instrument header falls below 80 psig. This will maintain the instrument air header pressure in the event of excessive service air demand or excessive leakage from the service air system. Local and remote indication and alarm devices are provided for monitoring the system. Isolation of the service air header is desirable because instrument air loads are of greater importance to plant operation than service air loads.

Plant areas and components supplied by the instrument and service air headers are listed in Figure 13-2. The compressed air piping system which furnishes air inside the containment is equipped with Containment isolation valving in accordance with the criteria for Containment Isolation System (CIS). All parts of the system, with the exception of the Containment penetrations, are designed to meet Seismic Category II requirements. The Containment isolation valves and piping between these valves are designed to meet Seismic Category I requirements.

13.3 Component Descriptions

13.3.1 Air Compressors

The four motor-driven air compressors are located in the turbine building. The normally in-service Sullair compressor (C-116) is a flood-lubricated screw type, positive displacement compressor rated to deliver 650 cfm (full capacity) at 125 psig discharge pressure. It normally maintains air pressure between 110 and 125 psig. Lubricating oil is supplied to the compressor to lubricate the rotors and cool the compressed air. The oil is cooled by bearing cooling water (BCW) in a heat exchanger. (The bearing cooling water system is a closed-cycle system that cools several loads in the turbine building and is itself cooled by service water.) This compressor is driven by a 150-hp motor powered from a 480-V nonvital bus. Pressure switch PS-4445 is provided for automatic control of compressor C-116 which is self-controlled and operated independently of compressors C-102A, B, and C.

The three half-capacity Joy air compressors (C-102A, B, and C) automatically operate as needed to maintain air pressure. The Joy air compressors are non-lubricated, vertical double-acting, single stage, water cooled, and v-belt driven compressors designed to provide 337 cfm at 125 psig discharge pressure. The heat generated by each compressor is removed by Bearing Cooling Water (BCW) in a water jacket that surrounds the unit. The compressors are driven by 100-hp motors powered from 480-V nonvital busses for compressors C-102A and C-102C, and a 480-V vital bus for compressor C-102B. Compressor C-102B is the only compressor of the four that is powered from a Class 1E source, thus providing some flexibility during an emergency condition in which nonvital load centers are de-energized. However, the dependence of this compressor on bearing cooling water (powered from nonvital sources) means that cooling water from a fire main must be supplied when only vital power is available. Pressure switches PS-4461, PS-4462, and PS-4463 are provided in the air receiver outlet header for automatic control of compressors C-102A, B, and C.

13.3.2 Aftercoolers

Each motor-driven compressor has an aftercooler, with the after cooler for the Sullair compressor being part of the Sullair skid. The Joy air compressor aftercoolers (E-18A, B, and C) are heat exchangers in which bearing cooling water cools the compressed air. The cooling of the air helps to condense any moisture that could cause equipment damage and aids in the removal of entrained oil by cooling and coalescing it. Condensed moisture and coalesced oil are removed from each aftercooler by a moisture separator and automatic condensate drain trap.

13.3.3 Air Receivers

Compressed air from the outlet of each after-cooler flows into its associated air receiver (T-160 & T-118A, B, and C). The air receivers reduce pressure pulsations from the compressor discharge lines and serve as storage volumes. They supply a limited amount of compressed air following a compressor failure. The Sullair compressor's receiver has a capacity of 96 ft^3, and each of the three Joy motor driven air compressors have a receiver with a capacity of 57 ft^3.

13.3.4 Service and Instrument Air Filters

After leaving the air receivers, the air passes through the service and instrument air filters. The Particulate first filter (F-135) removes particles larger than 0.3 microns. This filter also handles water carryover if an aftercooler drain trap fails. The Coalescent second filter (F-136) removes particulates and aerosols larger than 0.01 microns. This second step of filtration is necessary because air going to the service air header receives no further drying or filtration.

13.3.5 Dryer/Filter Trains

To reduce the possibility of damage to instrument air components caused by moisture, the instrument air distribution system includes a dual train arrangement of pre-filters, air dryers, and after-filters. The parallel arrangement of each pair of components allows one to be in service while the other is undergoing maintenance such as filter media replacement or air dryer regeneration.

The in-service pre-filter (F-104A or B) removes most of any moisture present as air passes through a bed of absorbent material. The air handling capacity of each prefilter is 600 cfm. The pre-filter is equipped with an automatic drain trap to remove any liquid that accumulates in the bottom of the unit. To change the lineup, the prefilters are valved in and out manually (normally when the differential pressure across the in-service filter reaches 6 psid). An alarm actuates at 10 psid on the local control panel to indicate the need to shift filters.

From the prefilter, the air passes through an air dryer (X-103A or B), in which any excess moisture is absorbed by desiccant. A motor-driven timer automatically switches the in-service dryer every four hours. The dryer removed from service enters into a regeneration mode, in which an electrical heater in the dryer is energized and a small flow of dry air is passed through the dryer in order to dry the desiccant. This practice ensures that a continuous supply of dry air is available for the instrument air loads.

The dried air then passes through the in-service 0.3-micron after-filter (F-105A or B), where a final filtration removes entrained desiccant. The air exiting this arrangement is very pure and dry. The moisture content of the instrument air is monitored with a hygrometer. A lineup change for the after-filters is accomplished as described above for the pre-filters.

13.3.6 Accumulators

Several air-operated valves in the plant are vital to plant safety. To ensure extended operation of these valves upon a loss of instrument air, the valve operators are provided with accumulators. See Figure 13-3. Each pressurizer power-operated relief valve (PORV) is provided with two Seismic Category I accumulators, which are designed to accommodate 32 cycles of the PORV during the 10-minute period following a loss of instrument air. Each steam supply valve to the turbine-driven auxiliary feedwater (AFW) pump also has a Seismic Category I accumulator designed to allow three movements of the valve (open-closed-open) 20 minutes after a loss of instrument air. Each main steam isolation valve has a Seismic Category II accumulator designed to maintain the valve open for 10 to 15 minutes following a loss of instrument air.

In addition, components in several fire protection system water spray systems have Seismic Category II accumulators designed to provide sufficient air pressure for operation for a minimum of one hour following a loss of instrument air.

13.3.7 Containment Isolation Valves

The isolation valves installed in the compressed air containment penetrations will prevent releases from the containment in the event of failure of the compressed air system pressure boundary inside the containment. The air operated isolation valves (CV-4470 and CV-4471) located outside the containment are installed in series with check valves located inside the Containment in both the service air and instrument air lines. The isolation valves will automatically operate to the closed position upon initiation of a Containment Isolation Signal Phase A (CISA) and are designed to operate to the closed position upon failure of air pressure or electrical power to the valve.

Since the instrument and service air headers penetrate the containment, automatic isolation of the lines is provided (Figure 13-2). The instrument air header isolation valve (CV-4471) is normally open and automatically shuts on a containment isolation phase A (CISA) signal from protection train B. The service air header containment isolation valve (CV-4470) is normally shut and receives a containment isolation phase A (CISA) signal from protection train A.

13.4 System Operation

Service air is supplied throughout the plant for service and maintenance operation. Instrument air is provided throughout the plant to operate diaphragm valves and control devices. The instrument air system is physically connected to every major system in the plant. The following are air-operated valves which rely on instrument air for proper operation during normal at-power operation: main feed regulating valves, main steam isolation valves, letdown and orifice isolation vales, the charging flow control valve, and the pressurizer spray valves. Air-operated valves that can be important for decay heat removal during shutdown and emergency conditions are the steam dump valves, secondary PORVs, steam supply valves to the turbine-driven AFW pump, and the pressurizer PORVs.

During normal at-power operation, the Sullair air compressor is available for service at all times. The other air compressors are placed in the standby mode, with one compressor selected as the lead (it starts first on low air pressure). In the event of a loss of the operating compressor or during heavy load demands, the lead compressor automatically starts when the header pressure decreases to 105 psig. If the pressure continues to drop, the second standby compressor starts at a header pressure of 103 psig. The third standby compressor automatically starts at a header pressure of 100 psig. The control system for any operating compressor regulates the compressor air intake to match the amount of compressed air used, thereby minimizing the amount of compressor starts and stops required to maintain pressure. The selection of the lead standby compressor can be varied to permit equal operating time for the three reciprocating air compressors.

The discharge lines from the air receivers are connected in parallel to a common header. The discharge from the air receivers passes through the service and instrument air filters before entering the service and instrument air headers. The service air header directs the distribution of service air to various outlets throughout the plant. The instrument air header directs the air from the filter outlet to the in-service instrument air filter/dryer train. The filter/dryer train processes the air to the required cleanliness and dryness and supplies it to the instrument air header, which distributes air throughout the plant to air-operated devices. For components with associated accumulators, the instrument air header pressurizes the accumulators via in-series check valves.

13.5 System Importance

The compressed air system is required for normal operation and startup of the plant; however, all pneumatically operated devices in the plant which are essential for the safe shutdown of the plant are designed to the safe position upon loss of air pressure. Therefore, a supply of compressed air is not essential for safe shutdown of the plant and the compressed air system is not designed to meet seismic category I or the single failure criterion.

Because compressed air is not essential for safe shutdown of the plant the compressed air system will not automatically switch to operation from diesel generator power under blackout conditions. One or more compressors can be <u>manually</u> restarted during the blackout conditions to restore compressed air supply provided that the diesel generators are not fully loaded and temporary cooling water can be supplied.

As mentioned above, instrument air is supplied to many important components in many major plant systems. Accordingly, the loss of instrument air pressure with the plant operating at power results in a severe plant transient. The loss of air pressure causes the main feed regulating valves to close completely, and the reactor trips on the loss of heat sink. The steam dump valves and secondary PORVs remain closed during and following the reactor trip, leaving only the steam generator safety valves available for decay heat removal from the steam generators. AFW flow to the steam generators is available for heat sink restoration, with accumulators ensuring the opening of the steam supply valves to the turbine-driven pump.

Even though the loss of instrument air prevents the normal post-trip alignment of plant components, all pneumatically operated devices in the plant that are essential for the safe shutdown of the reactor are designed to assume their fail-safe positions upon a loss of air pressure. Components that are required to operate following the loss of air are supplied with accumulators. Even without air pressure, the following conditions should be achieved and maintained:

1. The reactor is subcritical in a stable configuration.
2. The reactor coolant system is in a controlled condition with pressure, temperature, reactor coolant inventory, and the cooldown rate within acceptable limits.
3. Reactor decay heat and system sensible heat are being removed at a controlled rate.

A loss of instrument and service air pressure results from a loss of offsite power, as ac power is lost to three of the four motor-driven air compressors, and no bearing cooling water flow is available to any of the four. System air pressure can be restored by (1) operating the “B” (vital-powered) Joy air compressor with fire main cooling aligned to it, (2) restoring power to at least one other motor-driven air compressor and one bearing cooling water pump by cross-tying a nonvital bus to a vital bus, or (3) starting the diesel-driven air compressor and aligning it to one of the air receivers.

In addition to an abrupt, complete loss of system air pressure, difficult-to-control transients can result from (1) a loss of air pressure in a portion of the system, (2) a slow degradation of air pressure, and (3) the failure or unpredictable operation of pneumatic components caused by the introduction of contaminants from the air system.

13.6 Summary

The instrument and service air system supplies low pressure air (125 psig) for several functions around the plant. Service air is for general plant use. Instrument air is used to operate pneumatic valves and instruments. Four motor-driven air compressors, with one usually in service and the others in standby, can supply both the service and instrument air distribution portions of the system. A diesel-driven air compressor is available as a manually initiated backup to the other compressors. The instrument air distribution section includes parallel prefilters, air dryer units, and afterfilters to supply it with clean, dry air.

A loss of instrument air pressure results in a severe plant transient, including a reactor trip and the unavailability of normal decay heat removal methods. However, pneumatically operated devices that are essential for the safe shutdown of the reactor assume fail-safe positions upon a loss of air pressure. Components that are required to operate following the loss of air are supplied with accumulators.

A loss of offsite power results in the loss of instrument and service air pressure, as ac power is lost to air compressors and components which support compressor operation. Operator action is required to restore air pressure following this event.

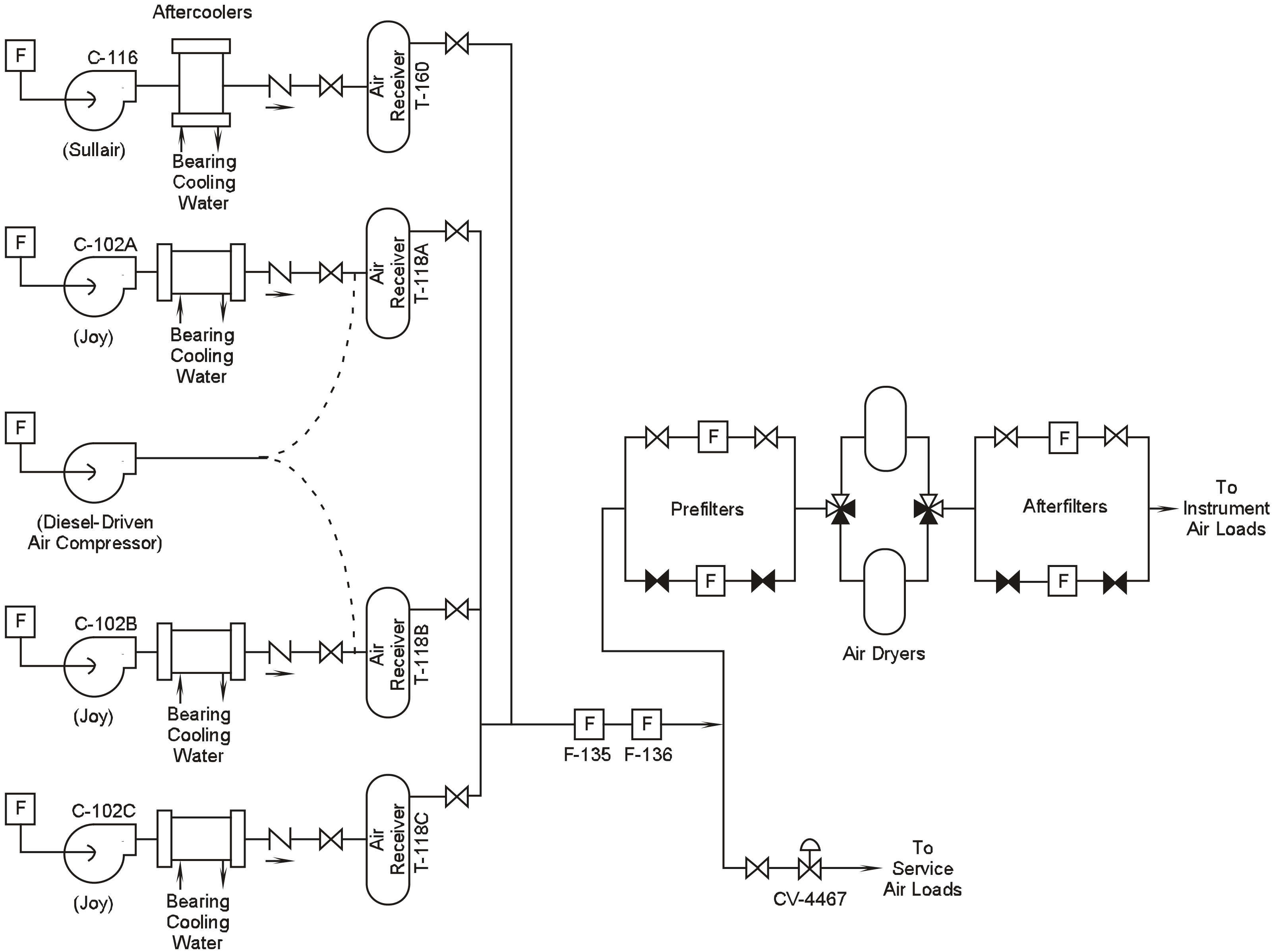


Figure 13-1 Instrument and Service Air

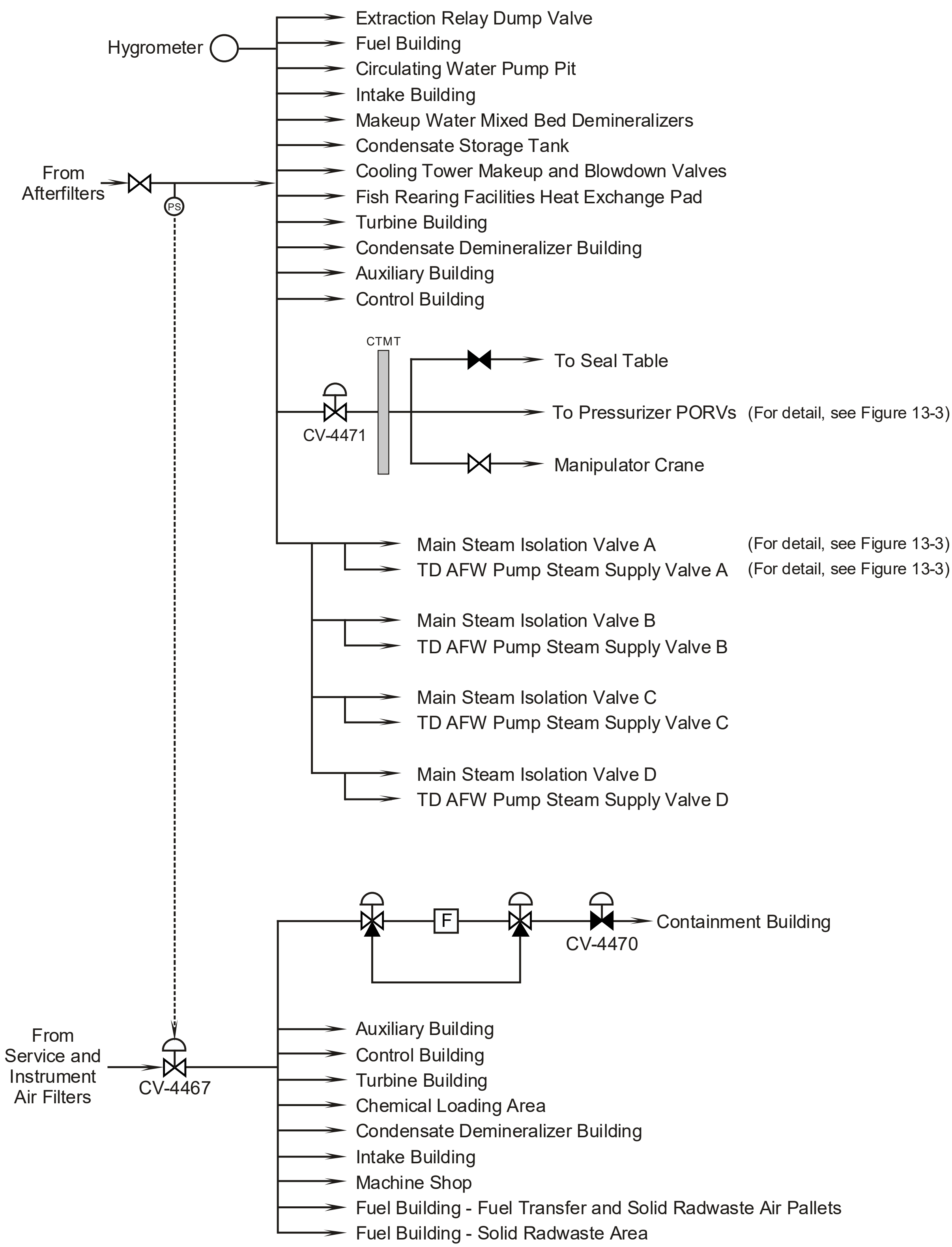


Figure 13-2 Instrument and Service Air Loads

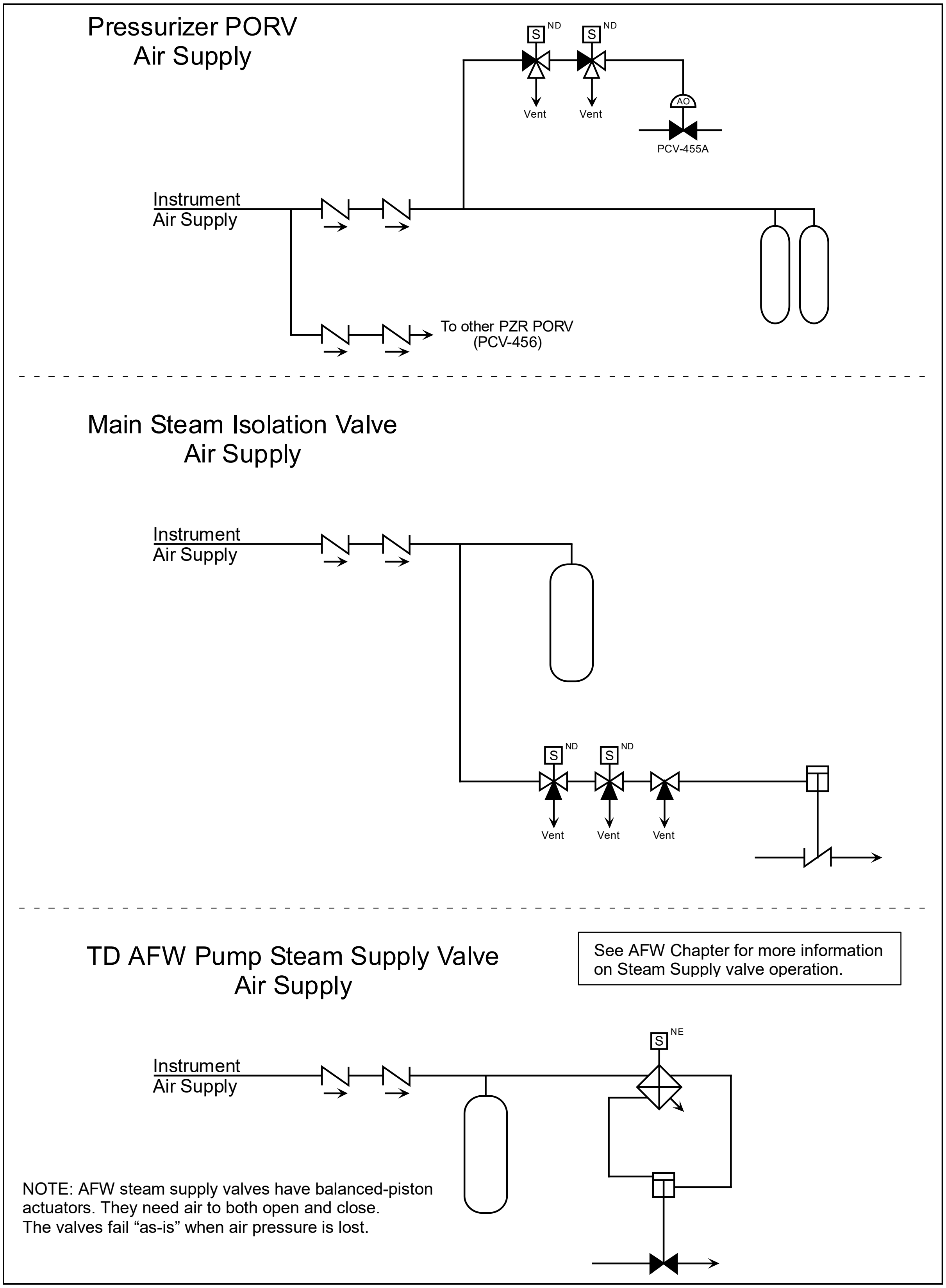
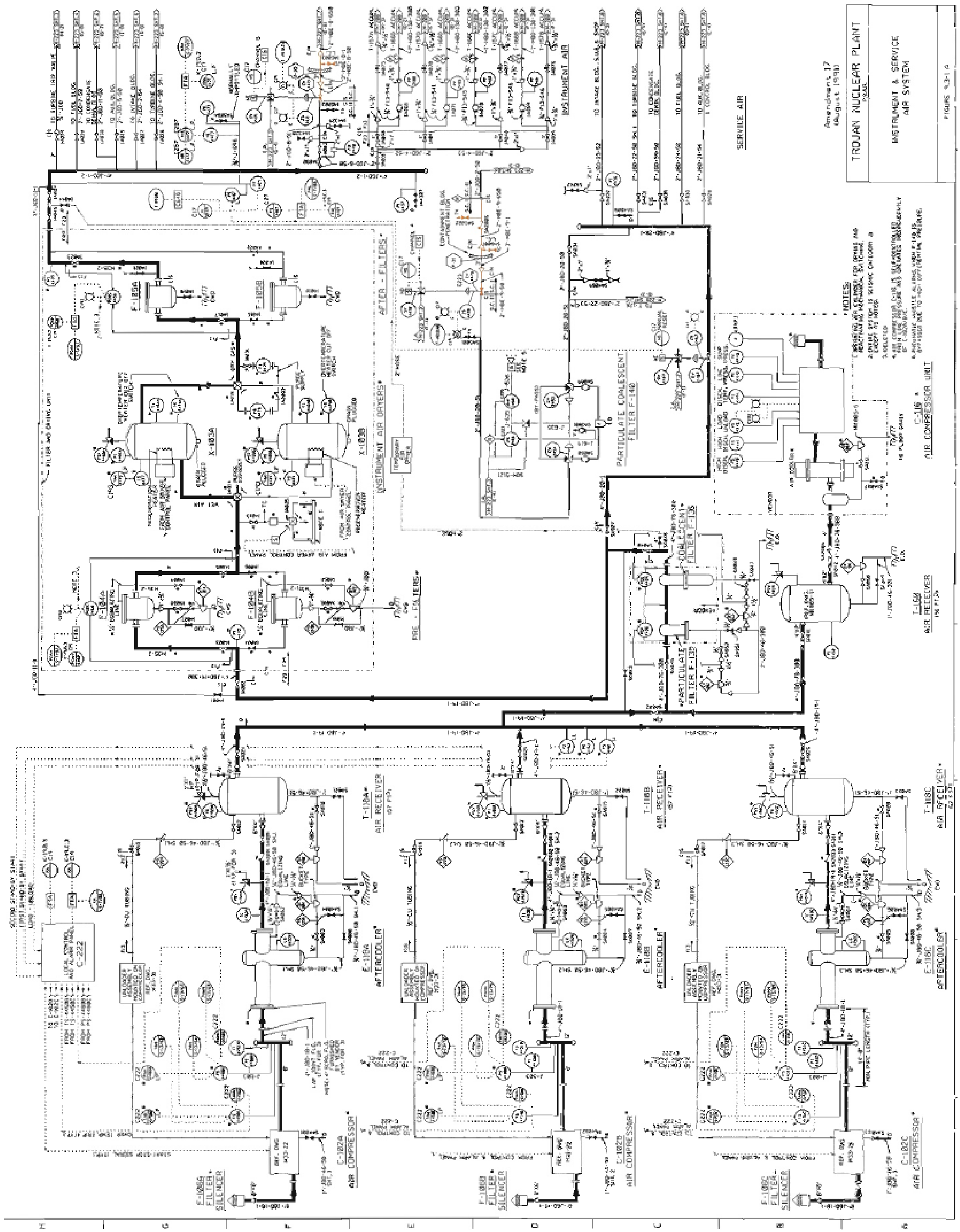


Figure 13-3 Pressurizer PORV, MSIV, and AFW Steam Supply Details



Example P&ID of Compressed Air System

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Chapter 14

COOLING WATER SYSTEMS

Section

Westinghouse Technology Systems Manual

Section 14.1

<u>Ultimate Heat Sink (UHS) Cooling Tower System</u>

"READ ONLY SELF STUDY MATERIAL"

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14.1 ULTIMATE HEAT SINK (UHS) COOLING TOWER SYSTEM

Learning Objective:

1. State the purposes of the ultimate heat sink.

14.1.1 Introduction

The river is used as the ultimate heat sink for the plant. The ultimate heat sink's principal safety function is to dissipate residual heat after a normal reactor shutdown or following an accident that results in emergency shutdown conditions. In the event that the intake structure is lost, the cooling tower basin becomes the ultimate heat sink.

The design basis of the SWS is to provide sufficient heat removal capacity and reliability to safely operate, shut down, and cool down the plant and to maintain it in a cold shutdown condition. Continuation of the minimum required cooling water flow to the safety-related equipment, auxiliary feedwater system, spent fuel pool emergency makeup, and component cooling water emergency makeup is essential to assure safe operation and safe shutdown of the plant as described in chapter 14.6.

The ultimate heat sink (UHS) cooling tower, is part of the circ water and service water systems as described in chapter 14.7 and shown in Figure 14.7-1. During normal operations, the Plant ultimate heat sink consists of a single water source comprising the Columbia River up to but not including the Intake Structure, together with the numerous dams which regulate its flow. However, no reliance is placed on river regulation, and the system would operate satisfactorily if all flow were stopped at the lowest dam on the mainstream and those on each lower tributary. In the unlikely event that the Intake Structure is blocked, the Plant cooling tower and cooling tower basin will comprise the ultimate heat sink.

The ultimate heat sink performs the two principal safety functions of dissipating residual heat after normal reactor shutdown and dissipating residual heat after an accident resulting in emergency shutdown conditions.

14.1.2 System Design Description

The design basis of the Plant ultimate heat sink is to provide sufficient heat removal capacity and reliability for a minimum of 30 days to permit the safe shutdown and cooldown of the reactor Plant and to subsequently maintain safe shutdown conditions. This capability is provided for both normal shutdown and accident conditions.

The design basis safety functions of the ultimate heat sink are assured following:

1) The most severe natural phenomena associated with the site location, including earthquake, tornado, volcanic eruption, flood or drought, taken individually.

2) Site-related events, such as river blockage, river diversion, transportation accidents, oil spills or fires, that historically have occurred or that may occur during the Plant lifetime.
3) Any single failure of a man-made structure, including successive failure of all dams upstream of the Plant.

During normal Plant operations, the design objectives of the Plant ultimate heat sink are assured through the use of the Columbia River up to but not including the Intake Structure, together with the numerous dams which regulate its flow. There are no dams downstream of the Intake structure, and the river channel is considerably below sea level continuously from the site to the ocean.

The Intake structure is located directly on the river and therefore no canals, conduits or waterways are associated with or required as part of the ultimate heat sink. The river will continuously supply water to the Intake structure when river water level is above Elevation -2 feet, whereas the lowest water level possible is above Elevation -1.5 feet.

Evaluation as to the capability of the Columbia River to meet the Plant ultimate heat sink design objectives is presented at length in Chapter 2 of the FSAR. The chapter includes complete analyses of the site location with regard to geography, meteorology, hydrology, geology, seismology and volcanology, as well as site-related events and man-made structures which could affect the ultimate heat sink.

In the unlikely event of blockage of the Intake structure, the cooling tower and cooling tower basin will comprise the ultimate heat sink. Blockage of the Intake structure is discussed *in* detail in FSAR section 2.2.3 and a discussion of the heat sink capabilities of the cooling tower and cooling tower basin is presented in FSAR section 9.2.1.

The design of the Plant ultimate heat sink provides sufficient capacity and reliability to assure compliance with Regulatory Guide 1.27, Ultimate Heat Sink. Specific requirements of the Regulatory Guide, in part, include:

(1) "The ultimate heat sink should be capable of providing sufficient cooling for at least 30 days (a) to permit simultaneous safe shutdown and cooldown of all nuclear reactor units that it serves, and maintain them in a safe shutdown condition, and (b) in the event of an accident in one unit, to limit the effects of that accident safely, to permit control of that accident safely and permit simultaneous safe shutdown and cooldown of the remaining units and maintain them in a safe shutdown condition. Procedures for ensuring a continued capability after 30 days should be available."

The Columbia River provides this capability. Information concerning the Plant residual heat after reactor shutdown and after an accident is presented in detail in FSAR Chapter 15 and defines the required heat sink capacity provided by the ultimate heat sink.

In the event of Intake Structure blockage, the cooling tower and basin is considered the ultimate heat sink, but its heat removal capability is limited to normal shutdown cooling. This limited capability is adequate because blockage of the Intake Structure, coincident with a Chapter 15 accident requiring ESF actuation, is not considered credible. A discussion of the heat sink capability of the cooling tower and basin is presented in FSAR section 9.2.1.

(2) "The ultimate heat sink complex, whether composed of single or multiple water sources, should be capable of withstanding, without loss of the sink safety functions specified in regulatory position 1, the following events:

a) The most severe natural phenomena expected at the site, with appropriate ambient conditions, but with no two or more such phenomena occurring simultaneously,
b) The site-related events (e.g. transportation accident, river diversion) that historically have occurred or that may occur during the plant lifetime,
c) Reasonably probable combinations of less severe natural phenomena and/or site-related events,
d) A single failure of manmade structural features.

Ultimate heat sink features, which are constructed specifically for nuclear power plants and which are not required to be designed to withstand the Safe Shutdown Earthquake or the Probable Maximum Flood, should at least be designed and constructed to withstand the effects of the Operating Basis Earthquake (as defined in 10 CFR Part 100, Appendix A) and waterflow based on severe historical events in the region.

The Columbia River, and to a lesser degree the cooling tower and basin in the event of Intake Structure blockage, provides this capability. The Columbia River will function as the ultimate heat sink during all conditions of operation throughout Plant life except during periods of Intake Structure blockage when the cooling tower and cooling tower basin will comprise the ultimate heat sink (as described in FSAR Section 9.2.1).

Although the cooling tower is a Seismic Category II structure, ultimate heat sink capability is maintained because blockage of the Intake Structure simultaneous with a seismic event is not considered a reasonable combination of natural phenomena and site-related events.

This conclusion is based on: (a) the fact that the Intake Structure and associated systems are redundant systems designed to withstand the effects of the most severe natural phenomena associated with their location and remain functional (see section 3.8), and (b) the only probable means for loss of function of the Intake structure is blockage by a ship or similar object (see FSAR Section 2.2.3). In contrast, although the cooling tower and basin are not designed to withstand the most severe natural phenomena, they are impervious to failure by events that would block the Intake Structure, such as the ship collision.

Therefore, since those events which could lead to failure of either system are independent and each is of low probability, it is not considered reasonable to combine these effects.

(3) "The ultimate heat sink should consist of at least two sources of water, including their retaining structures, each with the capability to perform the safety functions specified in regulatory position I, unless it can be demonstrated that there is an extremely low probability of losing the capability of a single source. For close-loop cooling systems, there should be at least two aqueducts connecting the source(s) with the intake structures of the nuclear power units and at least two aqueducts to return the cooling water to the source, unless it can be demonstrated that there is extremely low probability that a single aqueduct can functionally fail entirely as a result of natural or site-related phenomena. For once-through cooling systems, there should be at least two aqueducts connecting the source(s) with the intake structures of the nuclear power units and at least two aqueducts to discharge the cooling water well away from the nuclear power plant to ensure that there is no potential for plant flooding by the discharged cooling water, unless it can be demonstrated that there is extremely low probability that a single aqueduct can functionally fail as a result of natural or site-related phenomena. All water sources and their associated aqueducts should be highly reliable and should be separated and protected such that failure of anyone will not induce failure of any other."

The Columbia River, Intake structure and SWS provide this capability. In the extremely unlikely event of Intake structure blockage, the cooling tower and basin serve as the ultimate heat sink to the extent described in (1) above.

(4) "The technical specifications for the plant should include provisions for actions to be taken in the event that conditions threaten partial loss of the capability of the ultimate heat sink or the plant temporarily does not satisfy regulatory positions 1 and 3 above during operation.

To ensure full ultimate heat sink capability at all times, sufficient Columbia River water flow must be continuously available to maintain SWs suction flow. This requires that river level be above Elevation -1.5 feet at all times. If water level decreases below Elevation -1.5 feet, the Plant will be shut down and remain shut down until adequate river flow *is* restored. Additionally, the cooling tower and cooling tower basin must be continuously available to provide ultimate heat sink capability in the event of Intake structure blockage. Any degradation in the ability of the cooling tower and basin to fulfill the ultimate heat sink objectives described in (1) above will require that the Plant be shut down and remain shut down until the capability is restored.

The cooling tower cools the circulating water using a counter-flow, natural-draft arrangement. Due to system impurities, a continuous blowdown is performed on the circulating water system. This inventory loss, combined with losses due to evaporation and drift, requires two cooling tower makeup pumps, which take water from the cooling tower makeup reservoir section of the discharge and dilution structure and deliver it to the suction of the circulating water pumps.

14.1.3 Component Descriptions

14.1.3.1 Circulating Water Pumps

The two circulating water pumps are single-stage, horizontally split, centrifugal pumps which supply the necessary head for system flow. Each pump can supply 210,000 gpm at a design head of 100 feet. The pumps are powered from 12.47-kv buses H1 and H2. Each pump shaft is sealed at each casing exit point by a self-supplied stuffing box (gland) that has filters, heat tracing, throttle valves, and flow sight glasses. The pumps are located outside, in the circulating water pump pit. A common lubricating oil system is shared by the two pumps.

14.1.3.2 Cooling Tower

The cooling tower cools the circulating water returning from the various components served by the CWS and TBCW systems. The hyperbolic tower, designed for strength alone, is evaporative in design and contains no fans. The air flow within the shell is created by the density difference between atmospheric air and the hotter air inside the tower. The counter-flow design provides a highly efficient heat transfer mechanism since the coolest air contacts the coolest water initially. The heat transfer process occurs in the fill section of the tower.

The cooled water falls into the cooling tower basin, passes through a set of double screens in the basin outlet, and then circulates to the suction of the circulating water pumps. The cooling tower basin has a capacity of 5.2×10^6 gallons.

The spray header can be bypassed to allow warmup of the CWS on startup or to maintain the proper temperature during cold weather operation. Bypass flow is controlled by a 72-inch, motor-operated, butterfly valve located near the tower basin. There are no interlocks associated with this valve, though only one CWS pump should be in operation with the valve open.

14.1.3.3 Cooling Tower Makeup Pumps

The cooling tower makeup system uses two makeup pumps in conjunction with a flow control valve to supply water to the CWS pump suction header to makeup for losses. Water is lost from the system due to evaporation, blowdown, and drift. The makeup pumps take suction on the makeup section reservoir of the discharge and dilution structure. This bay receives water from the discharge of the service water pumps after passing through the component cooling water heat exchangers, and is ultimately derived from the river.

The makeup pumps are 450-horsepower, turbine-type pumps rated at 18,000 gpm at a design head of 75 feet. They are powered by 4.16-kv buses A5 and A6.

14.1.3.4 Motor-Operated Valves

The valves discussed herein are the CWS pump suction and discharge valves, the discharge cross-connect valve, and the condenser outlet valves. These valves are all 96-inch, motor-operated, butterfly valves.

Each pump suction valve is interlocked with the associated CWS pump. The suction valve must be fully open to start the pump, and the pump will trip if the suction valve is not fully open. When a pump is energized, the respective pump suction valve cannot be closed.

The CWS pump discharge valve does not have its own control switch. Starting a CWS pump sends a signal to open the pump discharge valve. If the discharge valve is not fully open within two minutes, the pump will trip. Stopping the pump will send a closing signal to the discharge valve motor operator. The pump will stop when the discharge valve reaches the fully closed position. An auto trip of the pump will also initiate discharge valve closure.

The cross-connect valve is interlocked to prevent the valve from being opened with both pumps in operation. If one discharge valve and the discharge cross-connect valve are open, opening the other discharge valve will cause the cross-connect to close. If either discharge valve is open, then the cross-connect valve cannot be opened. This interlock prevents excessive circulating water pump reverse rotation, which would occur during one-pump operation with the cross-connect and both discharge valves open.

The condenser outlet valves are interlocked with the CWS pumps such that the associated condenser outlet valve must be at least 48° open any time a pump is running. A valve position of less than 48° will prevent the pump from starting and will trip the pump if it is running. Each of these valves is also prevented from closing any time the associated CWS pump is running. This interlock prevents condenser tube overpressurization.

14.1.3.5 Chemical Injection

Chemicals are manually added to the circulating water on a routine basis to help eliminate algae buildup in the system. The system taps into the pump suction header through six-inch piping. The chemicals pass through a diffuser section to ensure good mixing and dilution prior to injection. Chemical injection is automatically blocked whenever the CWS pumps are de-energized.

14.1.3.6 Columbia River UHS and Service Water System

The river is used as the ultimate heat sink for the plant. The ultimate heat sink's principal safety function is to dissipate residual heat after a normal reactor shutdown or following an accident that results in emergency shutdown conditions. In the event that the intake structure is lost, the cooling tower basin becomes the ultimate heat sink.

The design basis of the SWS is to provide sufficient heat removal capacity and reliability to safely operate, shut down, and cool down the plant and to maintain it in a cold shutdown condition. Continuation of the minimum required cooling water flow to the safety-related equipment, auxiliary feedwater system, spent fuel pool emergency makeup, and component cooling water emergency makeup is essential to assure safe operation and safe shutdown of the plant.

14.1.4 Summary

The ultimate heat sink should be capable of providing sufficient cooling for at least 30 days (a) to permit simultaneous safe shutdown and cooldown of all nuclear reactor units that it serves, and maintain them in a safe shutdown condition, and (b) in the event of an accident in one unit, to limit the effects of that accident safely, to permit control of that accident safely and permit simultaneous safe shutdown and cooldown of the remaining units and maintain them in a safe shutdown condition. Procedures for ensuring a continued capability after 30 days should be available.

The Columbia River, and to a lesser degree the cooling tower and basin in the event of Intake Structure blockage, provides this capability. The Columbia River will function as the ultimate heat sink during all conditions of operation throughout Plant life except during periods of Intake Structure blockage when the cooling tower and cooling tower basin will comprise the ultimate heat sink.

The Columbia River, Intake structure and SWS provide this capability. In the extremely unlikely event of Intake structure blockage, the cooling tower and basin serve as the ultimate heat sink to the extent described in (1) above

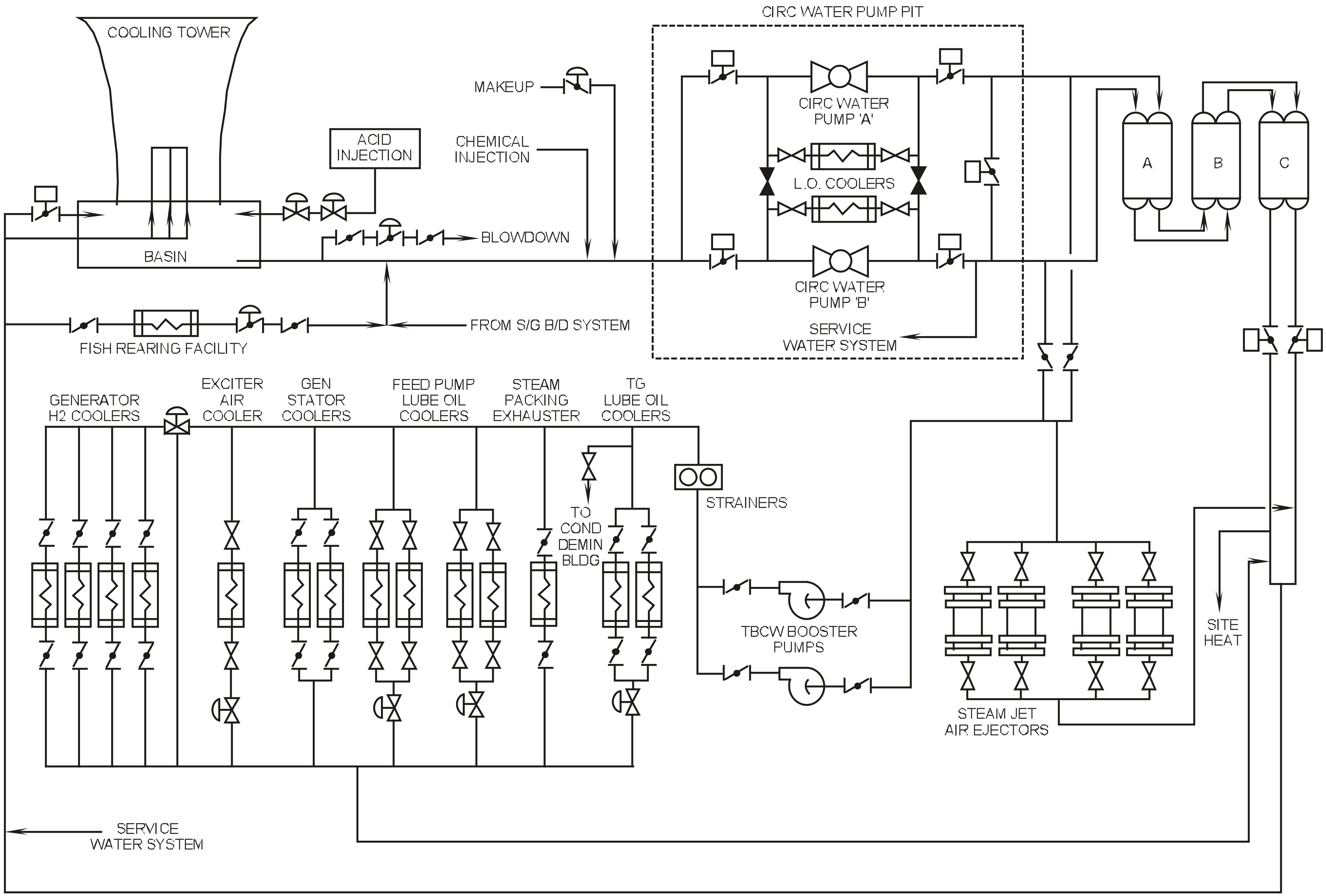

Figure 14.7-1 Circulating Water System

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Section 14.2

Bearing Cooling Water System (BCWS)

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14.2 BEARING COOLING WATER SYSTEM (BCWS)

Learning Objective:

1. State the purpose of the Bearing Cooling Water (BCW) System.

14.2.1 Introduction

The primary purpose of the Bearing Cooling Water System (BCWS), shown in Figure 14.2-1,, is a closed-cycle system that provides cooling water for the removal of heat from the following components:

(1) Air compressor aftercoolers and jackets.

(2) Condensate pump motors oil coolers.

(3) Electrohydraulic fluid coolers.

(4) Secondary system sample coolers.

The BCWS has no safety-related functions.

14.2.2 System Description

The Bearing Cooling Water System (BCWS) consists of two BCWS pumps, two BCWS heat exchangers, one BCWS surge tank, one chemical addition tank, and associated piping and instrumentation. The entire system is located in the Turbine Building. The system is of the closed-cycle type with the same fluid being continuously recirculated through the system by one of the BCWS pumps.

The system is designed for full-capacity operation with one of the two BCWS pumps and one BCWS heat exchanger in service.

14.2.3 Component Descriptions

14.2.3.1 Bearing Cooling Water Pumps and Valves

The system is required to be in continuous service during all periods of normal Plant operation and provide cooling water to the compressed air system during periods of Plant shutdown. The system functions with one BCWS pump in operation and the second pump on standby. The second pump automatically starts upon low pressure in the pump discharge header.

Pressure switch PS-3854 will initiate automatic startup of the standby BCWS pump in the event of low discharge pressure from the operating pump. Local and remote indicators and alarms, are provided for monitoring the performance of the system.

The two BCWS pumps and the two BCWS heat exchangers are periodically rotated in service to provide for equal wear and to monitor the operating condition of these components. (See Figure 14.2-1.)

Data for the BCWS pumps are listed in Table 14.2-1. The pumps were designed and fabricated in accordance with the standards of the Hydraulic Institute.

14.2.3.2 Surge Tank and Heat Exchangers

A positive pressure is maintained at all points in the system by the elevated BCWS surge tank. Heat is removed from the system by the flow of service water through the tube side of one of the BCWS heat exchangers. Makeup water is supplied to the system from the demineralized water storage tank through the demineralized water transfer pump.

Data for the BCWS heat exchangers are listed in Tables 14.2-2. The BCWS surge tank is a 265-gallon capacity carbon steel vented tank. The chemical addition tank is a 70-gallon capacity ASME carbon steel tank designed for 150 psig.

14.2.3.3 Makeup and Chemical Addition

Makeup water is added to the system by opening the normally closed valve in the makeup line from the demineralized water storage tank and operating the demineralized water transfer pump until the water level in the BCWS surge tank stabilizes at the proper level.

The periodic addition of makeup water to the system is required due to the small amount of leakage expected, and to control the water chemistry so as to inhibit corrosion of the system water passages. The water in the system is analyzed on a regular basis for pH, conductivity, dissolved oxygen and concentration of corrosion inhibitors. Corrosion inhibitors are added as required through the chemical addition tank.

The system is designed to permit the use of corrosion inhibitors for the prevention of long-term corrosion and organic fouling of the water passages in the system.

The heat exchangers were designed and fabricated in accordance with the TEMA Standards for Class R heat exchangers and ASHE B&PV Code, Section VIII. The chemical addition tank was designed and fabricated in accordance with the ASHE B&PV Code, Section VIII. The BCWS surge tank was designed and fabricated in

accordance with API 620. The system piping was fabricated and installed in accordance with ANSI B3l.l.0, Code for Pressure Piping. The entire system is designed to meet Seismic Category II requirements.

14.2.4 System Features and Interrelationships

14.2.4.1 Design

The components of the system are sized to remove the maximum heat loads developed by the components served by the system while maintaining the temperature of the water leaving the BCWS heat exchanger at 95°F maximum. The design calculations assumed a maximum service water temperature of 75°F and service water flow of 350 gpm through the BCWS heat exchanger.

The system is not required for safe shutdown of the Plant under any of the postulated accident conditions and is therefore not required to meet Seismic Category I or single-failure criteria.

The closed-cycle design of the system permits the use of corrosion inhibitors for preventing long-term corrosion and organic fouling. The system is designed to accomplish the heat removal required to maintain the integrity of the components served by the system.

The standby BCWS heat exchanger and BCWS pump increase system availability and permit repair and maintenance of one heat exchanger and/or one pump while the system is in operation.

In the BCWS, leakage flows due to passive failures which exceed the capacity of the building drains will drain into the spaces below Elevation 45 feet in the Turbine Building. These spaces contain no ESF equipment and are capable of containing well in excess of the volume of water contained in the BCWS.

14.2.4.2 Modes of Operation

The system is required to be in continuous service during all periods of normal Plant operation and provide cooling water to the compressed air system during periods of Plant shutdown. The system functions with one BCWS pump in operation and the second pump on standby. The second pump automatically starts upon low pressure in the pump discharge header.

The two BCWS pumps and the two BCWS heat exchangers are periodically rotated in service to provide for equal wear and to monitor the operating condition of these components. (See Figure 14.2-1.)

14.2.5 Summary

The Bearing Cooling Water System (BCWS) consists of two BCWS pumps, two BCWS heat exchangers, one BCWS surge tank, one chemical addition tank, and associated piping and instrumentation. The entire system is located in the Turbine Building. The system is of the closed-cycle type with the same fluid being continuously recirculated through the system by one of the BCWS pumps.

The system is designed for full-capacity operation with one of the two BCWS pumps and one BCWS heat exchanger in service. The BCWS has no safety-related functions.

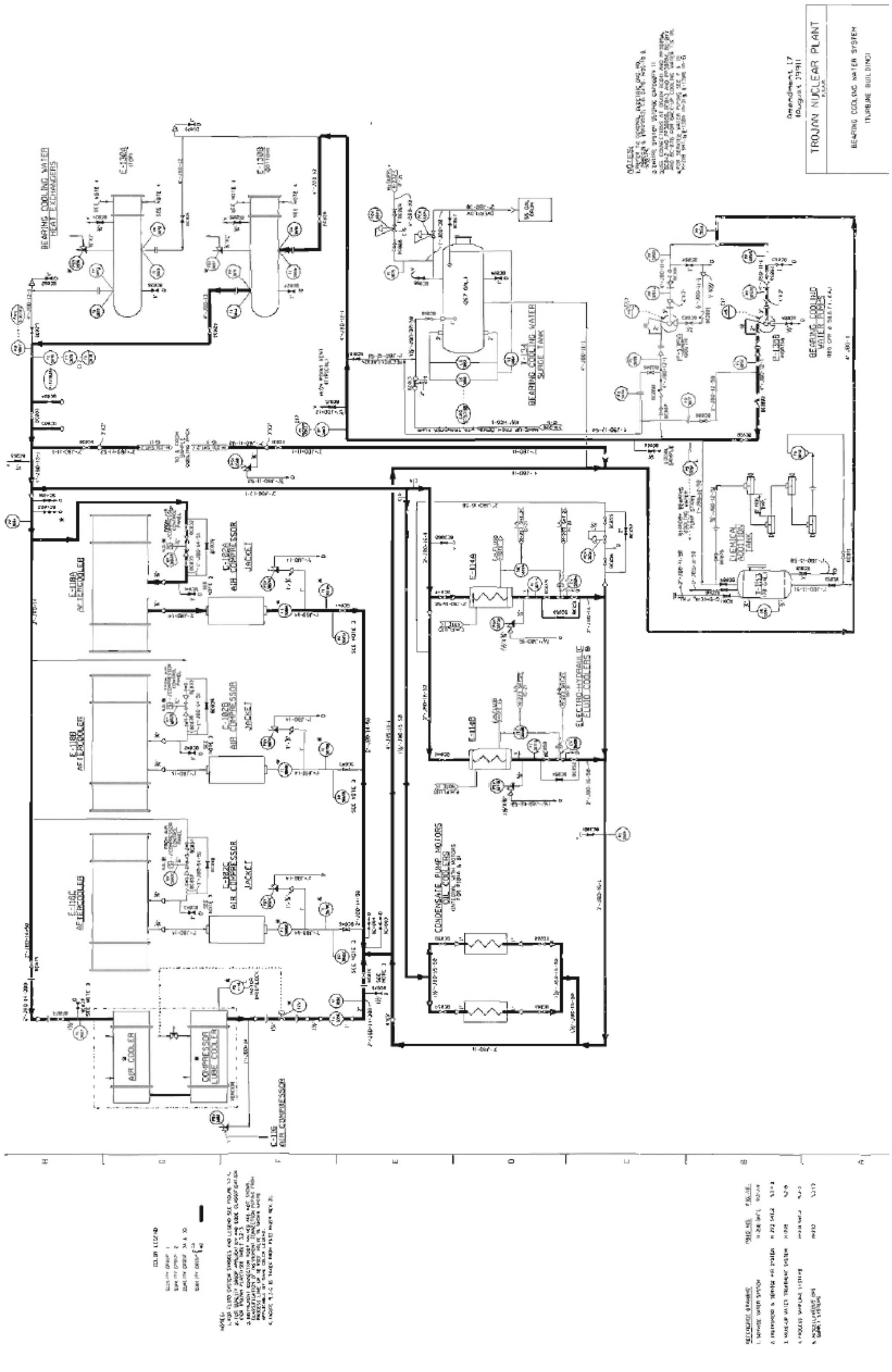

Figure 14.2-1 Bearing Cooling Water (BCW) System

TABLE 14.2-1 Bearing Cooling Water System Pump Data

Characteristics	Data
Quantity	Two
Equipment numbers	P-135A & B
Type	Horizontal centrifugal
Pumped fluid	water
Design pressure, psig	150
Design flow rate, gpm	185
Design head, ft	58
NPSH required at design flow rate, ft	20
Maximum operating flow rate, gpm	185
Head at maximum operating flow rate, ft	58
NPSH required at maximum operating flow rate, ft	20
Discharge pressure at shutoff, psig	68
Minimum available NPSH, ft	42
Materials of construction:	
Casing	Cast iron
Impeller	Bronze
Shaft	Carbon steel
Motor:	
Type	Electric motor
Service factor, %	1.15
Nameplate rating, hp	5
Voltage	480
RPM	1750

TABLE 14.2-2 Bearing Cooling Water System Heat Exchanger Data

Characteristics	Data
Quantity	Two
Equipment number	E-130A & B
Type	Shell and Tube (Double-Pass)
Design heat duty, Btu/hr	2.3×10^6
Overall heat transfer coefficient, Btu/hr - °F	1.5×10^5
Shell side:	
Fluid	Water
Design temperature, °F	200
Design inlet temperature, °F	114
Design outlet temperature, °F	95
Design pressure, psig	150
Design flow, gpm	240
Pressure loss at design flow, psi	4
Design fouling factor, hr/ft^2 - °F/Btu	0.0005
Tube side:	
Fluid	Water
Design temperature, °F	200
Design inlet temperatue, °F	75
Design outlet temperature, °F	88
Design pressure, psig	150
Design flow, gpm	350
Pressure loss at design flow, psi	2
Design fouling factor, hr/ft^2 - °F/Btu	0.002
Materials of construction:	
Shell	Carbon steel
Tube	Admiralty
Tubesheet	Aluminum bronze

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Chapter 14.3

<u>SYSTEM</u>

THIS CHAPTER HAS BEEN DELETED AND IS NO LONGER PART OF THE COURSE

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Section 14.4

Spent Fuel Pool (SFP) Cooling and Cleanup System

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14.4 SPENT FUEL POOL (SFP) COOLING AND CLEANUP SYSTEM

Learning Objectives:

1. State the purposes of the spent fuel pool cooling and cleanup system.

2. Describe the design features of the spent fuel pool cooling and cleanup system which prevent inadvertently lowering the water level in the spent fuel pool.

14.4.1 Introduction

The Spent Fuel Pool (SFP) cooling and cleanup system is a closed-loop system consisting of three subsystems: the cooling, purification, and skimmer subsystems. The major purpose of the cooling and cleanup system is to remove decay heat generated by the stored spent fuel and to transfer this heat to the component cooling water system. This system continuously purifies, filters, and maintains the optical clarity of the water in the spent fuel pool, fuel transfer canal and the spent fuel cask loading pit. Finally, this system maintains the water inventory in the spent fuel pool.

All nuclear reactor plants include a spent fuel pool for the wet storage of spent fuel assemblies. The methods used to provide cooling for the removal of decay heat from the stored assemblies vary from plant to plant depending upon the individual design. The safety function in all cases is the same; that is, the spent fuel assemblies must be cooled and remain covered with water during all storage conditions. Other functions performed by the system, but not related to safety, include water cleanup for the spent fuel pool, refueling canal, refueling water storage tank, and other equipment storage pools; and a means for filling and draining the refueling canal and the other storage pools. In addition, surface skimming is incorporated into the design to provide optically clear water in the storage pool.

To meet the above considerations, the spent fuel pool, the surrounding structure, the building in which it is housed, and the cooling and cleanup system must meet, in part, the following 10 CFR Part 50, Appendix A, General Design Criteria (GDC):

- GDC 2, “Design bases for protection against natural phenomena,”
- GDC 4, “Environmental and dynamic effects design bases,”
- GDC 61, “Fuel storage and handling and radioactivity control,” and
- GDC 63, “Monitoring fuel and waste storage.”

Meeting the requirements of GDC 2 and GDC 4 provides assurance that the components and systems necessary for spent fuel cooling are designed to withstand the effects of expected natural phenomena (earthquakes, floods, etc.) and to accommodate the effects of normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. Meeting the requirements of GDC 61 provides assurance that fuel storage and handling systems are inspected and tested, provided with shielding for radiation protection, designed with appropriate containment, confinement, and filtering systems, designed with a reliable and testable residual heat removal capability, and designed to prevent significant losses of fuel storage coolant inventory. Finally, GDC 63 ensures that fuel storage systems are provided with monitoring capabilities that can detect conditions that could result in the loss of residual heat removal capability.

To meet the above criteria, the entire spent fuel pool cooling, and cleanup system need not be designed to Seismic Category I requirements, provided that the makeup system and the building ventilation and filtration systems are designed to Seismic Category I specifications. Also, to satisfy the shielding requirement of GDC 61, the spent fuel pool and connected systems must be designed so that, in the event of a failure of the inlets, outlets, or any piping or drain lines inserted into the pool; the level in the pool cannot be inadvertently drained below a point approximately 3 m (10 ft) above the top of the active fuel. Therefore, piping extending into the pool must be equipped with siphon breakers, check valves, or other devices to prevent draining the spent fuel pool. Finally a Seismic Category I makeup system and an appropriate backup method to add coolant to the spent fuel pool must be provided. The backup system need not be a permanently installed system, nor designed to seismic Category I specifications, but it must take water from a Seismic Category I source.

The cooling and cleanup system described in this chapter is designed to perform the following functions:

1. Maintaining the spent fuel pool water temperature $\leq$ 60°C (140°F) by removing the decay heat input from the maximum number of fuel assemblies less a full-core off-load (a total of 1215 assemblies), including the assemblies from the last refueling discharged 100 hours after shutdown. The decay heat load under these conditions is calculated at 20.1 x 10^6 BTU/hr. After 11 days the decay heat output drops to 13 x 10^6 BTU/hr, which is within the capacity of the spent fuel pool cooling heat exchangers.
2. Maintaining the spent fuel pool water temperature below 60°C (140°F) with the assistance of the residual heat removal system in the event that the pool contains the maximum number of fuel assemblies (1408 assemblies), including a complete core unloaded 150 hours following shutdown. The heat load under these conditions is calculated at 44.3 x 10^6 BTU/hr.
3. Maintaining cladding integrity if all forced cooling is lost.
4. Maintaining the purity and clarity of borated water in the spent fuel pool, the fuel transfer canal, the refueling cavity, and the refueling water storage tank.
5. Supplying normal and emergency makeup to the spent fuel pool.
6. Maintaining sufficient cooling if a fuel assembly or other object is dropped in the spent fuel pool.

The spent fuel pool, the emergency makeup supply lines, and the lines connecting to the residual heat removal system are designed to Seismic Category I requirements. The remaining components and piping of the cooling and cleanup system are designed to applicable industry codes and standards.

14.4.2 System Description

The basic flow path of the cooling system is shown in Figure 14.4-1. The system consists of two half-capacity pumps which take suction on the spent fuel pool through a common strainer located approximately 15 feet below the surface of the pool, and discharge back to the pool through two half-capacity heat exchangers. The cooling loop return line discharges directly above the fuel assembly storage racks (about 27 feet below the normal level of the pool surface). The downward momentum and negative buoyancy of the cool discharged water carries the flow downward. The coolant flows beneath the storage racks and begins the process of natural circulation as it heats up and rises up through the stored spent fuel toward the suction strainer. The cooling loop is completed by natural circulation flow within the spent fuel pool. The cooling loop return line has a siphon breaker hole machined into the discharge line about seven feet below the normal level of the pool. This hole (siphon break) prevents inadvertent siphoning of the pool and ensures that at least 10 ft of water (actually 17 ft in this particular design) are retained above the top of the active fuel.

The cooling loop contains connections to the residual heat removal system in the suction piping between the spent fuel pool and the cooling pumps, and in the return piping to the pool from the spent fuel pool heat exchangers. These connections make possible the substitution of a residual heat removal pump and its associated heat exchanger in place of the spent fuel pool cooling pumps and heat exchangers when the heat load exceeds the capacity of the spent fuel cooling system. During refueling the entire core is off-loaded to the spent fuel pool. The spent fuel cooling system by itself does not have sufficient capacity for decay heat removal under these conditions. Therefore, the system is aligned so that the “B” train of the residual heat removal system aids in the cooling of the spent fuel pool.

The purification subsystem consists of a branch line containing a pump, filter, demineralizer, and afterfilter, as shown in Figure 14.4-1. The purification line branches from the outlet of the spent fuel pool cooling heat exchangers. The purification pump diverts a small amount of coolant flow (~150 gpm) from the heat exchanger outlet through the purification filter and/or demineralizer before returning the coolant to the pool. The demineralizer is 90 ft^3 in size and contains about 50 ft^3 of HOH resin. The purification subsystem is designed to remove fission products and other contaminants from the coolant by chemical ion exchange. The purification loop also contains connections to the refueling water storage tank. This feature enables the purification subsystem to circulate and purify the contents of the refueling water storage tank if required.

Makeup water to the spent fuel pool from the demineralized water makeup system compensates for the loss of coolant from the spent fuel pool due to evaporation. The normal makeup line has a siphon breaker hole machined into the supply line approximately seven feet below the level of the normal water surface in the spent fuel pool. Under worst-case conditions, a loss of all forced cooling flow to the spent fuel pool with an initial pool water temperature of 60°C (140°F), the water in the spent fuel pool would reach the boiling point in about 3.5 hours. The integrity of the spent fuel is assured under these conditions, as the maximum calculated peak centerline temperature of the fuel would be 135°C (275°F). Under these conditions the evaporation rate from a boiling pool would be approximately 90 gpm. If makeup water from the normal supply source is not available, inventory in the spent fuel pool could be recovered from an emergency source of water (the service water system) which has the capability of supplying 200 gpm.

The skimmer subsystem improves water clarity and maintains the transparency of the spent fuel pool water for underwater fuel handling. It consists of portable floating skimmers, a skimmer suction header, one skimmer pump and filter, and a return line to the spent fuel pool. Floating skimmers can be placed in the spent fuel pool, the cask loading pit, the fuel transfer canal, or the refueling cavity. The skimmer pump takes suction from the pool surfaces through a floating screen and discharges water through the skimmer filter back into the pool. At some facilities the 5 micron filter elements have been removed from the filter unit due to ALARA concerns. At these units there is no filtration of the pool fluids. However, the skimmer screen does provide removal of debris or floating particulates from the pool surface.

