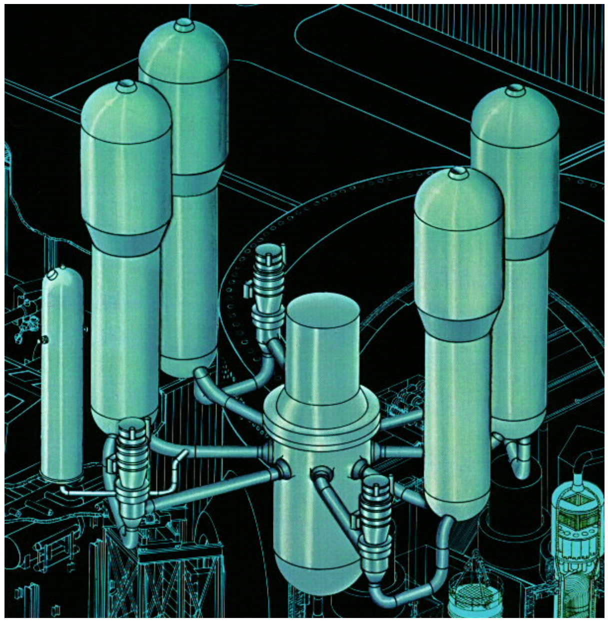


Westinghouse Advanced Technology Manual

Chapter 1 – Index & Acronyms

2020

HRTD Human Resources Training & Development
U.S.NRC UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

WESTINGHOUSE ADVANCED TECHNOLOGY COURSE R504P
Chapter Index with Objectives and ACRONYMS

1.0 INDEX WITH OBJECTIVES AND ACRONYMS

2.1 REPORTING REQUIREMENTS

Learning Objectives:

1. Recognize the purpose for reporting events under 10 CFR 50.72 and 10 CFR 50.73.

2. Identify the five types of reports required under 10 CFR 50.72.

3. Recognize the preferred method for making immediate notifications, alternate methods for making the reports and who receives the reports.

4. Recognize when ERDS is required to be initiated.

5. Distinguish between a valid and an invalid actuation of RPS and ESF systems.

2.2 REACTIVITY BALANCE CALCULATIONS

Learning Objectives:

1. Relate a change in a plant parameter to its effect on estimated critical rod position (ECP).

2. Relate a change in a plant parameter to its effect on estimated critical boron concentration.

3. Relate a change in a plant parameter to its effect on the value of shutdown margin.

2.3 TURBINE IMPULSE PRESSURE CHANNEL FUNCTIONS

Learning Objectives:

1. List the protection system inputs provided by the turbine impulse pressure channels.

2. List the control signals provided by both channels of turbine impulse pressure.

3. Explain the plant response for a given scenario involving the failure of a turbine impulse pressure channel.

2.4 TRANSIENT SCENARIOS

Learning Objectives:

1. Given a plant transient scenario, explain the behavior of selected plant parameters, control systems, and equipment for the time designated in the statement of the scenario.

3.1 ANALYSIS OF TECHNICAL SPECIFICATIONS - UNIT 1

Learning Objectives:

1. State the requirements for and briefly describe the categories included in technical specifications.

2. Demonstrate understanding of the meanings of all defined terms in the technical specifications by applying them correctly in operational scenarios.

3. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation..

4. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.

3.2 ANALYSIS OF TECHNICAL SPECIFICATIONS - UNIT 2

Learning Objectives:

1. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation.

2. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.

3.3 ANALYSIS OF TECHNICAL SPECIFICATIONS - UNIT 3

Learning Objectives:

1. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation.

2. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.

3. Use the design features section of technical specifications to determine required features of the plant.

4. Use the administrative control section of technical specification to determine requirements for given situations.

3.4 ANALYSIS OF TECHNICAL SPECIFICATIONS - UNIT 4

Learning Objectives:

1. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation.

2. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.

4.1 Maintenance of the Licensing and Design Bases

Learning Objectives:

1. Recognize the definition of the following terms:
   a. Design basis function
   b. Design basis values or bounding conditions
   c. Design basis supporting information
   d. Topical design bases
   e. Engineering design bases

2. Recognize how the facility specific design basis was established during the plant licensing process.

3. Recognize the relationship between the design bases and the final safety analysis report (FSAR).

4. Recognize the regulatory controls used to ensure the design bases are maintained over the life of the plant.

5. Recognize the purpose of the 10 CFR 50.59 Rule, “Changes, Tests and Experiments.”

6. Recognize the definition of the following terms as used in the 50.59 Process:

   a. Change
   b. Facility as described in the FSAR
   c. Procedure as described in the FSAR
   d. Test or Experiments not described in the FSAR
   e. Departure from a method of evaluation
   f. Accidents
   g. Conservative versus Non-conservative evaluation results

7. Recognize the criteria used to determine if the 50.59 Rule is applicable to a proposed change or activity.

8. Recognize the criteria used to determine if a proposed change or activity may be screened out from a 50.59 evaluation.

9. Recognize the 50.59 Rule evaluation criteria used in to determine if a licensee may implement a proposed change or activity without prior NRC approval.

4.2 STEAM GENERATOR TUBE RUPTURE

Learning Objectives:

1. Discuss why operator intervention is necessary to limit or prevent radiological releases during a steam generator tube rupture (SGTR) event.

2. Discuss the primary-side and secondary-side indications of an SGTR in the control room.

3. Discuss how the affected generator may be identified either prior to or following the reactor/turbine trip.

4. List the initial actions taken by the operator once the affected steam generator has been identified.

5. Discuss the actions required to stop the primary-to-secondary leakage.

6. Discuss the problems associated with the following:

    a. Secondary-to-primary leakage
    b. Steam generator overfill

7. List the principal systems/components affected by a loss of offsite power (LOOP).

8. Discuss how a plant cooldown and pressure control are accomplished with an SGTR and LOOP.

9. Discuss what affect the following events had on the SGTR transient at the Ginna plant:

    a. Tripping of the reactor coolant pumps
    b. Failure of a power-operated relief valve (PORV)
    c. Automatic operation of letdown valves
    d. Pressurizer relief tank failure
    e. Steam generator safety valve failure

4.3 ANTICIPATED TRANSIENT WITHOUT SCRAM (ATWS)

Learning Objectives:

1. Define the term “anticipated transient without scram” (ATWS).

2. Describe the limiting (most severe) ATWS case for a pressurized water reactor (PWR).

3. List three parameters or components that affect a plant’s sensitivity to an ATWS event.

4. Describe the modification made to the Westinghouse reactor trip breakers after the Salem ATWS.

5. State the functions of the ATWS mitigation system.

4.4 LOSS OF ALL AC POWER (STATION BLACKOUT)

Learning Objectives:

1. Define the term “station blackout.”

2. Describe the initial plant response to a station blackout.

3. Describe the requirements of the blackout rule (10 CFR 50.63).

4. Describe the requirements of 10 CFR 50.155 regarding extended station blackout.

5. Describe the accident sequence that makes the loss of all Alternating Current (AC) power a major contributor to the total core damage frequency at some reactor plants.

4.5 SHUTDOWN PLANT PROBLEMS

Learning Objectives:

1. State the purposes of the residual heat removal (RHR) system.

2. Describe the alignment and operation of the RHR system during its shutdown cooling mode of operation.

3. Describe the design features of the RHR system which could reduce its reliability when it is being used for decay heat removal.

4. Describe the consequences of losing decay heat removal capability when the reactor is in cold shutdown.

4.6 VOIDED PIPING CONCERNS

Learning Objectives:

1. Describe the causes of voided piping.

2. Describe the potential consequences of voided piping.

3. Describe licensee actions to minimize the consequences of voided piping.

5.0 WESTINGHOUSE FOUR-LOOP DESIGN TRANSIENTS

Learning Objectives:

1. Given a set of transient curves and Table 5-1, demonstrate an understanding of plant characteristics and control, protection, and safeguards systems by:

    a. Explaining why the parameter values are trending as shown at selected numbered portions of curves,
    b. Explaining plant effects caused by parameters reaching certain values at selected numbered points, and
    c. Explaining the cause(s) of the reactor trip and/or engineered safety features (ESF) actuation, if either occurs.

7.1 EVENTS THAT SHAPED THE NUCLEAR INDUSTRY

Learning Objectives:

1. Briefly discuss these events.
2. Explain the causes of the events.
3. Explain the safety implications of the events.
4. Explain what industry or regulatory changes occurred as a result of the events.

7.2 V. C. SUMMER INADVERTENT CRITICALITY

Learning Objectives:

1. Briefly discuss the V. C. Summer startup accident.
2. Explain the causes of the accident.
3. Explain the safety implications of the accident.
4. Explain what procedural limitations and administrative controls should have prevented this accident.

7.3 WATER HAMMER AT SAN ONOFRE

Learning Objectives:

1. Describe three types of water hammer and their causes.
2. Describe corrective actions that were taken to prevent previous steam generator water hammer problems.
3. Describe the damage caused by the water hammer event at San Onofre Nuclear Generating Station Unit 1 (SONGS-1).
4. Describe how multiple check valve failures contributed to the initiation of the water hammer at SONGS-1.
5. Discuss how check valve testing required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code could have prevented the SONGS-1

water hammer incident.

7.4 CORE DAMAGING EVENTS

Learning Objectives:

1. State how the following parameters respond to a stuck-open pilot-operated relief valve (PORV) following a reactor trip from 100% power:
   a. PORV tail-pipe temperature
   b. Reactor coolant system pressure
   c. Pressurizer level
   d. Reactor vessel level
2. State the significance of superheated conditions in the reactor coolant system.
3. State the key operator errors that contributed to core damage during the Three Mile Island (TMI) accident.
4. Describe the event that initiated the core damage sequence at TMI.
5. Discuss industry and regulatory changes that resulted from the accident at TMI.
6. Describe the differences in technology that make U.S. commercial reactors not susceptible to an event similar to the Chernobyl accident.
7. Recognize the sequence of events that led to fuel damage at Fukushima Dai-ichi.
8. Recognize the NRC regulatory response to the accident at Fukushima Dai-ichi.

Acronyms

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 damage 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	nonradiologically controlled area
NS	non-seismic
NSAL	Nuclear Service Advisory Letter
NSR	non-safety-related
NSSS	nuclear steam supply system
NUREG	NRC technical report designation - (Nuclear Regulatory Commission)
O-RAP	operational reliability assurance process

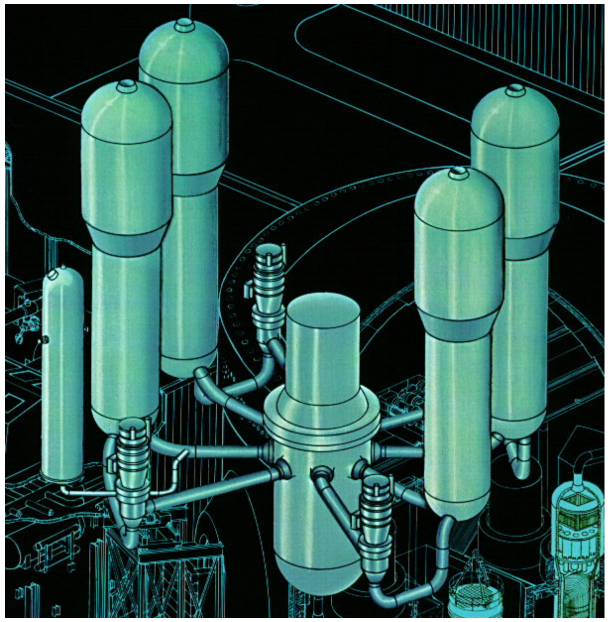
OBE	operating-basis earthquake
OCS	operation and control centers system
ODCM	offsite dose calculation manual
OECD	Organization for Economic Cooperation and Development
OER	operating experience review
OL	operating license
OM	operation and maintenance
OPDMS	on-line power distribution monitoring system
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 Advanced Technology Manual

Chapter 2.1 – Reporting Requirements

Reference read Only - 2020

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2.1 REPORTABILITY

Learning Objectives (Reference Read Only)

1. Recognize the purpose for reporting events under 10 CFR 50.72 and 10 CFR 50.73.

2. Identify the five types of reports required under 10 CFR 50.72.

3. Recognize the preferred method for making immediate notifications, alternate methods for making the reports and who receives the reports.

4. Recognize when ERDS is required to be initiated.

5. Distinguish between a valid and an invalid actuation of RPS and ESF systems.

2.1.1 Purpose

The purpose of the requiring licensees to report certain events is to help fulfill the NRC mission by aiding emergency response and providing feedback of operating experience into plant operations. These are achieved partly by the licensee event reporting requirements of Title 10 of the *Code of Federal Regulations*, Part 50, Sections 50.72 and 50.73 (10 CFR 50.72 and 50.73). Section 50.72 provides for immediate notification requirements via the emergency notification system (ENS) and Section 50.73 provides for 60-day written licensee event reports (LERs). Other regulations require event reporting including Standards for Protection Against Radiation (10 CFR Part 20), Reporting Defects and Non-Compliances (Part 21), Fitness for Duty Programs (10 CFR Part 26), Completeness and Accuracy of Information (10CFR50.9), Technical Specifications (10CFR50.36), Acceptance Criteria for ECCS (10CFR50.46), Licensing Requirements for ISFSI (10 CFR Part 72) and Physical Protection of Plants and Materials (10 CFR Part 73).

The information reported under 10 CFR 50.72 and 50.73 is used by the NRC staff in responding to emergencies, monitoring ongoing events, confirming licensing bases, studying potentially generic safety problems, assessing trends and patterns of operational experience, monitoring performance, identifying precursors of more significant events, and providing operational experience to the industry.

2.1.2 Overview

Each licensee must send information to NRC about certain "reportable events" that occur at their facility or during their use of nuclear materials. The NRC has issued NUREG-1022, Event Reporting Guidelines 10 CFR 50.72 and 10 CFR 50.73, to provide detailed guidance on what to report and how, for those events listed in the regulation.

The objectives of these rules are:

(1) To align the reporting requirements with the NRC's current reporting needs for information to carry out its safety mission.

(2) To reduce the unnecessary reporting burden, consistent with the NRC's reporting needs associated with events of little or no safety significance.

2.1.2.1 Immediate Notification Requirements for Operating Nuclear Power Plant (10CFR50.72)

The essential safety purposes for immediate reports made under 10 CFR 50.72 are to provide for immediate reporting of significant events where: (1) immediate NRC action may be required to protect the public health and safety, or (2) the NRC needs timely, accurate information to respond to heightened public concern. These reports are made to the Headquarters Operations Officer (HOO) using the Emergency Notification System. Reports range from immediate notifications of emergencies to non-emergency reports required to be made within a specified time frame (i.e., one-hour, four-hour or eight-hour reports).

The vast majority of event reports do not require activation of our incident response program. However, the NRC emergency preparedness programs enable emergency personnel to rapidly identify, evaluate, and react to a wide spectrum of emergencies, including those arising from terrorism or natural events such as hurricanes. The incident response program integrates the overall NRC capabilities for the response and recovery of radiological incidents and emergencies involving facilities and materials regulated by the NRC or an Agreement State. Under the National Response Framework, the NRC will coordinate with other Federal, State, and local emergency organizations in response to various types of domestic events. The NRC emphasizes the integration of safety, security, and emergency preparedness as the basis for the NRC's primary mission of protecting public health and safety.

2.1.2.2 Licensee Event Reports (10CFR50.73)

The essential safety purpose of licensee event reports required by 10 CFR 50.73 is to identify the types of events and problems believed to be significant and useful to the NRC's effort to identify and resolve threats to public health and safety. It is designed to provide information needed for engineering studies of anomalies, trend analysis of occurrences, and identification of accident precursors. This enables the

NRC to determine whether further action is needed to maintain or improve reactor safety.

Licensee Event Reports (LERs) are detailed reports submitted to NRC within 60 days of a plant abnormality in accordance with 10 CFR 50.73. These reports contain root causes and corrective actions undertaken by licensees. The reported events are reviewed at NRC Headquarters by a group of technical experts using plant specific risk insights and operating experience to identify significant weaknesses in plant design, operation, or equipment. Some plant abnormalities that are not of a significant nature are reported only through LERs. When problem areas are identified, the NRC coordinates the appropriate level of inspections with the regional offices to reach a satisfactory resolution. In certain cases, these reported events are addressed through generic communications to the industry and other interested or potentially affected parties and are made available to the public through the NRC's public web site. The reports that address a major deficiency in design or construction, major degradation of essential safety-related equipment, or moderate release or exposure to radioactive material are forwarded to the NRC Office of Research for inclusion in the annual Report to Congress on Abnormal Occurrences.

2.1.2.3 Emergency Notification System (ENS)

Each commercial nuclear power reactor facility has ENS telephones. These telephones are located in each licensee's control room, technical support center (TSC), and emergency operations facility (EOF). A separate ENS line is installed at EOFs which are not onsite. The ENS is part of the Federal Telecommunications System (FTS) and provides a direct link from the utility to the Headquarters Operations Officer in the NRC Operations Center.

If the Emergency Notification System is inoperative, the licensee shall make the required notifications via commercial telephone service, other dedicated telephone system, or any other method which will ensure that a report is made as soon as practical to the NRC Operations Center. Typically, each utility will have multiple means of communication and their emergency response plan will establish the priority that each is used. These alternate means of communication may include commercial phone lines, cellular phones, satellite phones and/or radio links to other facilities where communications can be relayed to the NRC Operations Center.

The NRC Operations Center is the nucleus of the ENS and has the capability to handle emergency communication needs. The NRC's response to both emergencies and non-emergencies is coordinated in this communication center. The key NRC emergency communications personnel, the emergency officer (EO), regional duty officer (RDO), and the headquarters operations officer (HOO), are trained to notify appropriate NRC personnel and to focus appropriate NRC management attention on any significant event.

The NRC records all conversations with the NRC Operations Center. The tape is saved for a month in case there is a public or private inquiry. During an emergency the NRC may request the licensee to remain on the phone for improved communication.

At the time of an ENS notification, the NRC must independently assess the status of the reactor to determine if it is in a safe condition and expected to remain so. The HOO needs to understand the safety significance of each event to brief NRC management or initiate an NRC response. The HOO will be primarily concerned about the safety significance of the event, the current condition of the plant, and the possible near-term effects the event could have on plant safety. The HOO will attempt to obtain as complete a description as possible at the time of the notification of the event or condition, its causes, and its effects.

The licensee's first responsibility during a transient is to stabilize the plant and keep it safe. However, licensees should not delay declaring an emergency class when conditions warrant because delaying the declaration can defeat the appropriate response to an emergency. Because of the safety significance of a declared emergency, time is of the essence. The NRC needs to become aware of the situation as soon as practical to activate the NRC Operations Center and the appropriate NRC regional incident response center, as necessary, and to notify other Federal agencies.

The effectiveness of the NRC response during an event depends largely on complete and accurate reporting from the licensee. During an emergency, the appropriate regional incident response center and the NRC Operations Center become focal points for NRC action. Licensee actions during an emergency are monitored by the NRC to ensure that appropriate action is being taken to protect the health and safety of the public. When required, the NRC supports the licensee with technical analysis and coordinates logistics support. The NRC keeps other Federal agencies informed of the status of an incident and provides information to the media. In addition, the NRC assesses and, if necessary, confirms the appropriateness of actions recommended by the licensee to local and State authorities.

It is the licensee's responsibility to ensure that adequate personnel, knowledge about plant conditions and emergency plan implementing procedures, are available on shift to assist the shift supervisor to classify an emergency and activate the emergency plan, including making appropriate notifications, without interfering with plant operation. When 10 CFR 50.72 was published, the NRC made clear its intent in the Statements of Consideration that notifications on the ENS to the NRC

Operations Center should be made by those knowledgeable of the event. If the description of any emergency is to be sufficiently accurate and timely to meet the intent of the NRC's regulations, the personnel responsible for notification must be properly trained and sufficiently knowledgeable of the event to report it correctly.

2.1.2.4 Emergency Response Data System (ERDS)

The Emergency Response Data System (ERDS) is a direct near real-time electronic data link between the licensee's onsite computer system and the NRC Operations Center that provides for the automated transmission of a limited data set of selected parameters. The ERDS supplements the existing voice transmission over the Emergency Notification System (ENS) by providing the NRC Operations Center with timely and accurate updates of a limited set of parameters from the licensee's installed onsite computer system in the event of an emergency.

ERDS is required as part of each licensee’s Emergency Response Plan (10 CFR 50, Appendix E) and is required to be activated within one hour of declaring an Alert emergency declaration or above (10 CFR 50.72).

The Commission has defined the NRC's primary role in an emergency at a licensed nuclear facility as one of monitoring the licensee to assure that appropriate recommendations are made with respect to offsite protective actions. Other aspects of the NRC’s role include supporting the licensee with technical analysis and logistic support, supporting offsite authorities, including confirming the licensee's recommendations to offsite authorities, keeping other Federal agencies and entities informed of the status of the incident, and keeping the media informed of the NRC's knowledge of the status of the incident.

To fulfill the NRC's role, the NRC requires accurate, timely data on four types of parameters: (1) core and coolant system conditions must be known well enough to assess the extent or likelihood of core damage; (2) conditions inside the containment building must be known well enough to assess its status; (3) radioactivity release rates must be available promptly to assess the immediacy and degree of public danger by these pathways; and (4) the data from the plant's meteorological tower is necessary to provide insight into the potential distribution of a release.

For boiling water reactors (BWRs), the selected parameters are: (1) Reactor coolant system: Reactor pressure, reactor vessel level, feedwater flow, and reactor power; (2) Safety injection: Reactor core isolation cooling flow, high-pressure coolant injection/high-pressure core spray flow, core spray flow, low-pressure coolant injection flow, and condensate storage tank level; (3) Containment: drywell pressure, drywell temperatures, drywell sump levels, hydrogen and oxygen concentrations, suppression pool temperature, and suppression pool level; (4) Radiation monitoring system: Reactor coolant radioactivity level, primary containment radiation level, condenser off-gas radiation level, effluent radiation monitor, and process radiation levels; and (5) Meteorological data: Wind speed, wind direction, and atmospheric stability. Table 4.14-1 provides a typical listing of parameters transmitted by ERDS for BWRs.

2.1.2.5 Valid Actuation

Valid ESF actuations are those actuations that result from "valid signals" or from intentional manual initiation, unless it is part of a preplanned test. Valid signals are those signals that are initiated in response to actual plant conditions or parameters satisfying the requirements for initiation of the safety function of the system. Invalid actuations are, by definition, those that do not meet the criteria for being valid. In other words, a valid actuation is one that occurs as a result of the measured process parameter exceeding its setpoint. An example of a valid actuation would be when an emergency diesel starts on an actual undervoltage on the safety bus. An invalid actuation would be if the same diesel started due to a failure of a relay and no actual undervoltage on the safety bus was present. Another example of a valid actuation of RPS is when actual reactor power exceeded the APRM setpoint, whereas an invalid actuation would be spiking of an APRM with another APRM in trip (and no actual high flux existed).

Except for critical scrams, invalid actuations are not reportable by telephone under 10CFR50.72. In addition, invalid actuations are not reportable under 10CFR50.73 in any of the following circumstances:

(A) The invalid actuation occurred when the system is already properly removed from service. This means all requirements of plant procedures for removing equipment from service have been met. It includes required clearance documentation, equipment and control board tagging, and properly positioned valves and power supply breakers.

(B) The invalid actuation occurred after the safety function has already been completed. An example would be RPS actuation after the control rods have already been inserted into the core.

If an invalid ESF actuation reveals a defect in the ESF system so the system failed or would fail to perform its intended function, the event continues to be reportable under other requirements of 10CFR50.72 and 50.73. When invalid ESF actuations excluded by the conditions described above occur as part of a reportable event, they should be described as part of the reportable event, in order to provide a complete, accurate and thorough description of the event

2.1.3 Immediate Reports

10 CFR 50.72 requires telephone reports to be made to the Headquarters Operations Officer (HOO) via the Emergency Notification System for specific events and conditions where immediate NRC action may be required, or the NRC needs timely information to respond to heightened public concern.

The non-emergency reports contain a time requirement for reporting. Specifically, these reports are made as soon as practical and in all cases within one, four or eight hours of occurrence of the event that meets the criteria of the regulation as clarified in NUREG 1022. For events that are not on-going, the reporting clock starts at the time of discovery. If more than one criterion for reporting is met during an event, a single notification can be made which includes all the reporting criteria.

Licensees typically implement this regulation using an administrative procedure which lists the reporting criteria and assigns responsibility for reporting with the Shift Manager. In general, if it is not clear if the event meets the criteria for reporting, the on-shift personnel will make the report. If a licensee makes a 10 CFR 50.72 ENS notification and later determines that the event or condition was not reportable, the licensee should call the NRC Operations Center on the ENS telephone to retract the notification and explain the rationale for that decision. There is no set time limit for ENS telephone retractions. However, since most retractions occur following completion of engineering and/or management review, it is expected that retractions would occur shortly after such review.

Although not required under the regulation, the NRC has provided an ENS Event Notification Worksheet (NRC Form 361) which provides the usual order of questions and discussion for easier communication and its use often enables a licensee to prepare answers for a more clear and complete notification. Table 4.14-2 is a copy of the form. Licensees may obtain an event number and notification time from the HOO when the ENS notification is made.

Clear, complete and accurate ENS notification helps the HOO to understand the safety significance of the event. Licensees should use proper names for systems and components, as well as their alphanumeric identifications during ENS notifications. Licensees should avoid using local jargon for plant components, areas, operations, and the like so that the HOO can quickly understand the situation and have fewer questions and others not familiar with the plant can more readily understand the situation.

Specific reporting criteria are discussed below.

2.1.3.1 Emergency Reports

The licensee shall notify the NRC **immediately** after notification of the appropriate state or local agencies and **not later than one hour** after the time the licensee declares one of the Emergency Classes. Time frames specified for notification in 10 CFR 50.72(a) use the words "immediately" and "not later than one hour" to ensure the Commission can fulfill its responsibilities during and following the most serious events. Follow-up notifications for changes in emergency level or effectiveness of actions are discussed later in this chapter.

Occasionally, a licensee discovers that a condition existed which met the emergency plan criteria, but no emergency was declared and the basis for the emergency class no longer exists at the time of this discovery. This may be due to a rapidly concluded event or an oversight in the emergency classification made during the event or it may be determined during a post-event review. Frequently, in cases of this nature, which were discovered after the fact, licensees have declared the emergency class, immediately terminated the emergency class and then made the appropriate notifications. However, the NRC staff does not consider actual declaration of the emergency class to be necessary in these circumstances; an ENS notification within one hour of the discovery of the undeclared (or miss-classified) event provides an acceptable alternative.

2.1.3.2 One-Hour Non-Emergency Report

2.1.3.2.1 Licensee Invokes 10CFR50.54(x)

If not reported as a declaration of an Emergency, the licensee shall notify the NRC as soon as practical and in all cases within one hour of the occurrence of any deviation from the plant's Technical Specifications authorized pursuant to 10 CFR 50.54(x). 10 CFR 50.54(x) allows a licensee to take reasonable action that departs from a license condition or a technical specification in an emergency when this action is immediately needed to protect the public health and safety and no action consistent with license conditions and technical specifications that can provide adequate or equivalent protection is immediately apparent. The decision to invoke 10 CFR 50.54(x) must be approved by a licensed senior reactor operator.

Although rarely required, 10CFR50.54(x) has been used to suspend portions of the station’s security plan during hurricanes and to reduce the fire brigade below required staffing levels to allow the brigade to respond to an offsite fire.

2.1.3.3 Four-Hour Non-Emergency Reports

2.1.3.3.1 Initiation of Shutdown Required by Technical Specifications

This reporting requirement is intended to capture those events for which TS require the initiation of reactor shutdown to provide the NRC with early warning of safety significant conditions serious enough to warrant that the plant be shut down. The phrase "initiation of any nuclear plant shutdown" includes action to start reducing reactor power (i.e., adding negative reactivity) and does not include mode changes required by TS if initiated after the plant is already in a shutdown condition.

The corresponding requirement for a written report under 10 CFR 50.73 is the completion of a shutdown required by TS.

2.1.3.3.2 ECCS Discharge into the RCS

Licensees are required to report any event that results or should have resulted in emergency core cooling system (ECCS) discharge into the reactor coolant system as a result of a **valid** signal except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation. This includes both automatic and manual actuation.

One example would be if HPCI actuated and injected into the RCS on a Level 2 signal following a scram.

2.1.3.3.3 RPS Actuation while Critical

Licensees are required to report any event or condition that results in actuation of the reactor protection system (RPS) when the reactor is critical except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation. Again, this applies to both manual and automatic actuations, but **it does not necessarily require a valid actuation**.

2.1.3.3.4 News Release or Notification to Other Government Agency

Licensees are required to report any event or situation, related to the health and safety of the public or on-site personnel, or protection of the environment, for which a news release is planned or notification to other government agencies has been or will be made. Such an event may include an on-site fatality or inadvertent release of radioactively contaminated materials.

The purpose of this criterion is to ensure the NRC is made aware of issues that will cause heightened public or government concern related to the radiological health and safety of the public or on-site personnel or protection of the environment. For the case of an event for which a news release is planned, the purpose of the report is to provide timely and accurate information so the NRC can respond to heightened public concern. Accordingly, it makes sense to provide the report prior to the time the news release is issued.

Licensees typically issue press releases or notify local, county, State or Federal agencies on a wide range of topics that are of interest to the general public. The NRC Operations Center does not need to be made aware of every press release made by a licensee. Licensees generally do not have to report media and government interactions unless they are related to the radiological health and safety of the public or onsite personnel, or protection of the environment.

For example, the NRC does not generally need to be informed under this criterion of:

- minor deviations from sewage or chlorine effluent limits
- minor non-radioactive, onsite chemical spills
- minor oil spills
- problems with plant stack or water tower aviation lighting
- peaceful demonstrations
- routine reports of effluent releases to other agencies
- releases of water from dams associated with the plant

Since the purpose of this type of report is to make the NRC aware of breaking issues, an LER is not required to be submitted as a result (unless it meets some other criteria for reporting).

2.1.3.4 Eight-Hour Non-Emergency Report

2.1.3.4.1 Serious Degradation of Safety Barriers or Unanalyzed Condition

Licensees are required to report any event or condition that results in the condition of the nuclear power plant, including its principal safety barriers, being seriously degraded; or the nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.

For the criteria of a nuclear power plant, including its principal safety barriers, being seriously degraded, applies to material (e.g., metallurgical or chemical) problems that cause abnormal degradation of or stress upon the principal safety barriers (i.e., the fuel cladding, reactor coolant system pressure boundary, or the containment). Examples include:

- Fuel cladding failures in the reactor, or in the storage pool, that exceed expected values, or that are unique or widespread, or that are caused by unexpected factors.
- Welding or material defects in the primary coolant system.
- Low temperature over pressure transients where the pressure-temperature relationship violates pressure-temperature limits.
- Loss of containment function or integrity.

For an unanalyzed condition that significantly affects plant safety, the licensee should use engineering judgment and experience to determine whether an unanalyzed condition existed. It is not intended that this paragraph apply to minor variations in individual parameters, or to problems concerning single pieces of equipment. For example, small voids in systems designed to remove heat from the reactor core which has been previously shown through analysis not to be safety significant need not be reported. However, the accumulation of voids that could inhibit the ability to adequately remove heat from the reactor core would constitute an unanalyzed condition and would be reportable. Another example would be if fire barriers are found to be missing, such that the required degree of separation for redundant safe shutdown trains is lacking, the event would be reportable as an unanalyzed condition that significantly degraded plant safety. On the other hand, if a fire wrap, to which the licensee has committed, is missing from a safe shutdown train but another safe shutdown train is available in a different fire area, was protected such that the required separation for safe shutdown trains is still provided, the event would not be reportable.

2.1.3.4.2 Valid Safety System Actuations

Licensees are required to report any event or condition that results in **valid** actuation of specific systems listed except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation. The systems listed include:

- RPS
- Containment isolation signals affecting containment isolation valves in more than one system or multiple main steam isolation valves (MSIVs).
- Emergency core cooling systems including high-pressure and low-pressure core spray systems; high-pressure coolant injection system; low pressure injection function of the residual heat removal system.
- Reactor core isolation cooling system; isolation condenser system; and feedwater coolant injection system.
- Containment heat removal and depressurization systems, including containment spray and fan cooler systems.
- Emergency ac electrical power systems, including: emergency diesel generators (EDGs); and BWR dedicated Division 3 EDGs.

This criterion requires events to be reported whenever one of the specified systems actuates either manually or automatically. It is based on the premise that these systems are provided to mitigate the consequences of a significant event and, therefore: (1) they should work properly when called upon, and (2) they should not be challenged frequently or unnecessarily. The Commission is interested both in events where a system was needed to mitigate the consequences of an event (whether or not the equipment performed properly) and events where a system actuated unnecessarily.

The intent is to require reporting actuation of systems that mitigate the consequences of significant events. Usually, the staff would not consider this to include single component actuations because single components of complex systems, by themselves, usually do not mitigate the consequences of significant events. Single trains do mitigate the consequences of events, and, thus, train level actuations are reportable. This includes actuation of a diesel-generator which is considered to be an actuation of a train, not actuation of a single component.

2.1.3.4.3 Loss of Safety Function

Licensees are required to report any event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident. However, individual component failures need not be reported if redundant equipment in the same system was operable and available to perform the required safety function.

The level of judgment for reporting an event or condition under this criterion is a reasonable expectation of preventing fulfillment of a safety function. The intent of these criteria is to capture those events where there would have been a failure of a safety system to properly complete a safety function, regardless of whether there was an actual demand. For example, if the core spray system (both trains) failed, the event would be reportable even if there was no demand for the system's safety function.

There are a limited number of single-train systems that perform safety functions (e.g., the High Pressure Coolant Injection System in BWRs). For such systems, loss of the single train would prevent the fulfillment of the safety function of that system and, therefore, is reportable even though the plant technical specifications may allow such a condition to exist for a limited time.

It should also be noted that the NRC uses the number of safety system function failures in the previous four quarters as one of the Performance Indicators used in the Reactor Oversight Process to monitor plant performance.

2.1.3.4.4 Transport of Potentially Contaminated Personnel Offsite

Licensees are required to report any event requiring the transport of a radioactively contaminated person to an offsite medical facility for treatment. The phrase "radioactively contaminated" refers to either radioactively contaminated clothing and/or person. If there is a potential for contamination (e.g., an initial onsite survey for radioactive contamination is required but has not been completed before transport of the person off site for medical treatment) the licensee should make an ENS notification.

As with the requirement for reporting news releases, the NRC needs to be aware of events that cause heightened public or government concern related to the radiological health and safety of the public or on-site personnel. Similar to the criterion for news releases, following the initial event there is no need for a follow-on LER.

2.1.3.4.5 Major Loss of Emergency Assessment, Response Capability or Communications

Licensees are required to report any event that results in a major loss of emergency assessment capability, offsite response capability, or offsite communications capability (e.g., significant portion of control room indication, Emergency Notification System, or offsite notification system).

This reporting requirement pertains to events that would impair a licensee's ability to deal with an accident or emergency. Notifying the NRC of these events may permit the NRC to take some compensating measures and to more completely assess the consequences of such a loss should it occur during an accident or emergency.

Examples of events that this criterion is intended to cover are those in which any of the following is not available:

- Emergency Assessment Capabilities
  - safety parameter display system (SPDS)
  - primary emergency response facilities (ERFs)
  - plant monitors necessary for accident assessment
- Offsite Response Capabilities
  - public prompt notification system(s) including sirens (primary system)
- Offsite Communication Capabilities

– ENS, ENS and HPN
– other emergency communications facilities and equipment used between the licensee's onsite and offsite ERFs, and between the licensee and offsite officials

In general, the licensee will establish specific thresholds which constitute a "major loss". For example, a loss of only the SPDS for a short period of time need not be reported, but loss of SPDS and other assessment equipment at the same time may be reportable. Another example would be the loss of a single siren for a short time is not a major loss of offsite response capability, however the loss of a large number of sirens, other alerting systems (e.g., tone alert radios), or more importantly, the lost capability to alert a large segment of the population would warrant an immediate notification.

A major loss of communications capability includes those events that would significantly impair the ability of the licensee to implement the functions of its emergency plans if an emergency were to occur. The failure of a single communication system need not be reported if there are viable alternative methods of communicating information about the emergency. Each site's communications system will be different, and the significance of the loss of any one communication system may differ from site to site. This reporting requirement is intended to apply to serious conditions during which the telecommunications system can no longer fulfill the communications requirements of the emergency plan.

This criterion also includes instances where a significant natural hazard (e.g., earthquake, hurricane, tornado, flood, etc.) or other event causes evacuation routes to be impassible or other parts of the response infrastructure to be impaired to the extent that the State and local governments are rendered incapable of fulfilling their responsibilities in the emergency plan for the plant.

2.1.3.5 Follow-up Reports

Following the initial notification, the licensee should conduct follow-up notifications if there is any further degradation in the level of safety of the plant or other worsening plant conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made, or any change from one Emergency Class to another, or a termination of the Emergency Class.

In addition, the licensee should report the results of ensuing evaluations or assessments of plant conditions, the effectiveness of response or protective measures taken, and information related to plant behavior that is not understood.

These criteria are intended to provide the NRC with timely notification when an event becomes more serious or additional information or new analyses clarify an event. They also permit the NRC to maintain a continuous communications channel because of the need for continuing follow-up information or because of telecommunications problems.

2.1.4 Licensee Event Reports

The purpose of licensee event reports is to identify events and problems believed to be significant and useful to the NRC's effort to identify and resolve threats to public health and safety and to determine whether further action is needed to maintain or improve reactor safety.

LERs are required to be submitted within 60 days of the discovery of a reportable event. Many reportable events are discovered when they occur. However, if the event is discovered at some later time, the discovery date is when the reportability clock starts under 10 CFR 50.73.

LERs are submitted using a standard report format as described in NUREG 1022 on Form 366. Table 4.14-3 is a copy of the form. If a licensee submits a 10 CFR 50.73 LER and later determines that the event or condition was not reportable, the licensee should cancel it. Cancellations of LERs should be made by letter. The letter should state that the LER is being canceled (i.e., formally withdrawn). The bases for the cancellation should be explained so that the staff can understand and review the reasons supporting the determination.

In the case of an invalid actuation of safety systems reported under § 50.73(a)(2)(iv), other than actuation of the reactor protection system (RPS) when the reactor is critical, the licensee may, at its option, provide a telephone notification to the NRC Operations Center within 60 days after discovery of the event instead of submitting a written LER.

It should be noted that all LERs are inspected by the resident inspectors under Inspection Procedure 71153, Follow-up of Events and Notices of Enforcement Discretion, and formally closed out in their quarterly inspection reports.

The following sections contain a discussion on LER reporting criteria as compared with immediate notification criteria contained in 10 CFR50.72.

2.1.4.1 Immediate Reports Requiring an LER

A summary listing of immediate report criteria and the associated LER report criteria are provided in Table 4.14-4 and are not repeated here.

The immediate report required for the initiation of a shutdown required by Technical Specifications has a corresponding LER criterion of completion of a shutdown required by TS. Therefore, if the condition requiring the shutdown was corrected before achieving Mode 3, an LER is not required to be submitted.

2.1.4.2 Immediate Reports Not Requiring an LER

Several criteria for making immediate notifications involve informing the NRC of events which could create heightened public awareness so that the NRC is prepared to respond “real-time”. These reports generally (unless they meet some other criteria) do not require an LER since the event has passed. These criteria are listed in Table 4.14-4 and include:

- Planned news release
- Notification of other government agencies
- Transport of potentially contaminated person offsite
- Loss of emergency preparedness capability

2.1.4.3 LERs with No Corresponding Immediate Report

These criteria are also listed in Table 4.14-4. In general, these criteria either did not pose an immediate risk to public health and safety or if they had, would have been reportable under another criterion of 10 CFR 50.72.

The most frequent criteria in this category are **conditions prohibited by Technical Specifications**. Licensees are required to submit an LER for any operation or condition which was prohibited by the plant's Technical Specifications except when the Technical Specification is administrative in nature; the event consisted solely of a case of a late surveillance test where the oversight was corrected, the test was performed, and the equipment was found to be capable of performing its specified safety functions; or the Technical Specification was revised prior to discovery of the event such that the operation or condition was no longer prohibited at the time of discovery of the event.

An LER is required if a condition existed for a time longer than permitted by the technical specifications (i.e., greater than the allowed outage time) even if the condition was not discovered until after the allowable time had elapsed and the condition was rectified immediately upon discovery. For Technical Specification operability, the allowed outage time begins on discovery. For reportability, if there is firm evidence that the component was inoperable before discovery, then that is the time the allowed outage time clock starts. For example, if a diesel fails during testing and the cause was due to a faulty governor installed several months ago, the operators will declare the diesel inoperable at time of failure, but because of the firm evidence, it would have become inoperable when the governor was replaced and therefore would be reportable.

As discussed above, discrepancies found in technical specifications surveillance tests should be assumed to occur at the time of the test unless there is firm evidence, based on a review of relevant information (e.g., the equipment history and the cause of failure) to indicate that the discrepancy occurred earlier. However, the existence of similar discrepancies in multiple components is an indication that the discrepancies may well have arisen over a period of time and the failure mode should be evaluated to make this determination. For example, if several safety valves fail their lift setpoint tests during an outage, it can be assumed that at least some of the failures occurred before the outage (prior to discovery) and therefore would be reportable as a condition prohibited by Technical Specifications.

Other criteria for which an LER is required and there is no directly related immediate report include:

- Any **natural phenomenon** or other external condition that posed an **actual threat** to the safety of the nuclear power plant or significantly **hampered site personnel** in the performance of duties necessary for the safe operation of the nuclear power plant.

- Any event where a **single cause** or condition caused at least **one independent train or channel to become inoperable in multiple systems or two independent trains or channels to become inoperable in a single system** designed to:
  (A) Shut down the reactor and maintain it in a safe shutdown condition;
  (B) Remove residual heat;
  (C) Control the release of radioactive material; or
  (D) Mitigate the consequences of an accident.

- Any **airborne radioactive release** that, when averaged over a time period of 1 hour, resulted in airborne radionuclide concentrations in an unrestricted area that exceeded 20 times the applicable concentration limits specified in appendix B to part 20, table 2, column 1.

- Any **liquid effluent release** that, when averaged over a time period of 1 hour, exceeds 20 times the applicable concentrations specified in appendix B to part 20, table 2, column 2, at the point of entry into the receiving waters (i.e., unrestricted area) for all radionuclides except tritium and dissolved noble gases.

- Any event or condition that as a result of a **single cause** could have prevented the fulfillment of a safety function for **two or more trains or channels in different systems** that are needed to:
  (1) Shut down the reactor and maintain it in a safe shutdown condition;
  (2) Remove residual heat;
  (3) Control the release of radioactive material; or
  (4) Mitigate the consequences of an accident.

  However, licensees are not required to report an event pursuant this section if the event results from:
  (1) A shared dependency among trains or channels that is a natural or expected consequence of the approved plant design; or
  (2) Normal and expected wear or degradation.

- Any event that posed an actual threat to the safety of the nuclear power plant or significantly **hampered site personnel** in the performance of duties necessary for the safe operation of the nuclear power plant including **fires, toxic gas releases, or radioactive releases**.

2.1.5 Other Event Reports Required by Regulation

There are numerous other regulations that require the licensee to notify the NRC within a specified time period following events by telephone and/or through a written report. These reporting criteria are typically listed in the same administrative procedure for 10 CFR 50.72 reports and the shift manager is response for making the reports when less than 24 hours is allowed. Although they do not necessarily require phone reports to be made on the ENS, most licensees use the system for these reports. Likewise, many of the written reports required by these regulations are submitted on the LER Form 366. A summary of these reporting requirements is provided in Table 4.14-5. The following sections provide a brief summary of some of the more common reporting criteria.

2.1.5.1 Standards for Protection against Radiation (Part 20)

10 CFR Part 20 provides regulations governing reporting of events that include **radiological exposures, contamination and releases**. A summary of the criteria is listed below:

<u>Immediate notifications</u>

- (20.1906) The licensee shall immediately notify the final delivery carrier and the NRC Operations Center (301-816-5100), by telephone, when (1) Removable radioactive surface contamination exceeds the limits or (2) External radiation levels exceed the limits

- (20.2201) Immediately after its occurrence becomes known to the licensee, any lost, stolen, or missing licensed material in an aggregate quantity equal to or greater than 1,000 times the quantity specified in appendix C to part 20 under such circumstances that it appears to the licensee that an exposure could result to persons in unrestricted areas
- (20.2202) Immediately report any event involving byproduct, source, or special nuclear material possessed by the licensee that may have caused or threatens to cause any of the following conditions
    - An individual to receive (i) A total effective dose equivalent of 25 rems or more; or (ii) A lens dose equivalent of 75 rems or more; or (iii) A shallow-dose equivalent to the skin or extremities of 250 rads or more; or
    - The release of radioactive material, inside or outside of a restricted area, so that, had an individual been present for 24 hours, the individual could have received an intake five times the annual limit on intake

<u>Twenty-four hour notification</u>

- (20.2202) Report any event involving loss of control of licensed material that may have caused, or threatens to cause, any of the following conditions:
    - An individual to receive, in a period of 24 hours (i) A total effective dose equivalent exceeding 5 rems; or (ii) A lens dose equivalent exceeding 15 rems; or (iii) A shallow-dose equivalent to the skin or extremities exceeding 50 rems
    - The release of radioactive material, inside or outside of a restricted area, so that, had an individual been present for 24 hours, the individual could have received an intake in excess of one occupational annual limit on intake

<u>30 day reports</u>

- Reports of exposures, radiation levels, and concentrations of radioactive material exceeding the constraints or limits

  (1) Any incident for which notification is required by § 20.2202; or

  (2) Doses in excess of any of the following:
    - The occupational dose limits for adults, minors, an embryo/fetus of a declared pregnant woman, an individual member of the public,
    - Any applicable limit in the license; or
    - ALARA constraints for air emissions

  (3) Levels of radiation or concentrations of radioactive material in a restricted area in excess of any applicable limit in the license; or an unrestricted area in excess of 10 times any applicable limit set forth in this part or in the license; or
- Planned special exposures
- Occurrence of any lost, stolen, or missing licensed material becomes known to the licensee, all licensed material in a quantity greater than 10 times the quantity specified in appendix C to Part 20 that is still missing at this time.

2.1.5.2 Reporting Defects and Non-Compliances (Part 21)

10 CFR Part 21 provides guidance on reporting **defects and non-compliances in parts or components** used in nuclear power plants.

It requires that any individual director or responsible officer of a firm constructing, owning, operating or supplying the components of any facility or activity who obtains information reasonably indicating that the facility, activity, or **basic component** supplied to such facility or activity contains **defects**, which could create a **substantial safety hazard**, to **immediately notify** the Commission of such failure to comply or such defect, unless he has actual knowledge that the Commission has been adequately informed of such defect or failure to comply.