14.4.3 Component Descriptions

14.4.3.1 Spent Fuel Pool

The spent fuel pool is a reinforced concrete structure with a seam-welded stainless steel plate liner. It is designed and built to Seismic Category I specifications. The pool contains about 390,000 gallons of coolant, measures 39 ft by 24 ft, and is 40 ft deep. The depth of the pool is selected to maintain at least 23 feet of water above the tops of spent fuel assemblies in the storage ranks, and at least 9.5 feet above the top of the active fuel during fuel transfer operations. This water barrier serves as a radiation shield, limiting the gamma dose rate at the surface of the pool to a maximum of 2.5 mrem/hr.

14.4.3.2 Spent Fuel Pool Cooling Pumps

Each spent fuel pool cooling pump is a half-capacity pump rated for 1500 gpm at a discharge pressure of 43 psig. Its function is to circulate spent fuel pool water through the heat exchangers and the pool. Each pump is a horizontal, single-stage, centrifugal pump driven by a horizontal, 1770-rpm, induction motor rated for 60 hp, 480 vac, and 60 hz. The pump casing, impeller, and shaft are constructed of stainless steel. Each pump is equipped with a vent to atmosphere and a casing drain to the clean waste receiver tank. Sealing water supply for the shaft seal is taken from pump discharge, and seal leakoff is returned to the pump suction.

14.4.3.3 Spent Fuel Pool Cooling Heat Exchangers

Each spent fuel pool heat exchanger is a shell-and-straight-tube-type heat exchanger with a design heat transfer capacity of 6.5×10^6 BTU/hr. This heat removal capacity is based on a maximum service water temperature of 75°F. However, since the average service water temperature is 53°F, these heat exchangers are capable of removing more heat than designed. The tube-side fluid is spent fuel pool coolant, and the shell-side fluid is component cooling water. Both sides of this heat exchanger are single pass. The inlet for the tube side is equipped with a vent to atmosphere. The tube side inlet and outlet are equipped with drains to the clean waste receiver tank. Both the tube and shell sides are designed for 1500 gpm, 150 psig, and 100°C (212°F). The tubes are constructed of stainless steel; the shell of carbon steel. The heat exchangers are half capacity and arranged in parallel.

14.4.3.4 Purification Pump

The spent fuel pool purification pump develops the pressure head required to force flow through the purification demineralizer and filters. It is a horizontal, single-stage, centrifugal pump driven by a 480-vac induction motor. Its capacity is 132 gpm with maximum backpressure and 232 gpm with minimum backpressure.

14.4.3.5 Demineralizer

The spent fuel pool demineralizer removes fission products and other contaminants from the coolant by chemical ion exchange. The demineralizer is designed for 150 psig, 93°C (200°F), and a maximum flow rate of 250 gpm. Piping and valving is supplied to allow removal of spent resin. The demineralizer can be back-flushed to remove suspended particulates. In addition, back-flushing fluffs the resin, removing any channels that may have formed and thereby increasing the efficiency the demineralizer.

14.4.4 Summary

The purpose of the spent fuel pool cooling and cleanup system is to remove decay heat from fuel stored in the spent fuel pool. The system is provided with a demineralizer and filters to maintain the chemical purity and optical clarity of coolant in the refueling cavity, transfer canal, spent fuel pool, and refueling water storage tank. The spent fuel pool heat exchangers are cooled by component cooling water.

In order to prevent a single component failure from draining the pool and removing the shielding provided by the coolant; the pool is designed with:

1. No drains in the bottom of the pool (hence the pool cannot be inadvertently drained).
2. The cooling pumps taking suction fifteen feet below the surface of the pool. An antisiphon hole in the suction piping maintains a minimum of 12 feet of water above the fuel assemblies.
3. The return line terminating near the top of the fuel racks also has an antisiphon hole. The suction and return antisiphon holes are machined into their respective pipes at the same elevation.

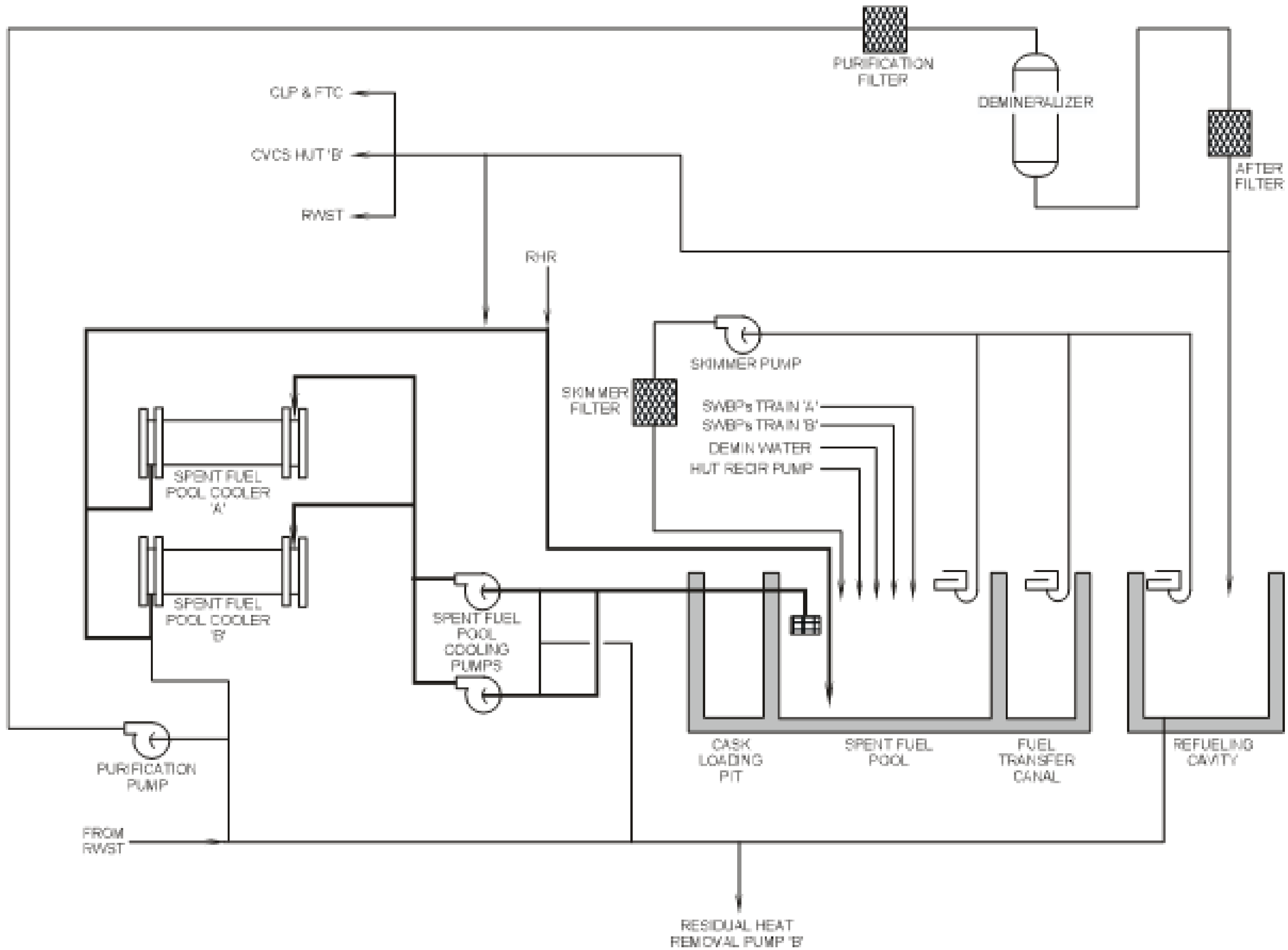

Figure 14.4-1 SFP Cooling and Cleanup System

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Section 14.5

Component Cooling Water System (CCW)

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14.5 COMPONENT COOLING WATER SYSTEM (CCW)

Learning Objectives:

1. State the purposes of the Component Cooling Water (CCW) System.

2. List the loads served by the CCW system.

3. Explain how the design of the CCW system prevents the release of radioactivity to the environment.

4. Describe both methods of detecting leakage into the CCW system.

5. Describe how the CCW system is protected against leakage in the thermal barrier heat exchangers.

14.5.1 Introduction

During the course of normal operation, many of the processes fundamental to power production produce heat. To successfully achieve useful power production at the plant, the heat from various components must be removed. Many of these same components also contain radioactive fluids. Removing the heat produced by various plant systems while limiting the release of radioactive fluids to the environment to an absolute minimum is the function of the component cooling water (CCW) System.

By virtue of their status as part of the emergency core cooling systems, some of the components cooled by CCW are more important than others. These include the residual heat removal pumps and heat exchangers, the charging, safety injection, and spray pumps, and the containment air coolers. They are needed by the plant during emergency conditions to remove heat. These components, as well as several others, are part of the Seismic Category I loops. The rest of the loads cooled by CCW are not critical to the successful outcome of any major emergency situations. These loads are part of the Seismic Category II loop.

As component cooling water flows through both these loops, it picks up thermal energy and rejects it, but not directly to the environment. CCW is a closed system which transfers heat to the service water system for ultimate disposal. As such, it provides a monitored intermediate barrier to the release of radioactive fluids which might leak from the components it cools. The service water system transfers heat absorbed from the CCW system to the ultimate heat sink.

14.5.2 System Description

As shown in Figure 14.5-1, the CCW system is a closed-cycle system designed to provide a monitored intermediate barrier between components handling RCS fluids and the primary heat sink which is service water flowing through the tube side of the CCW heat exchangers. There are three CCW pumps, one for the A train, one for the B train, and a swing pump that can be valved in to supply either train. During normal operation, the system operates in a split-train configuration, with one pump in each train running to supply that train's essential loads, and with suitable suction and discharge isolation so that only one train supplies nonessential loads.

The CCW pumps discharge to a main header that delivers flow through two heat exchangers, one per train. The component heat load of the CCW system is rejected to the service water system, which flows through the tube side of the heat exchangers. Freshly cooled water from the outlets of the heat exchangers is delivered to the various cooling loops. Because the service water system is more subject to fouling, its use on the tube side reduces the opportunity to foul.

Two Seismic Category I trains supply water to various engineered safety feature (ESF) loads. These trains also provide flow to other plant loads in the containment and auxiliary building. Several branches from the main header are needed to supply all loads.

The first branch in each Seismic Category I train, as shown in Figure 14.5-2, delivers flow to the following ESF loads located in the auxiliary building:

1. Safety Injection Pump (SIP) seal cooler,
2. Containment Spray pump seal cooler,
3. Residual heat removal Pump (CSP) mechanical seal cooler,
4. Residual Heat Removal (RHR) heat exchanger, and
5. Positive Displacement charging Pump (PDP) lube oil cooler (Not ESF).

A second branch in each Seismic Category I train supplies cooling water to four containment air coolers.

There is a third branch in each Seismic Category I train. The loads supplied by this branch, as shown in Figure 14.5-3, are automatically isolated by a Phase B containment isolation signal or by a Phase A containment isolation signal coincident with a low CCW surge tank level. In the A train, CCW is supplied to two reactor coolant pumps (RCPs) and the excess letdown heat exchanger. In the B train, CCW is supplied to the other two reactor coolant pumps. A motor-operated valve in the return line from the thermal barrier heat exchanger of each reactor coolant pump automatically closes on high flow (100 gpm); such high flow would result from a leak in the heat exchanger. This feature protects the CCW system against the high pressure of the reactor coolant system.

A fourth branch in the B train, also isolated during by a Phase A containment isolation signal, supplies the seal water and letdown heat exchangers.

During a safety injection actuation sequence, valves in the suction and discharge lines of both trains close to provide train isolation. When these valves close, they also remove the flow to the Seismic Category II loop, which is supplied by a common header supplied from both trains. The loads on the Seismic Category II (nonessential) loop are as follows:

1. Spent Fuel Pool (SFP) heat exchangers,
2. Boric acid evaporator packages,
3. Waste gas compressor and compressor aftercooler,

4. Primary sample conditioning panel, and
5. Fill and flushing supply to the chemical addition tank.

Return flows from the various loads combine in the main suction header from which the CCW pumps receive their supply. Two CCW makeup pumps (one per train) supply makeup water to the suction header from the Demineralized Water (DW) system. An emergency makeup supply to each makeup pump from the service water system is also provided for when the demineralized water storage tank is not available. All components served by the CCW system are located in the Auxiliary Building (AB) and the Containment (CTMT).

The CCW system is equipped with a surge tank in each train to absorb system volume changes. A single chemical addition tank services both trains. The chemical addition tank is used to add corrosion-inhibiting chemicals to maintain system integrity.

14.5.3 Component Descriptions

14.5.3.1 CCW Pumps

The CCW pumps (P-210A, B, & C) are 500 hp, horizontally mounted, single-stage, double-suction, centrifugal pumps. Each CCWP has a design flow of 11,500 gpm, a design pressure of 180 psig, a cast steel casing, a bronze impeller, and a stainless-steel shaft. Electrical power is supplied from 4.16-kv vital buses A1 and A2. Each pump is designed to provide 100 percent of water requirements during normal operation and 100 percent of requirements for each train during abnormal conditions or plant cooldowns.

One pump (A) is aligned directly to train A, and the other (B) is aligned directly to train B. The third pump (C) can be lined up to either train by opening normally locked-closed cross-connect valves. During normal plant operations, one pump and heat exchanger are in operation in each train, with one train supplying cooling to Category II loads. The C pump is isolated and serves as an installed spare. Power to the C pump can be supplied from either bus A1 or A2 through a manually operated transfer switch. To maintain the required train separation and independence, the transfer switch is constructed so that the two power supply sources can never be connected in parallel. Controls for the switchgear breakers feeding the C pump are interlocked such that when the A pump is running, the C pump breaker from bus A1 cannot be closed; it can only be closed when the A pump breaker is in the disconnected or test position, and the transfer switch is in the channel A position.

Similarly, the C pump can be run from bus A2 only when the B pump breaker is racked out in the disconnected or test position, and the transfer switch is in the channel B position. If the C pump is running in place of either the A or B pump and that pump's breaker is racked in to the connected position, the C pump breaker trips open, unless it is operated in local mode with its remote-control switch in "pull to lock". The transfer switch position does not affect breaker closure, but it will determine whether the pump is aligned to the breaker and receives power when the breaker is closed. This arrangement minimizes the chances that the normally operating pump and the standby pump are supplied from the same bus and maintains electrical separation. This arrangement also helps prevent supplying two CCW pumps from one emergency diesel generator after losses of normal and preferred power sources.

The following signals start the pumps automatically:

1. CCW surge tank level low-low,
2. Low service water system pressure (from the opposite train),
3. Low differential pressure across the opposite train's CCW pump,
4. Low service water booster pump header pressure (from the opposite train),
5. Design-Basis-Accident (DBA) sequencer (20 seconds after initiation), or
6. Normal shutdown sequencer (6.5 seconds after initiation).

Of these automatic starts, only those by the DBA and normal shutdown sequencers activate if the lockout relay has tripped.

The following conditions activate the pump control circuit lockout relay and stop the CCW pumps:

1. Pump motor phase overcurrent,
2. Pump motor ground overcurrent,
3. Bus undervoltage, or
4. Standby (C) pump breaker will trip if the preferred pump (A or B) breaker is racked in to the connected position on the same bus.

Each of the A and B CCW pumps discharges through a 24-in. header that leads to the respective heat exchanger. The C pump discharges to a similar header that spans the discharge of the other two pumps and is isolated by a single locked-closed valve and check valve in series in the piping to either train. A temperature element in each train provides indication of CCW heat exchanger inlet temperature on control board recorders.

14.5.3.2 CCW Heat Exchangers

The two identical CCW heat exchangers (E-204A & B) are horizontal, counter-flow, shell-and-straight-tube-type heat exchangers with a design heat duty of 175 x 10^6 Btu/hr each. The shell is carbon steel and the tubes are Admiralty (copper, tin, zinc) while the tubesheets are aluminum bronze. Cooling flow from the Service Water (SW) system circulates through the tube sides to minimize fouling of the heat transfer surfaces. The SW tube side has a design temperature of 200°F, a design inlet temperature of 75°F, a design outlet temperature of 95°F, and a design flow of 17,500 gpm. The component cooling water on the shell side is oriented in counter-flow to the Service Water (SW). The CCW shell side has a design of 200°F, a design inlet temperature of 153°F, a design outlet temperature of 120°F, and a design flow of 10,500 gpm.

The CCWS heat exchangers are sized to provide the overall heat transfer required to maintain the CCWS temperatures within the maximum acceptable limits under all operating conditions assuming a maximum service water temperature of 75°F.

The normal maximum heat exchanger outlet temperature of 120°F supports the design criteria of maintaining the Spent Fuel Pool (SFP) temperature and the containment operating temperature no greater than 125°F and 120°F, respectively. To ensure that the above temperatures are not exceeded, CCW flow to the Residual Heat Removal (RHR) heat exchangers might need to be reduced by throttling the inlet valves.

Despite the fact that both trains are normally operating, the CCW system is designed to operate with one CCW heat exchanger in use during normal full-power operation. The remaining heat exchanger provides for 100% standby capacity should the operating heat exchanger become inoperable. The provision of two heat exchangers allows for maintenance on one heat exchanger while the other is in service.

A continuously operating automatic radiation detection system is provided in each train of the system. Each radiation detector is installed at the outlet of a CCW heat exchanger by a "strap-on" external mount. This system detects any ingress of radioactive material before the levels become potentially dangerous. The normal monitor readings should be equivalent to background radiation levels, since contaminated leakage into the CCW system is not expected. Each monitor provides an alert alarm when the radiation level reaches 1.5 times background, positive indication of contaminated leakage into the system. An additional high alarm set at 430 cpm above background is provided to indicate large-magnitude leakage. Radioactive fluids leaking into the CCW system would also be indicated by a rising surge tank level.

CCW flow from the outlets of both heat exchangers enters an 18-inch cross-connect header from which all loads receive their cooling flows. This header is divided into three sections by air-operated isolation valves CV-3287 and CV-3288. The two sections nearest the heat exchanger piping carry flow to the Seismic Category I loads. The piping between the isolation valves is where the Seismic Category II and the chemical addition tank piping attach. The air-operated return header isolation valves, CV-3303 and CV-3304, similarly separate the Category I and Category II piping. Flow returns to the suctions of the CCW pumps. Normally, one set of valves (e.g., CV-3304 and CV-3288) is closed to isolate the trains. Additionally, valves CV-3287, -3288, -3303, and -3304 automatically close in response to low-low level in the corresponding surge tank or a safety injection actuation signal.

14.5.3.3 Surge Tanks and Chemical Additive Tank

The CCW system is equipped with a surge tank in each train to absorb system volume changes. A single chemical addition tank (T-209) services both trains. The chemical addition tank is used to add corrosion-inhibiting chemicals to maintain system integrity. The chemical additive tank is a vertical carbon steel tank with a capacity of 70 gallons, a design temperature of 120°F, and a design pressure of 150 psig. The chem add tank has a normal operating temperature of <100°F, and a normal operating pressure of 100 psig.

The two identical surge tanks (T-204A & B) are vertically mounted, carbon steel cylinders with hemispherical top and bottom heads. The tanks are connected to the

Seismic Category I loops downstream of the CCW heat exchangers via four-inch lines. The functions of each CCW surge tank are as follows:

1. Provide system net positive suction head (NPSH),
2. Prevent boiling in the system high points by keeping the system full and pressurized at the containment air cooler outlets,
3. Dampen pressure transients due to load changes or pump startup or shutdown,
4. Act as an expansion volume due to changes in the CCW temperature,
5. Monitor fluid system volume via level instrumentation, and
6. Provide pressure relief through the safety relief valves to DRWS.

Each surge tank has a capacity of 2000 gallons with a normal operating temperature of <100°F, and the normal operating level is maintained between 45% and 60%. Water levels in the tanks are monitored by level transmitters. Each level transmitter also inputs a signal to a level switch which, in combination with its paired pressure switch, operates solenoid valves that supply and vent the nitrogen cover gas for that surge tank.

Pressurized cover gas maintains the NPSH of the CCW system. The plant nitrogen supply delivers gas to each surge tank through its pressure regulating valve to maintain pressure at 113 psig. A second pressure regulating valve in the vent line from each tank also helps to regulate pressure by venting excess nitrogen to the Dirty Radioactive Waste (DRW) drain tank at 125 psig.

To achieve adequate pressure control in the surge tanks, each pressure regulating valve comes equipped with a solenoid-operated bypass valve that is normally closed. Each of these valves is operated by an OPEN-RESET switch that spring-return to an unlabeled mid-position. With the switches in the mid-position, the solenoid valves control pressure between 115 psig and 125 psig. This control is accomplished through inputs from the level transmitter and pressure transmitter on each tank. Control of the solenoid-operated valves is as follows:

1. Supply bypass valves:
   a. Each opens automatically if its associated tank level is greater than 65% and its tank pressure is less than 115 psig.
   b. Each close automatically if its associated tank pressure is greater than 120 psig.
2. Vent bypass valves:
   a. Each opens automatically if its associated tank level is less than 54% and its pressure is greater than 130 psig.
   b. Each closes automatically if its associated tank level is greater than 56% or pressure is less than 125 psig.

The valves can be opened manually at any time, provided that a safety injection (SI) actuation signal is not present. A safety injection actuation signal either closes the valves or prevents them from opening. Following the reset of the SI actuation signal, the solenoid valve switches must be reset to permit their operation.

Overpressure protection for each tank is provided by two relief valves installed in a line off the tank vent. Both pressure relief valves lift at 130 psig. Tank design pressure is 150 psig and design temperature of 200°F.

The level instrumentation for the CCW surge tanks provide several functions in addition to the role they play in maintaining tank pressure. Functions of the level instrumentation are listed below:

1. A surge tank B level switch starts the B CCW makeup pump when the B CCW surge tank level drops below 40%, and stops the pump when level rises to 56.6%.
2. A surge tank A level switch starts the A CCW makeup pump when the A CCW surge tank level drops below 40%, and stops the pump when level rises to 56.6%.
3. A second surge tank B level switch starts the B CCW and B service water pumps when the B CCW surge tank level is $\leq$ 8.3%. Note that this instrument starts the C CCW and/or C service water pumps if these pumps are in the standby mode.
4. A second surge tank A level switch starts the A CCW and A service water pumps when the A CCW surge tank level is $\leq$ 8.3%. Note that this instrument starts the C CCW and/or C service water pumps if these pumps are in the standby mode.
5. A third surge tank B level switch closes the B train CCW seismic category I/II isolation valves when the B CCW surge tank level drops below 8.3%.
6. A third surge tank A level switch closes the A train CCW seismic category I/II isolation valves when the A CCW surge tank level drops below 8.3%.
7. The surge tank B level transmitter opens and closes the nitrogen supply and vent solenoid-operated bypass valves for the B CCW surge tank. It also provides a signal to a B CCW surge tank level indicator and high-level alarm in the control room.
8. The surge tank A level transmitter opens and closes the nitrogen supply and vent solenoid-operated bypass valves for the A CCW surge tank. It also provides a signal to an A CCW surge tank level indicator and high-level alarm in the control room.

14.5.3.4 CCW Makeup Pumps

The CCW makeup pumps (P-218A & B) are single-stage, horizontal, centrifugal pumps. Each CCW makeup pump has a design pressure of 650 psig, a design flow of 80 gpm, a cast steel casing, a bronze impeller, and a stainless-steel shaft. The pumps are powered from 480-vac ESF buses. Each train’s makeup pump is automatically started and stopped by level switches at its associated surge tank.

The CCW makeup pumps normally take suction from the Seismic Category II Demineralized Water Storage Tank (DWST). A Seismic Category I source of makeup water from the service water system is available for emergency use.

14.5.3.5 Piping and Valves

All CCW piping in the system is seamless carbon steel and was fabricated and installed in accordance with the requirements of ANSI B31.1.0, code for Pressure

Piping, with the exception of the Containment penetrations which are in accordance with ANSI B31.7 between the isolation valves inside and outside the containment.

Valves CV-3303, CV-3304, CV-3287 and CV-3288 are air-operated butterfly valves and are provided for separation of the two Seismic Category I loops and closing off the Seismic Category II portions of the CCWS under emergency conditions. Either "A" Train valves, CV-3303 and CV-3287, or "B" Train valves CV-3304 and CV-3288 are closed during split-train operation to provide train separation The remaining valves close automatically upon the initiation of a SIS or upon low-low water level in the CCWS surge tanks upon actuation of level indicating switches LIS-3211 and LIS-32l2. During single-train cross-connect operation, valves CV-3303, CV-3304, CV-3287, and CV-3288 are open and close automatically upon the initiation of an SIS or actuation of CCWS surge tank low-low level indicating switches, LIS-3211 and LIS-3212. The valves are air-to-open type so that air pressure failure will cause them to close.

Motor-operated valves MO-3290, MO-3291, MO-3292, and MO-3346 are provided for containment isolation. These valves provide capability of isolating the parts of the CCWS inside the Containment and closing the leak path from inside the containment to the CCWS should failure of the system pressure boundary inside the containment occur. Valves MO-3294, MO-3300, MO-3296 and MO-3320 close automatically on either of the following signals:

1) A containment isolation signal coincident with a low component cooling water surge tank level, or
2) A high-high Containment pressure signal.

Closure of the valves isolates the RCPs and excess letdown heat exchanger from the rest of the system. Motor-operated valves MO-3295 and MO-33l9 close automatically on a CIS to isolate the seal water heat exchanger and the letdown heat exchanger from the rest of the system.

Motor-operated valves MO-3293 and MO-3347 are provided for regulating the flow to the containment air coolers. Under normal operating conditions, these valves are closed and the required total flow of 1950 gpm to each train of coolers is provided through the 10-inch orificed bypass line around these valves. Upon the initiation of a SIS, these valves automatically move to the fully open position to allow a minimum flow of 6000 gpm to each train of coolers.

Motor-operated valves MO-3298A, B, C and D are located in the cooling water outlet lines from the RCPs. These valves are under the automatic control of the flow-sensing devices in the outlet lines which close the valves under excessive flow in the lines. This prevents blowdown of the RCS into the CCWS should a leak develop in an RCP thermal barrier cooler.

Flow regulation valves are furnished in the cooling water outlet lines from all components served by the system for establishing the proper flows.

14.5.3.6 Instrumentation

Differential pressure indicating switches PDIS-3399A and B are provided at the CCW pump discharge headers in both trains to initiate automatic startup of the standby CCW pump, if not already in operation, and its associated SWS train in the event of low differential pressure across the CCW pump of the train in operation. Level indicating switches LIS-3211 and LIS-3212 installed on the CCWS surge tanks limit a loss of inventory from the non-isolated train of the CCWS due to a single passive failure by causing closure of either isolation valves CV-3287 and CV-3303, or CV-3288 and CV-3304 upon low-low water level in the surge tanks during split-train operation or closure of all isolation valves CV-3287, CV-3288, CV-3303, and CV-3304 upon low-low water level in the CCWS surge tanks during single-train cross-connect operation.

Level switches LIS-3216 and LIS-3217 are installed on the CCWS surge tanks to control automatic makeup to the CCWS. However, current procedures require the Makeup Pumps to be placed in a "pull-lock-position" in order to monitor CCW inventory. The pumps are currently set to operate by manual control. Level switches LS-3387 and LS-3394 are interlocked with the CIS to close valves MO-3294, MO-3296, MO-3300, and MO-3320 on a CIS coincident with a low CCW surge tank level to limit CCWS inventory loss in the event of system leakage.

Thermowells and pressure indicator connections are provided where required for testing and balancing the system. Additional level and control switches on the surge tank automatically maintain a water level of 45 to 55 inches to minimize variations in tank pressure. Manual push-button controls are installed on Panel C18 to allow the control room operator to adjust CCWS surge tank pressure during operation of the CCWS makeup pumps to operation of the CCWS makeup pumps to maintain levels within the normal control band. Flow indicator taps are provided at strategic points in the system for initial balancing of the flows in the system and for verifying flows during Plant operation. Sufficient number of these taps are provided with permanently mounted local indicators to allow periodic monitoring of CCWS pump performance.

14.5.4 System Features and Interrelationships

14.5.4.1 Design Bases

The CCW system is designed to provide the required heat removal rates while maintaining system temperatures within the following limits:

1. CCW temperatures at the inlets to the residual heat removal heat exchangers do not exceed 120°F and 95°F, respectively, at the beginning and end of a normal cooldown of the reactor coolant system from 350°F to 140°F, as required to provide the 20-hour cooldown capability.
2. CCW heat exchanger outlet temperatures under design basis accident conditions do not exceed 140°F to protect against degradation of the pumps served by the system.

3. Temperatures remain less than the boiling point corresponding to the minimum pressure that occurs in the system at the outlets of the containment air coolers under design-basis accident conditions.

Maintaining the minimum required cooling water flow to the ESF equipment served by the CCW system is essential for ensuring the safe operation and safe shutdown of the plant. The ESF components of the CCW system are designed to meet Seismic Category I requirements and the single-failure criterion. The components of the CCW system which serve the reactor coolant pumps, the excess letdown heat exchanger, the letdown heat exchanger, and the seal water heat exchanger are also designed to meet Seismic Category I requirements to assure the integrity of these components under the postulated maximum seismic loading conditions.

A closed-cycle design was used for the CCWS to provide a monitored intermediate barrier between components handling RCS fluids and the primary heat sink consisting of cooling water flow through the SWS. The closed-cycle design also permits the use of a corrosion inhibitor in the system for protecting the system water passages from corrosion. Water chemistry control of the CCW system is accomplished by addition of a corrosion inhibitor via the chemical addition tank. The corrosion inhibitor protects the piping from corrosion to a degree sufficient to prevent long-term degradation of system capability. A slightly elevated pH is also desirable for corrosion control.

14.5.4.2 System Operation

Due to the pump design, the mechanical seals on the CCW pumps are pressure and temperature sensitive. To ensure the design life span of the seals, the CCW pumps must have adequate flow to ensure a minimal heatup of the fluid in the pump casing and to limit the pressure. Therefore, a minimum flow limit of 3,000 gpm per pump is required. During normal operations with all equipment aligned, this is not a direct concern. However, during Modes 4, 5, and 6, equipment may be secured or tagged out, thereby reducing the total flow in the system. Since there is no direct flow indication for CCW, the CCW system aligned to supply flow to the residual heat removal system heat exchangers (5,000 gpm each) ensures adequate flow.

The controls of the CCW pumps are interlocked with the service water pumps, so that the automatic start of a CCW pump on low-low surge tank level causes the automatic start of the service water pump in the same train in which the CCW system is operating.

During normal Plant operation. the CCW system provides the required cooling water flows for removal of heat from:

1) The RCS via the Residual Heat Removal (RHR) heat exchangers.
2) Letdown flows from the RCS via the letdown heat exchanger, and at times the excess letdown heat exchanger.
3) The Reactor Coolant Pumps (RCPs) via the thermal barrier heat exchanger in the RCPs.
4) RCP seal leakoffs via the seal water heat exchanger.
5) The containment atmosphere via the containment air coolers.

6) The SFP during spent fuel storage via the SFP cooling water heat exchangers.
7) The boric acid evaporators distillate coolers. The boric acid evaporators. vent condensers and the boric acid evaporator condensers.
8) The discharge of the waste gas compressor via the waste gas compressor after coolers and diaphragm coolers.
9) The bearing lube oil coolers for the following reactor auxiliaries and ESFs during normal operation or testing:

    (a) RCP motors.

    (b) Reciprocating (positive displacement) charging pump.

(10) Sample flows via the sample heat exchangers.

NORMAL: Normal Plant operation conditions can occur with a split-train condition or a single-train cross-connect condition. During split-train operating conditions, two CCW pumps and two CCW heat exchangers are in continuous operation. One CCW pump and heat exchanger supplies one Seismic Category I loop and the Seismic Category II loop. The other CCW pump and heat exchanger supply cooling water to the remaining two RCPs and the redundant train of containment air coolers. During single-train cross-connect operating condition, one CCW can supply both Seismic Category I and Seismic Category II loops. Cooling water is not required for the RHR heat exchangers, and the valves in the lines to these heat exchangers are in the closed position. Cooling water flow through the SFP heat exchangers is required during periods of spent fuel storage in the SFP.

COOLDOWN: During the plant cooldown phase following initiation of a normal plant shutdown, two CCW pumps are required to be in operation, and flow through both residual heat removal heat exchangers at $\geq$ 5000 gpm is required to provide the 20-hour cooldown capability. The plant can be brought safely to the cold shutdown condition with one residual heat removal heat exchanger in operation, but that evolution require approximately 100 hours.

COLD SHUTDOWN: The administrative controls applicable to RCS reduced inventory conditions are described in FSAR Section 5.1.3.5. Otherwise during periods of Plant cold shutdown for maintenance or refueling operations following the Plant cooldown phase, two CCWS trains are available, or one of the trains of the CCWS can be shut down, as long as a spare pump is available. One of the RHR heat exchangers can be taken out of service once the point has been reached where the temperature of the reactor coolant can be maintained below 140°F with one RHR heat exchanger in operation. At least one CCWS pump and one RHR heat exchanger are required to be in operation at all times during cold shutdown for the removal of decay heat from the RCS if fuel is in the reactor vessel or SFP. Cooling water flow through the SFP heat exchangers is required during all normal modes of operation, including periods of Plant shutdown when spent fuel is stored in the SFP.

During accident conditions such as the Design Basis Accident (DBA). The CCW system provides the required cooling water flows for removal of heat from:

    (1) The RCS via the RHR heat exchangers.
    (2) The Containment atmosphere via the Containment air coolers.
    (3) The seals for the following ESF equipment:

(a) RHR pumps.
(b) Containment Spray pumps (CSP).
(c) Safety Injection pumps (SIP).

An SI actuation signal causes actuation of ESF equipment as a result of postulated accident conditions. An SI actuation signal causes the following to occur:

1. Automatic start of both CCW system trains and service water system trains by the DBA sequencer. (Running pumps receive confirmatory start signals; standby pumps are started.)
2. Separation of the two Seismic Category I trains and isolation of the Seismic Category II part of the system by automatic closure of valves CV-3287, CV-3288, CV-3303, and CV-3304.
3. Automatic opening of flow control valves MO-3293 and MO-3347 in the return headers to provide full flow through the containment air coolers.
4. Removal of power from the solenoid-operated surge tank nitrogen supply and vent bypass valves. The valves must be reset following the reset of the SI actuation signal to enable the solenoids to function.

A Safety Injection Actuation Signal (SIAS) also causes a Containment Isolation Signal Phase A (CISA). Automatic or manual initiation of a containment isolation signal causes automatic closure of isolation valves MO-3295 and MO-3319, which isolates CCW flow to the letdown heat exchanger and the seal water heat exchanger. A Containment Isolation Signal Phase B (CISB), or a CCW surge tank low level (less than 18.3%) alarm concurrent with a Containment Isolation Signal Phase A (CISA), causes the automatic closure of isolation valves MO-3294, -3300, -3296, and -3320. This action isolates CCW to the RCPs and to the excess letdown heat exchanger and requires the shutdown of all running RCPs until CCW cooling is restored.

Operator action is not required for the CCW system to perform its required functions during the injection phase of an accident. When the recirculation phase is initiated, the operator must open the motor-operated valves at the inlets to the residual heat removal system heat exchangers.

MAKEUP WATER & CHEMISTRY: The periodic addition of water to the CCW is required due to the normal small amount of leakage to be expected from the system and for control of the chemistry of the water for the prevention of long-term corrosion of the water passages in the system. CCW makeup pumps are supplied with water from one of the demineralizer water transfer pumps and can be operated to add water automatically or manually to maintain each surge tank at a level of 45 to 55 inches. Makeup pump operation is controlled automatically by the CCW surge tank level switches LIS-3216 and LIS-3217. Manual push-button controls are installed on Panel C18 to allow the control room operator to adjust CCW surge tank pressure during operation of the CCW makeup pumps to maintain levels within the normal control band.

The emergency makeup supply from the SWS is used only when makeup water from the demineralized water storage tank is not available. Emergency makeup water is supplied to either of the loops by opening the normally closed valves in the emergency makeup line to the loop, opening manual valves in the alternate makeup pump discharge flowpath, and operating the appropriate CCWS makeup pump. The alternate flow path bypasses the spring-loaded discharge check valves, thereby reducing flow resistance. The bypass line permits adequate makeup flow to the CCWS with the service water supply, which is at a lower pressure than the normal demineralized water supply source.

The water in the CCWS is analyzed weekly for pH, conductivity, and corrosion inhibitor concentration. Abnormal pH or conductivity is corrected by draining water from the system as required and adding makeup water. Corrosion inhibitors are added as required through the chemical additive tank. Corrosion inhibitor concentration is maintained as required for the control of long-term corrosion.

14.5.5 PRA Insights

The component cooling water system of some plants is a major contributor to core damage frequency (79% at Zion, and 31% at Sequoyah). This is due to its role in Reactor Coolant Pump (RCP) seal cooling and cooling of equipment in the emergency core cooling systems (ECCSs). RCP seal cooling is provided by the thermal barrier heat exchanger and the normal charging seal injection from Chemical and Volume Control System (CVCS). Both of these heat removal mechanisms can be dependent on CCW for pump seal cooling.

However, many Westinghouse plants modified their Centrifugal Charging Pumps (CCPs) to an improved design that provided for self-cooling CCP seals. In this configuration, a loss of CCW does not result in a coincident failure of both thermal barrier heat exchanger flow and seal cooling flow to the RCPs. Accordingly, this modification significantly reduced the contribution of the CCW System to core damage frequency. The Trojan plant incorporated this modification and the Westinghouse Simulator reflects the improved design CCPs.

For plants which did not adopt this modification, a loss of CCW would result in a failure of the RCP seal as both the thermal barrier heat exchanger and CCPs would be lost due to a lack of cooling water flow. This would result in an RCP seal loss-of-coolant accident (LOCA). The charging pumps and safety Injection pumps are needed to supply injection to the core to make up for the loss of inventory. Without CCW, they would fail due to overheating. The resultant unrecoverable inventory from the reactor coolant system would lead to core damage. Probable causes of failure of the CCW system are as follows:

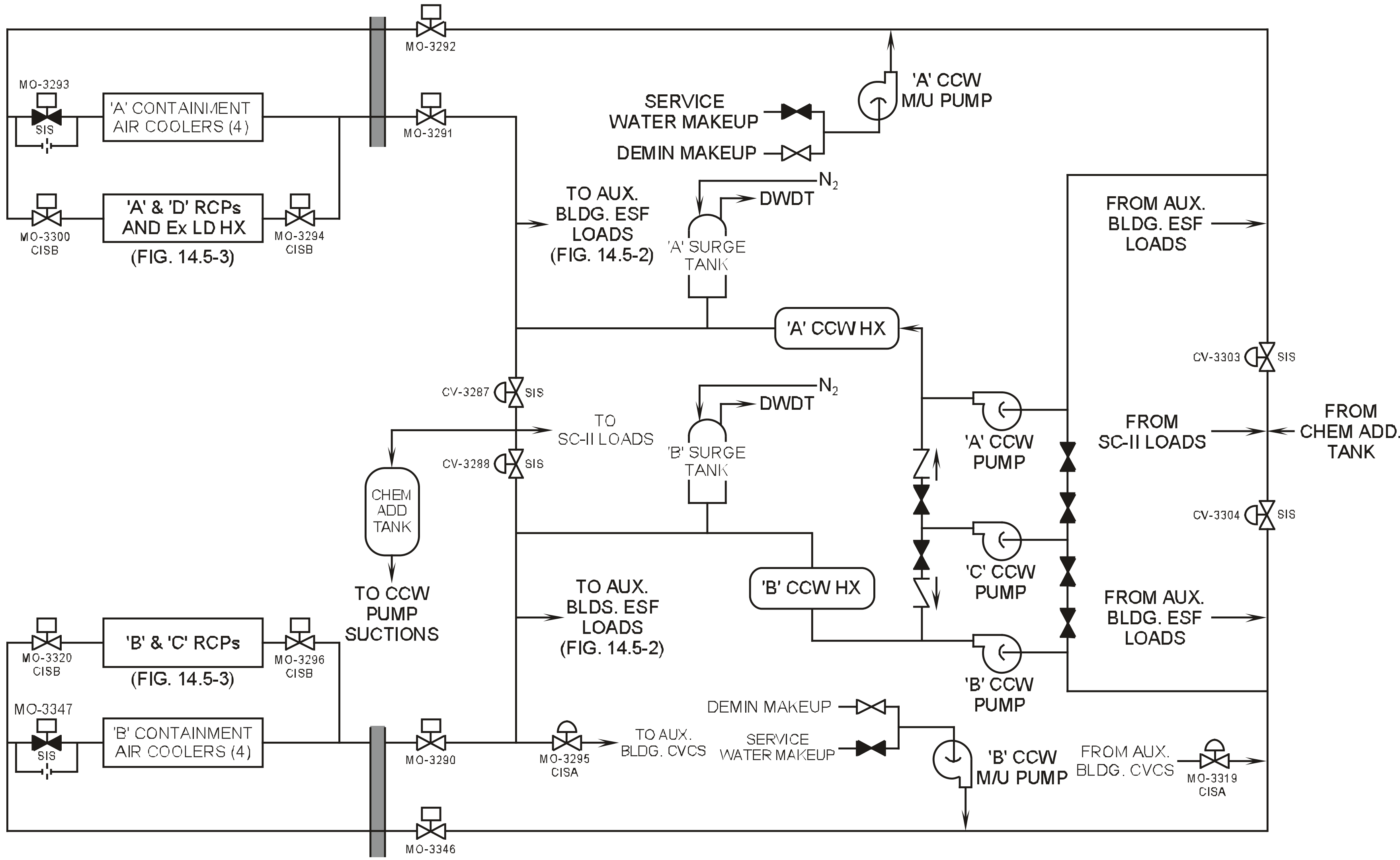
1. Human error - At those sites such as Zion and Sequoyah where the CCW system is shared between units, failure to manually align the standby train after failure of the operating loop.
2. Loss of CCW pumps - The pumps fail to start, or fail to continue to run after starting, due to some common-mode failure, such as loss of power.
3. Valve failure - Local fault of the heat exchanger outlet or bypass valves, or on some designs, a local fault of the header isolation valve to the ECCS pump coolers.

4. Piping failure - At Zion, the most significant failure is a rupture of the CCW piping. A review of the Probabilistic Safety Study identified 30 pipe sections whose failure would lead to a loss of CCW.

PRA studies (Reactor Risk Reference Document NuReg-1150) on importance measures have shown that the CCW system can be a major contributor to both risk reduction and risk achievement (Sequoyah - risk reduction factor of 450, risk achievement factor of 120-630).

14.5.6 Summary

The CCW system removes heat from various plant components during normal plant operation, plant cooldowns, and post-accident conditions. This system serves as a monitored intermediate barrier between radioactive fluid systems and the ultimate heat sink. The CCW system has two surge tanks, three pumps, and two heat exchangers. It consists of two Seismic Category I, safety-related trains and a common Seismic Category II non-safety-related loop. This system is an ESF system with two 100% capable trains to mitigate accident conditions. Makeup water to the system is available normally from the demineralized water system; it is supplied from the service water system during emergency conditions.



DWDT = Dirty Waste Drain Tank

Figure 14.5-1 Component Cooling Water System

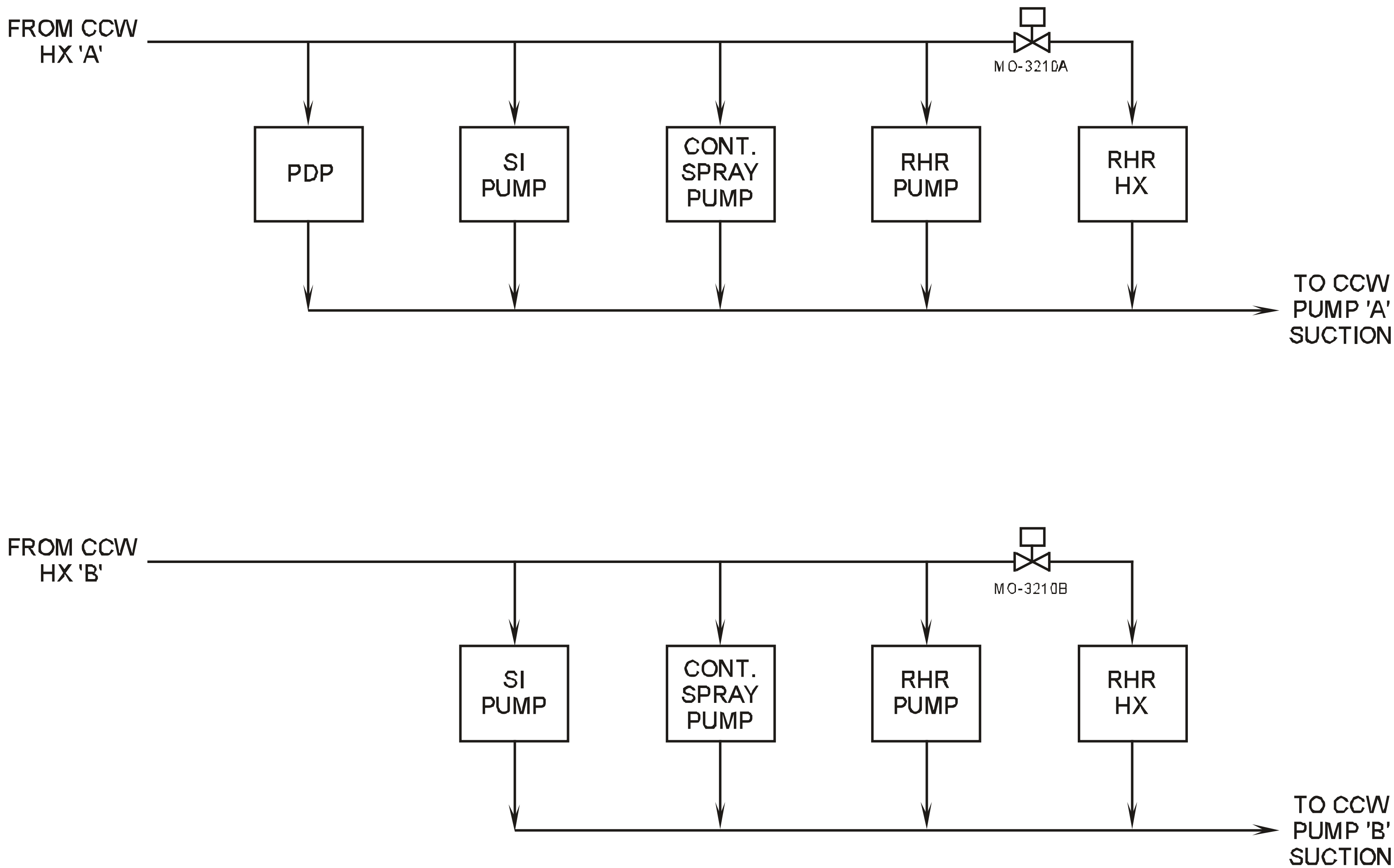


Figure 14.5-2 Auxiliary Building ESF Loads

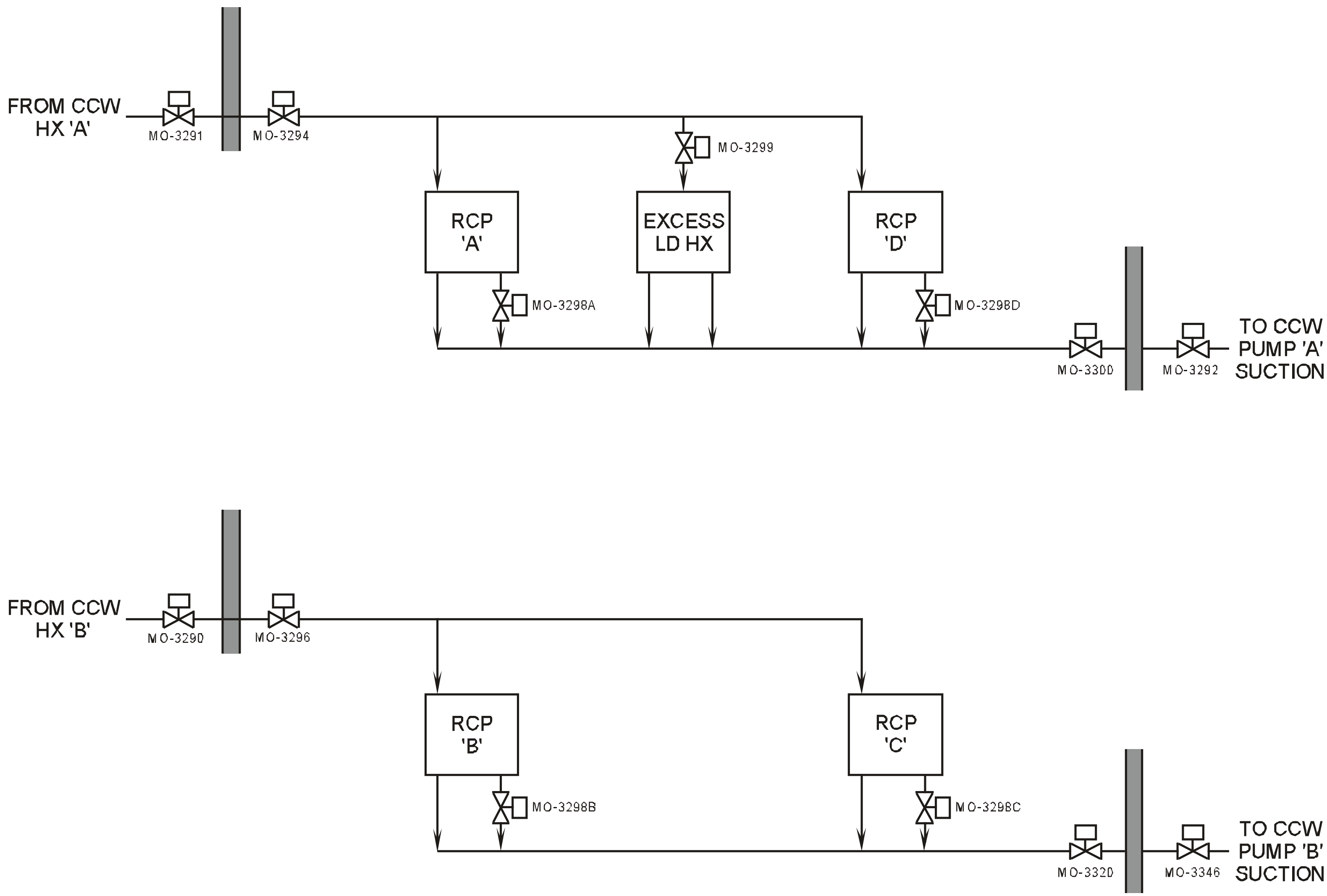


Figure 14.5-3 RCP Loads

TABLE 14.5-1a

COMPONENT COOLING WATER SYSTEM
DESIGN BASIS HEAT LOADS

Component	Normal Plant Operation[d]	Heat Load[a] (millions of Btu/hr): Heat Load[b] (millions of Btu/hr): 4 Hr After Plant Shutdown	Heat Load[b] (millions of Btu/hr): 20 Hr After Plant Shutdown	Design Basis Accident[c]: Injection Phase	Design Basis Accident[c]: Recirculation Phase
RHR heat exchangers	-	133.1[e]	75.2	-	88
SFP cooling water heat exchangers	13	13	13	-	-
Letdown heat exchanger	15	1.2	1.2	-	-
Excess letdown heat exchanger[f]	-	-	-	-	-
Reactor coolant pumps	4.8	1.2[e]	-	-	-
Seal water heat exchanger	2.5	0.75	0.75	-	-
Boric acid evaporators distillant cooler, vent condenser and condenser	16.25	8.6	8.6	-	-
Waste gas compressors	0.33	0.33	0.33	-	-
Sample heat exchangers	1.2	1.4	1.4	-	-
RHR pumps	0.15[g]	0.15	0.15	0.075	0.075
Safety injection pumps	0.15[g]	-	-	0.075	0.075
Reciprocating charging pumps	0.45	-	-	-	-
Containment spray pumps	0.19[g]	-	-	0.094	0.094
Containment air coolers	12.5	12.5	10.8	230	110
TOTAL	66	173	112	231	199

[a] Heat loads calculated on basis of nominal water temperatures.
[b] Both CCW pumps and heat exchangers in operation.
[c] Only one CCW pump and heat exchangers required for safe shutdown of Plant. Maximum heat load (Train B) shown here.
[d] One CCW pump and one heat exchanger in operation.
[e] One reactor coolant pump in service adding 17.4 x 10^6 Btu/hr reactor coolant.
[f] Not operated simultaneously with letdown heat exchangers.
[g] During testing only (not included in total).

TABLE 14.5-1b

COMPONENT COOLING WATER SYSTEM
DESIGN BASIS COOLING WATER FLOW RATES

Component	Flow Rate (gpm) Normal Plant Operation[b]	Normal Plant Cooldown[c]	Design Basis Accident[a] Injection Phase	Recirculation Phase
Residual Heat Removal heat exchangers	-	10,000[g]	-	5,000[g]
Spent fuel pool cooling water exchangers	3,000	3,000	-	[d]
Letdown heat exchanger	1,000	300	-	-
Excess letdown heat exchanger[e]	-	-	-	-
Reactor coolant pumps	780	780[f]	-	-
Seal water heat exchanger	210	210	-	-
Boric acid evaporators distillate cooler, vent condenser and condenser	1,290	1,290	-	-
Waste gas compressors	10	10	-	-
Sample heat exchangers	98	98	-	-
Residual Heat Removal pumps	10[f]	10	5	5
Safety Injection pumps	14[f]	14[f]	7	7
Reciprocating charging pump	93	93	-	-
Containment spray pumps	10[f]	10[f]	5	5
Containment air coolers	3,900	3,900	6,000	5,250[d]
TOTAL	10,415	19,715	6,017	10,267

[a] Per loop, only one CCW pump and heat exchanger required for safe shutdown of Plant. Maximum flowrate (Train B) is shown here.
[b] One CCW pump and heat exchanger in operation.
[c] Both CCW pumps and heat exchangers in operation.
[d] Flow to Containment air coolers can be reduced as required to provide flow to spent fuel pool cooling water heat exchangers if required during recirculation phase.
[e] Not operated simultaneously with letdown heat exchanger.
[f] Components not normally in operation, but flow is assumed to continue to components connected to system through normally open manually controlled valves.
[g] Design basis flow of 5,000 gpm to each RHR heat exchanger is based on normal Plant cooldown. A flow of 4,000 gpm or greater is acceptable in order to remove the required heat load during recirculation phase.

TABLE 14.5-1c

COMPONENT COOLING WATER SYSTEM
CALCULATED MAXIMUM WATER TEMPERATURE AND
OVERALL HEAT TRANSFER CHARACTERISTICS

Component	Normal Plant Operation	Normal Plant Cooldown 4 Hr After Plant Shutdown	Design Basis Accident[d]	
			Injection Phase	Recirculation Phase
Calculated CCW flow through each CCW heat exchanger, gpm	11,470[a]	10,905[b]	7,575	11,390
Calculated heat load on each CCW heat exchanger (10^6 Btu/hr)	68	74[b]	243	179
Minimum required service water flow through each CCW heat exchanger, gpm[c]	13,750	13,750	13,750	13,750
Design service water inlet temperature °F	75	75	75	75
Calculated CCW heat exchanger inlet temperature, °F	105	108[b]	198	154
Calculated CCW heat exchanger outlet temperature, °F	93	94[b]	134	122

[a] Assumes one CCW pump and heat exchanger serve both trains. Maximum flow (Pump B) is shown.

[b] Assumes two CCW pumps and heat exchangers in service. Maximum value (Train B) is shown.

[c] The original design basis fouling factor of 0.002 has been reduced to 0.0165 based on actual Plant measurements. This results in a lowering of the required service water flow from 17,500 gpm to 13,750 gpm as shown in Table 9.2-12.

[d] Single-train operation. Maximum values (Train A) are shown.

TABLE 14.5-2

COMPONENT COOLING WATER SYSTEM
SINGLE FAILURE ANALYSIS

Component	Failure	Comments and Consequences
CCW pumps	One pump malfunctions.	The second operating pump will provide 100 percent of minimum requirements under all operating conditions. The installed spare pump can be placed in operation to restore flow to the train served by the failed pump.
Make-up water supply	Failure of normal Seismic Category II source of make-up from the demineralized water storage tank.	Make-up can be provided from the Seismic Category I Service Water System.
	Failure of one CCW make-up pump.	One full capacity pump is provided for each train.
CCW heat exchangers	One heat exchanger malfunctions.	The standby heat exchanger will provide 100 percent of heat removal requirements under all operating conditions.
System pressure boundary	Single-failure in Seismic Category I pressure boundary.	Trains A and B are normally isolated by closure of the train isolation valves on one of the Seismic Category I loops so that a single failure in one train will not affect the other train. The trains can be isolated by operator action during other operating conditions.
	Any failure or failures in Seismic Category II pressure boundary.	The Seismic Category II parts are isolated from one Seismic Category I train by normally closed train isolation valves so that failure in Seismic Category II pressure boundary will not affect both Seismic Category I parts of the system. The Seismic Category II parts of the system can be closed off the system by operator action during other Plant operating conditions.
Valve CV-3033	Valve fails to close after SIS or low-low level in CCW surge tank.	If A Train Isolation Valves CV-3303 and CV-3287 are open, then CV-3304 and CV-3288 already will be closed providing the necessary train separation from Seismic Category II parts of system and Train A.
Valve CV-3304	Valve fails to close after SIS or low-low level in CCW surge tank.	If B Train Isolation Valves CV-3304 and CV-3288 are open, then Valve CV-3303 and CV-3287 already will be closed, providing separation of Train A from the Seismic Category II parts of system and separation from Train B.
Valve CV-3287	Valve fails to close after SIS or low-low level in CCW surge tank.	If A Train Isolation Valves CV-3303 and CV-3287 are open, then Valve CV-3288 and CV-3304 already will be closed, providing separation of Train B from the Seismic Category II parts of the system and separation from Train A.
Valve CV-3288	Valve fails to close after SIS or low-low level in CCW surge tank.	If B Train Isolation Valves CV-3304 and CV-3288 are open, then Valve CV 3287 and CV-3303 already will be closed, providing separation of Train A from the Seismic Category II parts of the system and separation from Train B.
Instrument air	Failure of air pressure to air-operated valves.	All air-operated valves in the system will move to safe position upon air pressure failure.
Power supplies	Failure of normal power source.	All system components will automatically switch to operation from preferred power.
	Failure of both normal and preferred power sources.	All system components will automatically switch to operation from power supplied by emergency diesel generators.
	Failure of power supply bus to one train.	Other train is supplied from an independent and physically separate bus.

Westinghouse Technology Systems Manual

Section 14.6

Service Water System (SWS)

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14.6 SERVICE WATER SYSTEM (SW)

Learning Objectives:

1. State the purposes of the Service Water System (SWS).

2. Identify the nonsafety-related loads supplied by the SWS.

3. Identify the safety-related loads supplied by the SWS.

14.6.1 Introduction

Plant cooling loads not served by the Circulating Water System and Cooling Tower are served by the Service Water System. Turbine building Cooling Water System is part of the Circulating Water System.

The Service Water System (SWS), shown in Figure 14.6-1, is an engineered safety features (ESF) support system which supplies continuous cooling water to the power plant. It is used to cool safety- and nonsafety-related components. The SWS serves two identical trains of ESF equipment, each consisting of one component cooling water heat exchanger, one emergency diesel generator, one train of room and pump coolers for ESF equipment, one auxiliary feed pump, and one component cooling water makeup pump, and spent fuel pool emergency makeup. Only one train of these components is required for safe shutdown of the plant following any of the postulated accident conditions. During accident or emergency conditions, flow to nonsafety-related components is isolated.

14.6.2 System Description

Three service water pumps take suction from the river at the intake structure. Trash racks, traveling screens, and a chlorination system protect the pump suctions from debris and marine growth. There is a pump for each of the A and B trains, and a spare swing pump that can be used to supply either train. The discharge of the service water pumps supplies the suction of the bearing lube water booster pumps. During normal operation, the bearing lube water booster pumps provide bearing cooling flow to the service water pumps. If necessary, the service water pumps can supply their own bearing cooling water.

The discharge of the service water pumps (SWP) goes through two independent Seismic Category I (safety-related) flow paths (trains A and B). The trains supply water to redundant safety-related components. The service water pumps themselves supply the normal source of cooling to the component cooling water heat exchangers, SW pump bearing lube water, SW strainer backwash, and the suction of four service water booster pumps (SWBP), two in each train. A portion of the SWS discharge at the Discharge and Dilution Structure provides suction to the cooling tower makeup pumps for makeup to the Circulating Water System (CWS).

The service water piping at the discharge of the booster pumps is divided into two trains by isolation valves that close on a safety injection actuation signal or an emergency diesel generator load signal from the associated train. During normal operation, the piping downstream of these valves supplies the Seismic Category II (non-safety-related) loads.

The service water supplies the following Seismic Category I loads:

- Component Cooling Water (CCW) heat exchangers (SWP header)
- Emergency Diesel Generator (EDG) combustion air and jacket coolers
- Room cooling units for coolers containing ESF equipment
- Centrifugal Charging Pumps (CCP) bearing and gear oil coolers
- Safety Injection Pumps (SIP) bearing oil coolers
- Backup cooling to the turbine driven AFW pump and driver
- Diesel-driven Auxiliary Feed Water (AFW) pump and driver
- SW Pump Bearing Lube Water Loads and SW Strainer Backwash are supplied off the SWP header (SWP header)

The service water supplies emergency makeup for the following safety related systems and equipment:

- Component Cooling Water (CCW) System makeup (SWP header)
- Auxiliary Feed Water (AFW) pump suction (SWBP header)
- Spent Fuel Pool (SFP) (SWBP header)

Service water booster pumps supply the following non-safety-related loads:

- Bearing Cooling Water (BCW) heat exchangers,
- Isophase bus duct coolers,
- Room cooling units for non-safety-related equipment - PDP charging pump room, Tank area cooler, reactor auxiliary building chillers, control building chillers, computer room air-conditioning condenser, electrical auxiliary room coolers, control building and maintenance shop chillers
- Blowdown radiation monitor flush, water treatment system
- Steam Generator BlowDown (SGBD) heat exchanger
- Steam jet air ejectors after condenser
- Heater Drain Pump (HDP) gland seal quenching water
- Process steam vent condenser

The service water supplies non-safety-related makeup for the following systems and equipment:

- Backup Domestic Water System (DWS) (SWP header supplied)
- Fire Water System (FWS) jockey pump
- Clean radioactive waste discharge line flushing
- Cooling tower makeup reservoir (SWP header supplied)
- Miscellaneous filter/exhaust unit drain trap makeup

Both trains are required during normal operation, normal cooldowns, and emergency diesel generator loading. Both trains available will allow a plant cooldown within 20 hours. One train is required during cold shutdown, for a safety injection actuation, and for safe shutdown and cooldown.

In the event the intake structure fails, water can be supplied to either train from the circulating water system or from portable pumping units via hose connections. The circulating water system supply can be returned to the cooling tower, or aligned to the discharge and dilution structure.

The river is used as the ultimate heat sink for the plant. The ultimate heat sink's principal safety function is to dissipate residual heat after a normal reactor shutdown or following an accident that results in emergency shutdown conditions. In the event that the intake structure is lost, the cooling tower basin becomes the ultimate heat sink.

The design basis of the SWS is to provide sufficient heat removal capacity and reliability to safely operate, shut down, and cool down the plant and to maintain it in a cold shutdown condition. Continuation of the minimum required cooling water flow to the safety-related equipment, auxiliary feedwater system, spent fuel pool emergency makeup, and component cooling water emergency makeup is essential to assure safe operation and safe shutdown of the plant.

The components of the SWS are sized to deliver the minimum required flows of water assuming a minimum water level of 1.5 feet below mean sea level (MSL) in the Columbia River. The SWS pumps themselves are designed to provide adequate flow for safe shutdown and cooldown at a minimum water level of -2.0-foot MSL.

Heat transfer equipment was selected based on a temperature of 75 ° F, which exceeds the highest recorded Columbia River temperature.

Continuation of the minimum required cooling water flows to the ESF equipment served by the system and continuation of availability of water supplies for the Auxiliary Feedwater System (AFWS), for the SFP emergency makeup, and for CCWS emergency makeup is essential to assure safe operation and safe shutdown of the Plant. The components of the system required to deliver these flows are accordingly designed to meet Seismic Category I requirements in accordance with the seismic criteria for Essential Safety Features (ESF) and are designed to meet the single-failure criterion.

The system is designed to permit using the Circulating water System as a water supply and heat sink in the unlikely event of unavailability of water supply from the Intake Structure. Loss of availability of water from the Intake Structure is considered an isolated event. It is not considered credible that events which would cause the inability of the Circulating Water System to supply the necessary water to the SWS or a Loss-of-Coolant Accident (LOCA) would occur simultaneously with loss of availability of water from the Intake Structure. The 30-inch JFD-16 and JFD-17 lines, interconnecting the SWS and the Circulating Water System are therefore designed to meet Seismic Category II requirements. These lines are isolated with normally shut Seismic Category I Valves SW-45 and SW-46.

The system design includes provision for inhibition of long-term corrosion and organic fouling of the system water passages sufficient to prevent long-term degradation of system capability.

14.6.3 Component Descriptions

14.6.3.1 Service Water Pumps (P-108A, B, C)

The three 500 hp service water pumps (P-108A, B, C) are vertical, centrifugal, wet-pit pumps, each with a design flow of 20,000 gpm at 80 psig. Each pump is capable of delivering 20,000 gpm at 85 feet. The pump bearings are water lubricated with the exception of the grease-packed suction bell bearings. Bearing lubrication is normally provided by the bearing lube water supply booster pumps. The pump casings are bronze lined cast iron while the impellers and shaft are made of stainless steel to resist corrosion.

The service water pumps take suction from the river through two automatic self-cleaning traveling water screens at the intake structure each with a design flow of 45,000 gpm and a normal flow of 21,500 gpm. The SW traveling screens are 304 stainless steel #5 mesh with three cleaning speed of 50%, 70%, and 100% clean.

Each pump is designed to supply 100 percent of the system flow requirements during each operating condition. Pump P-108A is aligned directly to train A and pump P-108B is aligned directly to train B. Pump P-108C can be lined up to either train to replace either pump A or pump B by opening normally locked-closed valves. During periods of single-pump operation, one of the other two nonoperating pumps is lined up to the opposite train discharge header in standby. The third pump is not lined up to the system and serves as an installed spare.

Power is supplied to pump A from 4.16-kv safeguards bus Al (Channel A) and to pump B from 4.16-kv safeguards bus A2 (Channel B). Pump C can be supplied from either bus A1 or A2 through a manually operated transfer switch that transfers the motor feeders between the two buses. To maintain the required channel separation and independence, the transfer switch is constructed so that the two power supply sources can never be connected in parallel. Controls for the switchgear breakers feeding pump C are interlocked such that when pump A is running, the pump C breaker, racked in to the connected position on bus A1, cannot be closed. It can only be closed when the pump A breaker is in the disconnect or test position. Similarly, pump C can be run from bus A2 only when the pump B breaker is racked out to the disconnect or test position. Note that if pump C were operating on bus A1 (i.e., with its breaker shut) and the breaker for pump A were racked in to the connected position, the pump C breaker would trip, unless it is operating in local mode with its remote control switch in “pull to lock.” The same holds for pumps B and C operating on bus A2. The transfer switch position does not affect breaker closure, but it will determine if the pump runs when the breaker is closed. This arrangement ensures that electrical channel separation is maintained at all times, and also minimizes the chances of powering two service water pumps from one emergency diesel generator during loss of normal power conditions.

Listed below are the six automatic start features for each service water pump. The first two auto start features require only that the pump's remote control switch be in auto. Given that the circuit breaker closing spring is charged, the pump will then start upon activation of either the DBA or the normal shutdown sequencer. However, the four remaining auto start features listed below (3 through 6) require the pump selector switch to be in REMOTE, the control switch in AUTO, and the breaker lockouts reset to start service water pump A:

1. DBA sequencer - channel A,
2. Normal shutdown sequencer - channel A
3. Train A CCW low surge tank level ($\leq$ 8.3%),
4. Train B service water system pressure low ($\leq$ 15 psig),
5. Train B CCW pump differential pressure low ($\leq$ 40 psid), or
6. Service water booster pumps B&D discharge header pressure low ($\leq$ 40 psig).

Start signals for the B and C service water pumps are similar to those described for the A pump.

The discharge of the A and B service water pumps goes to the respective service water system trains through 30-inch supply piping. A 30-inch header which cross-connects the two trains accepts the discharge from the C pump and directs it to the appropriate train. Normally locked-closed isolation valves are repositioned to allow pump C to supply either train.

Filtered lubricating water is supplied to all three pumps from a common header supplied from both SWS trains. Upon the initiation of a SIS, the lubricating water supply to the pump connected to Train A is isolated from that connected to Train B. When pump P-108C is used to replace P-108A, it is necessary to open the normally locked-closed valves in the lubricating water line to pump P-108C and close normally locked-open valves in the lube water line from Pump P-108B. In order to improve lubricating water quality for prevention of excessive wear to the service water pump shafts and shaft bearings, two booster pumps (P-180A and B) and two laval separators are provided in the lubricating water supply line. One 60-gallon per minute (gpm) booster pump is normally operated to feed the water to the Laval separators connected in series for removal of solids from the lubricating water flow.

Several SWS loads are supplied directly from the discharge of the service water pumps. The domestic water system is one of those loads. Its supply comes from the Seismic Category II piping between valves CV-3804 and CV-3803. The other major loads supplied directly include strainer backwash flow, the CCW heat exchangers, and the CCW emergency makeup supply. The rest of the flow from the service water pumps goes to the suctions of the service water booster pumps.

14.6.3.2 Service Water Strainers and Backwash Pumps

Just downstream of where the system pressure is sensed, there is a service water strainer in each train. Each strainer is sized for a design flow of 45,000 gpm and a normal flow of 21,500 gpm. The strainers are of the automatic self-cleaning, multiple element type. They are designed to trap particles larger than 62.5 mil (1/16 in.).

The normal SW strainer flow path is through the inlet, around the filter tube sheet, into the ends of the filter, and flow through the sides of the filter to the outlet.

Each strainer has a revolving dual backwash arm and drain valve that can be activated by a timer, high differential pressure across the strainer assembly, or manual (continuous) control. The backwash flow path is from the outlet, through the sides of the filter, out the rotating dual backwash arm, and to the backwash pump or bypass valve to the discharge and dilution structure. The backwash arm is driven by a motor mounted on top of the service water strainer.

The service water strainer backwash pumps are located in the service water strainer pits. They are designed to increase backwash flow to 600 gpm vice 350 gpm bypass flow. The “start” position continuously runs the backwash pump and is the normal position. In the “auto” position, the backwash pump would receive start and stop signals from strainer differential pressure or from a timer.

14.6.3.3 Service Water Booster Pumps (P-148A, B and P-148C, D)

Two 100 hp service water booster pumps (P-148A, B, or P-148C, D) in each train take suction on the discharge of that train’s service water pump. The service water booster pumps are horizontal centrifugal pumps with a design flow of 2500 gpm at 650 psig. The service water booster pumps are powered from vital 480-vac motor control centers.

For any service water booster pump to be started either manually or automatically, the permissive of service water pump discharge header pressure greater than 10 psig must be met. The automatic starts and permissives for the A and B pumps are different from those for the C and D pumps:

1. Each of the A and B pumps automatically starts on any related-train service water pump auto start. Each also auto starts if the related-train pump discharge decreases to less than 50 psig and its remote control switch is in “auto after stop” (green flagged).
2. Each of the C and D pumps automatically starts on any related-train service water pump auto start only if the related-train booster (A or B) pump is in the pull-to-lock position. If the C or D pump’s remote control switch is in “auto after stop” (green flagged), it auto starts if the related-train pump control switch is in “auto after start” (red flagged) and that pump’s discharge pressure decreases to less than 50 psig for greater than 3 seconds. Also, the C or D pump auto starts if any related-train service water pump auto starts, the related-train pump discharge is less than 50 psig for greater than 3 seconds, and its remote control switch is in auto after stop (green flagged).

Two service water booster pumps are connected in parallel in each train to provide flexibility in meeting the system flow requirements of the various operating conditions. Each of these trains is designed to provide 100 percent of the design requirements during normal operation.

14.6.3.4 Piping

The majority of 4-inch and lar-ger diameter piping is internally coated and seamless carbon steel. Exceptions are the uncoated seamless carbon steel piping used for the emergency siamese hose connections, at the service water strainer backwash pumps, and for the discharge from the auxiliary feedwater pump (AFWP) coolers. Uncoated carbon steel piping is also used for the connections to the Circulating Water System. The majority of piping less than 4-inches in diameter is either stainless steel, copper-nickel, or copper. Exceptions are the seamless uncoated carbon steel lube water booster pump and laval separator supplies and drains, service water strainer backwash pump supplies, component cooling water heat exchanger vents and drains, connections and discharges for the AFWP and AFWP driver coolers and supplies to several non-essential heat exchangers and sumps. Compatible fittings with corrosion resistant properties similar to the base piping are utilized. The exterior surfaces of buried piping are coated with a suitable material to inhibit corrosion.

14.6.3.5 Valves

The automatic valves that open or close automatically with a SIS or an EDG start are air-operated butterfly valves. Those that are required to open automatically under these conditions are air-to-close type so that they will open upon failure of air pressure, while those that are required to close are air-to-open type so that they will close upon loss of air pressure. Manually operated gate valves or butterfly valves are provided at all equipment served by the system for isolation of such equipment from the system. Check valves are furnished at the discharge of all pumps to prevent backflow through the pumps.

Globe valves for flow regulation are furnished at the cooling water outlets of the EDG heat exchangers, the bearing cooling water heat exchanger, the isophase bus duct cooler and all room coolers to allow the establishment of proper flows through these parts of the system.

14.6.3.6 Instrumentation

Pressure switches are provided in the supply headers to both trains for causing automatic startup of the standby service water pump and the CCW pump of the corresponding CCW train in the event of low pressure in the train in operation. Pressure switches are provided in the discharge line from each service water booster pump to cause automatic startup of the standby service water booster pump in each train in the event of loss of pressure in the discharge line. Pressure switches are provided near the service water pumps to prevent the service water booster pumps from starting when the service water pump is shutdown. Differential pressure switches that close when the differential level across either traveling water screen reaches 6 inches or more are provided for automatically activating the screen wash system.

The Elevation 45-foot level in the Auxiliary Building is protected from flooding by leakage from the SWS upstream from the service water booster pumps by level switches LS-3752A and B. Thermowells and pressure and flow indicator connections are provided where required for testing and balancing the system. Local reading flow indicating instrumentation is provided at the service water pump discharge and the service water booster pump suction headers to allow monitoring of pump performance.

14.6.4 System Features and Interrelationships

14.6.4.1 Alternate Sources of Supply

There are two alternate methods of supplying water to the service water system in the event of failure of the intake structure. A single 30-inch line from the circulating water system connects to each train of the service water system at the inlet and outlet of the component cooling water heat exchanger. The return flow from the heat exchanger outlet(s) goes to the cooling tower or to the discharge and dilution structure. Water can also be supplied through six 4-inch hose connections in each train that can be cross-connected and supplied from the installed fire pumps. These connections are just upstream of the service water strainer in each train.

14.6.4.2 Intake Structure, Screen Wash, and Chlorination Systems

The SW system components include three service water pumps located in the Intake Structure, two service water strainers in concrete pits between the Intake Structure and the Auxiliary Building, four service water booster pumps in the Auxiliary Building at Elevation 45 feet, and the required interconnecting piping, valves and instrumentation. Water is supplied through the trash rack and traveling water screens at the Intake Structure, and cooling water is discharged to the Discharge and Dilution Structure. The water entering the system is chlorinated through the microbiological control system. All water discharged to the Discharge and Dilution Structure is dechlorinated before being discharged to the Columbia River. In order to minimize plant thermal discharge to the Columbia River, service water through the steam generator blowdown heat exchanger is routed back to the cooling tower basin through an 8-inch line.

Each of the three service water pumps is contained within its own concrete cubicle in the intake structure. The intake structure sits on the bank of the river. The intake structure design and a trash rack between the river and the suctions of the wet-pit type service water pumps keep large debris out of the pump suctions.

Between the intake trash rack and the pump suctions are traveling screens. The traveling screens are designed to keep smaller debris and marine life out of the suctions of the service water pumps. The screens are kept clean by the screen wash system. This system employs two vertical pumps which take clean water that has already passed through the traveling screens and spray it through high velocity spray nozzles. The stationary spray nozzles wash the debris from the screens as they travel past. This cycle is automatically controlled by an adjustable timer that can provide up to 48 wash operations per day. There are also differential level controllers which start a screen-wash cycle whenever the levels on either side of the screen differ by six inches or more. It should be noted that no more than one service water pump may be in operation with one intake bay out of service.

Sodium hypochlorite, used for biofouling control of both the service water and the circulating water systems, is supplied from a portable storage tank, through a metering valve, to the chlorine injectors. Sodium sulfite from the sodium bisulfate tank is used to neutralize the sodium hypochlorite at the discharge and dilution structure.

14.6.4.3 Normal System Operation

NORMAL OPERATIONS: During normal operating conditions, water flow is through both of the Seismic category I trains and the Seismic Category II piping system. The intake structure screen wash and chlorination system and one bearing lube water pump are placed in operation. Each train of service water has one service water pump and one service water booster pump running, with both trains aligned to Seismic Category II loads. Flow is required to all of the equipment with the exception of the emergency diesel generators, the auxiliary feedwater pumps and drivers, and the makeup emergency water supply to safety systems. The SWS normally provides intermittent flow on an as-required basis to the steam jet air ejector after condenser and to the makeup water to non-safety systems. The discharge of the SWS loads is directed to the Discharge and Dilution Structure. A portion of the flow is used for cooling tower makeup; remaining discharge provides dilution water flow.

During normal single-pump operation, the system automatically shifts to operation on the other pump under the following conditions:

1. Loss of pressure in the operating service water pump discharge header (PS-3701A or B)
2. Loss of pressure in the associated booster pumps' discharge header
3. Low differential pressure across the operating component cooling water (CCW) pump

The controls of the SW and CCW systems are interlocked so that a failure of an operating train of any system will automatically start the standby train of the same system, and also the associated standby train of the other system.

The loads cooled by service water can normally receive flow from either train via the normally open (train A and B) isolation valves. Thus, during normal operations, both trains of service water are cross-connected at their cooling loads.

The service water booster pumps are electrically interlocked with the associated service water pump such that, for instance, the automatic start of the train A service water pump causes the automatic start of the A booster pump. If the A booster pump fails to start automatically, as indicated by inadequate booster pump discharge header pressure, the C booster pump starts following a three second time delay. The B train pumps are similarly interlocked.

During normal operation only one booster pump in each train is required to operate. When operating normally, the control switch for the running pump will be in the auto-after-start position; the control switch for the standby pump will be in the auto-after-stop position. If the running pump discharge pressure drops sufficiently while operating in this normal configuration, a pressure switch (PS-3711A/B/C/D) will cause the standby booster pump to start.

Pressure switches at the discharge header of the associated service water pump prevent a manual or automatic start of a booster pump until sufficient pressure exists to prevent damage to the booster pump. However, it should be noted that the pressure switches are upstream of the service water strainer. If the strainers become clogged, the pressure switches would see adequate discharge pressure from the operating service water pump. The booster pumps would then start with inadequate suction pressure. In the unlikely event the service water strainer has a high differential pressure, the standby booster pump on the affected train will be placed in pull-to-lock. This action will prevent an AutoStart of the standby booster pump during periods when the NPSH available may be inadequate. If both pumps fail to reach sufficient discharge pressure, a pressure switch (PS-3844A/B) will cause an AutoStart of the other service water train, if it is in standby.

NORMAL COOLDOWN: During the plant cooldown phase following initiation of a normal plant shutdown, two service water pumps are required to be in operation. Full flow through both component cooling water heat exchangers is required for 20-hour cooldown capability. The plant can be safely cooled down by one heat exchanger, but this will require a time period considerably longer than 20 hours.

COLD SHUTDOWN: During periods of cold shutdown for maintenance and/or refueling, one train of the SWS remains in operation. Flow through one component cooling water heat exchanger is required at all times during plant shutdown for removal of residual heat from the reactor coolant system. Two booster pumps may be required, depending on the operating equipment requiring cooling. During cold shutdown, the reactor coolant system is aligned to the residual heat removal system for decay heat removal. Flow through the in-service residual heat removal heat exchanger is cooled by component cooling water, which is cooled by the service water system.

14.6.4.4 Abnormal System Operation

<u>For Essential Safety Features (ESF) Actuations</u>: A Safety Injection Signal (SIS) causes actuation of ESF equipment as a result of postulated accident conditions and initiates the automatic start of both Emergency Diesel Generators (EDGs). The safety injection actuation signal causes the following to occur:

1. Automatic start of the standby Service Water System (SWS) train;
2. Separation of the two safety-related trains and isolation of the nonsafety-related parts of the system by automatic closure of valves CV-3720A and B, CV-3714 and CV-3725, and CV-3803 and CV-3804; and
3. Initiation of water flow to the Emergency Diesel Generator heat exchangers by automatic opening of valves CV-3712A and B.

A <u>loss of preferred power supply</u> (off-site power) under conditions of unavailability of normal onsite power sources causes automatic startup and loading of the Emergency Diesel Generators. When the emergency diesel generators are the sole sources of power to the 4160-vac emergency buses (A1 and A2), service water realigns the same as after a safety injection actuation signal.

Unavailability of water supply from the Intake Structure: In the unlikely event of the unavailability of water from the Intake Structure, water can be supplied to the SWS from the Circulating water System and the hose connections provided outside the Intake Structure. Water is supplied from the Circulating Water System by opening the valves in the 30-inch lines from the Circulating Water System which connect to the SWS at the inlet and outlet of the component cooling water heat exchangers and closing the valves in the normal discharge lines from the component cooling water heat exchanger. Flow to the SWS can be increased by throttling the appropriate motor-operated valve at the outlet of the main condensers. In the event of such an occurrence, the Circulating Water System, with a minimum quantity of 3 x 106 gallon in the cooling tower basin, is capable of supplying the water flow necessary to maintain the RCS in a safe condition for greater than 100 hours. One circulating water pump is capable of supplying more than 26,000 gpm to the SWS when the appropriate motor-operated valve at the outlet of the main condenser is throttled to 48 degrees open. (A total flow of approximately 23,000 gpm will be supplied with the condenser valves unthrottled.) Of this 26,000 gpm, approximately 11,300 gpm will flow through each component cooling water heat exchanger. Under design basis maximum summer temperature conditions, the water in the cooling tower basin will reach a maximum temperature of approximately 95°F. An analysis was performed to determine CCW performance for plant cooldown using 95°F circulating water. The plant cooldown would exceed the normal 20-hour period

With at least one circulating water pump in operation, water is supplied to the component cooling water heat exchangers and to the suction of the service water booster pumps. Service water passing through the CCW heat exchangers flows back into the Circulating Water System and is pumped through the cooling tower and back into the SWS. Water flow from safety-related components downstream of the service water booster pumps which normally discharges to the cooling tower makeup reservoir section of the Discharge and Dilution structure can discharge normally. With one cooling tower makeup pump in operation, this discharge can be pumped back into the circulating water system on the suction side of the circulating-water pump with no loss to the river.

All other service water booster pump discharge flow will be isolated except cooling water for the diesel-driven AFW pump, which is required for no more than 4 hours during Plant cooldown. This flow will total <150,000 gallons and constitutes the only loss from the Circulating Water System other than evaporation and drift losses in the cooling tower. The turbine-driven AFW feedwater pump can be operated without reliance on cooling water from the SWS. It is assumed that no cooling water is supplied to the emergency diesel generators (EDGs). In this scenario, off-site power is still available; otherwise, the circulating water pump could not operate.

In the event that water supply from the Intake Structure cannot be restored to the SWS before the water in the Circulating Water System is lost by evaporation and drift losses in the cooling tower, water can be supplied to the system through the hose connections provided in the service water pump discharge headers just outside the Intake Structure.

14.6.5 Summary

The service water system is an ESF support system essential to maintaining safe operation and shutdown of the plant. During normal plant operation it supplies safety- and non-safety-related components. During emergency conditions, the non-safety-related portions of the system are isolated from the safety-related portions to ensure that plant integrity is maintained.

The system consists of two independent Seismic category I flow paths

(designated Train A and Train B), each of which furnishes a single train of identical ESF equipment, and a single Seismic category II piping system that furnishes water to the Seismic Category II components served by the system. The Seismic Category I flow paths are normally interconnected downstream of the service water booster pumps, but each flow path is isolated from the other and from the Seismic Category II parts of the system by automatic closure of the system isolation valves upon the initiation of a safety injection signal (SIS) or loading of one or both of the emergency diesel generators (EDGs) unless the EDG output breaker is open or the supply breaker from the substation transformer is closed. The Seismic Category II piping system can be supplied from either Seismic Category I train during normal operating conditions. All components of the power supply provided for the SWS, except for Seismic Category II components, are Class IE electric systems.

Two alternative sources of water are provided for the system and can be activated in the event that the supply from the Intake Structure fails. Water can be supplied to each train from a single 30-inch line from the Circulating Water System which connects to each train in the service water supply line to the component cooling water heat exchangers. The circulating water supply to each component cooling water heat exchanger can be returned to the cooling tower through a single 30-inch line that connects to the service water discharge line from the heat exchangers. The circulating water lines are normally isolated from the SWS by locked-closed valves at each connection to the SWS. Water can also be supplied to the system through six 4-inch by 2 l/2 inch siamese fire hose connections (three for each train) provided outside the Intake structure.

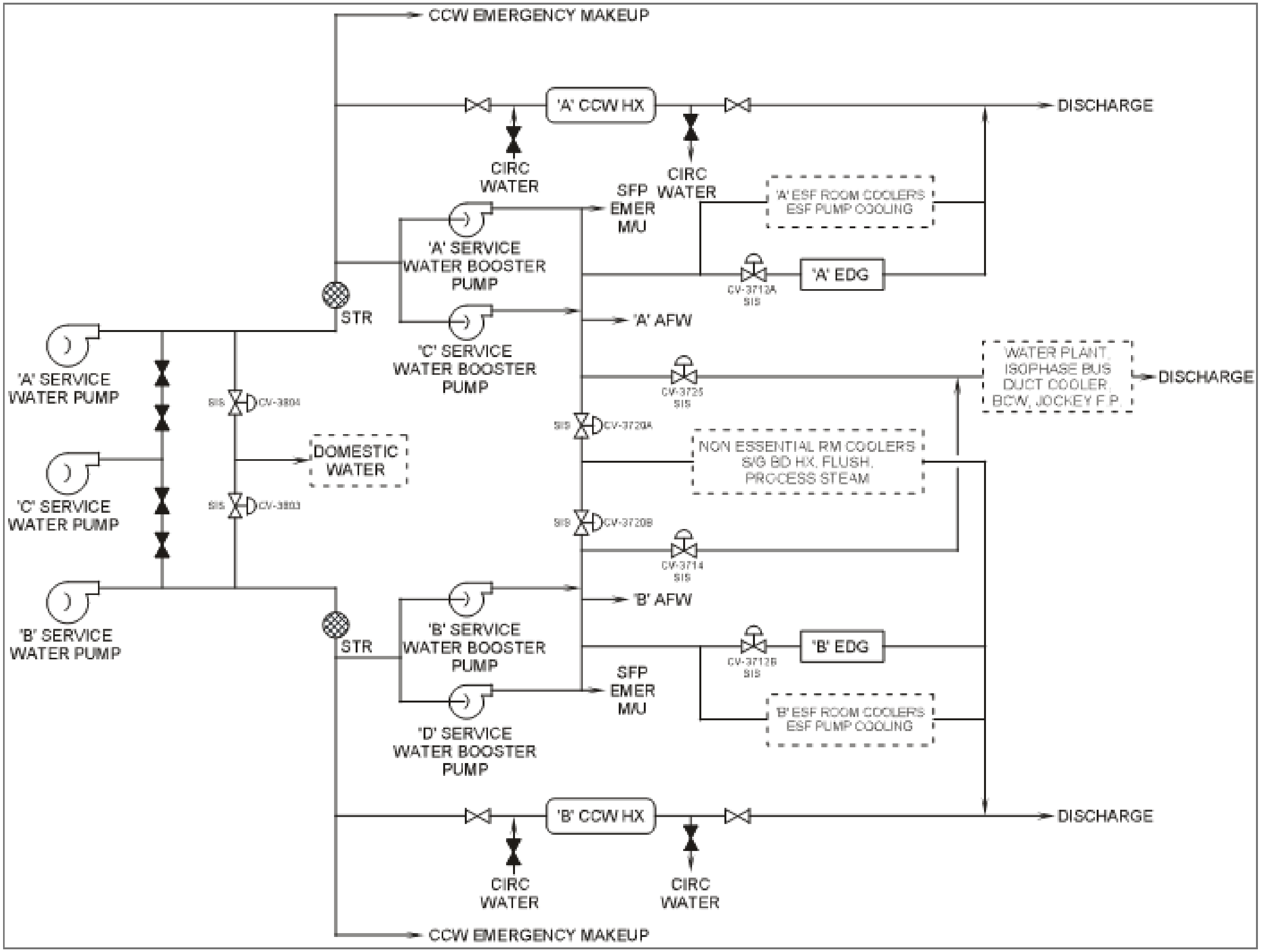


Figure 14.6-1 Service Water System

TABLE 14.6-1a

SERVICE WATER SYSTEM
DESIGN BASIS FLOW
EACH TRAIN, GALLONS PER MINUTE

Component	Normal Plant Operating Conditions and Cold Shutdown [a]	Normal Plant Cooldown [b]	Engineered Safety Features Actuation or Loading of Emergency Diesel Generators	Safe Plant Shutdown and Cooldown [a]
Emergency diesel generators	-	-	950	-
Auxiliary feedwater pump suction[c]	-	-	960	-
Auxiliary feedwater pump cooling water	-	-	370	-
Room coolers for rooms containing Engineered Safety Features	732	366	366	366
Emergency makeup to spent fuel pool	-	-	200	-
Shop and warehouse	40	40	-	-
Centrifugal charging pump lube oil coolers	80	40	40	40
Administration Building	75	75	-	-
Safety injection pump lube oil coolers	32	16	16	16
Process steam system	43	43	-	-

[a] Only one train is required.
[b] Both trains are required for 20 hour cooldown capability.
[c] Required only upon failure of normal auxiliary feedwater pump supply from condensate storage tank.

TABLE 14.6-1 b

Component	Normal Plant Operating Conditions and Cold Shutdown [a]	Normal Plant Cooldown [b]	Engineered Safety Features Actuation or Loading of Emergency Diesel Generators	Safe Plant Shutdown and Cooldown [a]
Nonessential room coolers	1,115	1,115	-	-
Bearing cooling water heat exchanger	350	350	-	-
Isolated phase bus duct cooler	155	155	-	-
Steam generator blowdown heat exchanger	1,000	-	-	-
Makeup Water Treatment System	200	200	-	-
Fire Water System jockey pump	50	50	-	-
Total for Component Supplied from the Service Water Booster Pumps	3,872	2,450	2,902	422
Component Cooling Water Heat Exchanger[e]	13,750	13,750	13,750	13,750
Component Cooling Water Makeup[d]	-	-	80	-
Chlorine Dilution	20	20	-	-
Service Water Pump Bearing Lube Water	10	10	10	10
Service Water Strainer	500	500	500	500
Total for All Components	18,152	16,730	17,242	14,682

[a] Only one train is required.
[b] Both trains are required for 20 hour cooldown capability.
[d] Required only upon failure of normal component cooling water makeup supply from demineralized water storage tank.
[e] Component cooling water heat exchanger flow based on reduced fouling factor.

COLOR LEGEND

QUALITY GROUP 1

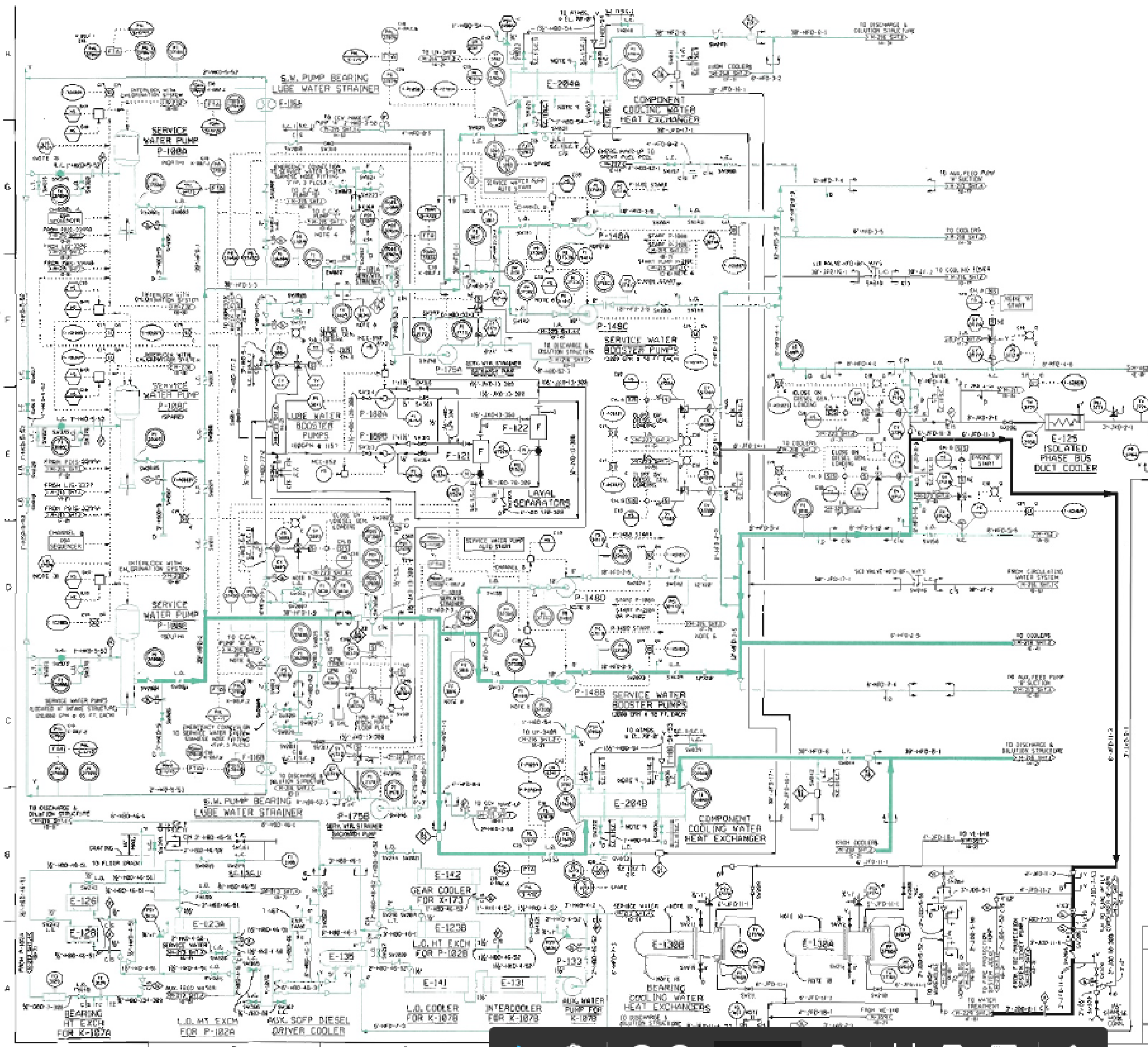
QUALITY GROUP 2

QUALITY GROUP 3A & 3B

QUALITY GROUP 4A / 4B

NOTES:

1. FOR FLUID SYSTEM SYMBOLS AND LEGEND SEE FIGURE 1.7-1.
2. FOR QUALITY GROUP APPLICATION AND CODE CLASSIFICATION FOR TROJAN PLANT SEE TABLE 3.2-1.
3. INSTRUMENT CONNECTION ROOT VALVES ARE NOT SHOWN. CLASSIFICATION OF INSTRUMENT CONNECTION PIPING FROM PROCESS LINE UP TO ROOT VALVE IS SHOWN WHERE APPLICABLE BY SAME COLOR LEGEND.
4. FIGURE 9.2-1A IS TAKEN FROM P&ID M-218 SH. 1, REV. 4A.
5. BY CONVENTION SOME INSTRUMENT TIE LINES, SUCH AS THOSE FOR PRESSURE POINTS, ARE SHOWN AS BLACK. IN SOME CASES, A MINIMUM LENGTH OF TUBING OR SMALL PIPE ARE DEPICTED ON THE P&ID, AND EXIST. THIS CONVENTION IS NOT MEANT TO IMPLY THAT THIS TUBING OR PIPING IS QUALITY CATEGORY 4B. ANY TUBING OR PIPING BRANCHING OFF THE PROCESS PIPE MUST MEET THE QUALITY CATEGORY GUIDELINES AS DISCUSSED IN CHAPTER 3.



REFERENCE DRAWING	P&ID NO.	FIG. NO.
1. HEATER & MISCELLANEOUS DRAINS SHEET 2	M-206	10.4-6
2. CONDENSATE & FEEDWATER SYSTEMS	M-210 SHT.2	10.4-2 B
3. AUXILIARY STEAM SYSTEM	M-214 SHT.2	10.4-3 B
4. COMPONENT COOLING WATER SYSTEM	M-216 SHT.1	9.2-4 A
5. CIRCULATING WATER & TURBINE BLDG. COOLING WATER SYSTEM	M-218 SHT.1 M-218 SHT.2	10.4-1 A 10.4-1 B
6. SERVICE WATER SYSTEM	M-218 SHT.2	9.2-1 B
7. BEARING COOLING WATER SYSTEM	M-219	9.2-6
8. INSTRUMENT AND SERVICE AIR SYSTEM	M-223 SHT.4 M-223 SHT.6	9.3-1 D 9.3-1 F
9. SPENT FUEL POOL COOLING & DEMINERALIZER SYSTEM	M-227	9.1-4
10. DOMESTIC WATER SYSTEM	M-229 SHT.1	9.2-7 A
11. INTAKE STRUCTURE & SCREEN WASH SYSTEM	M-238	9.2-2
12. FIRE PROTECTION SYSTEM	M-233 SHT.1	9.5-1
13. CHILLED WATER SYSTEM	M-305	9.4-15
14. EMERGENCY DIESEL GENERATOR COOLING WATER SYSTEM	M-402	9.5-8

NOTES:

1. ENTIRE SYSTEM IS SEISMIC CATEGORY I EXCEPT AS NOTED.
2. DELETED
3. LIS-3702 HAS CAUSE SHUTDOWN OF SERVICE WATER PUMPS FOR PREVENTION OF FLOODING AT ELEV. 45 IN THE AUX. BUILDING IN THE EVENT OF A FAILURE IN SERVICE WATER SYSTEM PIPING. WATER ON THE FLOOR AT ELEV. 45 ACTUATES THE SW. CONTROL.
4. CORNER & CHILLER FROM DISCHARGE & 2" BED PLATE DRAINS TO BE ... SPEC. AT ... CHANGE FROM SEISMIC CAT. II TO CAT. I AT OUTLET OF ... BED PLATE ... PLATE DRAINS WHICH ARE SEISMIC CATEGORY II.
5. DELETED
6. PS-2700 A/B OR PS-2804 A/B ACTUATION WILL START THE OPPOSITE TRAIN SW AND ... PUMPS IF NOT RUNNING.
7. DISSIMILAR METAL CONNECTIONS (S.S. OR C.S. TO CUPRO-NICKEL) COOLING COILS OF PUMPS AND ASSOCIATED PIPING SHALL HAVE ... KITS.
8. INDICATORS ... THE INSTRUMENT ROOT VALVES SHOULD BE NORMALLY CLOSED UNLESS SPECIFICALLY AUTHORIZED TO BE OPEN. INSTRUMENT ROOT VALVES FOR ... HAVE BEEN EVALUATED ... AND MAY BE LEFT OPEN.
9. FOR COMPONENT COOLING WATER PIPING SEE P&ID M-216 ...
10. FOR BEARING COOLING WATER PIPING SEE P&ID M-219 ...
11. SEGMENT OF LINE MATERIAL FOR LINE ... MATERIAL ... RELATED ...

Amendment 19
(December 1992)

TROJAN NUCLEAR PLANT
FSAR

SERVICE WATER SYSTEM

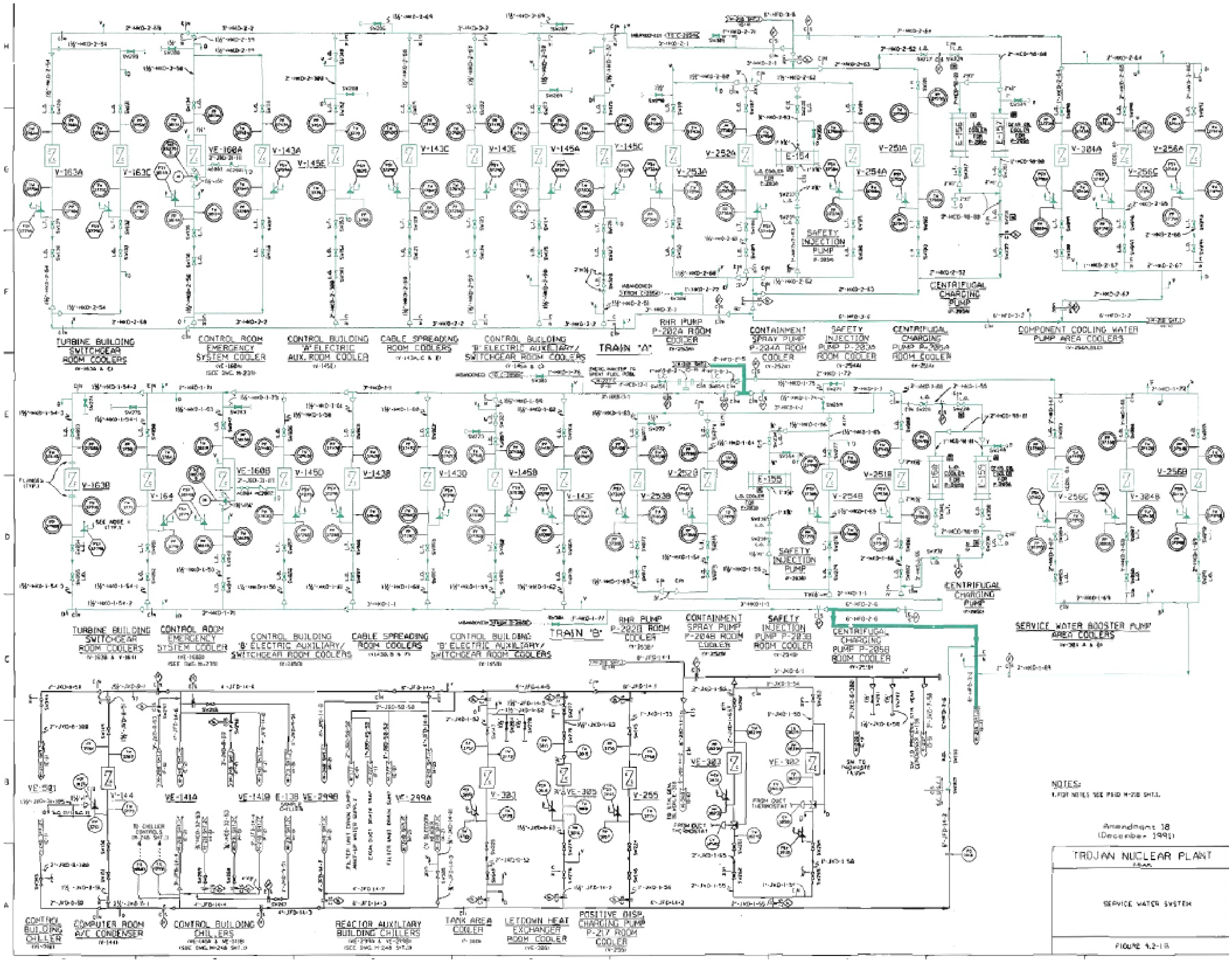
FIGURE 9.2-1A

COLOR LEGEND

QUALITY GROUP 1
QUALITY GROUP 2
QUALITY GROUP 3A & 3B
QUALITY GROUP 4A / 4B

NOTES:

1. FOR FLUID SYSTEM SYMBOLS AND LEGEND SEE FIGURE 1.7-1.
2. FOR QUALITY GROUP APPLICATION AND CODE CLASSIFICATION SEE TROJAN PLANT QET TABLE 3.2-1.
3. INSTRUMENT CONNECTION ROOT VALVES ARE NOT SHOWN. CLASSIFICATION OF INSTRUMENT CONNECTION PIPING FROM PROCESS LINE UP TO ROOT VALVE IS SHOWN WHERE APPLICABLE BY SAME COLOR LEGEND.
4. FIGURE 9.2-1 B IS TAKEN FROM P&ID M-218 SHT.2, REV. 12.
5. BY CONVENTION, SOME INSTRUMENT TIE LINES, SUCH AS THOSE FOR PRESSURE POINTS, ARE SHOWN AS BLACK. IN SOME CASES, A MINIMAL LENGTH OF TUBING OR SMALL PIPE, NOT DEPICTED ON THE P&ID, MAY EXIST. THIS CONVENTION IS NOT MEANT TO INFER THAT THIS TUBING OR PIPING IS QUALITY CATEGORY 4B. ANY TUBING OR PIPING BRANCHING OFF THE PROCESS PIPE MUST MEET THE QUALITY CATEGORY GUIDELINES AS DISCUSSED IN CHAPTER 3.



REFERENCE DRAWING	P&ID NO.	FIG. NO.
1. SERVICE WATER SYSTEM	M-218 SHT.1	9.2-1 A
2. CLEAN RADIOACTIVE WASTE TREATMENT SYSTEM	M-228	11.2-1
3. RADIOACTIVE GASEOUS WASTE SYSTEM	M-232	11.3-1
4. PROCESS SAMPLING SYSTEM	M-217 SHT.2	9.3-5
5. PROCESS STEAM SYSTEM	M-227	10.4-9
6. CHILLED WATER SYSTEM	M-248 SHT.1 M-248 SHT.2	9.4-2 A 9.4-2 D
7. STEAM GENERATOR BLOWDOWN SYSTEM	M-319	10.4-8

Amendment 18
(December 1998)

TROJAN NUCLEAR PLANT
PSAR

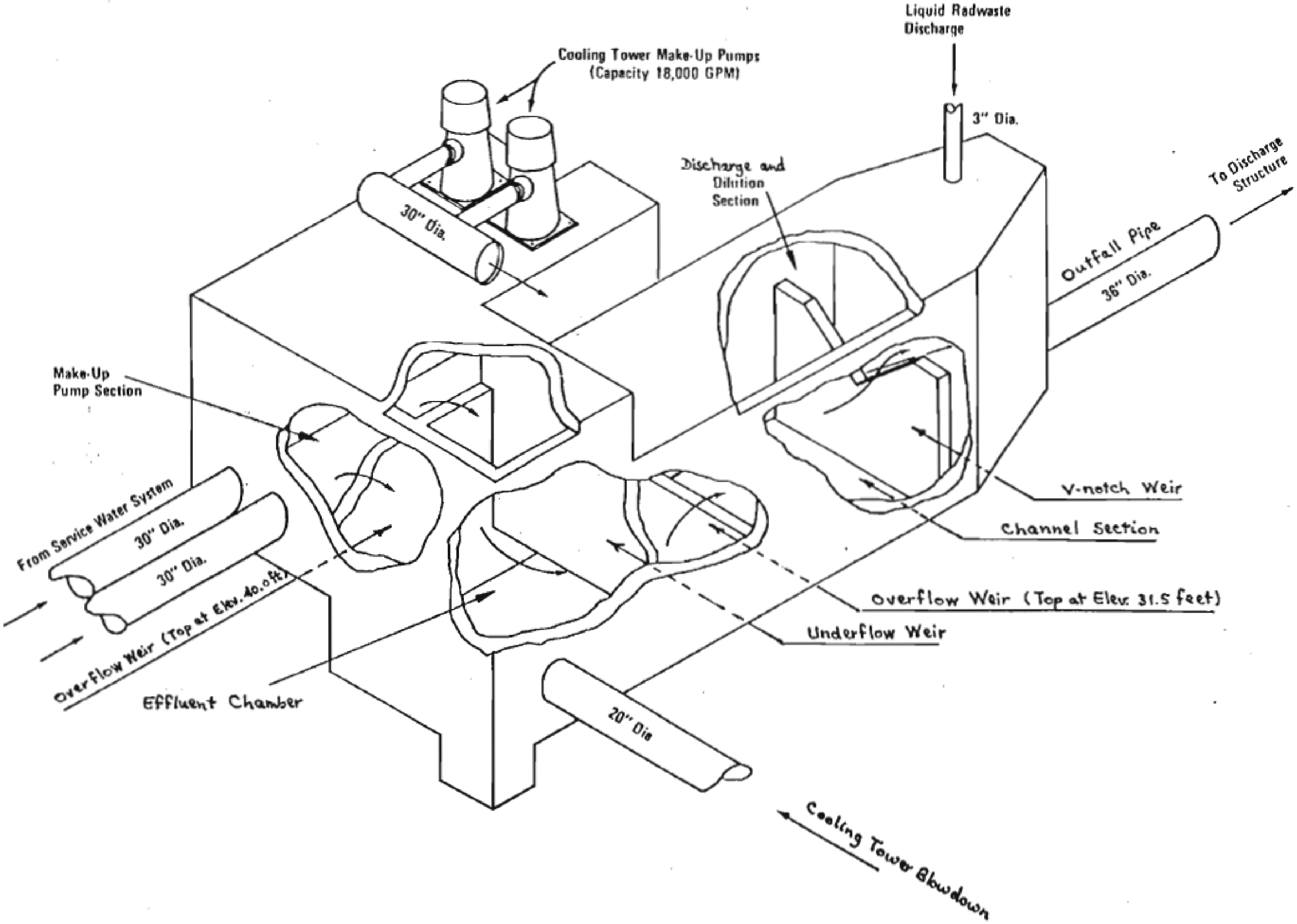
SERVICE WATER SYSTEM

FIGURE 9.2-1 B

TABLE 14.6-2

SINGLE FAILURE ANALYSIS SERVICE WATER SYSTEM

Component	Failure	Comments and Consequences
Intake Structure	Blockage of water flow to the service water pumps	Water is supplied to the system from the Circulating Water System or from the river through the hose connections provided.
Service water pumps	One pump malfunctions	The standby pump will provide 100% of minimum requirements under all operating conditions.
Service water strainers	Blockage of water flow in one strainer	The second train will provide 100% of minimum requirements under all operating conditions.
Service water booster pumps	One pump malfunction	The second train will provide 100% of minimum requirements under all operating conditions. The installed spare pump in each train provides further backup and will start automatically upon failure of the operating pump when available for operation.
System pressure boundary	Single failure in Seismic Category I pressure boundary	Fluid system Trains A & B are isolated by a safety injection signal (SIS) and loading of the emergency diesel generators so that a single failure in one train will not affect the other train. The trains can be isolated by operator action during other plant operating conditions.
	Any failure or failures in Seismic Category II pressure boundary	The Seismic Category II parts of the system are closed off from the system by an SIS and loading of the emergency diesel generators so that any failure in Seismic Category II pressure boundary will not affect the Seismic Category I parts of the system. The Seismic Category II parts of the system can be closed off from the system by operator action during other plant operating conditions.
Valve CV-3720A	Valve fails to close after SIS or loading of the emergency diesel generators	Valve CV-3720B closes to provide separation of Train B from Seismic Category II parts of the system and separation from Train A.
Valve CV-3720B	Valve fails to close after SIS or loading of the emergency diesel generators	Valve CV-3720A closes to provide separation of Train A from the Seismic Category II parts of the system and separation from Train B.
Valve CV-3725	Valve fails to close after SIS or loading of the emergency diesel generators	Valve CV-3714 closes to provide separation of Train B from the Seismic Category II parts of the system and separation from Train A.
Valve CV-3714	Valve fails to close after SIS or loading of the emergency diesel generators	Valve CV-3725 closes to provide separation of Train A from the Seismic Category II parts of the system and separation from Train B.
Valves CV-3712A & B	One valve fails to open after SIS or loading of the emergency diesel generators	One emergency diesel generator is sufficient to supply all emergency power requirements.
Instrument Air System	Failure of air pressure to air-operated valves	All air-operated valves in the system will move to safe position upon air pressure failure.
Power Supplies	Failure of normal power source	All system components will automatically switch to operation from preferred power.
	Failure of both normal and preferred power sources	All system components will automatically switch to operation from power supplied by the emergency diesel generators.
	Failure of power supply bus to one train	Other train is supplied from an independent and physically separate bus.



FSAR CH 9.2. **Figure 9.2-10 Dilution Structure**

Westinghouse Technology Systems Manual

Section 14.7

Circulating Water System (CW)
and Turbine Building Cooling Water (TCW) System

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14.7 CIRCULATING WATER (CW) SYSTEM AND TURBINE BUILDING COOLING WATER (TCW) SYSTEM

Learning Objective:

1. State the purposes of the circulating water system and the turbine building cooling water system.

14.7.1 Introduction

The Circulating Water (CW) system and Turbine Building Cooling Water(TBCW) system, as shown in Figure 14.7-1, provides cooling water for heat removal from the main condenser, the steam jet air ejector inter and after condensers, the turbine-generator auxiliary coolers, and the turbine generator feedwater pump turbine lube oil coolers.

The system serves as the preferred heat sink for normal reactor cooldown. as an emergency source of water supply to the Service Water System (SW) and for the fire water supply system in the unlikely event of unavailability of water from the Intake Structure.

14.7.2 System Description

CW System is designed to dissipate 7.92 x 10^9 Btu/hr, which equals the total heat load from the main condenser and other components served by the system. The CWS supplies:

- Cooling water for the main condensers,
- Cooling water for the steam jet air ejector inter and after condensers,
- Emergency water supply to the service water system,
- Emergency water supply to the fire main,
- Water supply to the turbine building cooling water system,
- Return point for service water flow from the steam generator blowdown heat exchangers,
- Water for the administration building and the shop and warehouse heating systems,
- Cooling water for the circulating water pump lube oil coolers, and
- Heating water for the fish rearing facility.

The TBCW system supplies cooling water to:

- Turbine-generator lube oil coolers,
- Steam packing exhauster,
- Steam generator turbine feed pump lube oil coolers,
- Generator stator coolers,
- Exciter air cooler,
- Generator hydrogen gas coolers, and
- Condensate demineralizer building.

The Circulating Water System and TCW System is a closed-loop system with provision for continuous makeup for water loss from the system by means of the cooling tower makeup pumps.

The two half-capacity' circulating water pumps circulate water from the cooling tower basin outlet structure, through the tube side of the main condenser and finally discharge the water to the cooling tower. The pumps also supply water to steam jet air ejector intercondensers and aftercondensers and to the TCW System.

The two Turbine Building Cooling Water (TCW) booster pumps take suction from the circulating water pump discharge lines. These booster pumps provide cooling water to two turbine generator lube oil coolers, one steam packing exhauster, four steam generator feed pump turbine driver lube oil coolers, four generator hydrogen coolers, two generator stator coolers, and one exciter air cooler. Subsequently, this water is returned to the condenser outlet side of the circulating water piping.

The natural draft cooling tower cools the heated circulating water returning from the components served by the Circulating Water (CW) System and TCW System.

The two cooling tower makeup pumps supply water to the Circulating Water System to replace water losses due to evaporation, windage and blowdown from the Circulating Water System. The pumps are located in the Plant Discharge and Dilution structure. The pumps take suction from the makeup suction sump and supply makeup water to the circulating water piping between the cooling tower basin outlet and circulating water pump suction.

Motor-operated butterfly valves which can be operated either locally or from the control room are provided at the suction and discharge of the circulating water pumps and at the outlets of condenser shell “C”.

Shutoff valves are provided upstream and downstream of all equipment served by the system to enable isolation of any specific equipment. Control valves are provided in the cooling water lines for equipment where flow regulation is necessary, and in the blowdown lines to regulate quantity of blowdown from the Circulating Water System.

Circulating Water System piping is constructed of carbon steel. All piping 96-inch diameter or larger has an internal coating of material intended to protect the piping from the abrasive action of silt and to inhibit corrosion. TCW System piping is of carbon steel, coated internally with coal tar epoxy.

Since the CW System requires the addition of sulfuric acid to minimize scale buildup, a pH-controlling acid addition system is provided. Sulphuric acid injection piping, fittings, and valves are provided with polypropylene liner.

During normal Plant operating conditions, with the Plant operating above 55 percent of the full rated Plant load, both circulating water pumps must be in operation. During Plant operation at or below 55 percent of rated load, one circulating water pump is sufficient. The pumps can be started either locally or from the control room.

One Turbine Building cooling water (TCW) booster pump is normally in operation. The second pump is on standby and starts automatically upon system low pressure. The pumps are also provided with control switches for local manual operation or remote manual operation from the control room.

One cooling tower makeup pump is normally operating. The second pump is on standby and can be started either locally or from the control room upon failure of the preferred pump to supply the required makeup water.

During normal Plant operation, chlorination of circulating water is intermittent. Sulphuric acid injection is manually controlled in accordance with the amount of cooling tower makeup flow and pH of the circulating water.

14.7.3 Component Descriptions

14.7.3.1 Circulating Water Pumps

The two half-capacity circulating water pumps (P-107A and B) are single-stage, horizontally split, centrifugal pumps which supply the necessary head for system flow. Each pump has a design flow of 210,000 gpm, design pressure of 95 psig, and a design temperature of 95°F. The pumps have a carbon steel casing with a stainless-steel impeller and shaft. The 6250-horsepower pumps are powered from 12.47-kv buses H1 and H2. Each pump shaft is sealed at each casing exit point by a self-supplied stuffing box (gland) that has filters, heat tracing, throttle valves, and flow sight glasses. The pumps are located outside, in the circulating water pump pit. A common lubricating oil system is shared by the two pumps.

14.7.3.2 Cooling Tower

The hyperbolic natural draft cooling tower (E-112) cools the circulating water returning from the various components served by the CW and TCW systems. The cooling tower has a design water flow of 425,000 gpm, a design heat duty of 7.92 x 10^9 Btu/hr, and a design range of 37°F. The hyperbolic tower, designed for strength alone, is evaporative in design and contains no fans.

The air flow within the shell is created by the density difference between atmospheric air and the hotter air inside the tower. The counter-flow design provides a highly efficient heat transfer mechanism since the coolest air contacts the coolest water initially. The heat transfer process occurs in the fill section of the tower. The design velocity of the plume is 17 ft/sec winter and 14 ft/sec summer.

The cooled water falls into the cooling tower basin, passes through a set of double screens in the basin outlet, and then circulates to the suction of the circulating water pumps. The cooling tower basin has a capacity of 5.2 x 10^6 gallons with a design water loss due to evaporation of 11,300 gpm at rated capacity.

The spray header can be bypassed to allow warmup of the CW System on startup or to maintain the proper temperature during cold weather operation. Bypass flow is controlled by a 72-inch, motor-operated, butterfly valve located near the tower basin.

There are no interlocks associated with this valve, though only one CW pump should be in operation with the valve open.

14.7.3.3 Cooling Tower Makeup Pumps

The cooling tower makeup system uses two full-capacity vertical makeup pumps (P-109A and B) in conjunction with a flow control valve to supply water to the CWS pump suction header to makeup for losses. Water is lost from the system due to evaporation, blowdown, and drift. The makeup pumps take suction on the makeup section reservoir of the discharge and dilution structure. This bay receives water from the discharge of the service water pumps after passing through the component cooling water heat exchangers and is ultimately derived from the river.

Each turbine-type makeup pump has a design flow of 18,000 gpm, a design pressure of 195 psig, a design temperature of 90°F, and are built with a bronze casing and impeller. The makeup pumps are 450-horsepower powered by 4.16-kv buses A5 and A6.

14.7.3.4 Motor-Operated Valves

The valves discussed herein are the CWS pump suction and discharge valves, the discharge cross-connect valve, and the condenser outlet valves. These valves are all 96-inch, motor-operated, butterfly valves.

Each pump suction valve is interlocked with the associated CWS pump. The suction valve must be fully open to start the pump, and the pump will trip if the suction valve is not fully open. When a pump is energized, the respective pump suction valve cannot be closed.

The CWS pump discharge valve does not have its own control switch. Starting a CWS pump sends a signal to open the pump discharge valve. If the discharge valve is not fully open within two minutes, the pump will trip. Stopping the pump will send a closing signal to the discharge valve motor operator. The pump will stop when the discharge valve reaches the fully closed position. An auto trip of the pump will also initiate discharge valve closure.

The cross-connect valve is interlocked to prevent the valve from being opened with both pumps in operation. If one discharge valve and the discharge cross-connect valve are open, opening the other discharge valve will cause the cross-connect to close. If either discharge valve is open, then the cross-connect valve cannot be opened. This interlock prevents excessive circulating water pump reverse rotation, which would occur during one-pump operation with the cross-connect and both discharge valves open.

The condenser outlet valves are interlocked with the CWS pumps such that the associated condenser outlet valve must be at least 48° open any time a pump is running. A valve position of less than 48° will prevent the pump from starting and will trip the pump if it is running. Each of these valves is also prevented from closing any time the associated CWS pump is running. This interlock prevents condenser tube overpressurization.

14.7.3.5 Chemical Injection

Chemicals are manually added to the circulating water using two positive displacement cooling tower acid pumps (P-145A and B) on a routine basis to help eliminate algae buildup in the system. The system taps into the pump suction header through six-inch piping. The chemicals pass through a diffuser section to ensure good mixing and dilution prior to injection. Chemical injection is automatically blocked whenever the CWS pumps are de-energized.

14.7.3.6 Turbine Building Cooling Water Booster Pumps

Two full-capacity horizontal centrifugal TCW booster pumps (P-146A and B) supply the turbine building cooling water system. Each booster pump has a design flow of 9100 gpm, and a design temperature of 95°F. Each pump has a cast iron casing, a bronze impeller, a stainless-steel shaft, and the shaft is sealed at each end by a gland which is supplied with sealing water from the pump's discharge. The 150-horsepower booster pumps are powered from 480-vac nonvital load centers.

14.7.3.7 Instrumentation

Indicating lights are provided in the control room to indicate open and closed positions of motor-operated butterfly valves in the circulating water piping. The motor-operated valves at the circulating water pump suction and at the outlet of the condenser shell "C" are interlocked with the corresponding pump to prevent starting of the pump unless both valves are open. The motor-operated valves at the pump discharge are interlocked with the pumps such that the pump will be shut down if the discharge valve fails to reach the full-open position shortly after starting the pump. The motor-operated valves are provided with position switches required for indicating lights and interlocking with the pumps.

Local pressure indicators and pressure transmitters with indication in the control room are provided on the circulating water pump suction and discharge lines. Pressure switches are provided to alarm low pressure at the circulating water pump suction.

Local pressure indicators are provided at the inlet and outlet of each condenser shell. Local and remote indicators are provided for circulating water temperature at the inlet and outlet of each condenser shell.

A pressure switch is provided to start the standby Turbine Building cooling water booster pump automatically on low cooling water pressure. Control valves are provided at the inlet of the main generator hydrogen coolers, and at the outlet of turbine generator oil coolers, steam generator feedwater pump turbine oil coolers and exciter air cooler for automatic control of cooling water flow.

Local pressure and temperature indicators are provided at the outlet of the components served by the TCW System. A pressure differential indicating switch is provided to alarm a high differential across the strainer in the cooling water line.

A level transmitter with a remote indicator in the control room is provided in the cooling tower makeup pump sump to provide indication of water level in the sump. A level switch trips both the cooling tower makeup pumps if the level in the sump falls below a predetermined level.

The cooling tower makeup is controlled manually to provide a constant level in the cooling tower basin. Necessary instrumentation, such as makeup flow transmitters and cooling tower pond water level transmitters, is provided for control. A remote water level indication with high and low water level alarms for the cooling tower pond is provided in the control room.

Cooling tower blowdown is controlled manually and is governed by plant procedures. Local meter indication is present on the cooling tower blowdown line to provide readout of blowdown flow.

14.7.4 Summary

The Circulating Water (CW) System is designed to supply cooling water required to remove heat loads developed in the main condenser, steam jet air ejector intercondensers and aftercondensers, and other auxiliary coolers when the Plant is operating at maximum rated load.

The Turbine building Cooling Water (TCW) System is designed to receive the required amount of cooling water from the Circulating Water System, supply it to the auxiliary coolers located in the Turbine Building, and return the heated water to the Circulating Water System.

The Circulating Water (CW) System can also provide cooling water to the SW System through a 30-inch cross-connection line. The Circulating Water System will provide water through this cross-connection when service water is not available due to blockage of the Intake Structure.

The Circulating Water System design includes provision for acid and sodium hypochlorite injection into the cooling water in order to maintain control of algae and slime as well as water chemistry.

All components of the Circulating Water System and TCW System are designed to meet Seismic Category II requirements.