Initial notification should be by facsimile, which is the preferred method of notification, to the NRC Operations Center at (301) 816 - 5151 or by telephone at (301) 816 - 5100 within **two days** following receipt of information by the director or responsible corporate officer on the identification of a defect or a failure to comply.

Deviations and failures to comply shall be evaluated to identify defects and failures to comply associated with substantial safety hazards as soon as practicable, and, in all cases within **60 days of discovery**, in order to identify a reportable defect or failure to comply that could create a **substantial safety hazard**, were it to remain uncorrected.

A ***basic component*** means a structure, system, or component, or part thereof that affects its safety function necessary to assure:

(A) The integrity of the reactor coolant 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 offsite exposures comparable to those referred to in §50.34(a)(1), §50.67(b)(2), or §100.11 of this chapter, as applicable

Substantial safety hazard means a loss of safety function to the extent that there is a major reduction in the degree of protection provided to public health and safety for any facility or activity licensed or otherwise approved or regulated by the NRC

Defect means:

(1) A deviation in a basic component delivered to a purchaser for use in a facility or an activity subject to the regulations in this part if, on the basis of an evaluation, the deviation could create a **substantial safety hazard**;

(2) The installation, use, or operation of a basic component containing a defect;

(3) A deviation in a portion of a facility provided the deviation could, on the basis of an evaluation, create a **substantial safety hazard** and the portion of the facility containing the deviation has been offered to the purchaser for acceptance;
(4) A condition or circumstance involving a basic component that could contribute to the **exceeding of a safety limit**; or
(5) An error, omission or other circumstance in a design certification, or standard design approval that, on the basis of an evaluation, could create a **substantial safety hazard**.

Although reports made under Part 21 typically originate from the suppliers of components or services, licensees are required to evaluate such defects and ensure they are reported if they meet the requirements for reporting.

2.1.5.3 Fitness for Duty Programs (Part 26)

10 CFR Part 26 provides guidance on reporting deficiencies in and violations of the licensee's fitness for duty (FFD) program. FFD program ensures that individuals are free from the influence of alcohol or drug and are not overly fatigued. Some aspects apply to all individuals with unescorted access whereas others only to those employees that perform safety related tasks. A summary of reporting criteria in Part 26 follows.

<u>24-hour Reports</u>

(1) The use, sale, distribution, possession, or presence of illegal drugs, or the consumption or presence of alcohol within a protected area;

(2) Any acts by any person licensed under 10 CFR parts 52 and/or 55 to operate a power reactor (i.e. licensed operators), if such acts:

   a. Involve the use, sale, or possession of a controlled substance;

   b. Result in a determination that the individual has violated the licensee's or other entity's FFD policy (including subversion); or

   c. Involve the consumption of alcohol within a protected area or while performing the duties that require the individual to be subject to the FFD program;

(3) Any intentional act that casts doubt on the integrity of the FFD program; and

(4) Any programmatic failure, degradation, or discovered vulnerability of the FFD program that may permit undetected drug or alcohol use or abuse by individuals within a protected area, or by individuals who are assigned to perform duties that require them to be subject to the FFD program.
(5) false positive error occurs on a blind performance test sample submitted to an

HHS-certified laboratory

(6) false negative error occurs on a quality assurance check of validity screening tests

30 Day Report

Testing errors or unsatisfactory performance discovered in performance testing at either a licensee testing facility or an HHS-certified laboratory, in the testing of quality control or actual specimens, or through the processing of reviews and MRO reviews, as well as any other errors or matters that could adversely reflect on the integrity of the random selection or testing process.

2.1.5.4 Completeness and Accuracy of Information (10 CFR 50.9)

10 CFR 50.9 requires that information provided to the Commission by a licensee or information required by statute or by the Commission's regulations, orders, or license conditions to be maintained by the applicant or the licensee shall be **complete and accurate** in all material respects.

If the licensee identifies information that was submitted that was not complete and/or accurate and it has a significant implication for public health and safety or common defense and security, the licensee is required to notify the Administrator of the appropriate Regional Office within **two working days** of identifying the information.

An example of when this report is required would be if a licensee identifies that information provided to the NRC in a license amendment on which the NRC approval was based, was later found to be inaccurate. The licensee would not violate 10 CFR 50.9 if they notify the regional administrator within two days of discovering that inaccurate information had been submitted. Otherwise, the NRC could pursue traditional enforcement on the violation of 10 CFR 50.9.

2.1.5.5 Technical Specifications (10 CFR 50.36)

10 CFR 50.36 provides guidance on a facility's **Technical Specifications** which include safety limits, limiting safety system settings and limiting conditions for operation. Should the facility violate any of the requirements, it also requires that the licensee 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. In each instance it requires the licensee to notify the Commission as required by § 50.72 and submit a Licensee Event Report to the Commission as required by § 50.73. In addition, if any safety limit is exceeded, the reactor must be shut down. Operation must not be resumed until authorized by the Commission.

2.1.5.6 Acceptance Criteria for Emergency Core Cooling Systems for Light Water Reactors (10 CFR 50.46)

10 CFR 50.46 contains reporting criteria for changes to or errors found in emergency core cooling system **(ECCS) analysis**. It requires that each licensee perform an analysis to demonstrate that the ECCS is designed so that its calculated cooling performance following postulated loss-of-coolant accidents conforms to the criteria set forth below:

- *Peak cladding temperature*. The calculated maximum fuel element cladding temperature shall not exceed 2200º F.

- *Maximum cladding oxidation*. The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.

- *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 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.

- *Coolable geometry*. Calculated changes in core geometry shall be such that the core remains amenable to cooling.

- *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.

For each change to or error discovered in an acceptable evaluation model or in the application of such a model that affects the temperature calculation, the applicant or holder of an operating license shall report the nature of the change or error and its estimated effect on the limiting ECCS analysis to the Commission at least **annually**.

If the change or error is significant, the applicant or licensee shall provide this report within **30 days** and include with the report a proposed schedule for providing a reanalysis or taking other action as may be needed to show compliance with § 50.46 requirements.

Any change or error correction that results in a calculated ECCS performance that does not conform to the ECCS acceptance criteria is a reportable event as described in § **50.72, and 50.73**. The affected applicant or licensee shall propose immediate steps to demonstrate compliance or bring plant design or operation into compliance with § 50.46 requirements.

2.1.5.7 Licensing Requirements for ISFSI (Part 72)

Part 72 establishes requirements, procedures, and criteria for the issuance of licenses to receive, transfer, and possess power reactor spent fuel, power reactor-related Greater than Class C (GTCC) waste, and other radioactive materials associated with spent fuel storage in an **independent spent fuel storage installation (ISFSI)** and the terms and conditions under which the Commission will issue these licenses. It contains a specific section reporting criterion for accidental criticality or loss of special nuclear material (10 CFR 72.74) and other reports analogous to reporting requirements of 10CFR50.72 and 50.73 (10 CFR 72.75). A summary of the reporting criteria is provided below:

<u>One Hour Report (72.74)</u>
Each licensee shall notify the NRC Operations Center within one hour of discovery of accidental criticality or any loss of special nuclear material.

<u>Emergency notifications</u>:
Each licensee shall notify the NRC Headquarters Operations Center upon the declaration of an emergency as specified in the licensee's approved emergency plan. The licensee shall notify the NRC immediately after notification of the appropriate State or local agencies, but not later than one hour after the time the licensee declares an emergency.

<u>Four-hour Non-Emergency Notifications</u>:
(1) An action taken in an emergency that departs from a condition or a technical specification contained in a license or certificate of compliance issued under this part when the action is immediately needed to protect the public health and safety, and no action consistent with license or certificate of compliance conditions or technical specifications that can provide adequate or equivalent protection is immediately apparent. (Equivalent to 50.54(x)

(2) Any event or situation related to the health and safety of the public or onsite personnel, or protection of the environment, for which a news release is planned or notification to other Government agencies has been or will be made. Such an event may include an onsite fatality or inadvertent release of radioactively contaminated materials. (Written Report not required)

<u>Eight-hour Non-Emergency Notifications</u>:
(1) A defect in any spent fuel structure, system, or component that is important to safety.

(2) A significant reduction in the effectiveness of any spent fuel storage confinement system during use.

(3) Any event requiring the transport of a radioactively contaminated person to an offsite medical facility for treatment. (Witten report not required).

<u>24-hour Non-Emergency Notifications</u>:
An event in which important to safety equipment is disabled or fails to function as designed when (equivalent to safety system functional failure):

- The equipment is required by regulation, license condition, or certificate of compliance to be available and operable to prevent releases that could exceed regulatory limits, to prevent exposures to radiation or radioactive materials that could exceed regulatory limits, or to mitigate the consequences of an accident; and
- No redundant equipment was available and operable to perform the required safety function

<u>Follow-up Notification</u>:
With respect to the telephone notifications, in addition to making the required initial notification, each licensee shall during the course of the event:

(1) Immediately report any further degradation in the level of safety of the ISFSI or other worsening conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made; or any change from one Emergency Class to another; or a termination of the Emergency Class.

(2) Immediately report the results of ensuing evaluations or assessments of ISFSI or MRS conditions; the effectiveness of response or protective measures taken; and information related to ISFSI behavior that is not understood.

(3) Maintain an open, continuous communication channel with the NRC Headquarters Operations Center upon request by the NRC.

<u>60 Day Written Reports</u>
Each licensee who makes an initial notification described above (except as noted) shall also submit a written report to the Commission within 60 days of the initial notification (equivalent to 10 CFR 50.73).

2.1.5.8 Physical Protection of Plants and Materials (Part 73)

Part 73 prescribes requirements for the establishment and maintenance of a **physical protection** system which will have capabilities for the protection of special nuclear material at fixed sites and in transit and of plants in which special nuclear material is used. Similar to Part 72, it contains a specific section on reportability (10 CFR 73.71). A summary of the reporting criteria is listed below.

<u>One-hour Notifications, (followed by a written report within 60 days)</u>

(a) Any event in which there is reason to believe that a person has committed or caused, or attempted to commit or cause, or has made a credible threat to commit or cause:
   (1) A theft or unlawful diversion of special nuclear material; or
   (2) Significant physical damage to a power reactor or any facility possessing SSNM or its equipment or carrier equipment transporting nuclear fuel or spent nuclear fuel, or to the nuclear fuel or spent nuclear fuel a facility or carrier possesses; or
   (3) Interruption of normal operation of a licensed nuclear power reactor through the unauthorized use of or tampering with its machinery, components, or controls including the security system.

(b) An actual entry of an unauthorized person into a protected area, material access area, controlled access area, vital area, or transport.

(c) Any failure, degradation, or the discovered vulnerability in a safeguard system that could allow unauthorized or undetected access to a protected area, material access area, controlled access area, vital area, or transport for which compensatory measures have not been employed.

(d) The actual or attempted introduction of contraband into a protected area, material access area, vital area, or transport.

2.1.6 Summary

The purpose of the requiring licensees to report certain events is to help fulfill the NRC mission by aiding emergency response and providing feedback of operating experience into plant operations. NUREG 1022 provides clarification on the reporting regulations for immediate reports and licensee event reports.

Immediate reports made under 10 CFR 50.72 provide immediate reporting of significant events where: (1) immediate NRC action may be required to protect the public health and safety, or (2) the NRC needs timely, accurate information to respond to heightened public concern. These reports are made to the Headquarters Operations Officer (HOO) using the Emergency Notification System (ENS). Should ENS be unavailable, the licensee can contact the HOO by alternate means of communication. These alternate means of communication may include commercial phone lines, cellular phones, satellite phones and/or radio links to other facilities where communications can be relayed to the NRC Operations Center. There are five types of immediate reports required under 10 CFR 50.72: Emergency Reports, 1-hour, 4-hour and 8-hour non-emergency reports; and Follow-up Reports.

Some of the 10 CFR 50.72 reporting criteria apply only to valid actuations of systems. A valid actuation is when the actual plant process parameter (e.g., level, pressure, temperature, or voltage) monitored for the actuation exceeds the actuation setpoint. An invalid actuation can be caused by instrument failure, errors during maintenance or other causes where the actual conditions of the plant did not warrant actuation.

Emergency Response Data System is used during an emergency to transmit data directly from the licensee to the NRC to aid in monitoring and response. It is required to be placed in service within one hour of declaration of Alert or above.

Licensee event reports required by 10 CFR 50.73 describe events and problems believed to be significant and useful to the NRC's effort to identify and resolve threats to public health and safety.

There are other reports required by regulation which are needed to ensure the NRC can respond to events or conditions that could threaten the health and safety of the public. These events include radiological events, safeguards events and identification of basic component defects that pose a substantial safety hazard.

2.1.7 References

- NUREG 1022, Event Reporting Guidelines, 10 CFR 50.72 and 50.73
- 10 CFR Part 20, Standards for Protection Against Radiation
- 10 CFR Part 21, Reporting Defects and Non-Compliances
- 10 CFR Part 26, Fitness for Duty Programs
- 10 CFR 50.9, Completeness and Accuracy of Information
- 10 CFR 50.36, Technical Specifications
- 10 CFR 50.46, Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors
- 10 CFR 50.72, Immediate notification requirements for operating nuclear power reactors
- 10 CFR 50.73, Licensee event report system

- 10 CFR Part 72, Licensing requirements for the independent storage of spent nuclear fuel and high-level radioactive waste, and reactor related greater than Class C waste
- 10 CFR Part 73, Physical Protection of Plants and Materials

Table 2.1-1 Typical ERDS Data Points

Browns Ferry Unit 1 - ERDS Data Point Library

ERDS PNT No	NRC ERDS PARAMETER	POINT ID	PLANT SPECIFIC POINT DESCRIPTION
1	NI POWER RNG	SPDS0001	RX POWER APRM - COMPOSED
2	NI INTER RNG	CALC045	AVERAGE OF 8 IRM'S
3	NI SOURC RNG	SPDS0041	RX POWER SRM - AVG
4	REAC VES LEV	SPDS0007	RX WATER LEVEL - COMPOSED
5	MAIN FD FLOW	CALC040	RFW FLOW TO REACTOR
6	RCIC FLOW	71-36	RCIC PUMP DISCHARGE FLOW
7	RCS PRESSURE	SPDS0008	RX PRESSURE - COMPOSED
8	HPCI FLOW	73-33	HPCI PUMP DISCHARGE FLOW
9	LPCI FLOW	74-50	RHR SYS I FLOW
10	LPCI FLOW	74-64	RHR SYS II FLOW
11	CR SPRAY FL	75-21	CORE SPRAY SYS I FLOW
12	CR SPRAY FL	75-49	CORE SPRAY SYS II FLOW
13	CND A/E RAD	SPDS0047	OFFGAS POST TREATMENT AVG
14	CND A/E RAD	90-157	OFFGAS PRE TREATMENT AVG
15	DW RAD	90-272A	DW RAD-RX 582,45 DEG AZIMUTH
16	DW RAD	90-273A	DW RAD-RX 560, 270 DEG AZIMUTH
17	MN STEAM RAD	90-136	MAIN STM LINE A RAD LEVEL
18	MN STEAM RAD	90-137	MAIN STM LINE C RAD LEVEL
19	MN STEAM RAD	90-138	MAIN STM LINE B RAD LEVEL
20	MN STEAM RAD	90-139	MAIN STM LINE D RAD LEVEL
21	DW PRESS	SPDS0009	DRYWELL PRESSURE - COMPOSED
22	DW TEMP	SPDS0010	DRYWELL TEMPERATURE-COMPOSED
23	SPTEMP	SPDS0016	SUPPR PL WTR TEMP - COMPOSED
24	SP LEVEL	SPDS001 3	SUPPR PL WTR LVL (IN) - COMPOSED
25	H2 CONC	76-39	DRYWELL H2 CONCENTRATION
26	02 CONC	76-43	DRYWELL OXYGEN CONCENTRATION
27	CST LEVEL	2-169	CONDENSATE STORAGE TANK #1 LEVEL
28	WIND SPEED	MET005	91M AVERAGE WIND SPEED (15 MIN AVG)
29	WIND SPEED	MET013	46M AVERAGE WIND SPEED (15 MIN AVG)
30	WIND SPEED	MET021	10M AVERAGE WIND SPEED (15 MIN AVG)
31	WIND DIR	MET003	91 M VECTOR WIND DIR (15 MIN AVG)
32	WIND DIR	MET011	46M VECTOR WIND DIR (15 MIN AVG)
33	WIND DIR	MET019	1OM VECTOR WIND DIR (15 MIN AVG)
34	STAB CLASS	MET035	STACK LVL ATM STAB CLASS (15 MIN)
35	STAB CLASS	MET037	OVERALL ATM STAB CLASS (15 MIN)
36	STAB CLASS	MET039	GRND LVL ATM STAB CLASS (15 MIN)
37	TYPEDATA	REAL/ SIMULATED	INDICATES IF DATA IS FROM THE UNIT OR SIMULATOR.
38	EFF GAS RAD	SPDS0024	STACK RELEASE RATE - COMPOSED

Table 2.1-2 ENS Worksheet

NRC FORM 361
(12-2000)

U.S. NUCLEAR REGULATORY COMMISSION
OPERATIONS CENTER

REACTOR PLANT
EVENT NOTIFICATION WORKSHEET

EN #

NRC OPERATION TELEPHONE NUMBER: PRIMARY -- 301-816-5100 or 800-532-3469*, BACKUPS -- [1st] 301-951-0550 or 800-449-3694*, [2nd] 301-415-0550 and [3rd] 301-415-0553 *Licensees who maintain their own ETS are provided these telephone numbers.

NOTIFICATION TIME	FACILITY OR ORGANIZATION	UNIT	NAME OF CALLER	CALL BACK #

EVENT TIME & ZONE	EVENT DATE	POWER/MODE BEFORE	POWER/MODE AFTER

EVENT CLASSIFICATIONS		1-Hr. Non-Emergency 10 CFR 50.72(b)(1)					
GENERAL EMERGENCY	GEN/AAEC		TS Deviation	ADEV	(v)(A)	Safe S/D Capability	AINA
SITE AREA EMERGENCY	SIT/AAEC	**4-Hr. Non-Emergency 10 CFR 50.72(b)(2)**			(v)(B)	RHR Capability	AINB
ALERT	ALE/AAEC	(i)	TS Required S/D	ASHU	(v)(C)	Control of Rad Release	AINC
UNUSUAL EVENT	UNU/AAEC	(iv)(A)	ECCS Discharge to RCS	ACCS	(v)(D)	Accident Mitigation	AIND
50.72 NON-EMERGENCY	(see next columns)	(iv)(B)	RPS Actuation (scram)	ARPS	(xii)	Offsite Medical	AMED
PHYSICAL SECURITY (73.71)	DDDD	(xi)	Offsite Notification	APRE	(xiii)	Loss Comm/Asmt/Resp	ACOM
MATERIAL/EXPOSURE	B???	**8-Hr. Non-Emergency 10 CFR 50.72(b)(3)**			**60-Day Optional 10 CFR 50.73(a)(1)**		
FITNESS FOR DUTY	HFIT	(ii)(A)	Degraded Condition	ADEG		Invalid Specified System Actuation	AINV
OTHER UNSPECIFIED REQMT.	(see last column)	(ii)(B)	Unanalyzed Condition	AUNA	**Other Unspecified Requirement (Identify)**		
INFORMATION ONLY	NNF	(iv)(A)	Specified System Actuation	AESF			NONR
							NONR

DESCRIPTION

Include: Systems affected, actuations and their initiating signals, causes, effect of event on plant, actions taken or planned, etc. *(Continue on back)*

NOTIFICATIONS	YES	NO	WILL BE			
NRC RESIDENT				ANYTHING UNUSUAL OR NOT UNDERSTOOD?	YES (Explain above)	NO
STATE(s)						
LOCAL				DID ALL SYSTEMS FUNCTION AS REQUIRED?	YES	NO (Explain above)
OTHER GOV AGENCIES				MODE OF OPERATION UNTIL CORRECTED:	ESTIMATED RESTART DATE:	ADDITIONAL INFO ON BACK: YES / NO
MEDIA/PRESS RELEASE						

NRC FORM 361 (12-2000)

Table 2.1-2 ENS Worksheet (continued)

RADIOLOGICAL RELEASES: CHECK OR FILL IN APPLICABLE ITEMS ***(specific details/explanations should be covered in event description)***

LIQUID RELEASE	GASEOUS RELEASE	UNPLANNED RELEASE	PLANNED RELEASE	ONGOING	TERMINATED
MONITORED	UNMONITORED	OFFSITE RELEASE	T. S. EXCEEDED	RM ALARMS	AREAS EVACUATED
PERSONNEL EXPOSED OR CONTAMINATED		OFFSITE PROTECTIVE ACTIONS RECOMMENDED		*State release path in description	

	Release Rate (Ci/sec)	% T. S. LIMIT	HOO GUIDE	Total Activity (Ci)	% T. S. LIMIT	HOO GUIDE
Noble Gas			0.1 Ci/sec			1000 Ci
Iodine			10 uCi/sec			0.01 Ci
Particulate			1 uCi/sec			1 mCi
Liquid *(excluding tritium and dissolved noble gases)*			10 uCi/min			0.1 Ci
Liquid (tritium)			0.2 Ci/min			5 Ci
Total Activity						

	PLANT STACK	CONDENSER/AIR EJECTOR	MAIN STEAM LINE	SG BLOWDOWN	OTHER
RAD MONITOR READINGS					
ALARM SETPOINTS					
% T. S. LIMIT *(if applicable)*					

RCS OR SG TUBE LEAKS: CHECK OR FILL IN APPLICABLE ITEMS: ***(specific details/explanations should be covered in event description)***

LOCATION OF THE LEAK *(e.g., SG #, valve, pipe, etc.)*

LEAK RATE	UNITS: gpm/gpd	T. S. LIMITS	SUDDEN OR LONG-TERM DEVELOPMENT
LEAK START DATE	TIME	COOLANT ACTIVITY AND UNITS: PRIMARY	SECONDARY

LIST OF SAFETY RELATED EQUIPMENT NOT OPERATIONAL

EVENT DESCRIPTION *(Continued from front)*

Table 2.1-3 LER Form 366

NRC FORM 366 (10-2010) U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB: NO. 3150-0104 EXPIRES: 10/31/2013
LICENSEE EVENT REPORT (LER) (See reverse for required number of digits/characters for each block)	Estimated burden per response to comply with this mandatory collection request: 80 hours. Reported lessons learned are incorporated into the licensing process and fed back to industry. Send comments regarding burden estimate to the FOIA/Privacy Section (T-5 F53), U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001, or by internet e-mail to infocollects.resource@nrc.gov, and to the Desk Officer, Office of Information and Regulatory Affairs, NEOB-10202, (3150-0104), Office of Management and Budget, Washington, DC 20503. If a means used to impose an information collection does not display a currently valid OMB control number, the NRC may not conduct or sponsor, and a person is not required to respond to, the information collection.

1. FACILITY NAME	2. DOCKET NUMBER	3. PAGE
	05000	1 OF

4. TITLE

5. EVENT DATE			6. LER NUMBER			7. REPORT DATE			8. OTHER FACILITIES INVOLVED	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER 05000
				-	-				FACILITY NAME	DOCKET NUMBER 05000

9. OPERATING MODE

10. POWER LEVEL

11. THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(Check all that apply)*

☐ 20.2201(b)	☐ 20.2203(a)(3)(i)	☐ 50.73(a)(2)(i)(C)	☐ 50.73(a)(2)(vii)
☐ 20.2201(d)	☐ 20.2203(a)(3)(ii)	☐ 50.73(a)(2)(ii)(A)	☐ 50.73(a)(2)(viii)(A)
☐ 20.2203(a)(1)	☐ 20.2203(a)(4)	☐ 50.73(a)(2)(ii)(B)	☐ 50.73(a)(2)(viii)(B)
☐ 20.2203(a)(2)(i)	☐ 50.36(c)(1)(i)(A)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(ix)(A)
☐ 20.2203(a)(2)(ii)	☐ 50.36(c)(1)(ii)(A)	☐ 50.73(a)(2)(iv)(A)	☐ 50.73(a)(2)(x)
☐ 20.2203(a)(2)(iii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(v)(A)	☐ 73.71(a)(4)
☐ 20.2203(a)(2)(iv)	☐ 50.46(a)(3)(ii)	☐ 50.73(a)(2)(v)(B)	☐ 73.71(a)(5)
☐ 20.2203(a)(2)(v)	☐ 50.73(a)(2)(i)(A)	☐ 50.73(a)(2)(v)(C)	☐ OTHER Specify in Abstract below or in NRC Form 366A
☐ 20.2203(a)(2)(vi)	☐ 50.73(a)(2)(i)(B)	☐ 50.73(a)(2)(v)(D)	

12. LICENSEE CONTACT FOR THIS LER

FACILITY NAME	TELEPHONE NUMBER *(Include Area Code)*

13. COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT

CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX	CAUSE	SYSTEM	COMPONENT	MANU-FACTURER	REPORTABLE TO EPIX

14. SUPPLEMENTAL REPORT EXPECTED	15. EXPECTED SUBMISSION DATE	MONTH	DAY	YEAR
☐ YES *(If yes, complete 15. EXPECTED SUBMISSION DATE)* ☐ NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines)*

NRC FORM 366 (10-2010)

Table 2.1-4 Summary of 50.72 and 50.73 Reporting Criteria

Immediate Report Criteria Under §50.72	LER Criteria Under § 50.73
Emergency Report	
§ 50.72(a)(1)(i) The declaration of any of the Emergency Classes specified in the licensee's approved Emergency Plan.	*No direct LER criteria*
One-Hour Non-Emergency	
§ 50.72(b)(1) Any deviation from the plant's Technical Specifications authorized pursuant to § 50.54(x) of this part.	**§ 50.73(a)(2)(i)(C)** Any deviation from the plant's Technical Specifications authorized pursuant to § 50.54(x) of this part.
Four-Hour Non-Emergency	
§ 50.72(b)(2)(i) The initiation of any nuclear plant shutdown required by the plant's Technical Specifications.	**§ 50.73(a)(2)(i)(A)** The completion of any nuclear plant shutdown required by the plant's Technical Specifications.
§ 50.72(b)(2)(iv)(A) Any event that results or should have resulted in emergency core cooling system (ECCS) discharge into the reactor coolant system as a result of a **valid** signal except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.	*LER may be required if manual or automatic actuation of safety system per § 50.73(a)(2)(iv)(A)*
§ 50.72(b)(2)(iv)(B) Any event or condition that results in actuation of the reactor protection system (RPS) when the reactor is critical except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.	*LER may be required if manual or automatic actuation of safety system per § 50.73(a)(2)(iv)(A)*
§ 50.72(b)(2)(xi) Any event or situation, related to the health and safety of the public or onsite personnel, or protection of the environment, for which a news release is planned or notification to other government agencies has been or will be made. Such an event may include an onsite fatality or inadvertent release of radioactively contaminated materials.	None
Eight-Hour Non-Emergency	
§ 50.72(b)(3)(ii) Any event or condition that results in: **(A)** The condition of the nuclear power plant, including its principal safety barriers, being seriously degraded; or **(B)** The nuclear power plant being in an unanalyzed condition that significantly degrades plant safety.	**§ 50.73(a)(2)(ii)** Any event or condition that resulted in: **(A)** The condition of the nuclear power plant, including its principal safety barriers, being seriously degraded; or **(B)** The nuclear power plant being in an unanalyzed condition that significantly degraded plant safety.

Table 2.1-4 Summary of 50.72 and 50.73 Reporting Criteria (Cont.)

Immediate Report Criteria Under §50.72	LER Criteria Under § 50.73
Eight-Hour Non-Emergency (Cont.)	
§ 50.72(b)(3)(iv)(A) Any event or condition that results in **valid** actuation of any of the systems listed below, except when the actuation results from and is part of a pre-planned sequence during testing or reactor operation.	**§ 50.73(a)(2)(iv)(A)** Any event or condition that resulted in manual or automatic actuation of any of the systems listed below, except when: (1) The actuation resulted from and was part of a pre-planned sequence during testing or reactor operation; or (2) The actuation was **invalid** and; (i) Occurred while the system was properly removed from service; or (ii) Occurred after the safety function had been already completed.
(1) Reactor protection system (RPS) *(2)* General containment isolation signals affecting containment isolation valves **in more than one system** or multiple main steam isolation valves (MSIVs). *(3)* ECCS for PWRs *(4)* ECCS for BWRs including: HPCS, LPCS, HPCI and LPCI *(5)* RCIC; isolation condenser system; and feedwater coolant injection system. *(6)* PWR AFW or emergency feedwater *(7)* Containment heat removal and depressurization systems, including containment spray and fan cooler systems. *(8)* Emergency ac diesel generators (EDGs); including dedicated Division 3 diesels.	*(1)* Reactor protection system (RPS) *(2)* General containment isolation signals affecting containment isolation valves **in more than one system** or multiple main steam isolation valves (MSIVs). *(4)* ECCS including: HPCS, LPCS, HPCI and LPCI *(5) RCIC*; isolation condenser system; and feedwater coolant injection system. *(7)* Containment heat removal and depressurization systems, including containment spray and fan cooler systems. *(8)* Emergency ac diesel generators (EDGs); *(9)* Emergency service water systems that do not normally run and that serve as ultimate heat sinks.
§ 50.72(b)(3)(v) Any event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident. **§ 50.72(b)(3)(vi)** Events covered in paragraph (b)(3)(v) of this section may include one or more procedural errors, equipment failures, and/or discovery of design, analysis, fabrication, construction, and/or procedural inadequacies. However, individual component failures need not be reported if redundant equipment in the same system was operable and available to perform the required safety function.	**§ 50.73(a)(2)(v)** Any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident. **§ 50.73(a)(2)(vi)** Events covered in paragraph (a)(2)(v) of this section may include one or more procedural errors, equipment failures, and/or discovery of design, analysis, fabrication, construction, and/or procedural inadequacies. However, individual component failures need not be reported pursuant to paragraph (a)(2)(v) of this section if redundant equipment in the same system was operable and available to perform the required safety function.

Table 2.1-4 Summary of 50.72 and 50.73 Reporting Criteria (Cont.)

Immediate Report Criteria Under §50.72	LER Criteria Under § 50.73
Eight-Hour Non-Emergency (Cont.)	
§ 50.72(b)(3)(xii) Any event requiring the transport of a radioactively contaminated person to an offsite medical facility for treatment."	None
§ 50.72(b)(3)(xiii) "Any event that results in a major loss of emergency assessment capability, offsite response capability, or offsite communications capability (e.g., significant portion of control room indication, emergency notification system, or offsite notification system).	None
Follow-up ENS Notifications	
§ 50.72(c) Follow-up notification. With respect to the telephone notifications, in addition to making the required initial notification, each licensee, shall during the course of the event: *(1) Immediately report* (i) any further degradation in the level of safety of the plant or other worsening plant conditions, including those that require the declaration of any of the Emergency Classes, if such a declaration has not been previously made, or (ii) any change from one Emergency Class to another, or (iii) a termination of the Emergency Class. *(2) Immediately report* (i) the results of ensuing evaluations or assessments of plant conditions, (ii) the effectiveness of response or protective measures taken, and (iii) information related to plant behavior that is not understood. (3) Maintain an open, continuous communication channel with the NRC Operations Center upon request by the NRC.	None

Table 2.1-4 Summary of 50.72 and 50.73 Reporting Criteria (Cont.)

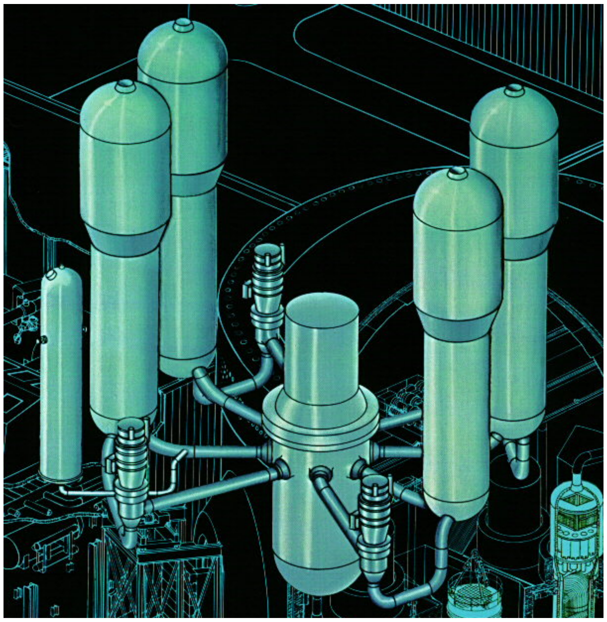
Immediate Report Criteria Under §50.72	LER Criteria Under § 50.73
LERs Not Associated with Immediate Notifications	
None	**§ 50.73(a)(2)(i)(B)** Any operation or condition which was prohibited by the plant's Technical Specifications except when: 1) The Technical Specification is administrative in nature; 2) The event consisted solely of a case of a late surveillance test where the oversight was corrected, the test was performed, and the equipment was found to be capable of performing its specified safety functions; or 3) The Technical Specification was revised prior to discovery of the event such that the operation or condition was no longer prohibited at the time of discovery of the event.
Maybe reportable as Emergency Declaration	**§ 50.73(a)(2)(iii)** Any natural phenomenon or other external condition that posed an actual threat to the safety of the nuclear power plant or significantly hampered site personnel in the performance of duties necessary for the safe operation of the nuclear power plant.
Maybe reportable as unanalyzed condition or safety system loss of safety function	**§ 50.73(a)(2)(vii)** Any event where a single cause or condition caused at least one independent train or channel to become inoperable in multiple systems or two independent trains or channels to become inoperable in a single system designed to: (A) Shut down the reactor and maintain it in a safe shutdown condition; (B) Remove residual heat; (C) Control the release of radioactive material; or (D) Mitigate the consequences of an accident.
No direct 50.72 equivalent although it may require a telephone notification as an Emergency Declaration or news release or under 10CFR Part 20	**§ 50.73(a)(2)(viii)(A)** Any airborne radioactive release that, when averaged over a time period of 1 hour, resulted in airborne radionuclide concentrations in an unrestricted area that exceeded 20 times the applicable concentration limits specified in appendix B to part 20, table 2, column 1. **§ 50.73(a)(2)(viii)(B)** Any liquid effluent release that, when averaged over a time period of 1 hour, exceeds 20 times the applicable concentrations specified in appendix B to part 20, table 2, column 2, at the point of entry into the receiving waters (i.e., unrestricted area) for all radionuclides except tritium and dissolved noble gases.

Table 2.1-4 Summary of 50.72 and 50.73 Reporting Criteria (Cont.)

Immediate Report Criteria Under §50.72	LER Criteria Under § 50.73
LERs Not Associated with Immediate Notifications	
Maybe reportable as unanalyzed condition or safety system loss of safety function	**§ 50.73(a)(2)(ix)(A)** Any event or condition that as a result of a single cause could have prevented the fulfillment of a safety function for two or more trains or channels in different systems that are needed to: *(1)* Shut down the reactor and maintain it in a safe shutdown condition; *(2)* Remove residual heat; *(3)* Control the release of radioactive material; or *(4)* Mitigate the consequences of an accident. **§ 50.73(a)(2)(ix)(B)** Events covered in paragraph (ix)(A) of this section may include cases of procedural error, equipment failure, and/or discovery of a design, analysis, fabrication, construction, and/or procedural inadequacy. However, licensees are not required to report an event pursuant to paragraph (ix)(A) of this section if the event results from: *(1)* A shared dependency among trains or channels that is a natural or expected consequence of the approved plant design; or *(2)* Normal and expected wear or degradation.
Maybe reportable as Emergency Declaration	**§ 50.73(a)(2)(x)** Any event that posed an actual threat to the safety of the nuclear power plant or significantly hampered site personnel in the performance of duties necessary for the safe operation of the nuclear power plant including fires, toxic gas releases, or radioactive releases.

Table 2.1-5 Summary of Other Regulatory Required Event Reports

Regulation	Title	General Subject
10 CFR Part 20	Standards for Protection Against Radiation	Radiological events including releases, exposures and contaminations
10 CFR Part 21	Reporting Defects and Non-Compliances	Defects in basic components or services used in nuclear facilities that constitute a substantial safety hazard
10 CFR Part 26	Fitness for Duty Programs	Violations of or deficiencies in a facility's fitness for duty program
10 CFR 50.9	Completeness and Accuracy of Information	Incomplete or inaccurate information contained in licensee submittals that pose a significant implication for public health and safety or common defense and security
10 CFR 50.36	Technical Specifications	Violations of TS safety limits, limiting safety system settings or limited conditions for operation
10 CFR 50.46	Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors	Change to or errors in the ECCS analysis that are significant and/or result in not meeting the ECCS acceptance criteria
10 CFR Part 72	Licensing requirements for the independent storage of spent nuclear fuel and high-level radioactive waste, and reactor related greater than Class C waste	Includes reporting criteria for events pertaining to Independent Spent Fuel Storage Installations (ISFSIs)
10 CFR Part 73	Physical Protection of Plants and Materials	Security Safeguards Events



Westinghouse Advanced Technology Manual

Chapter 2.2 – Shutdown Margin and Reactivity Balance

2020

HRTD Human Resources Training & Development

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

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2.2.0 Shutdown Margin and Reactivity Balance

Learning Objectives:

1. Relate a change in a plant parameter to its effect on estimated critical rod position (ECP).
2. Relate a change in a plant parameter to its effect on estimated critical boron concentration.
3. Relate a change in a plant parameter to its effect on the value of shutdown margin.

2.2.1 Introduction

The plant reactivity (ρ) procedure provides guidance for the calculation of estimated critical positions, estimated critical boron concentrations, and shutdown margins, and for the analysis of reactivity anomalies. All of these calculations are safety-related and are addressed in plant technical specifications. These calculations are described in the following paragraphs of this section.

2.2.2 Estimated Critical Position (ECP)

The purpose of the calculation is to ensure that core criticality occurs with an optimum control rod position. The calculation of the ECP may be performed with two different methods. These are the reactivity (ρ) change (Δ) method and the reactivity balance method. The basis of both calculations is that core reactivity is equal to zero when the reactor is critical.

2.2.2.1 Delta Rho ($\Delta\rho$) Method

In order to calculate an ECP with the $\Delta\rho$ method, a previous critical condition must be known. This previous condition may be an operating situation or data obtained from the startup performed following refueling. Regardless of the source of data, the sum of the reactivity contributions to the previous critical condition (net reactivity) must equal zero. With the subscript 1 indicating a parameter from the previous critical condition, the following relationship holds:

$$\rho_{net_1} = \rho_{power_1} + \rho_{rods_1} + \rho_{boron_1} + \rho_{xe_1} + \rho_{sm_1} = 0 \qquad (2.2\text{-}1)$$

where:

ρ_{net_1} = algebraic sum of all core reactivity components,

ρ_{power_1} = reactivity contribution from power defect,

ρ_{rods_1} = reactivity contribution based on rod position,

ρ_{boron_1} = reactivity contribution based on boron concentration,

ρ_{xe_1} = reactivity contribution due to Xenon concentration, and

ρ_{sm_1} = reactivity contribution due to Samarium concentration.

Since the net reactivity for the critical condition to be calculated (designated with subscript 2) also must equal zero, it can be expressed as:

$$\rho_{net_2} = \rho_{power_2} + \rho_{rods_2} + \rho_{boron_2} + \rho_{xe_2} + \rho_{sm_2} = 0 \qquad (2.2\text{-}2)$$

Since both equations equal zero:

$$\rho_{net_1} = \rho_{net_2} \qquad (2.2\text{-}3)$$

or:

$$\rho_{power_2} + \rho_{rods_2} + \rho_{boron_2} + \rho_{xe_2} + \rho_{sm_2} = \rho_{power_1} + \rho_{rods_1} + \rho_{boron_1} + \rho_{xe_1} + \rho_{sm_1} \qquad (2.2\text{-}4)$$

Subtracting the terms with subscript 1 from the corresponding terms with subscript 2, equation 2.2-4 becomes:

$$0 = (\rho_{power_2} - \rho_{power_1}) + (\rho_{rods_2} - \rho_{rods_1}) + (\rho_{boron_2} - \rho_{boron_1})\ (\rho_{xe_2} - \rho_{xe_1}) + (\rho_{sm_2} - \rho_{sm_1}) \quad (2.2\text{-}5)$$

or

$$-\Delta\rho_{rods} = \Delta\rho_{power} + \Delta\rho_{boron} + \Delta\rho_{xe} + \Delta\rho_{sm} \quad (2.2\text{-}6)$$

Equation 2.2-6 states that the negative change in reactivity attributable to the change in rod position between the current calculated condition and the previous critical condition is equal to the sum of the changes in reactivity attributable to other factors that have occurred during the time interval between the two critical conditions. The new critical rod position can thus be determined with a rod worth curve.

2.2.2.2 **Reactivity Balance Method**

With this method, knowledge of a previous critical condition is not required. However, reference conditions for the various reactivity factors and fuel reactivity are required. The reference conditions for the reactivity balance method are:

1. No xenon concentration,
2. No power defect,
3. Control rods completely withdrawn,
4. Boron concentration of zero,
5. No-load T_{avg}, and
6. Equilibrium samarium concentration.

The fuel reactivity (ρ_{fuel}) accounts for the excess amount of fuel (above that required for a critical mass) that is loaded into the core. ρ_{fuel} is usually reduced by the amount of negative reactivity added by the Reactor Coolant System (RCS) heatup to no-load T_{avg} and by the equilibrium samarium concentration. Also, all startup criticalities are conducted at no-load T_{avg}. Therefore, only deviations from this temperature are considered. With these considerations, the equation for net reactivity (ρ_{net}) is:

$$0 = \rho_{net} = \rho_{fuel} - \rho_{rods} - \rho_{boron} - \rho_{xe} - \rho_{sm} - \rho_{mod} \quad (2.2\text{-}7)$$

Where:

ρ_{sm} = equilibrium samarium - Present Samarium

ρ_{mod} = No-load T_{avg} - Present T_{avg}

Adding ρ_{rods} to each side of the equation yields the equation for the ECP:

$$\rho_{rods} = \rho_{fuel} - \rho_{boron} - \rho_{xe} - \rho_{sm} - \rho_{mod} \quad (2.2\text{-}8)$$

In this equation, the absolute value of reactivity is used. Because of the reference condition conventions, all reactivity additions to the fuel reactivity are expected to be negative, with the exception of the moderator temperature reactivity, which may be either positive or negative. Again, the new critical rod position can be determined with a rod worth curve.

2.2.2.3 Xenon and Samarium Calculations

Changes in xenon and samarium concentrations affect the reactivity added by these fission product poisons. Plant computer programs often provide the xenon and samarium reactivity values.

2.2.3 Estimated Critical Boron Concentration

Many situations arise in which the calculated critical rod position is undesirable (i.e., below the rod insertion limit). In order to achieve criticality at a rod height permitted by the rod insertion limit, the RCS boron concentration must be adjusted. Equations 2.2-5 and 2.2-7 may be solved for boron reactivity instead of rod reactivity. When the algebraic manipulations are made, the equations to determine the estimated critical boron concentration are:

Delta Rho Method:

$$-\Delta\rho_{boron} = \Delta\rho_{power} + \Delta\rho_{rods} + \Delta\rho_{xe} + \Delta\rho_{sm} \qquad (2.2\text{-}9)$$

Reactivity Balance Method:

$$\rho_{boron} = \rho_{fuel} - \rho_{rods} - \rho_{xe} - \rho_{sm} - \rho_{mod} \qquad (2.2\text{-}10)$$

The normal procedure is to choose a critical rod position and then adjust the RCS boron concentration to provide the reactivity predicted by equation 2.2-9 or 2.2-10. Once the RCS boron concentration is adjusted to the desired value, the rods are withdrawn until criticality is achieved.

2.2.4 Shutdown Margin (SDM)

Plant technical specifications contain shutdown margin (SDM) requirements. According to technical specifications:

SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming:

a. All Rod Cluster Control Assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and

b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.

When the reactor is critical, the shutdown margin is normally ensured by verifying that the shutdown and control banks are withdrawn above the heights specified by the rod insertion limits. However, Limiting Conditions for Operability (LCOs) 3.1.4, 3.1.5, and 3.1.6 require verification of an adequate SDM if any control rod is inoperable or if any bank has been inserted below its rod insertion limit. As a result, it is necessary to be able to calculate the SDM at all times. The value of the shutdown margin **for a critical reactor** is calculated by performing a reactivity balance which accounts for changes from a known critical condition in accordance with the definition of SDM.

$$SDM = |\rho_{rods}| - |\rho_{mod}| - |\rho_{fuel}| \qquad (2.2\text{-}11)$$

where:

ρ_{rods} = available rod worth, i.e., the negative reactivity that would be added by a trip from the present position, less the value of the most reactive control rod.

ρ_{mod} = the moderator defect, i.e., the positive reactivity added by T_{avg} going from its existing value to the no-load value.

ρ_{fuel} = the fuel temperature (doppler) defect, i.e., the positive reactivity added by power going from the existing value to 0%.

If T_{avg} remains on program, the moderator and the fuel defects can be replaced by the power defect.

The technical specification requirement for an inadequate SDM is to initiate boration. Note that changing the boric acid concentration does not directly change any of the components of the SDM. However, to maintain the reactor critical, one or more of the SDM parameters must change in response to the change in boric acid concentration. The expectation is that the boration will cause control rods to withdraw, thereby increasing the "$|\rho_{rods}|$" component of the SDM calculation.

Also note that, by itself, a new control rod position, if compensated for by changes in power and/or T_{avg}, does not change the SDM. Since, after rod motion, the reactor will return to an exactly critical condition, the changes in reactivity exactly offset each other, causing no change in the SDM.

A change in SDM in a critical reactor requires a change in boric acid concentration or a change in fission product poison concentration. A useful tool to evaluate changes in shutdown margin is to place reactivity parameters in two boxes. One box contains parameters that will instantaneously change at the time of the trip, i.e., rod position, power and coolant temperature. The other box contains parameters that will NOT instantaneously change at the time of the trip, i.e., boron, xenon, and samarium concentration.

Control rod position T_{avg} Power

Boron Xenon Samarium

If all of the changes are contained in one box, the SDM does not change. If changes occur in BOTH boxes, the SDM changes. If the SDM changes, the changes can be evaluated using equation 2.2-11.

2.2.5 Reactivity Anomaly

Technical specifications require that a reactivity balance be performed every 31 effective full power days to ensure that actual values of reactivity agree with the predicted values. The predicted values of reactivity are the values used in safety analyses. Any difference between the actual values and predicted values is called a reactivity anomaly. The maximum allowable value for a reactivity anomaly is 1% $\Delta K/K$. Since the predicted values are also used in the calculation of shutdown margins, nonconservative reactivity anomalies affect the safety of the plant.