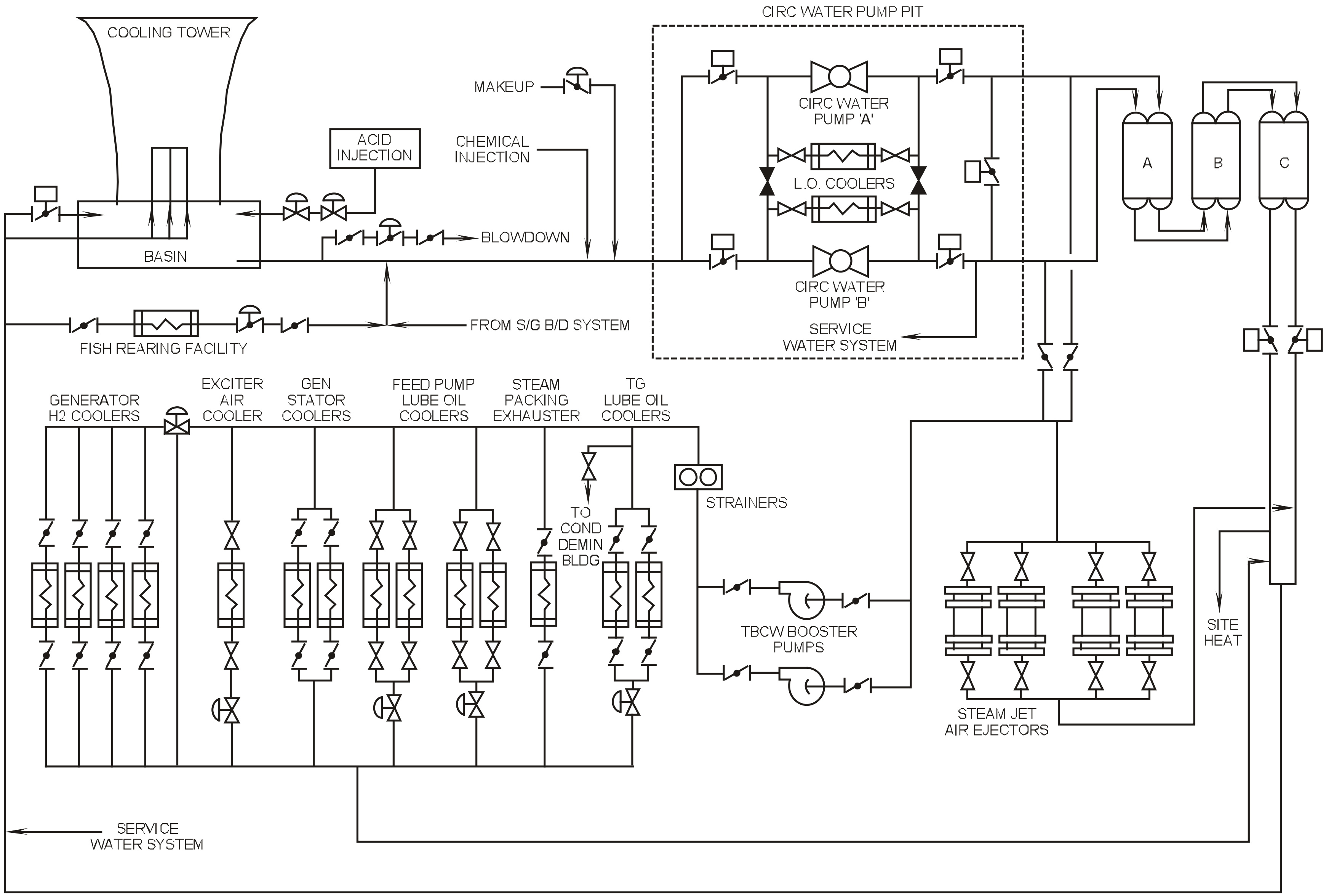
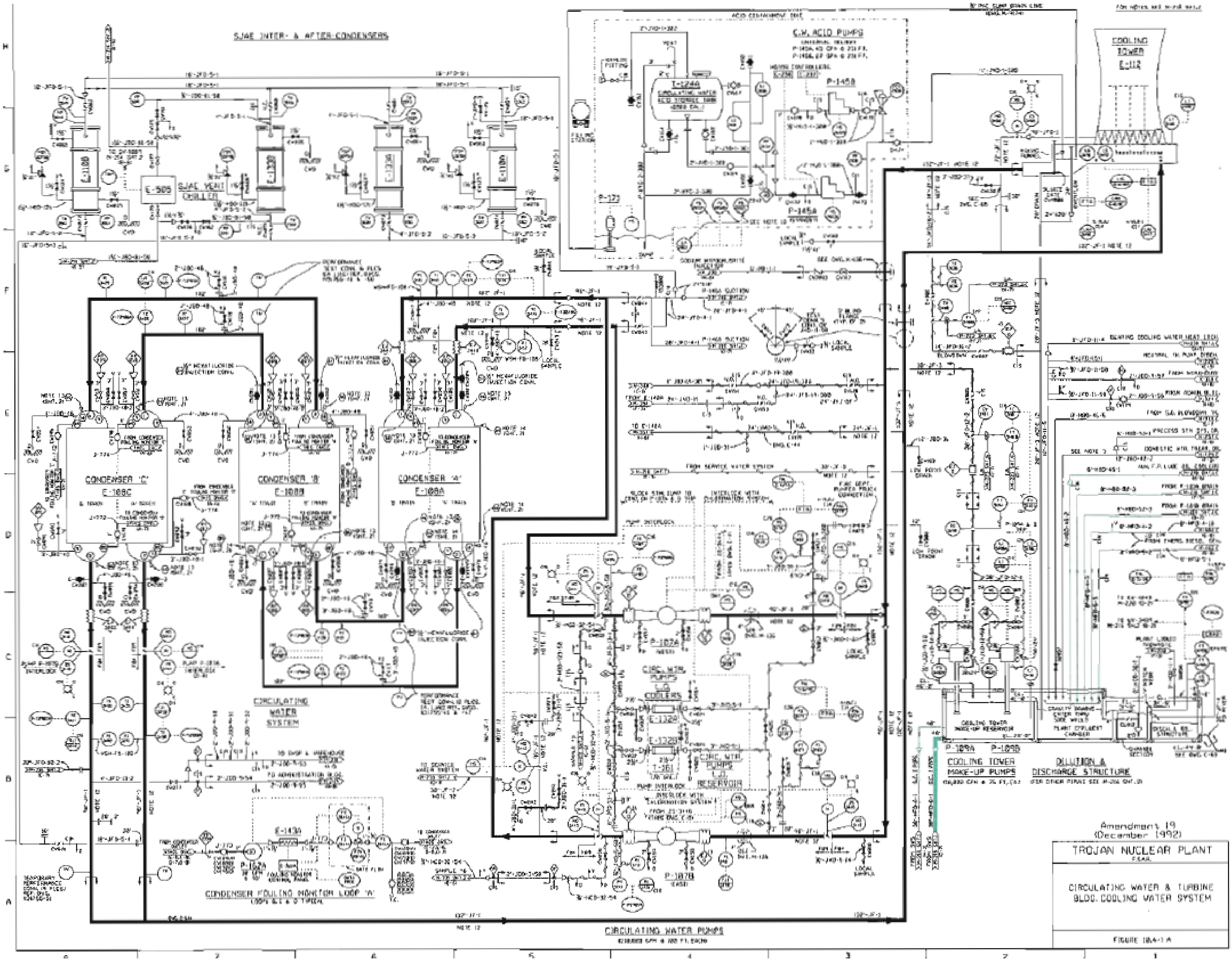
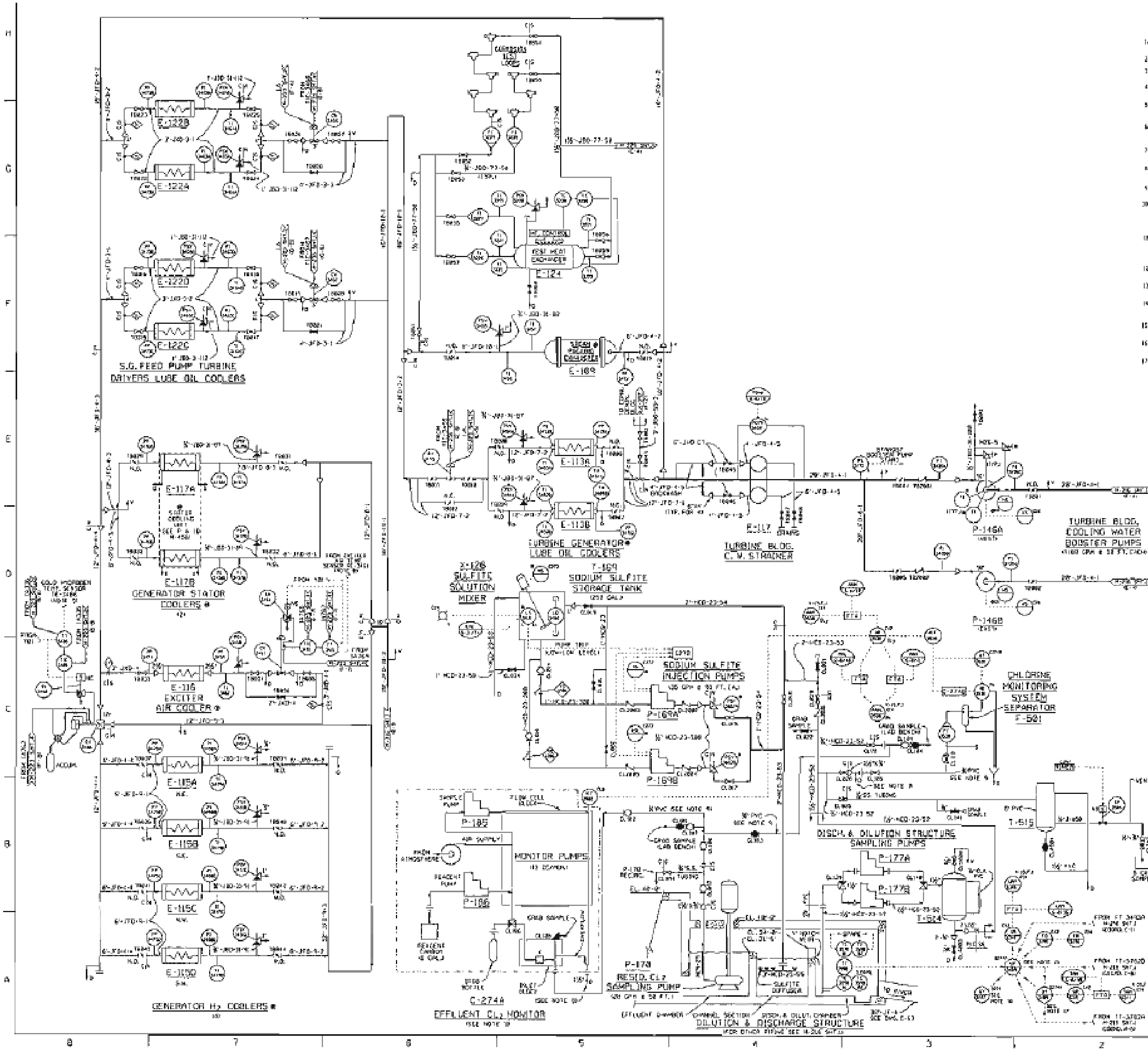


Figure 14.7-1   Circulating Water System



SJAE INTER- & AFTER-CONDENSERS
E-505
SJAE VENT CHILLER
C.W. ACID PUMPS
P-145B
P-145A
P-171
COOLING TOWER E-112
CONDENSER 'C' E-108C
CONDENSER 'B' E-108B
CONDENSER 'A' E-108A
CIRCULATING WATER SYSTEM
P-107A
P-107B
CIRC. WTR. PUMPS L.O. COOLERS
E-132A
E-132B
CIRC. WTR. PUMPS L.O. RESERVOIR
T-161
E-143A
P-162A
CONDENSER FOULING MONITOR LOOP 'A'
CIRCULATING WATER PUMPS
P-109A
P-109B
COOLING TOWER MAKE-UP PUMPS
DILUTION & DISCHARGE STRUCTURE
COOLING TOWER MAKE-UP RESERVOIR
Amendment 19 (December 1992)
TROJAN NUCLEAR PLANT
FSAR
CIRCULATING WATER & TURBINE BLDG. COOLING WATER SYSTEM
FIGURE 10.4-1 A



NOTES:

1. ENTIRE SYSTEM IS SEISMIC CATEGORY II EXCEPT AS NOTED.
2. (*) - PROVIDED WITH EQUIPMENT.
3. [illegible] TO BE A GRAVITY DRAIN LINE.
4. SULFITE TANK LOW LEVEL ALARM ON SEQUENCE OF EVENTS RECORDING SYSTEM.
5. REFER TO [illegible] FOR LOCATION OF [illegible]
6. [illegible] IS A SAMPLE AND HOLD AMPLIFIER. [illegible] SIGNALS SUPPRESSED [illegible] DURING DISCHARGE BACKFLOW.
7. [illegible] ARE HEAT TRACED.
8. DRAIN LINES RETURN WATER TO DISCHARGE STRUCTURE [illegible]
9. REFER TO [illegible] FOR PIPING LAYOUT [illegible]
10. [illegible] IS A YELLOW BEACON ACTUATED MANUALLY BY [illegible] OR AUTOMATICALLY BY [illegible] WHEN THE EMERGENCY SHOWER IS USED OR AUTOMATICALLY BY [illegible] WHEN THE EYE WASH STATION IS USED.
11. PANEL C-274A [illegible] DEFINED BY BOUNDARY LINE WAS PROVIDED UNDER [illegible]. REFER TO THE TECHNICAL MANUAL FOR EQUIP. ON THIS PANEL.
12. FOR CIRCULATING WATER LINES [illegible] & DETAILS SEE [illegible]
13. CONDUCTIVITY METER CONNECTION REF. DWGS. [illegible]
14. [illegible] MEASUREMENT CONNECTION REF. DWGS. [illegible]
15. [illegible] IS A CONFIGURABLE CONTROLLER WITH [illegible] AND LINEARIZED FLOW OUTPUTS.
16. [illegible] IS AN AUXILIARY RELAY ENERGIZED FOR SERVICE WATER [illegible] FLOW.
17. [illegible] IS AN AUXILIARY RELAY WHICH SELECTS AN OPERATING SERVICE WATER TRAIN TEMPERATURE TO SUPPLY TO [illegible] FOR TEMPERATURE DIFFERENTIAL TRENDING AND ALARMING.

Amendment 19
(December 1992)

TROJAN NUCLEAR PLANT

CIRCULATING WATER & TURBINE BLDG. COOLING WATER SYSTEM

SHT.2 OF 2

FIGURE 10.4-18

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Chapter 15

RADIOACTIVE WASTE PROCESSING SYSTEMS

THIS CHAPTER HAS BEEN DELETED AND IS NO LONGER PART OF THE COURSE

Westinghouse Technology Systems Manual

Section 16.0

Radiation Monitoring System (RM)

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16 RADIATION MONITORING SYSTEM (RM)

Learning Objectives:

1. State the purposes of the radiation monitoring system.

2. List the two classes of radiation monitors.

3. Identify radiation monitors that provide automatic actions (other than alarms), and briefly describe the actions provided.

4. Delete.

5. List the radiation monitors which identify the following:

    a. Primary-to-secondary leakage, and
    b. Primary-to-containment leakage.

16.1 Introduction

The purposes of the radiation monitoring system (RMS) are as follows:

1. To continuously monitor radiation levels of various plant areas, processes and effluents, and
2. To provide alarms and/or automatic actions if preset limits are exceeded.

The radiation monitoring system is divided into the following: process radiation monitoring (PRM), described in section 16.2.1, and area radiation monitoring (ARM), described in section 16.2.2.

16.2 System Description

16.2.1 Process Radiation Monitoring System

The PRM system monitors the radiation level of various process liquid and gas streams that may serve as discharge routes for radioactive materials. These monitors are provided to indicate the radioactivity of the process stream and to alert operating personnel when operational limits are approached for the normal release of radioactive material to the environment.

On process streams that do not discharge to the environs, such as the component cooling water system (Section 14.1), process monitors are provided to indicate process stream malfunctions. This is accomplished by detecting the normal background radiation of the system and by alerting the operator with an annunciator if an accumulation of radioactive material occurs in the system. In addition to providing continuous indication and alarms, the PRM may provide various automatic functions, such as the closing of vent valves, discharge valves, etc.

If the activity level in the process stream reaches a predetermined setpoint, the system will perform its automatic function, which ensures that the discharge of radioactive material to the environs is limited. The PRM system can monitor a process stream with one of two types of monitors: in-line monitors and off-line monitors.

IN-LINE monitor

An in-line monitor has the detector probe directly immersed in the process stream. The advantage of this type of monitoring is that the detector probe will be provided a representative sample of the process and responds rapidly to activity changes. The disadvantages of this monitor are that if the process has a turbulent flow the detector probe must be protected by placing it in a well, which lowers the sensitivity of the probe, and if the probe fails, the system must either be secured or a means of bypassing flow around the probe must be provided (only for directly immersed probes).

OFF-LINE monitor

An off-line monitor contains piping, valves, detector probes (usually two in parallel), and a motive force device, such as a pump or a fan. This monitor will take suction on the process stream, pass the flow to the detector, and then return the sample to the process stream. The advantages of this monitor are that with lower flow rates, the detector probe can be directly immersed into the sample stream without a protection well, therefore increasing probe sensitivity, and if a detector fails, it can be isolated (by inlet and outlet valves), and the process stream is not affected.

The disadvantages of this monitor are that it may not be receiving a representative sample of the process stream and may not be as responsive to rapid changes of activity in the process. At the time of this writing there is no preferred method of process monitoring. Both types, IN-LINE and OFF-LINE monitors, are found throughout the industry.

16.2.2 Area Radiation Monitoring System

The area radiation monitors are located in selected areas of the plant, such as the control room, the containment building, and various areas or rooms in the auxiliary building. The purposes of the area monitors are to give continuous indication of background radiation and to alert plant personnel to high radiation. The alarms associated with area radiation monitors include annunciators in the control room area and local alarms. The local alarms are at the radiation detectors and provide indication of high radiation both visually (flashing light) and audibly (horn or buzzer).

16.3 Component Descriptions

16.3.1 Radiation Detectors

There are various types of detectors used in both the process and area radiation monitoring systems. Some of the most commonly used detectors are explained in this section.

Geiger-Mueller Tube

The Geiger-Mueller (G-M) tube is a gas filled chamber with a center electrode as shown in Figure 16-1. The G-M tube operates by sensing an incident particle, such as a beta or gamma, interacting with the gas inside the chamber to produce a few ion pairs. As the ion pairs are accelerated towards the wall and electrode, they will produce more ions pairs until there are millions of ion pairs produced inside the chamber.

The effect of this mass production of ions is called avalanching and results from the high voltage potential between the chamber and the center electrode. When avalanching occurs, the millions of ions, both positive and negative, are collected on the chamber wall and center electrode. When this happens, a pulse is produced. The pulse is always the same size. Therefore, it is not possible to tell the type or energy of the incident particle from the pulse, but only that radiation is present.

This instrument will use a gas that is easily ionized, such as argon. However, when the positive ions are collected on the center electrode, secondary photons, in the form of ultraviolet light, are produced. These photons will then travel across the gas volume and interact with the walls of the chamber. This interaction produces electrons which starts the avalanche all over again. To prevent this undesired secondary avalanche, another gas is normally added to the chamber and mixed with the ionizing gas. This second gas is called a quenching gas and is normally a halogen, such as bromine or chlorine.

Once the avalanche occurs, the detector will be saturated with ions, and another incident particle entering the detector will not be seen. After the quenching takes place, the detector will be able to sense another incoming particle. Due to this time between avalanches and quenching, a G-M tube will only be useful in certain radiation fields. The problem with high radiation areas is that there are so many incident particles that the detector will stay saturated. When this occurs the output from the detector will go to zero, and the meter reading would be full downscale. To overcome this effect, the circuitry is designed so that the meter reading will read full scale if the detector becomes saturated.

Scintillation Detector

The scintillation detector consists of a crystal, window, and a photomultiplier tube, as shown in Figure 16-2.

The scintillation detector works on the principle that when a radioactive particle interacts with certain materials (crystal), light is produced. By measuring the light that is emitted, the energy and amount of the original radioactive particle can be determined. Scintillation detectors can accurately measure different types of radiation, such as alphas, betas, or gammas. This is accomplished by using different types of materials (crystals) for each type of radiation.

A scintillation detector is constructed such that it is sensitive to only one type of radiation; i.e., if beta and gamma radiation levels are to be measured in a process, both a beta scintillation and a gamma scintillation detector must be provided. The scintillation detector operates by a radioactive particle interacting with the crystal, which causes ionization of some of the atoms. These ionized atoms now have electrons in the excited state, but the excitation is not great enough for the electron to escape. Since these atoms are now in an excited state, they will radiate this excess energy in the form of photons (light rays).

The photons are transmitted from the sensing crystal to the photomultiplier tube via a quartz window. Quartz is used to transmit the light produced in the crystal because it will not distort the photons emitted from the crystal.

The photomultiplier tube consists of a photocathode, dynodes, anode, and outer chamber wall. The light produced by the crystal interacts with the photocathode which then produces electrons. These electrons are then attracted to the first positively charged dynode. When an electron strikes the dynode several electrons will be produced (typically for each electron striking a dynode, two to four electrons will be produced).

The electrons produced by the dynode will then be directed to the next dynode for further multiplication. The result of this multiplication process is that generally about one million electrons are produced from each electron produced by the photo cathode. This large electron flow is then collected by the anode, and an electrical current is produced and measured by the circuitry. This circuitry can be setup so that the detectors output can be in counts per minute or as a dose rate in mrem/hr or rem/hr.

The scintillation detector is useful not only in detecting radiation, but also in laboratory work, since this detector can also measure the energy of the incident radiation. The energy can be measured because the pulse of electrons at the anode is proportional to the energy of the original incident radiation, i.e. the more energy the radioactive particle has, the more light that will be emitted from the crystal. This will in turn cause more electrons to be produced by the photo cathode, which, after the electron multiplication, causes a larger pulse at the anode.

16.3.2 Plant Radiation Monitors

Table 16-1 lists the process radiation monitors described in this section. For each monitored location, the table indicates the type of detector used and the automatic actions provided by the monitor.

Containment Air Particulate Detector

The containment air particulate detector (Figure 16-4) is sufficiently sensitive for detection of reactor coolant leakage into the containment. This instrument is capable of detecting leakage rates of 5 cc/min within minutes after the leak occurs.

Continuous air samples are taken from the containment atmosphere near the reactor containment fan cooler inlet, drawn outside the containment in a closed, sealed system, and monitored by a scintillation counter and movable filter paper detector assembly. The air sample is passed through a filter paper which collects 99% of all particulate matter greater than 0.3 microns in size. The constantly moving filter paper is viewed by the scintillation detector, which then transmits the activity level to the main control room.

The activity level is then indicated on a meter and on a recorder. The air sample, after passing through the detector, is returned to the containment. The detector is used principally to detect the following radioactive isotopes in the containment atmosphere: I-131, I-133, CS-134 and CS-137. Receipt of a high activity level in the containment will be annunciated in the control room. In addition to the annunciator, the following automatic actions will occur:

- The containment purge supply and exhaust dampers will close,
- The pressure and vacuum relief valves will close (if they are open), and
- The containment fan cooler dampers shift to the accident mode (the fans, however, remain in fast speed).

Containment Noble Gas Monitor

The containment gas monitor (Figure 16-4) is provided in order to supply the operator with information pertaining to the noble gas activity in the containment. This activity is due to neutron activation of the primary shield cooling air and from leaks in the reactor coolant system when operating with cladding defects in the fuel. Continuous samples are taken from the containment atmosphere. After the sample passes through the previously described air particulate monitor, it flows through a closed sealed system to the gas monitor assembly. The samples flow continuously to a fixed, shielded volume, where the activity is measured by a Geiger-Mueller tube or beta scintillation detector. The air sample is then returned to the containment. The activity level is sent to the main control room, where the level is indicated on a meter and on a recorder. The detector is used principally to detect the following noble gases: Kr-85, Ar-41, Xe-133 and Xe-135. Receipt of high activity will annunciate in the main control room. In addition to the annunciator, the following automatic actions occur:

- The containment purge and exhaust dampers will close,
- The pressure and vacuum relief valves will close (if they are open), and
- The containment fan cooler dampers shift to the accident mode (the fans, however, remain in fast speed).

The radio gas detector supplements the information obtained from the air particulate monitor regarding the occurrence of leakage from the primary system.

Containment Purge Exhaust Monitor

This channel (Figure 16-4) monitors the effluent from the containment purge for gaseous activity, iodine, and particulate activity whenever the purge system is in operation. The system consists of three separate channels, one of which is a fixed filter air particulate monitor with a beta scintillation detector, the second is a Geiger-Mueller detector for monitoring gaseous activity, and the third is a spectrometer grade gamma scintillation detector for iodine monitoring.

Detector outputs are transmitted to the main control room where they provide indication on meters and recorders. High radioactivity during the containment purge operations will be annunciated in the control room. In addition to the alarm, the purge supply and exhaust dampers will automatically close.

Auxiliary Building Ventilation System Monitor

This channel (Figure 16-4) continuously monitors the ventilation system exhaust air from all the potentially contaminated equipment cubicles in the auxiliary building. This system uses one moving filter monitor for particulates and a fixed filter unit for iodine. The detector for particulates uses a moving filter paper and monitors this filter with a beta scintillation detector. For iodine monitoring, a spectrometer grade gamma scintillation detector is used.

The outputs from these detectors are transmitted to the main control room for indication on meters and recorders. High radioactivity from either detector will be annunciated in the main control room. Detection of high radioactivity from the iodine monitor will automatically realign the auxiliary building ventilation system so that the exhausts from the equipment cubicles will be routed through charcoal filter banks prior to exhausting to the atmosphere.

Plant Vent Stack Monitor

This channel (Figure 16-4) monitors the ventilation system air discharging from the auxiliary building ventilation system to the plant ventilation stack. The sample gas is returned to the suction of the auxiliary building exhaust fans. The channel utilizes four Geiger-Mueller tubes connected in parallel. The radioactivity is indicated by a meter and recorder located in the main control room. High radiation at this monitor will actuate an annunciator in the main control room. There are no automatic functions associated with this channel. This monitor is used principally to detect Kr-85, Ar-41, Xe-133, and Xe-135.

Control Room Intake Air Monitor

This channel continuously monitors the outside air intake to the control room. Two monitors, one for particulates and one for iodine, are provided. The particulate monitor uses moving filter paper and a beta scintillation detector, and the iodine monitor employs a fixed filter and gamma scintillation detector. The detector outputs are transmitted to the control room, where the radioactivity levels are indicated by meters and recorders. High radiation conditions are annunciated in the main control room. In addition to the annunciators, an alarm in either channel will cause the ventilation system air inlet to close, and makeup air, for maintaining a slightly pressurized control room, will be introduced from the turbine building.

Condenser Air Discharge Gas Monitor

This channel (Figure 16-4) receives a continuous air sample from the air ejector exhaust header, monitors it for gaseous radioactivity, and provides the plant operator with a rapid indication of a primary to secondary leak. The sample gas is returned to the gas effluent. This channel uses a G-M detector whose output is transmitted to the main control room for indication on meters and recorders. A high radiation condition will be annunciated in the main control room. There is no automatic function associated with this channel. This monitor is used principally to detect noble gases such as Kr-85, Xe-133, and Xe-135.

Steam Generator Blowdown Liquid Monitor

This channel (Figure 16-4) monitors the liquid phase of the secondary side of the steam generator for radioactivity, which would indicate a primary to secondary system leak, providing backup information to that of the condenser air ejector gas monitor. Samples from each of the four steam generator bottoms are mixed in a common header and the common sample is continuously monitored by a scintillation counter and holdup tank assembly. Upon indication of high radioactivity, each steam generator is individually sampled in order to determine which unit is leaking. The detector output is transmitted to the main control room where indication is provided by both a meter and a recorder. A high radiation condition will be annunciated in the control room. There are no automatic functions associated with this channel. This monitor is used principally to detect Co-60.

Component Cooling Water System Monitor

This channel continuously monitors the component cooling water system (Section 14.1) for activity which would be indicative of a leak from one of the components that this system is cooling. A gamma scintillation detector is used for this monitor, and its output is transmitted to the control room. The activity level is indicated on a meter and a recorder. A high radiation condition will be annunciated in the control room. After receiving this alarm, the operator will isolate the affected component to stop the radioactive in-leakage. In addition to the annunciator, the component cooling water surge tank vent valves automatically close. The sensitivity range of this monitor is based on Co-60.

Service Water Effluent Discharge Monitor

This channel continuously monitors the service water system (Sections 14.2, 14.6) discharge to the ultimate heat sink. An increase in activity would be indicative of radioactive in-leakage to this system. A gamma scintillation detector is used for this monitor, and its output is transmitted to the control room. The activity level of this system is indicated on a meter and a recorder. A high radiation level in this system will be annunciated in the control room. There is no automatic function associated with this channel. The sensitivity of this monitor is based on Co-60.

Waste Disposal System Liquid Effluent Monitor

This channel (Figure 16-4) continuously monitors all waste disposal system liquid releases from the waste monitor tanks.

A Geiger-Mueller detector monitors all effluent discharges. The signal from this monitor is transmitted to the control room for indication on a meter and a recorder. A high radiation level on this discharge line will annunciate in the control room. In addition to the annunciator, the discharge valve located on the discharge line automatically closes. The discharge valve is located far enough downstream of the monitor to allow for the closure of this valve prior to any unplanned radioactive release. A single monitor is provided on each discharge line and is considered adequate since the monitor tanks are sampled and analyzed prior to any allowable discharge flow. The release of liquid waste is under administrative control, and this monitor is provided to maintain surveillance over the release.

Gas Decay Tank Effluent Gas Monitor

This channel (Figure 16-4) monitors the radioactivity released through the plant vent, especially during the venting of the gas decay tanks (Section 15.3). The detector is either a G-M tube or a beta scintillation detector. The detector output is transmitted to the control room for indication on a meter and a recorder. A high radioactivity condition will be annunciated in the control room. In addition to the annunciator, the isolation valve on the gas decay tank's vent line automatically closes. This will terminate the release and will initiate operator action to establish and correct the cause of this alarm. This monitor principally is used to detect Kr-85, Xe-133, and Xe-135, and its sensitivity is based on Kr-85.

Main Steam Line Radiation Monitor

This channel uses four GM detectors, one on each steam line, located directly on the steam lines upstream of the MSIVs. These detectors are designed to monitor the release path of steam through the steam generator PORVs and safety valves.

Main Steam Line Nitrogen-16 Monitor

This system uses four scintillation detectors, located downstream of the MSIVs to determine the presence of N^{16} gamma radiation in the main steam pipe. The amount of N^{16} in this flow is proportional to the size of steam generator tube leakage and reactor power level.

Area Radiation Monitoring System

This system consists of channels which monitor and indicate the radiation levels in various physical areas of the plant. Table 16-2 lists the most common locations of area monitors. The detectors most generally used for area monitors are G-M tubes, beta or gamma scintillation detectors, and in some cases, air particulate with fixed filter collectors may be used. The detector output is transmitted to the control room where the radioactivity level is indicated and recorded. If the radiation level in a particular area exceeds a preselected setpoint, an annunciator will alarm in the control room.

The area radiation monitoring system normally supplies indication and alarms, both in the control room and locally, and provides no automatic functions. However, there is one channel which normally provides an automatic function. If the fuel handling building pool area monitor (Figure 16-4) should alarm, it causes the fuel handling ventilation exhaust to be routed from its normal exhaust to a special exhaust system, comprised of booster fans and activated charcoal filters.

16.4 System Interrelationships

16.4.1 Gross Failed Fuel Detector

There are several different methods used to detect failed fuel, of which only two methods are explained below.

The first method is to monitor the radiation level in the chemical and volume control system volume control tank room. In the event of a failure of a fuel assembly or fuel element, the radioactive noble gas inventory in the volume control tank increases, resulting in a higher radiation level inside the volume control tank room and thereby alerting the operator to the failure of a fuel assembly. The expected or predicted radiation levels in the volume control tank room are as follows:

- Reactor shutdown ~ 1 millirem per hour
- Reactor operating ~ 100 millirem per hour
- 1% failed fuel ~ 1000 rem per hour

The problem with this type of system is that with increasing reactor power, a phenomenon called "iodine spiking" occurs. This iodine spiking will cause the radiation level in the volume control tank room to increase to high levels, giving this system a false indication.

A second method used to detect failed fuel is with a neutron detector, as shown in Figure 16-3. This system continuously monitors the reactor coolant system via a sample line from the hot legs, through two containment isolation valves, a sample cooler, neutron detector, then through a flow control device where the sample is discharged to the chemical and volume control system letdown line.

The sample is supplied to the neutron detector (BF_3 proportional counter) via two containment isolation valves. These valves will automatically isolate on a containment isolation phase B isolation signal. The detector samples for delayed neutrons from short-lived fission products, namely bromine-87, iodine-137, and bromine-88.

The 40-second delay prior to the exit of containment is for N-16 gamma considerations, and the remaining 20 seconds is to ensure that the detector is sampling these particular fission products. The time delay is established with the length of the sample line and the flow control device. Normally, the flow rate through this system will be set at approximately one gallon per minute.

The detector is a calibrated BF_3 proportional counter whose indication ranges from 10^1 counts per minute (cpm) to 10^6 cpm on a logarithmic scale. Generally, there are two alarms associated with this system. The high alarm is normally set at 2×10^4 cpm above a preselected level. When this alarm actuates, a chemistry sample is required of the reactor coolant system. This alarm is indicative of the possibility of some fuel damage.

The other alarm is the high-high alarm, which is set at 1×10^5 cpm above a preselected level. Upon the receipt of this alarm, an immediate sample of the reactor coolant system is required, and reactor power is to be reduced 25 percent. This alarm is an indication of excessive fuel defects or failures.

16.4.2 Leakage detection

Primary-to-secondary leakage is indicated by the following monitors:

- Condenser air discharge gas
- Steam Generator Blowdown Liquid Sample
- Main Steam Line
- Main Steam Line Nitrogen-16

Primary-to-containment leakage is indicated by the following monitors:

- Containment air particulate
- Containment noble gas
- Containment area

16.5 Summary

The radiation monitoring system measures the radiation or activity levels in various process streams and areas. It provides information to the operator in the control room via indicating meters, recorders, and alarms, both audible and visual. The radiation monitoring system is comprised of two subsystems, process monitors and area monitors. Tables 16-1 and 16-2 list some of the processes and areas that are generally monitored. In addition to the detector locations, these tables list the most commonly used detectors for those locations and the automatic functions, if any, that those channels may provide. In addition to these monitors, each facility has some type of system or component to detect a gross failure of the fuel.

Table 16-1 Process Radiation Monitors

	Location	Detector Type	Automatic Action
a.	Containment Air Particulate Detector	Gamma scint.	Isolates containment purge and exhaust if running.
b.	Containment Noble Gas Monitor	Beta scint.	Same as above
c.	Purge Exhaust Monitor	APD, G-M tube, gamma scint.	Isolate containment purge supply and exhaust valves if running
d.	Auxiliary Building Ventilation Monitor	Beta scint., Gamma scint.	Initiates auxiliary building isolation Diverts to gas treatment system
e.	Plant Vent Stack Monitor	G-M tube	Alarm function only
f.	Main Control Room Intake Air Particulate Monitor	Beta scint., Gamma scint.	Isolates main control room ventilation
g.	Condenser Air Ejector Gas Monitor	G-M tube	Alarm function only
h.	Steam Generator Blowdown Liquid Sample	Gamma scint.	Alarm function only
i.	CCW - Downstream of Heat Exchanger	Gamma scint.	Closes CCW surge tank vent
j.	Service Water Effluent Discharge	Gamma scint.	Alarm function only
k.	Waste Disposal System Liquid Discharge to the Environment	Gamma scint. or G-M tube	Closes the effluent discharge to the environment
l.	Gas Decay Tank Effluent Discharge Monitor	Beta scint. or G-M tube	Closes the effluent discharge to the environment
m.	Main Steam Line	G-M tube	Alarm function only
n.	Main Steam Line N-16	Gamma Scint.	Alarm function only

Table 16-2 Area Radiation Monitors

Location	Detector Type	Automatic Action
1. Main Control Room	G-M tube	Alarm function only*
2. Containment a. Operating deck b. Seal table area c. Dome monitor	 G-M tube or gamma scint. G-M tube Ion Chamber	Alarm function only
3. Radio Chemistry Lab	G-M tube	Alarm function only
4. Charging Pump Room	G-M tube	Alarm function only
5. Drumming Station	G-M tube or gamma scint.	Alarm function only
6. Sampling Room	G-M tube	Alarm function only
7. Spent Fuel Building	G-M tube or gamma scint.	Isolates auxiliary building exhaust to gas treatment system.
8. Dry Active Waste Storage Area	Air particulate beta scint.	Alarm function only
9. Gas Decay Tank Rooms	Air sample beta scint.	Alarm function only
10. Radwaste Evaporator Room	Air sample beta scint.	Alarm function only

*At some facilities, this detector may provide an automatic isolation of the normal control room ventilation system.

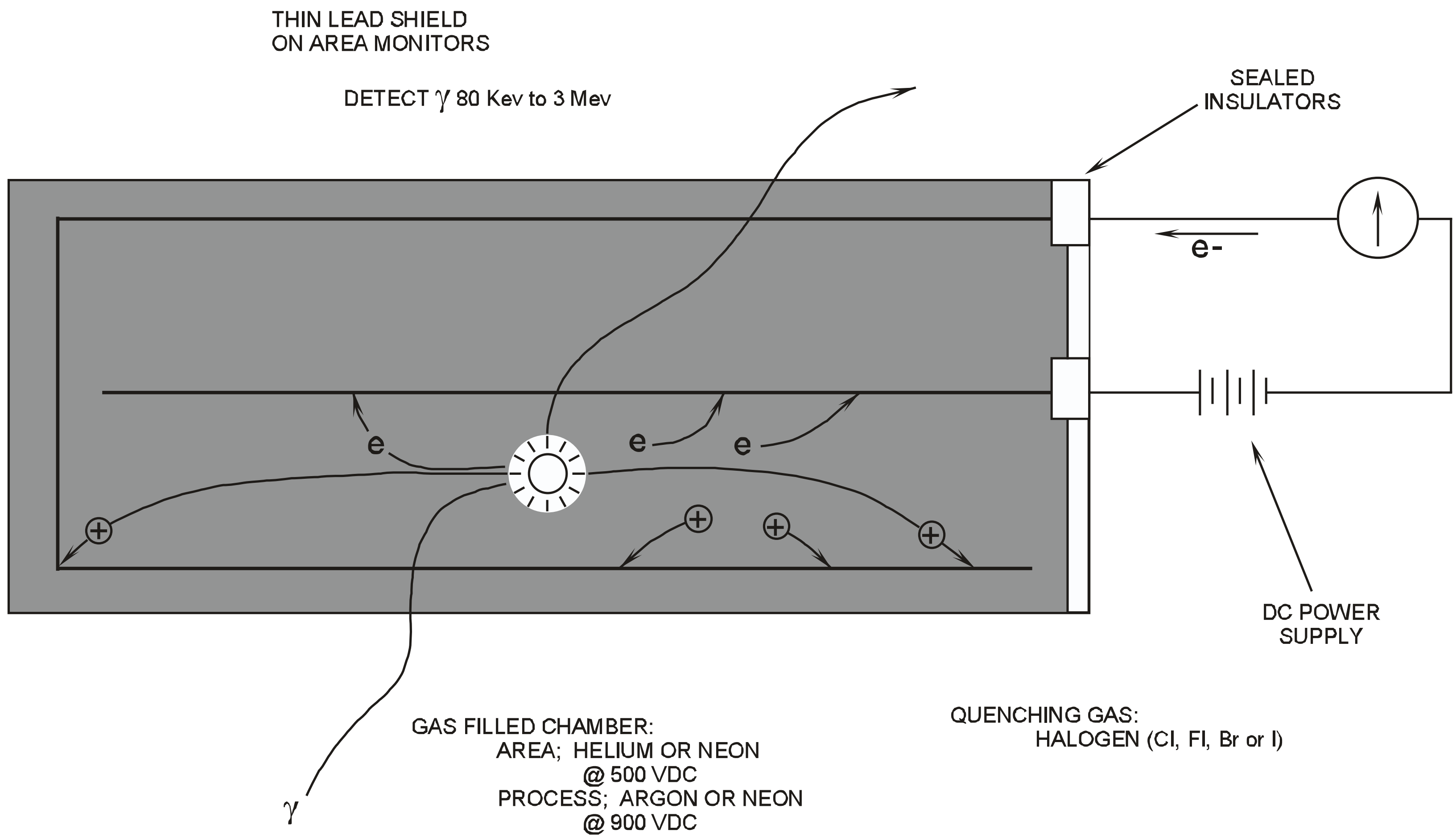

Figure 16-1 Geiger – Mueller Tube

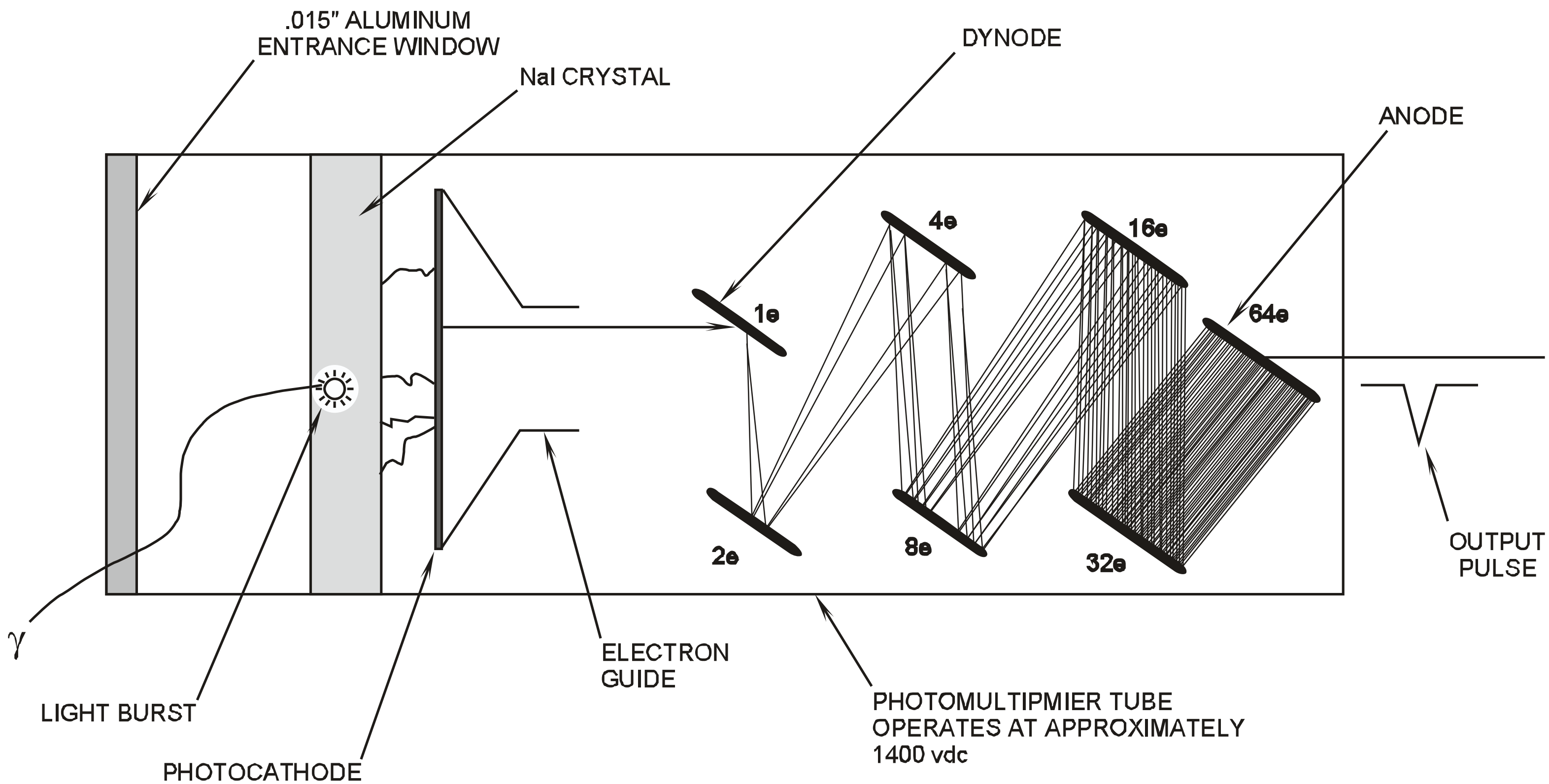

Figure 16-2 Scintillation Detector

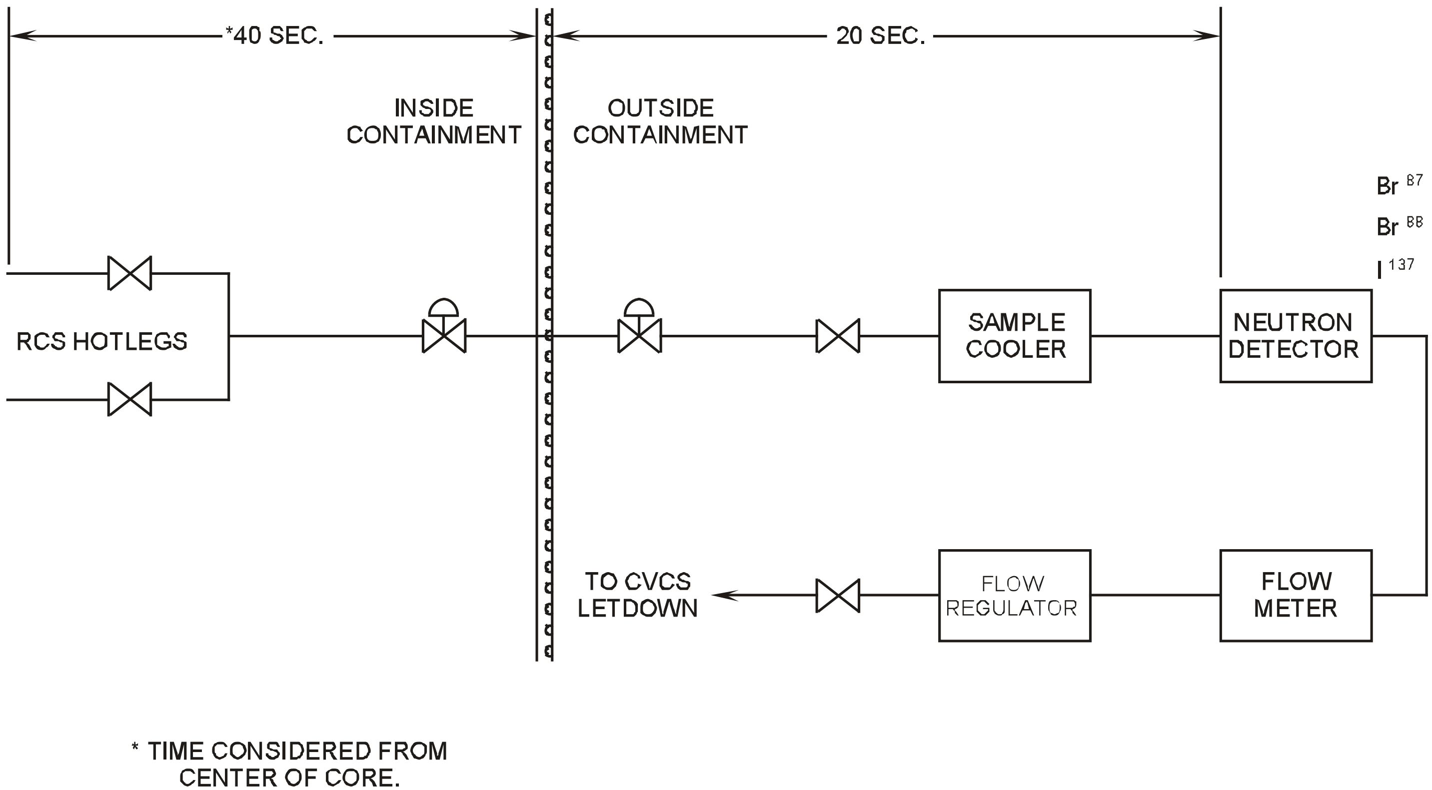

Figure 16-3 Gross Failed Fuel Detector

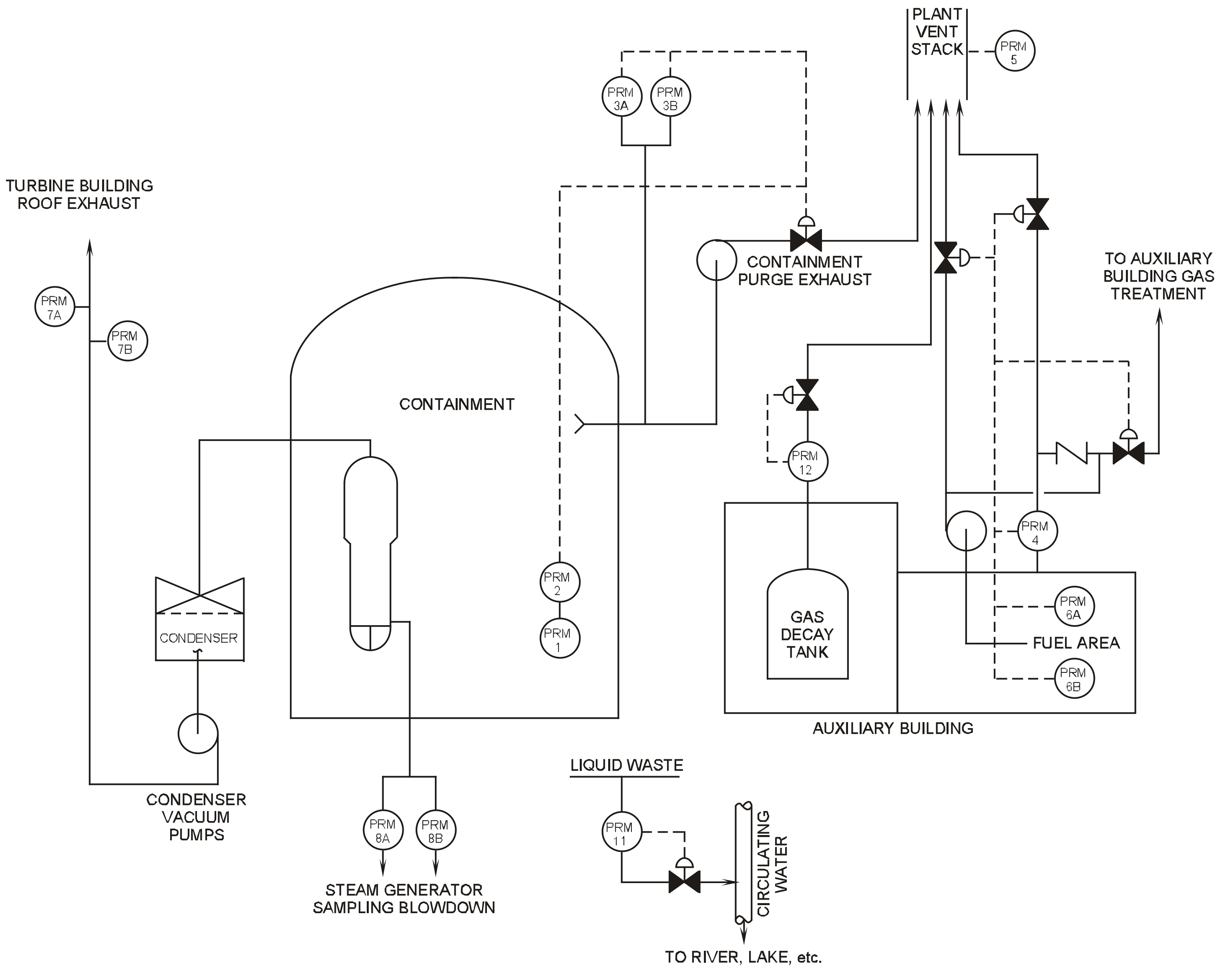

Figure 16-4 Radiation Monitor Locations

Westinghouse Technology Systems Manual

Chapter 17

FUEL HANDLING and SPENT FUEL STORAGE

Section

Westinghouse Technology Systems Manual

Section 17.1

Fuel Handling and Storage

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17.1 FUEL HANDLING AND STORAGE

Learning Objectives:

1. State the purposes of the fuel handling and storage systems.

2. State the functions of the following fuel handling system equipment:

   a. Spent fuel pool bridge crane,
   b. New fuel elevator,
   c. Fuel transfer canal,
   d. Polar crane,
   e. Manipulator crane,
   f. RCCA change fixture,
   g. Reactor vessel stud tensioner,
   h. Conveyor car, and
   i. Upenders.

3. State the reasons for handling spent fuel under water.

17.1.1 Introduction

The purposes of the fuel handling and storage systems are to receive, store, and transfer new and spent fuel. The fuel handling system has been designed to minimize the possibility of mishandling or operational errors that could cause fuel damage and result in a potential fission product release. The system is also designed to expedite the refueling operation while maintaining safe fuel handling practices. To facilitate this procedure, the reactor is refueled with equipment designed to handle the spent fuel under water from the time it leaves the reactor vessel until it is placed in a cask for shipment from the site. This practice allows the operator to view the refueling operation while the water acts as a shield and coolant. In addition, the boron concentration of the water ensures that the core remains subcritical, with a sufficient margin of safety, during fuel handling operations.

The fuel handling system consists of three areas of operation which contain various systems and equipment. These areas are as follows:

1. Fuel Storage Building - where new and spent fuel is received, stored and shipped.
2. Containment - where the reactor is located and most of the handling of the fuel assemblies occurs during refueling operations.
3. Fuel Transfer System – the space which connects the fuel storage building to the containment and provides a means of transferring fuel assemblies between the two.

17.1.2 Fuel Storage Building

17.1.2.1 System Description

New fuel assemblies are received and stored in racks in the new fuel storage area (Figure 17.1-1). New fuel is delivered to the reactor by retrieving it from the new fuel storage area, transferring it to the new fuel elevator where it is lowered into the spent fuel pool, and taken through the transfer system into the containment. When inside the containment, the fuel is transferred to the reactor vessel where it is lowered into place. The transfer of fuel is done with the spent fuel pool, the fuel transfer canal, and the refueling cavity flooded for shielding requirements. The equipment used is designed to handle the spent fuel underwater.

The refueling operation is divided into five major phases:

1. Preparation,
2. Reactor disassembly,
3. Fuel handling,
4. Reactor assembly, and
5. Spent fuel cask loading.

A general description of a typical refueling operation through the five phases is given below:

Phase I - Preparation

In order to minimize the radiation exposure during the refueling, the reactor coolant system is cleaned up and decontaminated as much as possible. This is accomplished by maximizing reactor coolant system cleanup using the chemical and volume control system prior to shutdown and after the reactor is shutdown. Hydrogen peroxide is added to remove deposited crud, which is then removed from the coolant by the chemical and volume control system. The containment atmosphere is cleaned up using the purge and filtration systems.

The reactor is shutdown and cooled to cold shutdown conditions with a final effective multiplication factor (K_{eff}) less than 0.95 (all rods in) and reactor coolant system temperature less than 140°F (MODE 6). Following a radiation survey, the containment structure is entered. At this time, the coolant level in the reactor vessel is lowered to a point slightly below the reactor vessel flange. Then the fuel transfer equipment and manipulator crane are checked for proper operation.

Phase II - Reactor Disassembly

The disassembly of the reactor vessel begins with the removal of the missile shield. All cables, air ducts, and insulation are then removed from the vessel head. The thermocouple conoseals are removed and protective covers are installed over the top of the thermocouple support columns. The incore instrumentation thimbles are disconnected from the transfer device, and the seals are broken at the seal table. The thimbles are then pulled back 24 feet through the bottom of the vessel. The reactor vessel stud tensioners are used to detension the vessel studs, and after removal of the studs, stud hole plugs are installed to protect the threads. Three stud holes are left unplugged and are fitted with threaded guide studs which help to position the various lifting rigs.

The refueling cavity is then prepared for flooding by sealing off the reactor cavity; checking the underwater lights, tools, and fuel transfer system; closing the refueling canal drain valves; and removing the blind flange from the fuel transfer tube. With the refueling cavity prepared for flooding, the vessel head is unseated and raised approximately one foot above the vessel flange. Water from the refueling water storage tank is pumped into the reactor coolant system by the residual heat removal pumps causing the water to overflow into the refueling cavity.

The vessel head and the water level in the refueling cavity are raised simultaneously, keeping the water level just below the head. When the water reaches a safe shielding depth, the vessel head is taken to its storage pedestal. The control rod drive shafts are then disconnected and, with the upper internals, are removed from the vessel. The fuel assemblies and rod cluster control assemblies are now free from obstructions and the core is ready for refueling.

Phase III - Fuel Handling

Fuel handling can start after the reactor has been subcritical for 100 hours (Technical Specification requirement). This allows time for the short-lived fission products to decay. The refueling sequence is started with the manipulator crane. As determined in the refueling guide, which is prepared before each refueling, spent fuel assemblies are removed from the core. The positions of partially spent assemblies are changed (fuel shuffle) and new assemblies are added to the core.

The fuel handling sequence proceeds as follows:

1. The manipulator crane is positioned over a fuel assembly in the most depleted region of the core.
2. The fuel assembly is lifted by the manipulator crane to a predetermined height sufficient to clear the reactor vessel and still leave sufficient water covering to eliminate any radiation hazard to the operating personnel (minimum of 9.5 feet).
3. If the removed fuel assembly contains a rod cluster control assembly (RCCA), the fuel assembly will be placed in the RCCA change fixture by the manipulator crane. The rod cluster control assembly is then removed from the spent fuel assembly and placed into a new or partially spent fuel assembly also located in the change fixture.
4. The fuel transfer (conveyer) car is moved into position in the transfer canal in the containment near the upender.
5. The fuel assembly container section is pivoted to the vertical position by the upender.
6. The manipulator crane is moved to line up the fuel assembly with the fuel transfer system.
7. The manipulator crane loads a fuel assembly into the container section of the conveyor car.
8. The container is pivoted to the horizontal position by the upender.

9. The fuel assembly is moved through the fuel transfer tube to the spent fuel pool by the conveyor car.
10. The fuel assembly container is raised to the vertical position by the upender. The fuel assembly is unloaded by the spent fuel pool bridge crane.
11. The fuel assembly is placed in the spent fuel storage rack.
12. A new fuel assembly is brought from dry storage, lowered into the transfer canal by the new fuel elevator, and loaded into the fuel assembly container of the conveyer car by the spent fuel pool bridge crane.
13. The fuel assembly container is pivoted to the horizontal position and the conveyor car is moved back into the containment.
14. Partially spent fuel assemblies are relocated (shuffled) in the reactor core, and new fuel assemblies are added to the core.
15. Any new fuel assembly or shuffled fuel assembly that will be placed in a control position is first placed in the rod cluster control assembly change fixture to receive a rod cluster control assembly from a spent fuel assembly.
16. This procedure is continued until refueling is completed.

Phase IV - Reactor Assembly

Reactor assembly, following refueling, is essentially achieved by reversing the operations given in Phase II, Reactor Disassembly.

Phase V - Spent Fuel Cask Loading

Spent fuel cask handling is as follows:

1. The fuel cask shipping conveyance is parked inside the fuel storage building.
2. The outside door is closed.
3. The shipping cask is picked up by the fuel storage building crane and is moved to an open area on the operating floor. If it is necessary to disengage the crane hook to free the crane for those uses, the cask is lowered to the cask decontamination facility or into the cask loading area of the spent fuel pool. In either of these locations, a seismic event would not overturn the cask.
4. The gate is placed in the slot between the spent fuel pool and the cask loading area.
5. The cask is picked up by the crane and is lowered onto the shelf in the loading area. The crane hook is disengaged from the cask, and an extension link is inserted between hook and cask. The cask then is lowered into the deep portion of the pit.
6. The cask lid is removed and placed in the cask set down area.
7. The gate is removed from the slot.
8. Using the spent fuel bridge and hoist, fuel assemblies are transferred, one at a time, from the spent fuel storage racks to the cask.
9. The gate is placed in the slot, and the cask lid is replaced.
10. The cask is lifted onto the shelf, the extension link is removed, and the cask is removed from the loading area. It is then placed in the cask decontamination room for washdown.
11. The cask is moved to the cask set down area, and tie down devices are affixed while the cask undergoes preshipment tests.

12. The cask is placed on the shipping conveyance with the fuel storage building outer door closed.
13. The conveyance is then moved out of the building.

17.1.2.2 Component Descriptions

The components of the fuel storage building are discussed individually. The functions of each of the components will be described as the "component's overall function" or role in the fuel handling system.

New Fuel Storage Area

The new fuel is stored in vertical storage racks in the new fuel storage area (Figure 17.1-2). This area is constructed of reinforced concrete designed in accordance with the Seismic Category I requirements, except that the storage racks are not seismically qualified since there is no radiological hazard associated with their failure.

The new fuel storage area is sized for storage of fuel assemblies associated with the replacement of one-third of the core (76 assemblies). The center-to-center spacing (21 inches) is sufficient to ensure a K_{eff} # 0.95 assuming the storage area is flooded with unborated water.

Spent Fuel Pool

The construction of the spent fuel pool and storage area is of reinforced concrete with a seam welded, 1/4-inch thick, stainless steel liner (Figure 17.1-2). The spent fuel pool structure includes a storage area, a spent fuel cask loading area and a transfer canal which is connected with the refueling cavity in the containment. The pool is designed to accommodate 1,408 fuel assemblies (approximately 7.3 cores). The normal depth of borated water in the spent fuel storage pool is approximately 39 feet. The requirement for a water shield of 23 feet (Technical Specifications requirement) above the fuel assemblies must always be met. A high/low level alarm is annunciated in the control room when the water level rises to 1.5 inches above normal level or drops to 6 inches below normal level. The hoist on the spent fuel pool bridge crane has a mechanical stop which prohibits lifting a fuel assembly higher than a level at which its top is 9.5 feet (radiation shielding requirement) below the low level alarm point.

Located at one end of the spent fuel pool is the fuel transfer canal. This area is separated from the pool and contains an upender (fuel lifting mechanism), the transfer tube gate valve and rails for the transfer canal, a gate has been provided for isolation of one area from the other. With the gate closed the refueling cavity and fuel transfer canal can be drained and maintenance performed. The gate swings on hinges and is kept closed by a series of wedges along its length. Leak tightness is provided by a rubber seal.

The spent fuel storage racks are designed with sufficient center-to-center spacing (10.5 inches) between the assemblies and a fixed neutron absorber in the fuel cell walls to maintain K_{eff} less than 0.95 even if unborated water were used to fill the pool.

Fuel Storage Building Crane

An overhead crane has been provided for handling equipment in the fuel storage building. The crane will normally be used for the following operations:

1. Unloading of new fuel shipping containers,
2. Movement of fuel assemblies from the shipping containers to the new fuel storage area and from the new fuel storage area to the spent fuel pool for placement in the new fuel elevator,
3. Transfer of spent fuel casks, and
4. Loading of spent fuel casks.

The crane is restricted from moving heavy loads over the spent fuel pool, the spent fuel cooling system, and engineered safety feature systems by electrical limit switches, which will de-energize the bridge drive, and mechanical stops which are installed on the rails. The purpose of the interlocks and stops is to protect the equipment from the damage that could be caused by a dropped load.

Spent Fuel Pool Bridge Crane

The spent fuel pool bridge crane is a wheel-mounted walkway, spanning the spent fuel pool and fuel transfer canal, Figure 17.1-3, which carries an electric monorail hoist on an overhead structure. The fuel assemblies are moved within the spent fuel pool and to and from the fuel transfer upender by means of the spent fuel handling tool. The tool's length is designed to limit the maximum lift of a fuel assembly to ensure a safe shielding depth and protect against lowering the hook into the pool water. Pointers located on the bridge and hoist when aligned with index marks on the side of the pool and bridge crane monorail provide the operator with proper location information of the various storage positions.

New Fuel Elevator

The transferring of new fuel from the new fuel storage area to the spent fuel pool is accomplished by the use of the fuel storage building crane and the new fuel elevator Figure 17.1-4. The new fuel elevator lowers the assembly from the surface of the spent fuel pool to the level of the spent fuel racks. There it can be latched by the spent fuel handling tool and transported to fuel transfer canal by the spent fuel pool bridge crane. This design eliminates lowering the fuel storage building crane hook and the new fuel handling tool into the spent fuel pool borated water.

New Fuel Assembly Handling Tool

This tool, commonly called the short-handled tool (25 inches long and weighing 75 pounds), is used to handle new fuel on the operating deck of the fuel storage building (Figures 17.1-5 and 17.1-6), to remove the new fuel from the shipping container, to facilitate inspection and storage of the new fuel and loading of new fuel into the new fuel elevator. These operations are performed with the new fuel handling tool attached to the hook of the fuel storage building crane.

Spent Fuel Handling Tool

This tool, Figure 17.1-5, is used to handle new and spent fuel in the spent fuel pool. It is a manually actuated tool on the end of a long pole suspended from the spent fuel pool bridge crane. An operator on the spent fuel pool bridge guides and operates the tool.

17.1.2.3 New Fuel Receipt and Storage

New fuel arrives on site in metal shipping containers, Figure 17.1-7. These containers hold two fuel assemblies, with rod cluster control assemblies or burnable poison rod assemblies inserted, if needed. The total weight, with fuel assemblies, is approximately 4800 pounds. Each shipping container is pressurized to 5 psig with air.

Several checks are made during fuel receipt to verify the shipping containers were not mishandled during shipment, mishandling could cause damage to the fuel assemblies. The first check is to verify that the container is pressurized. This is accomplished by opening a relief valve located at the end of the container, Figure 17.1-8.

The top of the container is then removed. The fuel assemblies are supported on a shock absorber mounted platform which is attached to the sides of the container. This platform must be raised to the vertical position for fuel assembly removal. Prior to raising the platform, a second check for mishandling is made by inspecting the overload indicators, Figure 17.1-9, which are mounted on the platform. Any excessive lateral motion will bend the indicators. Also located on the platform are accelerometer balls. These are steel balls held in position by spring pressure; any sudden jolt received by the container will cause the balls to move from under the springs. After all checks have been completed, the platform is raised to the vertical position using the fuel storage building crane.

Next, the new fuel handling tool is connected to the fuel storage building crane and then attached to the new fuel assembly. The fuel assembly is then removed from the platform. The fuel assembly is transported, in the vertical position using the fuel storage building crane, to the new fuel storage area. A visual inspection is made as a last check for damage and the new fuel assembly is lowered into its storage in the new fuel storage racks.

17.1.3 Containment

17.1.3.1 System Description

The containment building, Figures 17.1-1 and 17.1-10, contains the reactor, the refueling cavity, equipment storage areas and part of the fuel transfer system. In the refueling cavity, fuel is removed from the reactor vessel, and transferred by a manipulator crane to the fuel transfer system for movement into the fuel storage building.

17.1.3.2 Component Descriptions

The components of the fuel handling system inside the containment are discussed individually. In each case the component description, purpose and function is provided.

Refueling Cavity

The refueling cavity, Figures 17.1-1 and 17.1-10, is a stainless steel lined, reinforced concrete structure that forms a pool above the reactor when it is filled with borated water during refueling. The borated water is pumped from the refueling water storage tank (RWST) into the cavity by the residual heat removal system. Radiation at the surface of the water is designed to be < 2.5 mr/hr during fuel assembly transfer. (At all times during transfer the irradiated fuel is handled underwater.)

Vessel Area of Refueling Cavity

Prior to refueling operations, and after reactor cooldown, the reactor vessel flange is sealed to the bottom of the reactor cavity, Figure 17.1-10, by a clamped, gasketed seal. This seal ring prevents leakage of refueling water from the cavity into ventilation wells and the area beneath the reactor vessel. Special covers also are installed to seal off the excore detector wells. The floor and sides of the reactor cavity are lined with stainless steel to insure against leakage and to prevent contact of the coolant with the reinforced concrete walls of the cavity.

Fuel Transfer Canal

The canal is formed by two concrete shield walls, which extend upward to the same elevation as the refueling cavity. The floor of the fuel transfer canal and a portion of the refueling cavity are at a lower elevation than the reactor flange to provide the greater depth required for operation of the fuel transfer system upenders and the rod cluster control assembly change fixture. The fuel transfer tube enters the reactor containment and protrudes through the end of the fuel transfer canal. The fuel transfer tube is a 20 inch stainless steel pipe which connects the fuel transfer canal in the containment with the fuel canal in the fuel storage building.

Polar Crane

A large overhead crane has been provided to handle equipment inside containment. It is used to lift the reactor vessel head and the reactor internals during the refueling sequence.

Manipulator Crane

The manipulator crane, Figure 17.1-11, is used to remove, replace and position fuel assemblies within the core. The manipulator consists of a rectilinear bridge and trolley with a vertical mast which extends into the refueling water. The controls for the following components, which are located on the manipulator crane, are shown on Figure 17.1-12. The bridge, which spans the reactor cavity, runs on rails set into the operating deck of the containment along the edge of the refueling cavity and transfer canal. The trolley runs on the bridge and positions the operator's platform and mast assembly across the width of the refueling cavity.