2.2.6 Classroom Exercises

Exercise 1

Determine the estimated critical boron concentration for a startup 26 hours after shutdown. The desired rod position is control bank D at 60 steps. Use Attachment 2.2-1 and the following data:

Prior to Shutdown	Shutdown Conditions
Fuel Burnup = 100 EFPD RCS Boron = 800 ppm T_{avg} = 577°F Xenon Reactivity = Eq. for 100% Equilibrium Samarium Rod Position = CBD at 210 steps	RCS boron = 950 ppm Rod Position = SDBs withdrawn T_{avg} = 547°F

Table 2.2-1 Rod Worths

Worth of all RCCAs	(-)7744 pcm
Worth of all Control Banks	(-)4068 pcm
Worth of all Shutdown Banks	(-)3676pcm
Worth of most reactive rod	(+)1040 pcm

Exercise 2

Initial Conditions:

Fuel Burnup = 100 EFPD
Rod Position = CBD at 220 steps
Xenon Reactivity = Eq. for 100%
Equilibrium Samarium
T_{avg} = 577°F
Reactor power = 100%
RCS Boron = 750 ppm

1. Determine the shutdown margin using Attachment 2.2-2, Section I.
2. Assuming that a reactor trip has occurred and that the following conditions exist 40 hr after the trip, determine the shutdown margin using Attachment 2.2-2 Section II.

   T_{avg} = 547°F
   RCS Boron = 750 ppm

3. Use Attachment 2.2-2, Section III, to answer the following questions. Assuming that the shutdown banks are withdrawn, and no boron is added to the RCS:
   a. Will the reactor go critical?
   b. Will technical specification shutdown margin requirements be met?
   c. Is the plant still in mode 3?
4. From the above condition, assume the licensee withdraws the shutdown banks, then takes no further action. What will happen over the next two days?

Exercise 3

The initial conditions are as stated in Exercise 2. The unit has tripped, and the residual heat removal system is to be placed in service when the RCS temperature reaches 300°F. The RCS is to be maintained at 300°F for the next four days. Using Attachment 2.2-2, Section IV, determine the boron concentration change required to meet the shutdown margin requirements for this condition.

Attachment 2.2-1
Estimated Critical Condition Calculation (Delta Rho Method)

A. Rod worth (pcm) at desired startup critical position

Bank _____ at _____ steps (Figure 2.2-1) (-) ________ pcm

B. Rod worth (pcm) at last known critical condition

Bank _____ at _____ steps (Figure 2.2-1) (-) ________ pcm

C. Algebraic difference = [A - B] ( ) ________ pcm

D. Power defect at last known critical condition (Figure 2.2-2) x (-1) (+) ________ pcm

NOTE: ***Multiplication by (-1) accounts for reactivity change following reactor trip.***

E. Present boron concentration ________ ppm

F. Boron concentration at last known critical condition ________ ppm

G. Boron worth (Figure 2.2-3) (-)________ pcm/ppm

H. Reactivity due to change in boron concentration = [(E-F) x G] ( ) ________ pcm

I. Xenon worth at time of startup criticality (Figure 2.2-4) (-) ________ pcm

J. Xenon worth at last known critical condition (Figure 2.2-4) (-) ________ pcm

K. Reactivity due to change in xenon concentration = [I - J] ( ) ________ pcm

L. Samarium worth at time of startup criticality (Figure 2.2-5) (-) ________ pcm

NOTE: If shutdown less than 24 hr go to Line N and enter 0.

M. Samarium worth at last known critical condition (Figure 2.2-5) (-) ________ pcm

N. Reactivity due to change in samarium concentration = [L - M] ( ) ________ pcm

O. TOTAL REACTIVITY CHANGE

(C) _______ + (D) _______ + (H) _______ + (K) ______ + (N) _______ = ( ) ________ pcm

NOTE: ***This is the reactivity change required for criticality at the rod height in Line A. If Line O is positive, boration is required. If line O is negative, then dilution is required.***

NOTE: ***Since T_{avg} is required to be >541°F, the reactivity change from moderator temperature is considered negligible.***

Attachment 2.2-1

Estimated Critical Condition Calculation (continued)

P. Boron concentration change $\frac{(O)}{(G)}$ = (Dilute/Borate)________ ppm

Q. Reactivity anomaly calculation

Maximum position for criticality =

(A) _______ + 750 pcm = _______ pcm (Curve 1) Bank ____ Steps _____

Minimum position for criticality =

(A) _______ - 750 pcm = _______ pcm (Curve 1) Bank ____ Steps _____ OR

Rod insertion limit (technical specifications) Bank ____ Steps _____

Attachment 2.2-2
Shutdown Margin Calculation

Technical specification definition: SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full length rod cluster control assemblies (shutdown and control) are fully inserted except for the single rod cluster control assembly of highest reactivity worth, which is assumed to be fully withdrawn.

I. At-power SDM

A. Total rod worth (Table 2.2-1) (-) ________ pcm

B. Most reactive rod worth (Table 2.2-1) (+)________ pcm

C. Present rod worth

Bank _____ at _____ Steps (Figure 2.2-1) x (-1) (+)________ pcm

NOTE: Multiplication by (-1) accounts for reactivity not available due to partial insertion.

D. Present boron concentration ________ ppm

E. Power defect

Reactor power ________% (Figure 2.2-2) x (-1) (+)________ pcm

NOTE: Multiplication by (-1) accounts for reactivity change following reactor trip.

F. Total reactivity (Algebraic sum) ( ) ________ pcm

NOTE: Technical specifications require that Line F be a negative value > 1300 pcm.

II. Post-trip SDM

A. Reactivity total from line F, Section I ( )________ pcm

B. Reactivity changes since last known critical condition

1. Xenon (Figure 2.2-4)

a. Present value (-) ________ pcm

b. Last known critical condition value (-) ________ pcm

c. Reactivity change = [a-b] ( )________ pcm

Attachment 2.2-2
Shutdown Margin Calculation (continued)

2. Samarium (Figure 2.2-5)
   a. Present value (-) ________ pcm
   b. Last known critical condition value (-) ________ pcm
   c. Reactivity change = [a -b] ( )________ pcm
3. Moderator Temperature
   a. Present value ________ °F
   b. No-load value 547 °F
   c. Temperature change (a -b) ________ °F
   d. Moderator temp. coefficient (Figure 2.2-6) (-) ________ pcm/°F
   e. Reactivity change = [c x d] ( )________ pcm
4. Boron
   a. Present value ________ ppm
   b. Last known critical condition value ________ ppm
   c. Boron concentration change = [a -b] ________ ppm
   d. Boron worth (Figure 2.2- 3) (-)_______ pcm/ppm
   e. Reactivity change = [c x d] ( )________ pcm
5. Algebraic sum

   (A)________ + (B.1.c) ________ + (B.2.c) ________ +

   (B.3.e) ________ + (B.4.e) ________ = ( )________ pcm

***NOTE:** Technical specification requirement for SHUTDOWN MARGIN in modes 1, 2, and 3: the algebraic sum must be a negative value > 1300 pcm.*

III. Actual shutdown reactivity with shutdown banks withdrawn

A. Algebraic sum from B.5, Section II ( ) ________ pcm

B. Most reactive rod worth (Table 2.2-1) (-) ________ pcm

C. Rod worth of shutdown banks (Table 2.2-1) (+) ________ pcm

D. Actual shutdown reactivity = [A+B+C] ( ) ________ pcm

CAUTION: ***The definitions of OPERATIONAL MODES must be checked since they address the reactivity level of the core. Withdrawal of shutdown banks may cause a change in the OPERATIONAL MODE of the unit.***

IV. Plant Cooldown Reactivity Balance

A. Complete Sections II.A, II.B.1, II.B.2, and II.B.3.

B. Algebraic Sum

(II.A) ________ + (II.B.1.c) ________ + (II.B.2.c) ________ +

(II.B.3.e) ________ = ( )________ pcm

C. Shutdown margin requirement

1. Mode 3 (IV.B) ________ - (-1300) = ( ) ________ pcm
2. Modes 4,5 (IV.B) ________ - (-1600) = ( ) ________ pcm

NOTE: If C.1 or C.2 is positive, then boron addition is required.

D. Boron concentration change

1. Boron Worth (Figure 2.2-3) ________ pcm/ppm
2. $= \dfrac{(C.1 \text{ or } C.2)}{D.1}$ ________ ppm

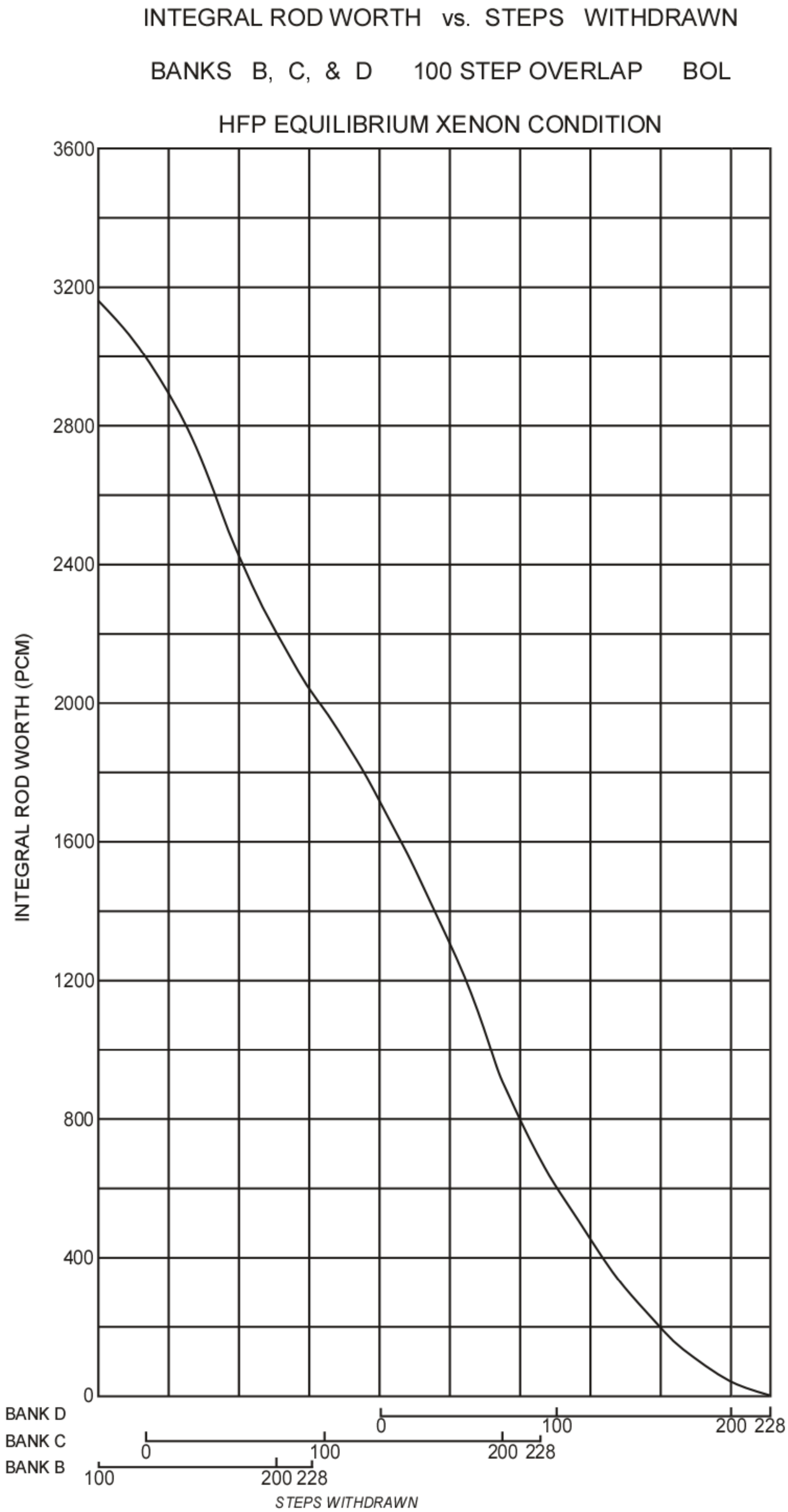


Figure 2.2.1 Rod Worth Curve

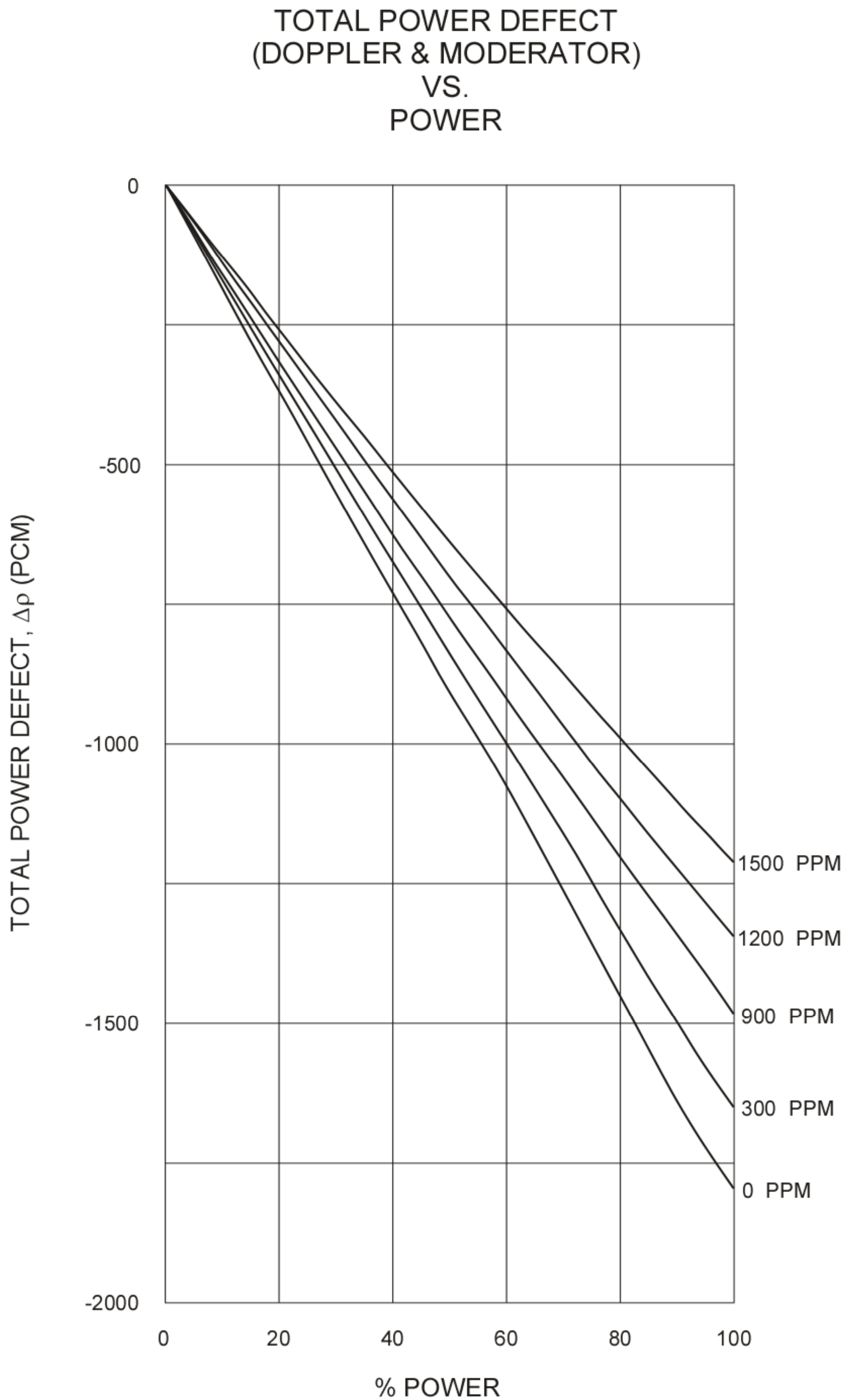


Figure 2.2-2 Total Power Defect

DIFFERENTIAL BORON WORTH
VS.
BORON CONCENTRATION
AT VARIOUS MODERATOR TEMPERATURES
CYCLE 1, BOL

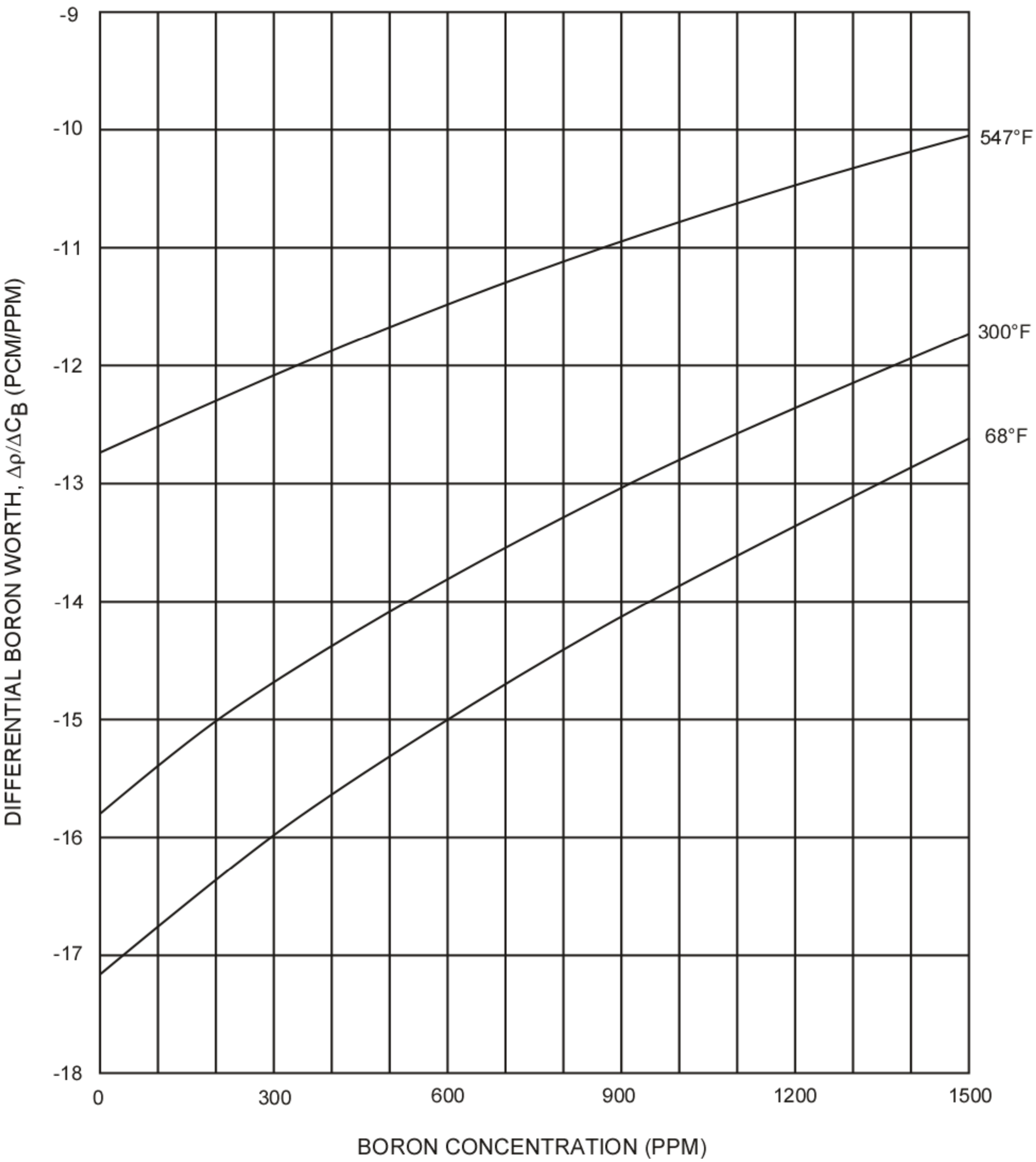


Figure 2.2-3 Boron Worth Curve

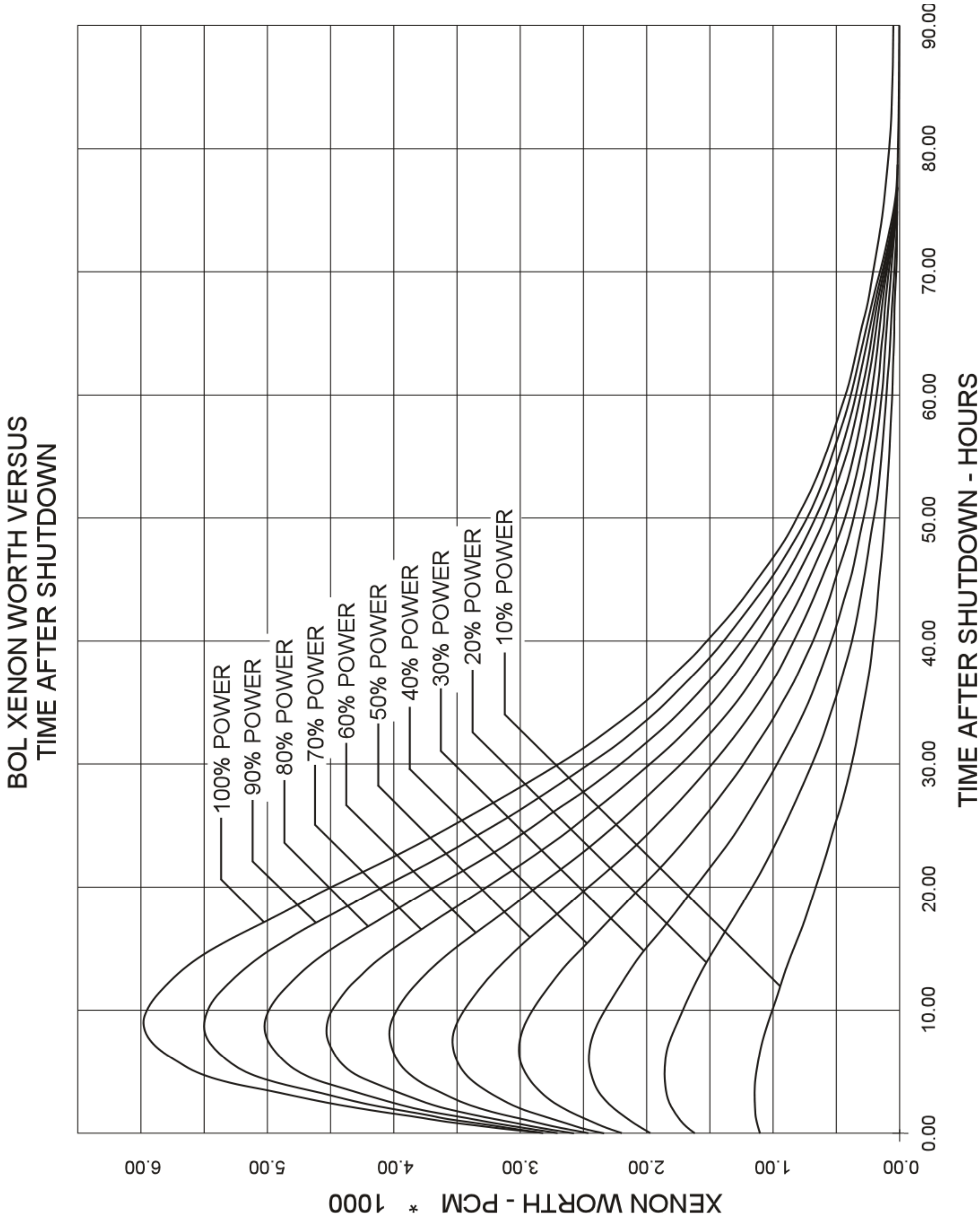


Figure 2.2-4 Xenon Worth Curve

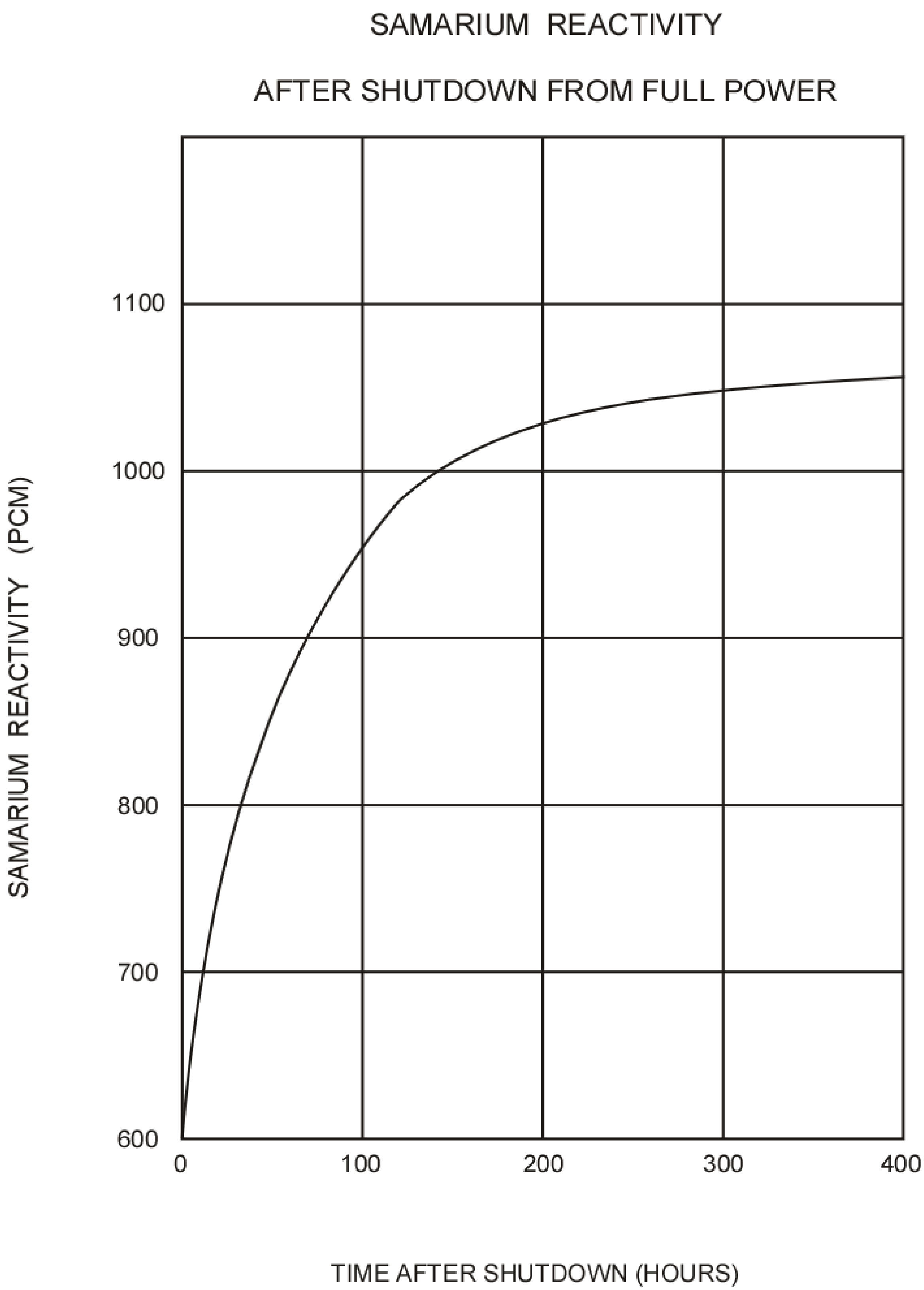


Figure 2.2-5 Samarium Worth Curve

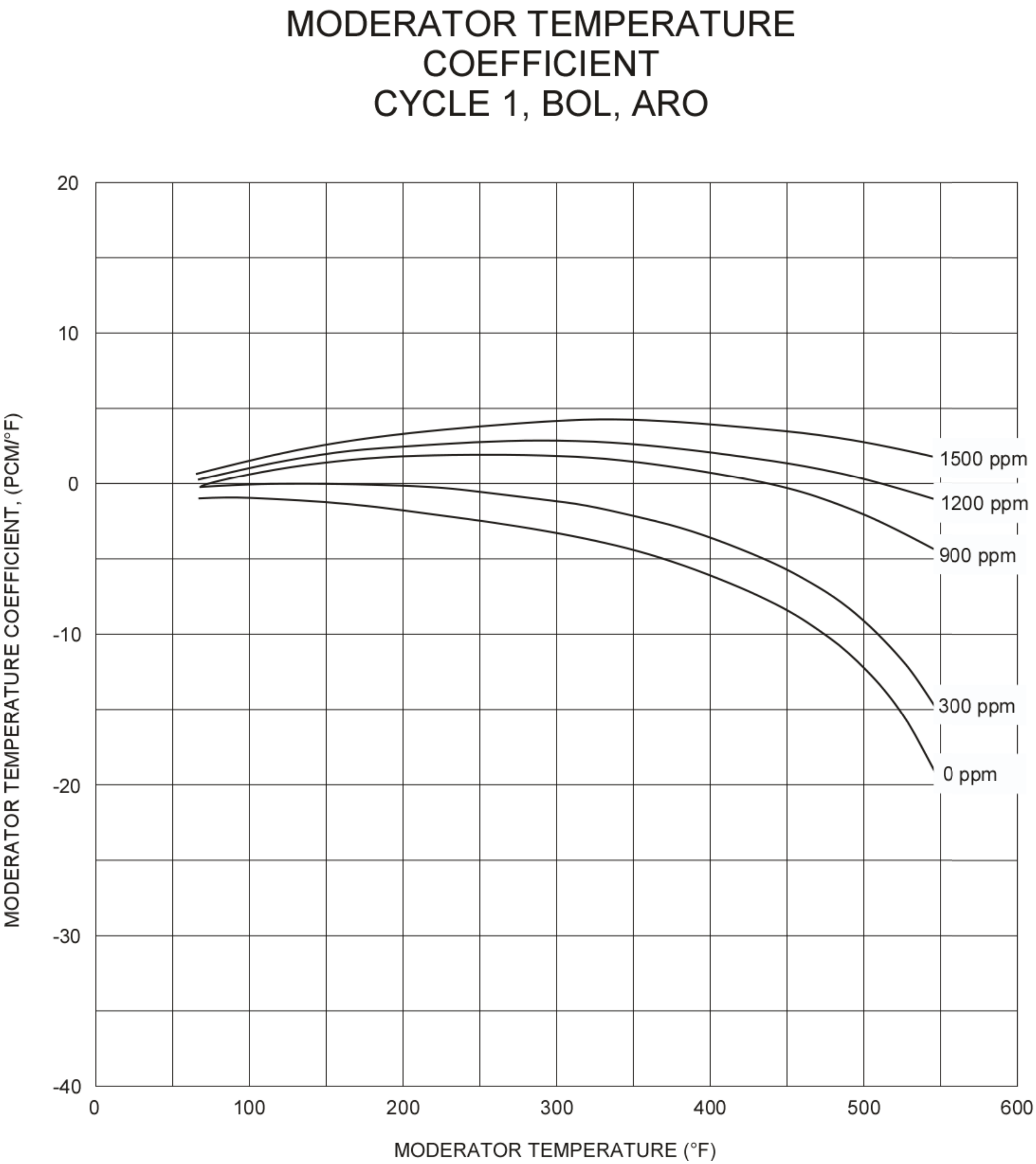
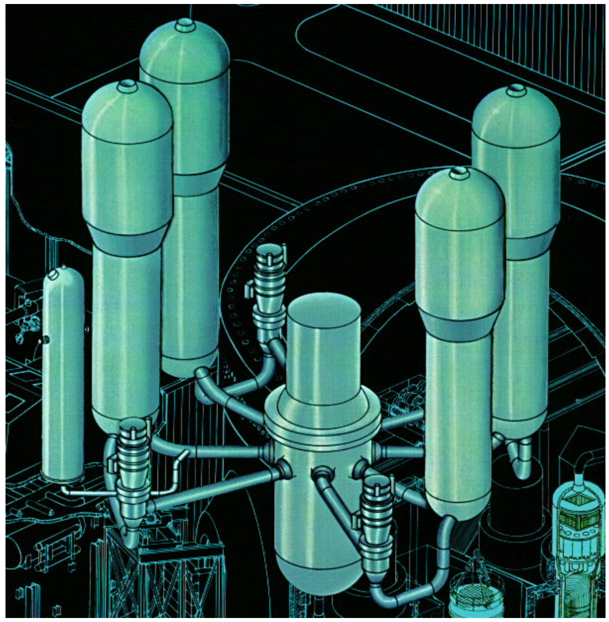


Figure 2.2-6 Moderator Temperature Coefficient



Westinghouse Advanced Technology Manual

Chapter 2.3 – Turbine Impulse Pressure Functions

2020

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2.3.0 Turbine Impulse Pressure Channel Functions

Learning Objectives:

1. List the protection system inputs provided by the turbine impulse pressure channels.
2. List the control signals provided by both channels of turbine impulse pressure.
3. Explain the plant response for a given scenario involving the failure of a turbine impulse pressure channel.

2.3.1 Introduction

The Westinghouse design makes extensive use of signals derived from steam pressure measured in the first stage (impulse stage) of the high pressure turbine. This pressure, known as impulse pressure (P_{imp}), increases linearly as the turbine-generator load increases. Impulse pressure thus provides an indication of the secondary plant load on the primary. Because the P_{imp} signals are used in control and protection systems, the failure of an impulse pressure channel can have a significant impact on the plant. Without operator intervention, the failure of a P_{imp} channel could cause a transient that would result in a reactor trip and/or engineered safety features actuation.

Figure 2.3-1 shows three pressure instruments measuring steam pressure in the first stage of the high pressure turbine. The pressure in the turbine varies from condenser pressure at no load to approximately 610 psig at full load. The pressure signals are converted to equivalent electrical signals and supplied to various control and protection systems. Table 2.3-1 lists the functions of two of the three channels, PT-505 and PT-506. The third of the three pressure channels shown on Figure 2.3-1 (PT-3529) supplies signals exclusively to the turbine Electro-Hydraulic Control (EHC) system and is not discussed in this section. The inputs supplied by and the effects of failures of channels PT-506 and 505 are discussed in the following paragraphs.

2.3.2 Control System Inputs

2.3.2.1 PT-506

PT-506 supplies an input to the circuit that generates the C-7 loss of load interlock. The C-7 interlock arms the steam dump system (see Figure 2.3-2) if impulse pressure decreases in excess of 5% per minute or a 10% step. The C-7 interlock seals in and must be reset at the steam dump control section of the main control board to remove the arming signal. When selected, PT-506 also supplies an input to the steam generator level program generator. The selector switch is normally selected to PT-505.

2.3.2.2 PT-505

The control functions of channel PT-505 include (1) an input to the desired T_{avg} (T_{ref}) program generator, (2) an input to the rod control system power mismatch rate comparator, (3) an input to the rod control system variable gain unit, (4) an input to the C-5 interlock for the automatic rod withdrawal block below 15% power, and (5) an input to the steam generator water level program generator.

T_{ref} is programmed to increase from its no-load to its full-load value as the plant load is increased from 0 to 100%. The P_{imp} signal is supplied to the T_{ref} program generator for the generation of an equivalent temperature signal that is used by the steam dump and rod control systems (see Figures 2.3-2 and 2.3-3) as a reference signal. The rod control system also uses the P_{imp} signal in the power mismatch circuit (1) as a direct indication of secondary plant load for comparison to nuclear power in the rate comparator and (2) as an input to the variable gain unit that modifies the output of the rate comparator. The C-5 interlock ensures that the rod control system is operated in manual at low loads, where P_{imp} is not reliable as an indication of power.

PT-505 is normally selected to supply an input to the steam generator level program generator for the generation of a reference level to be used by the steam generator water level control system. At some plants the steam generator level setpoint is not varied, so the output of the program generator is set to a constant value.

2.3.3 Protection System Inputs

Impulse pressure channels PT-506 and 505 also provide inputs to the Reactor Protection System (RPS), Engineered Safety Features Actuation System (ESFAS), and ATWS Mitigation System Actuation Circuitry (AMSAC). At first it might appear unacceptable to provide an input to the RPS that is derived from a control-grade instrument. The impulse pressure detectors and the majority of the hardware associated with the instrument loops are located in a non-seismically qualified area of the plant and cannot meet any of the requirements for protection-grade equipment. Westinghouse has justified the use of the signal by demonstrating that any failure of a P_{imp} instrument does not reduce the protection provided by the associated protective feature. This concept is discussed in more detail in section 2.3.4. A requirement for any instrument that supplies signals to both protection- and control-grade systems is that the outputs must be separated by isolation amplifiers (I/As). This feature prevents failures in the control systems from propagating into the protection systems and causing undesirable responses.

2.3.3.1 PT-506

Channel PT-506 supplies an input to permissive P-13, the turbine at-power permissive. The P-13 permissive is one of two inputs to permissive P-7, which automatically disables the at-power reactor trips (the low pressurizer pressure, high pressurizer level, and loss of reactor coolant system flow trips, and the reactor trip on turbine trip at some plants) below 10% power and reinstates them above 10% power (see Figure 2.3-4). The PT-506 input to the P-13 permissive logic is lost when impulse pressure decreases below 10%. The loss of both turbine impulse pressure channels removes the P-13 input to P-7. The second input to permissive P-7 is permissive P-10, which is derived from the excore power range signals. The P-13 permissive light on the main control board is illuminated as long as both turbine impulse pressure channels are below 10% and is extinguished when one pressure channel increases above 10%. The P-7 permissive light is illuminated as long as both turbine and nuclear power remain below 10% and is extinguished when either goes above 10%.

Channel PT-506 also provides an input to the high steam line flow ESFAS setpoint generator for protection channel II. At some plants the high steam flow ESF actuation signal (see Figure 2.3-5) initiates an ESF actuation after a steam line break of sufficient severity. The high steam flow setpoint varies with the value of impulse pressure. The setpoint is 1.4 X 10^6 lbm/hr from no load to 20% load, and it increases linearly to 110% of full-power steam flow at 100% power. Each main steam line has two steam flow detectors. The flow signal from one of the two detectors on each of the steam lines is compared to the setpoint from the channel II setpoint generator, and a bistable is tripped if the flow exceeds the setpoint. If a flow exceeding the high steam flow setpoint is sensed by either detector in at least two main steam lines, part of the logic necessary for an ESF actuation is satisfied. An ESF actuation is initiated when the high steam flow signal is coincident with either T_{avg} below the permissive P-12 (low-low T_{avg}) setpoint (553°F) or main steam pressure below 600 psig.

Channel PT-506 supplies an input to the AMSAC logic for starting auxiliary feedwater pumps and for tripping the turbine when conditions indicative of an ATWS are present. The AMSAC logic is satisfied when at least three steam generator narrow range levels are less than the low-low level setpoint and both turbine impulse pressure channels (PT-505 and PT-506) exceed 40%.

2.3.3.2 PT-505

The protection-grade inputs provided by channel PT-505 are completely analogous to those provided by channel PT-506. A redundant input to permissive P-13 is provided by channel PT-505. Also, the channel I high steam flow ESFAS setpoint generator receives its input from channel PT-505; it provides a setpoint for comparison to the signal from one steam flow detector on each steam line. Additionally, channel PT-505 supplies a second turbine power input to the AMSAC logic, as described above.

2.3.4 Channel Failures

A channel failure can be caused by the loss of power, the application of high voltage, an open circuit, a short circuit, or a physical malfunction in the detector itself. The following paragraphs consider only the effects of a signal from a failed channel going to its minimum or maximum value. A failure could cause the signal to go to some intermediate value, but this type of failure is not discussed because of the large number of possible outcomes. Each failure is assumed to occur at 100% power.

2.3.4.1 PT-506 Fails High

If PT-506 fails high, there is no immediate effect on the permissive P-13 logic. Since the initial plant load already exceeds 10%, there is no change in the P-13 status when the signal goes to maximum. If the unit were to be shut down following the failure, the P-13 input to permissive P-7 could not be removed, and therefore P-7 would not automatically block the at-power trips when all other inputs to P-7 are less than 10% power.

In addition, the high steam line flow ESFAS setpoint for protection channel II goes to its maximum value. Since the plant is already at 100% power, there is no effect on the setpoint. If the failure were to occur at a lower power level, the setpoint would be increased to a value that is farther from the actual steam line flow. This would appear to be a non-conservative failure. Westinghouse has demonstrated that protection is provided even for steam breaks at lower power levels with the high flow setpoint at 110% of rated steam flow.

The failed-high instrument has no immediate effect on the steam dump control system, because the C-7 interlock is generated only by a negative change in load. If a load reduction were to occur after the failure, the steam dumps could not be armed because the output of channel PT-506 would not respond to the actual impulse pressure decrease.

2.3.4.2 PT-506 Fails Low

If channel PT-506 fails low, its input to the permissive P-13 logic would be lost, but the P-13 input to P-7 remains intact because the output of the other turbine impulse pressure channel is still above 10%.

Also, the high steam line flow ESFAS setpoint for protection channel II decreases to its minimum value, causing the channel II high steam line flow bistables to trip (this will happen with any initial power level greater than 40%). An ESF actuation does not occur because T_{avg} and steam pressure remain at their normal full-power values; the high steam flow ESF actuation logic is not completely satisfied.

The steam dump system is armed by the C-7 interlock, but the steam dump valves remain closed because there is no temperature error present. This failure illustrates one reason why the high steam line flow ESF actuation signal and the steam dump control system are designed with coincidence features. A single failure cannot cause an ESF or steam dump actuation.

If plant power is > 40%, AMSAC will "disarm" after a 6 minute delay (see figure 4.7-4). Both PT-505 and PT-506 must be above 40% to enable AMSAC response. After either channel drops below 40% a timer holds the arming signal for an additional 6 minutes. After the timer elapses, AMSAC is not functional until operator action is taken at the AMSAC panel.

2.3.4.3 PT-505 Fails High

If channel PT-505 fails high, the effects on the channel I protection features (permissive P-13 and the high steam line flow ESFAS setpoint) are the same as those associated with a PT-506 failure (section 2.3.4.1).

The effects on the control systems are more pronounced. The T_{ref} program generator generates a reference temperature of desired full-power T_{avg}. With the unit already at full load, the channel failure has no effect, but at lower loads it would cause control rods to be withdrawn because T_{avg} would be less than T_{ref}. The P_{imp} input to the rod control system power mismatch circuit causes outward rod motion. The maximum signal from the failed channel is equivalent to 120%; therefore, even with an initial power of 100%, a difference in the rate of change exists between impulse pressure and auctioneered high nuclear power (the channel is assumed to fail to 120% instantaneously). The rods move out until the power mismatch signal decays to zero (the rate comparator provides an output when there is a changing difference between primary and secondary power), after which the rods adjust reactor power until T_{avg} equals T_{ref}. Outward rod motion likely would be limited by one of several rod stops (overtemperature and overpower ΔT, high nuclear power, and interlock C-11, which stops control bank D withdrawal at 223 steps); a rod stop would probably stop outward rod motion before the rate comparator signal completely decays off.

During a plant shutdown following the channel failure, the C-5 interlock would not actuate even though the actual impulse pressure would decrease, so there would be no block of automatic rod withdrawal below 15% load.

The steam generator level setpoint goes to its maximum value as a result of the failure, but with the plant at rated thermal power (RTP), the setpoint is already at its maximum value. The channel failure thus has no effect on steam generator water levels.

2.3.4.4 PT-505 Fails Low

If channel PT-505 fails low, the effects on the channel I protection features (permissive P-13 and the high steam line flow ESFAS setpoint) are the same as those associated with a PT-506 failure (section 2.3.4.2).

The effects on the control systems are more significant. Because PT-505 is failing to its minimum value, the C-5 interlock is actuated, and automatic rod withdrawal is blocked. Rod withdrawal in manual is not affected.

The steam generator water level program generator reduces the level setpoint to its minimum value. Feedwater flow decreases until the steam generator levels decrease to the new setpoint.

T_{ref} is reduced to its no-load value. A temperature error (T_{avg} - T_{ref}) is input to the steam dump system and the rod control system (T_{avg} is greater than the failed-low T_{ref}). Both T_{avg} mode controllers in the steam dump control system have maximum demands, but the steam dump valves do not open because there is no arming signal. If they become armed or another failure occurs, the steam dump valves would open.

The channel failure has a dual effect on the rod control system. The temperature error (T_{avg} greater than T_{ref}) causes inward rod motion. In the power mismatch circuit, there is a large rate of change in P_{imp} with respect to the stable excore nuclear power input. The rate comparator thus also calls for inward rod motion. The result of the inward rod motion is a decrease in nuclear power. T_{avg} decreases because the rate of energy removal from the primary system in the steam generators exceeds the rate of energy production by the reactor. Because it is unaffected by the failed impulse pressure channel, the turbine EHC system attempts to maintain the original load on the turbine (assuming impulse pressure feedback as an input to the turbine EHC system). Inward rod motion stops when the power mismatch signal decays to zero, but before it does, there are significant reductions in T_{avg}, pressurizer level, pressurizer pressure, and steam pressure. During the transient T_{avg} probably decreases to a value lower than the no-load T_{ref}, but the C-5 interlock prevents rod withdrawal. With the large mismatch between primary and secondary power, T_{avg} will likely continue to decrease until a reactor trip occurs. The possible causes of a trip are (1) low pressurizer pressure and (2) a high steam line flow ESF actuation (the high steam line flow bistables are tripped because of the channel failure, and T_{avg} or steam pressure might decrease below its setpoint).

This failure has the same effect on AMSAC as the low failure of PT-506, discussed in paragraph 2.3.4.2.

2.3.5 Operator Response

Each failure description discussed above assumes no operator response to terminate the subsequent plant transient. To determine the proper response and to preclude an unnecessary reactor trip, numerous indications and alarms are available to the operator in the control room. The resulting transient from each of these failures is slow enough that a trained operator would have sufficient time to detect and terminate it.

The initial operator response would be to verify that there is no valid need for rod motion (e.g., a reduction in turbine load) and then to take manual control of the rod control system. The operator would then scan the main control board for failed inputs to the rod control system. During this time the operator would reposition the control rods to maintain T_{avg} at its programmed value for the existing load. At some plants the non-failed channel of impulse pressure can be selected as the input to the T_{ref} program generator for the rod control system. If this is the case, then once the operator has selected away from the failed channel and T_{avg} has been adjusted to the correct value, the operator can put the rod control system back in automatic. If the operator is unable to select away from the failed channel, then the control rods must be operated in manual until the failed channel is repaired.

TABLE 2.3-1 Turbine Impulse Pressure Functions

PT-505	PT-506
PT-505 Protection 1. Input to P-13 (turbine at-power) permissive (protection channel I) 2. Input to high steamline flow ESFAS setpoint generator (protection channel I) 3. Input to AMSAC Control 1. Generates T_{ref} signal for rod control system temperature mismatch circuit and steam dump loss of load controller 2. Input to rod control system power mismatch circuit rate comparator 3. Input to rod control system variable gain unit 4. Input to C-5 interlock, which blocks automatic rod withdrawal when turbine load less than 15% 5. Generates reference level for steam generator water level control system when selected (normal)	**PT-506** Protection 1. Input to P-13 (turbine at-power) permissive (protection channel II) 2. Input to high steamline flow ESFAS setpoint generator (protection channel II) 3. Input to AMSAC Control 1. Provides arming signal for steam dump control system (C-7 loss of load interlock) 2. Generates reference level for steam generator water level control system when selected (normally not selected)

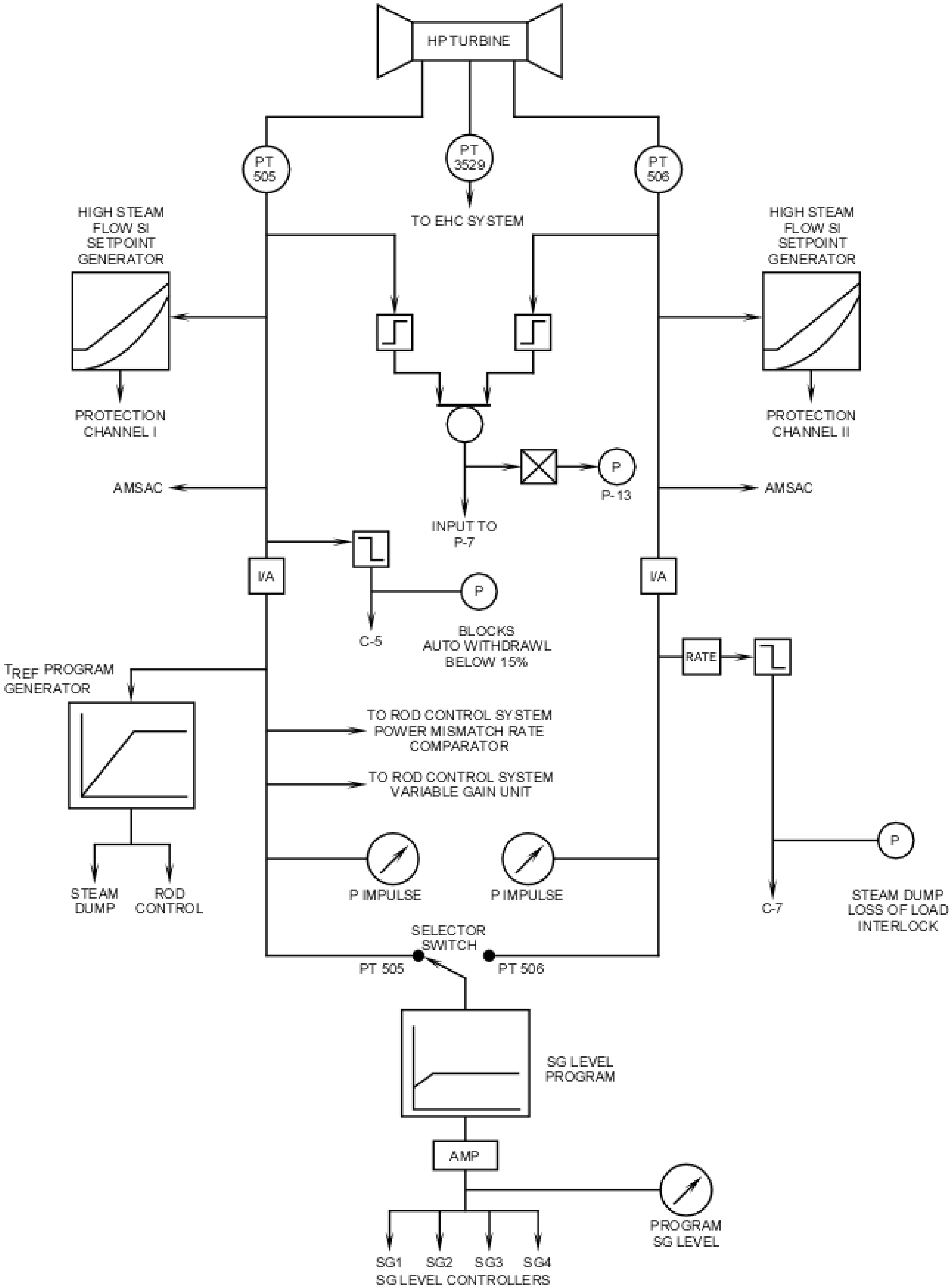


Figure 2.3-1 Turbine Impulse Pressure Functional Diagram

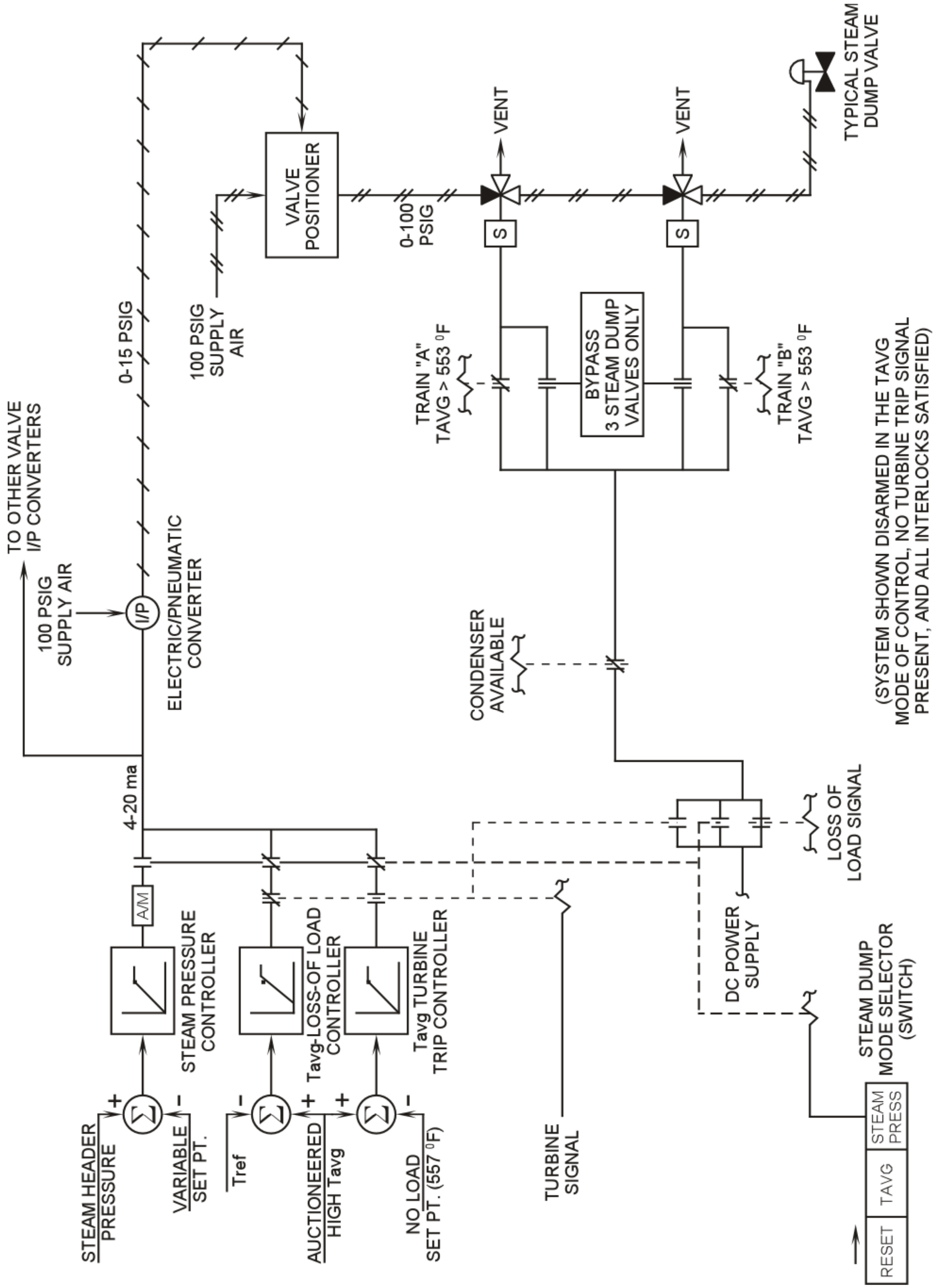


Figure 2.3-2 Steam Dump Control System

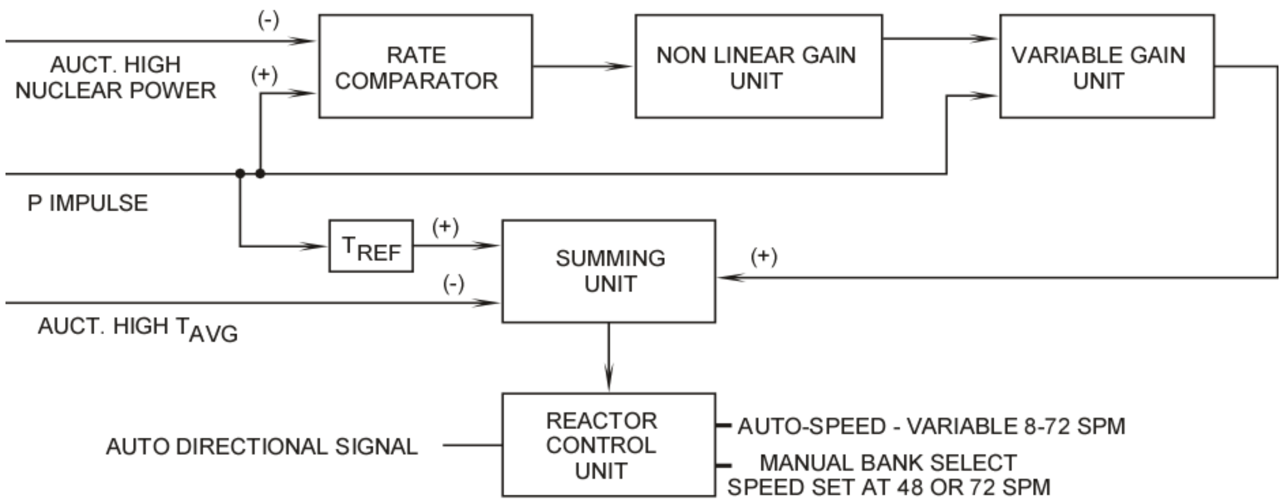


Figure 2.3-3 Rod Control Automatic Demand

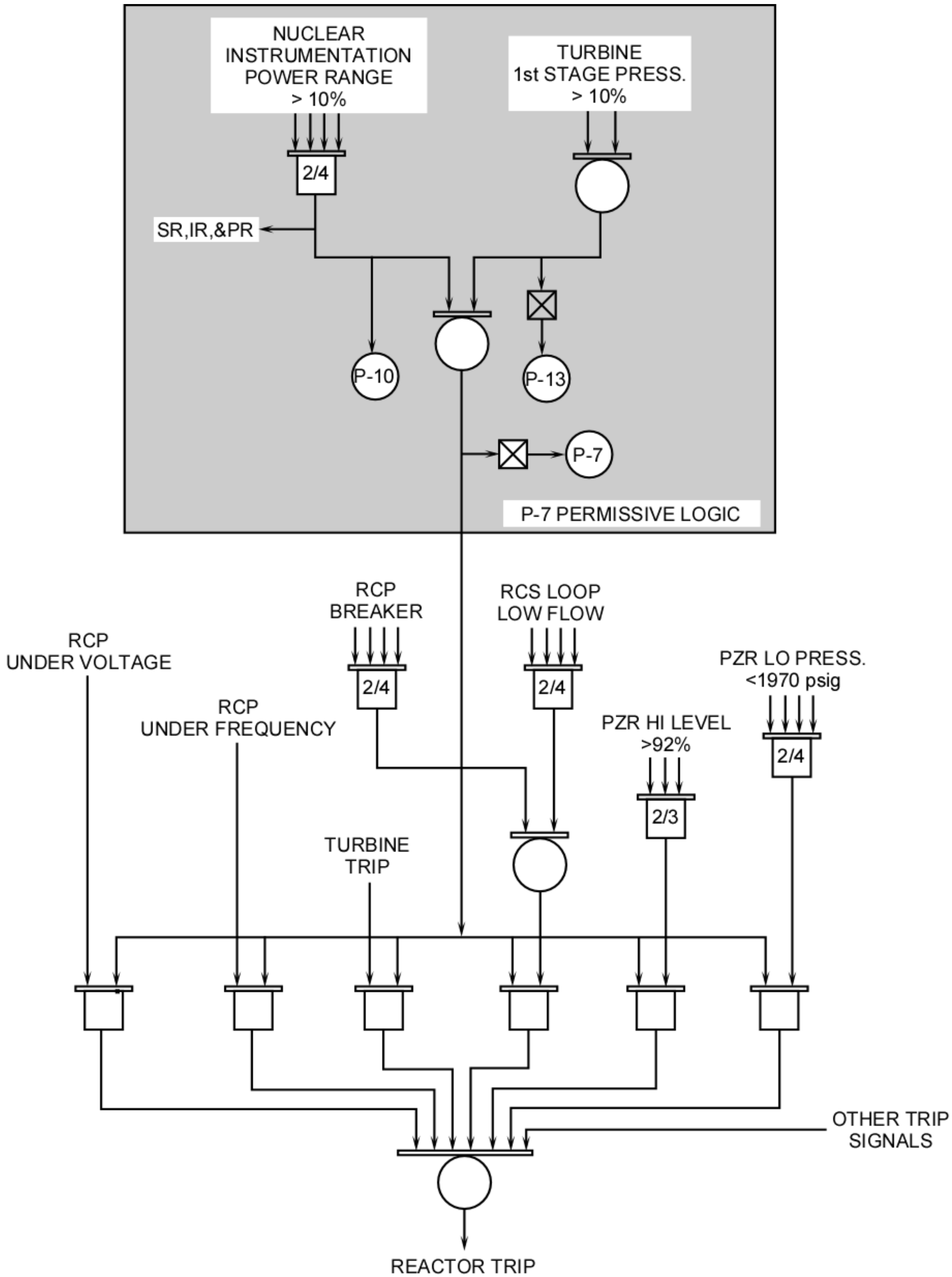


Figure 2.3-4 At-Power Reactor Trip Logic

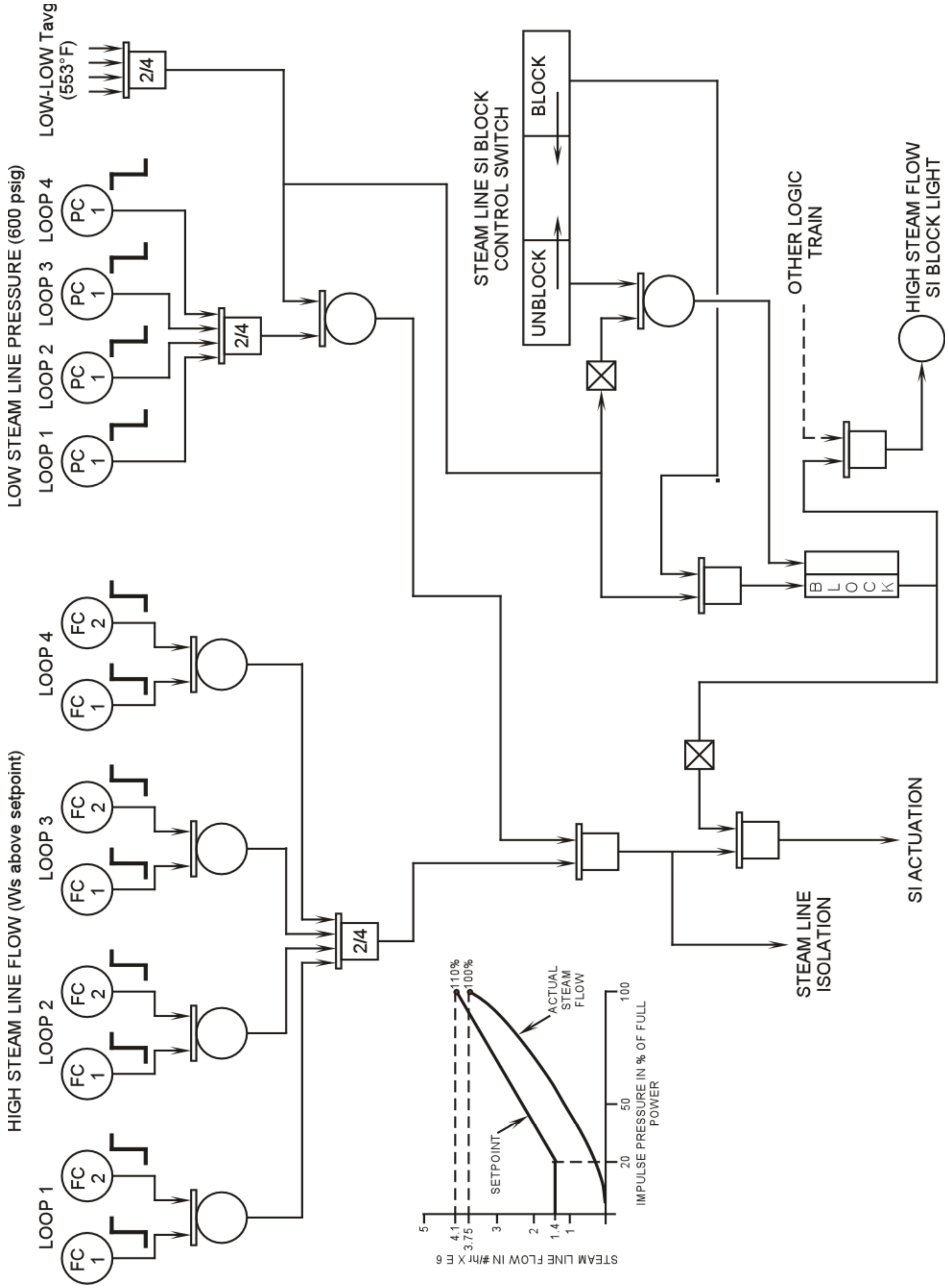
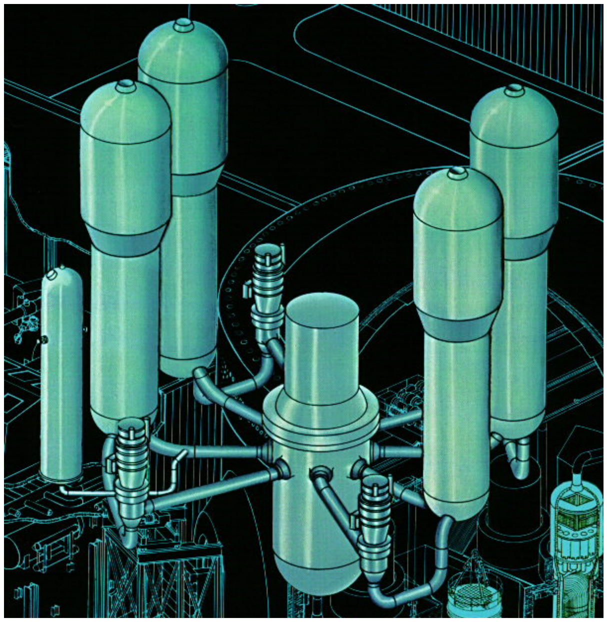


Figure 2.3-5 Hi Steamflow ESF Actuation Logic



Westinghouse Advanced Technology Manual

Chapter 2.4 – Transient Scenarios

2020

HRTD Human Resources Training & Development
U.S.NRC UNITED STATES NUCLEAR REGULATORY COMMISSION Protecting People and the Environment

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2.4.0 Transient Scenarios

Learning Objectives:

1. Given a plant transient scenario, explain the behavior of selected plant parameters, control systems, and equipment for the time designated in the statement of the scenario.

2.4.1 Turbine Impulse Pressure Channel Failure

A Westinghouse plant is operating at 100% power with all control systems in automatic. Turbine impulse pressure channel PT-505 fails low. Using Figure 2.3-1 (section 2.3), describe the responses of the following parameters:

1. T_{avg},
2. Pressurizer pressure,
3. Pressurizer level,
4. Main steam header pressure,
5. Main steam flow rate,
6. Power-range power,
7. Control bank D rod position, and
8. Charging flow rate.

2.4.2 Emergency Boration

A Westinghouse plant is operating at 100% power with the rod control system in manual and all other control systems in automatic. Explain the responses of reactor power and T_{avg} after two minutes of emergency boration.

If the plant were at 10^{-8} amps in the intermediate range and no-load T_{avg}, what would be the responses of reactor power and T_{avg} after a two-minute emergency boration?

2.4.3 Steam Generator Safety Valve Failure

A Westinghouse plant is operating at 80% power with control bank D at 220 steps. A code safety valve on the B steam generator fails open.

1. Describe the effect on the steam flow input to the steam generator level control system.
2. Describe the effect on the steam flows from the other steam generators.
3. Explain how plant parameters other than steam flows can aid the operator in diagnosing the problem.

2.4.4 Steam Flow Increase with - MTC

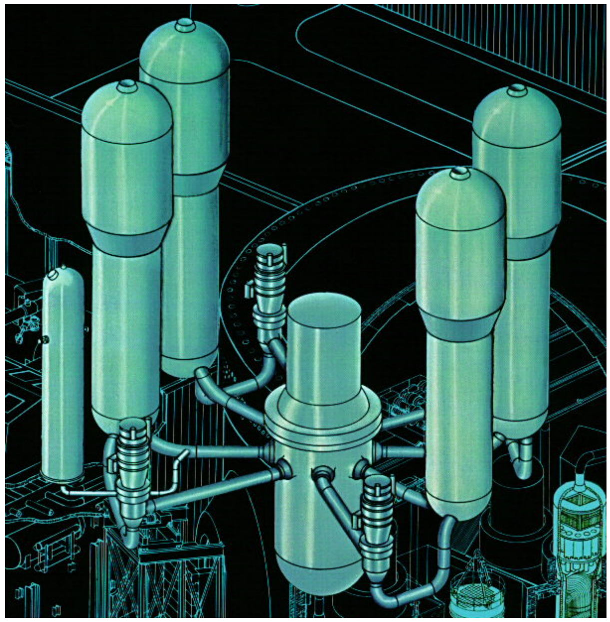
A Westinghouse plant is in the process of starting up with reactor power and steam flow matched at five percent. The steam flow is increased to seven percent. With a negative moderator coefficient and no operator action:

1. Describe the plant response.
2. State what plant condition will terminate the transient (reactor trip, engineered safety features actuation, steady-state operation, etc.).

2.4.5 Steam Flow Increase with + MTC

A Westinghouse plant is in the process of starting up with reactor power and steam flow matched at five percent. The steam flow is increased to seven percent. With a positive moderator coefficient and no operator action:

1. Describe the plant response.
2. State what plant condition will terminate the transient (reactor trip, engineered safety features actuation, steady-state operation, etc.).



Westinghouse Advanced Technology Manual

Chapter 3.1 – Analysis of Technical Specifications
Unit 1

2021

HRTD Human Resources Training & Development

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

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3.1.0 Analysis of Technical Specifications – Unit 1

Learning Objectives:

1. State the requirements for and briefly describe the categories included in technical specifications.
2. Demonstrate understanding of the meanings of all defined terms in the technical specifications by applying them correctly in operational scenarios.
3. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation.
4. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.

3.1.1 Introduction

This section is the first of four technical specification sections. It briefly discusses the requirements for technical specifications, covers the technical specification areas of definitions and safety limits, and provides general guidance for the use and application of the limiting conditions for operation (LCOs) and surveillance requirements. Safety limits are limits upon plant parameters, such as pressure, power, temperature, and flow, which are necessary to prevent fuel damage or the release of radioactive material. Limiting conditions for operation identify the required performance levels for safe operation, in terms of equipment operability and limits on certain plant parameters in areas such as reactivity control and power distribution. The limiting conditions for operation are verified by the performance of surveillance requirements. Surveillance requirements specify the tests and functional requirements that equipment must satisfy in order to meet the limiting conditions for operation.

The significance of the technical specifications is further realized through evaluation of the bases for the specifications. Each technical specification basis provides information as to why some limit or requirement has been established and how it contributes to plant safety.

3.1.2 Technical Specification Requirements

Each utility applying for a license to operate a nuclear reactor for commercial purposes must submit proposed technical specifications with its application to the Nuclear Regulatory Commission. This is a requirement of the Code of Federal Regulations, Title 10, Chapter I, Part 50, paragraph 36 (10 CFR 50.36). Each license authorizing operation of a production facility will then include technical specifications. Technical specifications are derived from analyses and evaluations included in the Final Safety Analysis Report (FSAR).

10 CFR 50.36 requires that technical specifications include the following categories:

- Safety limits and limiting safety system settings,
- Limiting conditions for operation,
- Surveillance requirements,
- Design features, and
- Administrative controls.

Safety limits are limits upon process variables necessary to protect the integrity of certain physical barriers which guard against the uncontrolled release of radioactivity. The physical barriers protected by safety limits are the fuel cladding and the reactor coolant system (RCS).

Limiting safety system settings are settings for automatic protective devices related to variables having significant safety functions. The protective action from a limiting safety system setting corrects the abnormal situation before the safety limits are exceeded.

Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation. Each LCO is accompanied by applicability and action statements. The applicability statement identifies plant conditions during which the limiting condition for operation applies. The action statements provide requirements that are invoked when the limiting condition for operation is not met. The lowest allowed performance level of a system is met when either an action statement of the LCO or the LCO itself is satisfied.

Surveillance requirements are requirements relating to tests, calibrations, and inspections which ensure that the LCOs are met.

Design features included in technical specifications are those features of the facility which, if altered or modified, would have a significant effect on safety. Such features include construction materials and geometric arrangements.

Administrative controls are provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to ensure safe operation.

The Code of Federal Regulations (10 CFR 50.36a) separately requires technical specifications for radioactive effluents. Radioactive effluent technical specifications require compliance with the dose limits of 10 CFR 20, procedures and equipment for the control of radioactive effluents, and reporting requirements for radioactive releases. These requirements are addressed in the administrative controls section of the technical specifications, which is discussed in Section 3.3 of this manual.

Other sections included in technical specifications are (1) definitions and (2) the bases for the safety limits, limiting safety system settings, LCOs, and surveillance requirements. The definitions section provides meanings for expressions used throughout the technical specifications. Bases are summary statements of the bases or reasons for specifications. Bases are required to be submitted with technical specifications for license application, but are not required as a part of technical specifications. Nevertheless, they are routinely included in technical specifications.

3.1.3 Technical Specification Formats

Three different technical specification formats are currently in use at licensed facilities: custom, standard, and improved standard technical specifications. These formats are discussed in the following paragraphs.

Originally, technical specifications were prepared on an individual basis for each facility and thus became known as custom technical specifications. This ad hoc approach resulted in the issuance of specifications which addressed each of the categories required by 10 CFR 50.36, but also resulted in great diversity in terms of the technical content of specifications and the interpretations of requirements by licensee staffs and NRC inspectors. Although custom technical specifications have largely been supplanted by standard formats throughout the commercial nuclear power industry, they remain in use at a few plants. Attachment A illustrates a custom LCO and accompanying surveillance requirements for the safety injection system.

In an effort to provide a systematic approach to technical specification content, the NRC initiated the Standard Technical Specification Program in the 1970s. This program resulted in the issuance of standard technical specifications for each nuclear steam supply system (NSSS) design. For Westinghouse plants, the standard format and content of technical specifications was provided in NUREG-0452, “Standard Technical Specifications for Westinghouse Pressurized Water Reactors” (revised several times). The standard technical specifications were used as the template for the technical specifications of newly licensed plants, and many licensees converted their custom technical specifications to the standard format as well. Attachment B illustrates a standard LCO and accompanying surveillance requirements for the emergency core cooling systems (ECCSs).

Over the last few decades there has been a trend toward including in technical specifications not only those requirements derived from the analyses and evaluations in the FSAR, but also essentially all other NRC requirements governing reactor operation. This extensive use of technical specifications has been due in part to a lack of well-defined criteria for what should be included in technical specifications. This practice has contributed to the volume of technical specifications, a large increase in the number of technical specification amendment applications, and a potentially adverse impact on safety.

To address these issues, in the 1980s the nuclear industry and the NRC began studying whether the existing technical specification requirements needed improvement. This effort culminated in 1993 with the issuance of revised criteria for the contents of technical specifications, published in the “Final Policy Statement on Technical Specification Improvements for Nuclear Power Reactors.” The final policy statement was incorporated into 10 CFR 50.36 in 1995 and reads as follows:

> (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.

Based on the criteria of the final policy statement (and the preceding interim criteria), improved standard technical specifications have been developed for each NSSS design. These improved standard specifications are the result of extensive public technical meetings and discussions between the NRC staff and various nuclear power plant licensees, NSSS owners groups, NSSS vendors, and the Nuclear Energy Institute. For Westinghouse pants, the improved standard technical specifications are provided in NUREG-1431, “Standard Technical Specifications, Westinghouse Plants,” originally issued in 1992 and first revised in 1995.

Licensees are encouraged to upgrade their technical specifications consistent with the criteria of the final policy statement and conforming to the improved standard technical specifications. The NRC continues to place the highest priority on requests for complete conversions to the improved standard technical specifications. Several licensees have already converted their technical specifications, and it is expected that ultimately most specifications will conform to the improved standard format. Technical specifications conforming to the improved standard technical specifications of NUREG-1431 have been developed for TTC Unit 2 (the Westinghouse simulator) and are used to illustrate technical specification requirements and usage in this manual.

3.1.4 Definitions

To ensure a uniform interpretation of technical specifications, selected terms are defined in the definitions section. The definitions comprise a subsection of the use and application section of the specifications. Defined terms used throughout technical specifications are identified by upper-case type (a practice also observed in the technical specification sections of this manual). Selected definitions are discussed in the following paragraphs.

3.1.4.1 Instrumentation

The proper measurement of process variables such as pressurizer pressure, RCS average temperature (T_{avg}), RCS differential temperature (ΔT), and nuclear power is verified by three methods:

- CHANNEL CHECK: the qualitative assessment of channel behavior during operation by observation.
- CHANNEL OPERATIONAL TEST: the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of the required alarm, interlock, display, and trip functions.
- CHANNEL CALIBRATION: the adjustment, as necessary, of the channel output such that it responds within the required range and accuracy to known values of input.

Control room operators perform CHANNEL CHECKS during routine observation of control board indications. For instance, the indications of all four RCS T_{avg} meters are compared to each other to ensure agreement among them. If a deviation exists, instrumentation and control technicians then perform a CHANNEL OPERATIONAL TEST on the instrument showing the deviation. CHANNEL OPERATIONAL TESTS are performed on all channels which measure process variables at routine intervals and when deviations are identified. Adjustments of trip, interlock, and alarm setpoints are made to ensure that the setpoints are within the required range of accuracy. A CHANNEL CALIBRATION is performed to ensure that a channel responds properly to a known input. During a channel calibration, the channel’s sensor and bistables are adjusted to provide accurate and proper responses.

3.1.4.2 RCS Leakage

Because of the potential radiological and equipment problems associated with RCS LEAKAGE, it is important to understand the types of LEAKAGE. These include:

- Identified LEAKAGE,

- Unidentified LEAKAGE, and
- Pressure boundary LEAKAGE.

Identified LEAKAGE is LEAKAGE:

Such as that from pump seals or valve packing, that is captured and conducted to collection systems or a sump or collecting tank;

Into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

From the RCS through a steam generator to the secondary system.

Pressure boundary LEAKAGE is LEAKAGE (except steam generator tube LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

Unidentified LEAKAGE is leakage which is not identified LEAKAGE. When LEAKAGE from the RCS is first suspected or discovered, it is normally categorized as unidentified LEAKAGE.

Once the source of LEAKAGE is determined, it can be recategorized as either identified or pressure boundary LEAKAGE.

3.1.4.3 Operability

Many limiting conditions for operation for specific equipment require systems or components to be OPERABLE. The designation OPERABLE/OPERABILITY stipulates that a system, subsystem, train, component, or device is capable of performing its specified safety functions, and that all necessary controls, power, and auxiliary equipment required for the system, subsystem, train, component, or device to perform its specified safety functions are also capable of performing their related support functions. For instance, a centrifugal charging pump that starts and delivers flow to the RCS could not be considered OPERABLE if its lubricating oil or cooling water support system is out of service.

3.1.4.4 Operational Modes

Operation of the plant is divided into six operational MODES. An operational MODE corresponds to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning, as specified in technical specification Table 1.1-1, with fuel in the reactor vessel.

Operational MODES are used to identify plant conditions during which certain limiting conditions for operation apply.

3.1.4.5 Shutdown Margin

SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming:

a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. However, with all RCCAs verified fully inserted by two independent means, it is not necessary to account for a stuck RCCA in the SDM calculation. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM, and

b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.

3.1.5 Use and Application

Section 1.0, Use and Application, contains definitions (as in the examples above) and also gives several examples of how to use technical specifications.

Section 1.2 explains the use of the logical connectors AND and OR. Levels of logic are identified by the placement (or nesting) of the logical connectors.

Section 1.3 establishes the completion time convention and gives several examples of completion time application. The completion time extension associated with subsequent inoperability is defined here.

Section 1.4 defines the proper use and application of the frequency requirements and gives several examples.

It is not the intention of this manual to repeat these sections of technical specifications. The student should read section 1.0 and work through the examples.

3.1.6 Safety Limits and Limiting Safety System Settings

3.1.6.1 Safety Limits

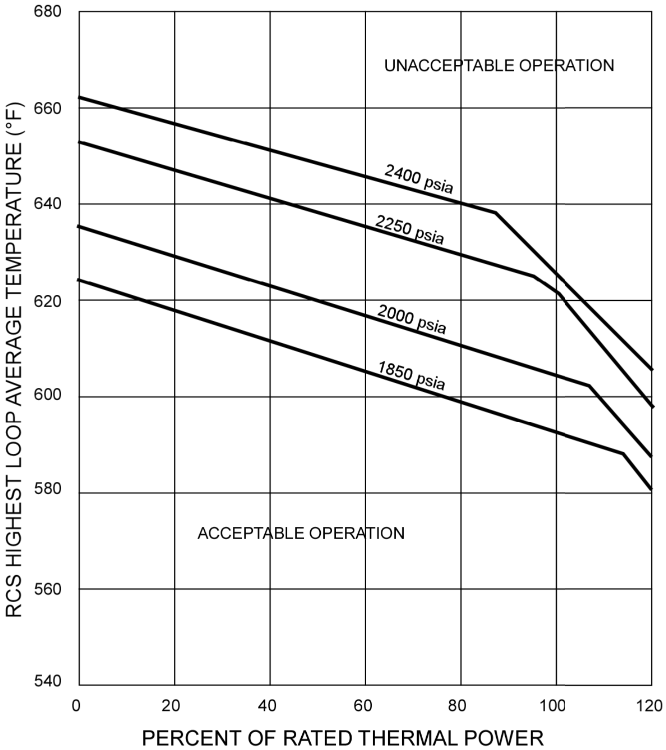
Safety limits are established to prevent the uncontrolled release of radioactivity by protecting the integrity of fission product barriers during normal operation and anticipated operational occurrences.

The safety limits on the reactor core address the first barrier to the release of radioactive material, the fuel cladding. The possibility of fuel cladding damage is prevented by observing operating limits that preclude violation of the following fuel design criteria:

There must be at least 95% probability at a 95% confidence level (the 95/95 departure from nucleate boiling [DNB] criterion) that the hot fuel rod in the core does not experience DNB; and the hot fuel pellet in the core must not experience centerline fuel melting.

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core safety limits.

The safety-limit curves in Figure COLR-1 show the loci of points of thermal power, pressure, and average coolant temperature for which either:



- The average enthalpy at the core exit is equal to the enthalpy of saturated liquid (left-hand segments),
- The minimum departure from nucleate boiling ratio (DNBR) is not less than the safety-analysis limit (right-hand segments), or
- The local core-exit quality is within the limits defined in the DNBR correlation (center segments of some curves).

Operation of the plant with a T_H less than saturation temperature results in a core ΔT (T_H - T_c) proportional to reactor power. Consequently, the measured ΔT can be used as an input to the reactor protection system for the prevention of overpower conditions. If the average core-exit temperature reaches saturation, the core ΔT is no longer proportional to power. With the hot leg at saturation, an increase in power increases steam formation (i.e., increases the steam fraction at the core exit) without an increase in ΔT. To prevent this condition, hot-leg saturation is a limiting factor for the safety-limit curves.

The DNBR limit is imposed because of the rapid and large increase in cladding wall temperature that accompanies the departure from nucleate boiling. (Refer to Section 3.4 of this manual for a discussion of DNB and DNBR.)

The safety limit on RCS pressure protects the integrity of the RCS. The limiting pressure for the RCS is the maximum pressure allowed in the reactor vessel by Section III of the ASME Code for Nuclear Power Plant Components. This pressure is 2735 psig, which corresponds to 110% of design pressure. By maintaining the integrity of the reactor vessel and the reactor coolant piping, valves, and fittings, the release of radionuclides to the containment atmosphere is prevented.

If any safety limit is violated during power operation, the licensee must restore compliance in accordance with SL 2.2. In addition to this, the licensee must comply with 10 CFR 50.36(c)(1) which includes the requirement that “Operation must not be resumed until authorized by the Commission.”. The licensee must also notify the NRC Operations Center within one hour, in accordance with 10 CFR 50.72.

3.1.6.2 Limiting Safety System Settings

Limiting safety system settings are protective device setpoints selected to prevent the reactor core and RCS from exceeding their safety limits during normal operation and anticipated operational occurrences (Condition I and II events). In standard technical specifications (conforming to NUREG-0452), the limiting safety system settings are listed in a separate section. In improved standard technical specifications (conforming to NUREG-1431), the limiting safety system settings are included as the reactor trip system (RTS) setpoints in the RTS instrumentation LCO. This LCO is discussed in Section 3.2 of this manual.

Figure 3.1-1 illustrates protective features designed to prevent exceeding the DNB safety limit.

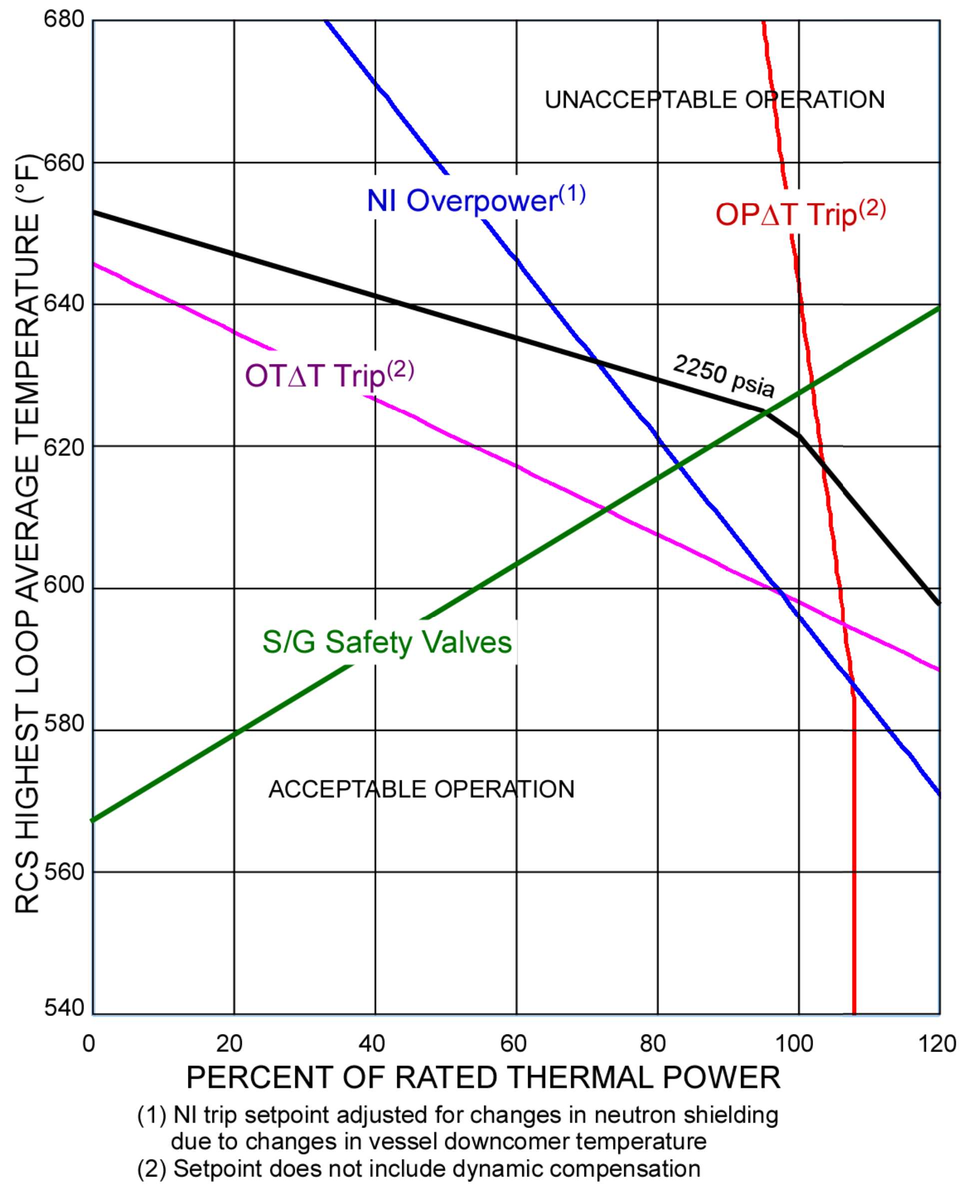


Figure 3.1-1 Reactor Core Safety Limits vs. Boundary of Protection

3.1.7 Limiting Conditions For Operation

Limiting conditions for operation provide the lowest functional performance levels required of equipment for safe operation.

Attachment A is an example of a custom technical specification LCO. Note that the statement of the LCO in the left-hand column specifies the extent of system OPERABILITY and the operational MODES in which the LCO is applicable. Note also that some of the left-hand column paragraphs provide additional requirements and time limits for action in the event that the LCO is not completely satisfied. The surveillance requirements applicable to each paragraph of the LCO are provided in the right-hand column. The bases for this LCO (not shown in Attachment A) and other ECCS LCOs are provided at the end of the ECCS section of the technical specifications.

Attachment B is an example of a standard technical specification LCO. The statement of the LCO, the applicability requirements, and the actions to be taken when the LCO is not met are provided in a more straightforward manner. This format for LCO presentation is consistently maintained throughout the technical specifications. The LCO and its associated applicability and action statements are immediately followed by the surveillances required to ensure that the LCO is satisfied (only the first page of surveillance requirements is shown in Attachment B). The bases for this LCO (also shown in Attachment B) and other ECCS LCOs are provided in the ECCS bases section of the specifications.

The LCO section of standard technical specifications (conforming to the NUREG-0452 format) is typically divided into the following subsections:

- Applicability,
- Reactivity control systems,
- Power distribution limits,
- Instrumentation,
- Reactor coolant system,
- Emergency core cooling systems,
- Containment systems,
- Plant systems,
- Electrical power systems,
- Refueling operations,
- Special test exceptions,
- Radioactive effluents, and
- Radiological environmental monitoring.

The bases section of the specifications immediately follows the last LCO. The bases section is divided into subsections consistent with those listed above for the LCOs.

The use and application section of the technical specifications provides guidance for the interpretation of the required actions and completion times included in the LCO action tables, and also for the frequencies with which required surveillances must be performed.

The LCO section of improved standard technical specifications (conforming to the NUREG-1431 format) is typically divided into the following subsections:

- Applicability,
- Reactivity control systems,
- Power distribution limits,
- Instrumentation,
- Reactor coolant system,
- Emergency core cooling systems,
- Containment systems,
- Plant systems,
- Electrical power systems, and
- Refueling operations.

These LCO groupings are similar to those of standard technical specifications. In improved standard technical specifications, special test exceptions are incorporated into the reactivity control systems section, and requirements for radioactive effluents and radiological environmental monitoring are incorporated into programs required by the administrative controls section.

The bases section of improved standard technical specifications is divided into subsections consistent with the list above and is provided in a separate specification volume. The basis for a particular LCO provides information in the following areas:

- Background information on the subject system, component, or parameter;
- How the LCO relates to applicable safety analyses in the FSAR;
- The contribution to unit safety provided by compliance with the LCO;
- The conditions in which the LCO applies;
- Reasons for the required actions to be taken when the LCO is not met;
- Reasons for the surveillance requirements which verify compliance with the LCO; and
- Referenced documents.

This information is generally much more extensive and far more indicative of the LCO's relationship to safety analyses than that provided by the superseded standard technical specifications.

Detailed discussions of the LCOs in each LCO subsection of the technical specifications are provided in Sections 3.2, 3.3, and 3.4 of this manual.

3.1.8 Technical Requirements Manual

Many LCOs which had been included in standard technical specifications (conforming to NUREG-0452) do not meet the updated criteria for inclusion in technical specifications and are thus not included in improved standard technical specifications (conforming to NUREG-1431). Many of these LCOs and their associated action and surveillance requirements have been relocated to the Technical Requirements Manual. These requirements are implemented in the same fashion as technical specifications, but they are treated as plant procedures. Violations of technical requirement action or surveillance requirements are not reportable as conditions prohibited by technical specifications per 10 CFR 50.72 or 10 CFR 50.73. Also, power reductions or plant shutdowns required to comply with technical requirement action statements are not reportable per 10 CFR 50.72 or 10 CFR 50.73. Violations of technical requirement action or surveillance requirements are treated as plant procedure violations by licensees and may be cited as such by NRC inspectors.

3.1.9 Exercises

Exercise 1

The unit is operating at 95% power. On May 15 at 1:00 p.m., accumulator A becomes inoperable because its boron concentration is not within limits. On May 17 at 2:00 p.m., accumulator D becomes inoperable for the same reason. On May 17 at 4:00 p.m., the boron concentration of accumulator A is restored to within limits (i.e., the operability of accumulator A is restored). See LCO 3.5.1.

1. At the time the first accumulator becomes inoperable, what condition is entered?
2. At the time the second accumulator becomes inoperable, what condition(s) apply?
3. When the first inoperable accumulator is restored to operable status, what condition(s) apply?
4. How long can accumulator D remain inoperable before a condition requiring a unit shutdown is entered?

Exercise 2

The unit is in Mode 1. The following sequence of events occurs (see LCO 3.8.1):

June 1, 8:00 a.m.	Diesel generator B becomes inoperable.
June 3, 8:00 a.m.	The offsite circuit which supplies power to ESF bus A becomes inoperable. The diesel generator remains inoperable.
June 3, 4:00 p.m.	Diesel generator B is restored to operable status. The offsite circuit remains inoperable.
June 5, 8:00 a.m.	Diesel generator A becomes inoperable. The offsite circuit remains inoperable. Assume the bus remains energized through the unit auxiliary transformer.
June 5, 2:00 p.m.	The inoperable offsite circuit is restored to operable status. Diesel generator A remains inoperable.

1. State the conditions which apply at each interval.
2. How long can diesel generator A remain inoperable before a condition requiring a unit shutdown is entered?

TECHNICAL SPECIFICATIONS UNIT 1 - EXERCISE 1 SOLUTION

1. At the time the first accumulator becomes inoperable, what condition is entered?

Condition A of LCO 3.5.1 (one accumulator inoperable due to boron concentration not within limits) is entered.

2. At the time the second accumulator becomes inoperable, what condition(s) apply?

Condition D of LCO 3.5.1 is entered, because two accumulators are now inoperable. Also, the Completion Time for Condition A continues to be tracked.

3. When the first inoperable accumulator is restored to operable status, what condition(s) apply?

When the first inoperable accumulator is restored to operable status, Condition D is exited; operation continues in accordance with Condition A. The unit has been in Condition A for 51 hours.