Gripper Mast Assembly

The gripper assembly, Figure 17.1-13, is mounted on the bottom of the gripper tube. The gripper tube telescopes into and out of the mast. A hoist on the manipulator crane trolley raises and lowers this gripper tube. Movement of the gripper tube within the mast is guided by seven sets of three roller bearings. The three rollers in each set are spaced evenly at 120-degree intervals and prevent the gripper tube from hanging up or swinging freely in the mast. The gripper assembly is air operated with air pressure needed to disengage the fingers. Raising and lowering of the gripper tube and gripper assembly is accomplished by the gripper tube hoist. The gripper tube is long enough so that the upper end is still contained in the mast when the gripper assembly contacts the fuel, yet short enough so that when the fuel is raised it is entirely contained within the mast to provide protection for the fuel assembly while being transported in the refueling cavity. Thus, fuel assembly protection and some additional shielding from the fuel assembly are provided. The mast is normally held stationary but may be rotated 300 degrees manually by retracting a position stop button and turning the outer mast with a turning bar.

Safety interlocks associated with manipulator crane travel and gripper tube hoist movement are designed to prevent damage to the fuel assembly being moved and the fuel remaining in the vessel. Figure 17.1-14 shows typical travel limits for the bridge and trolley positions. In an emergency, and for fine adjustments in position the bridge, trolley and hoist can be operated manually using hand wheels on the individual motor shafts.

Rod Cluster Control Assembly (RCCA) Change Fixture

The RCCA change fixture, Figure 17.1-15, is mounted on the transfer canal wall and is used in removing rod cluster control and spider mounted secondary source assemblies from spent fuel assemblies and inserting them into new or partially spent fuel assemblies. The fixture consists of two main components: a guide tube mounted to the wall for containing and guiding the withdrawn RCCAs, and a mounted carriage for holding the fuel assemblies under the guide tube.

A rod cluster control assembly can be removed by the RCCA change fixture gripper and hoist. The rod cluster control assembly can be aligned with the other fuel assembly's guide tubes for insertion into the new fuel assembly. The RCCA change fixture gripper is raised and lowered in the guide tube by a cable driven from a hoist.

The RCCA change fixture gripper is pneumatically operated to latch and unlatch the RCCA assemblies. The wheel mounted carriage support is anchored to the floor of the refueling cavity. The carriage contains compartments for two fuel assemblies and one RCC element with each one capable of being positioned by a chain and cable assembly operated by a hand winch from the operating floor. This winch has a lock or shaft clamp on it to prevent movement. Two stationary stops have been attached to the extremes of the support frame. These stops will prevent the carriage from rolling off the ends of the tracks. Positioning stops are also provided on both the carriage and frame to locate each of the three carriage compartments directly below the guide tube.

Reactor Vessel Head Lifting Device

The reactor vessel head lifting device, Figure 17.1-16, consists of a welded and bolted structural steel frame with suitable rigging to enable the polar crane operator to lift the head and store it during refueling operations. The lifting device is permanently attached to the reactor vessel head. Attached to the head lifting device are the monorail and hoists for the reactor vessel stud tensioners.

Reactor Internals Lifting Device

The reactor internals lifting device, Figure 17.1-17, is a structural frame suspended from the polar crane. The frame is lowered onto the guide tube support plate of the internals, and is manually bolted to the support plate by three bolts. Bushings on the frame engage guide studs in the vessel flange to provide guidance during removal and replacement of the internals package. The reactor internals lifting device is used to lift the upper internals package as well as the lower reactor internals package.

Reactor Vessel Stud Tensioner

Stud tensioners, Figure 17.1-18, are employed to secure the head closure joint at every refueling. The stud tensioner is a hydraulically operated device that uses oil as the working fluid. Stud tensioners minimize the time required for the tensioning or unloading operations of the reactor vessel head bolts. Three tensioners are provided and are applied simultaneously to three studs located 120 degrees apart. A single hydraulic pumping unit operates the tensioners, which are hydraulically connected in series. The studs are tensioned to their operational load in two steps to prevent high stresses in the flange region and unequal loadings in the studs. Relief valves on each tensioner prevent overtensioning of the studs due to excessive pressure.

Special Refueling Tools

Control Rod Drive Shaft Unlatching Tool

The control rod drive shafts are unlatched and latched to the full length rod cluster assembly spiders using the control rod drive shaft unlatching tool, Figures 17.1-5 and 17.1-19. This tool is suspended from the auxiliary hoist on the manipulator crane and is operated from the bridge. The latching mechanism is pneumatically operated. All full length RCCA drive shafts are removed as a unit with the reactor vessel upper internals.

Burnable Poison Rod Assembly (BPRA) Handling Tool

The burnable poison rod assembly handling tool, Figure 17.1-5, is a long handled tool used in the spent fuel pool and fuel transfer canal to transfer irradiated burnable poison rod assemblies between two fuel assemblies or between a fuel assembly and a special insert temporarily placed on selected spent fuel assembly storage racks. The tool is suspended from the hoist on the spent fuel pool bridge. An operator standing on the bridge guides the tool and manually actuates the engagement and handling mechanisms.

Irradiation Sample Handling Tool

The irradiation sample handling tool, Figure 17.1-5, is a long handled tool used to remove the irradiation specimens from their holders located on the outer surface of either the thermal shield or the neutron pads inside the reactor vessel. The tool is suspended from the polar crane and operated from the manipulator crane bridge.

Rod Cluster Control Thimble Plug Tool

The rod cluster control thimble plug tool is a manually operated tool, Figure 17.1-5, that is used in the transfer canal to remove or insert the thimble plug in a fuel assembly. When transferring an RCCA from one fuel assembly to another, a thimble plug is inserted in the fuel assembly from which the RCCA was removed.

17.1.4 Fuel Transfer System

17.1.4.1 System Description

The fuel transfer system is located in the fuel transfer canal area of the containment and fuel storage building, and utilizes an underwater conveyor to move fuel between these two areas, Figure 17.1-10. The underwater air-motor driven conveyor system runs on tracks extending from the containment through the transfer tube and into the fuel storage building. The container section of the conveyor car receives a fuel assembly is then lowered by the upender to a horizontal position for passage through the tube. Following that operation it is raised to a vertical position by a second upender in the fuel transfer canal (in the spent fuel pool side). The spent fuel pool bridge hoist then removes the assembly from the conveyor and places it in storage. A blind flange supplied with containment penetration pressurization air is bolted on the transfer tube inside the containment to seal the reactor containment.

17.1.4.2 Component Descriptions

Conveyor Car Assembly

The conveyor car assembly is made up of two parts: the conveyor car frame and the fuel assembly container. The conveyor car frame is built out of a long stainless steel pipe. Mounted on and welded to the pipe at eight locations are wheel assemblies. The wheels ride on tracks which extend from the containment to the fuel storage building. Located on the bottom of the car frame along its entire length is welded a roller chain. Two gears located on the drive frame assembly engage the chain and provide the driving force.

The fuel assembly container is pinioned at one end to the conveyor car and is capable of being rotated to the vertical position about this point. The container is provided with locating guides which mate with pins on the upender. It is through the pins that the upender attaches itself to the fuel assembly container. During normal operation the car travels without any difficulty; if the car were to become stuck in the tube or the transfer canal, the car can be retrieved by pulling on its attached emergency cable with the fuel storage building crane.

Drive Frame Assembly

The drive frame assembly consists of a two speed reversible air driven motor which turns two gears that are connected to the motor by a roller chain. The two gears engage the chain welded to the bottom of the conveyor car frame. By rotating the gears with the drive motor, the car is propelled along the track. The air to the drive motor is turned on and off through the operation of solenoid valves. The solenoid valves are controlled from the reactor side control panel.

Upenders (Lifting Mechanisms)

Each upender is made up of an “I” beam that pivots about a support which mates with guides located on the fuel assembly container support structure. The upender is raised and lowered with a cable driven by an electrically operated winch. A hand wheel has been provided to manually operate the winch.

Gate Valve

A wedge type gate valve is installed at the fuel storage building side of the fuel transfer tube to provide a means of isolating the fuel transfer tube. The valve is large enough to allow the conveyor car to pass freely.

Fuel Transfer Control System

The fuel transfer control system is located on two panels. The conveyor car and reactor side upender are operated from the panel located inside containment while the fuel storage building upender is controlled from the panel located in the fuel storage building. Various procedural requirements and an interlock system between the two control points provide adequate fuel, equipment, and personnel protection during the operation of the fuel transfer system.

17.1.5 Summary

The maximum design stress for the structures and for all parts involved in gripping, supporting, or hoisting the fuel assemblies is 1/5 of the ultimate strength of the material. This requirement applies to normal working load and emergency pullout loads, when specified, but not the earthquake loading. To resist safe shutdown earthquake forces, the equipment is designed to limit the stress for a combination of normal working forces plus safe shutdown earthquake forces.

The fuel handling building crane is provided to move new fuel and spent fuel casks in the fuel handling building. Movement of these loads by the fuel building crane is allowed in all areas of crane travel except directly over the spent fuel storage racks. These interlocks (mechanical stops) will help to eliminate the possibility of accidentally damaging the spent fuel.

The fuel transfer tube connecting the fuel transfer canal inside the containment and the fuel transfer canal in the fuel storage building is closed on the containment side by a blind flange at all times except during refueling operations. Two seals are located around the periphery of the blind flange with leak check provisions between them. The fuel transfer tube is isolated on the fuel storage buildings side by the gate valve.

During all phases of spent fuel transfer, the gamma dose rate, 3 feet above the surface of the water, is < 2.5 mr/hr or less. This is accomplished by maintaining a minimum of 9.5 feet of water above the top of an active fuel assembly during all handling operations.

The two cranes used to lift spent fuel assemblies are the manipulator crane and the spent fuel pool bridge hoist. The manipulator crane contains positive stops which prevent the top of a fuel assembly from being raised to within of 10 feet the normal water level in the refueling cavity. The hoist on the spent fuel pool bridge crane moves spent fuel assemblies with a long handled tool. Hoist travel and tool length limit the maximum height to which an assembly is lifted in the spent fuel pool.

As part of normal plant operations, the fuel handling equipment is inspected for operating conditions prior to each refueling operations. During the operational testing of this equipment, procedures are followed that will verify the correct performance of the fuel handling system interlocks.

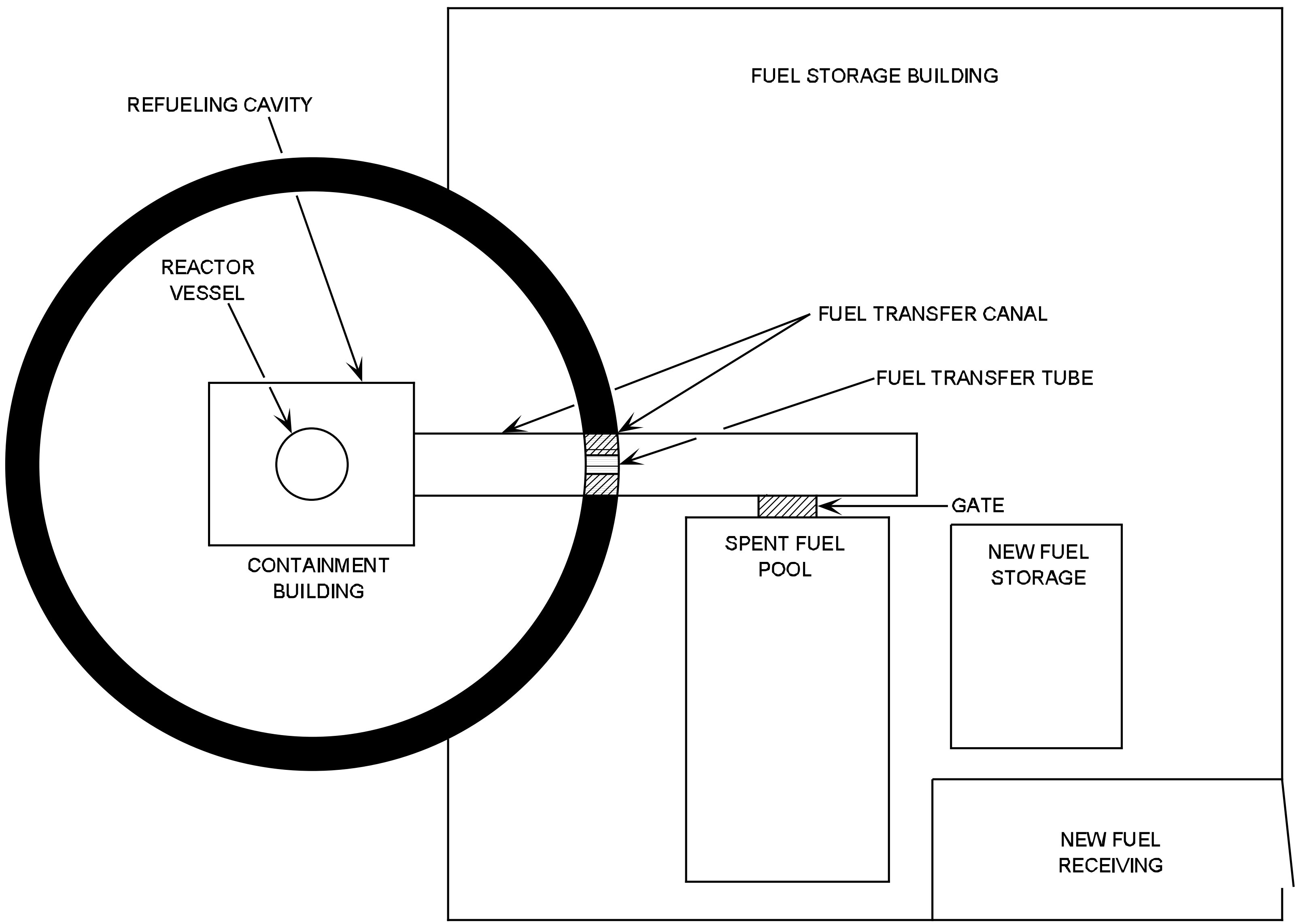
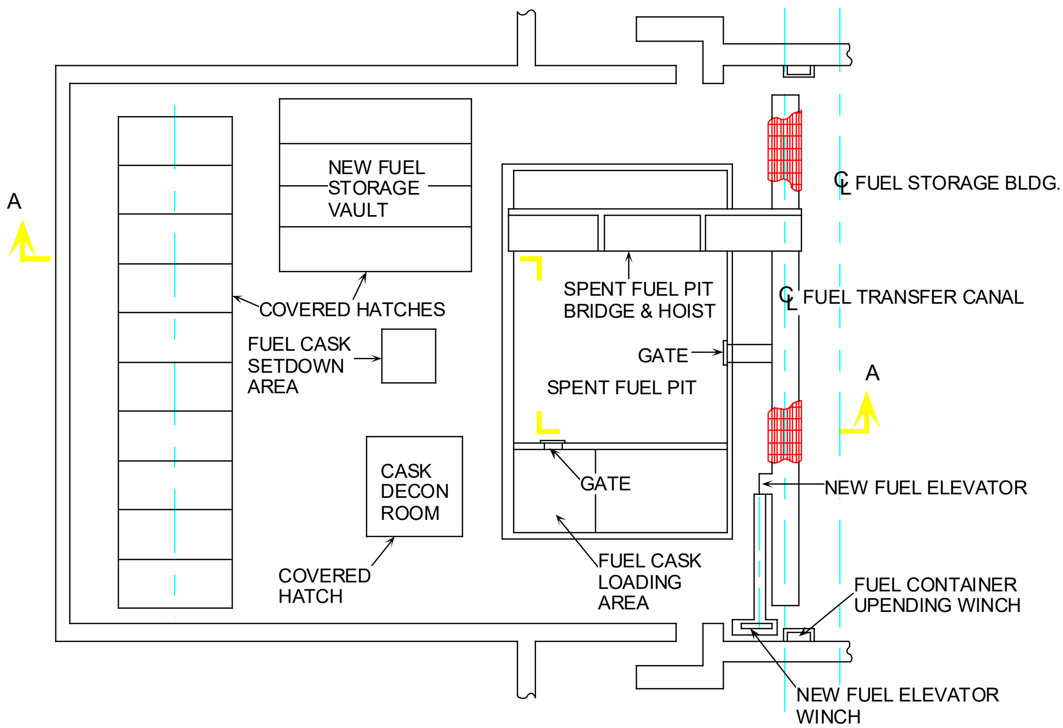
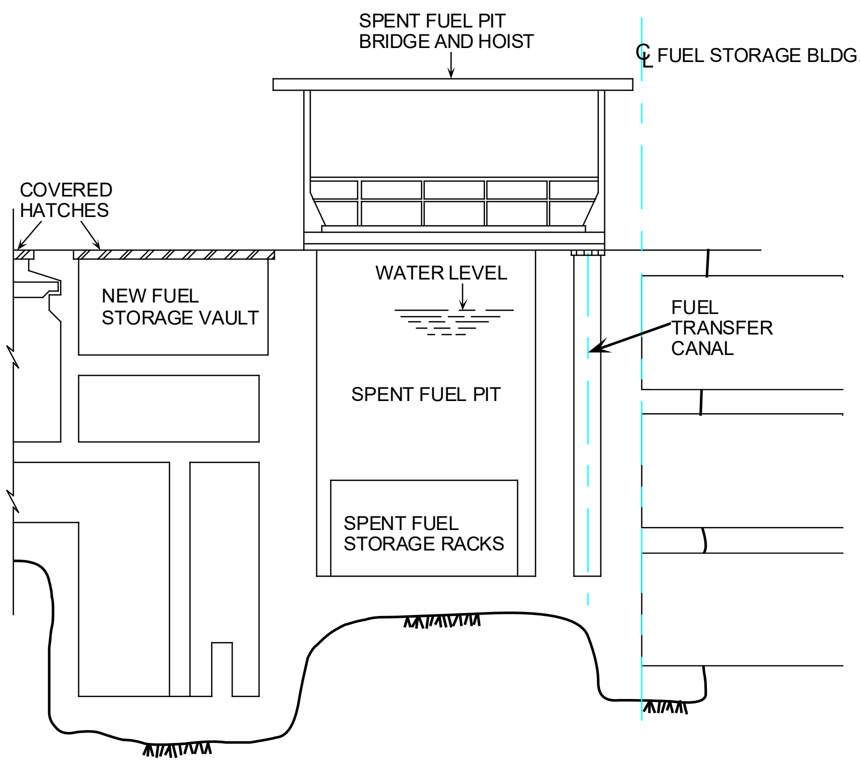


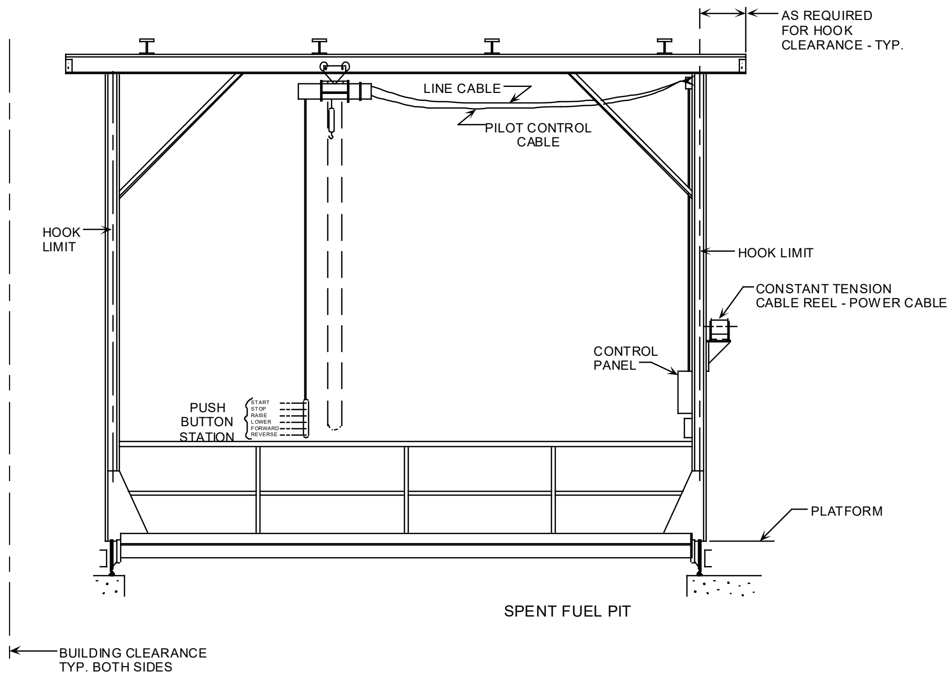
Figure 17.1-1 Containment – Fuel Handling Area Layout





SECTION A-A

Figure 17.1-2 Fuel Storage and Handling



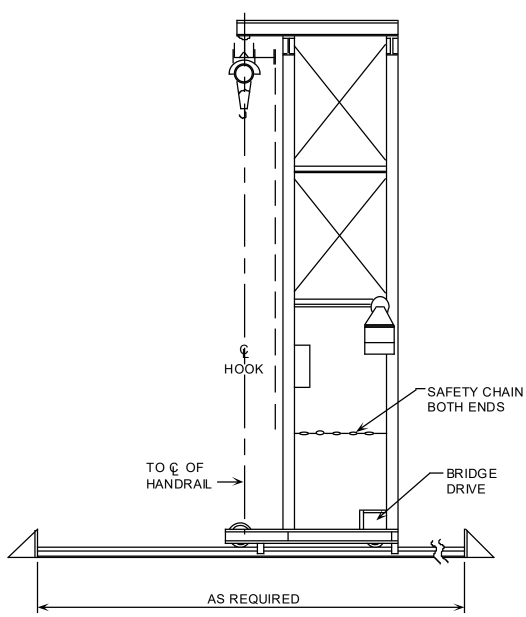


Figure 17.1-3 Spent Fuel Pit Bridge

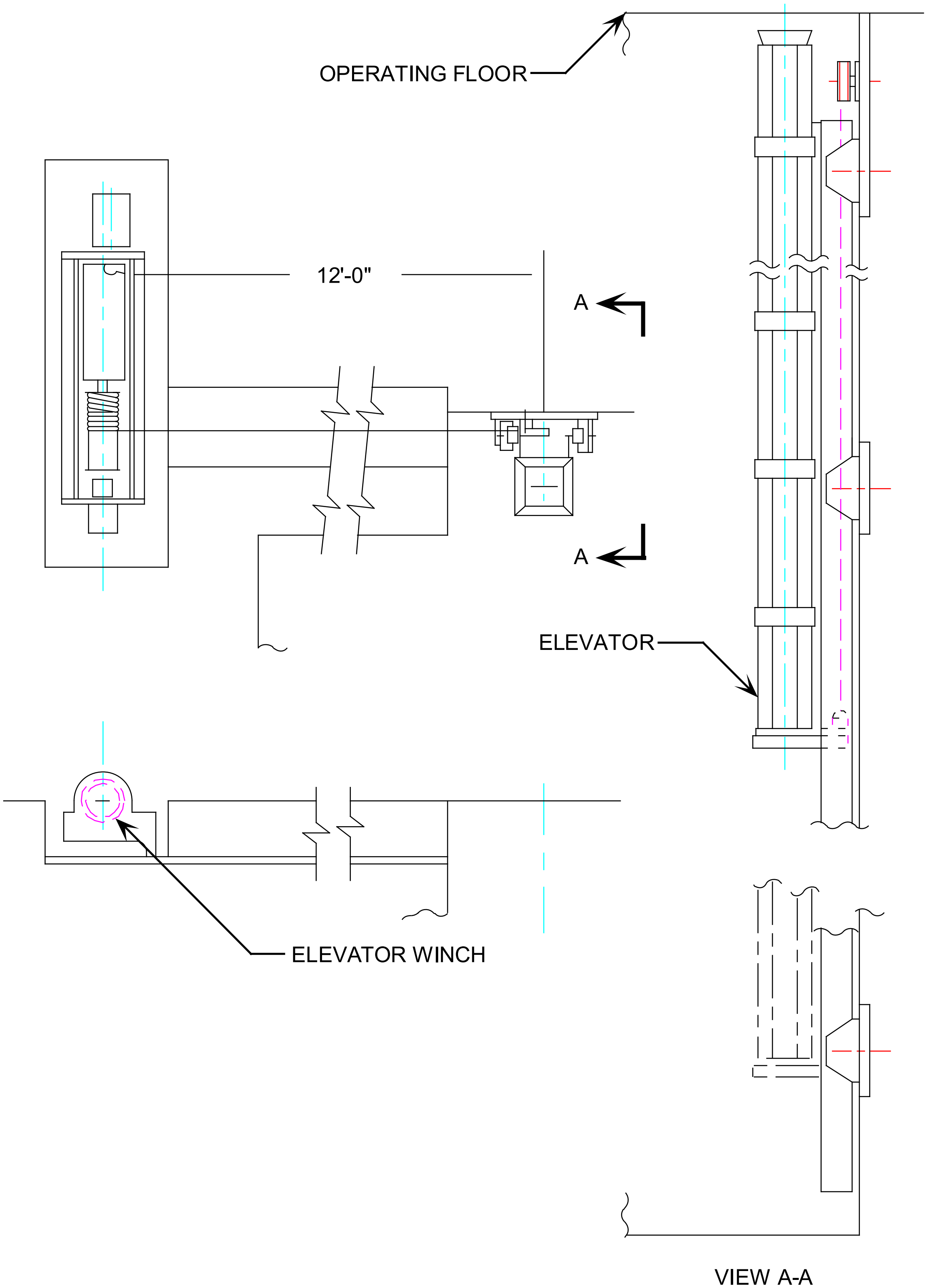


Figure 17.1-4 New Fuel Elevator

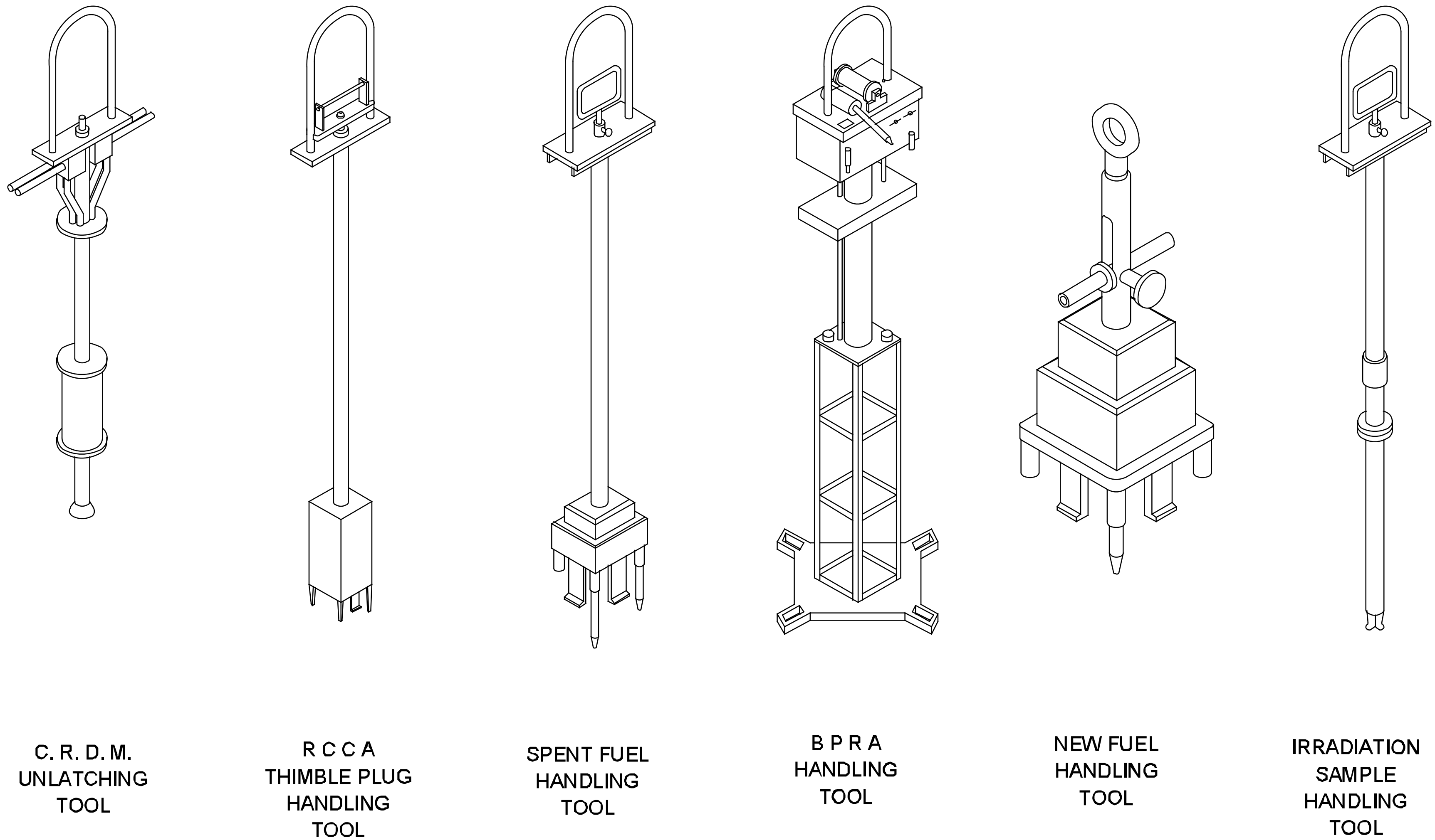


Figure 17.1-5 Fuel Handling Tools

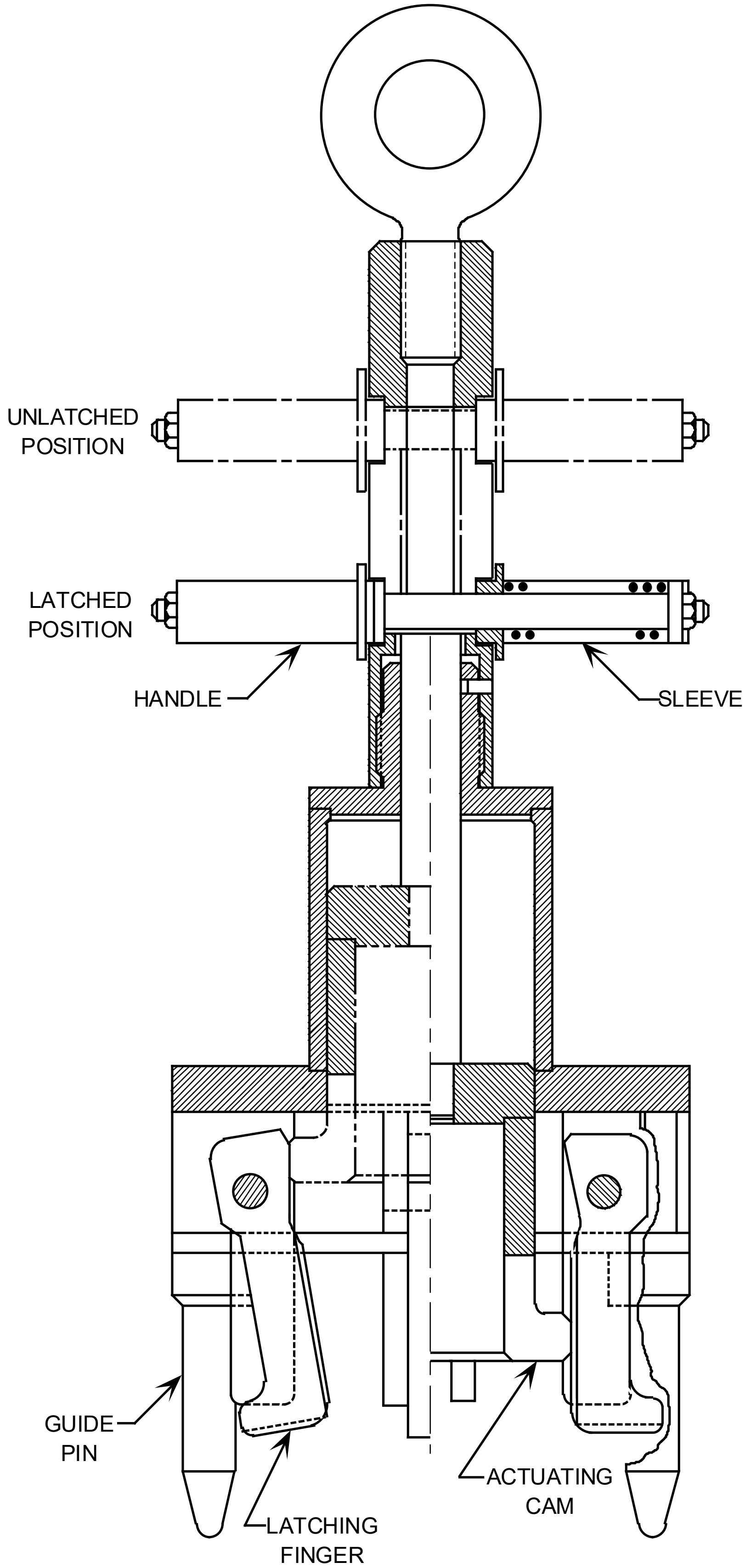


Figure 17.1-6 New Fuel Handling Tool

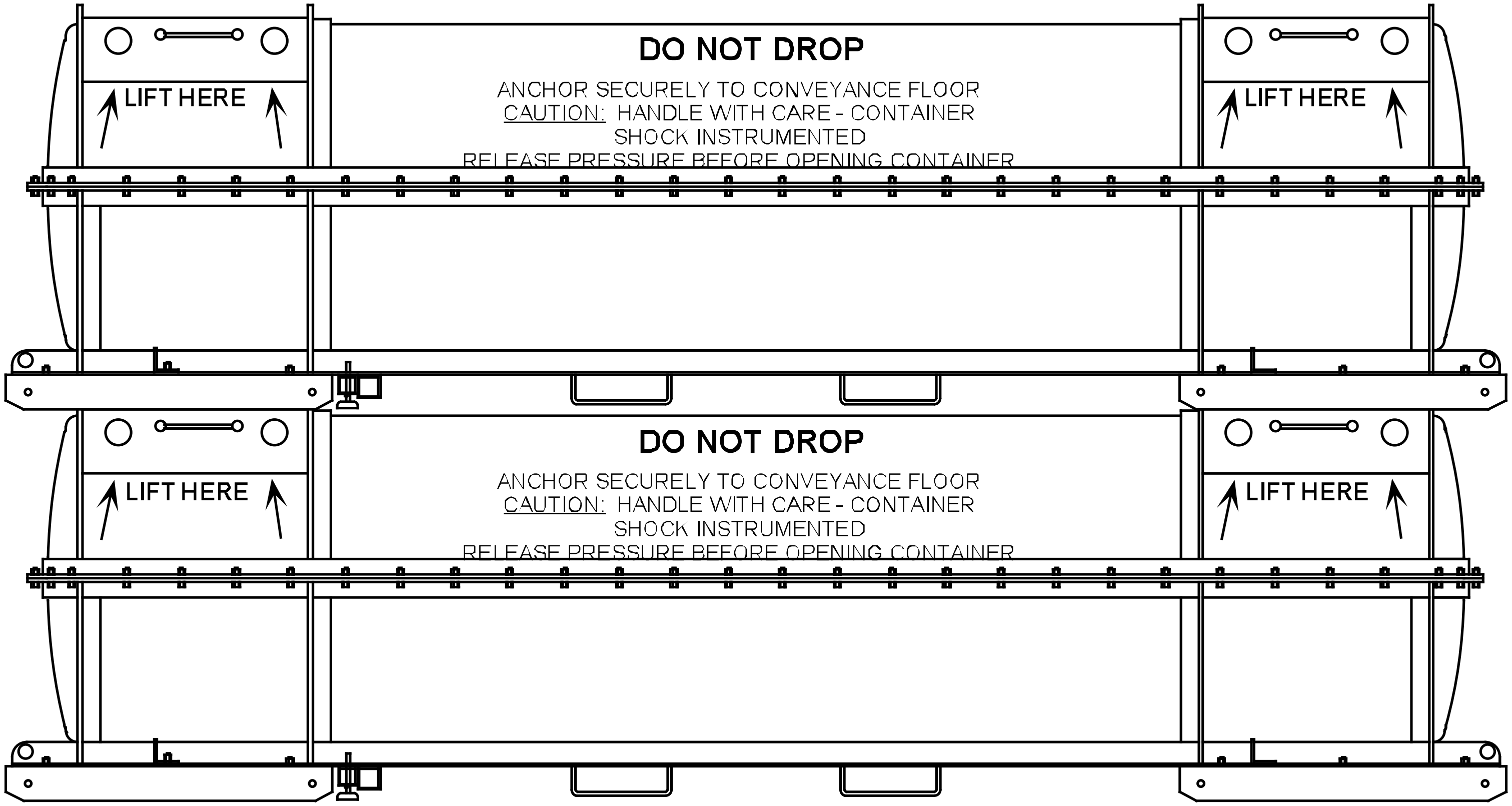


Figure 17.1-7 Loaded Shipping Container

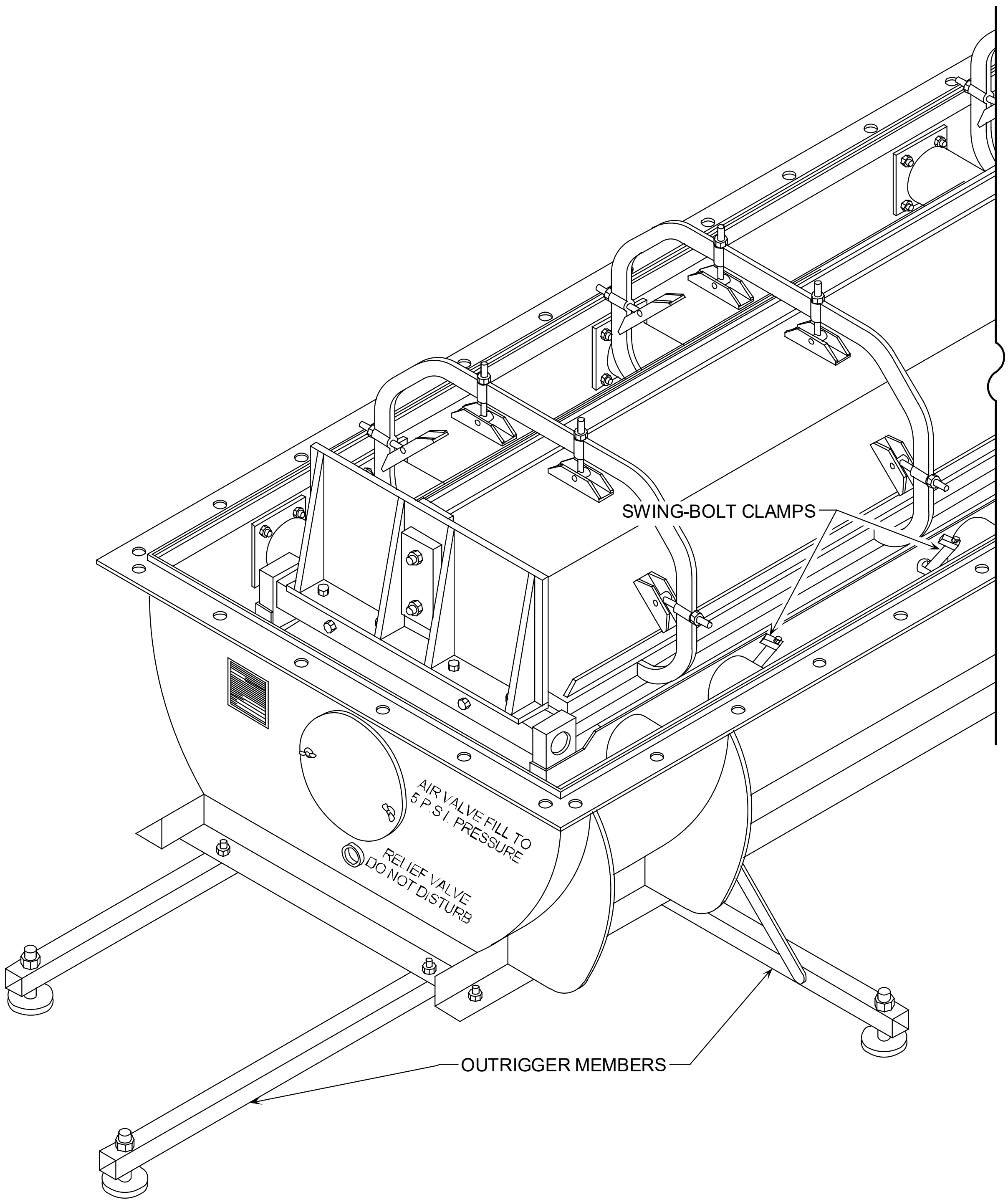


Figure 17.1-8 Preparation for Uprighting Internals

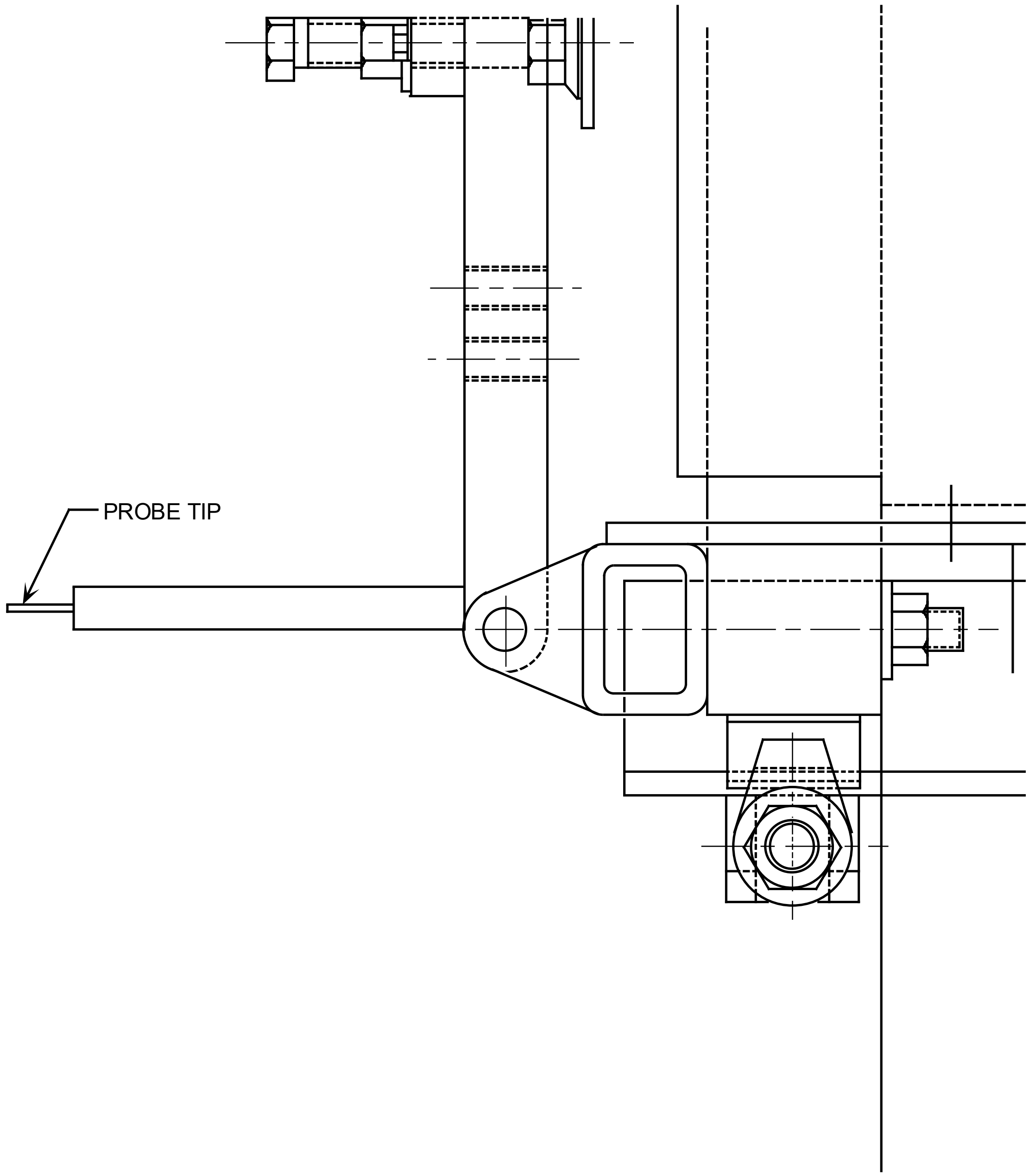


Figure 17.1-9 Overload Indicator

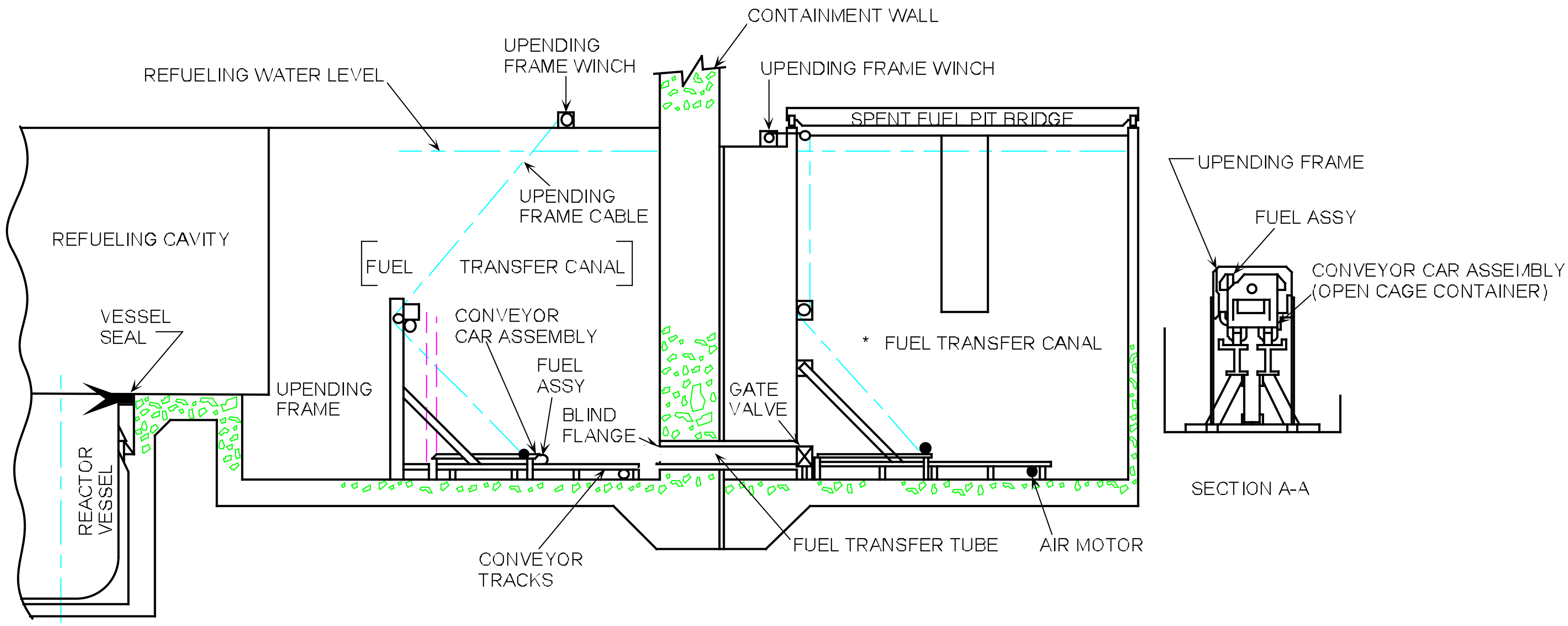
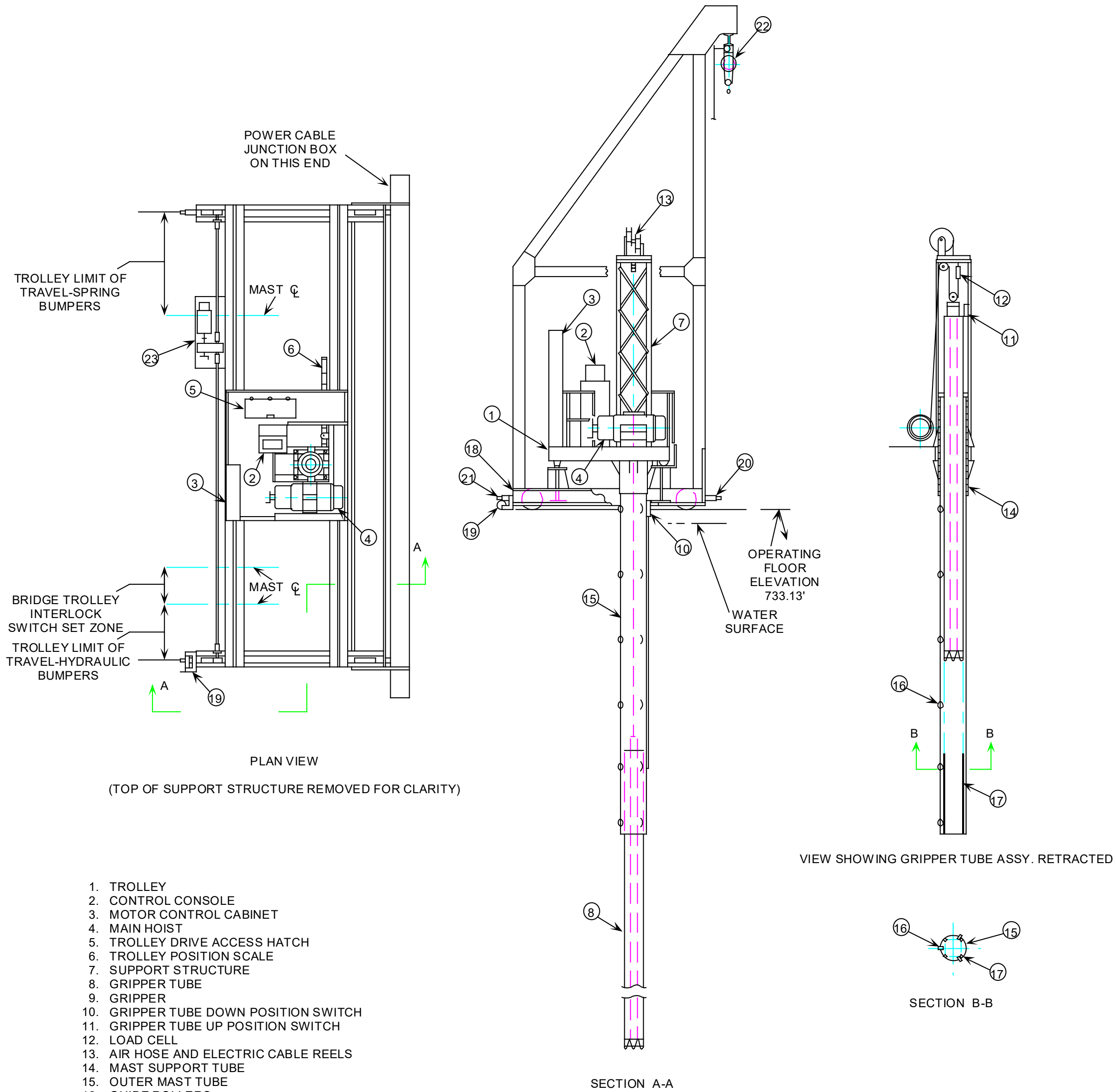


Figure 17.1-10 Fuel Transfer System



1. TROLLEY
2. CONTROL CONSOLE
3. MOTOR CONTROL CABINET
4. MAIN HOIST
5. TROLLEY DRIVE ACCESS HATCH
6. TROLLEY POSITION SCALE
7. SUPPORT STRUCTURE
8. GRIPPER TUBE
9. GRIPPER
10. GRIPPER TUBE DOWN POSITION SWITCH
11. GRIPPER TUBE UP POSITION SWITCH
12. LOAD CELL
13. AIR HOSE AND ELECTRIC CABLE REELS
14. MAST SUPPORT TUBE
15. OUTER MAST TUBE
16. GUIDE ROLLERS
17. FUEL ASSY. GUIDE BARS
18. BRIDGE
19. BRIDGE POSITION TRANSMITTER
20. HYDRAULIC BUMPER
21. SPRING BUMPER
22. MONORAIL HOIST
23. BRIDGE DRIVE