4. How long can accumulator D remain inoperable before a condition requiring a unit shutdown is entered?

In accordance with the rules for Completion Times and Completion Times example 1.3-2 in the Technical Specifications, the Completion Time for Condition A may be extended if the accumulator restored to operable status is the first inoperable accumulator. A 24-hour extension to the stated 72 hours is allowed, provided that accumulator D does not remain inoperable for greater than 72 hours. Extending the Completion Time by 24 hours allows Condition A to remain in effect until 1:00 p.m. on May 19, at which time accumulator D will have been inoperable for 47 hours. Unless additional time is provided by the risk informed completion time program, if the boron concentration of accumulator D is not restored by then, Condition D, a condition requiring a unit shutdown, will be entered.

TECHNICAL SPECIFICATIONS UNIT 1 - EXERCISE 2 SOLUTION

1. State the conditions which apply at each interval.

June 1, 8:00 a.m. Condition B is entered. Completion Time for restoration of operable status (Required Action B.4): 72 hours. (Other required actions apply.)

June 3, 8:00 a.m. Conditions A & D are entered. Completion Time for restoration of offsite circuit operability (Required Action A.3): 72 hours. (Other required actions for Condition A apply.) Completion Time for restoration of either diesel generator or offsite circuit (Required Action D.1 or D.2): 12 hours. Condition B still applies; the unit has been in Condition B for 48 hours.

June 3, 4:00 p.m. Conditions B & D are exited (each within the specified Completion Time). Condition A still applies; the unit has been in Condition A for 8 hours.

June 5, 8:00 a.m. Conditions B & D are reentered, with Completion Times of 72 hours and 12 hours, respectively. Condition A still applies; the unit has been in Condition A for 48 hours. Since the bus still has an AC power source (the unit auxiliary transformer), it is not necessary to declare the bus inoperable (i.e. apply actions of LCO 3.8.9). A bus is operable if it is energized, even if it has neither TS required source.

June 5, 2:00 p.m. Conditions A & D are exited (each within the specified Completion Time). Condition B still applies; the unit has been in Condition B for 6 hours.

2. How long can diesel generator A remain inoperable before a condition requiring a unit shutdown is entered?

Diesel generator A can remain inoperable until 8:00 a.m. on June 8, when its 72 hour completion time expires. Unless additional time is gained through application of the risk informed completion time program, condition H is entered at that time.

LIMITING CONDITION FOR OPERATION	SURVEILLANCE REQUIREMENT
3.8.2 Safety injection pump system	4.8.2 Safety injection pump system
A. The two safety injection systems shall be operable whenever the reactor is going from hot shutdown to hot standby.	A. Surveillance and pump testing of the safety injection system shall be performed as follows: 1. The safety injection pumps shall be started manually from the control room each month. Performance will be acceptable if the pump starts upon actuation, operates for at least 10 minutes on recirculation flow, and the discharge pressure and recirculation flow are within ± 10% of a point on the pump head curve. 2. The annunciators associated with the normally open valve (MOV-SI8806) in the suction of the safety injection pumps shall be checked quarterly. 3. The normally open valve (MOV-SI8806) in the suction line of the safety injection pumps shall be stroked manually from the control room to check the position indicators and annunciators every refueling outage.
B. The two safety injection systems shall be operable whenever the reactor is in hot standby or operating except as specified in 3.8.2.C.	B. Not Applicable
C. From and after the date that one of the two safety injection pumps is made or found to be inoperable for any reason, reactor operation including recovery from an inadvertent trip is permissible only during the succeeding 7 days provided that during those 7 days the remaining safety injection pump system and both centrifugal charging pump systems and both residual heat removal pump systems are operable.	C. When it is determined that one of the two safety injection pump systems is inoperable the remaining safety injection pump system, both centrifugal charging pump system, and both residual heat removal pump systems, including the associated standby AC and DC power supplies (see sections 4.15.1.B.2 and 4.15.1.B.1) shall be demonstrated to be operable immediately and daily thereafter.

EMERGENCY CORE COOLING SYSTEMS

ECCS SUBSYSTEMS - $T_{avg} \geq 350°F$

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent ECCS subsystems shall be OPERABLE with each subsystem comprised of:

a. One OPERABLE centrifugal charging pump,

b. One OPERABLE safety injection pump,

c. One OPERABLE residual heat removal heat exchanger,

d. One OPERABLE residual heat removal pump, and

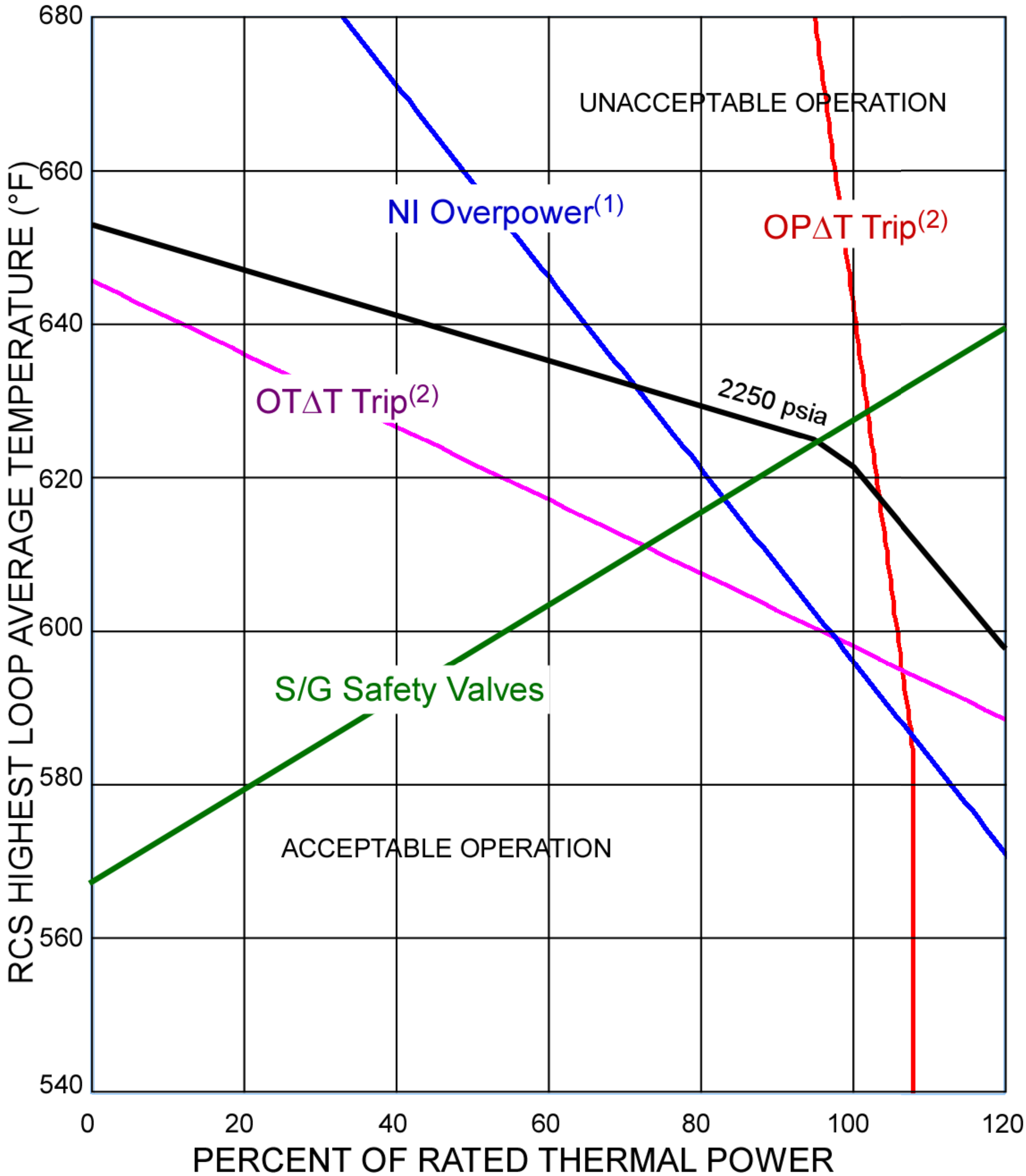
e. An OPERABLE flow path capable of taking suction from the refueling water storage tank on a safety injection signal and transferring suction to the containment sump during the recirculation phase of operation.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

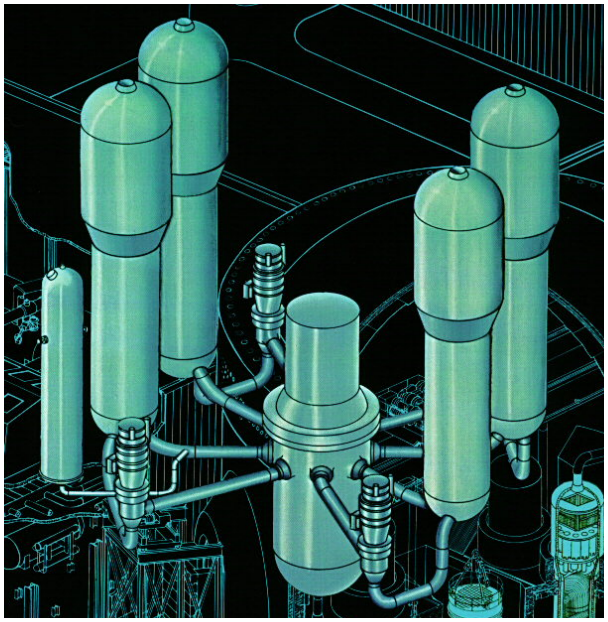
a. With one ECCS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.



(1) NI trip setpoint adjusted for changes in neutron shielding due to changes in vessel downcomer temperature
(2) Setpoint does not include dynamic compensation

Figure 3.1-1 Reactor Core Safety Limits vs. Boundary of Protection



Westinghouse Advanced Technology Manual

Chapter 3.2 – Analysis of Technical Specifications
Unit 2

2020

HRTD Human Resources Training & Development

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3.2.0 Analysis of Technical Specifications – Unit 2

Learning Objectives:

1. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation.
2. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.

3.2.1 Introduction

This section is the second of four technical specification sections. This section presents the limiting conditions for operation (LCOs), bases for LCOs, and applications of requirements during different situations for the following technical specification areas:

- Applicability,
- Reactivity control systems,
- Instrumentation,
- The reactor coolant system (RCS), and
- Emergency core cooling systems (ECCSs).

The limiting conditions for operation for these areas identify the minimum performance levels for equipment required to ensure safe operation.

3.2.2 Applicability

The applicability LCOs (also commonly referred to as "motherhood" LCOs) establish the general requirements applicable to all LCOs. The applicability LCOs may be summarized as follows:

- LCO 3.0.1 - Compliance with a particular LCO is required during the operational MODES or other conditions specified in the LCO's applicability statement.

- LCO 3.0.2 - Satisfying the requirements of an LCO or its associated required ACTIONS within the specified time interval(s) constitutes compliance with the specification.

  Together, LCOs 3.0.1 and 3.0.2 indicate that there are three ways to comply with any LCO:

  Meet the LCO (without having to resort to an ACTION requirement), or

  Meet the required ACTIONS of an associated condition, or

  Be in a MODE or other specified condition in which the LCO does not apply.

  There are also five special conditions when it is acceptable to do none of these three. These conditions are described by LCOs 3.0.5, 3.0.6, 3.0.7, 3.0.8, and 3.0.9.

- LCO 3.0.3 - When an LCO and its associated required ACTIONS cannot be satisfied because of circumstances beyond those addressed in the specification's ACTIONS table, action must be initiated to place the unit in an operational MODE in which the specification does not apply, in accordance with specified time intervals. According to the basis for LCO 3.0.3, "This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit.

- LCO 3.0.4. - When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

  1. When the associated ACTIONS permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time;

2. In accordance with the plant's risk management program, or;
3. When an allowance is stated in the individual value, parameter, or other Specification.

It is always acceptable to shut down the plant or comply with an ACTION requirement.

- LCO 3.0.5 - Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment.

  Sometimes, the only way to demonstrate OPERABILITY after maintenance is to place the plant in a condition that is prohibited by required ACTIONS. In this case, LCO 3.0.5 allows the otherwise prohibited condition to exist for the sole purpose of demonstrating OPERABILITY.

- LCO 3.0.6 - When the LCO for a supported system is not met solely due to the LCO for a support system not being met, the required ACTIONS for the supported system are not required to be entered. Only the required ACTIONS for the support system LCO are required to be entered. Entry into the required ACTIONS of the LCO for the supported system may be required, however, if a loss of safety function is determined to exist.

  This is often called the cascading rule. "Cascading" means that the loss of one system leads to the subsequent inoperability of other systems. For example, if one train of the service water system is inoperable, then, by the definition of OPERABILITY, every train and component that relies on cooling by that service water train is also inoperable. But LCO 3.0.6 says that it is not necessary to cascade, i.e., it is not necessary to also enter the required actions for the supported trains and components, unless the required ACTIONS of the service water system LCO specifically require it.

  It is possible that some equipment other than a service water train is also inoperable, and the combination of inoperable equipment causes the loss of a safety function. (For example, a loss of the low pressure injection (LPI) safety function would result if the train 'B' LPI pump were already inoperable and the train 'A' LPI pump is subsequently rendered inoperable by the inoperability of service water train 'A.') In that case, one would cascade (apply the required ACTIONS for the affected supported systems).

- LCO 3.0.7 – Test Exception LCO 3.1.8 allows specified TS requirements to be suspended to permit performance of special tests and operations.

- LCO 3.0.8 – When one or more required snubbers are unable to perform their associated support function(s), any affected supported LCO(s) are not required to be declared not met solely for this reason if the conditions of this specification are met.

- LCO 3.0.9 – When one or more required barriers are unable to perform their associated support function(s), any affected supported LCO(s) are not required to be declared not met solely for this reason if the conditions of this specification are met.

As an example of how applicability LCOs apply to unit operation, consider ECCS LCO 3.5.2. LCO 3.0.1 says that if the unit is in MODE 4, this specification contains no requirements. (LCO 3.5.2 is applicable in MODES 1, 2, and 3 only.) LCO 3.0.2 says that if the unit is in MODE 1, 2, or 3 and one train is inoperable, the required ACTION must be followed (fix it within 72 hours or shut down). LCO 3.0.3 requires that if both ECCS trains are intentionally made inoperable (a state of inoperability not described in any action condition); action must be taken within one hour to place the plant in a condition in which the LCO does not apply. LCO 3.0.4 says that the unit's MODE may be changed from MODE 4 to MODE 3 when the LCO is not met if it can be done in accordance with the licensee's configuration risk management program. LCO 3.0.5 says that if the only way to demonstrate OPERABILITY of an ECCS component is to place the plant in a condition that contradicts a required ACTION, the demonstration of OPERABILITY is allowed. LCO 3.0.6 says that if the only problem with the ECCS trains is the loss of a support system (e.g., a component cooling water train), it is not required to enter any of the conditions and required action of LCO 3.5.2. LCO 3.0.7 does not apply to any ECCS specifications. LCO 3.0.8 allows the ECCS to remain operable with inoperable snubbers if the conditions of LCO 3.0.8 are met. LCO 3.0.9 allows the ECCS to remain operable with inoperable barriers if the conditions of LCO 3.0.9 are met.

Just as the applicability LCOs are the general rules for LCO compliance, applicability surveillance requirements (SRs) are the general rules for performance of surveillance requirements.

- SR 3.0.1 - Surveillance requirements apply when the associated LCO applies. As soon as the licensee discovers that the requirements of a surveillance cannot be met, the LCO is not met (apply LCO 3.0.2).

- SR 3.0.2 - Generally, the surveillance interval can be extended to 1.25 times the interval specified in the frequency. There are two instances in which the interval cannot be extended.

    1. If the frequency is specified as "once" (e.g., once within four hours of a specified event), the interval may not be extended.

    2. If the performance interval applies to a required ACTION that is performed on a periodic or cyclic basis, the interval for the first performance cannot be extended. This type of required ACTION can be viewed as a "surveillance-like" requirement, and its completion time is specified as "once per...." For example, assume that a periodic ACTION is required once per 12 hours after an instrumentation channel failure. The first performance of the ACTION

must be done within 12 hours; the interval for the first performance is not extended. Subsequent performance intervals may be extended.

- SR 3.0.3 - If a surveillance is missed and the allowed interval has expired, the affected equipment is not immediately declared inoperable. A delay period is allowed for the performance of the missed surveillance. The delay may be up to 24 hours or the surveillance interval, whichever is greater. The risk of surveillance delay greater than 24 hours will be managed by the plant's risk management program.
- SR 3.0.4 - An LCO's surveillances must have been met before the unit enters a MODE in which that LCO applies. LCO 3.0.4 requires equipment to be OPERABLE prior to making a corresponding MODE change. SR 3.0.4 says that this OPERABILITY is demonstrated by a current surveillance. The surveillance is current when is has been performed within the specified interval prior to the associated MODE change. If a surveillance is not current, the MODE change shall only be made in accordance with LCO 3.0.4.

As an example of how the applicability SRs apply to unit operation, consider ECCS LCO 3.5.2. SR 3.0.1 says that SR 3.5.2.1 (valve position verification) must be satisfied every 12 hours when the unit is in MODE 1, 2 or 3. If the licensee learns that a valve is not in its required position, the LCO is not met, even if the surveillance is not due to be performed. SR 3.0.2 says that, for operational flexibility, a performance of SR 3.5.2.1 can be as much as 15 hours after the previous performance (12 hours x 1.25). SR 3.0.3 says that if the licensee discovers that the performance interval for SR 3.5.2.1 has inadvertently expired, the licensee does not have to declare that LCO 3.5.2 is not met as long as the surveillance is met within 24 hours of discovery.
SR 3.0.4 says that SR 3.5.2.1 must be met within the 12 hours (plus extension allowed by 3.0.2) prior to the transition from MODE 4 to MODE 3 or else the MODE change must be in accordance with LCO 3.0.4.

3.2.3 Reactivity Control Systems

3.2.3.1 Shutdown Margin

The LCO addressing the minimum SHUTDOWN MARGIN ensures that the reactor can be made subcritical from all operating conditions, transients, and design-basis accidents; that postulated reactivity transients during accidents are controllable within acceptable limits; and that inadvertent criticality during a shutdown condition is precluded. For a subcritical reactor, satisfaction of the LCO requiring an adequate SHUTDOWN MARGIN is verified by a reactivity balance calculation. There is no SHUTDOWN MARGIN LCO for a critical reactor, since this is ensured by verifying that the rod insertion limits are satisfied.

3.2.3.2 Core Reactivity

Accurate prediction of core reactivity is either an explicit or implicit assumption in safety analyses. Large differences between actual and predicted core reactivity may indicate that the assumptions of the design-basis accident and transient analyses are no longer valid. Hence, verifying relative agreement between measured and predicted values of core reactivity ensures that plant operation is maintained within the assumptions of the safety analyses.

3.2.3.3 Moderator Temperature Coefficient

The LCO limits for the moderator temperature coefficient (MTC) ensure that the MTC values are within the bounds assumed in the accident analyses and that inherently stable power operations result during normal operation and accidents. Both the most positive value and the most negative value of the MTC are important to safety; the most positive allowed value limits the consequences of accidents that cause core overheating, and the most negative allowed value limits the consequences of accidents that cause core overcooling.

3.2.3.4 Rod Alignment and Position Indication

The limits on shutdown and control rod alignments ensure that the assumptions in the safety analyses remain valid. Maximum rod misalignment is an initial assumption in the safety analyses that directly affects core power distributions and the available SHUTDOWN MARGIN. The requirement concerning rod OPERABILITY ensures that upon a reactor trip, the assumed reactivity is available and inserted. In addition to ensuring a sufficient SHUTDOWN MARGIN, the rod insertion limits ensure that acceptable power distributions are maintained and that the potential effects of a rod ejection accident are limited. The control bank sequence and overlap limits provide uniform rates of reactivity insertion and withdrawal and maintain acceptable power peaking during control bank motion. In order to ensure that the shutdown and control rods can satisfy these bases, rod position indication must be available and accurate. The OPERABILITY of two rod position indication systems ensures that inoperable, misaligned, or mispositioned rods can be detected.

3.2.3.5 Test Exceptions

The test exception LCOs allow specified LCO requirements to be suspended to permit the performance of special tests and operations. The requirements of the LCOs concerning rod group alignment limits, shutdown and control bank insertion limits, AXIAL FLUX DIFFERENCE, QUADRANT POWER TILT RATIO, moderator` temperature coefficient, and RCS minimum temperature for criticality may be suspended during the performance of PHYSICS TESTS. The MODE 2 SHUTDOWN MARGIN requirements may be suspended during the measurement of control rod worth and SHUTDOWN MARGIN.

3.2.4 Instrumentation

3.2.4.1 Reactor Trip and Engineered Safety Feature Actuation System Instrumentation

The reactor trip system (RTS) initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the reactor core and RCS pressure safety limits during anticipated operational occurrences and to assist the engineered safety feature (ESF) systems in mitigating accidents. The engineered safety feature actuation system (ESFAS) initiates necessary ESF systems, based on the values of selected unit parameters, to protect against violating the safety limits and to mitigate accidents. The OPERABILITY of the RTS and ESFAS instrumentation and interlocks ensures that:

- The associated reactor trip/ESF action will be initiated when required,
- The specified coincidence logic is maintained, and
- Sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance.

The LCOs for the RTS and ESFAS instrumentation include extensive tables which identify the applicable MODES and conditions, the required channels, the action requirements, the surveillance requirements, and the trip setpoint for each reactor trip/ESF actuation function. Detailed discussions of the reasons for each function are provided in the bases for these LCOs.

3.2.4.2 Monitoring and Control Instrumentation

The OPERABILITY of the post-accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident. The selected parameters enable the operator to determine whether safety systems are performing their intended functions, to determine the likelihood of a gross breach of the barriers to radioactive release, and to provide early indication of the need to protect the public from an actual or impending release of radioactive materials. This information from the monitoring instrumentation provides the necessary support for the operator to take manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions in response to design-basis accidents.

The OPERABILITY of the remote shutdown system ensures the availability of instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. The instrumentation and controls are required for core reactivity control, RCS pressure control, decay heat removal, RCS inventory control, and necessary support systems.

3.2.4.3 Other Protection Actuation Instrumentation

The LCO for the loss of power diesel generator (DG) start instrumentation requires that the loss of voltage and degraded voltage functions be OPERABLE for each ESF bus. The availability of these functions ensures that DGs are started to supply power to ESF systems during an accident in which offsite power is lost. The loss of these functions could result in the delay of safety system initiation when required and could lead to unacceptable consequences during accidents.

The containment ventilation isolation instrumentation closes containment isolation valves in certain ventilation systems to isolate the containment atmosphere from the environment so that radioactive release is minimized in the event of an accident. Containment ventilation isolation in response to appropriate signals ensures meeting the containment leakage rate assumptions of the safety analyses and ensures that the calculated accidental offsite radiological doses are below 10 CFR 100 limits.

The LCO requirements for the control room emergency ventilation system (CREVS) actuation instrumentation ensure that normal control room ventilation is isolated and that the CREVS is actuated in response to appropriate signals. These actions maintain the habitability of the control room for the operators stationed there during post-accident operations.

3.2.5 Reactor Coolant System

3.2.5.1 Departure from Nucleate Boiling (DNB) Limits

The LCO limits on pressurizer pressure, RCS average temperature, and RCS total flow rate ensure that the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the departure from nucleate boiling ratio (DNBR) criterion in the event of a DNB-limited transient.

3.2.5.2 RCS Minimum Temperature for Criticality

Compliance with the specified minimum temperature for criticality ensures that the reactor will not be maintained critical at a temperature less than a small band below the hot zero power temperature, which is assumed in safety analyses. This limit also ensures (1) that the plant is operated consistent with the MTC and operating temperature ranges assumed in accident analyses, (2) that protective instrumentation is functioning within the normal operating temperature envelope while the reactor is critical, (3) that pressurizer conditions (saturated with steam bubble) are consistent with those assumed in transient and accident analyses, and (4) that the reactor vessel temperature is greater than the minimum nil ductility reference temperature when the reactor is critical.

3.2.5.3 RCS Pressure and Temperature Limits

Although they are not derived from design-basis accident analyses, the pressure/temperature limits are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate-of-change conditions that might cause undetected flaws to propagate and cause nonductile failure of the reactor coolant pressure boundary, an unanalyzed condition. Violating the LCO limits places the reactor vessel outside the bounds of the stress analyses and can increase stresses in other pressure boundary components. The limits on pressure, temperature, and heatup and cooldown rates are actually stated in the Pressure and Temperature Limits Report (PTLR), which is referenced by the LCO.

3.2.5.4 RCS Loops

The reactor coolant loop LCOs specify the number of reactor coolant and/or residual heat removal (RHR) loops required to be in service for each operational mode. During power operation all four reactor coolant loops are required to be in service. This requirement ensures that core heat removal is sufficient to maintain the DNBR above the DNBR limit during all normal operations and anticipated transients, and that the safety analysis assumptions for design-basis initial conditions are valid.

During MODE 3 operation with the rod control system capable of rod withdrawal, two reactor coolant loops are required to be in service to mitigate the effects of a power excursion caused by an inadvertent control rod withdrawal. Otherwise, during periods of plant shutdown, two cooling loops are required to be operable, with one of the two loops actually in service. One cooling loop, which can be either a reactor coolant or RHR loop, depending on the operational MODE, provides sufficient decay heat removal during shutdown conditions. Two loops are required to be operable to satisfy single failure considerations. The operation of one reactor coolant or RHR pump also provides proper boron mixing in the RCS.

3.2.5.5 Pressurizer

The pressurizer LCO specifies a maximum water level, which ensures that a steam bubble for pressure control exists. The existence of a steam bubble and saturated conditions in the pressurizer is assumed in accident analyses. The minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained, so that subcooled conditions in the RCS can be maintained and that decay heat can be removed by either forced or natural circulation of the reactor coolant.

3.2.5.6 Overpressure Protection

Two LCOs deal with overpressure protection for the RCS. The first, applicable in MODES 1, 2, and 3 and in MODE 4 with RCS cold-leg temperatures greater than 290°F, requires that all pressurizer safety valves be OPERABLE. The combined capacity of the safety valves is required to limit the reactor coolant pressure to less than 110% of its design value (2750 psia) during certain accidents which tend to increase RCS pressure.

The second overpressure protection LCO, applicable in MODE 4 with any cold-leg temperature less than 290°F, in MODE 5, and in MODE 6 when the reactor vessel head is on, specifies the requirements for the low temperature overpressure protection system. The requirements involve minimizing the coolant input capacity by limiting the number of high head pumps capable of injecting to the RCS and by isolating the accumulators and having an adequate pressure relief capacity Overpressure protection is particularly critical at low RCS temperatures, where the reactor vessel is more susceptible to brittle failure. The PORV lift setpoints are included in the PTLR; they are updated when RCS pressure/temperature limits are modified as reactor vessel material toughness decreases due to neutron embrittlement.

3.2.5.7 PORVs and PORV Block Valves

The PORV LCO requires that the PORVs and their associated block valves be OPERABLE so that they can be manually operated to depressurize the RCS in response to certain plant transients and events if normal pressurizer spray is not available. In particular, the safety analysis for the steam generator tube rupture event assumes that the PORVs are used to depressurize the RCS in order to terminate primary-to-secondary break flow.

OPERABILITY of each PORV block valve assures the capability to isolate the flow path through a failed-open PORV or a PORV with excessive leakage. A failed-open PORV is, in effect, a small-break LOCA.

3.2.5.8 RCS Leakage and Leakage Detection Instrumentation

A limited amount of LEAKAGE is expected from the RCS; it is limited according to its source. The 10-gpm identified LEAKAGE limitation allows for a limited amount of LEAKAGE from known sources which will not interfere with the detection of unidentified LEAKAGE. Unidentified LEAKAGE is limited to one gpm, which is a reasonable minimum detectable rate that the containment air monitoring and containment sump level monitoring equipment can detect within a reasonable time period. No pressure boundary LEAKAGE is allowed, as it could be indicative of material deterioration of the reactor coolant pressure boundary.

Primary-to-secondary LEAKAGE is limited to 150 gpd through any one steam generator. The 150-gpd limit through any one steam generator is based on the assumption that a single crack leaking at this rate would not propagate to a tube rupture under the stress of a loss of coolant accident (LOCA) or a steam line rupture. The structural integrity of the steam generator tubes is ensured through periodic tube inspections, in accordance with the Steam Generator Tube Surveillance Program specified in the Administrative Controls section of the technical specifications. The intent of the inspections is to detect tube degradation at an early stage, so that degraded tubes can be plugged or repaired before LEAKAGE occurs.

Pressure isolation valves are normally closed valves in series which separate the high pressure RCS from attached low pressure systems. The basis for the limits on pressure isolation valve leakage is the 1975 NRC “Reactor Safety Study,” which identified potential intersystem LOCAs as a significant contributor to the risk of core melt.

The LCO dealing with leakage detection instrumentation requires that instruments of diverse monitoring principles be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe configuration.

3.2.5.9 RCS Specific Activity

The LCO for RCS specific activity ensures that the resulting 2-hour doses at the site boundary will not exceed an appropriately small fraction of 10 CFR 100 limits following a steam generator tube rupture. Operation for a limited time with the specific activity greater than 1.0 μCi/gm DOSE EQUIVALENT I-131 but < 60 μCi/gm DOSE EQUIVALENT I-131 accommodates possible iodine spiking. Iodine spiking is the release of iodine to the RCS through fuel cladding defects following power level or pressure changes.

3.2.6 Emergency Core Cooling Systems

3.2.6.1 Accumulators

The accumulators are assumed available to supply water to the reactor vessel in both the large- and small-break LOCA analyses. Accumulator OPERABILITY helps to ensure that the ECCS acceptance criteria of 10 CFR 50.46 will be met following a LOCA. Four accumulators are required to be OPERABLE to ensure that the contents of three of the accumulators reach the core during a LOCA, in accordance with the assumption that the contents of one accumulator spill through the break. The limits on accumulator contained volume, boron concentration, and nitrogen cover pressure ensure that the assumptions associated with accumulator injection in the safety analyses are met.

3.2.6.2 ECCS Trains

The OPERABILITY of the ECCS trains ensures that sufficient ECCS flow is available during large- and small-break LOCAs and helps to ensure that the ECCS acceptance criteria of 10 CFR 50.46 will be met following a LOCA. Borated ECCS flow also limits the potential for a post-trip return to power following a main steam line break.

In MODES 1, 2, and 3, an ECCS train consists of a centrifugal charging (high head) subsystem, a safety injection (SI) (intermediate head) subsystem, a residual heat removal (low head) subsystem, and an OPERABLE flow path capable of taking suction from the refueling water storage tank (RWST) upon a safety injection signal and transferring suction to the containment sump. In MODE 4, the SI subsystem is not included in an ECCS train. In MODES 1, 2, and 3, two OPERABLE ECCS trains are required, assuming a single failure affecting either train. In MODE 4, only one ECCS train is required; single failures are not considered during this MODE of operation.

3.2.6.3 Refueling Water Storage Tank

Satisfying the requirements for RWST temperature, water volume, and boron concentration ensures that an adequate supply of borated water is available (1) to cool and depressurize the containment in the event of a design-basis accident, (2) to cool and cover the core in the event of a LOCA, (3) to maintain the reactor subcritical following an accident, and (4) to ensure an adequate level in the containment sump to support ECCS and containment spray system operation in the recirculation mode.

3.2.6.4 Seal Injection Flow

The LCO limit on seal injection flow ensures that the flow through the reactor coolant pump seal injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the injection points during an accident.

3.2.7 Exercises

Exercise 1

On May 15, plant maintenance personnel are planning to cycle a PORV block valve. During the course of their preparations, they determine that the last time this surveillance was performed was January 5. All PORVs are OPERABLE.

1. Locate in the technical specifications the requirement for PORV block valve cycling.
2. Identify whether the specified frequency for this surveillance has been exceeded.
3. State the actions to be taken in accordance with technical specification requirements.

Exercise 2

During operation at 100% power, it is discovered that the individual rod position indicator for rod M-12 is inoperable. In addition, the group I step counter for control bank D is out of service (rod M-12 is in group 1 of control bank D). State the actions to be taken in accordance with technical specification requirements.

Exercise 3

With the plant at 85% power, a boration is performed to move control bank D from 200 steps withdrawn to 220 steps withdrawn. When the boration is complete, the operator notices that the group step counter for control bank D is reading 220, the individual rod position indication for rod M-12 (a bank D rod) is 198 steps, and the individual rod position indications for all other bank D rods are 222 steps. State the actions to be taken in accordance with technical specification requirements.

Exercise 4

During operation at 95% power, pressurizer pressure channel PT-455 fails high; the input of the failed channel into the pressurizer pressure control system causes the pressurizer spray valves to open. Pressurizer pressure decreases to 2170 psig before the operator manually shuts the spray valves. The operator declares PT-455 inoperable and changes pressure control functions to another channel. State the actions to be taken in accordance with technical specification requirements.

Exercise 5

During operation at 50% power, the operators detect a small RCS leak. A water inventory balance determines the leak rate to be two gpm.

1. Classify the LEAKAGE.
2. Subsequent to this, RHR pressure response indicates that the leak is through two series 6" check valves in an RHR discharge line. What do technical specifications require at this time?
3. State the actions to be taken in accordance with technical specifications if the leak rate increases to 20 gpm.

Exercise 6

After the drawing of accumulator samples, the volume of accumulator A is determined to be 6470 gallons. State the actions to be taken in accordance with technical specification requirements.

TECHNICAL SPECIFICATIONS UNIT 2 - EXERCISE 1 SOLUTION

1. Locate in the technical specifications the requirement for PORV block valve cycling.

A complete cycle of each PORV block valve is required once every 92 days in accordance with surveillance requirement (SR) 3.4.11.1.

2. Identify whether the specified frequency for this surveillance has been exceeded.

May 15 is 130 days after January 5, so the surveillance has not been performed in the last 130 days. SR 3.0.2 states, “The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance....” The specified interval for this surveillance is 92 days, and 1.25 times the interval is 115 days. Even with the additional 23-day “grace period,” the frequency has been exceeded.

3. State the actions to be taken in accordance with technical specification requirements.

SR 3.0.3 states, “If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance.

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.”

The PORV block valve must be cycled within the next 92 days. If the surveillance is not performed within that time, or if the surveillance is not met when performed, then the LCO 3.4.11 conditions for an inoperable PORV must be entered.

State the actions to be taken in accordance with technical specification requirements.

LCO 3.1.7 requires that individual and demand position indicators be OPERABLE.

For the inoperable DRPI for rod M-12, condition A applies. The required actions for this condition specify (1) verifying the position of rod M-12 with the movable incore detectors once every 8 hours (required action A.1), or (2) reducing THERMAL POWER to # 50% RTP within 8 hours (required action A.2).

For the inoperable bank D, group 1 demand position indicator, condition D applies. The required actions for this condition specify (1) verifying that all DRPIs for the affected bank are OPERABLE (required action D.1.1) and that the maximum distance between rods in that bank is # 12 steps once every 8 hours (required action D.1.2), or (2) reducing THERMAL POWER to # 50% RTP within 8 hours (required action D.2).

Because rod M-12 is in control bank D, the OPERABILITY of the DRPIs for all rods in that bank cannot be verified in accordance with required action D.1.1. Therefore, to fulfill the action requirements for both inoperable position indicators, THERMAL POWER must be reduced to # 50% RTP within 8 hours.

TECHNICAL SPECIFICATIONS UNIT 2 - EXERCISE 3 SOLUTION

State the actions to be taken in accordance with technical specifications.

From the statement of the problem, it can be concluded that rod M-12 did not withdraw with the other rods in its bank and that M-12 remains where it was before the boration. LCO 3.1.4 requires that all control rods be OPERABLE and that all individual rod position indications be within 12 steps of their group step counter demand positions. Rod M-12's position (198 steps) is now 22 steps below the bank D, group 1 demand position (220 steps).

Without further evidence, a licensee would be unlikely to declare rod M-12 untrippable, so condition A of LCO 3.1.4 would not be considered applicable.

On the other hand, condition B of LCO 3.1.4 is unquestionably applicable. The required actions for this condition specify (1) restoring rod M-12 to within 12 steps of the bank D, group 1 step counter indication within 1 hour (required action B.1), or (2) taking all of the B.2 required actions, which include reducing THERMAL POWER to # 75% RTP within 2 hours.

One way to comply with the required actions is to insert the other bank D rods to within 12 steps of rod M-12 (assuming that rod M-12 doesn't move when bank D rods are inserted). This action would satisfy required action B.1 while providing the licensee time to troubleshoot the rod control problem without having to reduce power. A check of Figure COLR-2 reveals that the rod insertion limits would be satisfied for a bank D position between 186 and 210 steps at 85% power.

TECHNICAL SPECIFICATIONS UNIT 2 - EXERCISE 4 SOLUTION

State the actions to be taken in accordance with technical specification requirements.

Several conditions of LCOs have been entered.

First, the current pressure is less than the DNB pressurizer pressure limit (2205 psig) specified by LCO 3.4.1. Condition A of that LCO applies; pressure must be restored to greater than the limit within 2 hours (required action A.1).

Second, the failed pressurizer pressure channel affects the following reactor trip system functions of LCO 3.3.1: overtemperature ΔT (for which condition H applies), pressurizer pressure - low (for which condition P applies), and pressurizer pressure - high (for which condition H applies). The required actions for conditions H and P both require that the inoperable channel be placed in trip within 72 hours (required actions H.1 and P.1), or that the plant be brought to a condition in which those functions are not required to be OPERABLE (required actions HH.1 and R.1). Note that as an alternative, the licensee may apply the risk informed completion time program (TS 5.5.20).

Third, the failed pressurizer pressure channel affects the following ESFAS functions of LCO 3.3.2: safety injection on pressurizer pressure - low (for which condition F applies) and the P-11 interlock (for which condition T applies). The required actions for condition F require that the inoperable channel be placed in trip within 72 hours (required action F.1), or that the plant be brought to a condition in which that ESFAS function is not required to be OPERABLE (required actions V.1 and V.2). The required actions for condition T require verification that the interlock is in the required state for 95% power operation (required action T.1), or that the plant be brought to a condition in which the interlock is not required to be OPERABLE (required actions V.1 and V.2). As an alternative, the licensee may apply the risk informed completion time program (TS 5.5.20).

In summary:

1. Pressurizer pressure should be restored through either manual or automatic operation of the pressurizer pressure control system.
2. Three reactor trip bistables and one ESFAS bistable associated with pressurizer pressure channel PT-455 should be tripped.
3. The P-11 interlock would be in the required state so long as the other two pressurizer pressure channels which provide inputs to the interlock are indicating the correct pressure.

TECHNICAL SPECIFICATIONS UNIT 2 - EXERCISE 5 SOLUTION

1. Classify the LEAKAGE.

In accordance with the definition for LEAKAGE in the definitions section of the technical specifications, it would be classified as unidentified LEAKAGE.

2. Subsequent to this, RHR pressure response indicates that the leak is through two series 6" check valves in an RHR discharge line. What do technical specifications require at this time?

The LEAKAGE is now specifically located, and it is not pressure boundary. Thus, the LEAKAGE would now be classified as identified LEAKAGE. A condition requiring action has not been entered, as the LCO 3.4.13 limit for identified LEAKAGE is 10 gpm.

3. State the actions to be taken in accordance with technical specifications if the leak rate increases to 20 gpm.

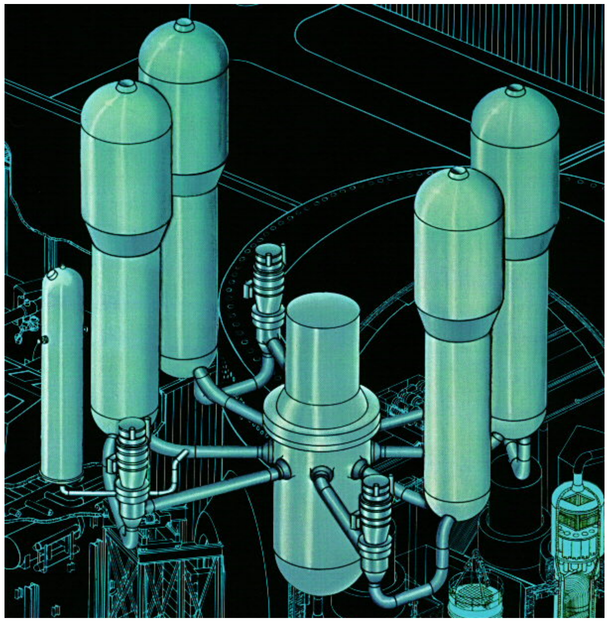
A 20-gpm leak rate exceeds the limit for identified LEAKAGE. Condition A of LCO 3.4.13 applies. The LEAKAGE must be reduced to within limits within 4 hours (required action A.1), or the plant must be brought to MODE 3 within the next 6 hours (required action B.1) and to MODE 5 within the next 36 hours (required action B.2).

Also, LCO 3.4.14 is not met. SR 3.4.14.1 specifies a maximum leakage of 5 gpm. Action condition A.1 must be carried out. This action could be satisfied by isolating the affected RHR line. This isolation would stop the RCS leak, allowing the licensee to exit Condition A of LCO 3.4.13, but RHR operability would have to be evaluated. A required plant shutdown is inevitable.

TECHNICAL SPECIFICATIONS UNIT 2 - EXERCISE 6 SOLUTION

State the actions to be taken in accordance with technical specification requirements.

The current accumulator volume is outside the acceptable range stated in SR 3.5.1.2 (6508 - 6956 gallons). As a result, condition B of LCO 3.5.1 applies. The accumulator must be restored to OPERABLE status (the water volume of the accumulator must be increased to ∃ 6508 gallons) within 24 hours. If the 24-hour completion time is not met, actions must be taken to place the plant in a MODE in which the LCO does not apply, in accordance with the required actions for condition D. As an alternative, the licensee may apply the risk informed completion time program (TS 5.5.20).



Westinghouse Advanced Technology Manual

Chapter 3.3 – Analysis of Technical Specifications
Unit 3

2020

Human Resources Training & Development
U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

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3.3.0 Analysis of Technical Specifications – Unit 3

Learning Objectives:

1. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation.
2. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.
3. Use the design features section of technical specifications to determine required features of the plant.
4. Use the administrative control section of technical specification to determine requirements for given situations.

3.3.1 Introduction

This section is the third of four technical specification sections. This section presents the limiting conditions for operation (LCOs), bases for LCOs, and applications of requirements during different situations for the areas of:

- Containment systems,
- Plant systems,
- Electrical power systems, and
- Refueling operations.

The LCOs for these areas identify the minimum performance levels for equipment required to ensure safe operation. This section also discusses the design features and administrative controls sections of the technical specifications.

3.3.2 Containment Systems

3.3.2.1 Containment

The design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting design-basis accident (DBA) without exceeding the design leakage rate. Limiting the containment leakage rate limits the rate of radioactive release to the environment resulting from accidents in which fission product activity is released to the containment atmosphere. The maximum allowable containment leakage rate, designated as L_a, is 0.10% of the containment air weight per day at the calculated peak containment pressure. Containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, which is periodically verified in accordance with the Containment Leakage Rate Testing Program. Containment OPERABILITY is also demonstrated through verification of containment structural integrity in accordance with the Containment Tendon Surveillance Program. Requirements for both programs are contained in the administrative controls section of the technical specifications.

In addition, the containment air locks and containment isolation valves form parts of the containment pressure boundary. The OPERABILITY of each air lock, including OPERABILITY of both air lock doors and the interlock mechanism and compliance with air lock leakage criteria, thus supports the maximum allowable leakage design basis of the containment. Similarly, the OPERABILITY requirements for the containment isolation valves support the containment design basis by helping to ensure that the containment is isolated within the time limits assumed in the safety analyses.

3.3.2.2 Containment Pressure and Temperature

The upper limit on containment pressure and the limit on containment average air temperature are initial conditions used in the DBA analyses to establish the peak containment internal pressure and the peak containment structure temperature. Compliance with these limits ensures that the peak containment pressure and temperature resulting from the limiting DBA, a large loss of coolant accident (LOCA), remain less than the design values.

The lower limit on containment pressure is an initial condition of the safety analysis of an inadvertent actuation of the containment spray system, which establishes the minimum containment internal pressure (and thus the maximum external pressure load on the containment). Compliance with the lower containment pressure limit ensures that the containment internal pressure does not fall below the design value if this event should occur.

3.3.2.3 Containment Spray and Cooling Systems

The containment spray system and containment cooling system (containment air coolers) provide containment atmosphere cooling to limit post-accident pressures and temperatures in containment. The limiting DBA for peak containment pressure and temperature is a large LOCA. The worst-case single failure assumed for this event is the loss of one containment spray train. The analysis of this accident shows that the remaining operating containment spray and containment cooling trains provide sufficient cooling to keep the peak containment pressure and containment structure temperature within design limits. Compliance with the OPERABILITY requirements for these systems ensures that the necessary trains are available to mitigate the effects of the DBA, even with the worst-case single active failure.

OPERABILITY of the containment spray trains, and the spray additive system ensures that at least one containment spray train and one spray additive train are available during an accident to scavenge iodine from the containment atmosphere and to maintain a sufficiently alkaline pH in the containment sump solution. The successful performance of these functions limits the amount of radioactive iodine that can be leaked from containment during and following an accident.

3.3.2.4 Hydrogen Mitigation Systems

OPERABILITY of the hydrogen mixing system minimizes the potential for local hydrogen burns. The hydrogen mixing system provides the capability for reducing the local hydrogen concentration to approximately the bulk average concentration.

3.3.3 Plant Systems

3.3.3.1 Steam and Feedwater System Valves

The main steam safety valves (MSSVs) provide overpressure protection for the secondary system and also provide protection against over pressurizing the reactor coolant pressure boundary by providing a heat sink for energy removal from the reactor coolant system (RCS) if the condenser is not available. The OPERABILITY of all MSSVs ensures that the secondary system pressure will be limited to ≤ 110% of design pressure when they are passing 105% of design steam flow. This capability is sufficient to cope with any anticipated operational occurrence (AOO) or accident; the limiting AOO is a full-power turbine trip without steam dump availability. Operation with less than the full number of MSSVs OPERABLE requires limitations on the allowable THERMAL POWER and the power range neutron flux - high trip setpoint.

The OPERABILITY of the main steam line isolation valves (MSIVs) precludes the blowdown of more than one steam generator in the event of a steam line break, assuming that one MSIV fails to close on demand. This capability limits the break-induced mass and energy release to the containment (for steam line breaks inside containment) and positive reactivity addition to the core resulting from the uncontrolled RCS cooldown.

The OPERABILITY of the main feedwater isolation valves (MFIVs), main feedwater regulating valves (MFRVs), and MFRV bypass valves ensures redundant isolation of main feedwater flow to the steam generators following a steam line break or feedwater line break (FWLB). Closure of the MFIVs, or MFRVs and MFRV bypass valves, terminates feedwater addition to an affected steam generator and thereby limits the mass and energy release for a steam line break or FWLB inside containment. For a FWLB occurring upstream of the MFIVs or MFRVs, closure of these valves terminates the event.