Figure 17.1-11 Manipulator Crane

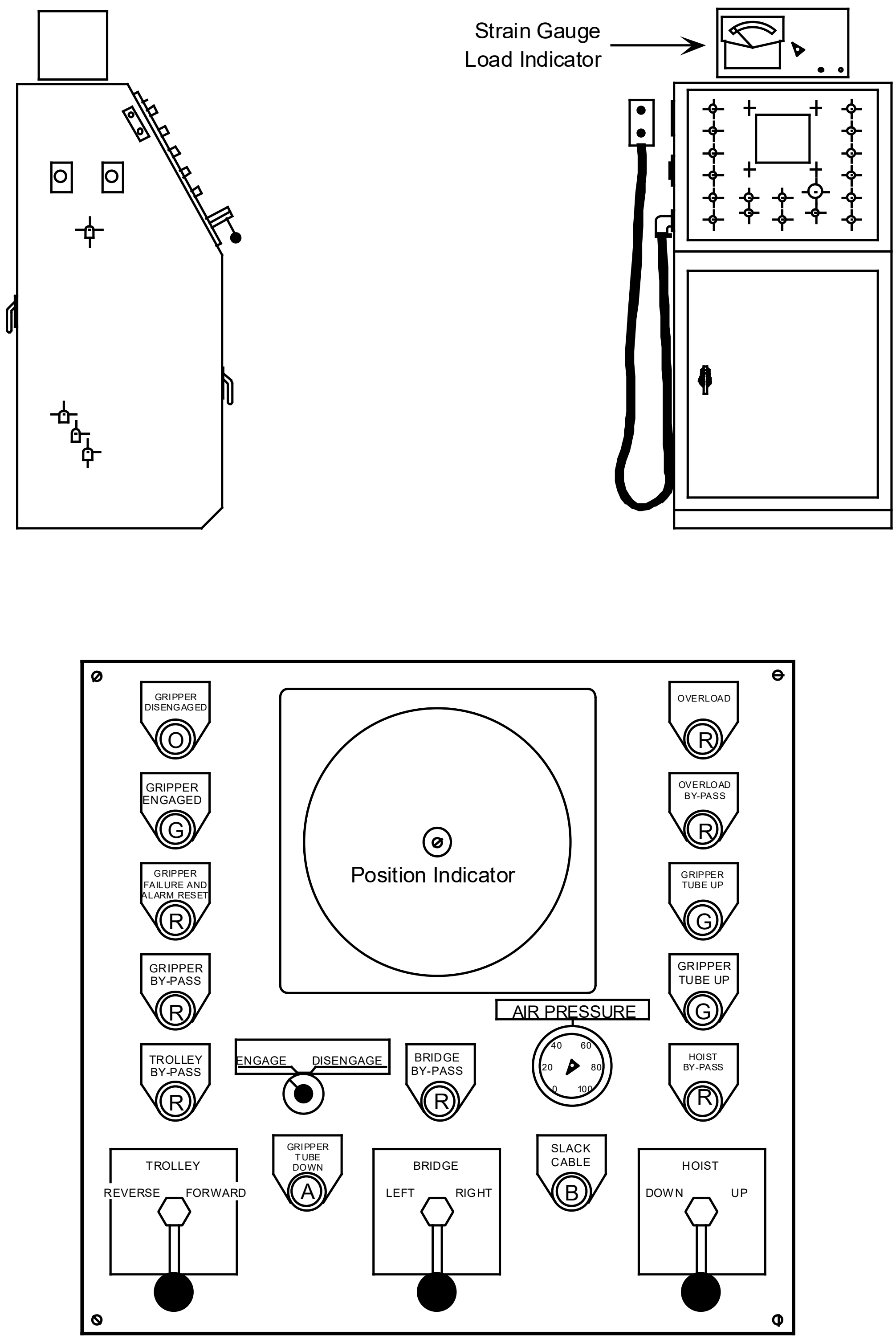


Figure 17.1-12   Manipulator Control Console

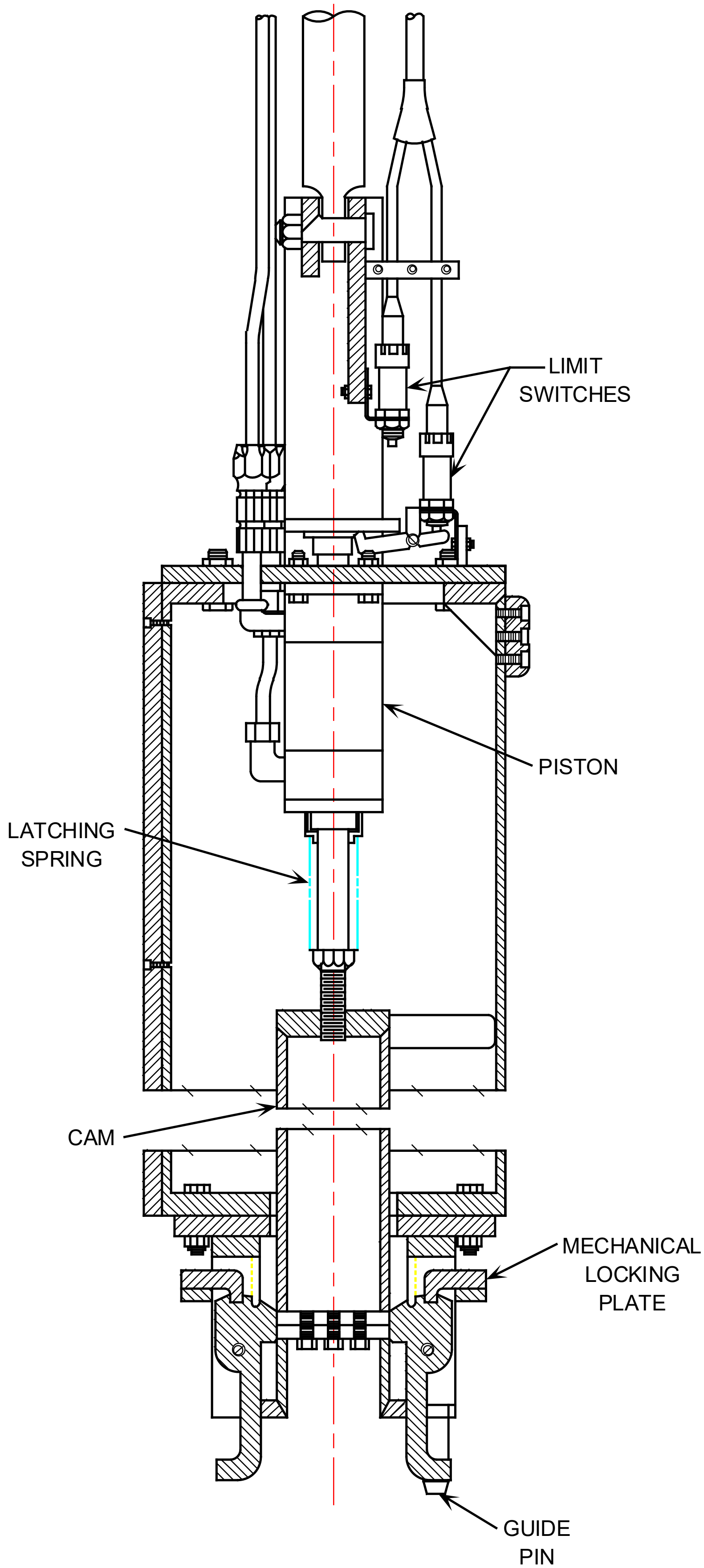


Figure 17.1-13 Gripper Assembly

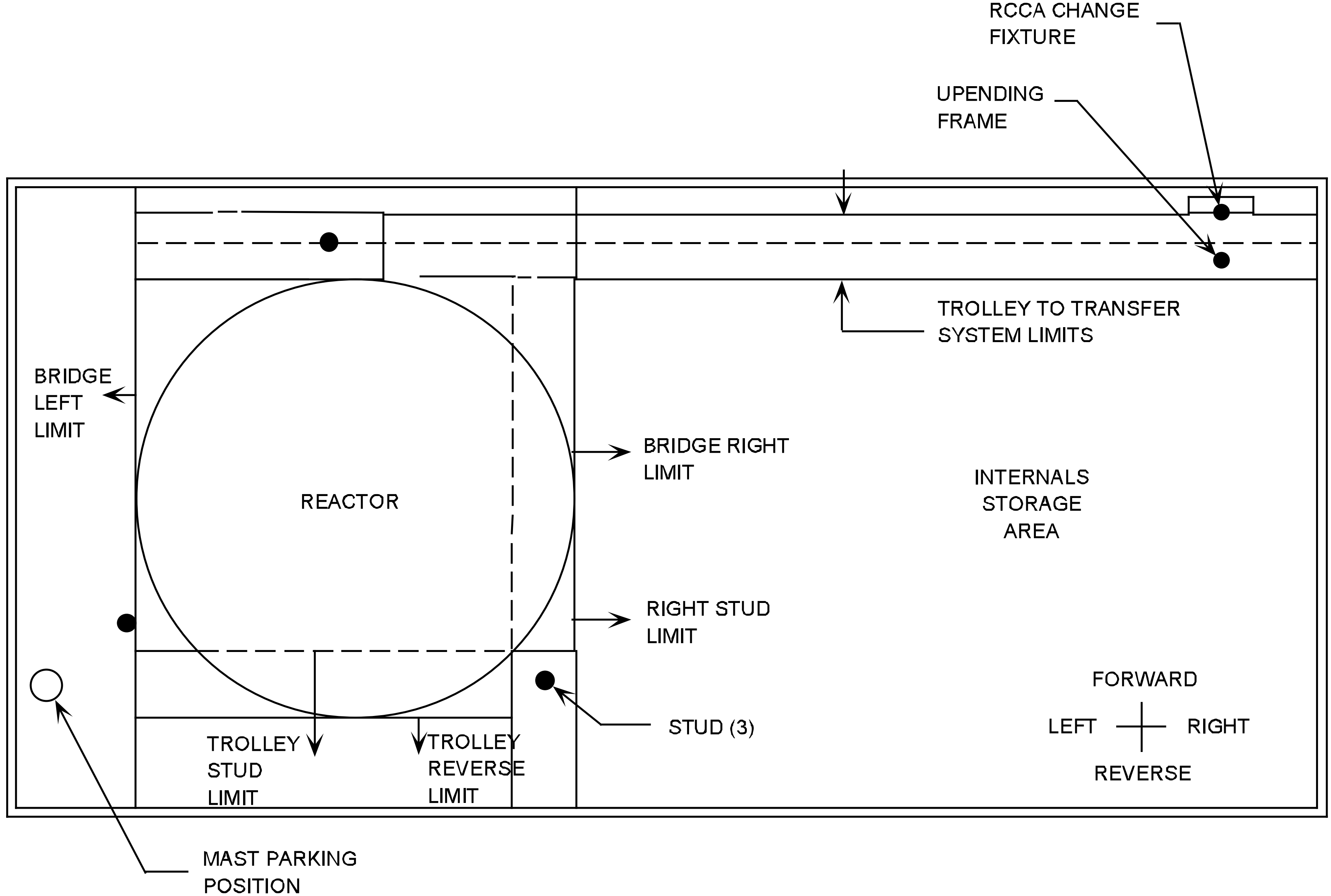


Figure 17.1-14   Manipulator Crane Travel Limits

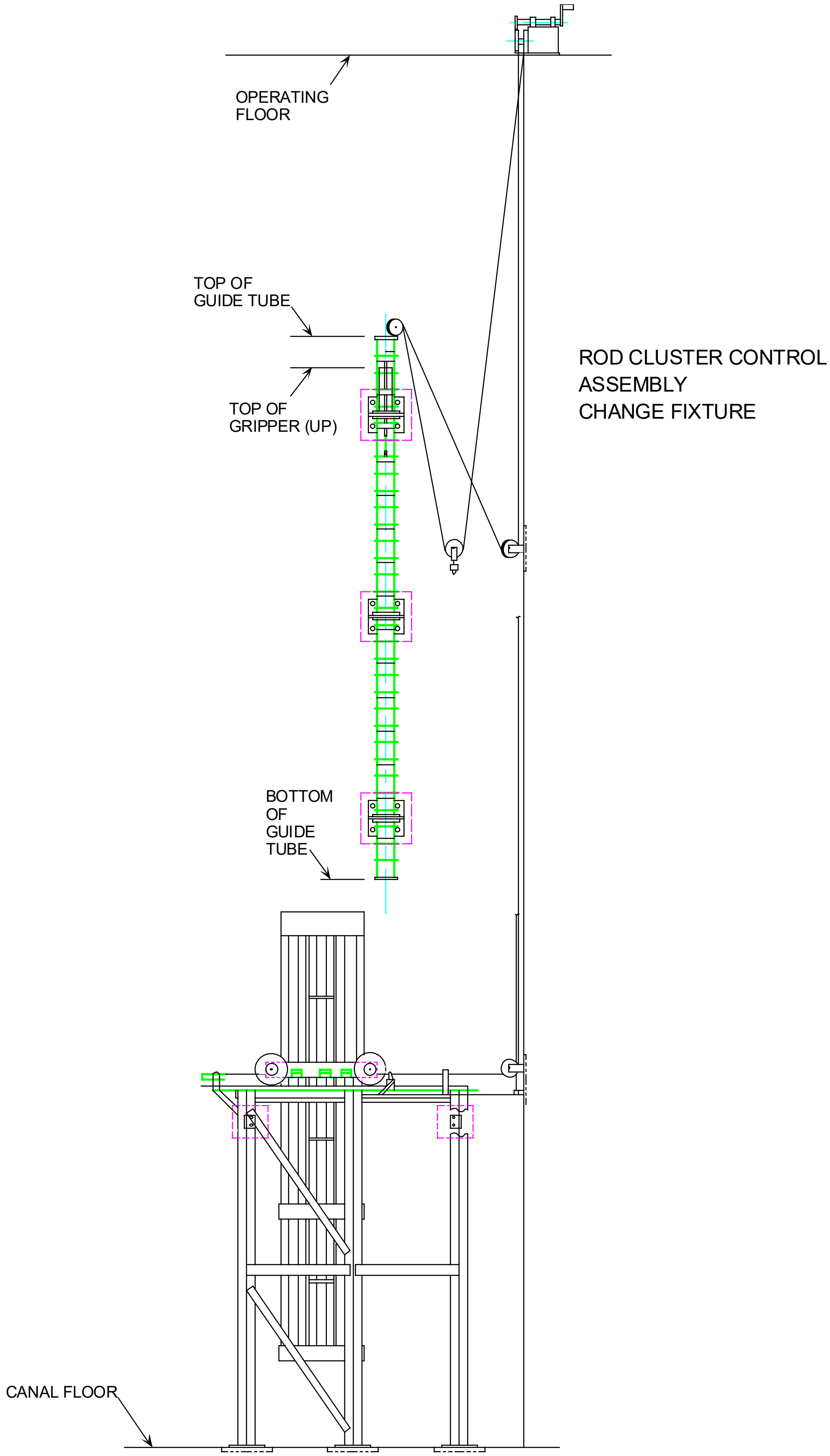


Figure 17.1-15 RCCA Change Fixture

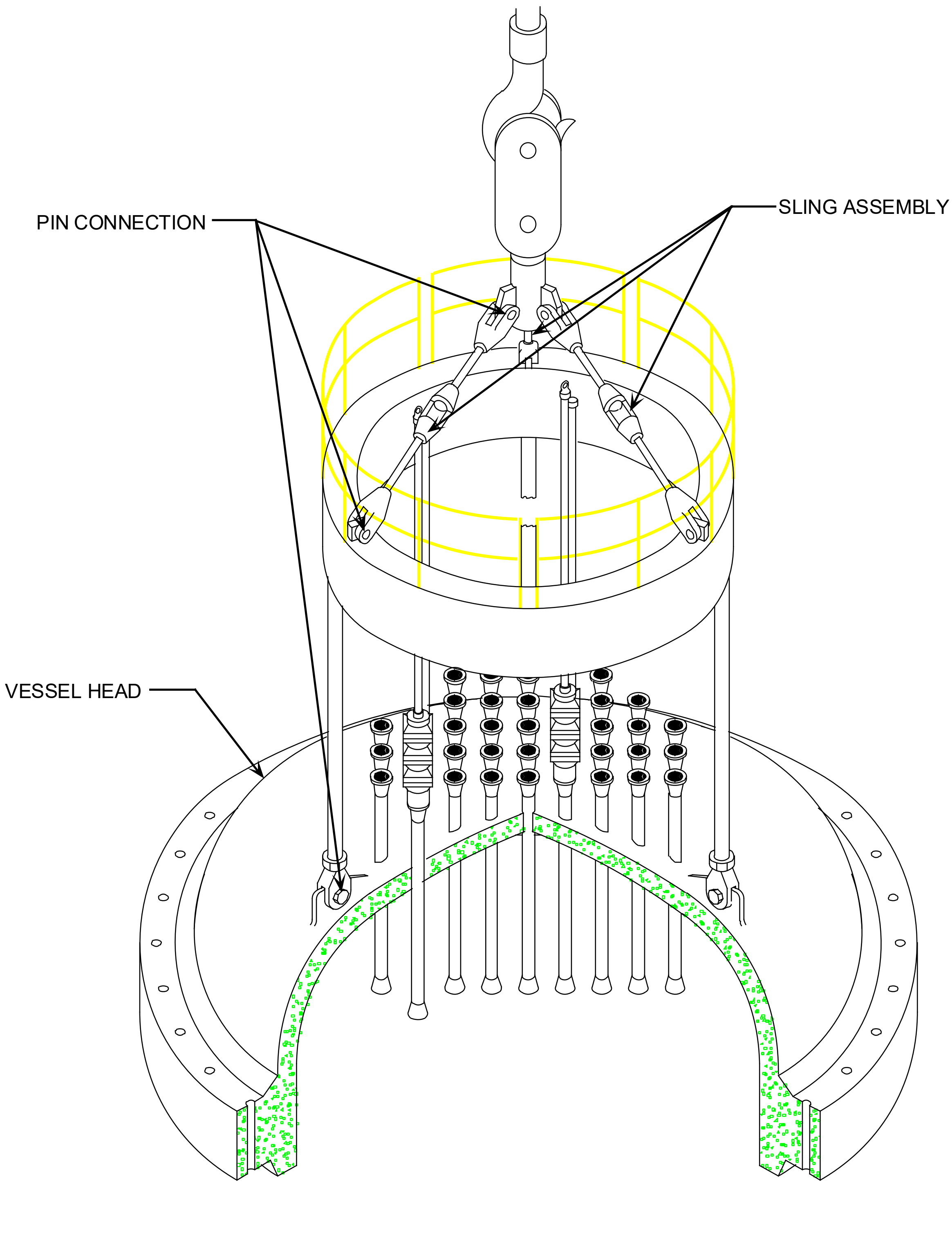
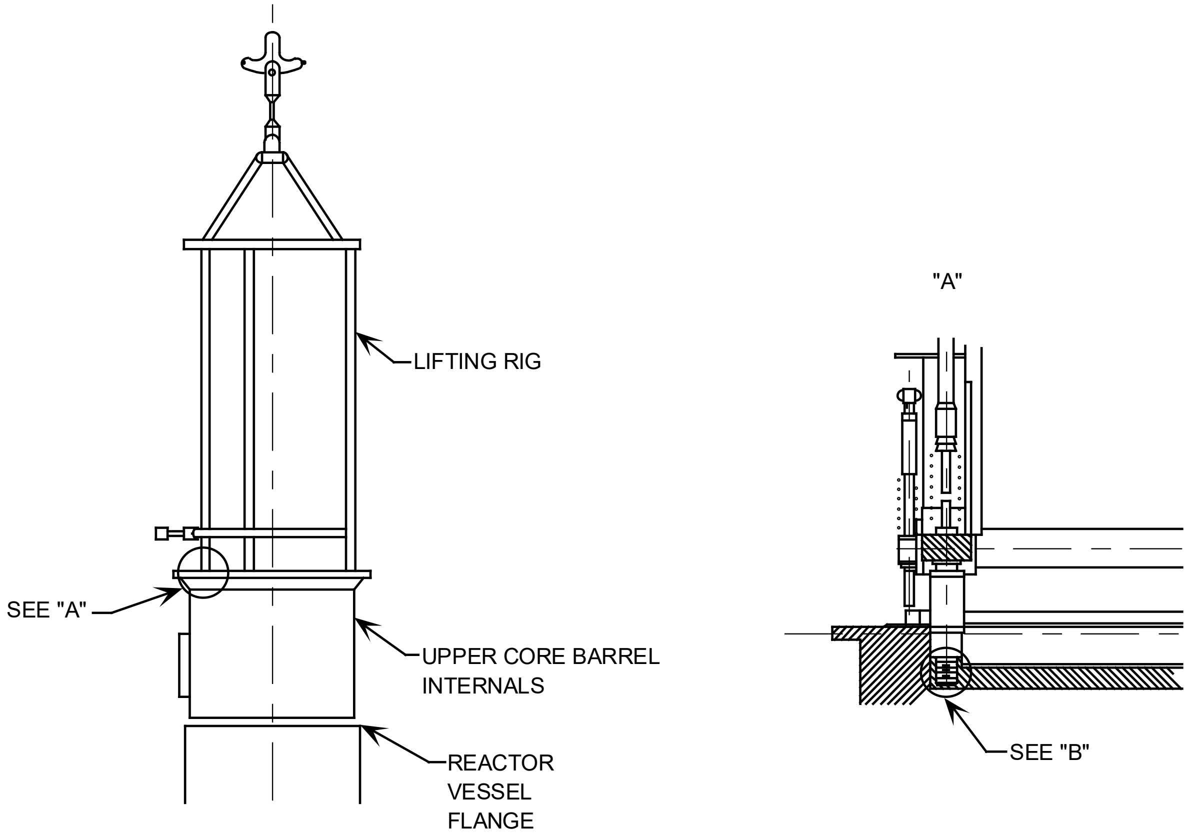
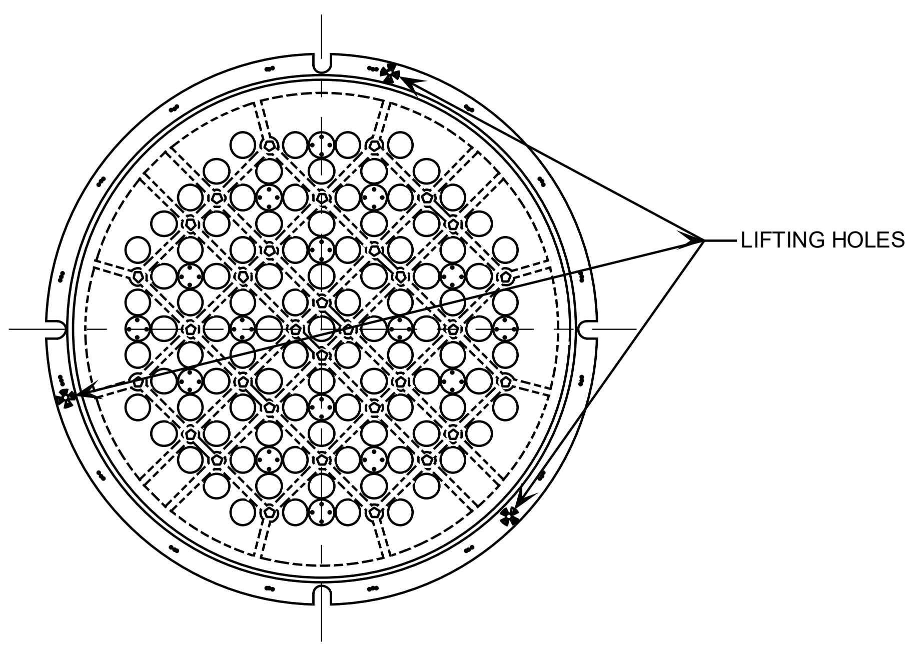


Figure 17.1-16 Reactor Vessel Head Lifting Device





PLAN VIEW OF UPPER CORE SUPPORT STRUCTURE

Figure 17.1-17   Reactor Internals Lifting Device

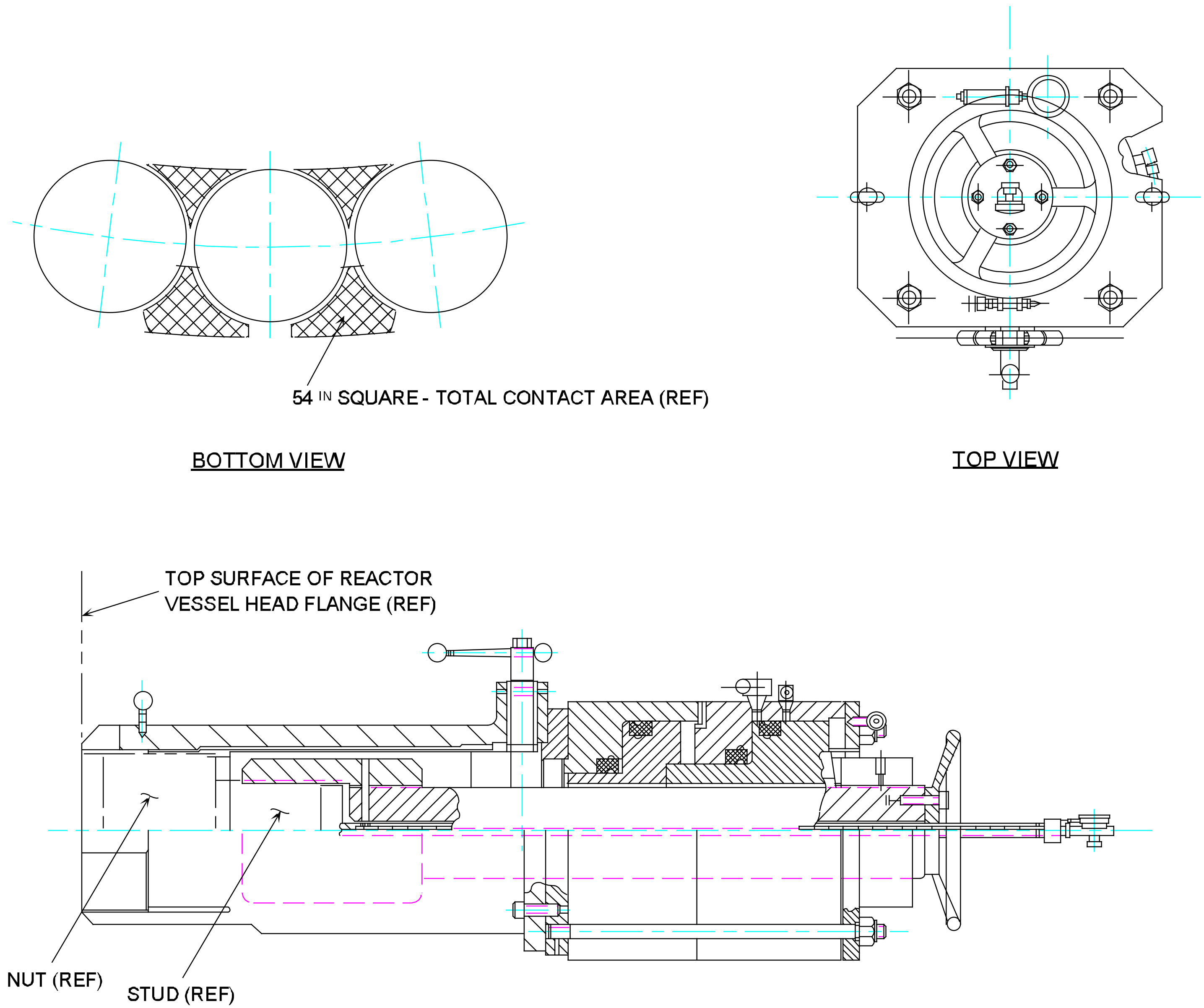


Figure 17.1-18 Reactor Vessel Stud Tensioner

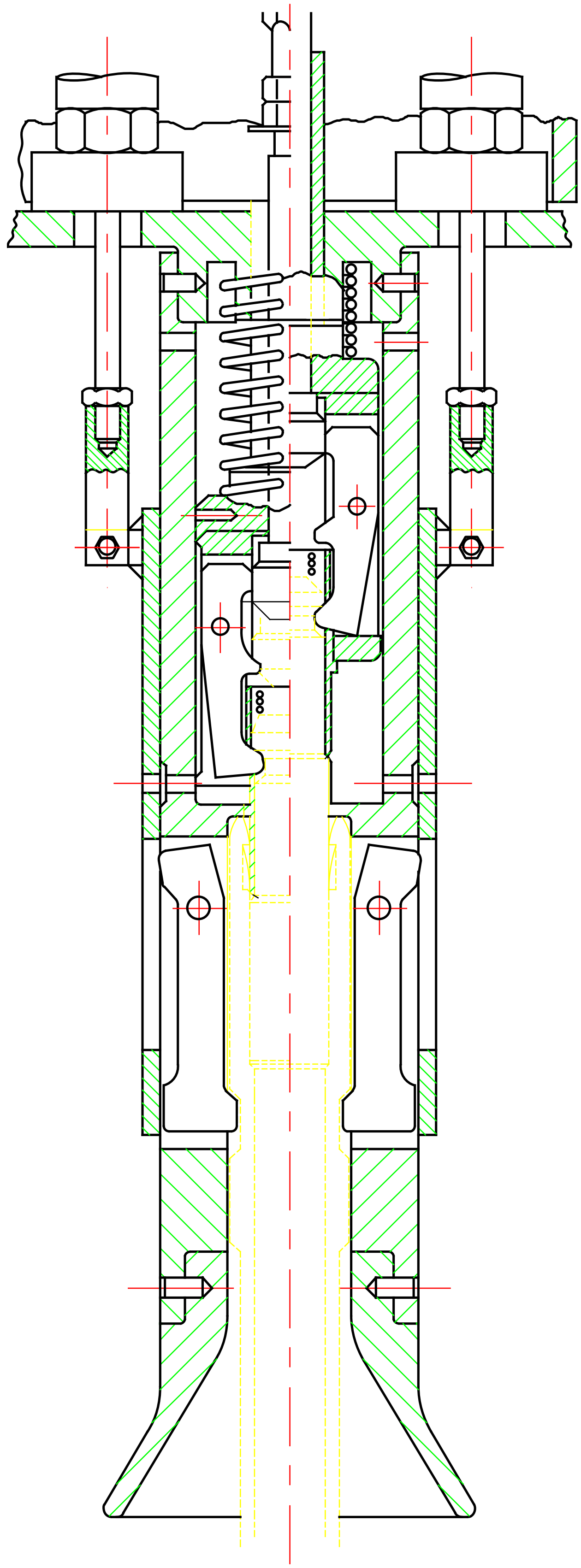


Figure 17.1-19 Rod Drive Shaft Unlatching Tool

Westinghouse Technology Systems Manual

Section 17.2

Spent Fuel Storage

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17.2 SPENT FUEL STORAGE

17.2.1 Introduction

Originally, the core was designed to be refueled with fuel assemblies containing recycled plutonium from spent fuel assemblies. Fuel assemblies would be sent to a facility where the plutonium and unused uranium would be chemically separated from the spent fuel and used in the manufacture of new assemblies. A demonstration plutonium extraction facility was designed and built, but fears associated with nuclear proliferation prevented the operation of the facility. The concern over the availability of relatively large quantities of weapons grade plutonium resulted in the U.S. government adopting policies which prohibited spent fuel assembly recycling. These policies forced the nuclear utilities to change spent fuel pool storage designs.

The original spent fuel pool storage design capacity was 4/3 core; i.e., if the core contained 200 fuel assemblies, the spent fuel pool storage could hold 266 spent fuel assemblies. This capacity would be sufficient for the 1/3 of the core's fuel assemblies that were changed out during a refueling plus a full core off load resulting from an unforeseen plant problem. Since spent fuel assemblies were to be recycled, this capacity was satisfactory. Also, the original spent fuel pool storage design had a 21-inch distance between the center lines of adjacent storage rack locations. This distance was required to prevent spent fuel pool criticality under postulated worst case reactivity conditions. The 21-inch distance allowed the utilities to redesign the spent fuel racks. The large center line to center line distance was eliminated, and metal plates containing boron were added to prevent criticality. The second iteration of spent fuel pool storage racks was called high density fuel racks and more than doubled the spent fuel pool storage capacity. The change-out of a spent fuel pool storage rack's design is called “re-racking.”

The increase in spent fuel pool capacities, combined with increases in core life, delayed the spent fuel storage problem. The arithmetic associated with spent fuel is not very complex. If 66 fuel assemblies are removed during each refueling, after 10 refuelings, the high density storage racks would be full. Many U.S. utilities have already re-racked twice.

17.2.2 Dry Storage

Another option open to utilities to provide extra storage is dry storage. This allows spent fuel assemblies to be removed from the spent fuel pool and stored on-site in metal or concrete canisters on a concrete base.

Spent fuel assemblies are placed in the canisters while in the spent fuel pool, and then the canisters are sealed. Because the oldest spent fuel would be placed in these canisters, the radioactivity and decay heat would be diminished, allowing the assemblies to be cooled by natural airflow around the outside of the canisters. Radiation from the canisters would be very low. At the boundary of the concrete base, there may be no detectable levels of radioactivity.

Dry storage entails the least amount of worker handling and therefore would result in less worker exposure to radioactivity. Canisters can hold between 7 and 24 PWR assemblies each. Dry storage could open enough space in the spent fuel pool to accommodate plant needs into the twenty-first century. Since the NRC has licensed dry storage canisters (10CFR72), utilities would only need an additional license amendment from the agency. The NRC has licensed many designs from different manufacturers. Table 17.2-1 lists some of the licensed manufacturers. The major features of the one of the designs will be discussed in the following paragraphs.

17.2.2.1 NUHOMS

The Pacific Nuclear Fuel Services, Incorporated dry storage system is called NUHOMS and is of the concrete modular design. As shown in Figure 17.2-1, the design consists of a dry shielded canister (DSC) and a reinforced concrete horizontal storage module. The DSC serves as the containment pressure boundary for the confinement of radioactive materials and provides a leak tight, inert atmosphere to ensure that the integrity of the fuel cladding is maintained.

The DSC is composed of two basic components: the basket and the shell. The DSC basket is designed to accommodate 24 fuel assemblies (Figure 17.2-2) in separate rectangular boxes. The 24 boxes are placed into spacer disks separated by support rods. The spacer disks allow the rectangular boxes to be placed into the circular shell.

The DSC shell assembly is a stainless steel, welded pressure vessel that provides a leak tight confinement barrier for all radioactive material and envelopes the spent fuel assemblies in an inert helium atmosphere. The DSC cylindrical shell and cover plates encapsulate the basket assembly holding the spent fuel. The DSC is placed in a transfer cask for loading, and it will remain in the cask until it is transferred into the horizontal storage module (HSM).

The ventilated reinforced concrete HSM is the principal structure that is located on each Independent Spent Fuel Storage Installation (ISFSI) site. Each HSM (Figure 17.2-3) is a free-standing prefabricated unit placed on a non-safety related basemat. Each HSM is designed to provide storage for one DSC. Ports in the bottom of the HSM allow for the passage of air into the vicinity of the DSC for cooling purposes. Heated air passes from the inside of the HSM to the environment via ports in the top of the HSM. HSMs are placed side by side until the desired number of fuel assemblies is stored.

The basic steps in the transfer of spent fuel from the spent fuel pool to the HSM are:

1. Clean and load the DSC into the transfer cask.
2. Fill the DSC and cask with water and install the cask/DSC annulus seal.
3. Place the transfer cask containing the DSC in the spent fuel pool.
4. Load the spent fuel assemblies into the DSC.
5. Place the top shield plug on the DSC.
6. Remove the loaded cask from the spent fuel pool and place it in the decontamination area.
7. Lower the water level in the DSC below the shield plug.

8. Place and weld the inner top cover to the DSC shell and perform NDE.
9. Drain the water from the cask/DSC annulus.
10. Drain the water from the DSC.
11. Evacuate and dry the DSC.
12. Fill the DSC with helium.
13. Perform a helium leak test on the seal weld.
14. Seal weld the siphon and vent port plugs and perform NDE.
15. Fit -up the outer top cover plate with the DSC shell.
16. Weld the top cover plate to the DSC shell and perform NDE.
17. Install the transfer cask top cover plate.
18. Lift and downend the transfer cask onto the transport trailer.
19. Ready the HSM to receive the DSC.
20. Ready the cask for transport and to the transport trailer to the HSM.
21. Position the transfer cask with the HSM access opening.
22. Remove the transfer cask top cover plate.
23. Align and secure the transfer cask to the HSM.
24. Set up for the DSC transfer.
25. Place the DSC into the HSM.
26. Disengage the transfer cask from the HSM.
27. Install the HSM door.

17.2.3 Pin Consolidation

The capacity of the spent fuel pool could also be expanded by pin consolidation, in which the fuel rods (or pins) within each fuel assembly are reconfigured to reduce the amount of space required for storage. The fuel pins in the assemblies are removed and placed in new "consolidation" cages which allow the rods to be stored closer together. The original end caps and grids are sheared to reduce their volume and are also stored in the spent fuel pool.

Several U.S. nuclear plants have performed pin consolidation demonstration projects while completing their own study of options for storage expansion. Because pin consolidation is very labor intensive, worker exposure to radioactivity must be taken into account when considering this storage option. There are ways to reduce exposure, such as consolidating older fuel first, since this fuel is less radioactive. With pin consolidation, all spent fuel generated during the remainder of the plant's licensed operating life could be safely stored within the spent fuel pool. Pin consolidation would require license amendments from the NRC.

17.2.4 Summary

The initial design of the spent fuel pool provided limited storage capacity. Political decisions dealing with fuel recycling forced the utilities to face the dilemma of storing fuel on site. Storage capacity has been increased by two methods: re-racking and dry storage. Re-racking involves using fuel storage racks with reduced distances between adjacent fuel assemblies. Dry storage involves transferring spent fuel to a shielded cask and placing the shielded cask in a concrete vault located on the plant site. The feasibility of pin consolidation has been demonstrated but is not currently being used.

Table 17.2-1 NRC-Approved Dry Spent Fuel Storage Designs

Vendor	Design Model	Capacity
General Nuclear Systems, Inc.	Metal Cask CASTOR V/21	21 PWR Fuel Assemblies
Pacific Nuclear Fuel Services, Inc.	Concrete Module NUHOMS-7	7 PWR Fuel Assemblies
Pacific Nuclear Fuel Services, Inc.	Concrete Module NUHOMS-24P	24 PWR Fuel Assemblies
Foster Wheeler Energy Applications, Inc.	Concrete Vault, Module Vault Dry Stone	83 PWR or 150 BWR Fuel Assemblies
Nuclear Assurance Corporation	Metal Cask NAC-STC	26 PWR Fuel Assemblies
Nuclear Assurance Corporation	Metal Cask NAC-128/ST	28 PWR Fuel Assemblies
Nuclear Assurance Corporation	Metal Cask NAC-C28T	28 Canisters (fuel rods from 56 PWR assemblies)
Transnuclear Incorporated	Metal Cask TN-24	24 PWR Fuel Assemblies
Pacific Sierra	Concrete Cask VSC-24	24 PWR Fuel Assemblies
Westinghouse Electric	Metal Cask MC-10	24 PWR Fuel Assemblies

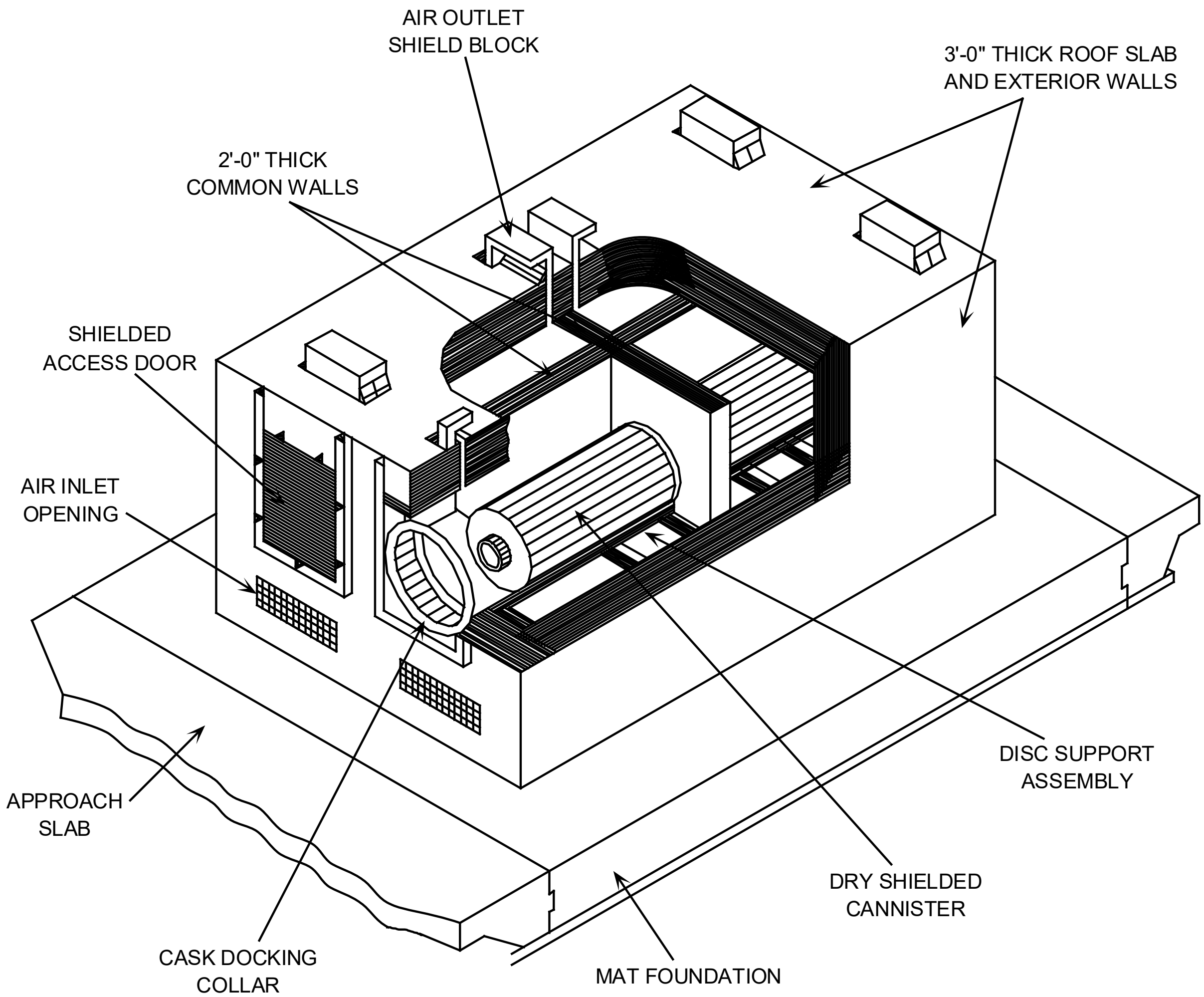

Figure 17.2-1 NUOMS

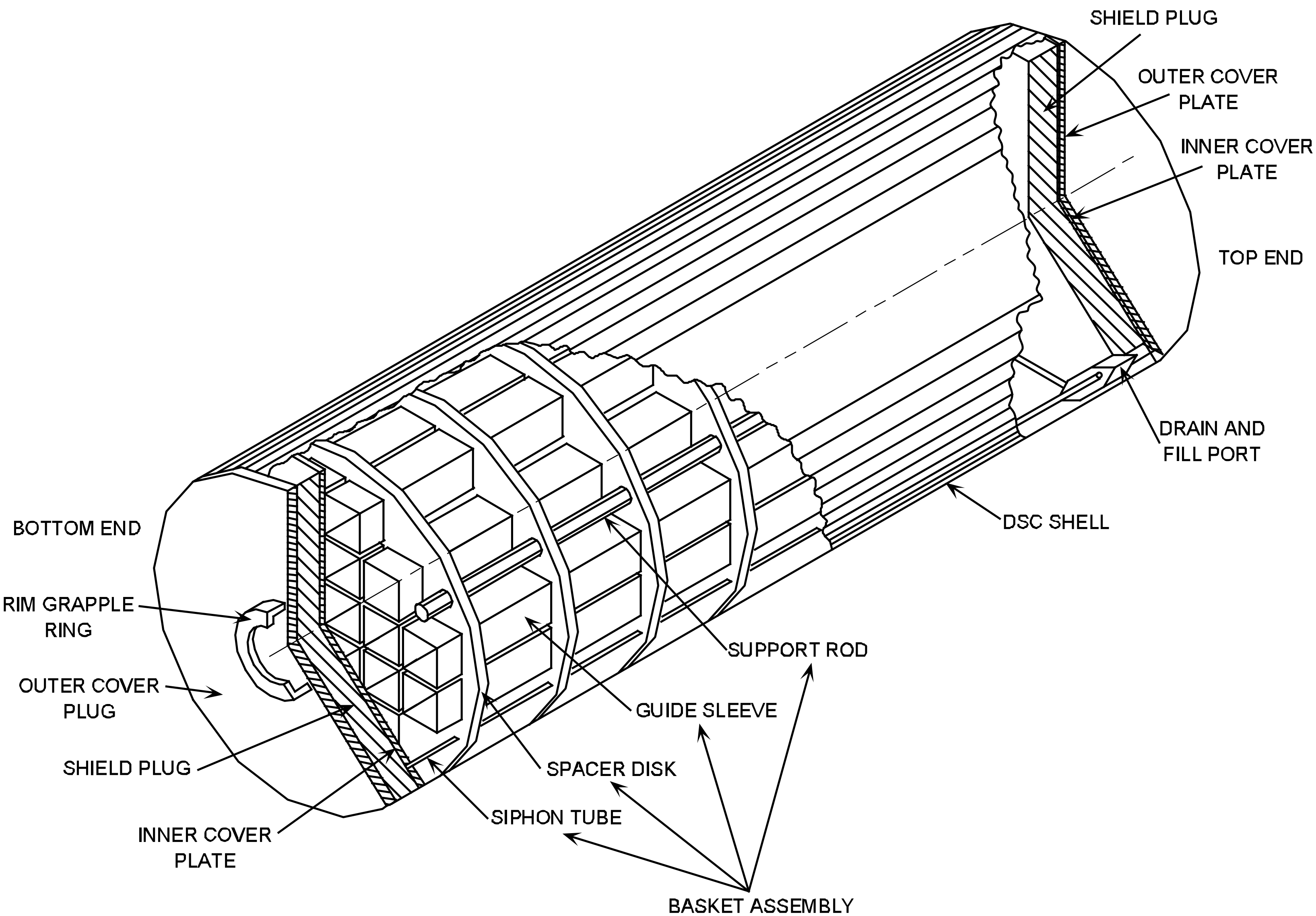

Figure 17.2-2 Dry Shielded Canister

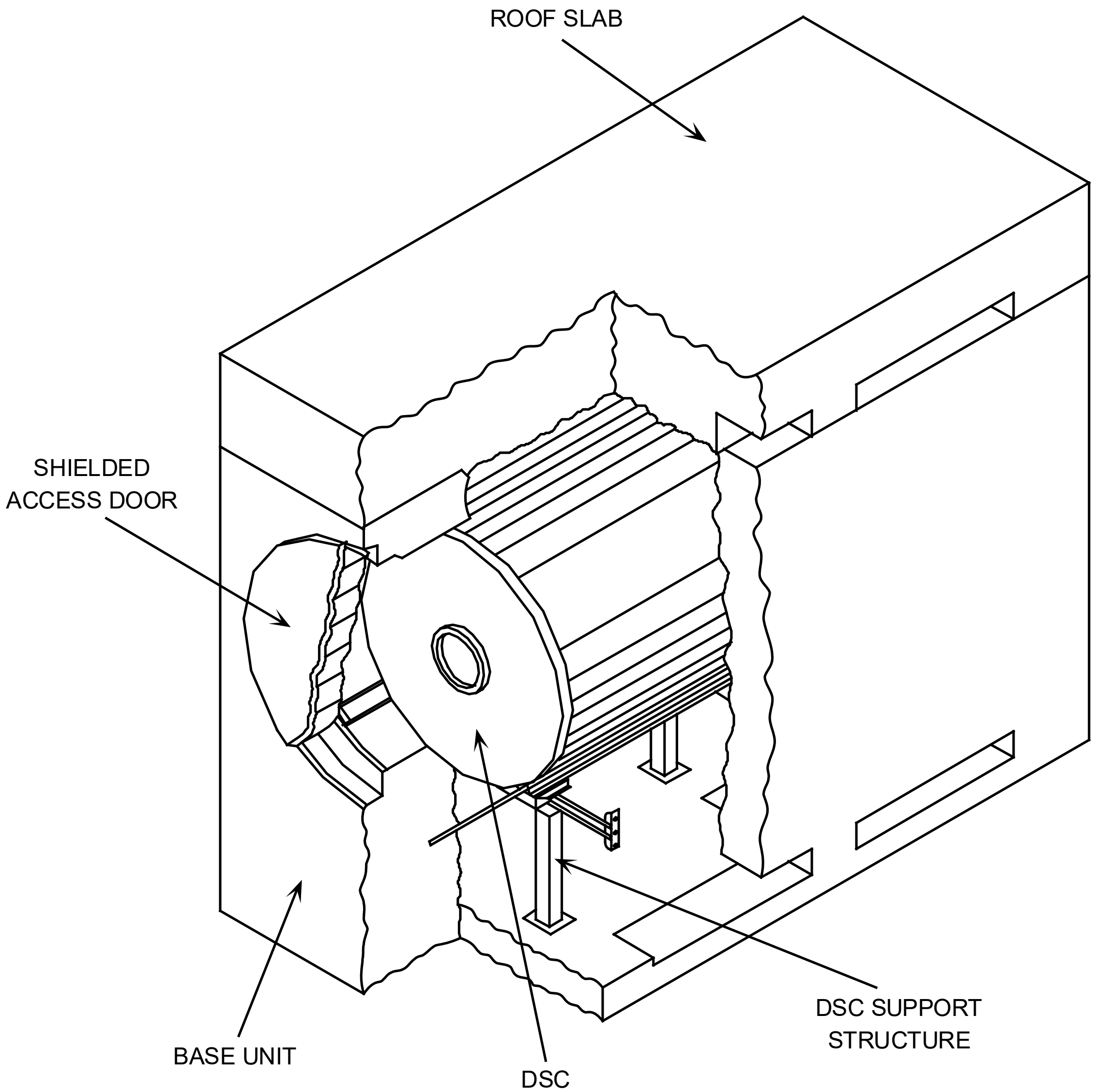

Figure 17.2-3 Horizontal Shielded Module

Westinghouse Technology Systems Manual

Section 18.0

<u>Plant Computer</u>

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18.0 PLANT COMPUTER

Learning Objectives:

1. State the purpose of the plant computer.

2. Given a list of application programs, state the purpose of each application.

3. State the purpose of the safety parameter display system (SPDS).

4. List the critical safety functions monitored by the SPDS.

18.1 Introduction

One of the most effective aids available to the operator of a nuclear unit is the plant computer. The plant computer performs real-time, on-line data acquisition, alarm monitoring, data manipulation, and performance calculations to provide the plant operator with accurate and reliable information. It has no direct control of any processes related to the operation of the unit. The operator interfaces with the plant computer are similar to the interfaces with a personal computer and likely include some combination of keyboards, printers, and CRT displays. This chapter discusses some of the major functions typically provided by the plant computer.

18.2 Data Acquisition

One of the primary functions of the plant computer is the processing of plant input signals for availability to the operator and for use in computer calculations and programs. Input information is stored in the computer's data base for use by other parts of the computer system.

Input signals may be analog or digital in nature. Analog inputs are electrical representations (voltages, currents, or resistances) of plant process variables such as pressure, temperature, and level. The inputs are provided by instrumentation such as thermocouples, resistance temperature detector bridges, and differential pressure cells. Analog inputs are digitized, checked for quality (e.g., flagged if determined to be bad inputs), and converted to engineering units by the computer. Some inputs may be further processed as averages, integrals, or rates of change.

Digital inputs have only two possible states. Digital inputs are typically sensed by the computer as electrical contacts that are open or closed. Such contacts indicate that motors are running or idle, that circuit breakers are open or closed, or that valves are open or shut.

18.3 Computer Applications

Plant computers were originally supplied by the nuclear steam supply system (NSSS) vendors. As computer hardware and software improved, the original plant computer designs were replaced with designs from computer companies (as opposed to NSSS suppliers). As a result, computer applications are quite diverse.

This section describes the most common applications. Specific values contained in this section apply to the Trojan plant computer.

18.3.1 Alarm Processing

The alarm processor collects and routes all computer-detected events defined as alarm conditions (limit violations, hardware malfunctions, etc.). Alarm conditions may be indicated via CRT displays, audible annunciation, and/or printouts. The alarm processor typically maintains a directory which lists the following information for each alarm condition: the time the alarm condition was detected, an alphanumeric point identifier, a point description, the value or state of the point, and the appropriate engineering units. The alarm processor likely provides a means for the operator to page through the alarm directory and to acknowledge or clear alarms.

The alarm processor supplements the control room annunciator system. However, unlike the control room annunciator system, the plant computer alarm processor gives the plant staff the ability to quickly trend the alarm condition. The control room annunciators are generally associated with bistable inputs, and other instrumentation must be used to determine trends. Also, with proper controls, alarms may be deleted from the alarm processor.

18.3.2 Post-Trip Review

The post-trip review (Figure 18-1) is a special-purpose 40-minute log. The log automatically collects selected plant data when triggered by a reactor trip. Once triggered, the post-trip review documents the time of the trip and records the values of 150 plant parameters at 10 second intervals for 20-minute periods before and after the trip. The operator is informed when the post-trip review is completed and ready for printout.

The data for the post-trip review is continuously collected and written to a buffer. Under normal operating conditions, the data is overwritten, but when a trip occurs, overwriting is terminated. This feature allows both pre- and post-trip parameter values (20 minutes before the trip and 20 minutes after the trip) to be compiled. The post-trip review allows the plant staff to verify proper plant response to the initiator, and it is also used for event re-creation, if desired.

18.3.3 Sequence-of-Events Monitoring

The sequence-of-events monitor produces a log which records the exact sequence and timing of contact status changes in order to document the causes of trips and equipment malfunctions. The log is initiated with the first change of state of any of the monitored contacts (a typical set includes 64 contacts). The monitor then logs sequential contact status changes until a fixed number of changes have been recorded or until a predefined time period has elapsed.

The sequence-of-events monitor is capable of resolving the time of a contact status change to within a small fraction of a second (one millisecond). The operator is notified when the sequence-of-events log is ready for printout.

The sequence-of-events log is used along with the post-trip review to help the plant staff determine the plant response to an initiator.

It should be noted that the sequence-of-events log maybe triggered by events other than a reactor trip. For example, the opening of bistable contacts during reactor protection system testing may also trigger the sequence-of-events log.

18.3.4 Calorimetric Calculation

Real-time calorimetric calculations are performed by the computer at one-minute intervals. The one-minute average plant input data are used by the calorimetric program to calculate reactor power output. The value of reactor core thermal power is determined as the product of loop feedwater flow values and the change in enthalpy of the feedwater as it is heated to saturated steam. Additional correction factors are included to account for the transfer of reactor coolant pump heat to the secondary fluid and for heat transfer to the blowdown flow from the steam generators. See Figure 18-2.

The real-time calorimetric program results are also used to monitor excore power-range calibration accuracy. The differences between the current power, as computed by the calorimetric program, and the powers indicated by the four power-range instruments are provided for calibration purposes.

18.3.5 RCS Leak Rate Monitor

The leak rate monitor application provides on-demand calculations of the identified, unidentified, and total leakages. The inventory mass balance used in determining leakage includes the coolant mass in the reactor coolant system (RCS), pressurizer, and volume control tank, as well as the mass flow rates entering and exiting the RCS via the RCS sample lines and the letdown and charging lines. In addition, the RCS leakage paths to the pressurizer relief tank and the reactor coolant drain tank are monitored to enable operators to distinguish between identified and unidentified leakage. See Figure 18-3.

The calculations may be performed automatically or manually; in manual, the operator designates the time period during which leakage is monitored and can enter data for tank levels and coolant temperatures. Other inputs needed for the calculation (such as conversion factors) are read from the computer files.

After the leakage rate has been calculated, the total is displayed on the screen and can be printed out. The periodic calculation of RCS leakage is a technical specification requirement, and the printout provides documentation of the completion of the requirement.

18.3.6 Rod Insertion Limits

Rod insertion limits (Figure 18-4) are computed for each control rod bank by the rod package program. These limit values reflect current plant technical specification limits for rod insertion and are computed as a function of core ΔT. The rod package program also receives rod bank position information from the pulse counting circuitry of the rod control system. The program provides inputs to computer alarms at two rod position setpoints: the rod insertion limit itself (the rod insertion LO-LO limit alarm), and 10 steps higher than the rod insertion limit (the rod insertion LO limit). The latter alarm provides an early warning concerning the approach to licensed rod insertion limit values.

Additional rod position alarms are provided to alert the operator to an abnormal state of any of the following rod position attributes:

- Bank D withdrawal,
- Rod bank sequence,
- Rod-to-bank deviation, and
- Rod-to-rod deviation.

18.3.7 Core Reactivity

The core reactivity calculations package provides automatic estimations of the current core reactivity and axial offsets for power, iodine, and xenon. The calculations are based on one-dimensional (axial) diffusion theory. Using the provided interface, the operator can modify the calculated results to reflect known values and can perform on-demand calculations of shutdown margin, estimated critical position, and core reactivity for operator-specified conditions.

18.3.8 Incore Thermocouple Package

The incore thermocouple software allows the operator to obtain reactor core power distribution information. The relative distribution of power within the reactor core is determined using several available sources of reactor thermal/hydraulic data.

The incore thermocouple program calculations are performed at 10-second intervals. Input data is averaged every 80 seconds and used to perform the power distribution calculations.

The calculations performed are based primarily on the temperature rise from the core inlet conditions to the fuel assembly exit conditions at each individual core exit thermocouple location. Several sources of data are available for determining the value of the core inlet temperature used to calculate the fuel assembly ΔT.

A measure of the relative local power at each thermocouple-equipped fuel assembly can be calculated based on the enthalpy rise associated with the known ΔT value. This relative local power is defined as the ratio of the local enthalpy rise to the core average value. See Figure 18-5.

Thermocouple tilts are computed based on the distribution of calculated relative local power data within the core. The tilts are a measure of the difference from quadrant to quadrant for the computed local power values.

A dynamic display (Figure 18-6) of core exit thermocouple readings is also provided. In addition to providing temperature indication, this display includes the value of the

RCS subcooling margin. The dynamic display is used during emergencies to determine the adequacy of core cooling.

18.3.9 Point/Group Trending

Almost any computer input can be selected for trending on computer-driven recorders or CRTs. This feature may be used when historical parameter data is needed to assess component or system operability.

Additionally, groups of inputs can be built to assess performance. For example, suppose a systems engineer wants to monitor the performance of a reactor coolant pump seal package. A computer data group consisting of seal injection flow, pressurizer pressure, #1 seal leak-off flow, and component cooling water flow to the pump could be created. The group could be displayed on a CRT or periodically printed out for examination.

18.4 Safety Parameter Display System (SPDS)

18.4.1 SPDS Introduction

The accident at Three Mile Island led to studies performed both within and outside the NRC which identified the need for extensive improvements in the response of management and operating personnel to accidents at nuclear power plants. One of the identified improvements entailed providing better information for the assessment of conditions at a plant and its environs prior to, during, and following an accident. The system developed to satisfy the need for improved plant information is the computer-based safety parameter display system (SPDS). The SPDS provides a display of plant parameters from which the safety status of the plant may be assessed by operators in the control room and by other licensee personnel in the utility's emergency response facilities.

18.4.2 Regulatory History

The initial requirement for each power plant licensee to install an SPDS was included in NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," published in May 1980. This document specified a system that would display "a minimum set of parameters … which define the safety status of the plant." NUREG-0737, "Clarification of TMI Action Plan Requirements," issued six months later, referenced NUREG-0696, "Functional Criteria for Emergency Response Facilities" for more detailed requirements related to the design and capabilities of the SPDS.

In January 1983, the NRC published Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability," to provide a distillation of basic requirements for emergency response facilities and systems from several guidance documents previously issued by the NRC. This document provides the following guidance concerning the SPDS:

1. The SPDS should provide a concise display of critical plant variables to control room operators to aid them in rapidly and reliably determining the safety status of the plant.
2. Each operating reactor shall be provided with an SPDS that is located convenient to the control room operators. This system will continuously display information from which the plant safety status can readily and reliably be assessed by control room personnel, who are responsible for the avoidance of degraded and damaged core events.
3. The SPDS is used in addition to the basic control room instrumentation and serves to aid and augment this instrumentation. Thus, requirements applicable to control room instrumentation are not needed for this augmentation. The SPDS need not satisfy single-failure criteria, and it need not be qualified to class 1E requirements. The SPDS shall be suitably isolated from equipment and sensors of safety systems. The SPDS need not be seismically qualified. Operators should be trained to respond to accident conditions both with and without the SPDS available.
4. Prompt implementation of the SPDS can provide an important contribution to plant safety. The selection of specific information that should be provided for a particular plant shall be based on the engineering judgment of the licensee, taking into account the importance of prompt implementation.
5. The SPDS display shall be designed to incorporate accepted human-factors principles so that the displayed information can be readily perceived and comprehended by SPDS users.
6. The minimum information shall be sufficient to provide information to plant operators about (1) reactivity control, (2) reactor core cooling and heat removal, (3) RCS integrity, (4) radioactivity control, and (5) containment conditions.

18.4.3 SPDS Implementation

The SPDS generates information necessary for rapid detection of abnormal or emergency operating conditions and also for monitoring the plant's response to corrective action. The SPDS performs this function in part by monitoring the status of the plant's critical safety functions (CSFs). By monitoring these functions on a continuous basis, the SPDS provides an indication of plant safety status during normal, abnormal, and emergency conditions. The critical safety functions are:

- Subcriticality,
- Core cooling,
- Heat sink,
- RCS integrity,
- Containment integrity, and
- RCS inventory.

The SPDS determines the status of each CSF by examining the values of parameters that are relevant to the particular safety function. The determination of CSF status will be in the form of a color, which reflects whether the CSF is satisfied or challenged, and thus characterizes the priority of the required response. The scheme of color coding used to identify CSF status is:

- GREEN - The critical safety function is satisfied; no operator action is required.
- YELLOW - The critical safety function is not fully satisfied; operator action may eventually be needed.
- ORANGE - The critical safety function is under severe challenge; prompt operator action is necessary.
- RED - The critical safety function is extremely challenged; immediate operator action is required.

The SPDS displays CSF status on control room CRTs via six indicator boxes, one for each CSF listed above; each is filled with the color indicative of that CSF's current status. These CSF boxes appear at the bottom of SPDS displays. Plant emergency procedures contain critical safety function restoration guidance.

Because there are a number of parameters of importance to each CSF, status trees are used. Each tree contains several logic branches and paths. The end point of each path defines a unique set of plant conditions, expressed as a combination of current values of parameters. Each set of conditions reflects whether the CSF is satisfied or challenged, and thus indicates the priority of the necessary operator response. Figure 18-7 shows a typical CSF status tree display.

The SPDS also provides displays of plant conditions during normal operation. A typical at-power display is shown in Figure 18-8. As shown in the figure, the display consists of a simplified RCS diagram, values of RCS and steam generator parameters, and summaries of the containment, radiation monitoring, and RCS status.

18.5 Regulatory Use of Computer Data

Plant computer data, like any other plant record, may be used by the NRC in its inspection efforts. Post-trip reviews, sequence-of-events logs, and alarm printouts are often used by agency inspectors in event re-creation. Such data provides the Commission with detailed event information and helps agency management to determine the necessary response.

Plant data may be supplied to the NRC as events are occurring. Real-time data from the plant's computer system is transmitted to NRC headquarters via an interface called the emergency response data system (ERDS). The ERDS is used only during emergencies and is activated by licensees during events classified as alerts, site area emergencies, or general emergencies. ERDS data is received by the NRC's Reactor Safety Team, Protective Measures Team, and Operations Duty Officer. The transmitted data includes the plant status information from the SPDS as well as meteorological data.

18.6 Summary

The plant computer receives analog and digital inputs that are used in its application programs. Application programs aid the operating staff in correctly monitoring and operating the plant. The safety parameter display system provides information relevant to determining the safety status of the plant, including the status of the critical safety functions. Plant computer data is used by the regulator/inspector in the inspection effort. The ERDS transmits data from the plant computer to NRC headquarters during emergencies.

1836 POST TRIP REVIEW

	N0049A	N0050A	N0051A	N0052A	TIME 1	P0398A	P0399A	00340A	T049A	TIME 2
	95.80	96.45	96.62	96.16	3252.4	422.7	423.1	929.2	572.1	3252.5
	95.86	96.56	96.62	96.16	3254.2	113.2	117.2	396.1	553.9	3254.2
	95.80	96.68	96.74	96.27	3256.4	92.4	95.0	327.5	552.5	3256.5
	56.72	58.01	57.66	51.98	3258.3	73.2	77.6	12.4	551.7	3258.4
1837 POST—TRIP DATA—TRIP TIME 183258										
	4.69	4.75	4.69	4.63	3300.5	79.8	82.4	4.4	551.9	3330.5
	3.81	3.93	3.87	3.70	3302.4	81.5	84.1	—4.0	551.9	3302.4
	3.23	3.28	3.23	3.05	3304.4	81.5	83.7	—4.0	552.0	3304.4
	2.41	2.46	2.41	2.34	3308.4	80.2	82.8	—4.0	551.8	3308.4

	N0031A	N0032A	N0035A	N0036A	N0041A	N0042A	N0043A	N0044A	N0045A	N0046A	N0047A	N0048A	N0049A	N0050A	N0051A
	0.03	0.03	305.04	349.11	3.60	4.03	3.61	3.99	3.64	4.03	3.66	4.00	95.92	96.68	96.80
	0.03	0.03	299.61	349.11	3.59	4.03	3.60	3.98	3.63	4.02	3.66	4.01	95.80	96.51	96.62
	0.03	0.03	296.92	345.98	3.58	4.02	3.60	3.98	3.63	4.01	3.66	4.00	95.57	96.56	96.62
	0.03	0.03	296.92	345.98	3.59	4.03	3.61	3.98	3.63	4.01	3.65	3.99	95.80	96.74	96.56
	0.03	0.03	302.31	342.88	3.60	4.03	3.59	3.97	3.64	4.03	3.65	4.00	95.86	96.39	96.80
	0.03	0.03	299.61	342.88	3.59	4.02	3.60	3.98	3.63	4.02	3.66	4.00	95.62	96.62	96.68
	0.03	0.03	299.61	339.81	3.60	4.03	3.60	3.98	3.63	4.01	3.66	3.99	95.80	96.51	96.56
	0.03	0.03	305.04	345.98	3.60	4.03	3.61	3.98	3.63	4.02	3.66	4.00	95.86	96.62	96.62
	0.03	0.03	305.04	349.11	3.60	4.03	3.60	3.98	3.63	4.02	3.67	4.01	95.80	96.51	96.68
	0.03	0.03	305.04	342.88	3.60	4.04	3.61	3.98	3.64	4.02	3.66	4.00	95.92	96.74	96.74
	0.03	0.03	299.61	339.81	3.59	4.03	3.60	3.97	3.63	4.02	3.66	4.00	95.69	96.51	96.62
	0.03	0.03	302.31	342.88	3.59	4.03	3.61	3.98	3.64	4.02	3.66	4.00	95.69	96.68	96.80
	0.03	0.04	304.04	345.98	3.59	4.03	3.60	3.98	3.64	4.02	3.67	4.01	95.80	96.51	96.86
	0.03	0.03	299.01	342.88	3.59	4.03	3.60	3.97	3.64	4.02	3.66	4.00	95.74	96.56	96.80
	0.03	0.03	299.61	342.88	3.59	4.03	3.60	3.98	3.63	4.02	3.66	4.00	95.80	96.51	96.62
	0.03	0.03	299.61	342.88	3.59	4.03	3.60	3.98	3.64	4.02	3.66	4.00	95.69	96.51	96.86
1844 POST—TRIP DATA—TRIP TIME 183258															
	0.03	0.04	205.35	235.01	2.03	3.27	2.07	3.23	2.08	3.26	1.84	3.08	56.72	58.01	57.66
	0.03	0.04	8.20	9.31	0.10	0.11	0.10	0.11	0.11	0.12	0.11	0.10	2.76	2.87	2.81
	0.03	0.04	5.05	5.73	0.07	0.07	0.07	0.07	0.08	0.07	0.06	1.76	1.87	1.76	1.76
	0.03	0.04	3.68	4.14	0.05	0.05	0.05	0.05	0.05	0.06	0.05	0.04	1.29	1.41	1.35
	0.03	0.04	2.79	3.13	0.04	0.03	0.03	0.03	0.04	0.04	0.04	0.02	1.00	1.05	1.00
	0.03	0.04	2.05	2.31	0.03	0.02	0.03	0.03	0.03	0.04	0.03	0.01	0.82	0.82	0.82
	0.03	0.04	1.65	1.88	0.03	0.02	0.02	0.02	0.03	0.03	0.03	0.01	0.70	0.82	0.77
	0.03	0.04	1.32	1.49	0.02	0.02	0.02	0.02	0.02	0.03	0.02	0.00	0.53	0.59	0.53
	0.03	0.04	1.14	1.29	0.02	0.01	0.02	0.01	0.02	0.03	0.02	0.00	0.53	0.59	0.53
	0.03	0.04	0.95	1.06	0.02	0.01	0.02	0.01	0.02	0.03	0.02	0.00	0.47	0.53	0.47
	0.03	0.03	0.76	0.85	0.01	0.00	0.01	0.00	0.01	0.02	0.01	—0.01	0.30	0.35	0.30
	0.03	0.03	0.62	0.70	0.01	—0.00	0.00	0.00	0.01	0.01	0.01	—0.01	0.18	0.23	0.23
	0.03	0.03	0.53	0.59	0.01	0.00	0.01	0.00	0.01	0.01	0.01	—0.01	0.18	0.30	0.23
	0.03	0.03	0.45	0.50	0.01	0.00	0.01	0.00	0.01	0.01	0.01	—0.01	0.23	0.30	0.23
	0.03	0.03	0.37	0.41	0.00	—0.00	0.00	0.00	0.01	0.01	0.00	—0.01	0.12	0.23	0.18
	0.03	0.03	0.32	0.35	0.00	—0.00	0.00	—0.00	0.00	0.01	0.00	—0.01	0.12	0.18	0.12
	0.03	0.03	0.27	0.30	0.00	—0.00	0.00	—0.00	0.00	0.01	0.00	—0.01	0.18	0.18	0.18
	0.03	0.03	0.23	0.26	0.00	0.00	0.00	0.00	0.01	0.01	0.01	—0.01	0.18	0.23	0.18
	0.03	0.03	0.20	0.22	0.00	—0.01	0.00	—0.00	0.00	0.01	0.00	—0.02	0.06	0.23	0.06
	0.03	0.03	0.17	0.19	0.00	—0.01	0.00	—0.00	0.00	0.00	0.00	—0.02	0.00	0.12	0.06
	0.03	0.03	0.15	0.16	0.00	—0.01	0.00	—0.00	0.00	0.00	0.00	—0.02	0.00	0.18	0.00
	0.03	0.03	0.13	0.14	0.00	—0.00	0.00	—0.00	0.00	0.00	0.00	—0.02	0.00	0.18	0.06
	0.03	0.03	0.11	0.13	0.00	—0.01	0.00	—0.00	0.00	0.00	0.00	—0.02	0.00	0.18	0.00
	0.03	0.03	0.10	0.11	—0.00	—0.01	0.00	—0.01	—0.00	0.00	—0.00	—0.02	—0.05	0.06	—0.05

Figure 18-1 Post-Trip Review

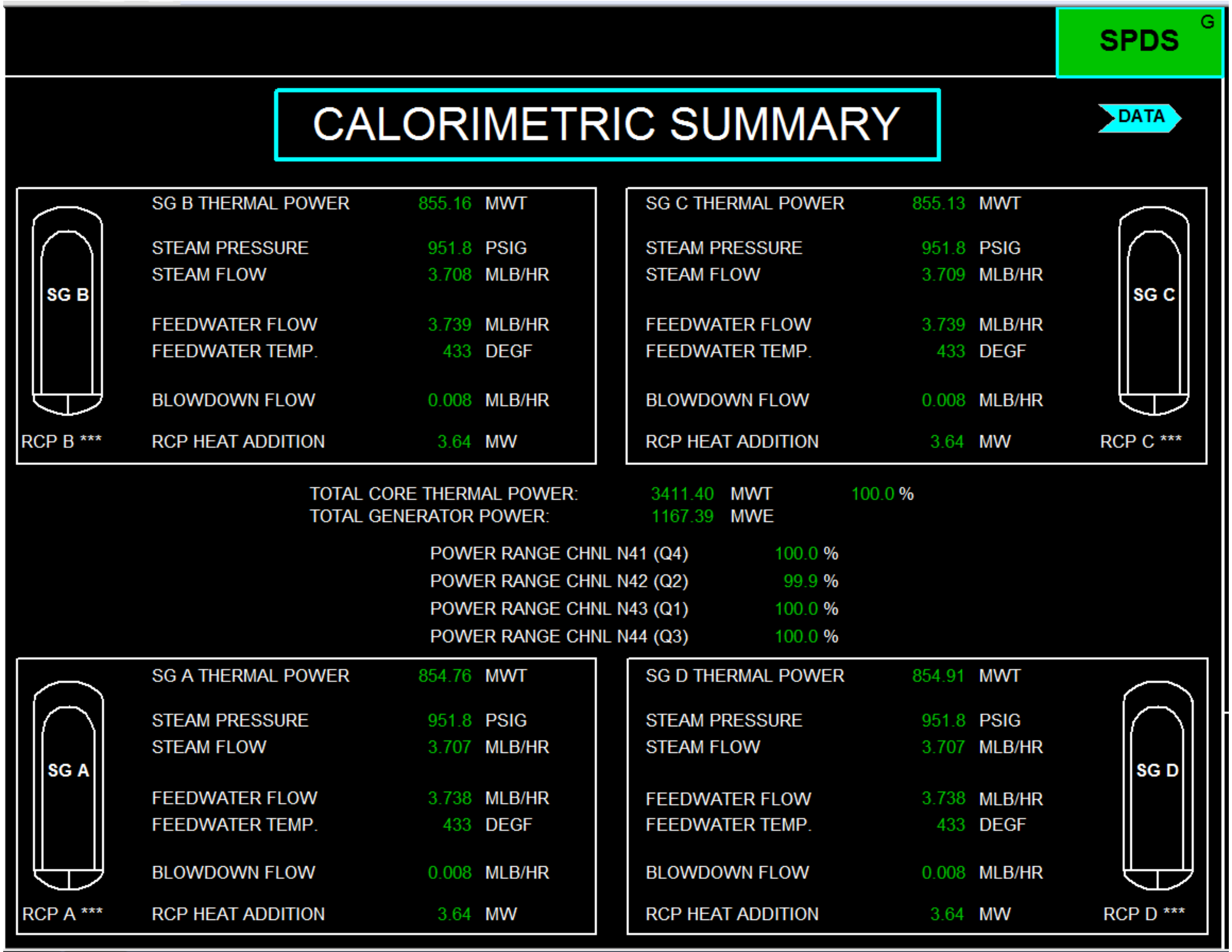
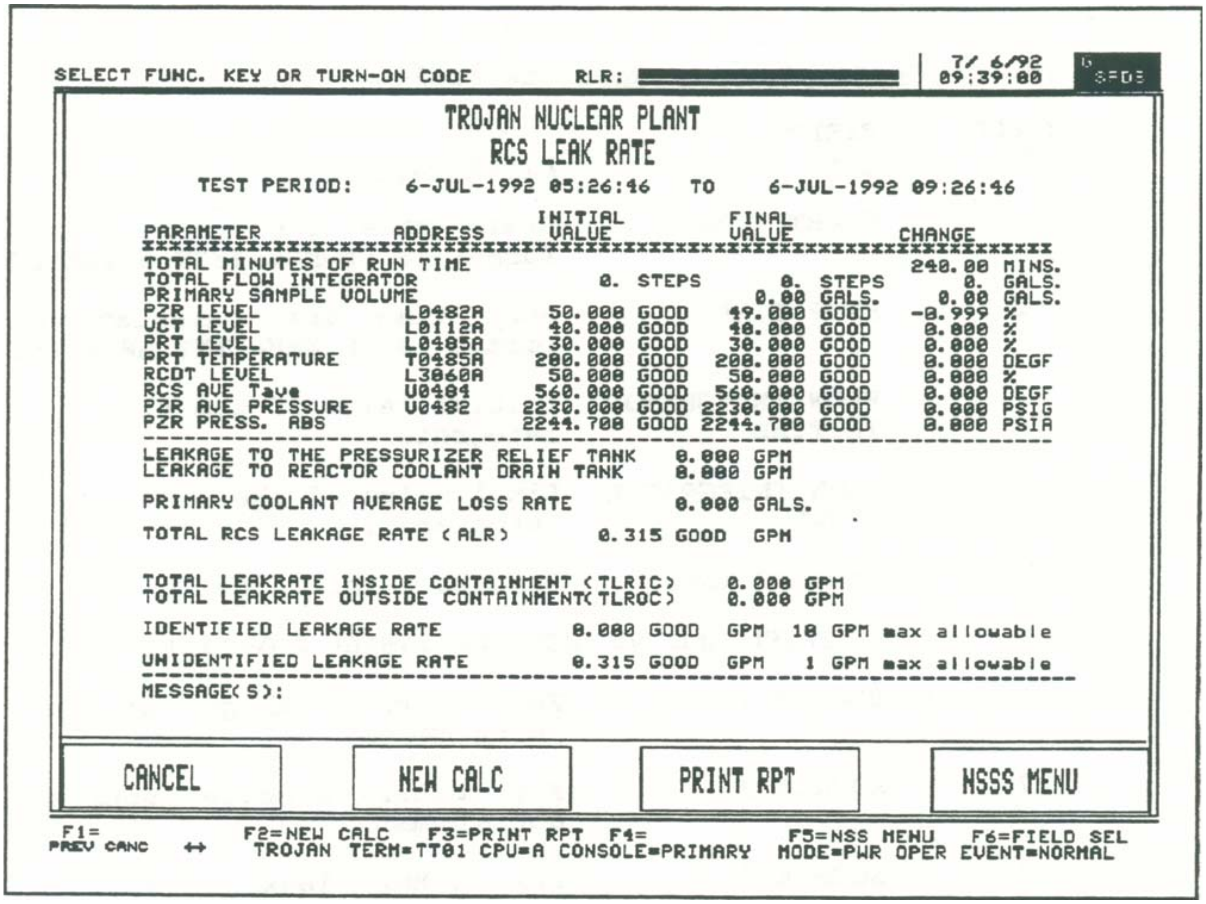


Figure 18-2 Calorimetric Calculation



SELECT FUNC. KEY OR TURN-ON CODE RLR: 7/ 6/92 09:39:00 SFDB

TROJAN NUCLEAR PLANT
RCS LEAK RATE

TEST PERIOD: 6-JUL-1992 05:26:46 TO 6-JUL-1992 09:26:46

PARAMETER	ADDRESS	INITIAL VALUE		FINAL VALUE		CHANGE	
TOTAL MINUTES OF RUN TIME						240.00	MINS.
TOTAL FLOW INTEGRATOR		0.	STEPS	0.	STEPS	0.	GALS.
PRIMARY SAMPLE VOLUME				0.00	GALS.	0.00	GALS.
PZR LEVEL	L0482A	50.000	GOOD	49.000	GOOD	-0.999	%
VCT LEVEL	L0112A	40.000	GOOD	40.000	GOOD	0.000	%
PRT LEVEL	L0485A	30.000	GOOD	30.000	GOOD	0.000	%
PRT TEMPERATURE	T0485A	200.000	GOOD	200.000	GOOD	0.000	DEGF
RCDT LEVEL	L3060A	50.000	GOOD	50.000	GOOD	0.000	%
RCS AVE Tave	V0484	560.000	GOOD	560.000	GOOD	0.000	DEGF
PZR AVE PRESSURE	V0482	2230.000	GOOD	2230.000	GOOD	0.000	PSIG
PZR PRESS. ABS		2244.700	GOOD	2244.700	GOOD	0.000	PSIA

LEAKAGE TO THE PRESSURIZER RELIEF TANK 0.000 GPM
LEAKAGE TO REACTOR COOLANT DRAIN TANK 0.000 GPM

PRIMARY COOLANT AVERAGE LOSS RATE 0.000 GALS.