The OPERABILITY of the atmospheric dump valves (ADVs) ensures the availability of a method for cooling the unit to residual heat removal (RHR) entry conditions when the preferred heat sink, the condenser, is not available. In accident analyses, the ADVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for accidents accompanied by a loss of offsite power. For the recovery from a steam generator tube rupture (SGTR), the limiting event for the ADVs, the operator is required to perform a limited cooldown as a necessary step to terminate primary-to-secondary break flow into the ruptured steam generator. Three ADV lines are required to be OPERABLE to ensure that at least one ADV line is available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable and a second ADV line on an unaffected steam generator fails.

3.3.3.2 Auxiliary Feedwater

The design basis of the auxiliary feedwater (AFW system) is to supply water to the steam generators to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest MSSV set pressure plus 3%. In addition, the AFW system must supply enough makeup water to replace the secondary water inventory lost as the unit cools to MODE 4 conditions. The required OPERABILITY of both AFW trains ensures the availability of the design RHR capability for all events, including the DBA (a feedwater line break), accompanied by a loss of offsite power and the worst-case single failure.

The condensate storage tank (CST) is the source of water for the AFW system. Safety analyses assume a CST inventory sufficient to remove decay heat for 30 minutes in MODE 3 and then to cool down the RCS to RHR entry conditions at the design cooldown rate, with steam relief to the atmosphere and a loss of offsite power. The required minimum CST volume exceeds the volume required by the safety analyses.

3.3.3.3 Cooling Water Systems

The component cooling water (CCW) and service water systems remove heat from safety-related components during normal operation and following accidents. In the event of a DBA, one CCW train and one service water train are required to remove the post-accident heat loads from the systems which they support. In MODES 1, 2, 3, and 4, both trains of each system are required to be OPERABLE to ensure that one train will operate, assuming the worst-case single failure coincident with a loss of offsite power. In MODES 5 and 6, the OPERABILITY requirements of these systems are determined by the systems that they support (there are no LCO OPERABILITY requirements for the CCW system or the service water system in MODES 5 and 6).

The design basis of the ultimate heat sink (UHS) is to provide a 30-day supply of cooling water in support of a safe shutdown of the unit from any conditions, so that the design-basis temperatures of safety-related equipment are not exceeded. For TTC Unit 2, this capability is provided by the Columbia River. In the event of a service water intake structure blockage, the cooling tower and cooling tower basin constitute the UHS. The LCO limits for the cooling tower basin ensure a cooling water supply (approximately 100 hours) adequate to support a normal shutdown and cooldown of the unit until makeup flow from the Columbia River to the cooling tower basin can be restored.

3.3.3.4 Ventilation Systems

The control room emergency ventilation system (CREVS) recirculates control room air and supplies makeup air through filters and adsorbers to provide airborne radiological protection for the control room operators. The system is designed to maintain the control room environment for 30 days of continuous occupancy after a DBA without exceeding a 5-rem whole-body dose or its equivalent to any part of the body. Requiring both trains of the CREVS to be OPERABLE ensures that at least one train is available to perform the system design function in the event of an assumed loss of offsite power and a worst-case single failure.

The spent fuel pool exhaust system (SFPES) directs air from the area of the spent fuel pool to the environment through filters and adsorbers to limit the airborne radioactive material discharged to the environment. The safety analysis of the design-basis fuel handling accident accounts for the filtration of airborne radioactive particulates and iodines by the SFPES. Requiring both trains of the SFPES to be OPERABLE ensures that at least one train is available to perform the system design function in the event of an assumed loss of offsite power and a worst-case single failure. In addition, one train is required to be operating during movement of irradiated fuel assemblies in the fuel handling building, when there is potential for damage to fuel assemblies.

3.3.3.5 Spent Fuel Pool

The spent fuel pool is divided into two separate and distinct regions. Region 1 is designed to accommodate new fuel with a maximum enrichment of 4.65 wt% U-235, or spent fuel regardless of the discharge fuel burnup. Region 2 is designed to accommodate fuel of various initial enrichments which have accumulated minimum burnups within the acceptable domain defined by the LCO for spent fuel assembly storage. Restricting the spent fuel assemblies stored in Region 2 to those which fall within the acceptable burnup domain ensures that the k_{eff} of the spent fuel pool remains less than 0.95, even with the conservatism that the pool is flooded with unborated water.

Although compliance with the LCO for spent fuel assembly storage provides assurance that the spent fuel remains in a subcritical configuration, accidents can be postulated which could increase the reactivity of the pool. The negative reactivity provided by the required spent fuel pool boron concentration compensates for the increased reactivity of the spent fuel storage configuration resulting from any postulated accident scenario. In accordance with this basis, the LCO for spent fuel pool boron concentration applies only until it is verified that spent fuel assemblies are properly stored following the last movement of assemblies within the spent fuel pool.

The minimum required spent fuel pool water level of 23 ft above the top of irradiated fuel assemblies provides shielding and minimizes the general area dose when the storage racks are filled to their maximum capacity. The minimum water level satisfies the assumptions concerning iodine decontamination factors following a fuel handling accident and limits the offsite doses from the accident to a small fraction of the 10 CFR 100 limits.

3.3.3.6 Secondary Specific Activity

The secondary coolant specific activity limit of 0.10 μCi/gm DOSE EQUIVALENT I-131, an assumed initial condition of the steam line break safety analysis, ensures that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR 100 limits in the event of a steam line break.

3.3.4 Electrical Power Systems

3.3.4.1 Electrical Power Systems - Operating

The initial conditions of DBA and transient analyses in the Final Safety Analysis Report (FSAR) assume that engineered safety feature (ESF) systems are OPERABLE. The electrical power systems (AC and DC power sources, inverters, and AC and DC electrical distribution systems) are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded. The OPERABILITY of both trains of the electrical power systems in MODES 1, 2, 3, and 4 ensures the availability of the required power to shut down the reactor and to maintain it in a safe shutdown condition after an AOO or a postulated DBA. Requiring both trains to be OPERABLE ensures that at least one train of the electrical power systems is OPERABLE during accident conditions in the event of an assumed loss of all offsite power or all onsite AC power and a worst-case single failure.

To satisfy the OPERABILITY requirements, all emergency buses must be energized. The required operable power sources for the emergency buses include two physically independent circuits between the offsite transmission network and the onsite Class 1E electrical distribution system and two separate and independent diesel generators. A circuit between the offsite transmission network and the onsite Class 1E electrical distribution system consists of a line from the switchyard to an emergency bus. The switchyard is considered to be part of the offsite transmission network.

3.3.4.2 Electrical Power Systems - Shutdown

During MODES 5 and 6 and during movement of irradiated fuel assemblies, the required OPERABLE portions of the electrical power systems are reduced to those necessary to support equipment required to be OPERABLE in those MODES. Maintaining these electrical subsystems and components available ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown conditions and the availability of instrumentation and control capability for monitoring and maintaining the unit in a cold shutdown condition or refueling condition. To support these capabilities, the required OPERABLE AC sources are reduced to one qualified offsite circuit and one diesel generator.

3.3.4.3 Diesel Support Systems

Sufficient stored diesel fuel oil and lubricating oil and a sufficiently charged diesel air start subsystem support diesel generator OPERABILITY. The required stored fuel oil and lubricating oil inventories for each diesel generator support seven days of full-load operation of the generator. The required starting air receiver pressure supports five successive diesel generator start attempts.

3.3.4.4 Battery Cell Parameters

Maintaining the battery cell parameters within the specified limits ensures the availability of the required DC power sources.

3.3.5 Refueling Operations

3.3.5.1 Boron Concentration and Unborated Water Isolation Valves

The limit on the boron concentrations of the RCS, the refueling canal, and the refueling cavity in MODE 6 prevents an inadvertent criticality by ensuring that the core k_{eff} remains ≤ 0.95 during fuel handling operations. The boron concentration limit is specified in the Core Operating Limits Report (COLR).

The LCO requiring that all unborated water sources be isolated from the RCS in MODE 6 prevents an unplanned boron dilution and the corresponding increase in core reactivity. With this requirement, a safety analysis for an uncontrolled boron dilution accident in MODE 6 is not required.

3.3.5.2 Nuclear Instrumentation

The required OPERABILITY of two source range neutron flux monitors ensures that redundant monitoring capability is available to detect changes in core reactivity. These monitors can alert the operator to abnormal conditions such as an improperly loaded fuel assembly. In MODE 6, there are no other direct means available for checking core reactivity.

3.3.5.3 Containment Penetrations

The LCO requiring containment penetration closure limits the potential escape paths for fission product radioactivity released within containment during a fuel handling accident. The containment penetrations treated by this LCO include the equipment hatch, the air locks, and ventilation penetrations providing direct access from the containment atmosphere to the outside atmosphere.

3.3.5.4 Residual Heat Removal and Coolant Circulation

One RHR loop is required to be in operation during MODE 6 to provide adequate decay heat removal and adequate mixing of borated coolant to minimize the possibility of criticality. With a water level of at least 23 ft above the top of the reactor vessel flange, only one RHR loop is required to be OPERABLE, because the volume of water above the vessel flange provides backup decay heat removal capability. Without a sufficient water volume above the vessel flange, a second RHR loop must be OPERABLE as a backup to the operating loop.

3.3.5.5 Refueling Cavity Water Level

The minimum required refueling cavity water level of 23 ft above the reactor vessel flange provides sufficient water to substantially retain the iodine fission product activity during a fuel handling accident. The minimum required water level allows a decontamination factor of 100 for iodine to be used in the fuel handling accident analysis and limits the offsite doses from the accident to less than 25% of the 10 CFR 100 limits.

3.3.6 Design Features

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 which are not covered by the technical specification sections devoted to safety limits, limiting safety system settings, LCOs, and surveillance requirements. Design features include the plant site, reactor core components, and fuel storage.

The reactor core contains 193 fuel assemblies, each of which contains uranium dioxide fuel rods clad with Zircaloy or ZIRLO. The reactor contains 53 control rod assemblies, which are composed of a silver-indium-cadmium alloy or hafnium.

Fuel storage facilities provide for the storage of new and irradiated fuel assemblies. The spent fuel storage racks are designed for a k_{eff} of less than 0.95 when flooded with unborated water. The spent fuel storage racks contain two sections: low density fuel storage racks with a nominal 10.5-in. center-to-center distance between fuel assemblies, and high density fuel storage racks with a nominal 9.15-in. center-to-center distance between fuel assemblies. The storage capacity of the spent fuel storage pool is 3006 fuel assemblies. The pool is designed to prevent draining below a height that maintains sufficient coverage of the fuel assemblies for cooling and limiting radiation exposure.

New fuel storage racks are designed for the storage of fuel assemblies enriched to 4.65 weight percent in U-235. A nominal center-to-center spacing of 21 in. ensures that a K_{eff} of 0.95 is not exceeded with the storage pit filled with unborated water.

3.3.7 Administrative Controls

Administrative controls are the provisions relating to organization and management, procedures, records, review and audit, and reporting necessary to assure operation of the facility in a safe manner. The administrative controls section includes requirements in the following areas.

3.3.7.1 Responsibility, Organization, and Staffing

The responsibility subsection of the administrative controls dictates that the Plant Superintendent is responsible for overall unit operation and that the Shift Supervisor is responsible for the control room command function.

The organization subsection states that lines of authority, responsibility, and communication are required in the form of organizational charts, functional descriptions of departments, and job descriptions of key personnel. These requirements are to be documented in the FSAR. This subsection also includes requirements pertaining to the minimum shift crew composition, absence of crew members, limits on overtime, and the presence and duties of certain key personnel.

The unit staff qualifications subsection provides the minimum qualifications for staff members.

3.3.7.2 Procedures and Programs

Procedures required to be established, implemented, and maintained include procedures recommended in Appendix A of Regulatory Guide 1.33 (administrative, general normal operating, system normal operating, off-normal, emergency, and radiological control procedures), emergency operating procedures required to implement the requirements of NUREG-0737 and its supplement, quality assurance procedures for effluent and environmental monitoring, procedures for implementation of the Fire Protection Program, and procedures for all programs specified in the administrative controls.

The following list provides brief descriptions of some of the more important programs required by the administrative controls:

- Offsite Dose Calculation Manual (ODCM): The ODCM contains the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program. The ODCM also contains radioactive effluent controls and radiological environmental monitoring activities.
- Radioactive Effluent Controls Program: This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining doses to the public from radioactive effluents as low as reasonably achievable. This program includes limits on the capability of monitoring instrumentation, limits on concentrations of radioactive material in effluent releases, limits on doses to the public from releases beyond the site boundary, and requirements for the capability and use of effluent treatment systems.
- Component Cyclic or Transient Limit Program: This program provides controls for tracking cyclic and transient events to ensure that components are operated within the design limits provided in the FSAR.
- Pre-Stressed Concrete Containment Tendon Surveillance Program: This program provides controls for monitoring tendon degradation and the effectiveness of the corrosion protection medium for the tendons. Verification of containment structural integrity through performance of tendon surveillances supports containment OPERABILITY.
- Inservice Testing Program: This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program includes requirements for testing frequencies.
- Steam Generator Program: Verification of tube integrity through performance of this program provides assurance that excessive tube leakage or catastrophic tube failure will not result from steam generator operation.
- Secondary Water Chemistry Program: This program provides controls for monitoring secondary water chemistry to inhibit steam generator tube degradation.
- Ventilation Filter Testing Program: This program ensures that filters perform as assumed in safety analyses.
- Explosive Gas and Storage Tank Radioactivity Monitoring Program: This program includes controls for potentially explosive gas mixtures contained in the gaseous waste processing system and for the quantities of radioactivity contained in gas and liquid storage tanks.
- Safety Function Determination Program: This program provides requirements for determining whether a loss of safety function exists when LCO 3.0.6 is entered

and for other appropriate actions to be taken as a result of the support system inoperability and the corresponding exception to entering the conditions and required actions for the supported systems.

- Containment Leakage Rate Testing Program: This program implements leakage rate testing of the containment, including testing of the air locks, in accordance with NRC requirements. Verification of containment leak tightness through performance of this program supports containment OPERABILITY.
- Surveillance Frequency Control Program: This program allows licensee control of surveillance intervals in accordance with NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1. For those licensees that have implemented the program, most surveillance frequencies have been moved to a licensee-controlled document.
- Risk Informed Completion Time (RICT) Program: This program provides controls to calculate a risk informed completion time and must be implemented in accordance with NEI 06-09, Revision 0, "Risk-Managed Technical Specifications (RMTS) Guidelines." Incorporation of the RICT Program results in a massive amendment to Technical Specifications. Most required actions have, as an alternative, the potential to extend the completion time to a maximum of 30 days. This RICT program cannot be applied where it is not possible to quantify the change in risk (e.g. exceeding a power distribution limit), or where the completion time is IMMEDIATE. The actual extension is a function of the calculated risk for the actual plant configuration. Also, the loss of safety function, which traditionally required application of LCO 3.0.3, has a corresponding action condition which may allow an extended completion time if the system is still “PRA functional”. For example, it is possible that the reason for inoperability is the failure of an automatic start, which makes the system inoperable. However, if a manual start is available, and certain criteria are met (like adequate procedures and training), PRA functionality remains. In this case, the RICT program may result in a longer completion time that that allowed by LCO 3.0.3. In all of these cases, a note prevents using the RICT program for intentional inoperability. If the licensee’s intentional actions result in a loss of safety function, LCO 3.0.3 would still apply. Incorporating this amendment into the ISTS results in the removal of all action requirements that say “enter LCO 3.0.3” and makes LCO 3.0.3 entry very unlikely.

3.3.7.3 Reports

Also required by the administrative controls section are a variety of routine reports to the NRC. Many of the reports provide information determined through the performance of the programs described above.

One important report is the Core Operating Limits Report. The COLR is a plant-specific document that provides core operating limits for the current reload cycle. The COLR shifts the numerical limits associated with several LCOs to a separate document, thereby eliminating the need to submit a technical specification amendment for each core reload. The COLR affects the LCOs for control rod insertion limits, AXIAL FLUX DIFFERENCE, heat flux hot channel factor, nuclear enthalpy rise hot channel factor, moderator temperature coefficient, and refueling boron concentration. Plants which do not issue COLRs must continue to submit technical specification amendments.

A report similar to the COLR is the Pressure and Temperature Limits Report (PTLR). The PTLR provides RCS pressure and temperature limits as well as RCS heatup and cooldown rate limits. The PTLR also provides the low temperature overpressure protection system lift settings for the pressurizer power-operated relief valves. The limits provided in this report change as the reactor vessel material toughness decreases due to neutron embrittlement, so the PTLR is updated and provided to the NRC for each reactor vessel fluence period. Updating the PTLR eliminates the need to submit technical specification amendments to incorporate new limits in the associated RCS LCOs.

3.3.8 Deviations From Technical Specifications

The NRC’s final rule on the applicability of license conditions and technical specifications in an emergency is stated in 10 CFR 50.54(x). This rule states, “A licensee may take reasonable action that departs from a license condition or a technical specification (contained in a license issued under this part) in an emergency when this action is immediately needed to protect the public health and safety and no action consistent with license conditions and technical specifications that can provide adequate or equivalent protection is immediately apparent.”

Unanticipated circumstances may occur during emergencies. These circumstances may require responses different from any considered by technical specifications during the course of licensing. These circumstances may not have been anticipated by the emergency procedures and may arise during emergencies involving multiple equipment failures or coincident accidents, in which procedures could be in conflict. The rule applies to those emergency situations where action is required immediately to protect the public and not to situations in which time allows for NRC amendments to licensee technical specifications.

10 CFR 50.72 requires that a licensee notify the NRC as soon as practical and within one hour of a deviation from technical specifications authorized by 10 CFR 50.54(x).

The language of the rule is permissive in nature. However, a licensee is responsible for operating its facility in such a manner as to protect the public health and safety. If, in an emergency, protective action is needed and no action consistent with the license that can provide adequate or equivalent protection is immediately apparent, the licensee is obligated to take the protective action that deviates from the license.

3.3.9 Exercises

Exercise 1

At 1:00 p.m. on May 15, with the unit at 3% power during a power ascension, two train A containment air cooler fans fail. Containment cooling train A is declared inoperable. It is later determined that the fans have failed due to excessive bearing wear. At 2:00 p.m. on May 19, with the unit at 45% power, a small leak from containment spray train B near the pump is discovered, and the train is declared inoperable. At 11 p.m. on May 19 (critical events curiously happen on the hour at this plant), with the unit still at 45% power, one of the air cooler fans is fixed, and containment cooling train A is declared operable.

1. Determine the LCO conditions and required actions which have been entered during this time period.
2. Determine whether the licensee has complied with all technical specification requirements.

Exercise 2

Suspicious of mistakes during recent bench testing of the MSSVs, a member of the plant maintenance staff consults the test records and finds that the following lift settings were verified for the tested valves:

MSSV	Lift Setting (psig)
PSV-2232	1245
PSV-2234	1260
PSV-2255	1240
PSV-2275	1270

Assume no adjustments were made and the valves were reinstalled.

The unit is operating at 87% power. State the actions to be taken in accordance with technical specification requirements.

Exercise 3

With the unit operating at 30% power, service water booster pump P-148B trips, and booster pump P-148D automatically starts (both pumps are train B pumps). Minutes later, pump P-148D also trips. It is determined that an improperly performed maintenance requirement has rendered both pumps inoperable.

Additionally, at the time both pumps are declared inoperable, the A train safety injection pump has been inoperable for 24 hours. Assume the required actions associated with the inoperable A train safety injection pump were in progress.

State the actions to be taken in accordance with technical specification requirements.

Exercise 4

During operation at 100% power, the normal supply breaker for bus #A1 opens. The A Emergency diesel generator started and loaded, as designed. The cause of the event is determined to be a faulty breaker. State the actions to be taken in accordance with technical specification requirements.

Exercise 5

During operation at 100% power, a power line problem results in the opening of a switchyard disconnect to the Rivergate substation. State the actions to be taken in accordance with technical specification requirements.

Exercise 6

During a refueling operation, an instrumentation and control technician requests permission from the shift supervisor to perform a retrofit modification to the power range nuclear instruments. To accomplish this change he will have to remove the instrument power fuses for all four power range instruments at the same time. (Hint: Removing the instrument power fuses from a power range instrument trips all bistables associated with that instrument.) Determine whether the shift supervisor should give permission for this work, and explain.

TECHNICAL SPECIFICATIONS UNIT 3 - EXERCISE 1 SOLUTION

1. Determine the LCO conditions and required actions which have been entered during this time period.

When containment cooling train A is declared inoperable, condition C of LCO 3.6.6 is entered. Required action C.1 requires restoration of the train to OPERABLE status within 7 days. When containment spray train B is declared inoperable, condition A LCO 3.6.6 is also entered. The required actions of condition A are the most restrictive. If a combination of action conditions is unacceptable, there will be another action condition directing further action (like Condition D).

2. Determine whether the licensee has complied with all technical specification requirements.

The required actions of conditions A and C have been met.

However, the unit made a transition from MODE 2 to MODE 1 at some point between May 15 and May 19. During this time LCO 3.6.6 was not satisfied. LCO 3.0.4 would only allow such a transition if performed in accordance with LCO 3.0.4.b. The mode change may have been acceptable.

TECHNICAL SPECIFICATIONS UNIT 3 - EXERCISE 2 SOLUTION

State the actions to be taken in accordance with technical specification requirements.

The MSSVs are required to have lift settings as specified in Table 3.7.1-2. The minimum and maximum allowable lift settings for the recently tested valves are as follows:

MSSV	Min. Lift Setting (psig)	Max. Lift Setting (psig)
PSV-2232	1164	1236
PSV-2234	1184	1256
PSV-2255	1194	1266
PSV-2275	1194	1266

The as-tested lift settings for PSV-2232, PSV-2234, and PSV-2275 exceed the maximum allowable lift settings. Condition B of LCO 3.7.1 applies. For 3 OPERABLE MSSVs per steam generator (PSV-2232 and PSV-2234 are on the same steam generator), a power reduction to # 46% RTP is required within 4 hours, and a reduction of the power range neutron flux - high trip setpoint to # 46% RTP is required within 36 hours.

TECHNICAL SPECIFICATIONS UNIT 3 - EXERCISE 3 SOLUTION

State the actions to be taken in accordance with technical specifications.

The basis for LCO 3.7.8 (service water system) states that an OPERABLE service water train has at least 1 OPERABLE service water booster pump. Since both of its booster pumps are inoperable, service water train B is inoperable, necessitating entry into condition A of LCO 3.7.8. Required action A.1 requires restoration of the train to OPERABLE status within 72 hours. Note 1 of required action A.1 requires that the applicable conditions and required actions of LCO 3.8.1 be entered for the diesel generator (B) made inoperable by inoperable service water train B.

Based on Required Action B.2 of LCO 3.8.1, the B train safety injection pump must be declared inoperable within 4 hours because the A train safety injection pump was already inoperable when the B train service water system was declared inoperable. This will require application of condition B of LCO 3.5.2.

If neither the service water train nor the SI pump is restored, it will be necessary to shut down the plant in accordance with Conditions B and C of LCO 3.5.2 or else apply the provisions of the risk informed completion time (RICT) program. In this case the RICT might give additional time because the A SI pump may still be “PRA functional” (TS 5.5.20 e).

TECHNICAL SPECIFICATIONS UNIT 3 - EXERCISE 4 SOLUTION

State the actions to be taken in accordance with technical specification requirements.

Two qualified circuits between the offsite transmission network and the onsite Class 1E AC electrical power distribution system no longer exist (there is no circuit between offsite and the A train of the Class 1E system). Condition A of LCO 3.8.1 applies; the required actions associated with this condition must be taken. The circuit must be restored within 72 hours (required action A.3). Application of the RICT may allow additional time. Also, the inoperable offsite circuit necessitates declaring supported features inoperable if opposite-train redundant features are inoperable (required action A.2).

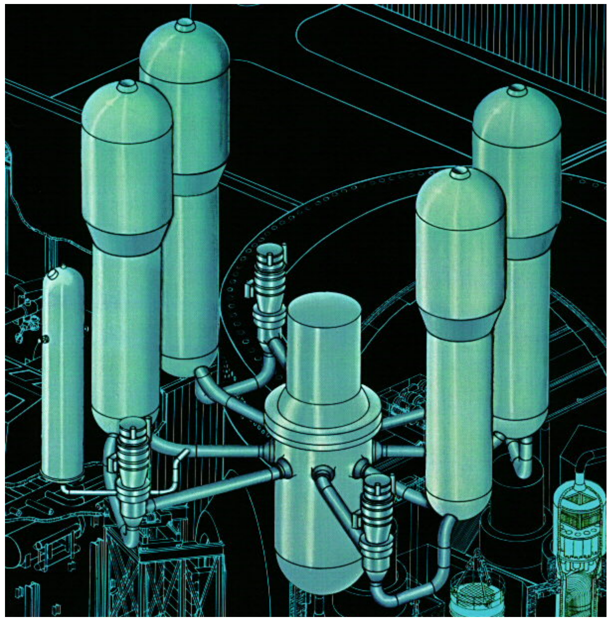
TECHNICAL SPECIFICATIONS UNIT 3 - EXERCISE 5 SOLUTION

State the actions to be taken in accordance with technical specification requirements.

Although one of the connections between the switchyard and the utility's electrical grid has been lost, two qualified circuits between the offsite transmission network and the onsite Class 1E AC electrical power distribution system continue to exist (the switchyard is considered part of the offsite transmission network). LCO 3.8.1 is satisfied; no actions are required by the technical specifications.

Determine whether the shift supervisor should give permission for this work, and explain.

Removing the instrument power fuses from each power range instrument causes all of its associated bistables to trip, including the P-10 permissive bistable. If the instrument power fuses are removed from all four power range instruments simultaneously, then all four P-10 bistables will be tripped, and the two-out-of-four coincidence for the permissive will be satisfied. One of the functions of P-10 is the de-energization of both source range nuclear instruments. This would render both instruments inoperable (without power, they are obviously incapable of monitoring core reactivity) and require entry into conditions A and B of LCO 3.9.3. The shift supervisor should not give permission for this work; he should permit de-energizing only one power range instrument at a time.



Westinghouse Advanced Technology Manual

Chapter 3.4 – Analysis of Technical Specifications
Unit 4

2020

HRTD Human Resources Training & Development
U.S.NRC UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

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3.4.0 Analysis of Technical Specifications – Unit 4

Learning Objectives:

1. Explain the bases of the safety limits, the limiting safety system settings, and the limiting conditions for operation.
2. When given an initial set of operating conditions and a copy of technical specifications, determine the required licensee response.

3.4.1 Introduction

This section is the last of the technical specification sections. It presents the limiting conditions for operation (LCOs) in the area of power distribution limits. Included are limits on:

- Heat flux hot channel factor (F_Q),
- Nuclear enthalpy rise hot channel factor ($F^N_{\Delta H}$),
- AXIAL FLUX DIFFERENCE (AFD), and
- QUADRANT POWER TILT RATIO (QPTR).

The definitions of these terms, their specified limits, and their bases are discussed in this section.

The heat flux hot channel factor and the nuclear enthalpy rise hot channel factor are peaking factors used to characterize core power distribution in terms of ratios of local maximum power output to average core output. These ratios are not monitored constantly; to ensure that they are maintained within limits between periodic measurements, limits are placed on gross measures of power distribution. The AXIAL FLUX DIFFERENCE provides a gross measure of axial power distribution, and the QUADRANT POWER TILT ratio provides a quadrant-to-quadrant comparison of core power generation. AFD and QPTR are constantly monitored; compliance with their limiting values provides assurance that the more infrequently measured peaking factors are maintained within limits.

The power distribution limits can vary with the core fuel cycle, in accordance with variations in the fuel loading characteristics. The Core Operating Limits Reports (COLRs) contain the limiting values for power distribution. The power distribution LCOs contain the associated action statements and surveillance requirements but reference the COLR for the limiting values. In accordance with the requirements for the COLR in the administrative controls section of the technical specifications, the COLR is revised and submitted to the NRC without the need for technical specification amendments.

3.4.2 Core Thermal Limits

Power generation in the fuel and heat removal from the fuel assemblies are regulated so that fuel and cladding damage is avoided. Overheating of the fuel is prevented by maintaining the local peak linear heat generation rate below the level at which fuel centerline melting occurs. Overheating of the cladding is prevented by restricting all areas of the core to the nucleate boiling regime (i.e., by preventing a departure from nucleate boiling [DNB]).

Fuel centerline melting (the nominal melting point of uranium dioxide fuel is 5080°F) would cause expansion of the fuel pellet. The adjacent cladding could be stressed to the point of failure, allowing the uncontrolled release of fission product activity to the reactor coolant.

Operation beyond the nucleate boiling regime would result in excessive cladding temperatures because of the degradation in heat transfer between the clad and the reactor coolant that accompanies DNB. With the breakdown of nucleate boiling, steam films develop adjacent to the cladding, hindering heat transfer to the coolant and causing cladding temperatures to rise sharply. High cladding temperatures promote the zirconium/water reaction, which can weaken the cladding structural integrity to the point that the clad fails, again resulting in the uncontrolled release of activity to the reactor coolant.

The prevention of DNB is assured by operating the core with a departure from nucleate boiling ratio (DNBR) greater than the design limit. Recall that the DNBR is the ratio of the heat flux predicted to cause DNB to the actual local heat flux. The DNBR limit is statistically determined so that there is a 95% confidence level that 95% of the most limiting fuel rods do not experience DNB when the minimum local DNBR is at the DNBR limit (the classic “95/95” criterion). A DNBR limit of 1.3, as determined through the application of the Westinghouse W-3 correlation, has been applied to many Westinghouse cores. The applications of more recently developed correlations have resulted in DNBR limits as low as 1.13 or 1.17. The DNB correlations do not always conservatively predict DNB; to provide the desired assurance that DNB will not occur, a DNBR limit greater than 1.0 must be selected.

The prevention of fuel centerline melting and the maintenance of the DNBR above the design limit are assured during normal operation and anticipated operational occurrences (Condition I and II events) through compliance with the core safety limits (see Section 3.1 of this manual). Recall that the core safety limits are combinations of operational parameters: pressurizer pressure, the highest coolant loop average temperature (T_{avg}), and core thermal power (see COLR-1). These are all factors which affect DNBR; an increase in T_{avg}, a decrease in pressure, or an increase in local power density can cause the local heat transfer regime to approach DNB and thus decrease the DNBR. (A reduction in reactor coolant flow can also reduce the DNBR; the core safety limit curves assume the forced reactor coolant flow associated with four-loop operation.)

The power distribution LCOs support compliance with the core safety limits by maintaining local core conditions within design limits. In fact, the bases for the core safety limits state that the safety limit curves are based on the nuclear enthalpy rise hot channel factor limits provided in the COLR. In addition, the power distribution LCOs establish bounds on the initial conditions assumed in accident analyses.

3.4.3 Peaking Factors

Power plant operators have no direct indications of DNBR and fuel temperature. Local variations in fuel rod power are not measured by the instrumentation normally online during power operation. To provide the operator with local power density information, the incore instrumentation system is used to construct flux maps of the core. The information from flux maps enables the calculation of peaking factors, which express core power distribution in terms of peak-to-average ratios. The two Westinghouse peaking factors which are periodically measured are the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy rise hot channel factor ($F_{\Delta H}^{N}$). LCOs for these peaking factors are included in the technical specifications, and their limits are included in the COLR.

As stated in the technical specification bases, the peaking factor LCOs (and the associated limits in the COLR) establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and that the accident analysis assumptions remain valid. Control of the power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses. The limits on $F_Q(Z)$and $F_{\Delta H}^{N}$ preclude core power distributions that exceed the following fuel design limits:

- There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition (during both normal operation and a loss of flow accident);
- During a large-break loss of coolant accident (LOCA), the peak fuel clad temperature will not exceed the 2200°F limit specified by 10CFR50.46 as an acceptance criterion for emergency core cooling systems (ECCSs). During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm; and
- The control rods must be capable of shutting down the reactor with a minimum required SHUTDOWN MARGIN with the highest worth control rod stuck fully withdrawn.

The bases for the peaking factor LCOs illustrate that the peaking factor limits provide a power distribution envelope for normal operation and establish the most extreme allowable power distribution at the start of an accident.

$F_Q(Z)$ and $F_{\Delta H}^{N}$ are discussed in detail in the following subsections.

3.4.3.1 Heat Flux Hot Channel Factor

F_Q is defined as the ratio of the maximum local fuel rod linear power density to the core average fuel rod linear power density. The limits for $F_Q(Z)$ have traditionally been expressed in the following form:

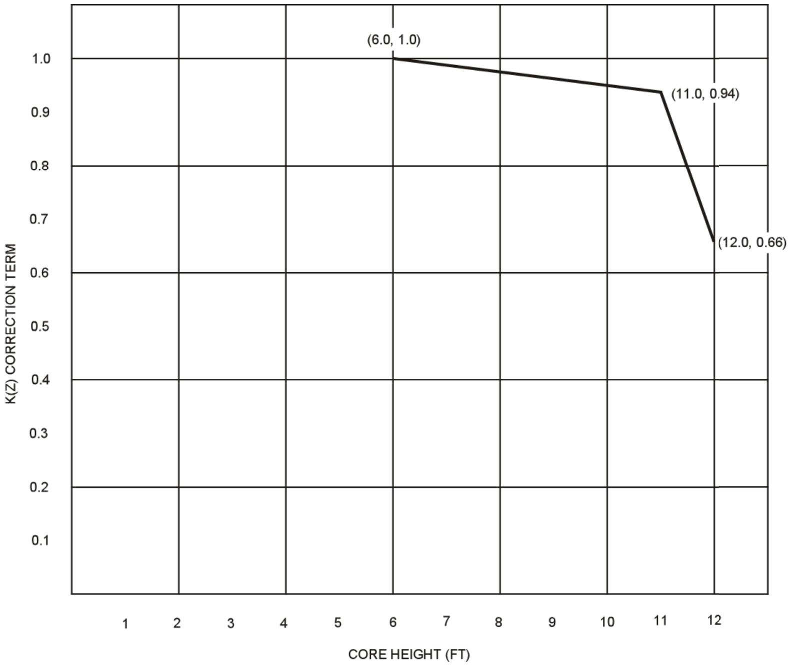
$$F_Q(Z) \le \frac{CFQ}{P} K(Z) \quad for \quad P > 0.5$$

$$F_Q(Z) \le \frac{CFQ}{0.5} K(Z) \quad for \quad P \le 0.5$$

Where: CFQ = 2.50

K(Z) is provided in Figure COLR-3, and

$$P = \frac{thermal\ power}{rated\ thermal\ power}$$, and



The above equations show that the $F_Q(Z)$ limits increase with decreasing thermal power. The average core linear power density is proportional to power, so at lower power levels the peak-to-average ratio of power density can be increased while the peak local linear power density is still maintained at a value which does not violate core design limits.

Also, the $F_Q(Z)$ limits include a height-dependent term. The function of core height is applied to ensure that the conditions in the core immediately prior to a LOCA are sufficiently limited that the 2200°F clad temperature limit is not exceeded during the accident. The K(Z) term is governed by the dynamics of core uncovery and reflood during LOCAs. During any LOCA, the upper portion of the core blows down first and refloods last. The upper portion of the core thus stays uncovered longer than the lower portion. Imposing more restrictive $F_Q(Z)$ limits for approximately the upper half of the core limits the power density there at the start of an accident and the resulting increase in clad temperatures. Additionally, during certain small-break LOCAs the backpressure opposing reflood flow could result in the exceptionally slow reflooding of the very top of the core (the last one or two feet). The even more restrictive $F_Q(Z)$ limits for the very top of the core limit the clad temperatures that could be reached there during such a small-break LOCA.

Verification that $F_Q(Z)$ is within the specified limits is performed in accordance with one of two methodologies, known as the F_{xy} methodology and the F_Q methodology. The F_Q methodology is more widely used at Westinghouse plants today and is applied to the $F_Q(Z)$ LCO in the TTC Unit 2 technical specifications. Each methodology is briefly described in the following paragraphs.

3.4.3.1.1 F_{xy} Methodology

In accordance with the F_{xy} methodology, two surveillances are performed periodically to ensure that the measured values of F_Q are within the limits specified in the COLR. In the first surveillance, measured values of $F_Q(Z)$ (designated as F_Q^M) are determined from a steady-state flux map and increased by 3% to account for fuel manufacturing tolerances and by 5% for flux map measurement uncertainty (resulting in an effective multiplier of 1.0815 on each F_Q^M). These adjusted measured values (designated as F_Q^C) are compared to the limits (a function of core elevation because of the K(Z) term) for the power level at which the flux map is generated. The surveillance is satisfied if F_Q^C is less than the F_Q limit at each core elevation.

Because flux maps are generated at steady-state conditions, axial variations in power distribution for normal maneuvers such as load following are not present in the flux map data. It is important, therefore, that flux maps verify that radial peaking is limited during steady-state operation, so that highly peaked local power densities do not result from large changes in the axial power distribution that could accompany operational maneuvers. Accordingly, the F_{xy} methodology includes a second surveillance which verifies that radial peaking is within limits. $F_Q(Z)$ can be expressed in terms of radial and axial components:

$F_Q(Z) = F_{xy}(Z)$ x (normalized average axial power at elevation Z)

where:

$F_{xy}(Z)$ = radial peaking factor at elevation Z

$$= \frac{\max.\ power\ density\ at\ elevation\ Z}{avg.\ power\ at\ elevation\ Z}$$

In other words,

$$F_Q(Z) = \frac{\max.\ power\ density\ at\ elevation\ Z}{avg.\ power\ at\ elevation\ Z}$$

multiplied by

$$\frac{avg.\ power\ density\ at\ elevation\ Z}{avg.\ core\ power\ density}$$

$F_{xy}(Z)$ thus characterizes radial peaking at elevation Z. If $F_{xy}(Z)$ is within the limits specified in the COLR for all core elevations, then there is assurance that unacceptable local power densities will not result from axial redistributions of core power. Put another way, satisfying the F_{xy} limits ensure that the core is not operated with a high radial peak at a core elevation where the average power density is low.

The F_{xy} surveillance involves obtaining $F_{xy}(Z)$ values (designated as F_{xy}^M) from a flux map for 30 to 75 core elevations and increasing them by the 1.0815 factor described above. The adjusted measured values of $F_{xy}(Z)$ (designated as F_{xy}^C) are compared to conservatively chosen radial peaking factor limits, which vary with core elevation and are included in the COLR. If each F_{xy}^C is less than the applicable limits at each core elevation, the F_{xy} surveillance is satisfied.

3.4.3.1.2 F_Q Methodology

The F_Q methodology also involves two surveillances for verifying that the $F_Q(Z)$ limits are satisfied. The first surveillance, a comparison of adjusted measured F_Q values (F_Q^C) to the $F_Q(Z)$ limits specified in the COLR, is identical to the first F_{xy} methodology surveillance.

Because flux maps are taken at steady-state conditions, a second surveillance is necessary to account for variations in power distribution resulting from normal operational maneuvers. These variations are conservatively calculated by considering a wide range of unit maneuvers in normal operation. Accordingly, W(Z), the maximum peaking factor increase over the steady-state value, is provided as a function of core elevation in the COLR. W(Z) is often provided as a table of multipliers vs. core elevation, as in the TTC Unit 2 COLR. The surveillance involves multiplying the adjusted measured peaking factor, F_Q^C, by W(Z) to obtain the maximum $F_Q(Z)$ expected to occur during normal operation, F_Q^W. The surveillance is satisfied if F_Q^W is less than the F_Q limit at each core elevation. Satisfying this surveillance provides assurance that unacceptable local power densities will not result from normal operational maneuvers.

The action statements for the $F_Q(Z)$ LCO involve reducing thermal power, reducing the power range neutron flux - high and overpower ΔT trip setpoints, and reducing the AFD acceptable operation limits (F_{xy} methodology only).

3.4.3.2 Nuclear Enthalpy Rise Hot Channel Factor

$F_{\Delta H}^N$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F_{\Delta H}^N$ is a measure of the total maximum power produced in a fuel rod. The $F_{\Delta H}^N$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus has the highest probability for a DNB.

The limit for $F_{\Delta H}^N$ is expressed as:

$$F_{\Delta H}^N \leq 1.65[1.0 + 0.3(1.0 - P)]$$

where:

$$P = \frac{thermal\ power}{rated\ thermal\ power}$$

The $F_{\Delta H}^{N}$ limit is included in the COLR. The value of 1.65 constitutes the maximum allowable $F_{\Delta H}^{N}$ at 100% power. The limit expression includes an additional margin for higher integrated rod power peaking from reduced thermal feedback and greater control rod insertion at lower power levels. The limiting value for $F_{\Delta H}^{N}$ increases 0.3% for each 1% reduction in power.

The action statements for the $F_{\Delta H}^{N}$ LCO call for reducing thermal power and the power range neutron flux - high trip setpoint within a few hours of determining that the limit is exceeded. If the unacceptable condition is not corrected, thermal power must be reduced below 50%, where the $F_{\Delta H}^{N}$ limit is no longer applicable. Acceptable values of $F_{\Delta H}^{N}$ must be verified at several points during the subsequent power escalation.

3.4.4 Operational Limits

The technical specification surveillance requirements for the power distribution peaking factors specify that $F_Q(Z)$ and $F_{\Delta H}^{N}$ are to be verified within their limits every 31 effective full power days. To ensure that each of the peaking factors is maintained within its limit between periodic measurements, the technical specifications provide limits on other parameters which can be readily monitored and controlled by the operators. These parameters include rod position, AFD, and QPTR. Satisfying the LCOs associated with these parameters should maintain the power distribution within limits on a continuous basis between measurements of the peaking factors. The following subsections discuss the operational limits which affect the maintenance of an acceptable core power distribution.

3.4.4.1 Rod Position

Although not included in the power distribution section of the technical specifications, part of the bases for the rod position LCOs is the maintenance of an acceptable power distribution. Compliance with the rod insertion limits helps to ensure that the core's axial power profile is not too highly skewed toward the bottom of the core. The control bank rod insertion limits are included in the COLR. Compliance with the requirement that each rod be operable and positioned within 12 steps of its group's demanded position prevents operation with a dropped or misaligned rod. Significant rod misalignment could result in abnormal radial flux peaking, which may constitute an initial condition inconsistent with the safety analysis.

3.4.4.2 Axial Flux Difference

AFD is defined as the difference in normalized flux signals between the top and bottom halves of a two-section excore neutron detector.

$AFD = \phi_{top} - \phi_{bottom}$

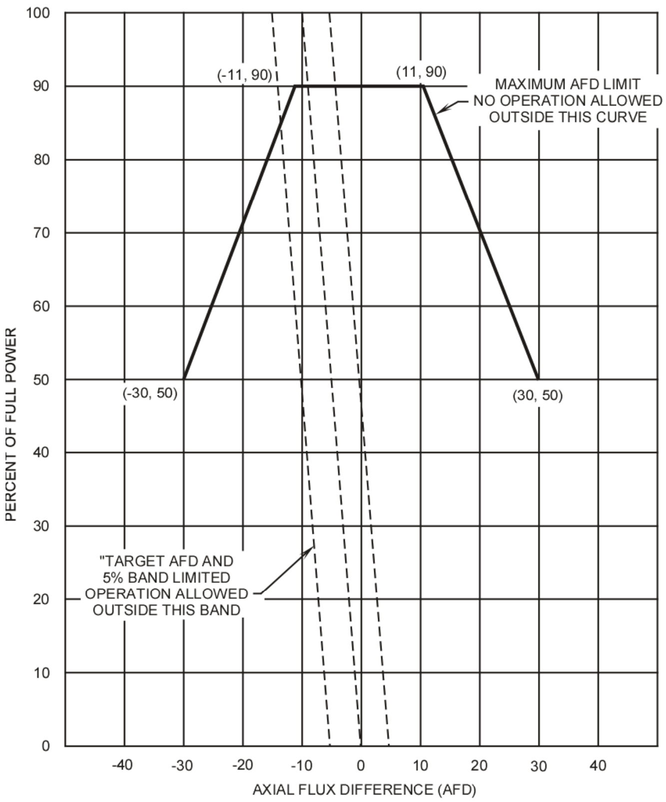
Where ϕ is expressed as a percentage of rated thermal power.

As AFD involves the difference of detector currents, it is often referred to as ΔI.

The limits on AFD limit the amount of power distribution skewing to the top or bottom of the core. The limits on AFD ensure that the $F_Q(Z)$ limits are not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on AFD also restrict the range of power distributions that are used as initial conditions in transient and accident analyses.

Two operating schemes are used to control the axial power distribution at Westinghouse plants. These are known as constant axial offset control (CAOC) and relaxed axial offset control (RAOC). RAOC applies to the AFD LCO in the TTC Unit 2 technical specifications. Each operating scheme is described in the following paragraphs.

3.4.4.2.1 Constant Axial Offset Control



CAOC is illustrated in Figure 3.4-2. Such a figure is included in the COLR. CAOC involves maintaining the AFD within a tolerance band around a burnup-dependent target, known as the target flux difference. The target flux difference is determined at equilibrium xenon conditions with power as near to rated thermal power as practical. The control rods are positioned as they normally would be for steady-state operation at high power levels, meaning that the bank D rods are completely or almost completely out of the core. The target flux difference obtained under these conditions, divided by the fraction of rated thermal power at which the flux difference is determined, is the target flux difference at rated thermal power for the associated core burnup conditions. Target flux differences for other power levels are obtained by multiplying the rated thermal power value by the appropriate fractional power level.

Periodic updating of the target flux difference value is necessary to follow the change of the flux difference at steady-state conditions with fuel burnup. The target flux difference at rated thermal power generally shifts from more negative to more positive with burnup in accordance with the general pattern of fuel depletion as the core ages.

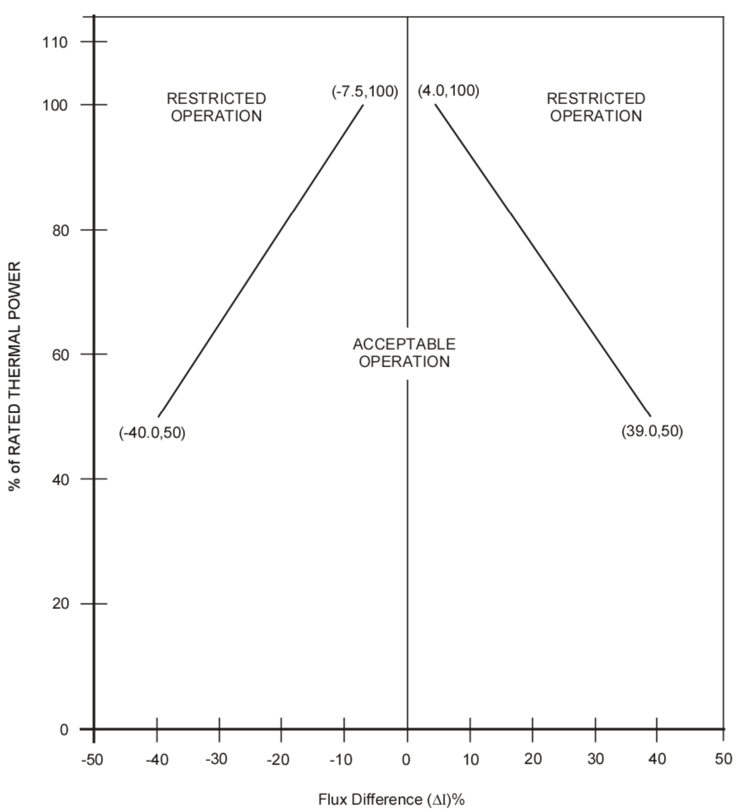
For power levels greater than 90%, the AFD must be kept within the target band. With the AFD outside the target band with power greater than 90%, the assumptions of accident analyses may be violated. Accordingly, above 90% power the AFD must be restored to within the target band almost immediately to avoid a potentially severe xenon redistribution.

However, during rapid power reductions, control bank motion may cause the AFD to deviate outside the target band at reduced power levels. This deviation does not affect the xenon distribution sufficiently to change the envelope of peaking factors that may be reached on a subsequent return to rated thermal power with the AFD within the target band, provided that the time duration of the deviation is limited. Accordingly, a one-hour deviation limit cumulative during the previous 24 hours is provided for operation outside the target band but within the acceptable operation limits. The region of acceptable operation is illustrated in Figure 3.4-2; it is often referred to as “the doghouse” because of its shape. The deviation penalty time is accumulated at the rate of one minute for each minute of operating time spent outside the target band at power levels greater than 50%.

For power levels between 15% and 50%, AFD deviations outside the target band are less significant. Below 50% power, deviation penalty time is accumulated at the rate of 1/2 minute per minute of operating time spent outside the target band.

With power between 50% and 90% and with the AFD either outside the acceptable operation limits or outside the target band for more than one hour of cumulative deviation penalty time during the previous 24 hours, power must be quickly brought to less than 50%. With power less than 50% and with the AFD outside the target band for more than one hour of cumulative deviation penalty time during the previous 24 hours, thermal power cannot be increased equal to or greater than 50% until the AFD is within the target band.

3.4.4.2.2 Relaxed Axial Offset Control



The AFD limits presented in the TTC Unit 2 COLR and shown in Figure 3.4-3 illustrate RAOC. The RAOC methodology establishes a xenon distribution library with tentatively wide AFD limits. Axial power distribution calculations are then performed to demonstrate that normal-operation power shapes are acceptable for the LOCA and loss of flow accident and for the initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements. Although RAOC defines the limits that must be met to satisfy the safety analyses, CAOC (with a specified AFD target band) is typically used to control the axial power distribution on a day-to-day basis. The CAOC operating space typically lies within the RAOC operating space.

The AFD LCO under RAOC methodology does not include a target band or the potential for accumulated deviation penalty time, but the plant operating instructions typically include a target band for normal operation. The LCO action statements simply call for restoring the AFD to within the acceptable operation region or reducing power to less than 50%.

3.4.4.3 Quadrant Power Tilt Ratio

QPTR is defined as the ratio of the maximum upper excore detector calibrated output to the average of the upper excore calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore calibrated outputs, whichever is greater.

The word "calibrated" in the definition reflects the fact that a full incore/excore calibration returns QPTR to a value of 1. Thus, a QPTR of > 1.02 indicates gross changes in core power distribution between monthly incore flux maps.

In other words, QPTR is not an absolute measure of anything. It is a relative measure that indicates changes in the gross radial power distribution since the most recent incore/excore calibration. If QPTR = 1, this does NOT indicate that the radial power distribution is perfectly flat. It simply indicates that there have been no significant changes since the last incore/excore calibration.

With a QPTR greater than the limit (typically 1.02), the QPTR must be restored to within its limit within two hours, or thermal power must be reduced at least 3% for each 1% of QPTR in excess of 1.00. Since this indicates significant changes in power distribution since the last incore/excore calibration, another flux map is performed (i.e. a verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their limits). If the flux map indicates acceptable results, an incore/excore calibration is performed per REQUIRED ACTION A.5, which returns QPTR to a value 1.0. The two-hour time allowance for operation with a QPTR greater than the limit allows for identification and correction of a dropped or misaligned rod.

With operation above 75% power and one excore channel inoperable, the movable incore detectors are used to confirm that the power distribution is consistent with the QPTR indicated by the remaining three excore channels.

3.4.5 Exercises

Exercise 1

An incore flux map is obtained with the plant at 95% power in accordance with a regularly scheduled surveillance. Core burnup is 150 MWD/MTU. Measured values of the heat flux hot channel factor, $F_Q^M(Z)$, at three core elevations are as follows:

Elevation (ft)	F_Q^M (Z)
4	1.8176
6	1.8549
10	1.7932

1. Calculate F_Q^C (Z) for each core elevation.
2. Calculate F_Q^W(Z) for each core elevation.
3. Determine whether the F_Q(Z) limit has been exceeded.
4. State the actions to be taken in accordance with technical specification requirements.

Exercise 2

With reactor power at 100%, it is noted that the current AFD value is − 8.3%.

1. State the actions to be taken in accordance with technical specification requirements.
2. State how the operator would restore the AFD to within the limits.

Exercise 3

While the plant is operating at 98% power, the following annunciators alarm: ROD BOTTOM, ROD DEVIATION POWER TILT, and POWER RANGE COMPARATOR DEVIATION. The digital rod position indication system indicates that one rod is on the bottom. The calculated QPTR immediately after the rod drop is 1.05.

1. State the actions to be taken in accordance with technical specifications.
2. State the basis for the 2-hour completion time for reducing thermal power.

Exercise 4

With reactor power at 90%, state the requirements for verifying the QPTR:

1. Under normal circumstances.
2. When the QPTR alarm is inoperable.
3. When one power range channel is inoperable.

TECHNICAL SPECIFICATIONS UNIT 4 - EXERCISE 1 SOLUTION

1. Calculate $F_Q^C(Z)$ for each core elevation.

Calculate each $F_Q^C(Z)$ by multiplying the measured value by 1.0815 to account for manufacturing tolerances and flux map measurement uncertainty.

Elevation (ft)	$F_Q^M(Z)$	x 1.0815 =	$F_Q^C(Z)$
4	1.8176		1.9657
6	1.8549		2.0061
10	1.7932		1.9393

2. Calculate $F_Q^W(Z)$ for each core elevation.

Calculate each $F_Q^W(Z)$ by multiplying $F_Q^C(Z)$ by the W(Z) value for the applicable core elevation. Obtain W(Z) values from Figure COLR-4 for the stated core burnup.

Elevation (ft)	$F_Q^C(Z)$	x	W(Z) =	$F_Q^W(Z)$
4	1.9657		1.2365	2.4306
6	2.0061		1.2049	2.4171
10	1.9393		1.3090	2.5386

3. Determine whether the $F_Q(Z)$ limit has been exceeded.

Determine the $F_Q(Z)$ limit for each core elevation with the formula provided in the COLR (CFQ = 2.50, P = 0.95) and the appropriate K(Z) value from Figure COLR-3. Then compare each $F_Q^C(Z)$ and $F_Q^W(Z)$ value to the applicable limit.

Elevation (ft)	CFQ/P	x	K(Z)	=	$F_Q(Z)$ limit
4	2.6316		1.000		2.6316
6	2.6316		1.000		2.6316
10	2.6316		0.950		2.5000

The $F_Q^W(Z)$ value at the 10-ft elevation (2.5386) exceeds the $F_Q(Z)$ limit (2.5000).

1. State the actions to be taken in accordance with technical specification requirements.

Condition B of LCO 3.2.1 applies. In accordance with action B.1, the AFD limits must be reduced at least 1% for each 1% by which $F_Q^W(Z)$ exceeds the limit within 2 hours.

$F_Q^W(Z)$ exceeds the limit by $(\frac{2.5386 - 2.5}{2.5}) \times 100 = 1.544\%$

Round up to 2% for conservatism. AFD limits at 95% power (see Figure COLR-8):

Lower limit: $-40 + \frac{(95-50)(-7.5-(-40))}{100-50} = -10.75$

Upper limit: $39 + \frac{(95-50)(4-39)}{100-50} = 7.5$

Add 2% to lower limit and subtract 2% from upper limit. New AFD bounds at 95% power are (!8.75, 5.5). If this action is not taken within 4 hours, then the plant must be brought to MODE 2 (where LCO 3.2.1 does not apply) within the next 6 hours, per action C.1.

TECHNICAL SPECIFICATIONS UNIT 4 - EXERCISE 2 SOLUTION

1. State the actions to be taken in accordance with technical specification requirements.

Condition A of LCO 3.2.3 applies. Power must be reduced to < 50% within 30 minutes if the AFD is not corrected to within the limits during that time.

2. State how the operator would restore the AFD to within the limits.

Since the AFD is too negative, the control rods are probably too deeply inserted; the operator would restore the AFD by borating the reactor coolant to drive the control rods farther out.

TECHNICAL SPECIFICATIONS UNIT 4 - EXERCISE 3 SOLUTION

1. State the actions to be taken in accordance with technical specifications.

Condition A of LCO 3.2.4 applies. The required actions associated with condition A must be taken. In the short term, power would be reduced to 85% (a 15% reduction from RTP because the QPTR exceeds 1.00 by 5%) in accordance with action A.1, unless the QPTR is made less than 1.02 within 2 hours. In addition, the periodic QPTR checks specified by action A.2 should alert the operators to a worsening QPTR condition, which would mandate further power reductions. Additional actions have longer completion times.

2. State the basis for the 2-hour completion time for reducing thermal power.

The basis for required action A.1 states, “The Completion Time of 2 hours allows sufficient time to identify the cause [of the QPTR exceeding its limit] and correct the tilt.”

TECHNICAL SPECIFICATIONS UNIT 4 - EXERCISE 4 SOLUTION

With reactor power at 90%, state the requirements for verifying the QPTR:

1. Under normal circumstances.

Surveillance requirement (SR) 3.2.4.1 requires verifying the QPTR by calculation once every 7 days.

2. When the QPTR alarm is inoperable.

The QPTR alarm has no significance in technical specification. The surveillance interval is still 7 days.

3. When one power range channel is inoperable.

SR 3.2.4.2 requires verifying the QPTR using the movable incore detectors once within 12 hours and once every 12 hours thereafter with one power range channel inoperable and power ∃ 75%.

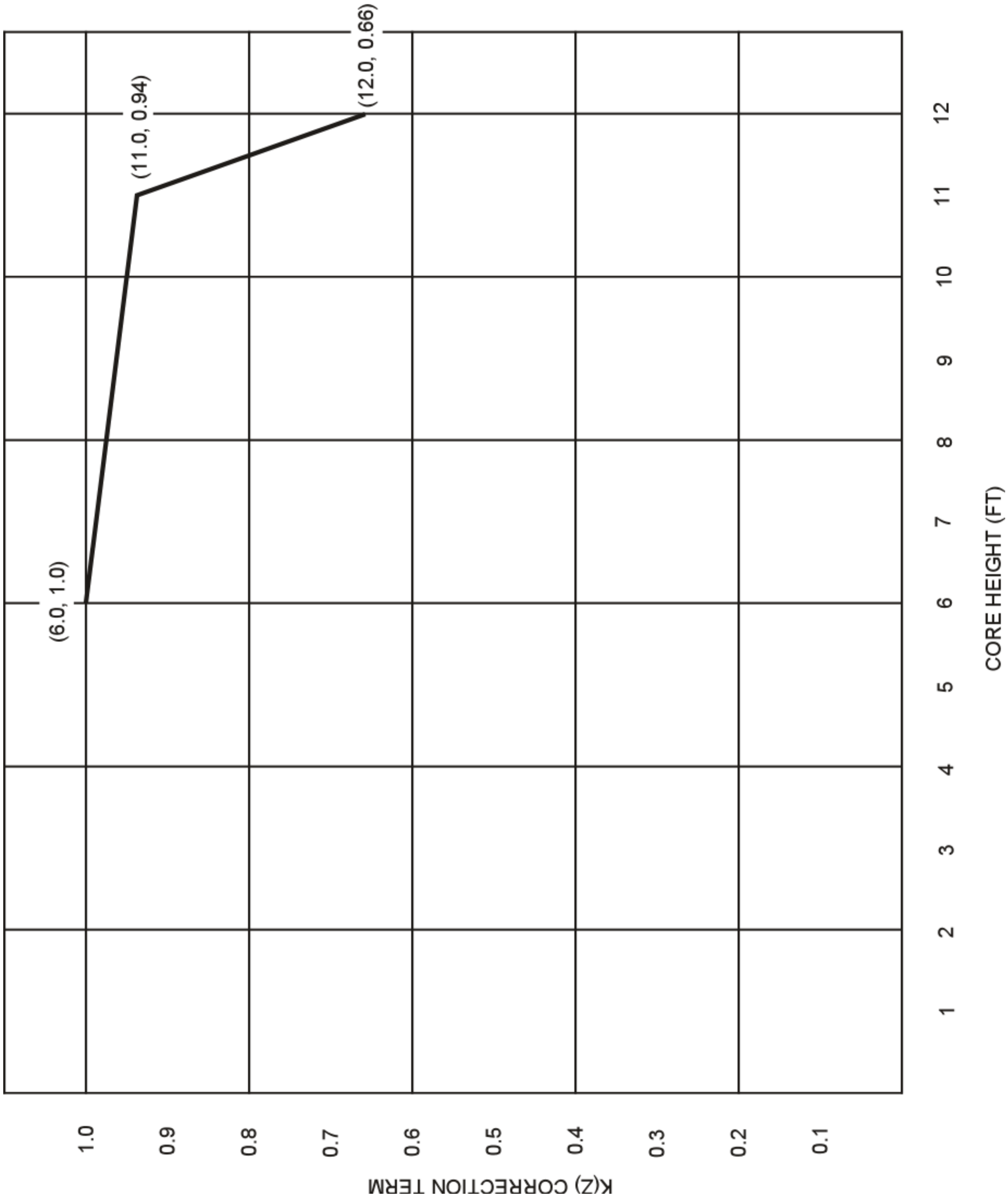


Figure 3.4-1 K(Z) Correction Term

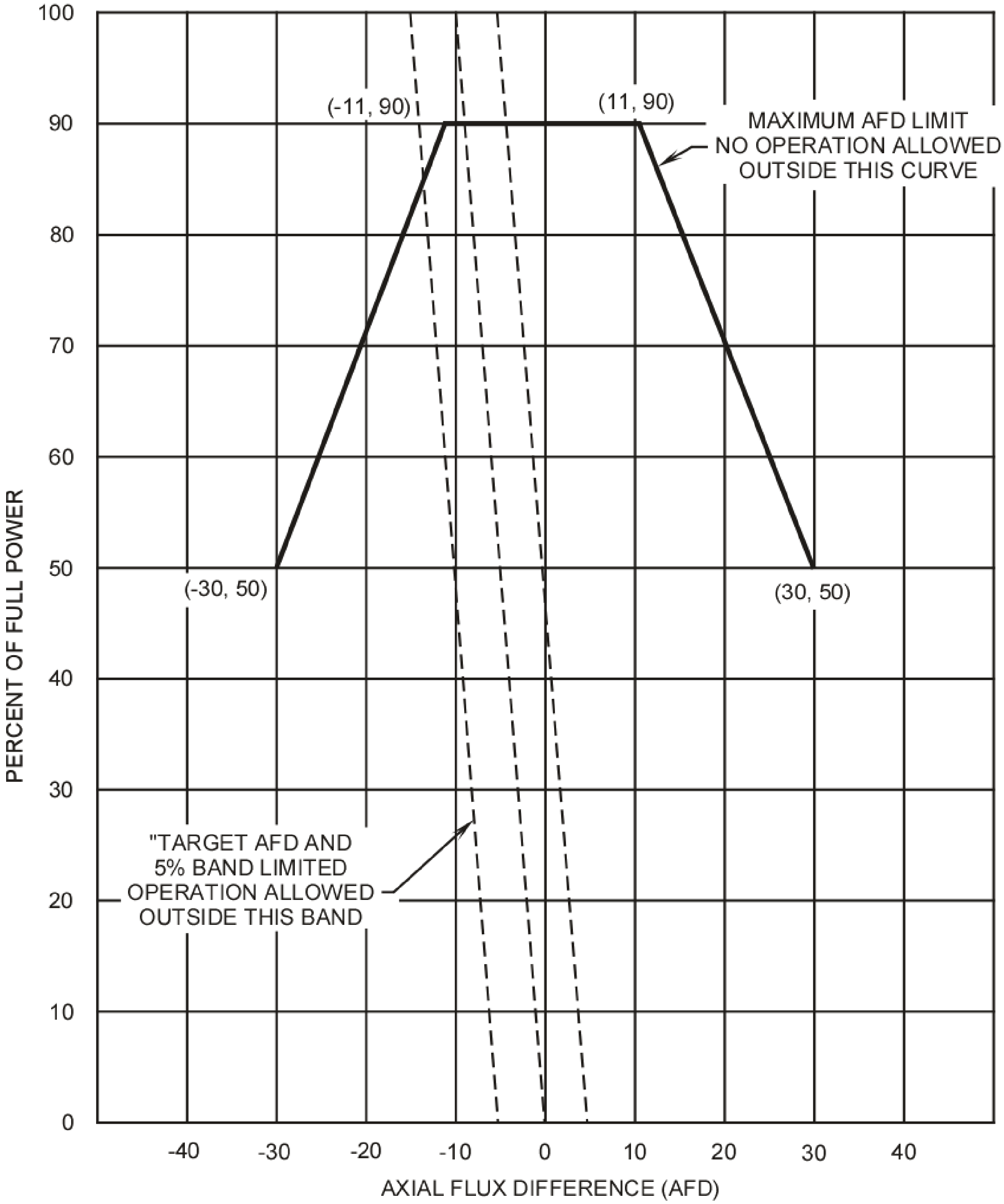


Figure 3.4-2 Axial Flux Difference Limits , CAOC

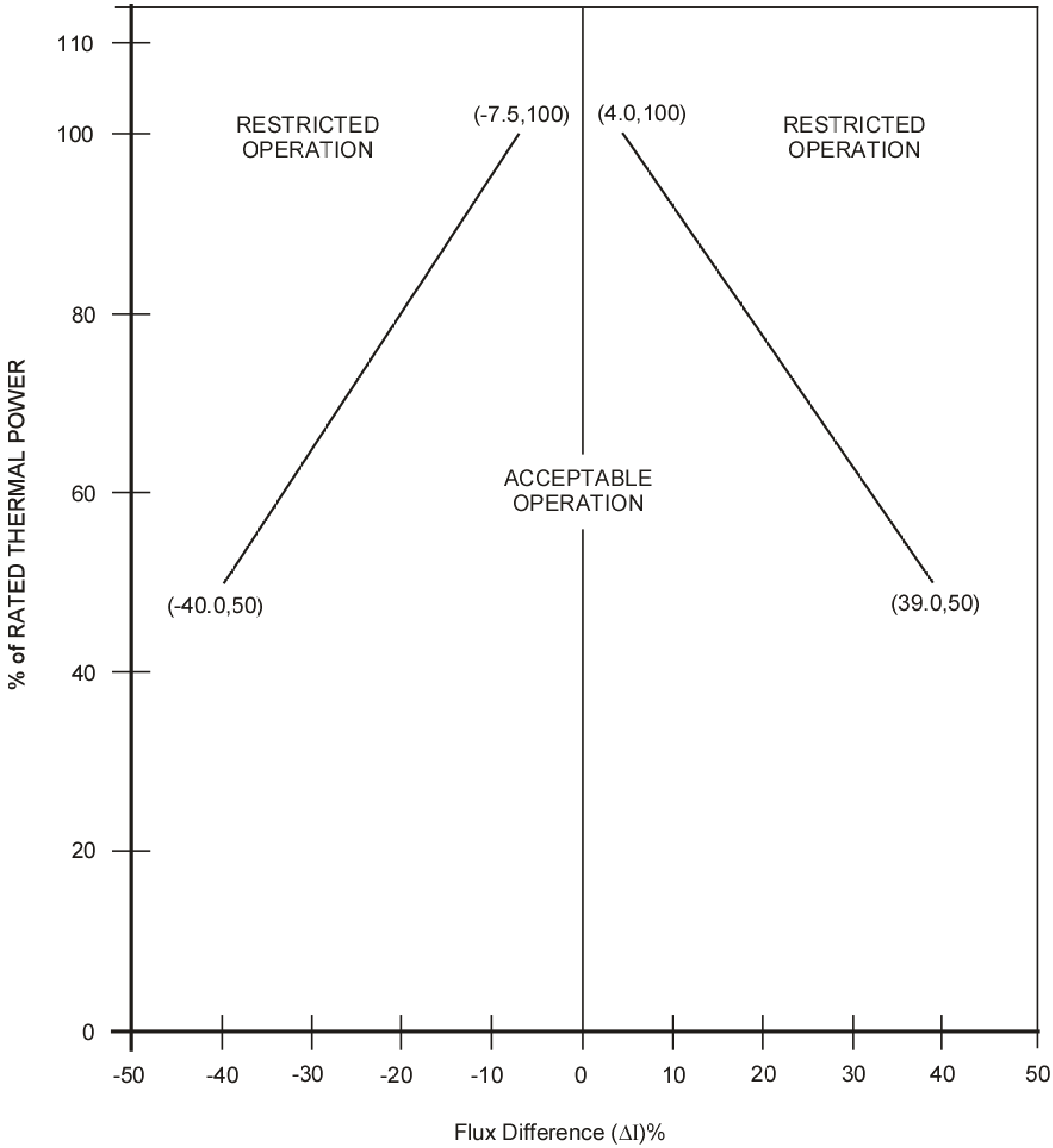
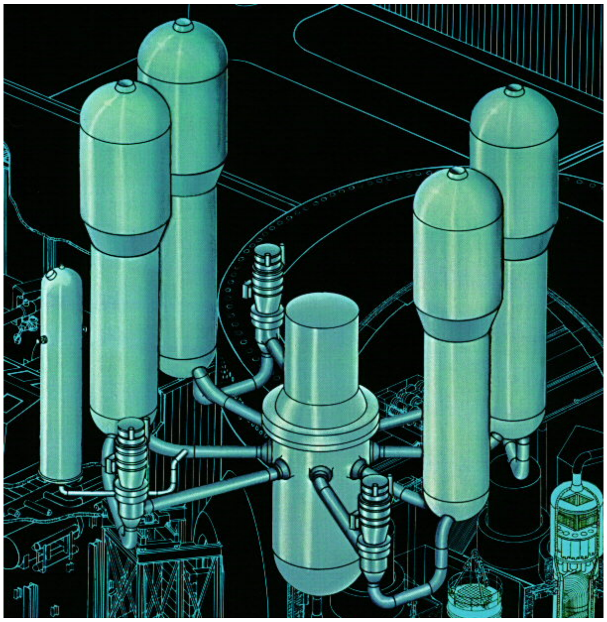


Figure 3.4-3 Axial Flux Difference, RAOC



Westinghouse Advanced Technology Manual

Chapter 4.1 – Design and Licensing Bases

NRC Mission Critical Terminology

2020

HRTD Human Resources Training & Development
U.S.NRC UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

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4.1 Design and Licensing Bases

Learning Objectives:

1. Recognize the definition of the following terms:
   a. Design basis function
   b. Design basis values or bounding conditions
   c. Design basis supporting information
   d. Topical design bases
   e. Engineering design bases

2. Recognize how the facility specific design basis was established during the plant licensing process.

3. Recognize the relationship between the design bases and the final safety analysis report (FSAR).

4. Recognize the regulatory controls used to ensure the design bases are maintained over the life of the plant.

5. Recognize the purpose of the 10 CFR 50.59 Rule, “Changes, Tests and Experiments.”

6. Recognize the definition of the following terms as used in the 50.59 Process:

   a. Change
   b. Facility as described in the FSAR
   c. Procedure as described in the FSAR
   d. Test or Experiments not described in the FSAR
   e. Departure from a method of evaluation
   f. Accidents
   g. Conservative versus Non-conservative evaluation results

7. Recognize the criteria used to determine if the 50.59 Rule is applicable to a proposed change or activity.

8. Recognize the criteria used to determine if a proposed change or activity may be screened out from a 50.59 evaluation.

9. Recognize the 50.59 Rule evaluation criteria used in to determine if a licensee may implement a proposed change or activity without prior NRC approval.

4.1.1 Introduction

The NRC established a framework of complementary regulations designed to ensure that power reactor licensees maintain fidelity of the design and licensee bases over the facility life. Recent inspection experience has highlighted the need to ensure that all NRC personnel involved with power reactor oversight are familiar with this regulatory framework.

The first issue was associated with the Fort Calhoun Station (FCS). Omaha Public Power District implemented an extended shutdown following a major flood event, a fire affecting safety related equipment, and significant reoccurring performance problems. In 2011, following the shutdown, the NRC transitioned FCS into the Inspection Manual Chapter (IMC) 0350, “Oversight of Reactor Facilities in a Shutdown Condition Due to Significant Performance and/or Operational Concerns” process. The licensee subsequently implemented a performance improvement program and the NRC concluded that corrective actions were sufficient to support plant restart.

Region IV completed a “lessons learned” evaluation after FCS exited the IMC 0350 process. Region IV concluded that NRC oversight could have been enhanced by improving inspector knowledge of the requirements for maintaining and implementing facility design and licensing bases. Many of FCS performance issues involved inadequate implementation of design basis requirements, design basis documentation, and control of plant modifications. Many of the FCS design and licensing bases issues were undetected for an extensive period, some dating all the way back to original plant licensing.

The second issue was associated with the San Onofre Nuclear Generating Station (SONGS) steam generator replacement. In January 2012, plant operators’ shutdown SONGS Unit 3 after identifying a steam generator tube leak. Inspections revealed unexpected steam generator tube wear. This was a concern because the licensee had replaced the steam generators the previous year.

The NRC launched an Augmented Inspection Team (AIT) to review the SONGS event. The AIT concluded that the premature wear was the result of the licensee’s inadequate verification of the new steam generator thermo-hydraulic design.

The NRC Office of Inspector General (OIG) subsequently conducted an inquiry into the NRC’s oversight of the 10 CFR 50.59 process at SONGS. The OIG concluded that the NRC missed two opportunities to identify deficiencies in the licensee’s steam generator 50.59 determination. The first missed opportunity was during the triennial 50.59 Baseline Inspection. The team had selected the replacement steam generator modification as an inspection sample but failed to identify the deficiencies with the determination. The second opportunity was associated with the AIT. The AIT report included an unresolved item related to the adequacy of 50.59 determination. However, the agency closed the item without drawing a conclusion if an amendment to the Operating License (OL) had been required. The OIG also identified improvement opportunities associated with the NRC Office of Nuclear Reactor Regulation's (NRR) oversight of Southern California Edison's Final Safety Analyses Report (FSAR) updates.

4.1.2 Development of Original Design and Licensing Bases

The current fleet of power reactors were licensed using the two step 10 CFR 50, "Domestic Licensing of Production and Utilization Facilities," process. During the first step, the utility would submit a Construction Permit (CP) application to the agency after making a decision to build a nuclear power facility. The specific requirements for the content of the application are detailed in 10 CFR 50.34, "Contents of the Applications and Technical Information." The preliminary safety analysis report (PSAR) was a key document required to be included in the CP application. The PSAR contained important information related to the safety of the proposed facility, including the principle design criteria to be used, the proposed design bases, and assurance that the proposed site satisfied the siting criteria specified in 10 CFR100, "Reactor Site Criteria." The utility would begin construction following agency approval of the CP.

During the construction phase, the utility would begin the second step in the licensing process. The applicant would submit an application for the OL. As in the case for the CP, the requirements for the OL application were also contained in 50.34. The final safety analysis report (FSAR) was a key document included in the OL application. The FSAR contained the applicant's written commitments describing:

- The principle design criteria used for the facility safety design,
- The facility specific design bases,
- The relationship of the design bases to the principle design criteria,
- Safety analysis demonstrating that the design basis would remain satisfied during normal operation and following postulated events,
- Descriptions how regulatory requirements will be satisfied, and
- The proposed plant technical specifications.

4.1.2.1 Final Safety Analyses Report (FSAR)

The FSAR was required to include accident analyses that demonstrated that the facility specific design basis would remain satisfied during normal operation, accidents, and transients. The FSAR also included supporting analyses that demonstrated that the design functions of important to safety structures, systems and components (SSC) would be accomplished as credited within the accident analyses. The FSAR also included analyses of other events required by specific regulations. For example, analyses that demonstrated adequate protection against events such as turbine missies, fires, floods, earthquakes as required by 10 CFR 50, Appendix A, "General Design Criteria (GDC)," or equivalent for older plants.

These supporting analyses ensured that the facility's principle safety barriers would be maintained following accidents and natural phenomena. These principle safety barriers ensured:

- *The integrity of the reactor coolant pressure boundary,*
- *The capability to shut down the reactor, and maintain it in a safe shutdown condition, and*
- *The capability to prevent and mitigate the consequences of accidents that could result in potential off-site exposures in excess of the guidelines contained in 10 CFR 100.*

FSAR safety evaluations included various analytical methods. These methodologies and inputs received varying levels of NRC review and approval during the original license review. Many of these methods were fundamental to how the facility design satisfied regulatory requirements. These methods also provided the bases for acceptable facility response to postulated accidents and events. The staff's review of these methods and inputs were an important part of the agency's conclusion that the facility would meet design bases and regulatory requirements prior to granting the OL.

Some FSAR safety analyses relied on methods and inputs from specific industry Codes, Standards, or NRC Regulatory Guides (RG). Many of these Codes and Standards had been formally accepted by the NRC and became part of the facility design and licensing bases. Some of these Codes and Standards were also specifically required by 10 CFR 50.55a, "Codes and Standards," and subsequently became a condition of the facility OL per 10 CFR 50.54, "Condition of Licenses."

For OL applications submitted after 1972, the agency required that FSAR formatting be consistent with RG 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants." RG 1.70 provided a systematic presentation of the license application information to help the agency staff ensure that all design basis and regulatory requirements were met by the applicant. In 1975, the NRC issued NUREG 0800, the "Standard Review Plan." The Standard Review Plan was structured in parallel with RG 1.70, providing a one to one correspondence between each FSAR section and the NRC's principle review acceptance criteria. RG 1.70 and NUREG 800 may be useful references for inspectors performing design basis reviews.

During original licensing, staff reviewers may have identified gaps between information provided in the FSAR (license application) and agency acceptance criteria. When this occurred, the agency provided feedback to the applicant in the form of safety evaluation reports, requests for additional information, letters, or at meetings. Based on this feedback, the applicant would amend the FSAR and resubmit the license application. This process may have been repeated many times during the OL review. For example, Pacific Gas and Electric amended the Diablo Canyon FSAR (license application) 85 times since first submitted in 1973 and approved in 1984. What is important for the inspector to understand is that, the applicant defined the proposed facility design and licensing bases by written commitments in the license application. The NRC's role was to either approve or disapprove the OL application. The license application, including the FSAR as amended, became the original facility licensing basis when the commission approved and issued the facility OL.

4.1.2.2 Current Licensing Basis

The current licensing basis (CLB) reflects the original facility licensing basis plus any changes implemented since the agency approved the OL. The CLB specifically includes those NRC requirements applicable to a specific facility. These requirements include:

- *The licensee's docketed written commitments for ensuring compliance with and operation within the regulations, Orders, License Conditions and exemptions;*
- *The plant specific technical specifications;*
- *The plant specific design basis (defined in Part 50.2);*
- *Written responses to NRC Bulletins, Generic Letters, enforcement actions; and*
- *Licensee commitment documented in NRC safety evaluations or licensee event reports.*

The NRC has defined the CLB in two places. The first is 10 CFR 54.3, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Generic Letter 92-03, "Verification of Plant Records," states that licensees should apply the 54.3 CLB definition to all Part 50 activities. The CLB is also defined in IMC 0326, "Operability Determinations & Functionality Assessments for Conditions Adverse to Quality or Safety." IMC 0326 provides inspection guidance for operability and functionality of plant SSCs.

4.1.3 Design Basis

The facility specific design bases are an important subset of the CLB. 10 CFR 50.34 required that the design bases be included in the original FSAR. Also, 10 CFR 50.71(e), "Maintenance of Records, Making of Reports", requires licensees to provide periodic updates to the design bases information in the FSAR. As defined in 10 CFR 50.2, design bases identifies the specific functions that plant SSC are required to perform as described in the original license application. Design bases also include the specific values, or ranges of values, chosen as controlling parameters used to establish the boundaries of the design.

Nuclear Energy Institute (NEI) 97-04, "Guidance and Examples for Identifying 10 CFR 50.2 Design Bases," Appendix B, provided an expanded definition and examples of design basis. The NRC endorsed the use of NEI 97-04, Appendix B, in RG 1.186, "Guidance and Examples for Identifying 10 CFR 50.2 Design Bases." NEI 97-04 defined design bases into three categories:

- Design basis functions,

- Design basis values, and
- Design basis supporting information.

4.1.3.1 Design Basis Functions

Design basis functions are those specific functions performed by facility SSCs that are either required by, or are necessary to comply with regulations, License Conditions, Orders, or technical specifications. Design basis functions includes all SSC functions credited in FSAR safety analysis to meet NRC requirements.

The facility specific design bases functional requirements are derived from specific regulations, primarily the principle design criteria contained in Part 50, Appendix A, “General Design Criteria (GDC) for Nuclear Power Plants,” or equivalent for older plants. The design bases also include the licensee’s written response to other regulatory requirements, such as 10 CFR 50.62, “Requirements for Reduction of Risk from Anticipated Transients without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants,” and 50.63, “Loss of All Alternating Current Power”.

For example, consider a power reactor containment structure. The containment design basis functions includes providing a leak tight barrier against the uncontrolled release of radioactive material to the environment and to ensure that environmental conditions are not exceeded during postulated accidents. These design basis functions were derived from the principle design criteria provided in the regulations (Part 50, Appendix A), specifically General Design Criteria (GDC) 16, “Containment Design;” GDC 38, “Containment Heat Removal;” GDC 50, Containment Design Basis; GDC 51, “Fracture Prevention of Containment Pressure Boundary;” and GDC 54, “Piping Systems Penetrating Containment.”

4.1.3.2 Design Basis Values

Design bases values are those specific values, or ranges of values, that are used as controlling parameters in the safety analyses. These values establish the analytical boundaries used to demonstrate that the design basis functions will remain satisfied for all licensed conditions. Design bases values may be established by NRC requirements, derived from or confirmed by safety analysis, or chosen from an applicable code, standard or guidance document.

For the containment example, design basis values include:

- *The containment system shall provide a barrier, which in the event of a loss of coolant accident, limits the release of fission products to the secondary containment/auxiliary building and the environment to ensure that radiological doses would be less than the values prescribe in 10 CFR 100.*
- *The containment system shall be capable of maintaining its leakage rate performance for at least 30 days following an accident.*

- *The containment shall be designed to withstand the design pressure of 60 psig.*

For example, the containment design pressure is a controlling parameter that is explicitly tied to the design basis function. This controlling parameter is relied upon in the safety analysis to ensure that the containment will provide a sufficient fission product barrier. Discovery of a condition that indicates that the containment is no longer capable of meeting the design pressure, would mean that the containment is "outside of the design basis."

4.1.3.3 Supporting Design Information

Design basis supporting design information is that substantial set of detailed design information that underlies the design bases. This includes design input information, design analysis, and the design output documents. Supporting design information may be included in the FSAR or other docketed documents. Supporting design information may also include non-docketed sources, such as calculations, SSC design specifications, and analyses retained by the licensee.

For the containment example, design basis supporting design information includes:

- *The containment is designed to permit and facilitate an initial demonstration of structural capability at pressures up to and including 1.15 times the design pressure.*
- *The containment isolation valves are designed and fabricated in accordance with ASME, Section III.*
- *The containment is designed to meet the leakage testing requirements of 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."*
- *The containment is designed, fabricated, constructed, and tested as a Class MC vessel in accordance with Subsection NE of the ASME Code.*
- *The containment is a steel pressure vessel with a spherical lower portion 107 feet in diameter, a cylindrical upper portion 43 feet in diameter, and an elliptical top head 35 feet in diameter.*

Each of these examples were used in the safety analyses to demonstrate that the design bases would remain satisfied. For example, the containment dimensions were used in calculations to show that the peak post-accident pressure was bounded by the design basis value.

4.1.3.4 Engineering Design Bases

The engineering design bases broadly refers to the entire set of constraints that were used to implement the facility design. This includes design information included in the CLB and used to form the basis for agency licensing actions, including acceptance of design basis functional requirements, design basis values, and design basis supporting information. The engineering design bases also includes design information not part of the CLB, but implemented by licensees to achieve economics of operation, maintenance, procurement, installation or construction. For example, the engineering design basis includes requirements for the condensate demineralizer control system, the condenser circulating water pumps, and main generator seal oil system.

4.1.4 Topical Design Bases

Topical design bases are requirements that apply to multiple plant systems. These include those design basis requirements derived from principle design criteria and other regulations. Examples include:

- Fire Protection (GDC-3 and 10 CFR 50.48)
- Flooding (GDC-2)
- Tornado winds/missiles (GDC-2)
- Seismic (GDC-2)
- Single Failure Criteria (GDC-22)
- Environmental Qualification (10 CFR 50.49)
- Station Blackout (10 CFR 50.63)
- Anticipated Transient Without Scram (10 CFR 50.62)

4.1.4.1 Topical Design Basis Functions

Topical design basis functions are functions that “generically” apply to multiple facility SSCs. For example, GDC 2, “Design Basis for Protection against Natural Phenomenon,” requires that all important to safety SSCs are capable of withstanding the effects of earthquakes, tornadoes, hurricanes, floods, tsunami, and seiches without the loss of capability to perform their safety functions. Protection against natural phenomenon, is considered “topical” because these design basis function requirements apply to all important to safety SSCs.

For example, consider SSC protection against earthquakes. The NRC provided additional information in 10 CFR 100, Appendix A, “Seismic and Geologic Siting Criteria for Nuclear Power Plants,” describing how this design basis function can be satisfied. Appendix A defined an Operational Bases Earthquake (OBE) and a Safe Shutdown Earthquake (SSE). These regulations required that the OBE be defined by a response spectra that represents the maximum earthquake potential that could reasonably be expected during the operating life of the plant, considering the regional and local geology and seismology. The topical design basis requires that all SSCs necessary for continued operation, without undue risks to the health and safety the public, be qualified to remain functional and within the applicable stresses and deformation limits when subject to the OBE in combination with other normal operating loads.

Similarly, the SSE topical design basis function is also found in Appendix A. The SSE represents the maximum earthquake potential that could affect the site considering the geology and seismology. The SSE is that postulated earthquake that would produce the maximum vibratory ground motion for which certain SSCs are designed to remain functional. The OBE and SSE topical design bases functional requirements apply to every importance to safety SSC in the facility.

4.1.4.2 Topical Design Bases Values

Topical design bases values are those controlling parameters, or bounding conditions, for the design. For the seismic topical design bases, these values may include:

> *SSCs shall be analyzed and designed to withstand the effects of an OBE with a peak ground acceleration of 0.1g and an SSE with the peak ground acceleration of 0.2g*.

These controlling parameters ensure that seismic loading on facility SSCs is characterized by the OBE and SSE.

Another topical design bases value example includes:

> *Category II SSCs installed in Seismic Category I structures, and whose failure could result in the loss of a required safety function of Category I SSCs, are either separated by distance, or barrier, from the affected structure, system, or component or designed together with their anchorages to maintain their structural integrity during the SSE.*

This controlling parameter assures that failure of Seismic category II SSCs during an earthquake would not result in the loss of the required safety function of any Seismic Category I SSC (category I SSCs are crediting in FSAR safety analyses).

4.1.4.3 Topical Supporting Design Information

Topical supporting design information includes that supporting information used to develop and demonstrate the design bases functions and values are satisfied. For the seismic qualification example, supporting information includes:

- *Seismic classification of plant SSCs are in accordance with NRC RG1.29, "Seismic Design Classification."*

  RG 1.29 provides an NRC approved list of important to safety SSCs to be seismically qualified to meet GDC 2. RG 1.29 becomes topical supporting design information when an applicant has included RG 1.29 in the license application (FSAR) to identify the scope of plant equipment that will be qualified for the OBE and SSE.

- *Seismic design response spectra are in conformance with the methodology described in NRC Regulatory Guide 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants."*

  RG 1.60 provides an NRC approved methodology for determining the response spectra for SSC seismic qualification.

- *Seismic damping values used in the structural dynamic analysis are in conformance with NRC RG 1.61, "Damping Values for Seismic Design of Nuclear Power Plants," with the exception of damping values for cable trays and supports. Damping values for cable trays and supports are based on test reports.*

  In this example, the applicant's written commitment to RG 1.61 includes an exception to the approved NRC methodology for cable trays and supports. This exception, once approved (when the NRC issues the OL), becomes part of the supporting design bases information. The NRC should have included any conditions or limitations associated with the exception in the Safety Evaluation Report (SER) which documented NRC approval of the design.

4.1.5 Regulatory Framework Used to Ensure Design Bases Fidelity

The facility specific design bases were reflected in the license application, including the FSAR. When the agency issued the OL, the license application and FSAR, as amended, documented the original design and licensing bases. The NRC established a complimentary regulatory framework of rules to ensure the fidelity of the design and licensing basis over the lifetime of the facility. These rules include:

- 10 CFR 50.34, "Contents of Applications; Technical Information"

  10 CFR 50.34 establishes the requirements for the content of the original CP and OL applications. These requirements included that the FSAR contain the applicant's written commitments describing how regulatory requirements would be satisfied, the facility principle design criteria, the design bases, the relationship between the principle design criteria and the design bases, and safety analyses that demonstrated that the design bases would remain satisfied for all postulated events.

- 10 CFR 50.54, "Condition of Licenses"

  10 CFR 50.54, in part, establishes compliance with Appendix B to Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," as a condition of the OL.

- 10 CFR 50, Appendix B, Criterion III, “Design Control”

  Criterion III requires licensees to establish measures to assure that applicable regulatory requirements and the design bases, as specified in the license application, are correctly translated into specifications, drawings, procedures, and instructions.

- 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,”

  Criterion XVI requires licensees to take prompt corrective actions after discovering conditions adverse to quality. This includes non-conformances with the design bases, as specified in the license application, as required by Criterion III.

- 10 CFR 50.71, “Maintenance of Records, Making of Reports”

  10 CFR 50.71 requires licensees to periodically update the FSAR, as originally submitted with the license application. These updates assure that the FSAR contains the latest information developed and plant specific safety analyses are consistent with the requirements of 10 CFR 50.34. Guidance for updating FSARs is provided by NEI 98-03, “Guidelines for Updating FSARs,” endorsed by RG1.181, “Content of the Updated FSAR in Accordance with 10 CFR 50.71(e).”

- 10 CFR 50.90, “Amendment of the License”

  10 CFR 50.90 allows licensees to request, and the NRC to approve, changes to the OL. The agency reviews these proposed changes against definitive acceptance criteria, primarily provided by NUREG 0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants.” The license amendment process also requires public notice and hearing opportunities similar to the original licensing process.

- 10 CFR 50.59, “Changes, Tests and Experiments.”

  10 CFR 50.59 establishes the threshold for changes, tests, and experiments that licensees may make to their facilities without first obtaining an amendment to the OL. Licensee are required to compare the potential effects of proposed changes and new activities against the specific criteria contained in the Rule.

4.1.6 “Changes, Tests, and Experiments – 10 CFR 50.59”

Purpose

The 10 CFR 50.59 Rule establishes the conditions under which licensees may make changes to the facility or procedures and conduct tests or experiments without prior NRC approval. The 10 CFR 50.59 provides the threshold for changes and new activities that required regulatory review, not if the proposed change is safe.

Defense in Depth Design Philosophy

The 10 CFR 50.59 Rule incorporates the agency’s “defense in depth philosophy.” The goal of this philosophy is to both prevent accidents from occurring and to mitigate their consequences. Public protection is provided by the design of the following engineered physical barriers:

- The Fuel Cladding,
- The Reactor Coolant System Pressure Boundary, and
- The Containment.

FSAR safety analyses evaluate how accidents and events may challenge the integrity of each barrier and demonstrate that the Part 100 dose limits would not be exceeded. Underpinning the 50.59 Rule is the necessity to ensure the integrity of these physical barriers is maintained. Postulated accidents and malfunctions are analyzed in terms of their effect on these physical barriers. The 50.59 threshold includes the relationship between the integrity of these barrier and dose.

4.1.6.1 Important Terminology Used in 50.59 Determinations

The 50.59 Process uses the following specific terms:

Design function: Design bases functions are functions performed SSCs that are (1) required by, or otherwise necessary to comply with, regulations, license conditions, orders or technical specifications, or (2) credited in licensee safety analyses to meet NRC requirements. Design functions implicitly include the conditions under which intended functions are required to be performed, such as equipment response times, environmental and process conditions, equipment qualification, and single failure criteria. It also includes those functions performed by non-safety related SSCs, that if not performed, may result a plant transient or accident.

Accidents: For purposes of 50.59 Rule, “accidents” broadly includes not only design basis accidents but other FSAR analyzed events. These other events include anticipated operational transients, high energy line breaks, turbine missiles, fires, earthquakes, and flooding. The term “accident” also includes any new transients or postulated events added by regulations since the facility was licensed. For example, protection against anticipated transient without scram and station blackout are also considered "accidents" for the purposes of the Rule.

Safety Analyses: Safety analyses are those analyses or evaluations that demonstrate that agency acceptance criteria are met for postulated events. Safety analyses include the accident analyses typically presented in FSAR Chapters 6 and 15 and those evaluations that demonstrate that SSC design functions will be accomplished as credited in the accident analysis. They also include evaluations that demonstrate that required SSCs can withstand other "accidents" as described above.

Methods of evaluation: Methods of evaluation are the analytical and calculational framework used by the applicant or licensee to demonstrate adequate facility SSC response to design basis events. These evaluation methods include:

- Methods used to demonstrate that design basis fission product barriers limits were met;
- Methods used in safety analyses, typically presented in FSAR Chapters 6 and 15 for containment, emergency core cooling systems (ECCS), and accident analyses.
- Methods used to demonstrate that the consequences of accidents will not exceed the dose limits for the site boundary and control room; and
- Methods of evaluation used in supporting FSAR analyses that demonstrate that the intended design functions would be accomplished under design basis accident conditions, including natural phenomena, environmental conditions, dynamic effects, station blackout, and anticipated transient without scram.

Facility as Described in the FSAR: The Updated FSAR includes the information submitted in the original license application, per 10 CFR 50.34, and updates made per the requirements of 10 CFR 50.71(e). For the purposes of the Rule, this includes supplemental information explicitly incorporated into the FSAR by reference. The "Facility as Described in the FSAR" means:

- SSCs that are described in the FSAR,
- Design and performance requirements for SSCs described in the FSAR, and
- Evaluations and methods of evaluation included in the FSAR which demonstrate that their intended functions will be accomplished.