TOTAL RCS LEAKAGE RATE (ALR) 0.315 GOOD GPM

TOTAL LEAKRATE INSIDE CONTAINMENT (TLRIC) 0.000 GPM
TOTAL LEAKRATE OUTSIDE CONTAINMENT (TLROC) 0.000 GPM

IDENTIFIED LEAKAGE RATE 0.000 GOOD GPM 10 GPM max allowable

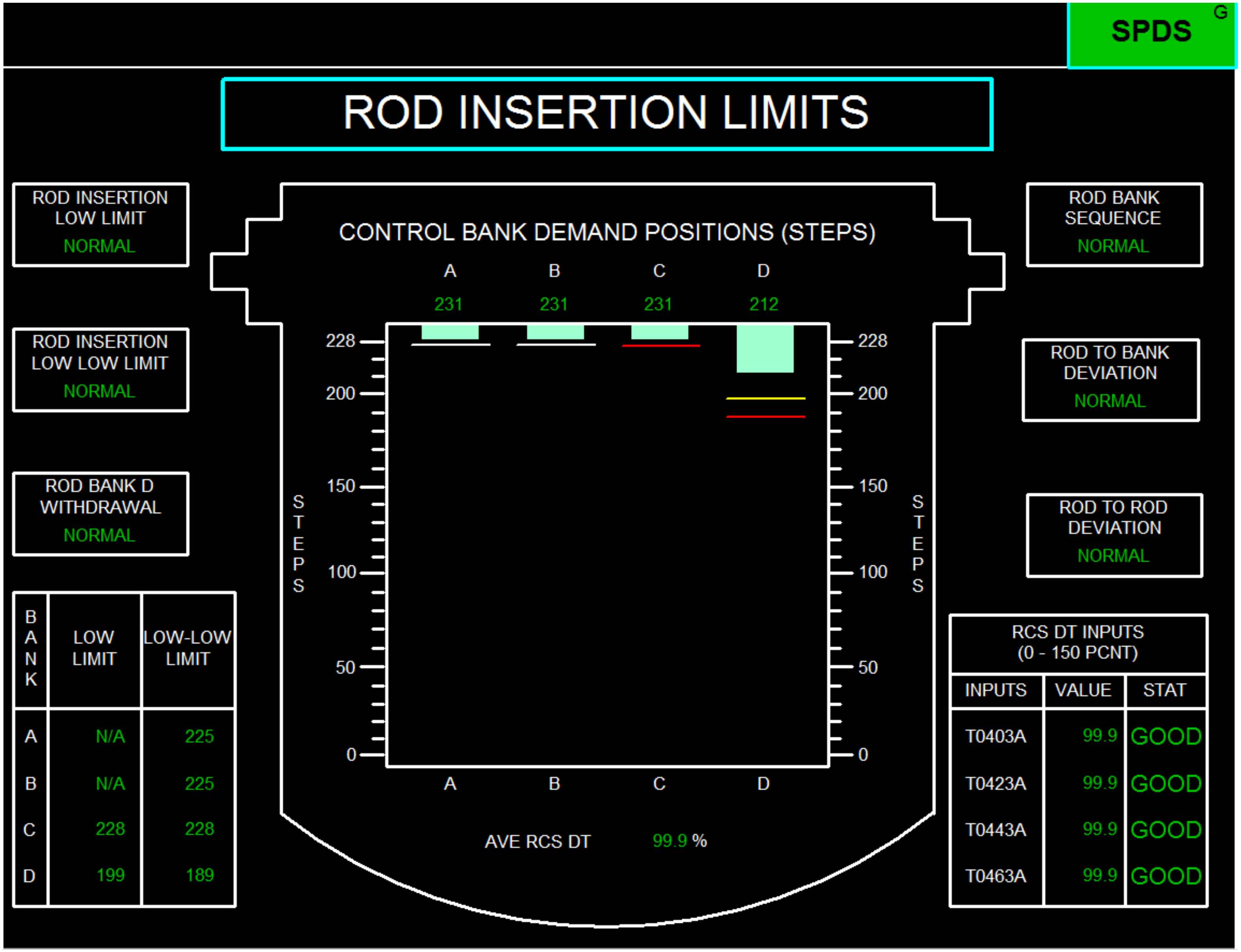
UNIDENTIFIED LEAKAGE RATE 0.315 GOOD GPM 1 GPM max allowable

MESSAGE(S):

CANCEL | NEW CALC | PRINT RPT | NSSS MENU

F1= PREV CANC ↔ F2=NEW CALC F3=PRINT RPT F4= F5=NSS MENU F6=FIELD SEL
TROJAN TERM=TT01 CPU=A CONSOLE=PRIMARY MODE=PWR OPER EVENT=NORMAL

Figure 18-3 RCS Leak Rate Calculation



BANK	LOW LIMIT	LOW-LOW LIMIT
A	N/A	225
B	N/A	225
C	228	228
D	199	189

RCS DT INPUTS (0 - 150 PCNT)		
INPUTS	VALUE	STAT
T0403A	99.9	GOOD
T0423A	99.9	GOOD
T0443A	99.9	GOOD
T0463A	99.9	GOOD

Figure 18-4 Rod Insertion Limit Display

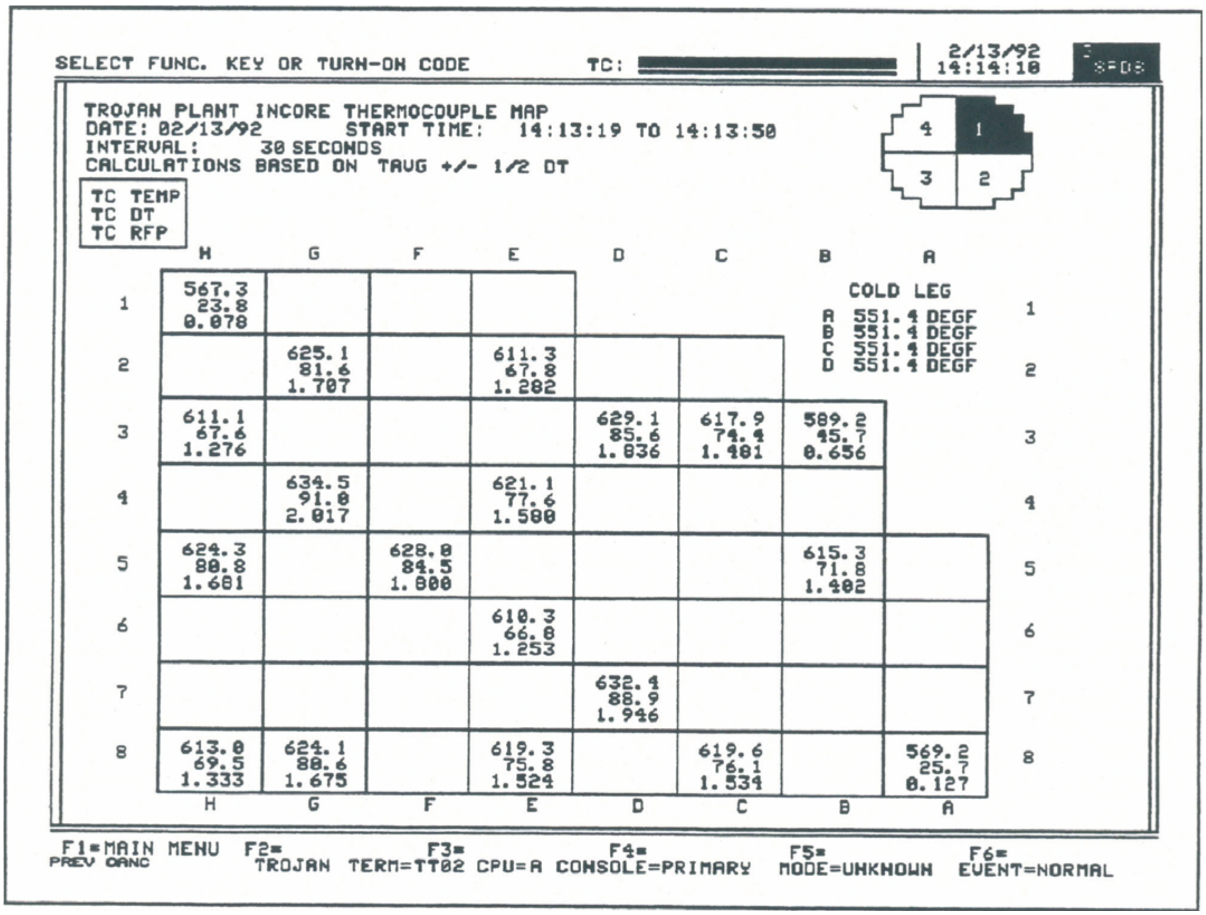


Figure 18-5 Core Exit Thermocouple Display

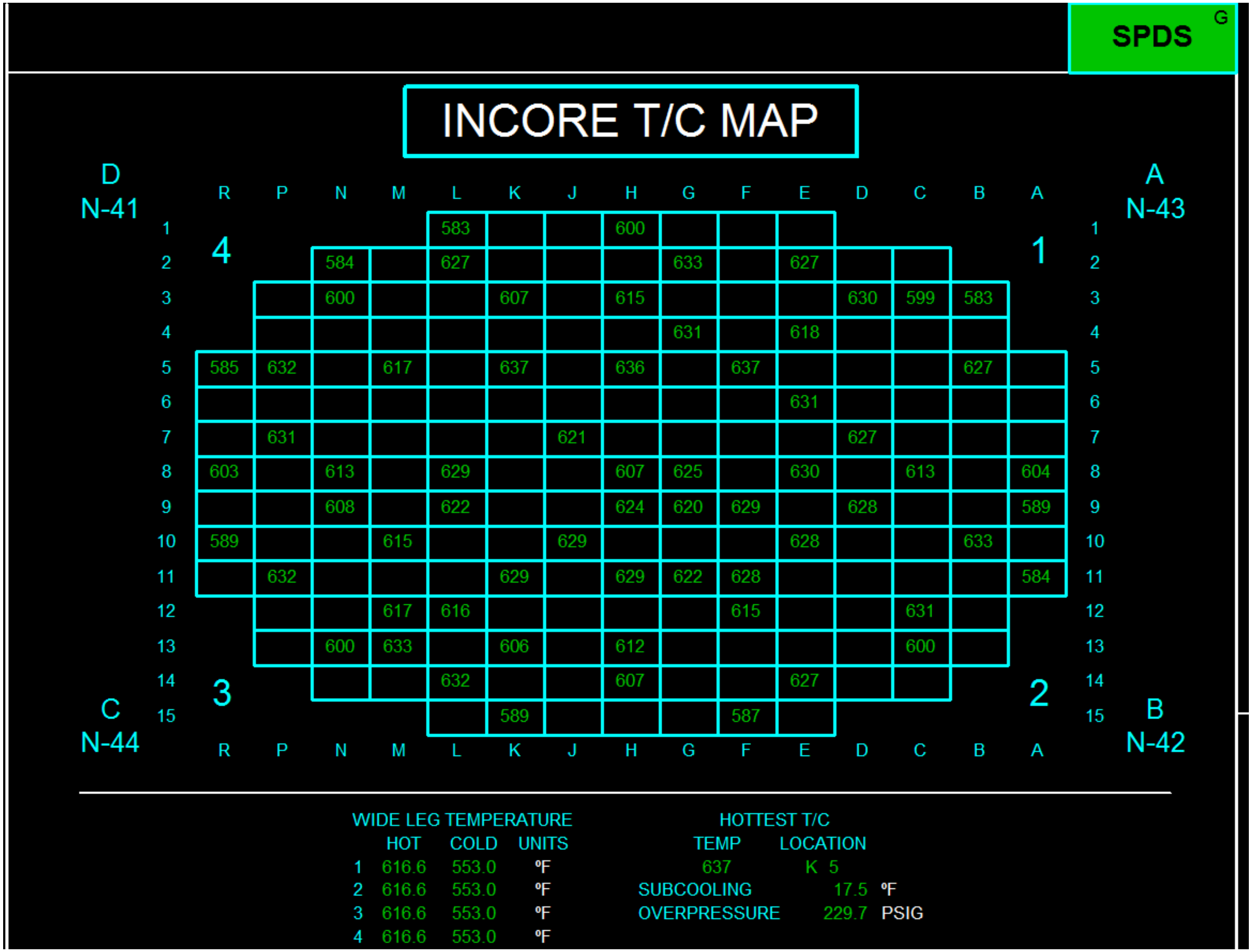


Figure 18-6 CET Map

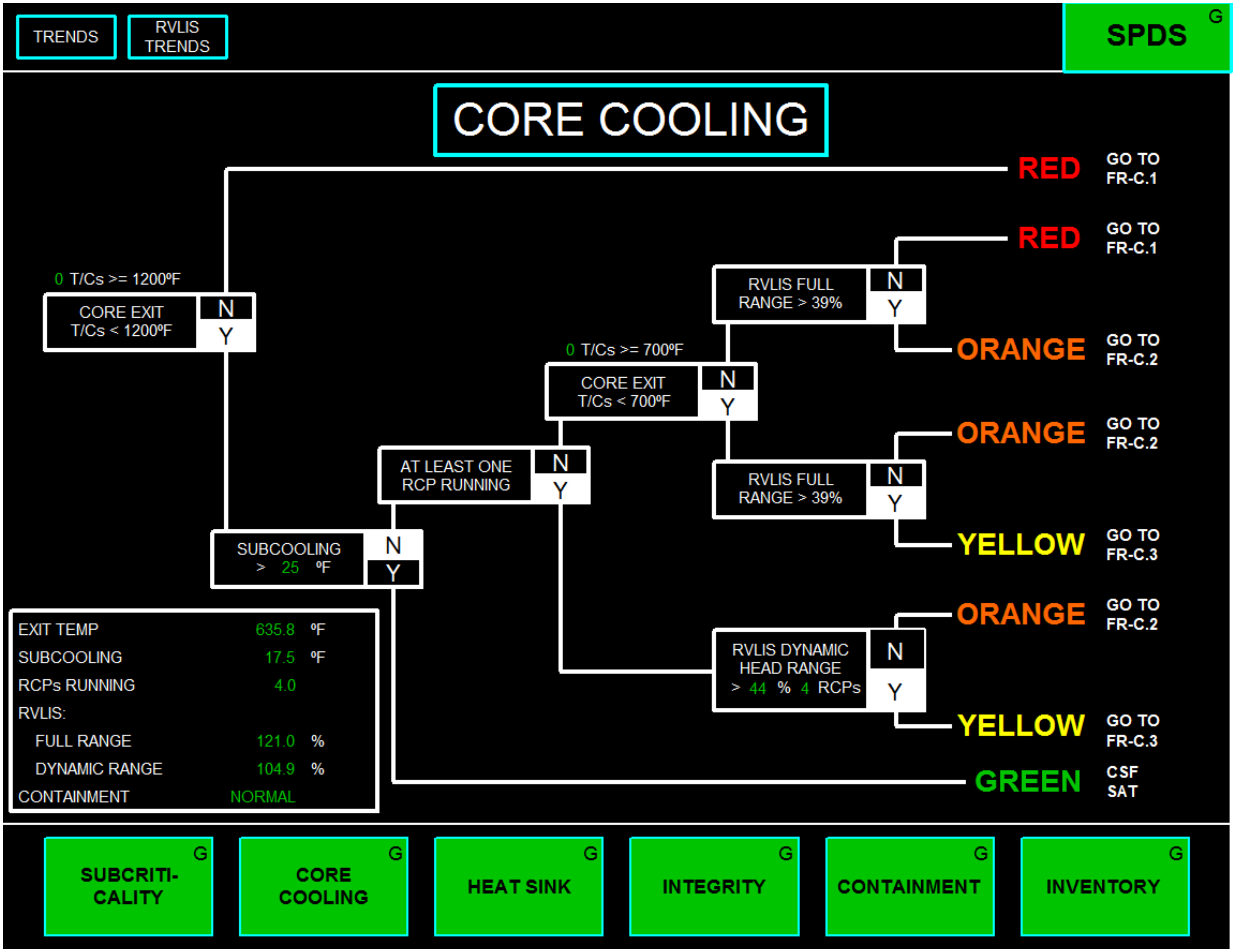


Figure 18-7 Critical Safety Function Display

Figure 18-8 SPDS At Power Display

Westinghouse Technology Systems Manual

Section 19.0

Plant Operations

"READ ONLY SELF STUDY MATERIAL"

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19.0 PLANT OPERATIONS

Learning Objectives:

1. Given a list of plant evolutions similar to the following, arrange them in the order that they are performed during plant startup, shutdown, or power operations.
    a. Reactor coolant system (RCS) filling and venting;
    b. Establishing a pressurizer steam bubble;
    c. Starting reactor coolant pumps;
    d. Placing all engineered safety features (ESF) systems in an operable condition;
    e. Establishing the no-load T_{avg};
    f. Taking the reactor critical;
    g. Placing main feedwater in service;
    h. Synchronizing and loading the turbine-generator;
    i. Placing the rod control system in automatic, placing the steam generator level control system in automatic, and shifting the steam dump control system to the T_{avg} mode; and
    j. Escalating the turbine-generator load to the desired value.

19.1 Introduction

The purposes of this chapter are as follows:

1. To review control, instrumentation, and plant systems, and
2. To describe plant operations and system alignments during plant shutdowns, plant startups, and power operations.

Basic procedures for starting up, and operating at power, a pressurized water reactor plant is described in this chapter. This discussion is general in nature and is designed to review the systems discussed in the previous chapters of this manual and describe how they function during plant operations. An abbreviated plant startup procedure is provided in Appendix 19-1 and is used in conjunction with the material contained in this chapter.

19.2 Plant Heatup

19.2.1 Initial Conditions

For the purposes of this discussion, it is assumed that the reactor coolant system has been filled and vented, the reactor coolant pumps (RCPs) are secured, and the plant is aligned in a solid-water condition as shown in Figure 19-1. Solid plant operation is one method of pressure control during a shutdown.

With this pressure control scheme, the pressurizer and the RCS are completely filled with water. The pressurizer power-operated relief valves (PORVs), their associated block valves, and the pressurizer spray valves are shut. The pressure in the RCS is controlled between 320 and 400 psig by maintaining a flow balance between the coolant removed from the RCS and the coolant being returned.

Coolant removal is accomplished by letdown, primarily from the residual heat removal system (RHR), and to a lesser extent from the chemical and volume control system (CVCS) letdown line. Coolant is returned to the primary system via the CVCS by one of the centrifugal charging pumps.

If the charging and the letdown flows are equal, RCS pressure remains constant. Any imbalance between charging and letdown causes the pressure in the RCS to increase or decrease. As an example, increasing charging flow and maintaining the letdown flow constant increase the mass of coolant in the RCS. Since water is virtually incompressible, a mass increase causes a pressure increase.

While the plant is in this configuration, HCV-128 (the letdown isolation valve from the RHR system) is fully open. The control room operator manipulates CVCS backpressure regulating valve PCV-131 in either automatic or manual to vary the rate of letdown from the RCS. Additional letdown flow from the CVCS is available through letdown orifices 8149A, B, and C. Since the pressure in the RCS is low at this time, letdown flow via this piping is extremely low.

RCS overpressure protection is provided by the CVCS letdown line relief valve located between the letdown orifice isolation valves and the containment letdown isolation valve (CV 8152), by the RHR pump suction and discharge relief valves, and by the pressurizer PORVs.

The pressurizer PORV low temperature overpressure mitigation switches must be in the UNBLOCK position for the PORVs to actuate at low pressures. The PORVs, if actuated, provide cold overpressure protection by discharging water from the pressurizer to the pressurizer relief tank (PRT). They open, if the pressure in the RCS exceeds the cold overpressure protection setpoint.

The nuclear steam supply system (NSSS) is in MODE 5, cold shutdown: T_{avg} < 200°F, K_{eff} < 0.99, and N/A for the core power level. In addition, the following conditions exist: the RCS pressure is being maintained between 320 and 400 psig, the boron concentration is sufficient to yield a shutdown margin of at least 1% ΔK/K, the pressurizer is solid, and reactor coolant pumps are secured.

Decay heat is removed from the core by the residual heat removal system with letdown established for RCS cleanup. The steam generators are in wet layup (filled to the 100% level with water), and all secondary systems are secured with the exception of one circulating water pump. The main turbine and both feedwater pump turbines are on their respective turning gears. All pre-startup checklists have been completed.

19.2.2 Heatup to Hot Zero Power (HZP)

As required by the plant's Technical Specifications, the reactor coolant must be at its no-load operating temperature prior to criticality. The reactor coolant is heated by decay heat from the reactor core and reactor coolant pump heat.

With the plant in cold shutdown, the pressure in the RCS must be at least 320 psig to support running the reactor coolant pumps. A pressure of 320 psig provides two functions: first, it ensures a net positive suction head for the RCPs and second, it ensures that the minimum differential pressure required for lifting the number one pump seals is met. In addition, the pressure in the RCS must be maintained below 450 psig while the residual heat removal system is aligned to the reactor coolant system. This ensures that the low-pressure piping of the RHR system is not over pressurized and prevents the lifting of the RHR pump discharge relief valves.

Finally, seal injection flow from the chemical and volume control system is required to cool and lubricate the lower radial bearings and the seal packages of the RCPs.

Prior to starting the reactor coolant pumps, a steam bubble is established in the pressurizer. This ensures that a surge volume is available in the pressurizer for water expansion caused by the heatup of the coolant.

Steam bubble formation in the pressurizer is accomplished by heating the water volume of the pressurizer with the pressurizer heaters. Concurrently, charging and letdown flows are adjusted to maintain the pressure within the RCS between 320 and 400 psig.

When the temperature in the pressurizer reaches 428°F to 448°F (saturation temperature for an RCS pressure between 320 psig and 400 psig), charging flow is reduced to form the steam bubble. As the steam bubble forms, RCS letdown is increased, and the charging flow is maintained constant. The difference between these flow rates causes the level in the pressurizer to decrease, and operators lower the level to 25 percent. With a steam bubble established in the pressurizer, RCS pressure is controlled is by pressurizer heater and spray valve operation.

Nitrogen Bubble Pressure Control

RCS pressure control through use of a nitrogen cover gas can be used as an alternate method of controlling pressure. This control scheme may be used when the shutdown requires access to the RCS. In this mode of pressure control, as shown in Figure 19-2, the pressurizer is filled to 90 percent, as indicated by the cold-calibrated level instrument, and vented to the PRT via open PORVs.

A Tygon hose is temporarily installed between the pressurizer vent line (upstream of the PORVs) and the vent on the PRT to supply nitrogen to the pressurizer. The nitrogen pressure regulator for the PRT is adjusted so that six psig of nitrogen overpressure is applied to the PRT. This form of pressure control provides a stable RCS pressure without constant operator action, while still allowing some expansion and contraction of the coolant.

During nitrogen bubble pressure control, RHR flow is maintained for decay heat removal, and letdown and charging are maintained for purification of the reactor coolant. Nitrogen is used as a cover gas to minimize corrosion and to prevent explosive mixtures of hydrogen and oxygen within the RCS piping or components.

RCS overpressure protection is provided by the letdown line relief valve (if aligned), the RHR pump suction and discharge relief valves, and the rupture discs installed on the PRT. Since the RCS and the pressurizer are not completely filled with coolant, the chances of an overpressure event are unlikely. The transformation of the pressurizer void from nitrogen to steam is accomplished at the start of the plant heatup.

Prior to drawing a steam bubble, charging and letdown must be in service. Letdown is via the RHR-to-CVCS cross-connect valve HCV-128. A letdown flow of 75 gallons per minute is established through coordinated operation of HCV-128 (fully open) PCV-131 (throttled). When pressurizer level is < 80 percent, a charging pump is started to maintain pressurizer level constant during bubble formation.

All groups of pressurizer heaters are energized to raise the pressurizer water temperature to saturation. Steam formation begins when the pressurizer water temperature is at saturation, approximately 230°F at 6 psig. With the pressurizer at saturated conditions, further heating causes the temperature and pressure in the pressurizer to increase. As pressure increases, steam and nitrogen are displaced to the PRT.

Indications of steam formation are provided by the pressurizer vapor space and pressurizer PORV tailpipe temperature instruments. Initially, these instruments indicate the containment ambient temperature. With steam formation, their indications approach the saturation temperature of 230°F. Positive indication of a steam bubble is determined by the use of the auxiliary spray valve from the CVCS. If a steam bubble exists, closing the PORVs and initiating auxiliary spray flow into the pressurizer cause a rapid pressure decrease in the pressurizer. When this phenomenon is observed, the PORVs are placed in automatic, and the connection between the PRT and the pressurizer is isolated, and the Tygon tubing is removed. As pressure increases toward 320 psig, letdown flow is increased to accommodate the expansion of the reactor coolant and to lower the level in the pressurizer.

Once a bubble is drawn in the pressurizer and the pressure in the RCS has reached 320 psig, the reactor coolant pumps are started. The RCPs are started one at a time until all four pumps are running. After all reactor coolant pumps are operating, the residual heat removal pumps are stopped, since they are no longer needed to remove decay heat or to provide forced flow through the core as required by the plant’s Technical Specifications.

With all four RCPs operating and the RHR system secured, the reactor coolant begins to heat up at a rate of approximately 50°F per hour. The residual heat removal system alignment is maintained in its initial configuration to provide an adequate letdown capacity for the removal of the excess coolant volume produced by expansion due to heatup. As a result of the heatup and the draining of the pressurizer, approximately one-third of the reactor coolant system volume (30,000 gallons) is diverted to the holdup tanks through the chemical and volume control system.

Prior to exceeding 200°F (entering MODE 4), all surveillance requirements for entering this MODE must be satisfactorily completed (see Checklist No.1). The plant's Technical Specifications define MODE 4, hot shutdown, as: 350°F > T_{avg} <

200°F, K_{eff} < 0.99, and N/A for the core power level.

As the reactor coolant temperature approaches 200°F, steam generator draining is commenced through the normal blowdown system. If the oxygen concentration in the reactor coolant is high, hydrazine is added through the chemical and volume control system for oxygen scavenging (the oxygen concentration must be within specification before the coolant temperature exceeds 250°F).

When the oxygen concentration is within specification, a hydrogen overpressure is applied to the volume control tank. This is accomplished by first securing the nitrogen regulator, opening the vent from the volume control tank to the waste gas header, and raising the volume control tank level to force the nitrogen to the waste gas system. After the volume control tank level has risen to approximately 95%, the hydrogen regulator is placed in service, and the last of the nitrogen is purged to the waste gas system. The volume control tank level is allowed to return to normal with the hydrogen regulator maintaining an overpressure of approximately 15 to 20 psig.

An inspection of containment is conducted for debris that could cause blockage of the containment sumps or produce fire hazards as the systems and their components heat up. Finally, before the plant enters MODE 4, the containment spray system is aligned for operation. At approximately 220°F RCS temperature, steam formation begins in the steam generators. The nitrogen supply to the steam generators, having been applied to prevent or minimize corrosion inside the steam generators, is now isolated.

Secondary Plant Heatup

Warming of the steam lines and the main turbine is performed simultaneously with the RCS heatup; however, before steam can be supplied to the main turbine, the turbine lubricating oil and cooling water systems must be placed in service. Motor-driven lubricating oil pumps provide the necessary lubrication for rolling the main turbine. To ensure the even heating of the turbine rotor, the turbine must be on the turning gear prior to warming.

The condensate and circulating water systems are started at this time. The condensate and feedwater systems are aligned to provide cleanup of the secondary water by circulating condensate through one condensate polishing demineralizer.

The condensate flows through the in-service polisher and the low-pressure heaters to the main feedwater pump suctions. The feedwater pumps are aligned for operation, and the feed pump turbines are rotating on their respective turning gears. Condensate flows through the idle feedwater pumps and the high-pressure heaters and then back to the condenser through the feedwater pump recirculation valve.

Warming of the steam lines is initiated by opening the main steam isolation valves (MSIVs). thereby admitting steam to the individual steam lines up to the main turbine stop valves. The steam lines are thus heated as the coolant is heated. Condensate that forms in the steam lines is drained to the condenser via steam line drain traps and drain trap bypasses. Simultaneous warming of the steam lines and the main turbine is accomplished by clearing all turbine generator trip signals and initiating turbine shell warming. The turbine electrohydraulic control (EHC), gland sealing steam, and condenser air removal systems must be placed in service to provide steam valve control and a condenser vacuum. Steam blanketing of the moisture separator reheaters (MSRs) is also initiated to warm and deaerate the MSR first- and second-stage reheater tube bundles. MSR blanketing steam is supplied by the auxiliary steam system.

Before the reactor coolant temperature reaches 350°F, the operators must satisfactorily complete the surveillance requirements for entering MODE 3, hot standby (see Checklist No. 1). MODE 3 is defined by the plant's Technical Specifications as: T_{avg} > 350°F, K_{eff} < 0.99, and N/A for the core power level.

The residual heat removal system is now isolated from the reactor coolant system and aligned for at power operation (emergency core cooling system lineup). At this time, all reactor coolant letdown is through the normal letdown orifices of the chemical and volume control system. After the residual heat removal system is isolated from the reactor coolant system, pressure is allowed to increase as the temperature in the pressurizer increases.

Primary Plant - RCS Heatup and Pressurization

As the plant heatup continues, the pressurizer level continues to increase due to coolant expansion. Once placed in automatic, the pressurizer level control system automatically compensates by reducing the charging flow. During this evolution, the seal injection flow control valve, HCV-182, may require adjustment by the control room operator to maintain the proper reactor coolant pump seal injection flows as the charging flow varies.

As reactor coolant pressure increases, letdown flow also increases. The letdown backpressure regulating valve (PCV-131) is adjusted until the normal letdown pressure (350 psig) is achieved, and the orifice isolation valves are closed as necessary to maintain letdown flow below the allowed maximum of 120 gpm. When reactor coolant system pressure reaches 1925 psig, the cold leg accumulator isolation valves are opened, and all emergency core cooling system equipment is checked for proper alignment.

Pressure and temperature relationships must be constantly observed during a combined plant heatup to prevent an inadvertent reactor trip or safety injection actuation signal. Although the reactor is shut down, a reactor trip signal would cause the shutdown rods, possibly already withdrawn, to trip into the core. A safety injection actuation signal would cause the insertion of the shutdown rods and the activation of the design bases accident (DBA) sequencers. A safety injection actuation can occur with sloppy RCS pressure control. Once the pressurizer pressure is raised above 1915 psig (P-11 setpoint), the block signal of the low pressurizer pressure safety injection actuation is automatically removed. After that, any evolution that would cause RCS pressure to decrease below 1807 psig initiates a low-pressure safety injection actuation.

A safety injection actuation and main steam isolation can occur if the high steam line flow setpoint is exceeded with steam pressures below 600 psig or the RCS T_{avg}

below 553°F. High steam flow could result from an increase in steam flow through the steam dump valves or from an increase in the turbine warming rate. Also, overfeeding a single steam generator with cold feedwater can cause its pressure to decrease, thereby initiating a high steam line ΔP safety injection actuation.

The primary plant heatup is terminated by automatic actuation of the steam dumps (in steam pressure control) when the pressure inside the steam header pressure reaches 1092 psig. The RCS temperature remains constant at 557°F, the steam dumps removing any excess energy that would tend to drive the RCS temperature higher.

Turbine warming is secured after a specified warming time has been completed. Upon completion of heatup and pressurization, the reactor coolant is at the normal no-load temperature and pressure values, and the plant is ready for a reactor startup. The turbine and steam lines are warmed, with preparations completed for secondary startup. The pressurizer heaters and sprays are placed in automatic control when the pressure reaches the normal operating value of 2235 psig.

A reactor coolant leak rate test is performed when the reactor coolant temperature is greater than 400°F and the pressure is equal to 2235 psig. This test is required at this time only if the reactor coolant system has been opened for refueling or maintenance.

Prior to reactor startup, the plant conditions are as follows:

- The RCS is at normal operating temperature and pressure (557°F, and 2235 psig),
- The reactor is shut down (subcritical),
- A condenser vacuum has been drawn,
- The steam dump control system is operating in the steam pressure mode,
- The main turbine and feedwater pump turbines are rotating on their turning gears, and
- All electrical power is supplied from off-site.

19.3 Reactor Startup to Minimum Load

A reactor startup is performed at the no-load temperature of 557°F. The Technical Specifications require a minimum temperature, 551°F, for criticality. If the coolant average temperature drops below this value, the operator either restores the temperature within a short period of time or makes the reactor subcritical.

Prior to the withdrawal of the control rods to cause core criticality, an estimated critical condition (ECC) is calculated. The ECC calculation is a reactivity balance comparing the previous critical condition and reactivity changes following the last shutdown to the desired conditions for the next startup. Since the previous and present reactivity conditions are known, it is relatively easy to calculate the required conditions for the next criticality. The reactivity variables for which the operator has direct control are boron concentration and control rod position. The ECC is normally computed using a desired critical rod position. The boron concentration is then adjusted so that the reactor will be critical at the desired rod position.

Prior to entering MODE 2, startup, and MODE 1, power operation, all surveillance requirements for entering these modes must be satisfactorily completed (see Checklist No. 2). MODE 2 is defined by the plant's Technical Specifications as: $K_{eff} \geq .99$ and core power level ≤ 5%. MODE 1 is defined as: $K_{eff} \geq 0.99$ and core power level > 5%.
Control rods are withdrawn to establish criticality. It is difficult to identify exactly when criticality is achieved during a startup; however, it is readily apparent when supercritical conditions are reached. Supercriticality is indicated by a constant positive startup rate and steadily increasing source range count rate with no control rod withdrawal. Criticality is declared when these conditions are observed. After criticality is achieved, the control rods are positioned to increase nuclear power to 10^{-8} amps in the intermediate range. When power exceeds the source range block permissive (P-6) setpoint, the source range trip is manually blocked, and the source range high voltage supply is de-energized. Power is stabilized at 10^{-8} amps to record actual critical conditions. The data recorded consists of the control rod positions, boron concentration, and RCS loop average temperatures.

After recording the critical data, the control rods are positioned to increase power to the point of adding heat, approximately one percent power as indicated on the power range instruments, and then to stabilize power at about two percent. As nuclear power increases above the point of adding heat, the fuel and moderator temperatures increase. These temperature increases add negative reactivity because of the negative fuel and moderator temperature coefficients.

As the moderator temperature increases, the coolant expands into the pressurizer, causing the level and pressure to increase. Also, the steam generator temperatures and pressures begin to increase. Since the steam dumps are in the steam pressure mode of control, the steam dump valves modulate open, maintaining the steam header pressure at 1092 psig. 1092 psig is the saturation pressure for 557°F, which is the no-load T_{avg}. With the steam dumps in steam pressure mode, the RCS T_{avg} does not follow the programmed T_{avg}; it increases to produce the primary-to-secondary ΔT needed to support a steam flow of about two percent of the full-load value.

As the steam dumps modulate open, increasing the steam flow to the main condenser, feedwater flows to the steam generators must be increased. Since the motor-driven (nonsafety-grade) auxiliary feedwater pump can supply only about two percent of rated feed flow, care is exercised to ensure that the power level does not exceed two percent.

With the power level at some point between 1×10^{-8} amps and two percent, the anticipated reactivity changes for power escalation, caused by the increase in power defect and by the change in xenon concentration, are determined, and the required boron concentration change is started. The rate of power increase could be limited by improper control rod position if the power defect and xenon concentration change are not predicted correctly.

The power level is maintained at two percent while a main feedwater pump is started and aligned to supply the steam generators through the main feed regulating bypass valves. The main feedwater bypass valves are then manually manipulated to control steam generator levels. The main feed pump speed is controlled in manual to maintain 50 - 150 psid between the feed and steam pressures, enough to ensure adequate feed flow to the steam generators through the bypass valves.

With a main feedwater pump feeding the steam generators and the auxiliary feedwater system realigned to its normal at-power standby lineup, turbine startup may proceed.

To minimize primary plant transients, the turbine is rolled with reactor power between 10 and 15 percent. Control rods are withdrawn to raise core power and the RCS temperature. The steam generator temperatures and pressures would tend to increase with the RCS temperature; however, the steam dumps modulate open to maintain a constant steam pressure constant and to create the steam demand which changes the ΔT across the core.

With nuclear power at 15 percent, the main turbine is rolled off the turning gear and accelerated to 1800 rpm. As steam flow to the turbine increases, the steam dumps modulate in the closed direction to maintain the 1092-psig steam header pressure. With the turbine running at 1800 rpm, the turbine auxiliary systems are aligned for normal operation, and the turbine protection system is tested to verify proper operation. And at this time, the MSR steam control is placed in automatic, thereby removing the auxiliary steam supply from MSR steam blanketing and initiating operation of the normal first- and second-stage MSR steam supplies. Generator synchronization is performed after satisfactory turbine protection system testing.

When the main generator voltage, frequency, and phases are matched with those of the grid, the generator output breakers are closed, and the generator picks up a minimum load of approximately 60 MWe. When the generator output breakers close, the turbine EHC system automatically shifts from speed control to load control, and operators can now increase the generator’s electrical output to the grid.

19.4 Power Operations

The turbine loading rate is determined by the most limiting of the following: the turbine loading limit curve, fuel pre-conditioning requirements, or the load dispatcher’s request. Once the loading rate is determined, the turbine load is increased to 180 MWe, about 15 percent turbine load. Increasing the turbine load to 180 MWe results in a shift of steam flow from the steam dumps to the turbine with little or no change in nuclear power. When the steam dump valves are fully closed, they are placed in the T_{avg} mode of operation.

Rod control is placed in automatic when the turbine load satisfies the C-5 interlock (15 percent turbine load) and T_{avg} is within 1°F of T_{ref}. Since the main feedwater bypass regulating valves are rated for 20 - 25 percent of full-load feedwater flow, the main feedwater regulating valves are placed in service prior to the load increasing above 20 percent. Main feed pump speed control can be placed in automatic when the main feed regulating valves are controlling the steam generator levels.

To prevent axial xenon oscillations and to maintain peaking factors within license limits, the operator must insure that the indicated axial flux difference (AFD) is maintained within the limits illustrated in Figure 19-3. Some nuclear units may operate with AFD maintained within a required target band which is more restrictive than the limits shown in this figure. Even with the liberal limits of Figure 19-3, the plant is likely to operate with AFD administratively maintained within a much more restrictive AFD target band. Such restrictions mandate the following operational conventions:

1. The control rods are nearly fully withdrawn during all phases of power operations (except for short-term transients). The increase in power defect associated with a power escalation, is thus overcome with boron dilution.
2. The dilution of the coolant boron concentration is a slow process. Therefore, power changes at sustained rates of greater than 1% - 2%/minute are not possible if the AFD is to be maintained within the band.

During the power escalation from 20 percent to 100 percent power, additional secondary pumps are placed into service. These include condensate pumps, circulating water pumps, service water pumps, the second feedwater pump, and heater drain tank pumps. Condensate demineralizers are also sequentially placed in service as power increases.

The turbine load is increased by selecting the desired loading rate and pressing the load increase pushbutton to increase the load setpoint to the desired value. The main turbine control valves modulate to positions which should produce the generator electrical output selected with the load-set controller. A turbine first-stage pressure feedback signal may adjust the control valve positioning signal to ensure that the desired load is actually attained.

The single-loop loss of flow permissive (P-8) enables the single-loop loss of flow reactor trip when reactor power exceeds 39%.

At approximately 50% load, a calorimetric calculation (heat balance) is performed on the secondary system, and an adjustment to the power range nuclear instruments is performed if necessary. Further calorimetric calculations are performed at 90% and 100% power. These additional calculations are performed to ensure that the power range nuclear instruments are properly calibrated.

At all times when the reactor is critical, the control banks must be maintained above their respective insertion limits. All shutdown banks and control banks A and B must be fully withdrawn, while control banks C and D must be withdrawn to positions that are greater than the limits specified in Figure 19-4. Maintaining the rod banks above their respective insertion limits ensures that sufficient negative reactivity is available to achieve and maintain the required shutdown margin in the event of a reactor trip.

19.5 Plant Shutdown

A plant shutdown is accomplished by essentially reversing the steps described for completing a plant startup.

APPENDIX 19-1
Plant Startup from Cold Shutdown

I. INITIAL CONDITIONS

1. Cold Shutdown - MODE 5:

   \$ K_{eff} <0.99
   - 0% power
   - T_{avg} < 200°F

2. Reactor Coolant System: solid.
3. RCS Temperature: 150 - 160°F.

> **Note:**
> *Temperature may be less than 150°F depending upon the decay heat load of the core.*

4. RCS Pressure: 320 - 400 psig.
5. Steam Generators: filled to wet layup (100% wide-range level indication).
6. Secondary Systems: shutdown, main turbine and feedwater pump turbines on their turning gears.
7. Pre-Startup Checklists: completed.

II. INSTRUCTIONS

A. Heatup from COLD SHUTDOWN to HOT SHUTDOWN (MODE 5 to MODE 4)

1. Permission received from Operations Supervisor for startup.
2. Begin establishing steam generator water levels to 33 " 5% narrow-range indication.
3. Verify or establish RCP seal injection flow.

> **CAUTION:**
> *Do not exceed a heatup rate of 100°F/hr in the pressurizer or 100°F/hr in the RCS. Do not exceed 320°F ΔT between pressurizer and spray temperature. Use auxiliary spray for pressurizer volume and coolant mixing.*

4. Energize pressurizer heaters and begin pressurizer heatup.
5. Establish a pressurizer steam bubble by;

   a. Increasing pressurizer temperature using pressurizer heaters.
   b. Adjust charging and letdown flow to maintain pressurizer pressure at approximately 320-400 psig while reducing pressurizer level.
   c. As pressurizer temperature approaches 428EF (saturation temperature for 320 psig), reduce pressurizer level toward 25%.

6. Start the reactor coolant pumps. After running the pumps for five minutes, sample the RCS for chemistry specifications. Partially open pressurizer spray valves for coolant mixing.
7. Maintain the RCS temperature < 160°F by adjusting flow through the RHR heat exchangers.

NOTE:
The 160°F limit is based on cold water addition accident. This limits the ΔT between seal injection water accumulating in the intermediate leg and the remainder of the RCS.

8. Stop RHR pumps.
9. Allow RCS temperature to increase to 200°F.
10. When RCS temperature reaches 200°F, ascertain that primary system water chemistry is within specifications.
11. When pressurizer level is at the no-load operating level (25%), place the pressurizer level control system in automatic.
12. Verify shutdown rods are withdrawn and that sufficient SHUTDOWN MARGIN is available.
13. Ensure applicable pre-startup Technical Specification requirements are met. (See Checklist No. 1.)
14. At 200°F RCS temperature, establish a hydrogen blanket in the volume control tank.
15. Open main steam isolation valves and warm main steam lines.
16. Continue pressurizer heatup to maintain desired pressure. Use low pressure letdown control valve to maintain letdown flow. Once a steam bubble is established in the pressurizer, RCS pressure will be controlled by heater and spray operation.
17. Condensate cleanup is in progress.
18. When condensate chemistry is within specifications, align the condensate and feedwater systems to the normal at-power configuration.
19. Verify condenser vacuum.
20. Warm the main turbine.

CAUTION:
Prior to reaching 350°F in the RCS, perform or verify the following:

- *Verify the control rod drive mechanism cooling fans are operating.*

B. Heatup from HOT SHUTDOWN to HOT STANDBY (MODE 4 to MODE 3)

1. Ensure applicable pre-startup Technical Specification requirements are met. (See Checklist No. 1.)
2. Complete the ECCS Master Checklist (SI, RHR, etc. are aligned).
3. Maintain RCS pressure within the operating band of the Pressure-Temperature Limitations Curve.

> **NOTE:**
> *As the RCS pressure increases, maintain letdown flow at a maximum of 120 gpm by increasing the setting of the backpressure regulator (PCV-131) until pressure reaches 350 psig and then by closing the letdown orifice isolation valves as necessary.*

4. Prior to the RCS reaching 1000 psig, open each cold leg accumulator isolation valve and then de-energize each valve's motor operator.
5. When RCS pressure exceeds 1915 psig, verify the block of the pressurizer low pressure safety injection actuation automatically resets.
6. When RCS temperature reaches 553°F, verify the block of the high steam line flow safety injection actuation automatically resets.
7. Maintain RCS temperature with the steam dump control system in the steam pressure mode.
8. Establish HOT STANDBY conditions of 557°F T_{avg}.

C. Heatup from HOT STANDBY to POWER OPERATIONS (MODE 3 to MODE 1)

> **NOTE:**
> *See Checklist No. 2.*

1. Obtain administrative permission to take the reactor critical.
2. Notify system dispatcher of unit startup and approximate time when the generator will be tied to the grid.
3. Notify onsite personnel of the reactor startup over the public address system.
4. Perform reactor trip breaker check (if not performed during the previous seven days).
5. Calculate the estimated critical boron concentration for the desired critical control rod withdrawal position.
6. If necessary, conduct a boron concentration change to achieve the estimated critical boron concentration. Equalize the boron concentrations in the reactor coolant loops and the pressurizer by turning on the pressurizer backup heaters.

NOTE:
Nuclear instrumentation shall be monitored very closely in anticipation of an unplanned rate of reactivity change.

NOTE:
Block the alarm for source range high flux level at shutdown at both source range drawers.

7. Verify all shutdown banks are fully withdrawn within 15 minutes of withdrawing control banks.
8. If the shutdown banks are inserted, complete a shutdown margin calculation (involving the shutdown banks at the fully withdrawn position) to preclude an inadvertent MODE change during rod withdrawal. Withdraw the shutdown banks to the fully withdrawn position.
9. Verify proper operation of all reactor coolant pumps.
10. Withdraw the control bank rods in manual to take the reactor critical.
11. If the control bank height at criticality is below the rod insertion limit for 0% power:

    a. Reinsert all control bank rods to the bottom of the core.
    b. Recalculate the estimated critical boron concentration.
    c. Borate to the newly calculated concentration.
    d. Withdraw the control bank rods in manual to take the reactor critical

12. Withdraw rods to increase reactor power. Block the source range high flux trip at P-6 (10^{-10} amps on the intermediate range). Take critical data at $1x10^{-8}$ amps (typically).
13. Withdraw rods to bring reactor power to approximately 2% on the power range indicators and select the highest indicating power range channel to be recorded on the NR-45 recorder.
14. Check that the steam dump pressure controller is set for 1092 psig and operating in automatic.
15. If one is not already running, start a main feedwater pump at 2% power. Maintain steam generator levels at 33 " 5% narrow-range level indication during secondary plant startup by throttling the feedwater bypass regulating valves.

CAUTION:
The secondary plant operator should coordinate changes in steam generator steaming rates removal and in feedwater addition rates with the reactor operator while rod control is in manual.

16. Verify the turbine has been on the turning gear for at least one hour.
17. Increase reactor power by manual withdrawal of the control banks until the steam dumps are bypassing steam flow equivalent to 10 - 15% nuclear power.

18. When reactor power increases above 10%, verify the "Nuclear At-Power" Permissive P-10 light illuminates and the "At-Power" Permissive P-7 light extinguishes.

NOTE:
The "At-Power" reactor trips are now enabled.

19. Manually block the intermediate range high flux reactor trip and the power range high flux, low setpoint reactor trip after P-10 has been reached.
20. Verify that the main and unit auxiliary transformer cooling systems are aligned for automatic operation.
21. Accelerate the main turbine to 1800 rpm, and then synchronize the generator and connect it to the grid.
22. Increase generator load at the desired rate while maintaining T_{avg} with manual rod control.

CAUTION:
Maintain programmed steam generator level during the following step.

23. At approximately 15% power, transfer feedwater flow control from the bypass valves to the main feedwater regulating valves.
24. When turbine power has increased above ~180 MWe (15% - the C-5 interlock setpoint), transfer the rod control system to automatic.
25. After rod control is placed in automatic, check that steam pressure is less than the pressure control setpoint (1092 psig) and that all steam dump valves are closed, then transfer the steam dump control system to the Tavg control mode.
26. Transfer steam generator feedwater regulating control valves and feed pump speed control to automatic when power exceeds 15%.
27. Place additional secondary equipment in service as necessary to support further load increases.
28. At 50% power, place the remainder of secondary pumps in service.
29. Perform secondary calorimetric (heat balance) calibrations for nuclear instrumentation adjustment as required

Checklist Number 1

NOTE:
This listing is typical of the TECHNICAL SPECIFICATION limiting conditions for operation and TECHNICAL REQUIREMENTS for changing MODES during a plant heatup. This is not a comprehensive list.

REACTIVITY CONTROL (Section 1):

Shutdown Margin	Boration Flow Paths
Charging Pumps	Borated Water Sources

INSTRUMENTATION (Section 3):

Reactor Trip System Instrumentation
Engineered Safety Features Actuation System Instrumentation

REACTOR COOLANT SYSTEM (Section 4):

RCS Loops	Pressurizer
Pressurizer Safety Valves	Pressurizer PORVs
RCS Leakage, Chemistry, Activity	RCS Pressure/Temperature Limits
Steam Generator Tube Integrity	

EMERGENCY CORE COOLING SYSTEMS (Section 5):

ECCS Trains	Refueling Water Storage Tank
Accumulators	

CONTAINMENT SYSTEMS (Section 6):

Containment Leakage, Structural Integrity	Air Locks
Internal Pressure	Air Temperature
Containment Spray and Cooling Systems	Spray Additive System
Containment Isolation Valves	

PLANT SYSTEMS (Section 7):

Main Steam Safety Valves	Auxiliary Feedwater System
Component Cooling Water System	Service Water System
Condensate Storage Tank	Main Steam Isolation Valves

ELECTRICAL POWER SYSTEMS (Section 8):

AC Sources	DC Sources
Distribution Systems	

Checklist Number 2

> **NOTE:**
> *This listing is typical of the TECHNICAL SPECIFICATION limiting conditions for operation and TECHNICAL REQUIREMENTS for changing MODES during reactor startup and power operations. This is not a comprehensive list.*

REACTIVITY CONTROL (Section 1):

Moderator Temperature Coefficient Rod
Group Alignment Limits
Shutdown and Control Banks - Rod Insertion Limits Rod
Position Indication

POWER DISTRIBUTION LIMITS (Section 2):

Axial Flux Difference
Heat Flux Hot Channel Factor ($F_Q(Z)$) Nuclear
Enthalpy Rise Hot Channel Factor Quadrant
Power Tilt Ratio

INSTRUMENTATION (Section 3):

Reactor Trip System Instrumentation
Engineered Safety Features Actuation System Instrumentation Movable Incore
Detectors

REACTOR COOLANT SYSTEM (Section 4):

DNB Parameters
Minimum Temperature for Criticality RCS
Loops

CONTAINMENT SYSTEMS (Section 6):

Hydrogen Mixing System

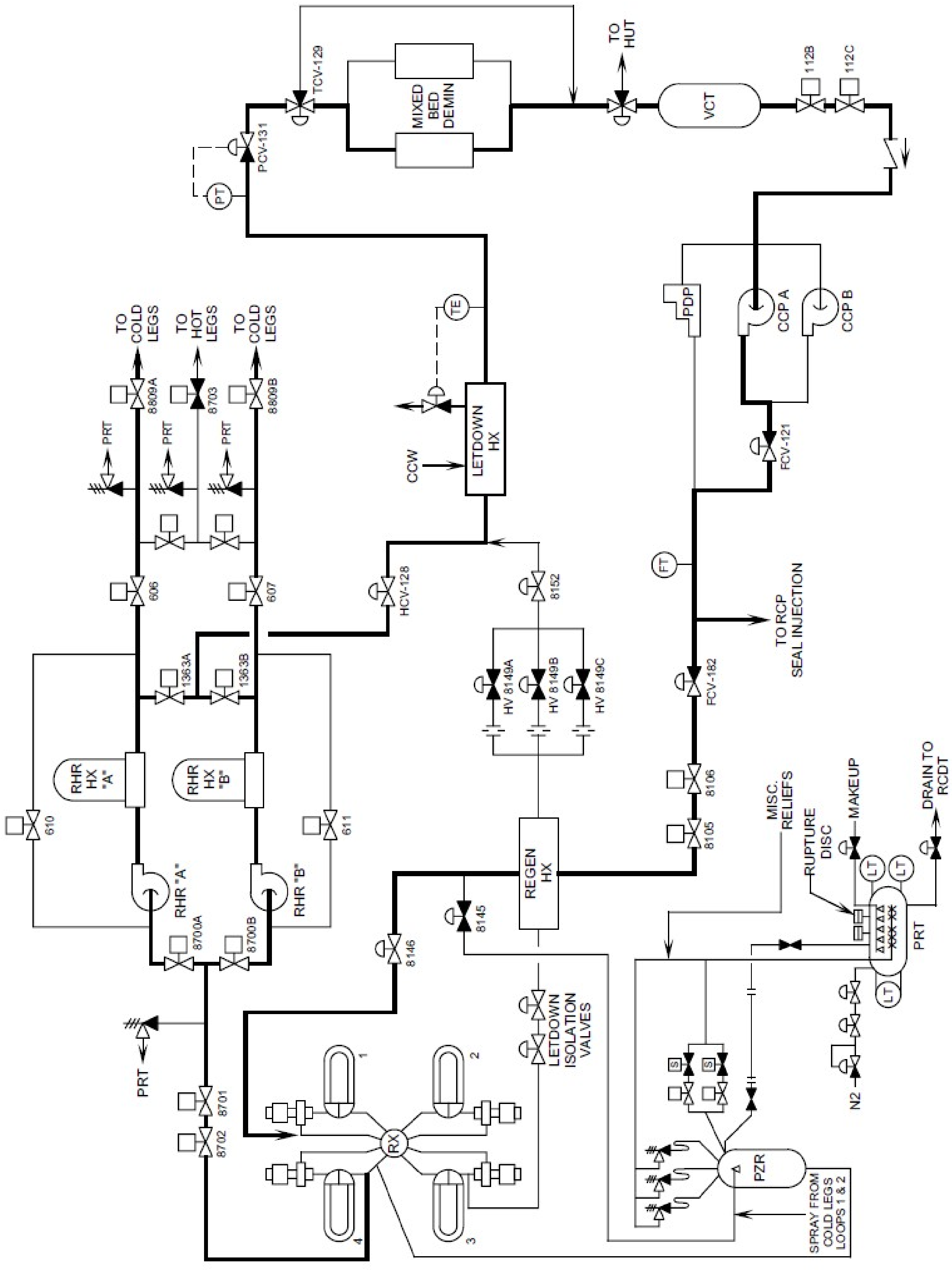

Figure 19-1 Solid Plant Pressure Control

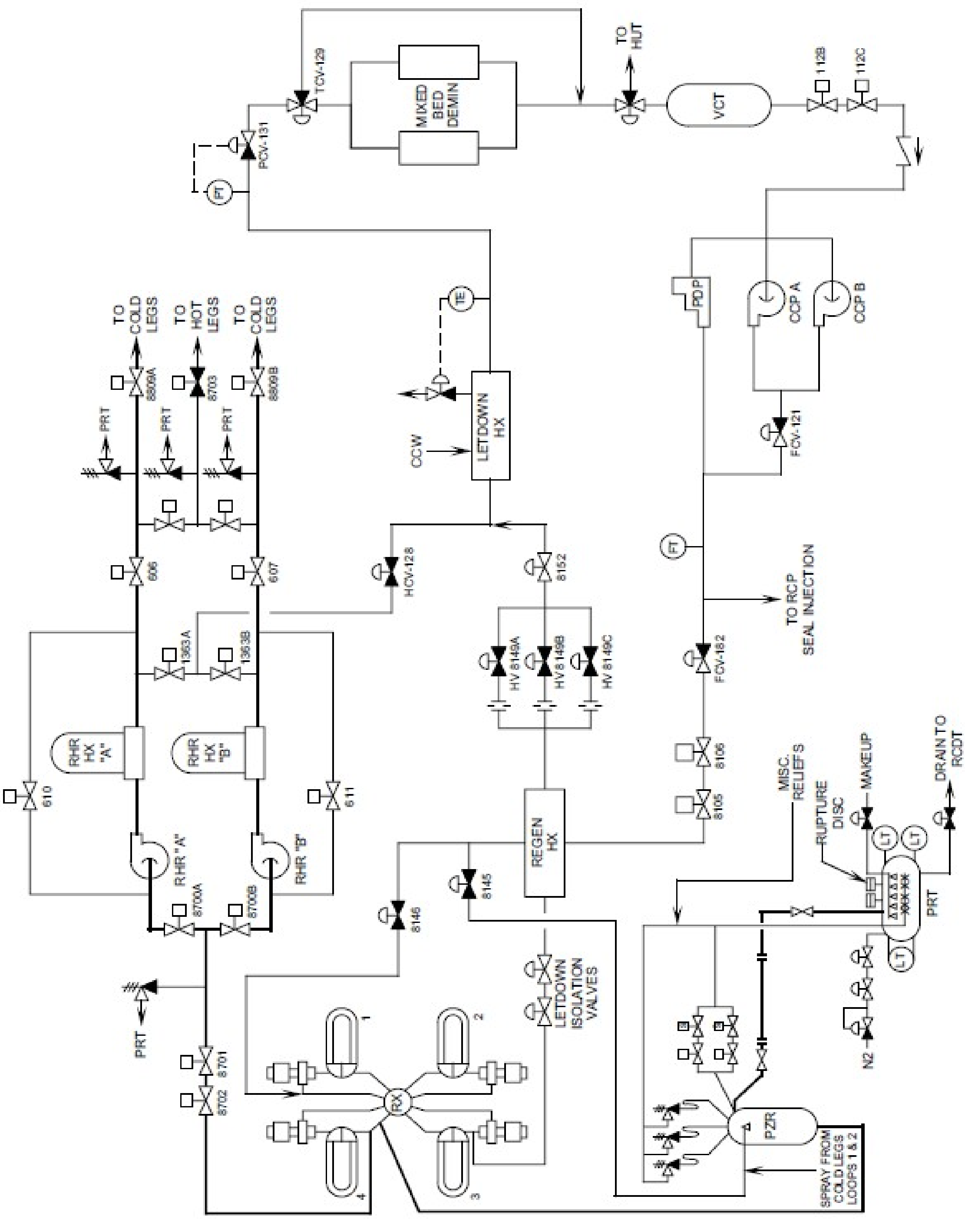

Figure 19-2 Nitrogen Bubble Pressure Control

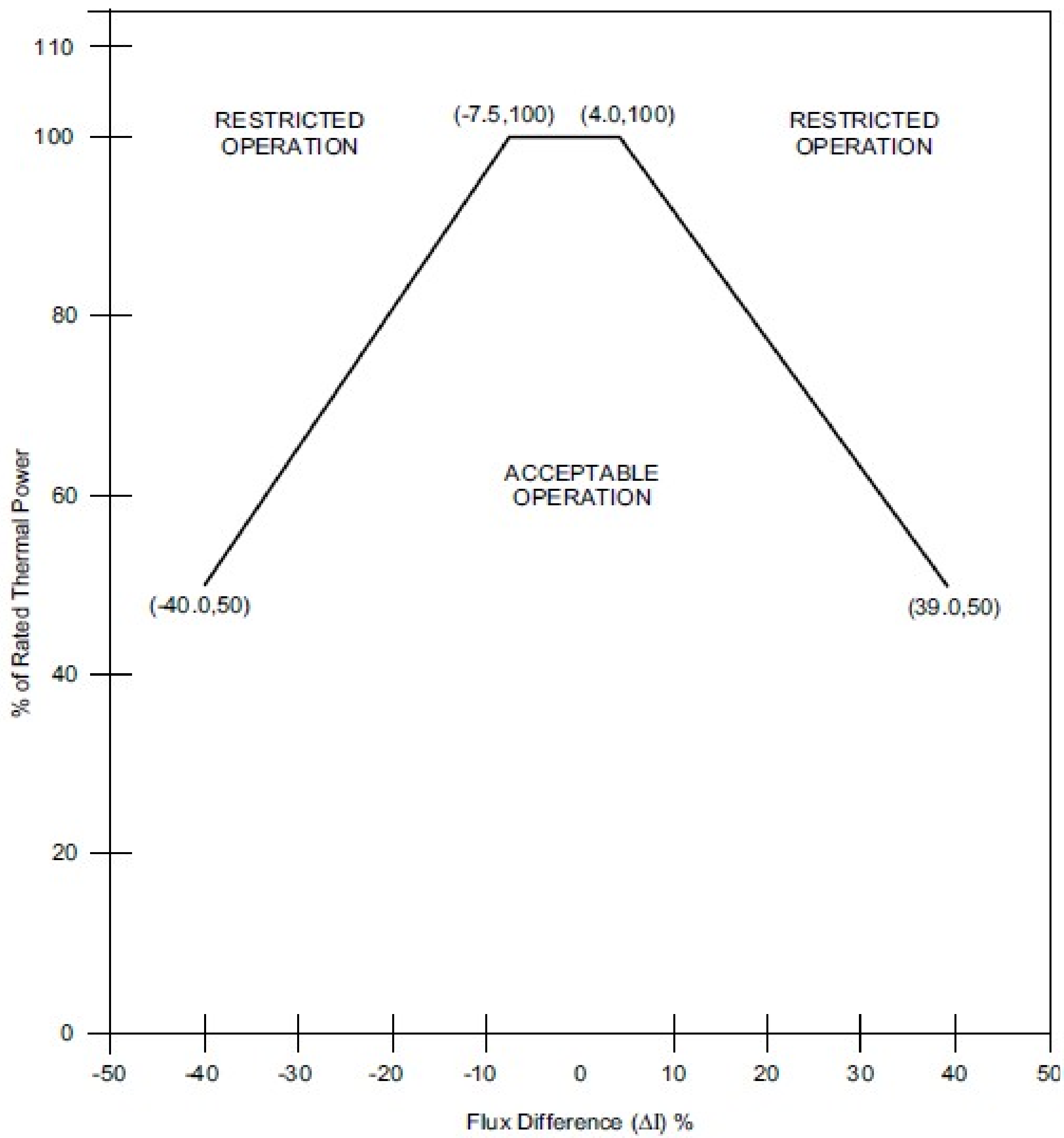

Figure 19-3 Axial Flux Difference Limits

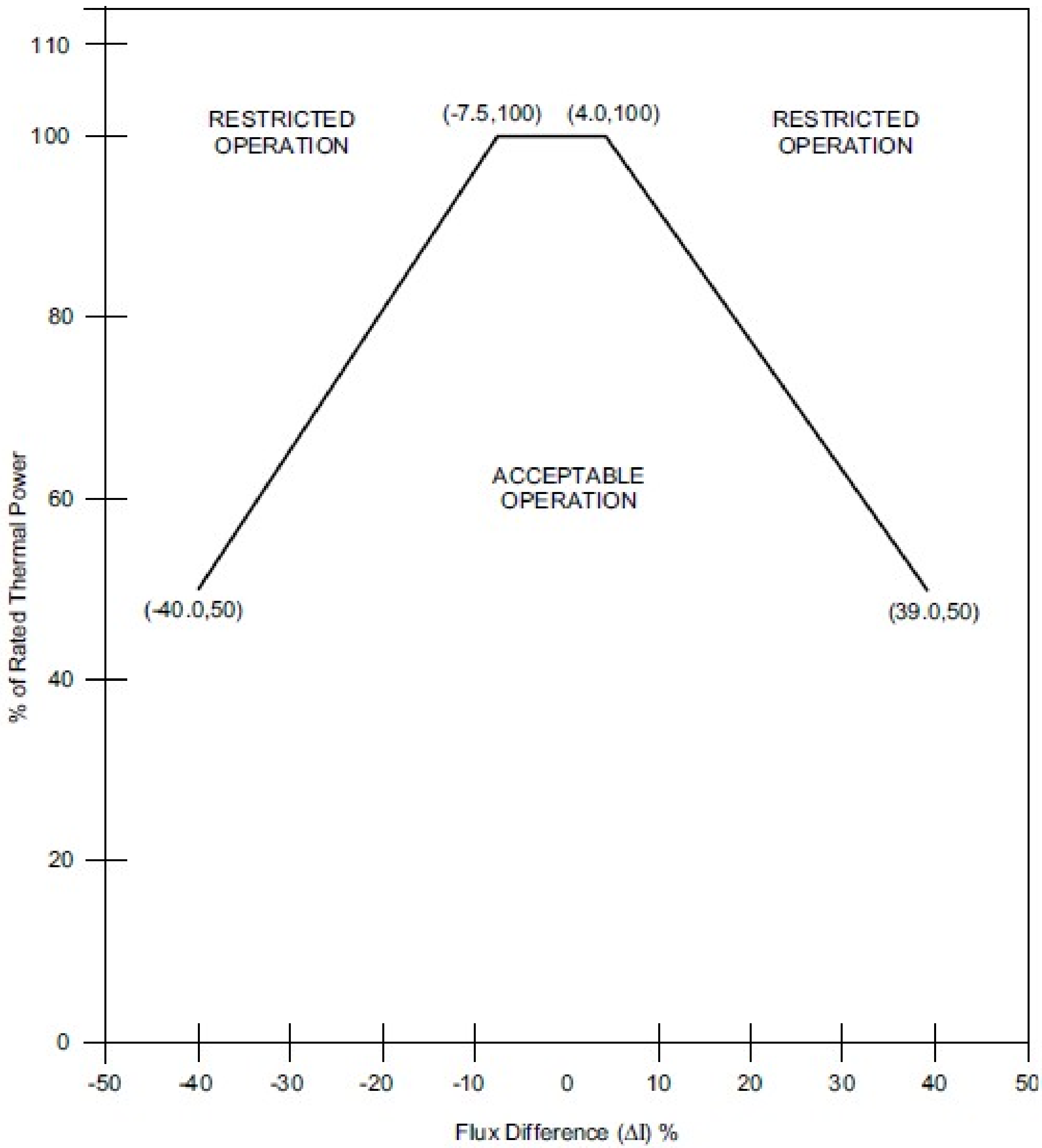

Figure 19-3 Axial Flux Difference Limits

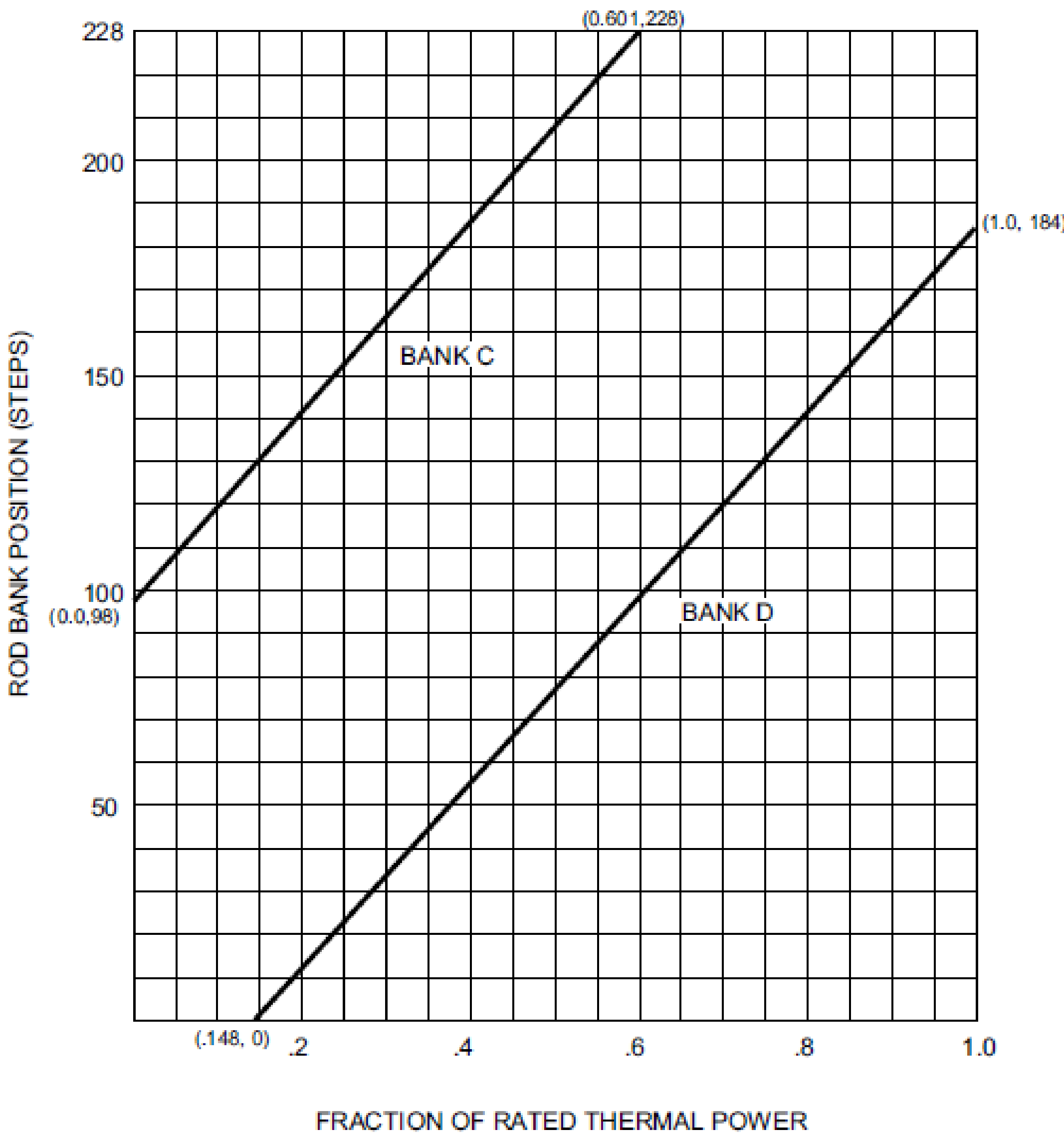

Figure 19-4 Rod Insertion Limits vs. Thermal Power

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

NUREG-0544, Rev. 5

Collection of Abbreviations

Office of Administration

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The NRC Technical Library
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New York, NY 10036-8002
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United States Nuclear Regulatory Commission
Protecting People and the Environment

NUREG-0544, REV. 5

Collection of Abbreviations

Manuscript Completed: November 2016
Date Published: December 2016

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Office of Administration

ABSTRACT

The U.S. Nuclear Regulatory Commission (NRC) has compiled this list of abbreviations commonly used by the agency staff, the regulatory community, and the nuclear industry. To create this list, the NRC staff sought to identify abbreviations that are so commonly used that some staff may not first define the term before using it either in writing or in speaking. This list of abbreviations is descriptive rather than prescriptive. In other words, this NUREG does not recommend one abbreviation to the exclusion of others. Nor does this NUREG intend to capture every abbreviation ever used in an NRC document. The audience of this NUREG is the public, stakeholders, industry, and NRC employees. The goal of this NUREG is to improve communication with and within the NRC.

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PREFACE

The U.S. Nuclear Regulatory Commission (NRC) publishes this list of abbreviations to help NRC staff, industry, stakeholders, and members of the public understand the many abbreviations used in NRC materials and presentations.

In an ideal environment, the NRC would not require a reference book of abbreviations. All NRC documents would minimize the use of abbreviations, and no NRC staff member would use an abbreviation in writing or speaking without defining it first and then redefining it often. However, the NRC regulates a highly technical and scientific industry. Abbreviations are commonly used to condense long and awkward organizational names, computer code names, nuclear power plant systems and parts, and many other scientific and technical terms.

Even outside of technical fields, abbreviations arise naturally in language. So naturally, in fact, that sometimes the abbreviated form of the term overtakes the original term. For example, laser originally stood for **l**ight **a**mplification by **s**timulated **e**mission of **r**adiation and scuba for **s**elf-**c**ontained **u**nderwater **b**reathing **a**pparatus.

Other abbreviated terms never need a definition. For example, no one would schedule a meeting for 3 post meridium (p.m.). Within the relatively small and specialized world of nuclear regulation, it is both natural and efficient for writers and speakers to use abbreviations that most of their peers will understand. When everyone in a field says HLW and understands it to mean high-level waste, it can feel just as unnecessary to define HLW as it would be to define p.m. or laser.

The reason that this NUREG is necessary is that not all users of NRC documents work in the nuclear industry. The NRC's mission is to protect public health and safety, promote the common defense and security, and protect the environment. To achieve this mission, the NRC must communicate regularly with diverse audiences such as Congress, other Federal agencies, State and local governments, Tribal Governments, foreign governments, international regulatory bodies, concerned citizens, stakeholders, and the general public. In addition, the NRC's Strategic Plan describes openness as one of two cross-cutting strategies for achieving its goals. The agency's activities to achieve openness include, "Enhance the readability of NRC materials intended for the general public," and "Expand the use of plain language…in communicating technical information."

For a general audience, a document with many abbreviations can be very difficult or nearly impossible to understand. NRC writers should keep the least technical audience member in mind when choosing to use abbreviations. Even within the agency, technical staff members have different areas of specialization. A resident inspector, a seismic expert, a financial assurance analyst, and an emergency response specialist will each have a different set of abbreviations that he or she considers to be commonly used. This revision of NUREG-0544 acknowledges that abbreviations must be used, but it also points out that overuse of abbreviations can impede communication. For this reason, this revision includes a new section on plain language principles and how to minimize abbreviations. This revision also greatly reduces the number of abbreviations presented. The previous revision of this NUREG contained over 8,000 abbreviations. This revision is streamlined to just over 1,000 abbreviations. The working group reduced the number of abbreviations by deleting outdated terms and focusing on abbreviations that are so commonly used that NRC staff might not define them before use.

The list of abbreviations in this NUREG is descriptive rather than prescriptive. No one abbreviation is recommended to the exclusion of another because the same abbreviation may, with equal validity, apply to two or more terms. This list includes major NRC program and staff offices, advisory groups, panels, and boards but not NRC divisions and branches. These can be found on the NRC's organization and functions Web page. Some abbreviations for organizations that no longer exist are included as historical references. This list does not include most chemical elements, computer codes, and units of measurement. Many of these abbreviations appear in readily accessible sources such as dictionaries, the *U.S. Government Printing Office Style Manual*, and other manuals.

ACKNOWLEDGMENT

This NUREG is the product of collaboration among staff from different organizations. Kimberly Ferrell, Chief of the Publications Branch in the Office of Administration, contributed the leadership and management of this revision. The Office of the Executive Director for Operations supported the streamlined direction of this revision. Finally, this revision would not be possible without the thoughtful contributions made by the NUREG-0544, Revision 5, working group, listed below.

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1 INTRODUCTION TO ABBREVIATIONS

Abbreviations are everywhere in modern language. You will find them used in casual conversation, e-mails, text messages, social media, postal addresses, company names, formal letters, legal documents, and scientific and technical reports. An abbreviation is any shortened form of a word or term. Acronyms and initialisms are simply two different types of abbreviations. The difference between an acronym and an initialism is explained below:

1.1 Definitions

Abbreviation: Any shortened form of a word or group of words used in place of the whole.

- **Acronym:** A type of abbreviation formed from the first letters of a group of words. Acronyms are pronounceable. Some examples include:
  - ANSI: American National Standards Institute
  - LOCA: loss-of-coolant accident
  - IKEA: Ingvar Kamprad Elmtaryd Agunnaryd (Ingvar Kamprad is the furniture store founder's name. Elmtaryd is the farm where he grew up and Agunnaryd is his home town.)
  - NASA: National Aeronautics and Space Administration
  - ASAP: as soon as possible

- **Initialism:** A type of abbreviation formed from initial letters of a group of words. Each letter is pronounced separately.
  - EPZ: emergency planning zone
  - NRC: U.S. Nuclear Regulatory Commission
  - SGTS: standby gas treatment system
  - EPA: U.S. Environmental Protection Agency
  - CNN: Cable News Network

1.2 Why Use Abbreviations?

We use abbreviations for many reasons. The most common reason is to shorten a long or unwieldy term, particularly if it is used several times. Abbreviations usually make communication easier for the speaker but not for the reader or the intended audience who may not know the abbreviation.

Technology also drives the creation and use of abbreviations. Text messaging limits the writer to 160 characters, and Twitter limits tweets further to just 140 characters. The need to type quickly when instant messaging or communicating on the Internet also introduced many new abbreviations that have spilled out into everyday language. For example, lol started out as a way to write "laugh out loud" in electronic communications, but now some people will say lol in speech instead of actually laughing. New abbreviations can crop up very quickly and enter everyday speech.

Abbreviations also serve another function—they help to create a common language used by an in-group. The group could be a subculture, interest group, age group, social group, or in the case of the NRC, a professional group.

1.3 How To Use Abbreviations

Use as few abbreviations as possible in both speaking and writing. The more abbreviations you use, the harder it will be for your audience to understand you. When choosing to use abbreviations, think of the least specialized audience member for your document. If you are writing a status report for your branch, you can assume most of your audience understands the same common abbreviations that you do. The same status report going to the Office of the Executive Director for Operations will likely be read by people with many different specializations. In that case, you should use far fewer abbreviations. If you are writing a report to Congress or a document for a public meeting, almost all of your common abbreviations may be unfamiliar to the primary audience. In that case, use almost no abbreviations.

Chapters 9 and 10 of the *U.S. Government Printing Office Style Manual* (https://www.gpo.gov/fdsys/pkg/GPO-STYLEMANUAL-2008/pdf/GPO-STYLEMANUAL-2008.pdf) present a comprehensive list of abbreviations and guidance for their use. Follow the guidance in Chapter 9 and 10 of the *U.S. Government Printing Office Style Manual* and rules 1 through 12 below unless publication requirements for a particular document dictate otherwise. For example, to publish an article in a journal, you may need to follow the publisher's in-house style. Some of the guidance below is excerpted from NUREG-1379, "NRC Editorial Style Guide."

1. Avoid using abbreviations whenever possible. Some exceptions include very common abbreviations like Mr., Ms., a.m., and p.m.

2. If you must use an abbreviation, always define it the first time you use it.

   - The safety evaluation report (SER) is a high priority. Staff estimates it will have a first draft of the SER completed by January.

3. Once you have defined an abbreviation, you can still go back to using the full term or switch back and forth between the abbreviation and the full term. You may choose to do this for several reasons:

   - To make the document easier for the reader to understand on first reading.
   - To remind the reader of what the abbreviation stands for, especially if it was first defined several paragraphs or pages back.
   - To avoid using back-to-back abbreviations or several abbreviations in one sentence.

4. If you are writing a long document, redefine the abbreviation in each new chapter. For a set of documents such as correspondence or a paper with enclosures, redefine the abbreviation in each new enclosure.

5. Do not use back-to-back abbreviations or several abbreviations in one sentence. This is true even if you have already used and defined the abbreviation earlier in the document.

   - *Instead of*—NRC asked the ACRS to review the HLW SER.
   - *Write*—The agency asked the ACRS to review the safety evaluation report on high-level waste.
   - *Or write*—NRC asked the Committee to review the SER on high-level waste.

6. Use the same form of an abbreviation for both the singular and plural forms of a unit of measure.
    - 1 m
    - 3 m
    - 1 kg
    - 5 kg
7. Omit internal and terminal punctuation unless its omission would cause confusion.
    - 1 in. (Period avoids confusion with the word “in”.)
    - 5 cm
8. Use abbreviations for units of measure only if they are used with numbers.
    - 200 r/min (*but*—The test would determine the number of revolutions per minute.)
    - Most U.S. nuclear power plants have a 10-mile radius plume exposure pathway emergency planning zone. (*but*—Most U.S. nuclear power plants use miles, not kilometers, to express the radius of their emergency planning zones.)
9. State the term from which an abbreviation not commonly known is formed, followed by its abbreviation in parentheses. Redefine abbreviations in every new chapter or major section.
    - iodine–131 metaiodobenzylguanidine (I–131 MIBG)
    - 60 indicated horsepower (ihp)
    - electromotive force (emf or EMF)
    - Office of Nuclear Regulatory Research (RES)
10. Use periods in abbreviations for foreign phrases. (Et is Latin for “and”; therefore, it is not an abbreviation and does not take a period.)
    - et al. (for et alii, meaning “and others”)
    - e.g. (exempli gratia, meaning “for example”)
    - i.e. (id est, meaning “that is”)
    - et seq. (for et sequentes, meaning “and the following”)
11. The abbreviations e.g. and i.e. (followed by a comma) should be used only inside parentheses. Otherwise, write out the English equivalents. Do not italicize e.g. and i.e.
    - Today we received specific instructions for preparing the report (i.e., its due date, contents, and format).
    - Today we received specific instructions for preparing the report, that is, its due date, contents, and format.
12. Use the U.S. Postal Service two-letter State and Province abbreviations in any address or capitalized geographic term.
    - Prince George’s County, MD
    - Atlanta, GA
    - *but*—deciduous forests of Wisconsin; black sand beaches in Hawaii

2 ACRONYMS AND INITIALISMS

As mentioned in the previous section, acronyms and initialisms are two types of abbreviations. An acronym is a pronounceable term formed from the initial letters of a compound expression (e.g., LOCA for loss-of-coolant accident). An initialism is formed from the initial letters of a term and the initial letters are pronounced as separate letters. (e.g., NRC for the U.S. Nuclear Regulatory Commission).

Most acronyms are capitalized except for certain well-known acronyms that are lower case by convention. Some of the guidance below is excerpted from NUREG-1379, "NRC Editorial Style Guide."

2.1 <u>How To Use Acronyms and Initialisms</u>

1. Use an acronym or initialism if the term it represents will be used more than several times in a document. The first time a term is used, state the words from which the acronym is formed, followed by the acronym in parentheses. In a lengthy document, restate the term followed by its acronym at the beginning of each chapter or major section. However, keep in mind that excess acronyms and abbreviations can make an otherwise well-written document difficult to understand. When writing for a lay audience, or even a technical audience that does not share your specialty, use acronyms sparingly and carefully. You may sometimes need to redefine an acronym, offer a brief explanation of the acronym, or use a synonym instead. Always avoid stringing several acronyms together in a single sentence. Do not include acronyms in headings and titles.

- The Resource Advisory Council (RAC) has reviewed this plan. The RAC advised the staff to revise three sections.
- The Resource Advisory Council has reviewed this plan. The council advised the staff to revise three sections.

2. Although an acronym or initialism is capitalized, do not capitalize the term it represents unless the term would ordinarily be capitalized.

- Office of the General Counsel (OGC)
- technical specification (TS)
- crack opening displacement (COD)

3. To form the plural for most acronyms and initialisms, add a lower case *s* without an apostrophe.

- 12 NPPs
- five RGs
- two NUREGs

4. To form the possessive of an acronym or initialism, use an apostrophe plus s, just as you would for a normal word.

- EDO’s report
- IAEA’s May conference
- RES’s funding (*also*—funding from RES; RES funding)
- O_3’s chemical instability (*also*—ozone’s chemical instability; the chemical instability of O_3)

5. To decide whether *a* or *an* should precede an acronym or initialism, pronounce the first syllable of the acronym. “A” should precede a consonant sound; “an” should precede a vowel sound.

- an ACRS meeting (“ay” is a vowel sound)
- an AEC report (“ay” is a vowel sound)
- a FEMA decision (“fee” is a consonant sound)
- an NRC office (“en” is a vowel sound)
- a LOCA occurred (“low” is a consonant sound)

3 PLAIN LANGUAGE AND ABBREVIATIONS

If you can't explain something simply, you don't understand it well. Most of the fundamental ideas of science are essentially simple, and may, as a rule, be expressed in a language comprehensible to everyone. Everything should be as simple as it can be, yet no simpler.

-Albert Einstein

3.1 What Is Plain Language?

Even though the NRC regulates a highly technical area and produces complex documents, the agency strives to use plain language. What is plain language exactly? Although there are many definitions, plain language is direct communication that focuses on making information easily understandable to a given audience.

The NRC regularly communicates with its own staff, the public, stakeholders, industry, other government agencies, the legislative and executive branches, international regulatory bodies, and representatives of foreign governments. The NRC relies on plain language to support its mission in many ways:

- NRC resident inspectors at nuclear power plants depend on clearly written inspection manuals to conduct the inspections that ensure safety for people and the environment.
- Nuclear power plant operators must follow safety guidelines to quickly identify and respond to emergencies.
- The Commission relies on NRC staff reports, safety evaluations, and licensing reviews to make decisions that affect the nuclear industry and public safety.
- Licensees must understand NRC regulations in order to comply with them.
- NRC staff uses plain language to explain regulatory requirements to applicants, certificate holders, licensees, and other government agencies.

With such a diverse audience and important mission, plain language makes sense for the NRC.

3.2 Plain Language: It's the Law

When the President signed The Plain Writing Act of 2010, using plain language became the law. This act requires Federal agencies to produce "clear Government communication that the public can understand and use." Executive Order 13563, "Improving Regulation and Regulatory Review," also addresses plain language. It states, "Our regulatory system must...ensure that regulations are accessible, consistent, written in plain language, and easy to understand."

3.3 Plain Language Resources and Guidance

There are many useful resources for learning about plain language, as shown in the following table:

The Government's plain language Web site	www.plainlanguage.gov
Federal Plain Language Guidelines	http://www.plainlanguage.gov/howto/guidelines/FederalPLGuidelines/TOC.cfm
NRC Plain Language Writing Techniques	http://www.internal.nrc.gov/ADM/DAS/cag/notices/notdocs/writingtech.html
NRC Plain Language Pointers	http://www.internal.nrc.gov/communications/plainlanguage.pdf
NRC Plain Language Action Plan	http://www.internal.nrc.gov/NRC/PLAIN/
Yellow Announcement, "Plain Language Guide for Agency Writing"	http://www.internal.nrc.gov/announcements/yellow/2002-1997/1999-008.html

3.4 Plain Language Means Fewer Abbreviations

Plain language principles always call for writers to minimize abbreviations. The Federal Plain Language Guidelines say, "When you are considering whether to use an abbreviation, or how many you can get away with in a document, remember that they should make it easier for your users. If they make it harder, you have failed to write for your audience."

Plain language is focused on the audience, not the writer. In most cases, abbreviations are about making writing easier for the writer. This is why plain language principles call for writers to avoid and minimize abbreviations.

Figure 1 on the next page is an excerpt from the Federal Plain Language Guidelines on how to use abbreviations in plain language writing.

iii. Minimize abbreviations

One legal scholar calls abbreviations a "menace to prose" (Kimble, 2006). Abbreviations were once intended to serve the audience by shortening long phrases. However, abbreviations have proliferated so much in current government writing that they constantly require the reader to look back to earlier pages, or to consult an appendix, to puzzle out what's being said.

Use "nicknames"

The best solution is to find a simplified name for the entity you want to abbreviate. This gives readers meaningful content that helps them remember what you're talking about. It may be a bit longer, but the gain in clarity and ease of reading is worth it. In most cases, you don't need to "define" this nickname the first time you use it, unless you are using lots of different nicknames. Especially when you are using a nickname for the major topic of your document, don't insult your users and waste their time. For example, in a paper about Resource Advisory Councils, don't tell them that when you say "Council" you mean "Resource Advisory Council."

For	Instead of	Consider
Engineering Safety Advisory Committee	ESAC	the committee
Small-quantity handlers of universal wastes	SQHUW	waste handlers
Fire and Police Employee Relations Act	FPERA	the Act

If everyone knows an abbreviation, use it without explanation

There's a short list of abbreviations that have entered common usage. When you use them, don't define them, you're just taking up space and annoying your user. But make sure the abbreviation you're using is on the list. Examples include IBM, ATM, BMW, PhD, CIA.

A closely related guideline is, "don't define something that's obvious to the user." Most federal agencies, when writing a letter responding to an inquiry, insist on defining the agency name, as in, "Thank you for writing to the Federal Aviation Administration (FAA) about your concerns …" The letterhead says the name of the agency. The person wrote to the agency, and now the agency is writing back. The user is *not* going to be confused about what FAA means!

If you must abbreviate

Of course, there are some situations in which you can't avoid an abbreviation. Always define an abbreviation the first time you use it, for example, "The American Journal of Plain Language Studies" (AJPLA). And limit the number of abbreviations you use in one document to no more than three, and preferably two. Spell out everything else. If you've used abbreviations for the two or three most common items, it's unlikely that the other items occur so frequently you can't spell them out every time.

Figure 1 Federal Plain Language Guidelines, March 2011

4 LIST OF COMMONLY USED ABBREVIATIONS AT THE NRC

Abbreviation	Full Term
10 CFR	Title 10 of the *Code of Federal Regulations*
3WFN	Three White Flint North
8(a)	8(a) Business Development Program
AASG	Association of American State Geologists
ABWR	advanced boiling-water reactor
AC	alternating current
ACC	additional Commission comments
ACHP	Advisory Council on Historic Preservation
ACI	American Concrete Institute
ACL	alternate concentration limit
ACMUI	Advisory Committee on the Medical Use of Isotopes
ACQC	American Society for Quality Control
ACRS	Advisory Committee on Reactor Safeguards
ACUS	Administrative Conference of the United States
ADAMS	Agencywide Documents Access and Management System
ADE	annual dose equivalent
ADM	Office of Administration
ADR	alternative dispute resolution
ADS-IDAC	Accident Dynamics Simulator Using Information, Decision, and Action in a Crew Context
A-E	architect-engineer
AEA	Atomic Energy Act of 1954, as amended
AEC	Atomic Energy Commission
AERB	Atomic Energy Regulatory Board
AFOE	annual frequency of exceedance
AFR	away from reactor
AIC	Akaike information criterion
AISC	American Institute of Steel Construction
ALARA	as low as is reasonably achievable (radiation exposure)
ALI	annual limit on intake
AM	Atlantic Margin
AMP	aging management program
AMR	analysis model report
ANL	Argonne National Laboratory
ANPR/ANPRM	advanced notice of proposed rulemaking
ANS	American Nuclear Society

ANS-8	American Nuclear Society Standards Subcommittee 8
ANSI	American National Standards Institute
ANSS	U.S. Advanced National Seismic System
AO	abnormal occurrence
AO	approving official
AOO	anticipated operational occurrence
AOR	analysis of record
AP1000	Advanced Passive 1000 Megawatt (Westinghouse pressurized-water reactor)
APC	action plan committee
APEX	Advanced Power Extraction
API	application programming interface
API	American Petroleum Institute
APM	available physical margin
APP	advanced procurement plan
APSR	axial power shaping rod
APWR	advanced pressurized-water reactor
AR	advanced reactor
ARAR	applicable or relevant and appropriate requirement
ARB	Allegation Review Board
ARRP	Advanced Reactor Research Program
ARS	Agricultural Research Service
ARTIST	Aerosol Trapping in Steam Generator
AS	Agreement State
ASC	Administrative Services Center
ASCE	American Society of Civil Engineers
ASCII	American Standard Code for Information Interchange
ASD	allowable stress design
ASEP	Accident Sequence Evaluation Program
ASER	annual site environmental report
ASLBP	Atomic Safety and Licensing Board Panel
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing
ASP	accident sequence precursor
ASR	alkali silica reaction
ASTM	American Society for Testing and Materials
ATF	Bureau of Alcohol, Tobacco, and Firearms
ATWS	anticipated transient without scram
AVLIS	advanced vapor laser isotope separation
AWS	American Welding Society
AWWA	American Water Works Association
B&PV	Boiler and Pressure Vessel (ASME Code)

B&R	budget and reporting
B&W	Babcock & Wilcox
BAC	Business Advisory Center
BADGER	Boron-10 Areal Density Gauge for Evaluating Racks
bcc:	blind carbon copy
BDD	binary decision diagrams
BEIR	biological effects of ionizing radiation
BFN	Browns Ferry Nuclear Power Plant
bgs	below ground surface
BIA	Bureau of Indian Affairs
BIP	Behavior of Iodine Project
BLM	Bureau of Land Management
BMI	bottom-mounted instrumentation
BMP	best management practice
BNL	Brookhaven National Laboratory
BOC	budget object classification code
BOG	IAEA's Board of Governors
BPA	blanket purchase agreement
BPR	burnable poison rod
BPRA	burnable poison rod assembly
BPT	best practicable technology
BPT	Brownian passage time
BR	breathing rate
BRIIE	Baseline Risk Index for Initiating Events
BTP	branch technical position
BUC	burnup credit
BWR	boiling-water reactor
CA	Commissioners' assistants (singular or plural)
CA	construction authorization
CAA	Clean Air Act
CAA	Office of the Commission Appellate Adjudication
CAD	computer-aided design
CAM	continuous air monitor
CAMP	Code Application and Maintenance Program
CAO	chief acquisition officer
CAP	corrective action program
CAP	containment accident pressure
CAR	construction authorization request
CAROLFIRE	Cable Response to Live Fire
CBDT	cause-based decision tree
CBP	Customs and Border Protection

CBR	center, body, and range
cc:	carbon copy
CCDP	conditional core damage probability
CCF	common-cause failure
CCI	core-concrete interaction
CDA	critical digital asset
CDC	Centers for Disease Control and Prevention
CDE	committed dose equivalent
CDF	core damage frequency
CE	combustion engineering
CEA	control element assembly
CEDE	committed effective dose equivalent
CENA	central and eastern North America
CEQ	Council on Environmental Quality
CER	cumulative effects of regulation
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFAST	Consolidated Fire Growth and Smoke Transport Model
CFD	computational fluid dynamics
CFE	cost-free expert
CFFA	Catalogue of Federal Finance Assistance
CFO	Chief Financial Officer
CFR	*Code of Federal Regulations*
CH	contact-handled
CHCO	Chief Human Capital Officer
CHF	critical heat flux
CHRISTI-FIRE	Cable Heat Release, Ignition, and Spread in Tray Installations During Fire
CI	confidence interval
CIO	Chief Information Officer
CIPAC	Critical Infrastructure Partnership Advisory Council
CJIS	Criminal Justice Information Services
CLASSI	continuum linear analysis of soil-structure interaction
CLIN	contract line item number
CMT	centroid moment tensor
CNWRA	Center for Nuclear Waste Regulatory Analyses
CO	contracting officer
COB	close of business
CoC	certificate of compliance
COCORP	Consortium for Continental Reflection Profiling
COI	conflict of interest
COL	combined license (combined construction and operating license)
COLA	combined license application

ComMIT	community model interface for tsunami
COMP	composite prior, composite superdomain
CONOPS	concepts of operations
COOP	continuity of operations
COP	community of practice
COP	containment overpressure
COR	contracting officer's representative
COSMOS	Consortium of Organizations for Strong-Motion Observation Systems
CP	computerized procedure
CP	construction permit
CP-ECR	Cathcart-Pawel Equivalent Cladding Reacted
CPFF	cost plus fixed fee
CPIC	Capital Planning and Investment Control
CPLD	complex programmable logic device
cpm	counts per minute
CPR	common prioritization of rulemaking
CPR	cardiopulmonary resucitation
CPT	cone penetration test
CR	continuing resolution
CR	control room
CRA	Congressional Review Act
CRADA	cooperative research and development agreement
CRCPD	Conference of Radiation Control Program Directors
CRDM	control rod drive mechanism
CRGR	Committee to Review Generic Requirements
CRPPH	Committee on Radiation Protection and Public Health
CRR	cyclic resistance ratio
CRT	crew response tree
CS	contract specialist
CSARP	Cooperative Severe Accident Research Program
CSAU	Code Scaling, Applicability, and Uncertainty
CsCl	cesium chloride
CSDRS	certified seismic design response spectra
CSFM	commercial spent fuel management
C-SGTR	consequential steam generator tube rupture
CSI	criticality safety index
CSM	conceptual site model
CSO	Computer Security Office (functions are now part of the Office of the Chief Information Officer)
CSR	cyclic stress ratio
CTBT	Comprehensive Test Ban Treaty

CTP	crack-tip parameter
CUF	cumulative usage factor
CV	cross vessel
CWA	Clean Water Act
CY	calendar year
D&D	decontamination and decommissioning
DAC	derived air concentration
DART	deep-ocean assessment and reporting of tsunamis
DAU	Defense Acquisition University
DBA	design-basis accident
DBE	design-basis event
DBEGM	design-basis earthquake ground motion
DBF	design-basis fire
DBFL	design-basis flood
DBT	design-basis threat
DBT	design-basis tornado
DBTT	ductile-to-brittle transition temperature
DBW	design-basis wind
DC	dose coefficient
DC	design certification
dc	direct current
DCAA	Defense Contract Audit Agency
DCF	dose conversion factor
DCPP	Diablo Canyon Power Plant
DCSS	dry cask storage system
DDA	deliquification, dissolution, and adjustment
DDE	double design earthquake
DDE	deep dose equivalent
DE	design earthquake
DECON	decontamination phase of a reactor
DEDCM	Deputy Executive Director for Corporate Management
DEDO	Deputy Executive Director for Operations
DEM	digital elevation model
DES	discrete element simulation
DESIREE-FIRE	Direct Current Electrical Shorting in Response to Exposure Fire
DF	decontamination factor
DFR	direct final rule
DFWCS	digital feedwater control system
DG	draft regulatory guide
DH	directive handbook
DHC	delayed-hydride cracking

DHR	decay heat removal
DHS	U.S. Department of Homeland Security
DI&C	digital instrumentation and control
DIP	damage indicating parameter
DLF	dynamic load factor
DLO	document liaison officer
DM	dissimilar metal
DMW	dissimilar metal weld
DNDO	Domestic Nuclear Detection Office
DNFSB	U.S. Defense Nuclear Facilities Safety Board
DOA	delegation of authority
DOC	U.S. Department of Commerce
DOE	U.S. Department of Energy
DOE-EHSS	U.S. Department of Energy—Office of Environment, Health, Safety and Security
DOI/IBC	U.S. Department of the Interior/Interior Business Center
DOL	U.S. Department of Labor
DOS	U.S. Department of State
DOT	U.S. Department of Transportation
DP	decommissioning plan
dpm	disintegrations per minute
DPO	differing professional opinion
DQO	data quality objectives
DSHA	deterministic seismic hazard assessment
DU	depleted uranium
DUF_6	depleted uranium hexafluoride
DWPF	Defense Waste Processing Facility
EA	environmental analysis
EA	environmental assessment
EA	enforcement action
EAC	environmentally assisted cracking
EAF	environmentally assisted fatigue
EAL	emergency action level
EAP	Employee Assistance Program
EB	Executive Branch
EBP	extrabudgetary program
EBS	engineered barrier system
EC	economic consequences
EC	emergency classification
ECC	extended continental crust
ECCS	emergency core cooling system
ECI	external communications interface

ECL	emergency classification level
ECMA	East Coast magnetic anomaly
ECR	equivalent cladding reacted
ECTM	Eastern Canada Telemetered Network
EDSB	economically disadvantaged small business
EDEGM	elastic design earthquake ground motion
EDGM	elastic design ground motion
EDMG	extensive damage mitigation guidelines
EDO	Executive Director for Operations
EDS	energy dispersive spectroscopy
EDWOSB	economically disadvantaged woman-owned small business
EEO	equal employment opportunity
EERI	Earthquake Engineering Research Institute
EGOE	Expert Group on Occupational Exposure
EHS	environment, health, and safety
EHSM	environment, health, and safety manager
EHSS	Office of Environment, Health, Safety and Security (DOE)
EIA	Energy Information Administration
EIS	environmental impact statement
EIT	electronic and information technology
EJ	environmental justice (per Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations)
EJS	environmental justice statement
ELECTRA-FIRE	Electrical Cable Test Results and Analysis during Fire Exposure
EMDC	Eastern Management Development Center
ENA	eastern North America
ENDF	evaluated nuclear data file
EnPA	Energy Policy Act of 1992
ENTOMB	entombment (of a shutdown reactor)
EO	executive order
eOPF	electronic official personnel folder
EOP	emergency operating procedure
EP	emergency preparedness/planning
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 2005
EPCRA	Emergency Planning and Community Right-to-Know Act
EPICUR	Experimental Program for Iodine Chemistry Under Irradiation
EPIX	Equipment Performance and Information Exchange System
EPR	U.S. Evolutionary Power Reactor
EPRI	Electric Power Research Institute
EPRI-SOG	Electric Power Research Institute--Seismic Owners Group

EPU	extended power uprates
EPZ	emergency planning zone
EQ	environmental qualification
ER	environmental report
ERDA	Energy Research and Development Administration
E-RIDS	Electronic Regulatory Information Distribution System
ERO	emergency response organization
ESA	Endangered Species Act of 1973, as amended
ESBWR	economic simplified boiling-water reactor (GE-Hitachi design)
ESF	engineered safety feature
ESP	early site permit
ESRI	Environmental Systems Research Institute
EST	extended storage and transportation
ET	evapotranspiration
EWC	enterprisewide contract
EXAFS	Extended X-Ray Absorption Fine Structure
FAC	Federal Acquisition Certification
FACA	Federal Advisory Committee Act
FAC-C	Federal Acquisition Certification in Contracting
FAC-COR	Federal Acquisition Certification-Contracting Officer's Representative
FAC-P/PM	Federal Acquisition Certification for Program and Project Management
FAI	Federal Acquisition Institute
FAIMIS	Financial Accounting and Integrated Management Information System
FAITAS	Federal Acquisition Institute Training Application System
FAM	financial assurance mechanism
FAQ	frequently asked question
FAR	Federal Acquisition Regulation
FAST	Free and Secure Trade Program
FBI	Federal Bureau of Investigation
FBO	Federal Business Opportunities (FedBizOpps)
FCF	fuel cycle facility
FCO	funds certifying official
FCOP	Fuel Cycle Oversight Process
FDA	U.S. Food and Drug Administration
FDC	future disposal cell
FDS	fire dynamics simulator
FDT	fire dynamics tools
FE	finite element
FEA	finite element analysis
FedBizOpps	Federal Business Opportunities
FEI	Federal Executive Institute (OPM-Charlottsville, VA)

FEIS	final environmental impact statement
FEMA	Federal Emergency Management Agency
FEMP	Federal Emergency Management Program
FEP	features, events, and processes
FERC	Federal Energy Regulatory Commission
FFA	Federal Facility Agreements
FFP	firm fixed price
FFRDC	Federally funded research and development center
FFT	fast Fourier transform
FG	fuel grade
FGDC	Federal Geographic Data Committee
FGR	fission gas release
FIN	financial identification number
FIRS	foundation input response spectra
FISMA	Federal Information Security Management Act
FOIA	Freedom of Information Act
FONSI	finding of no significant impact
FOSID	frequency of onset of significant inelastic deformation
FPP	fire protection program
FR	*Federal Register*
FR	final rule
FRN	*Federal Register* notice
FSAR	final safety analysis report
FSEIS	final supplemental environmental impact statement
FSME	Office of Federal and State Materials and Environmental Management Programs (now part of the Office of Nuclear Material Safety and Safeguards)
FSRP	Facilities Standard Review Plan
FTE	full-time equivalent
FTF	F-Area Tank Farm or F-Tank Farm
FTP	file transfer protocol
FUSRAP	Formerly Utilized Sites Remedial Action Program
FWS	U.S. Fish and Wildlife Service
FY	fiscal year
FYI	*for your* information
g	gravitational unit
G&A	general and administrative (expenses)
G8	*Group of* Eight
GA	General Atomics
GAO	U.S. Government Accountability Office
GC	Gulf Coast
GCC	Government Coordinating Council

GCP	general closure plan
GDC	general design criteria
GDP	gaseous diffusion plant
GE	General Electric
GEH	General Electric-Hitachi
GEIS	generic environmental impact statement
GG	General Grade
GHG	greenhouse gas
GL	generic letter
GL	general license
GLD	generally licensed device
GLTS	General License Tracking System
GM	Geiger-Mueller
GM	ground motion
GMC	ground motion characterization
GMRS	ground motion response spectra
GPO	U.S. Government Publishing Office
GPR	ground-penetrating radar
GPS	Global Positioning System
GROA	geologic repository operations area
GSA	Geological Society of America
GSA	General Services Administration
GSA	General Separations Area
GSC	Geological Survey of Canada
GSI	generic safety issue
GSL	geosynthetic clay liner
GTCC	greater-than-Class-C (waste)
GTRI	Global Threat Reduction Initiative
Gz	Graetz number
H&S	health and safety
H/U	hydrogen-to-uranium
H/U	heatup
HAC	hypothetical accident conditions
HAZ	heat-affected zone
HBF	high-burnup fuel
HBU	high burnup
HDPE	high-density polyethylene
HE	Hosgri Earthquake
HEU	high-enriched uranium
HFRA	Hafnium Flux Reduction Assembly
HHS	U.S. Department of Health and Human Services

HID	hazard input document
HLW	high-level waste (radioactive)
HM	heavy metal
HME	hazardous materials enforcement
HNA	high-nickel alloy
HOO	headquarters operations officer
HPIC	high-pressure ionization chamber
HPS	Health Physics Society
HPSSC	Health Physics Society Standards Committee
HPT	health physics technician
HQ	headquarters
HRMS	Human Resources Management System
HRQC	Highway Route Controlled Quantity
HRR	highly radioactive radionuclide
HSK	Swiss Federal Nuclear Safety Inspectorate
HSPD	Homeland Security Presidential Directive
HSSM	Highway Security-Sensitive Material
HTF	H-Area Tank Farm or H-Tank Farm
HTGR	high-temperature gas-cooled reactor
HUBZone	historically underutilized business zone
HV	high velocity
HVAC	heating, ventilation, and air conditioning
HWFP	hazardous waste facility permit
I&C	instrumentation and controls
IA	Interagency Agreement
IAEA	International Atomic Energy Agency
IASPEI	International Association of Seismology and Physics of the Earth's Interior
IBC	international building code
IBR	incorporation by reference
IC	increased controls
ICC	International Code Council
ICE	Immigration and Customs Enforcement
ICRP	International Commission on Radiological Protection
ICRU	International Commission on Radiation Units and Measurements
ICT	information and communication technology
ICWG	International Council Working Group
IDC	indefinite delivery contract
IDIQ	indefinite delivery/indefinite quantity
IDLH	immediately dangerous to life and health
IDS	intrusion detection system
IEEE	Institute of Electrical and Electronics Engineers

IERP	independent external review panel
IFNEC	International Framework for Nuclear Energy Cooperation
IGCE	independent Government cost estimate
IMPEP	Integrated Materials Performance Evaluation Program
IN	information notice
IND	improvised nuclear device
INES	International Nuclear Event Scale
INL	Idaho National Laboratory
INRA	International Nuclear Regulators Association
IP	inspection procedure
IPA	Intergovernmental Personnel Act
IPAC	Intergovernmental Payment and Collection System
IPPAS	International Physical Protection Advisory Service
IPT	integrated project team
IRIS	Incorporated Research Institutions for Seismology
IROFS	item(s) relied-on for safety
IRRS	Integrated Regulatory Review Service
ISA	integrated safety analysis
iSALE	Impact Simplified Arbitrary Lagrangian-Eulerian
ISC	International Seismological Centre
ISFSI	independent spent fuel storage installation
ISG	interim staff guidance
ISL	in situ leach
ISMP	Integrated Source Management Portfolio
ISR	in situ recovery
ISRS	in-structure response spectra
ISSO	information system security officer
IT	information technology
ITC	informed technical community
ITDB	Illicit Trafficking Database
ITWI	important to waste isolation
IX	ion exchange
J&A	justification and approval
JEAC	Japan Electric Association Code
JEAG	Japan Electric Association Guide
JFD	joint frequency distribution
JISAO	Joint Institute for the Study of the Atmosphere and Ocean
JLD	Japan Lessons-Learned Project Directorate
JMA	Japan Meteorological Agency
JNES	Japan Nuclear Energy Safety
JOFOC	justification for other than full and open competition

JPM	job performance measure
KARISMA	Kashiwazaki-Kariwa Research Initiative for Seismic Margin Assessment
K_d	distribution coefficient
k_{eff}	“k” effective-neutron multiplication factor
KK	Kashiwazaki-Kariwa
KM	knowledge management
L&D	learning and development
LA	license application
LAN	local area network
LANL	Los Alamos National Laboratory
LAR	license amendment request
LAW	low-activity waste
LBL	Lawrence Berkeley National Laboratory
LCO	limiting condition for operation
LDE	lens dose equivalent
LDO	Lamont-Doherty Earth Observatory
LES	Louisiana Energy Services
LEU	low-enriched uranium
LHS	Latin hypercube sampling
LiDAR	light detection and ranging
LLD	lower limit of detection
LLEA	local law enforcement agency
LLNL	Lawrence Livermore National Laboratory
LLRW	low-level radioactive waste
LLW	low-level waste
LOCA	loss-of-coolant accident
LPP	leadership potential program
LRFD	load resistance factor design
LSA	low specific activity
LSN	Licensing Support Network
LT	leak testing
LTC	long-term cooling
LTP	license termination plan
LTS	License Tracking System
LTSP	long-term surveillance plan
LVS	License Verification System
LWR	light-water reactor
M&D	manufacturer and distributor
MA	monitoring area
MAR	Marianna (RLME source)
MARSSIM	Multi-Agency Radiation Survey and Site Investigation Manual

MBES	multibeam echo sounding
MCC	moisture characteristic curve
MCE	maximum credible earthquake
MCEER	Multi-Disciplinary Center for Earthquake Engineering Research
MCL	maximum containment level
MCMC	Markov chain Monte Carlo
MD	management directive
MDC	minimum detectable contamination
MECE	mutually exclusive and collectively exhaustive
MESE	Mesozoic and younger extended crust
METI	Ministry of Economy, Trade, and Industry (Japan)
MF	monitoring factor
MFFF	mixed-oxide fuel fabrication facility
MIC	microbially influenced corrosion
MIDC	midcontinent
MIL	military
MIT	mechanical integrity testing
MLSR	monthly letter status report
MML	master materials license
MNOP	maximum normal operating pressure
MOA	memorandum of agreement
MofS	margin of safety
MOST	Method of Splitting Tsunami
MOU	memorandum of understanding
MOX	mixed oxide
MPC	multipurpose cask
MRB	Management Review Board
MRS	monitored retrievable storage
MSD	Mitigating Strategies Directorate
MSDS	material safety data sheet
MSL	mean sea level
MT	magnetic particle examination
NA or na	not applicable (also n/a or N/A)
NAC	National Agency Check
NAGRA	Nationale Genossenschaft für die Lagerung radioaktiver Abfälle (Switzerland National Cooperative for the Disposal of Radioactive Waste)
NAICS	North American Industry Classification System
NAS	National Academy of Sciences
NCAI	National Congress of American Indians
NCDC	National Climatic Data Center
NCOE	Niigataken Chuetsu-Oki earthquake

NCRP	National Council on Radiation Protection and Measurements
NCT	normal conditions of transport
NCTR	NOAA (National Oceanic and Atmospheric Administration) Center for Tsunami Research
NDAA	National Defense Authorization Act
NDE	nondestructive examination
NDT	nil-ductility transition
NDT	nondestructive test
NE	Office of Nuclear Energy (U.S. Department of Energy)
NEA	Nuclear Energy Agency (Organisation for Economic Co-operation and Development)
NEAT	NRC's Enterprise Acquisition Toolset
NEDB	National Earthquake Database
NEES	network for earthquake engineering simulation
NEHRP	National Earthquake Hazards Reduction Program
NEI	Nuclear Energy Institute
NEIC	National Earthquake Information Center
NELAC	National Environmental Laboratory Accreditation Conference
NEPA	National Environmental Policy Act of 1969, as amended
NERHC	New England Radiological Health Compact
NERI	Nuclear Energy Research Initiative
NESHAP	National Emissions Standard for Hazardous Air Pollutants
NEUP	Nuclear Energy University Program
NFH	nonfuel hardware
NFPA	National Fire Protection Association
NFS	Nuclear Fuel Services
NGA	National Governors Association
NGA	next generation attenuation relationship
NHPA	National Historic Preservation Act of 1966, as amended
NICEE	National Information Centre of Earthquake Engineering
NISA	Nuclear and Industrial Safety Agency (Japan)
NIST	National Institute of Standards and Technology
NLO	no legal objection
NLT	no later than
NMA	National Mining Association
NMED	Nuclear Material Events Database
NMMSS	Nuclear Materials Management & Safeguards System
NMP	National Materials Program
NMSS	Office of Nuclear Material Safety and Safeguards
NNSA	National Nuclear Security Administration
NOAA	National Oceanic and Atmospheric Administration

NOED	notice of enforcement discretion
NORM	naturally occurring radioactive materials
NORM/NARM	naturally occurring or accelerator-produced radioactive materials
NOV	notice of violation
NPDES	National Pollutant Discharge Elimination System
NPH	natural phenomena hazards
NPL	National Priorities List for CERCLA
NPO	noncompliant performance objective
NPP	nuclear power plant
NPSH	net positive suction head
NQA	nuclear quality assurance
NRC	U.S. Nuclear Regulatory Commission
NRO	Office of New Reactors
NRPB	National Radiation Protection Board
NRR	Office of Nuclear Reactor Regulation
NSA	neutron source assembly
NSC	Nuclear Safety Commission (Japan)
NSC	National Safety Council
NSHMP	National Seismic Hazard Mapping Project
NSIR	Office of Nuclear Security and Incident Response
NSSS	nuclear steam supply system
NSTS	National Source Tracking System
NTAS	National Threat Advisory System
NTEU	National Treasury Employees Union
NTIS	National Technical Information Service
NUREG	U.S. Nuclear Regulatory Commission technical report designation
NUREG/BR	NUREG brochure
NUREG/CP	conference proceedings NUREG
NUREG/CR	contractor-prepared NUREG
NUREG/IA	international agreement NUREG
NUREG/KM	knowledge management NUREG
NVLAP	National Voluntary Laboratory Accreditation
NWPA	Nuclear Waste Policy Act of 1982
NWPAA	Nuclear Waste Policy Amendments Act of 1987
NWS	National Weather Service
NWTRB	Nuclear Waste Technical Review Board
OAS	Organization of Agreement States
OBE	operating-basis earthquake
OCA	Office of Congressional Affairs
OCFO	Office of the Chief Financial Officer
OCHCO	Office of the Chief Human Capital Officer

OCIO	Office of the Chief Information Officer
OCOI	organizational conflict of interest
OCRWM	Office of Civilian Radioactive Waste Management (DOE)
OD	Office Director
OD	organizational development
OE	Office of Enforcement
OECD	Organisation for Economic Co-operation and Development
OEDO	Office of the Executive Director for Operations
OEL	occupational exposure limit
OFA	optimized fuel assembly
OFPP	Office of Federal Procurement Policy
OFR	Office of the Federal Register
OGC	Office of the General Counsel
OI	Office of Investigations
OIG	Office of the Inspector General
OIP	Office of International Programs
OIS	Office of Information Services (functions now in the Office of the Chief Information Officer)
OL	operating license
OMB	Office of Management and Budget
OPA	Office of Public Affairs
OpenSees	open system for earthquake engineering simulation
OPM	U.S. Office of Personnel Management
ORNL	Oak Ridge National Laboratory
ORR	operational readiness review
OSHA	Occupational Safety and Health Administration
OSL	optically stimulated luminescence
OSRP	Offsite Source Recovery Project
OUO	official use only
OWFN	One White Flint North
P&ID	piping and instrumentation diagrams
P5	permanent five members of United Nations Security Council
PA	performance assessment
PAG	protective action guide
PARS	Publicly Available Records System (ADAMS)
PASSCAL	program for array seismic studies of the continental lithosphere
PBPM	planning, budgeting, and performance management
PCSA	preclosure safety analysis
PCT	peak cladding temperature
PDF	Portable Document Format
PDR	Public Document Room (NRC)

PEER	Pacific Earthquake Engineering Research Center
PEGASOS	Probabilistische Erdbeben-Gefährdungs-Analyse für die KKW-Standorte in der Schweiz (Probabilistic Seismic Hazard Analysis for Swiss Nuclear Power Plant Sites)
PEM	Portfolio Enrollment Module
PG	power grade
PG&E	Pacific Gas & Electric
PGA	peak ground acceleration
PGD	peak ground displacement
PGV	peak ground velocity
PHA	peak horizontal ground acceleration
PII	personally identifiable information
PM	particulate matter
PM	project manager
PM10	particulate matter less than 10 micrometers
PMDA	program management and data analysis
PMEL	Pacific Marine Environmental Laboratory
PMF	probable maximum flood
PMP	probable maximum precipitation
PNNL or PNL	Pacific Northwest National Laboratory
PO	performance objective
POA&M	plan of action and milestones
POC	point of compliance
POC	point of contact
POC	project oversight committee
POP	period of performance
PPE	personal protective equipment
ppm	parts per million
PPRP	participatory peer review panel
PQD	post-quench ductility
PR	proposed rule
PRA	Paperwork Reduction Act
PRA	probabilistic risk assessment
PRB	Petition Review Board
PRM	petition for rulemaking
PSHA	probabilistic seismic hazard analysis
PSSCs	principal structures, systems, and components
PTFI	project technical facilitator integrator
PTHA	probabilistic tsunami hazard analysis
PTI	project technical integrator
Pub. L.	public law

PV	pore volumes
PVHA	probabilistic volcanic hazard analysis
PWHT	preheat and postweld heat treatment
PWR	pressurized-water reactor
Q&A	question and answer
QA	quality assurance
QAP	quality assurance program
QASP	quality assurance surveillance plan
QC	quality control
R&D	research and development
RA	Regional Administrator
rad	radiation absorbed dose
RAI	request for additional information
RAM	radioactive material
RAMQC	radioactive material in quantities of concern
RATS	Regulation Action Tracking System
RC	reinforced concrete
RCC	Rulemaking Coordinating Committee
RCCA	rod cluster control assembly
RCPD	radiation control program directors
RCRA	Resource Conservation and Recovery Act
RDD	radiological dispersal device
RED	radiation emitting device
REIRS	Radiation Exposure Information and Reporting System
rem	Roentgen equivalent man
REQ	requisition
RES	Office of Nuclear Regulatory Research
RFCOP	Revised Fuel Cycle Oversight Process
RFI	request for information
RFP	request for proposal
RFPA	request for procurement action
RFQ	request for quotation
RG	regulatory guide
RH	remote-handled
RI	NRC Region I (King of Prussia, PA)
RII	NRC Region II (Atlanta, GA)
RIII	NRC Region III (Lisle, IL)
RIL	research information letter
RIN	regulation identifier number
RIS	regulatory issue summary
RIV	NRC Region IV (Arlington, TX)

RLME	repeated large-magnitude earthquake
RLO	records liaison officer
RMEI	reasonably maximally exposed individual
RO	reverse osmosis
RO	reviewing official
ROD	record of decision
ROP	Reactor Oversight Process
RSAO	regional State agreements officer
RSI	request for supplemental information
RSICC	Radiation Safety Information Computational Center
RSLO	regional State liaison officer
RSO	radiation safety officer
RT	radiographic examination
RTS	Reciprocity Tracking System
RVT	random vibration theory
RWP	radiation work permit
SA	spectral acceleration
SA	security advisory (generic communications)
SAIC	Science Applications International Corporation
SAMGs	severe accident management guidelines
SAR	safety analysis report
SASSI	system for analysis of soil-structure interaction
SASW	spectral analysis of surface waves
SB	small business
SBA	Small Business Administration
SBCR	Office of Small Business and Civil Rights
SC	seismic category
SCATR	Source Collection and Threat Reduction (Program)
SCC	stress corrosion cracking
SCC	Standing Committee for Compatibility
SCEC	Southern California Earthquake Center
SCML	south-central magnetic lineament
SCO	surface contaminated object
SCR	stable continental region
SD	spectral displacement
SDC	seismic design category
SDE	shallow (skin) dose equivalent
SDF	Saltstone Disposal Facility
SDMP	site decommissioning management plan
SDVOB	service-disabled veteran-owned business
SECY	Office of the Secretary

SEI	Structural Engineering Institute
SEIS	supplemental environmental impact statement
SEM	scanning electron microscopy
SEP	source evaluation panel
SER	safety evaluation report
SERP	safety and environmental review panel
SEUS	southeastern United States
SF	standard form
SF	spontaneous fission
SFP	spent fuel pool
SG	safeguards
SGI	safeguards information
SGI-M	safeguards information modified-handling
SHPO	State historic preservation office
SI	Système International (d'unités) or International System of Units
SIFT	short-term inundation forecast tool
SILEX	Separation of Isotopes by Laser Excitation
SIP	State implementation plans
SLO	State liaison officer
SMA	seismic margin assessment
SNF	spent nuclear fuel
SNL	Sandia National Laboratories
SNM	special nuclear material
SOC	statement of considerations
SOG	Seismicity Owners Group
SOP	standard operating procedure
SOW	statement of work
SPF	Saltstone Processing Facility
SPRA	seismic probabilistic risk assessment
SPS	sample per second
SPT	standard penetration test
SR	surveillance requirement
SRM	staff requirements memorandum
SRNL	Savannah River National Laboratory
SRO	senior reactor operator
SRP	Standard Review Plan (NUREG-0800)
SRS	Savannah River Site
SRSS	square-root-of-the-sum-of-the-squares
SRTM	Shuttle Radar Topography Mission
SS&D	sealed source and device
SS&DR	Sealed Source and Device Registry

SSA	Seismological Society of America
SSAB	site-specific advisory board
SSC	seismic source characterization
SSCs	structures, systems, and components
SSE	safe shutdown earthquake
SSG	strategic sourcing group
SSHAC	Senior Seismic Hazard Analysis Committee
SSJ	sole-source justification
SSNM	strategic special nuclear material
SSRCR	Suggested State Regulations for the Control of Radiation
STAQS	Strategic Acquisition System
Stat.	statute
STPNOC	South Texas Project Nuclear Operating Company
SUNSI	sensitive unclassified nonsafeguards information
SUSN	Southeastern United States Network
SWPF	Salt Waste Processing Facility
SwRI	Southwest Research Institute
SWU	separative work unit
T&R	trustworthiness and reliability
TA	technical assistant
TAC	technical accountability code
TAC	technical assignment control (number)
TAD	transportation, aging, and disposal
TAR	technical assistance request
TCN	transaction control number
TDI	technically defensible interpretations
TEDE	total effective dose equivalent
TEM	transmission electron microscopy
TENORM	technologically enhanced naturally occurring radioactive material
TEPCO	Tokyo Electric Power Company
TER	technical evaluation report
TFI	technical facilitator integrator
TG	technical guide
TI	temporary instruction
TI	Transport Index
TI	technical integrator
TLD	thermoluminescent dosimeter
TMI	Three Mile Island
TOC	table of contents
TODE	total organ dose equivalent
TPA	Total-System Performance Assessment (NRC)

TR	technical report
TR	topical report
TRU	transuranic
TS	technical specification(s)
TSA	Transportation Security Administration
TSAR	topical safety analysis report
TSC	technical support center
TSP	Thrift Savings Plan
TSPA	Total System Performance Assessment
TWA	time-weighted average
TWFN	Two White Flint North
TWIC	transportation worker identification credentials
U&Th	uranium and thorium
U.S.C.	United States Code
UBC	Uniform Building Code
UCERF	uniform California earthquake rupture forecast
UCL	upper control limit
UF_6	uranium hexafluoride
UFD	used nuclear fuel disposal
UFSAR	updated final safety analysis report
UHS	uniform hazard spectrum
UIC	Underground Injection Control
UK	United Kingdom
UMTRCA	Uranium Mill Tailings Radiation Control Act
U-nat	natural uranium
UNAVCO	University NAVSTAR Consortium
UNSCEAR	United Nations Scientific Committee on the Effects of Atomic Radiation
UO_2	uranium dioxide
UPS	uninterruptible power supply
URL	underground research laboratory
USACE	U.S. Army Corps of Engineers
USCS	Unified Soil Classification System
USDA	U.S. Department of Agriculture
USEC	United States Enrichment Corporation
USGS	U.S. Geological Survey
USMA	United States Military Academy (West Point, NY)
USMMA	United States Merchant Marine Academy (Kings Point, NY)
USN	United States Navy
USNA	United States Naval Academy
USNSN	U.S. National Seismograph Network
USQ	Unreviewed Safety Question. For the FSRP, as defined at 10 CFR 72.48

UT	ultrasonic examination
UTC	coordinated universal time
UTR	Upper Three Runs
UUSA	URENCO USA
V&V	verification and validation
V/H	vertical-to-horizontal ratio
WAC	waste acceptance criteria
WBL	Web-based licensing
WC	waste confidence
WCD	waste confidence decision or Waste Confidence Directorate
WCD	worst-case difference
WCS	waste control specialists
WD	waste determination
WG	weapons grade
WG	working group
WIPP	Waste Isolation Pilot Plant
WIR	waste incidental to reprocessing
WMDC	Western Management Development Center (OPM-Aurora, CO)
WOSB	women-owned small business
WPS	welding procedure specification
WUS	western United States
WVDP	West Valley Demonstration Project
WWSSN	World-Wide Standardized Seismograph Network
XANES	X-Ray Absorption Near Edge Structure
XRD	x-ray diffraction
YMRP	Yucca Mountain Review Plan

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NRC FORM 335 (12-2010) NRCMD 3.7 U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET** *(See instructions on the reverse)*	1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.) **NUREG-0544, Rev. 5**
2. TITLE AND SUBTITLE **Collection of Abbreviations**	3. DATE REPORT PUBLISHED MONTH: **December** YEAR: **2016**
	4. FIN OR GRANT NUMBER
5. AUTHOR(S) Caroline Hsu	6. TYPE OF REPORT
	7. PERIOD COVERED (Inclusive Dates)

8. PERFORMING ORGANIZATION - NAME AND ADDRESS (If NRC, provide Division, Office or Region, U. S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)

Division of Administrative Services
Office of Administration
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

9. SPONSORING ORGANIZATION - NAME AND ADDRESS (If NRC, type "Same as above", if contractor, provide NRC Division, Office or Region, U. S. Nuclear Regulatory Commission, and mailing address.)

Division of Administrative Services
Office of Administration
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

10. SUPPLEMENTARY NOTES

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11. ABSTRACT (200 words or less)

The U.S. Nuclear Regulatory Commission (NRC) has compiled this list of abbreviations commonly used by the agency staff, the regulatory community, and the nuclear industry. To create this list, the NRC staff sought to identify abbreviations that are so commonly used that some staff may not first define the term before using it either in writing or in speaking. This list of abbreviations is descriptive rather than prescriptive. In other words, this NUREG does not recommend one abbreviation to the exclusion of others. Nor does this NUREG intend to capture every abbreviation ever used in an NRC document. The audience of this NUREG is the public, stakeholders, industry, and NRC employees. The goal of this NUREG is to improve communication with and within the NRC.

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)	13. AVAILABILITY STATEMENT
Abbreviations Writing Plain Language Descriptive Acronyms Technical editing	unlimited
	14. SECURITY CLASSIFICATION
	(This Page) unclassified
	(This Report) unclassified
	15. NUMBER OF PAGES
	16. PRICE