Procedures as Described in the FSAR: Procedures include those that contain information related to how SSCs are operated and controlled. These procedures may include assumed operator actions and response times described in the facility safety analyses.

Change: A “Change” is a modification of, addition to, or removal from, the facility or procedures that may adversely impact the performance of plant SSCs. For the purposes of the Rule, a “change” specifically affects: (1) a design function; (2) a method of performing or controlling a design function; or (3) an evaluation that demonstrates that the intended function would be accomplished. “Change” specifically includes modifications to the underlying design or analytical bases even if no physical changes to the facility are involved. “Change” also includes modifications, additions, or removal from facility procedures that affect a design function, a method of performing or controlling the function, or an evaluation that demonstrates that the intended functions would be accomplished.

Temporary changes: Licensees may make temporary changes to facilitate a range of plant activities. Examples include jumping across terminals, lifting leads, and placing temporary lead shielding on pipes or equipment. Included within the scope of 50.59 are:

- Temporary changes proposed as compensatory measures to address degraded or non-conforming conditions, and

- Other temporary changes to the facility or procedures which are not associated with maintenance.

- Temporary changes associated with maintenance planned to be in place greater than 90 days.

Departure from a Method of Evaluation Described in the FSAR: A “departure from a method of evaluation” occurs when a licensee:

- *Changes a method described in the FSAR to another method, unless that method has been approved by the NRC for the intended application, or*

- *Changes any of the elements of the method described in the FSAR, unless the results of the analysis are conservative or essentially the same.*

Conservative vs. Non-Conservative Evaluation Results: The 50.59 Rule provides licensees flexibility to change safety analysis methodologies or analytical inputs that do not add margin to existing FSAR analytical results. A change is considered "conservative," if the results are closer to a design bases or safety analysis limit, or to the applicable acceptance guideline. On the other hand, a “non-conservative” change results in margin being added to the analytical results. A “non-conservative” change is defined as a departure from a method of evaluation under the Rule and will generally require an amendment to the OL prior to implementation.

The Rule also uses the term "essentially the same." Results are considered "essentially the same" if they are within the margin of error for the type of analysis performed.

Input Parameters: Input parameters are those values derived directly from the physical characteristics of the SSC or processes in the plant, including flow rates, temperatures, pressures, dimensions, and system response times. Input parameters may be treated differently under the Rule than evaluation methods. If a methodology permits the licensee to establish the value of an input parameter, based on plant-specific considerations, then that value is considered as an input to the methodology, and is considered a change to the facility, rather than a change to the methodology. On the other hand, an input parameter is considered to be a change in methodology itself, if the evaluation method describes how to select the value of the input parameter or approval of the methodology was predicated on the use of a specific input value.

Tests or Experiments Not Described in the FSAR: These tests or experiments include any activity where any SSC is utilized or controlled in a manner which is either:

- Outside the reference bounds of the design bases as described in the FSAR, or
- Inconsistent with the analyses or descriptions in the FSAR.

This includes those tests or experiments that may result in the facility being placed in a previously unevaluated condition or that could affect the capability of plant SSCs to perform their intended functions as evaluated in facility safety analyses. Testing associated with maintenance activities are excluded from these tests and experiments.

4.1.6.2 Applicability and Screening Reviews under the 50.59 Rule

Applicability and screening reviews allow licensees to exclude certain proposed changes and activities from an in-depth 50.59 evaluation. From a regulatory prospective, our goal is to ensure that licensees effectively identify all changes that require NRC approval prior to implementation. Many 50.59 violations have been written after licensees improperly “screened out” changes.

The Nuclear Energy Institute (NEI) 96-07, “Guidelines FOR 10 CFR 50.59 Evaluations,” details an NRC acceptable approach for implementing a 50.59 Program. The agency endorsed NEI 96-07 by RG 1.187, “Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments,” Most licensee programs implement the Rule by evaluating proposed changes using the three major steps outlined in NEI 96-07:

- Applicability Review,
- Screening, and
- Evaluation

Applicability Review

The applicability review will determine if the proposed change or activity is within the scope of the 50.59 Rule. For example, a 50.59 evaluation is not required for a proposed technical specification change. Any technical specification change directly requires an amendment to the OL per 10 CFR 50.90. 50.59 evaluations are not required for proposed activities controlled by other specific regulations. For example, changes to the quality assurance, physical security and emergency plans are handled under 10 CFR 50.54, "Conditions of the License." Since control of these programs are handled under a different regulatory requirement, a 50.59 review would not be "applicable" to these proposed changes. This also includes proposed FSAR changes that are directly related to an activity implemented by another regulation.

Some proposed activities governed by other regulations may also require review under 50.59. An example would be a change to the Fire Protection Program to provide reactor coolant pump seal injection operation during certain fire scenarios. Generally, changes to the Fire Protection Program are addressed under the standard fire protection license condition. However, 50.59 may also be applicable to fire protection changes that potentially adversely affect other facility functions, analyses, or SSCs.

10 CFR 50.59 evaluations are not applicable to certain FSAR changes. This includes FSAR revisions affecting formatting, simplification, or removal of obsolete or redundant information. In addition, 50.59 evaluations are generally not required for changes to conduct of operations, managerial, and administrative procedures. These procedures are controlled under the quality assurance program.

10 CFR 50.59 evaluations are not required for maintenance activities that restore plant SSCs to the as-designed condition. Troubleshooting, calibration, refurbishment, post-maintenance testing, identical replacements, housekeeping, and similar activities that do not permanently alter the design or design function of SSCs, are not subject to 50.59 evaluations. An exception applies to temporary changes proposed as compensatory measures for degraded or non-conforming conditions and those temporary modifications installed for maintenance planned to be in place for greater than 90 days.

Even though maintenance activities do not require 50.59 evaluations, these changes are still subject to technical specification operability requirements. For example, plant operators observed periodic power spikes in a reactor protection system channel. The licensee installed a temporary non-safety related recorder to monitor the channel to help identify the cause of spikes. A 50.59 evaluation was not required because the temporary alteration was installed for maintenance and left in place for less than 90 days. However, because the licensee failed to properly isolate the non-safety recorder from the safety-related circuit, the temporary alteration also rendered the protection system inoperable for technical specifications.

A typical 50.59 applicability review form is provided in Table 1.

Screening Review

Licensees may further “screen out” proposed changes and activities that were determined to be “applicable” under the Rule. Screening allows licensees to apply broad criteria to exclude proposed changes from a 50.59 evaluation. The screening identifies those proposed changes that clearly will not challenge any of the Rule’s evaluation thresholds. The screening process allows licensees to focus evaluation resources on those proposed activities that may challenge one or more of the Rule’s criteria.

10 CFR 50.59 screening requires a thorough understanding of how the proposed change affects SSC’s design functions and evaluations. The inspector should verify that the licensee properly used engineering, design, and other technical information in screening determinations and that all design functions, including topical design bases, have been addressed.

Licensees should “screen in” any change or activity that:

- Involves changes to plant SSCs that may <u>potentially adversely affect</u> an FSAR described design function.
- Involves procedure changes that could <u>potentially adversely affect</u> how FSAR described design functions are performed or controlled.
- Revises or replaces an FSAR described evaluation methodology that was used to establish the design bases or in the safety analyses.
- Involves a test or experiment not described in the FSAR, including cases were SSCs would be utilized or controlled in a manner outside the reference bounds of the design or inconsistent with FSAR analyses or descriptions.

If the proposed activity meets any of these screening thresholds, then the licensee is required to complete a 50.59 evaluation to determine if an amendment to the OL is required prior to implementing the change or activity. Any adverse effect, regardless of magnitude, results in the proposed change to “screened in.” Also, proposed changes “screen in” that require FSAR safety analyses to be re-performed to demonstrate that all required safety functions and design requirements are met. For example, a change that increases the closure time of a control room ventilation isolation dampers would “screen in” because the existing operator dose calculation would need to be re-run to ensure that the GDC 19 limits continued to be met.

Screening Changes to the Facility and Indirect Effects

Inspecting 50.59 screens for changes to the facility are generally straightforward. However, facility safety analyses rely on many SSCs not explicitly described in the FSAR. This may include components, subcomponents, or even entire systems. The inspector needs to verify that the screen clearly identifies if the proposed change has the potential to indirectly affect any SSC design functions. Changes to non-safety-related equipment that affect seismic qualification, missile protection, flooding protection, fire protection, environmental qualification, and high energy line breaks, all potential affect FSAR design functions through indirect or secondary effects.

For example, a licensee proposed changing the motor-operators used for the safety injection accumulator isolation valves. The FSAR described these valves as open with the power removed during normal operation. The valves' safety-related function is pressure boundary integrity and to remain open allowing the accumulators to discharge following a loss of coolant accident. The design of these remotely operated valves included the capability to be close during a normal shutdown to prevent accumulator injection when not required. Technical and engineering work supporting this change ensured that the new valve operators were capable of performing the same functions of the existing operators and would not adversely affect Class 1E bus or diesel loading. This change would "screen out" and not require a 50.59 evaluation because; (1) the new valve operator does not perform, support, or impact the FSAR described design function to ensure pressure boundary integrity and remain open when required, and (2) the change does not adversely affect other SSC design functions (e.g., design functions of the Class 1E bus or diesel generator). However, if the proposed change was to configure the valve as a normally closed valve that automatically opened on loss of reactor coolant system pressure, a 10 CFR 50.59 evaluation would be required because the proposed change would adversely affect the reliability of the safety injection function as credited in the safety analyses.

Screening Procedures Changes

Proposed procedure changes that adversely affect how SSC design functions are performed or controlled "screened in." For example, a changes that involve FSAR described procedures, assumed operator actions, and response times all need to be evaluated under the eight 50.59 criteria. For purposes of screening, changes that fundamentally alter or replace the existing means of performing or controlling design functions should be considered as "adverse" and screened in. This would include replacing an automatic action with a manual action.

For example, a FSAR described reactor startup procedure contained eight fundamental sequences. The licensee revised the procedure to eliminate one of these sequences. This change would "screen in." On the other hand, if the revision consolidated the eight sequences into seven, without affecting the method of controlling or performing the reactor startup, then the change would "screen out."

Screening Changes to Evaluation Methods

The inspector should verify that the licensee's 50.59 screen properly addresses all evaluation methods affected by the change. Any adverse changes to elements or inputs used in FSAR methods, or use of an alternative method, must "screen in" and be evaluated under 10 CFR 50.59(c)(2)(viii), "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." Changes to FSAR evaluation methods outside of the constraints and limitations, as identified in a topical report and/or SER, are also considered adverse and require additional evaluation under 10 CFR 50.59. However, if the changes are within approved constraints and limitations, then the change may be screened out. Licensees may also "screen out" changes to methods that were not included in the FSAR or those methods not used in safety analyses or to establish design bases. This includes those methods solely listed as FSAR references. However, changes to a referenced method that was also used in the safety analyses or the design bases "screens in."

For example, the CONTEMPT and GOTHIC computer codes are both used for post-accident containment response. The FSAR described CONTEMPT as the method used for post-accident containment pressure response. The licensee also used the code to develop long term post-accident containment temperature profiles for equipment environmental qualification (EQ). However, use of CONTEMP for EQ was not discussed in the FSAR. The licensee proposed changing the method for post-accident containment temperature from CONTEMPT to GOTHIC. This change would "screen out" because the methodology for establishing EQ temperature profiles was not included in the FSAR. However, if the licensee also proposed using GOTHIC for containment post-accident pressure response, then the change would "screen in" because CONTEMP was the FSAR described method.

Screening Tests and Experiments

Licensees may "screen out" tests and experiments that are explicitly bounded by the FSAR. Licensees may also "screen out" tests and experiments not described in the FSAR, provided the affected SSCs will be appropriately isolated from the facility. For example, the addition of hydrogen injection to minimize stress corrosion cracking "screens in" if the activity was not discussed in the FSAR. Also, ECCS flow tests affecting decay heat removal or operation with demonstration fuel assemblies would also "screen in" if not described in the FSAR. Conversely, steam generator moisture carryover and balance-of-plant heat balance tests would "screen out," provided the testing had been described in the FSAR.

Screening Documentation

The 50.59 Rule does not require retention of either applicability or screening determinations. However, licensees should provide the inspector with the bases for their conclusion that a change, test, or experiment did not require prior NRC approval. Many, if not all licensee 50.59 Programs require these records to be maintained in accordance with station procedures. The record should include the basis for the licensee's conclusion that a 50.59 evaluation was not required. Typically, licensees will retain applicability and screening documentation as part of the modification change package.

Improper Screening Documentation

An inspector may come across a facility change that a licensee had improperly "screened out." As a result, the required 50.59 evaluation was not performed. Licensees have sometimes avoided performing an evaluation by justified why the change satisfied the 50.59 criteria in the screening document. Changes that "screen out" generally require less resources than full 50.59 evaluations. Also, these "screened-out" changes generally do not require on-site safety committee reviews nor are they required to be reported to the NRC per 10 CFR 50.59(d). When identified, the inspector should notify the licensee and verify that the improper screen was appropriately dispositioned in accordance with their corrective action program. Also, the inspector should evaluate the issue in accordance with Reactor Oversight Process and agency enforcement guidance contained in NRC Enforcement Manual, PART II-2: Reactor Topics, Section 2.1.3, "Enforcement of 10 CFR 50.59 and Related FSAR":

> *"Citations against 10 CFR 50.59 are appropriate when the licensee makes changes not allowed by 10 CFR 50.59 and/or when a 10 CFR 50.59 evaluation is not performed when required."*

4.1.6.3 Eight 10 CFR 50.59 Evaluation Criteria

The third NEI-96-07 step is to evaluate those changes and activities that "screen in" against the eight evaluation criteria contained in the 50.59 Rule. These criteria establish the threshold for facility changes and activities that a licensee may make without first obtaining an Amendment to the OL. A summary of the critical thinking used when evaluating these criteria is contained in the figures 4.17-1 through 4.17-5.

10 CFR 50.59(c)(2)(i): Does the Activity Result in More than a Minimal Increase in the Frequency of Occurrence of an Accident?

The first criterion focuses on the affect the change may have on the frequency of "accidents." The inspector should verify that the licensee's evaluation identified all FSAR "accidents" that may be affected by the proposed activity. Next, the evaluation should have determined if any of these "accidents" would occur more frequently as a result of the proposed change or activity. FSAR accidents and transients are divided into categories based on a qualitative assessment of frequency. An ANSI standard definition for event category, adapted by the NRC, includes:

I. Normal operations; expected frequently
II. Events of moderate frequency; expected to occur about once a year;
III. Infrequent incidents; expected to occur sometime during the plant lifetime; and
IV. Limiting Faults; while not expected to occur but could result in the release of significant amounts of radioactive material.

The agency assessed the frequency or likelihood of "accidents" during original plant licensing. Under this 50.59 criteria, licensees are permitted to make changes that don't significantly change the facility licensing basis or impact the agency's conclusions about the acceptability of the facility design. The inspector should verify that the change did not result in an event moving to a more frequent category of occurrence. Also, changes within a frequency category may also trip this threshold. Typically, this determination will include an engineering qualitative assessment consistent with the assumptions used in the FSAR. Licensees may use a plant-specific accident frequency calculation or PRA to quantitatively evaluate a proposed activity. In both cases, the licensee should have used reasonable engineering practices and judgment. For quantitative analyses, the increase is minimal if the calculation shows that the change in frequency is less than 10% or remains below $1x10^{-6}$ per year.

While this criterion focus on the "frequency of occurrence" of events, it's important for the regulator not to lose sight of the requirements of Part 50, Appendix B and 50.55a, "Codes and Standards." Appendix B and 50.55a, both conditions of the license per 10 CFR 50.54, require that licensees also meet all applicable regulatory requirements and acceptance criteria that they have committed to as part of the design bases. These requirements include commitments to Regulatory Guides and nationally recognized industry consensus standards, such as provided by the ASME Code and IEEE standards. Generally, a licensee should have concluded that more than a minimal increase in the frequency of an accident has resulted if the change included a departure from applicable requirements, standards, or from the design, fabrication, construction, testing, and performance standards, as outlined in the Appendix A, General Design Criteria, or equivalent.

10 CFR 50.59(c)(2)(ii): Does the Activity Result in More than a Minimal Increase in the Likelihood of Occurrence of a Malfunction of an SSC Important to Safety?

This next criterion is related to changes that may result in an increase in the malfunction frequency of plant equipment. In this context, a "malfunction" refers to the failure to perform an intended design function. This explicitly includes both safety related and non-safety related SSCs. The inspector should verify that the licensee identified the causes and modes of malfunctions affected by the change. This criterion only evaluates the frequency of malfunctions. The effect or result of a malfunction is considered under 10 CFR 50.59(c)(2)(iv).

The licensee should have first identified which SSCs were affected by the proposed activity. Next, the evaluation must have assessed the effect of the proposed activity on these SSCs. The licensee needed to include both direct and indirect effects. Direct effects are those changes that directly affected SSCs. For example, consider changing the type of ECCS pump motor being used. The direct effect is the ability of the pump to deliver the flow assumed in the accident analysis. An indirect effect would be the motor's electrical loading on the emergency diesel generator. In this example, the effect on diesel loading may not have been specifically identified in the safety analysis or credited in a direct sense.

The evaluation should have also determined if the likelihood of these malfunctions had increased. As with the previous criterion, licensees may use qualitative engineering judgment or an industry precedent to determine if the change resulted in more than a minimal increase in the likelihood of a malfunction. The activity is considered to have a “negligible effect” on frequency when the results were within the determination uncertainties or if the increase was shown to be less than a factor of two if calculated quantitatively. The inspector should also verify that the level of detail of the evaluation was consistent with the FSAR, including the failure modes and effects analyses.

This criterion is also applicable for changes affecting protection against natural phenomena, including earthquakes, flooding, and tornadoes. This criterion is satisfied for changes involving substitution of one type of component for another of similar function, provided all applicable design and functional requirements, and Codes and standards continue to be met; and any new failure modes were bounded by the existing analysis. In contrast, a change that resulted in component stress to exceed Code allowable or other applicable deformation limit would require an amendment to the OL. Also, changes that reduce system or equipment redundancy, diversity, separation, or independence would also require prior NRC approval under this criterion.

10 CFR 50.59(c)(2)(iii): Does the Activity Result in More than a Minimal Increase in the Consequences of an Accident?

The third criterion is related to the effect on accident consequences. In this context, consequences are limited to public and control room dose:

- *10 CFR 100 dose limit of 25 rem whole body, or 300 rem thyroid, at the exclusion area and low population zones following a postulated fission product release.*
- *10 CFR 50, Appendix A, GDC19, “Control Room,” required the safety analysis to demonstrate access and occupancy without personnel exceeding 5 rem equivalent for the duration of the accident (typically 30 days).*
- *The NRC has also established more limiting acceptance criteria for certain events such as a steam generator tube leak or rupture.*

For a given accident, the FSAR identifies the site boundary and control room doses. Under this criterion, a minimal increase in consequences is defined as:

- *Less than or equal to 10 percent of the difference between the current calculated dose and the regulatory guideline, and*
- *The increased dose does not exceed the current Standard Review Plan guideline value for the particular event.*

The inspector should verify that the licensee used the dose values from the most up-to-date analyses of record. Also, the inspector should ensure that the evaluation identified all radiological consequences affected by the proposed activity. If the calculated dose was already in excess of the NUREG 800, “Standard Review Plan,” limits, then “minimal increase” is defined as less than or equal to 0.1 rem.

For example, a FSAR safety analysis concluded 50 rem exclusion boundary thyroid dose following a fuel handling accident. The Standard Review Plan acceptance guideline was 75 rem and the regulatory limit was 300 rem (Part 100). The licensee recalculated the dose after applying a proposed configuration change. Assuming the modification was in place, the accident dose increased to 70 rem. Ten percent of the difference between the calculated value and the regulatory limit is 25 rem, [10% of (300 rem - 50 rem)]. In this case, the licensee satisfied this review criterion because the increase of 20 rem was less than 25 rem and the total dose was still less than the SRP guideline value of 75 rem.

Consider another example. In this example, the licensee modified the control room ventilation system. This modification resulted in the GDC 19 dose to increase from 4 rem to 4.5 rem. Although the new calculated dose was less than the 5.0 rem regulatory limit (GDC 19), the incremental increase in dose (0.5 rem) exceeded 10 percent of the difference between the previously calculated value and the regulatory value or 0.1 rem [10% of (5 rem - 4 rem)]. As a result, this change resulted in more than a minimal increase in consequences and would require approval in the form of an amendment to the OL prior to implementation.

10 CFR 50.59(c)(2)(iv): Does the Activity Result in More than a Minimal Increase in the Consequences of a Malfunction?

The fourth criterion involves determining if the proposed change would result in more than a minimal increase in consequences of a malfunction. As with the previous criterion, consequences equates to dose. The inspector should verify that the licensee correctly identified the FSAR malfunctions that may have radiological consequences affected by the proposed change. Then the inspector should ensure that the evaluation correctly determined if the proposed activity resulted in a more than minimal increase in the radiological consequences as described above.

10 CFR 50.59(c)(2)(v): Does the Activity Create a Possibility for an Accident of a Different Type?

The fifth criterion is related to the potential to create a new type of accident. This criterion compares the effect of the change against accidents of similar frequency and significance included in the facility licensing basis. Certain accidents were not included in the FSAR because their effects were bounded by other related events. For example, a postulated pipe break in a small line may not have been specifically evaluated in the FSAR because the effect of the event was less limiting than a pipe break in a larger line in the same area.

This evaluation criterion specifically addresses possible accidents of a different type that are as likely to occur as those previously evaluated in the FSAR. The accident must be credible in the sense of having been created within the range of assumptions previously considered in the licensing basis. A new accident initiator for an existing FSAR safety analysis is not consider a different type of accident. The inspector should verify that the licensee's evaluation included the types of accidents discussed in the FSAR. The licensee's evaluation should have also included a comparison of those events against any new event that may have been created by the change. The evaluation must include the bases for why these new events were bounded by those already included in the FSAR.

10 CFR 50.59(c)(2)(vi): Does the Activity Create a Possibility for a Malfunction of an SSC Important to Safety with a Different Result?

The sixth criterion focuses on potential SSC malfunctions that have a different outcome than those considered in the FSAR. Facility safety analyses generally included postulated single active failures when evaluating plant SSCs. These safety analyses focus on result of the failure rather than the cause or type of malfunction. In this criterion, "a malfunction with a different result" involves the effect of an initiator, or failure, that was not bound by those previously described in the FSAR. In other words, a new failure mechanism is not the same as a "malfunction with a different result."

For example, a licensee replaced a pump with a new design. The new pump has new failure mechanism which may prevent the pump from running. Under 50.59, a "malfunction with a different result" was not created because the failure of the pump to run had been previously evaluated in the safety analysis.

The inspector should verity that licensee's evaluation addressed the types and results of FSAR SSC failure modes affected by the proposed activity. This evaluation should have been performed consistent with the failure modes and effects analysis described in the FSAR. The inspector should recognize that certain proposed activities may require a new failure modes and effects analysis.

10 CFR 50.59(c)(2)(vii): Does the Activity Result in A Design Basis Limit for a Fission Product Barrier Being Exceeded or Altered?

The seventh criterion focuses on preserving the three fission product barriers:

- Fuel clad
- Reactor coolant system boundary,
- Containment.

Licensees typically apply a two-step approach to address this criterion. The first step involves identifying the design basis limits potentially affected by the proposed change. The second step is to evaluate if those limits have been "exceeded" or "altered" by the proposed change. Fission product design limits are controlling numerical values established during original licensing. This includes any parameter that was used to demonstrate fission product barrier integrity. 10 CFR 50.34(b) and 50.71(e) explicitly required that the original and updated FSARs include these limits. In some cases, these values may be located in a vendor topical report and incorporated into the FSAR by reference.

Examples of fission product limits are shown on Table 2. Some fission product limits are control by other specific regulations. For example, fuel clad oxidation and temperature limits are specified by 10 CFR 50.46, “ECCS Acceptance Criteria.” Reactor coolant system stress limits are established by ASME Codes and are indirectly required by 10 CFR 50.55a and 10 CFR 50.54. Any design basis limit controlled by a more specific regulation or a Technical Specification, is required to be evaluated in accordance with that regulation. Direct and indirect effects on design basis parameters covered by other regulations are not required to be considered under this 50.59 criterion. However, the proposed change or activities may be required to be evaluated under the other 50.59 criteria.

Exceeded or Altered

Licensees are required to obtain a License amendment for any change that results in a fission product design basis limit to be either "exceeded or altered." In this context, "exceeded" means that the change resulted in the facility's predicted response to be less conservative than the numerical limit identified in the FSAR. "Altered" means the design basis limit itself was changed.

Changes and activities may have both direct and indirect effects. For example, a direct effect may result from extending the maximum fuel burn-up limits. This change would directly affect the fuel rod internal gas pressure design basis limit and required a license amendment. A proposed activity may also have an indirect effect that cascades to the design basis limit. For example, a change to reduce the auxiliary feedwater flow could reduce reactor coolant system heat transferred to the steam generators following a loss of main feedwater event. The reduced flow could result in an increase in the reactor coolant system temperature. The higher temperature would result in higher reactor coolant system pressure and pressurizer level. In this example, the licensee’s evaluation should have focused on whether the change "exceeded" the design basis limit associated with reactor coolant system pressure for that accident.

Changes that “alter” a design basis limit are rare but do occur. For example, a change resulting in a portion of the reactor coolant pressure boundary to be noncompliant with ASME Code limits would have “altered” the design basis limit. While these are infrequent activities, they do affect key elements of the defense-in-depth philosophy. It’s also important for the inspector to understand that this criterion doesn’t include a distinction between conservative and non-conservative changes. Any change resulting in an "exceeded” or “altered" design basis limit requires an amendment to the OL prior to implementation.

Consider a 50.59 evaluation of a degraded RHR heat exchanger. In this example, a licensee identified that the heat transfer capability of heat exchanger was degraded due to corrosion. The licensee modified the FSAR to accept the degraded heat exchanger "as-is." The 50.59 evaluation was required to identify if the proposed change affected any design basis limits. A direct effect of the change would be the reduction in heat removal capability and an increase in containment sump temperature. Indirect effects may include an increase in post-accident peak containment pressure and ECCS flow enthalpy. Increased ECCS enthalpy may also affect peak clad temperature. As a result, this proposed change affected two design basis limits: Containment pressure and the peak clad temperature. The 50.59 evaluation was required to compare the increase in peak containment pressure against the design basis limit. If the revised peak post-accident containment pressure exceeded the design basis limit, then a license amendment was required under this criterion. However, the resulting peak clad temperature was governed by another specific regulation, in this case 10 CFR 50.46. The licensee would not be expected to include the impact on this parameter under this evaluation criterion.

Another example involved a degraded containment structure due to corrosion. The FSAR stated that containment design pressure was 55 psig. In this example, the licensee re-evaluated the containment design pressure considering the corrosion. This reevaluation concluded that the maximum pressure the containment could now support was only 48 psig. For corrective action, the licensee reduced the FSAR design pressure and safety analyses limit from 55 to 48 psig. This change directly affected the containment fission product barrier. The original FSAR design basis limit for the containment was 55 psig. The corrective action would have also required the OL to be amended because the change directly “altered" this design bases limit. Again, the question of whether or not this change was conservative is not relevant under 50.59(c)(2)(vii). Prior NRC approval was required regardless of whether or not the design pressure was reduced or increased because the design bases parameter was directly “altered."

10 CFR 50.59(c)(2)(viii): Does the Activity Result in a Departure from a Method of Evaluation Described in the UFSAR Used in Establishing the Design Bases or in the Safety Analyses?

The eighth criterion involves proposed changes to the FSAR methods used to evaluate accidents and SSC performance. The original FSAR included descriptions of the specific analytical methods the applicant used to demonstrate that the facility met the design bases and regulatory requirements. During licensing reviews, the NRC compared these methods with agency acceptance criteria. The results of these reviews were an important part of the agency’s conclusion that facility operation would not result in undue risk to the health and safety of the public.

In general, a licensee may change an <u>element or input</u> used in an FSAR methodology provided the results are more conservative, or essentially the same, as previous results.

Licensees may also use <u>different methods</u> as long as they have been approved by the NRC. The inspector should verify that the licensee identified all the FSAR evaluation methods that were affected by the change.

The 50.59 Rule defines a departure from a method of evaluation described in the FSAR as:

(i) *Changing any of the elements of the method described in the FSAR (as updated) unless the results of the analysis are conservative or essentially the same; or*

(ii) *Changing from a method described in the FSAR to another method unless that method has been approved by NRC for the intended application.*

Guidance for Changing One or More Elements of a Method of Evaluation

The definition of "departure" provides licensees with the flexibility to make changes to evaluation methods when the results are "conservative" or essentially the same.

A “non-conservative” change is defined as an analytical output that results in additional margin created to the limit. “Non-conservative” changes generally require prior NRC approval. Conversely, a "conservative," change results in an output closer to either a design bases or safety analyses limit and generally may be incorporated without NRC approval.

For example, a licensee used a new input parameter affecting the results of the FSAR post-accident containment pressure analysis. For this example, the containment design bases limit was 50 psig. The new input resulted in the peak pressure to increase from 45 psig to 48 psig. This change was “conservative” because the revised input predicted a peak pressure closure to the design basis limit.

In contrast, if the change resulted in a decrease in peak containment pressure, say from 45 psig to 40 psig, then this would be a “non-conservative” change. This change is “non-conservative” because the new input parameter added margin between the analytical output and the design basis limit. The licensee would be required to obtain an amendment to the OL before incorporating this input parameter into the analysis.

A licensee may change one or more elements even if the results move in the “non-conservative” direction, provided the overall end result is "essentially the same." In this context, "essentially the same" is defined as within the margin of error, or uncertainty, for the type of analysis being performed.

Changing from One Evaluation Method to Another

Licensees are allowed to use new or different methods that have been approved by the NRC. NRC approval typically follows one of two paths: The NRC may approve a new method describe in a topical report. These topical reports are submitted to the NRC by reactor or fuel vendors, by the utilities, or by owner groups. The NRC typically documents approval of the method, including conditions and limitations, by issuing a safety evaluation. The NRC may also approve a plant specific analytical method. This approval is generally limited to a specific plant design and application. As in the case of the topical report, the terms, conditions and limitations relating to the new methodology are document in license amendment request and the NRC's safety evaluation.

The inspector should verify that licensee's 50.59 evaluations demonstrated that the new method was technically appropriate for the application and consistent with the facility's licensing basis and plant-specific commitments. Prior NRC approval may have been required if the licensee had taken any exceptions to relevant industry standards and guidelines, or if the method was otherwise inconsistent with a facility's licensing basis. Also, the new method may not supersede a methodology addressed by specific regulations, such as 50.46, 50.55a, or plant technical specifications.

For example, a licensee increased the damping values used in the seismic analysis of safety-related piping from ½ to 4 percent. The increased damping resulted in a decrease in the amount of pipe stress predicted by ASME Code for a given design basis input. This change required prior NRC approval under this criterion since the licensee used the analysis to establish the seismic design bases and the change resulted in a "non-conservative" outcome. The revised Code calculations would result in a reduction in the predicted pipe stress following various design basis events.

On the other hand, the NRC approved use of up to 3% damping for the same application in RG 1.61, "Damping Values for Seismic Design of Nuclear Power Plants." The licensee could have increased the damping value up to 3% without prior NRC approval, provided that the utility maintained all of the limitations included in the Regulatory Guide. In other words, use of 3 percent damping under these circumstances would not have been a "departure" because use of the higher damping value, in this application, had been "approved by the NRC."

Considerer another example involving a post-accident containment analysis for two plants with similar large dry containments. Both plants' original FSARs stated that the CONTEMPT computer code was used for the post-accident containment pressure and temperature analysis. At one of the plants, maintenance personnel identified that containment cooler performance was degraded due to service water flow balance issues. The licensee evaluated the degraded flow using the CONTEMPT method. The licensee concluded that peak containment pressure would exceed the FSAR "design basis parameter." However, the licensee found that by using the newer GOTHIC Code, the design basis was preserved. The licensee's 50.59 evaluation correctly concluded that use of GOTHIC required prior NRC approval. The NRC subsequently approved use of GOTHIC for the facility containment pressure and temperature analysis.

After the NRC approved the license amendment for the first plant, maintenance personnel at the second plant identified degraded containment cooler performance due to service water fouling. Similar to the first case, reanalysis with CONTEMPT failed to demonstrate cooler operability, but engineers at the second plant were also successful reanalyzing the degraded condition using the GOTHIC code. Unlike the first case, GOTHIC could be directly added to the second plant's FSAR without a license amendment. The 50.59 evaluation for the second plant documented that GOTHIC was an NRC approved methodology and its use was consistent with the limitations described in the first plant's license amendment request and subsequent NRC safety evaluation.

4.1.6.4 Compensatory Actions for Nonconforming or Degraded Conditions

Inspectors should review temporary facility or procedure changes used as interim corrective actions to address non-conforming or degraded conditions. Licensees are required to evaluate these temporary changes under the 50.59 Rule. This review is focused on determining if the compensatory actions impacted other aspects of the facility or procedures described in the FSAR. The 50.59 review is not to directly evaluate the degraded condition itself. IMC 0326, Section 07.03, "Compensatory Measures," states:

> *"Additionally, if a compensatory measure involves a temporary facility or procedure change, 10 CFR 50.59 should be applied to the temporary change with the intent to determine whether the temporary change/compensatory measure itself (not the degraded or nonconforming condition) impacts other aspects of the facility or procedures described in the UFSAR. In considering whether a temporary facility or procedure change impacts other aspects of the facility, a licensee should apply 10 CFR 50.59, paying particular attention to ancillary aspects of the temporary change that result from actions taken to directly compensate for the degraded condition."*

For example, a licensee implemented a compensatory measure to address a failed lower reactor coolant pump oil reservoir transmitter. The transmitter was designed to alarm in the control room on low oil level. The FSAR described the transmitter and associated alarm as a "protective feature" for the reactor coolant pump (RCP). The failure of the transmitter did not result in the loss of operability for any technical specification equipment. However, the failure did result in a continuous control room trouble alarm. This alarm was common for both the upper and lower RCP reservoirs. As a result, the failure of the lower transmitter masked the upper reservoir alarm function.

The licensee used an alternate method to monitor the lower reservoir. The licensee also implemented an interim compensatory action to lift the leads from the failed transmitter to the annunciator circuit. This action restored the upper reservoir alarm function. This compensatory action was a temporary change under 50.59. The inspector should ensure that the screen focused on the lifted leads rather than the failed transmitter. The screen should have determined if the lifted leads impacted any other aspects of the facility as described in the FSAR.

4.1.6.5 Disposition of 10 CFR 50.59 Evaluations

There are two possible actions following a completed 50.59 evaluation:

(1) The activity may be implemented, or

(2) The proposed activity requires an amendment to the OL prior to implementation.

Changes and activities are considered "implemented" when the licensee declared the affected SSCs operable. Licensees are permitted to design, plan, install, and test a modification prior to receiving a license amendment, to the extent that these activities do not themselves require prior NRC approval. For example, consider a facility modification involving replacement of a diesel driven pump with a motor-driven pump. In this example, the installation of the replacement train was largely in a new, separate structure. Ultimately, the modification would require NRC approval because of the impact on the facility technical specifications and due to differences in reliability of the replacement pump. The licensee prepared a 50.59 screen to support construction of the stand-alone facility and preliminary testing. The limited interfaces with the existing facility were assessed and determined to not affect the facility as described in the FSAR. Final tie-in, testing and operation would be delayed until after the NRC approved the license amendment.

Another example involved a major modification to replace the reactor head. In this example, the inspector identified that the licensee failed to obtain required NRC approval for new inputs used in the supporting safety analysis. However, because the inspection issues were identified prior to the licensee placing the reactor back in service, a 50.59 violation had not yet occurred.

Documentation and Reporting

The Rule requires licensees to retain 50.59 evaluations until the termination of a license. These written evaluations must address each of the eight criteria and include an explanation that provides an adequate basis for the review's conclusion. Consistent with the intent of 50.59, these explanations should be complete in the sense that another knowledgeable reviewer could draw the same conclusion. The Rule requires retention of evaluations involving procedure changes and test and experiments for five years. The Rule also requires that licensee to submit a report to the NRC containing a brief description and evaluation summary of each change, tests, and experiment completed under 10CFR50.59 every 24 months.

The Rule does not require retention of activities or changes that were “screened out,” canceled, not implemented, or that concluded prior NRC approval was required and implemented through the license amendment process.

4.1.7 Encroachment on Design and Licensing Basis

From time to time an inspector may identify that a licensee has made changes to the facility without obtaining a required amendment to the OL. When this occurs, the licensee’s actions adversely affect our ability to perform our regulatory oversight function. These unauthorized changes may have also encroached upon the facility’s principle safety barriers established in the plant license. Any changes the licensee made to the facility or FSAR that required prior NRC approval, but a license amendment was not obtained, should not be considered part of the current licensing basis. In these cases, the facility design and licensing basis reverts back to the pre-changed state. These encroachments may directly or indirectly challenge SSC operability and trigger reportability and operability evaluations. As in the case of an improperly “screened out” change, the inspector should disposition these findings in accordance with the ROP and Enforcement Policy.

TABLE 1
50.59 APPLIABILITY

Does the proposed Activity involve a change to the:

- Technical Specifications or Operating License (10CFR50.90)?
- Conditions of License
  - Quality Assurance program (10CFR50.54(a))?
  - Security Plan (10CFR50.54(p))?
  - Emergency Plan (10CFR50.54(q))?
- Codes and Standards
  - IST Program Plan (10CFR50.55a(f))?
  - ISI Program Plan (10CFR50.55a(g))?
- ECCS Acceptance Criteria (10CFR50.46)?
- Radiation Protection Program (10CFR20)?
- Fire Protection Program (applicable UFSAR or operating license condition)?
- Programs controlled by the Operating License or the Technical Specifications (such as the ODCM).
- Environmental Protection Program
- Other programs controlled by other regulations

Does the proposed Activity involve maintenance which restores SSCs to their original condition or involve a temporary alteration supporting maintenance that will be in effect during at-power operations for 90 days or less?

Does the proposed Activity involve a change to the:

- UFSAR (including documents incorporated by reference) that is excluded from the requirement to perform a 50.59 Review by NEI 96-07 or NEI 98-03?
- Managerial or administrative procedures governing the conduct of facility operations (subject to the control of 10CFR50, Appendix B)
- Procedures for performing maintenance activities (subject to 10CFR50, Appendix B)?

If <u>all</u> aspects of the Activity are controlled by one or more of the above processes, **then** a 50.59 Screening is not required, and the Activity may be implemented in accordance with its governing procedure.

If <u>any</u> portion of the Activity is **not** controlled by one or more of the above processes, then process a 50.59 Screening for the portion not covered by any of the above processes. The remaining portion of the activity should be implemented in accordance with its governing procedure.

Table 2
Fission product design limits

Barrier	Design Basis Parameter	Typical Design Basis Limits
Fuel Cladding	Clad Temperature Fuel Burnup Linear Heat Rate DNBR/MCPR	2,200 °F MWd/ton kW/ft 95%/95% Correlation
RCS Boundary	Pressure Stress Heatup/Cooldown	Safety Analysis limit ASME Code ASME Code
Containment	Pressure	Design Pressure

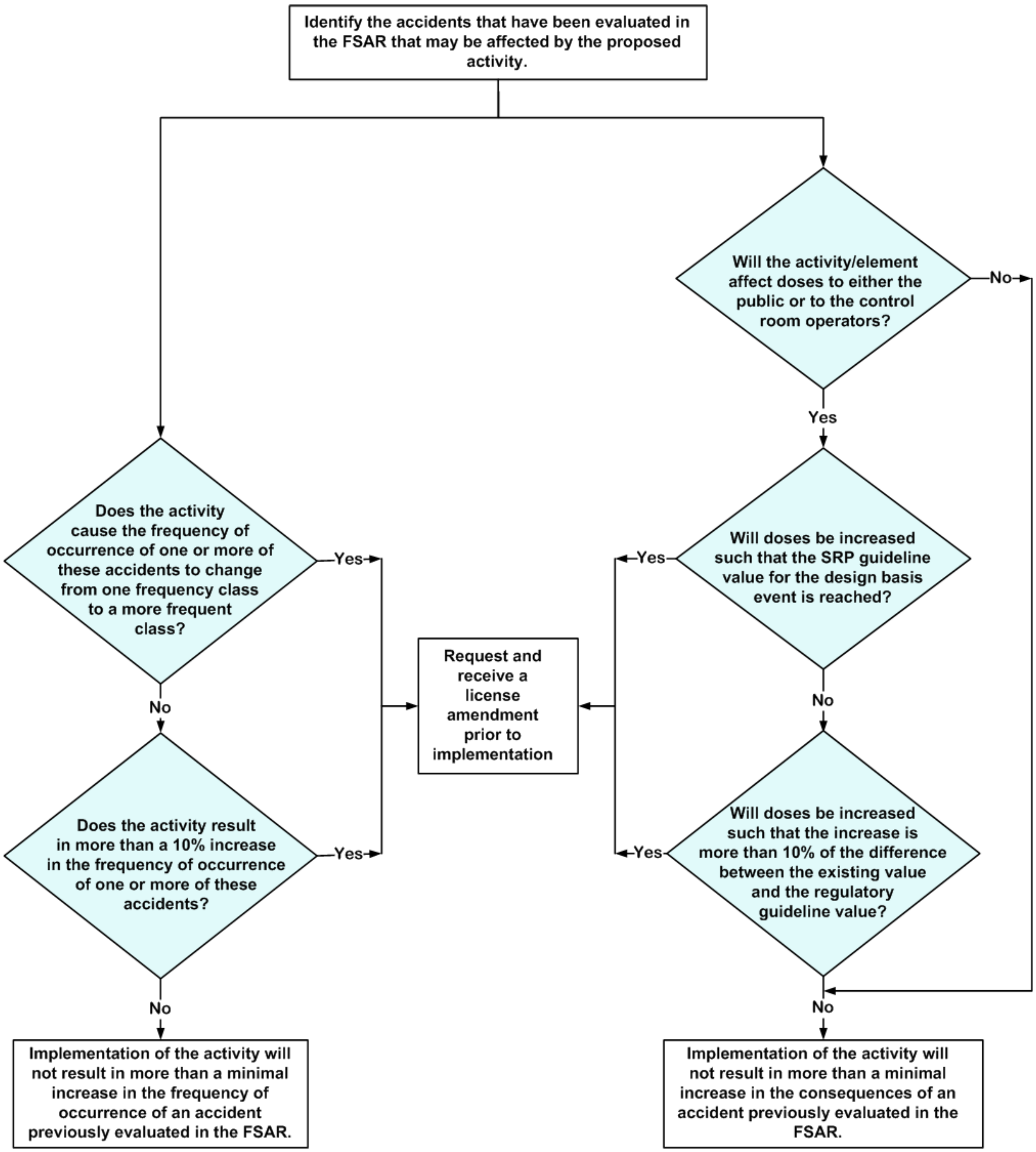


Figure 4.1-1 Frequency or Consequences of an Accident

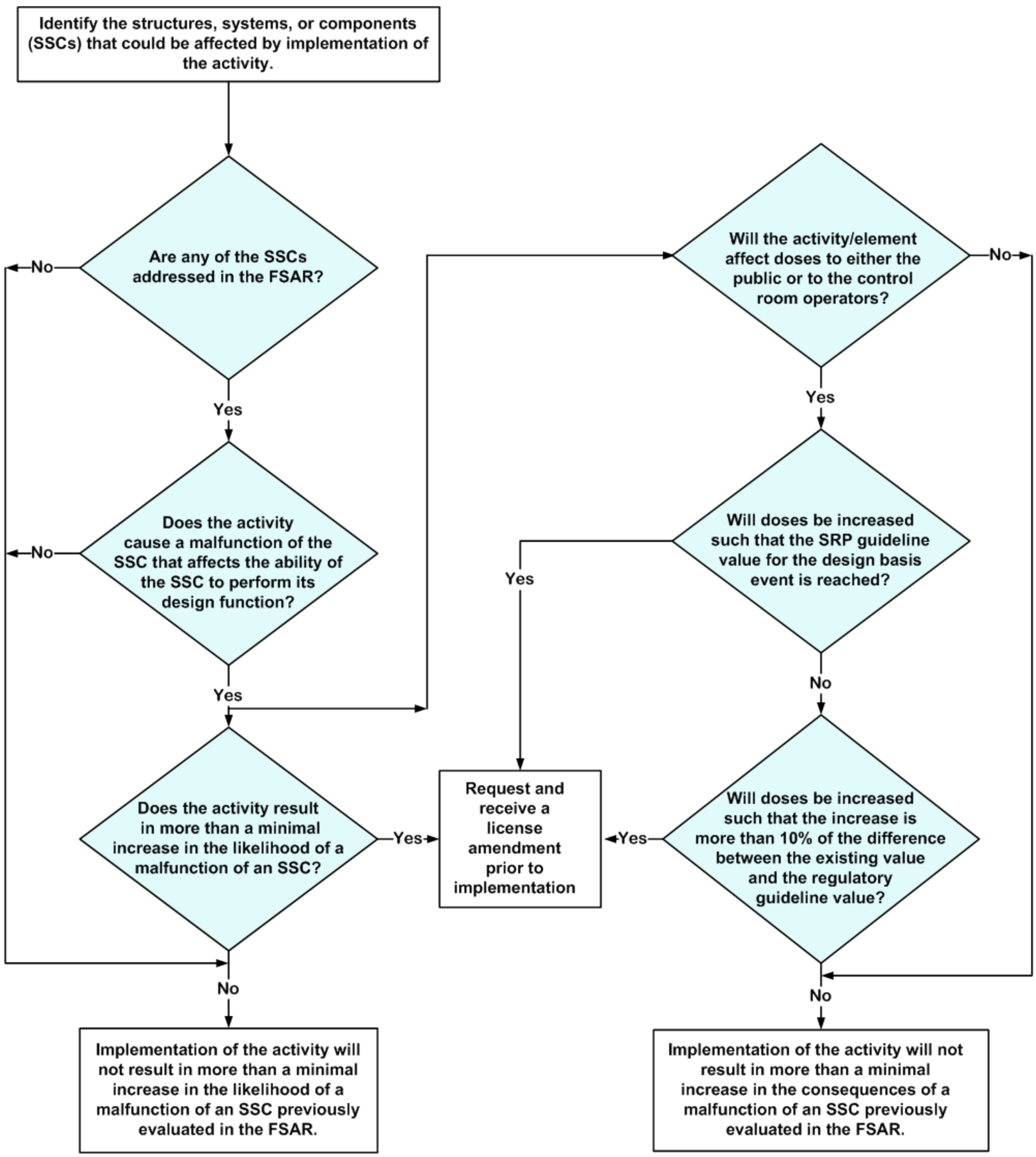


Figure 4.1-2 Frequency or Consequences of a Malfunction

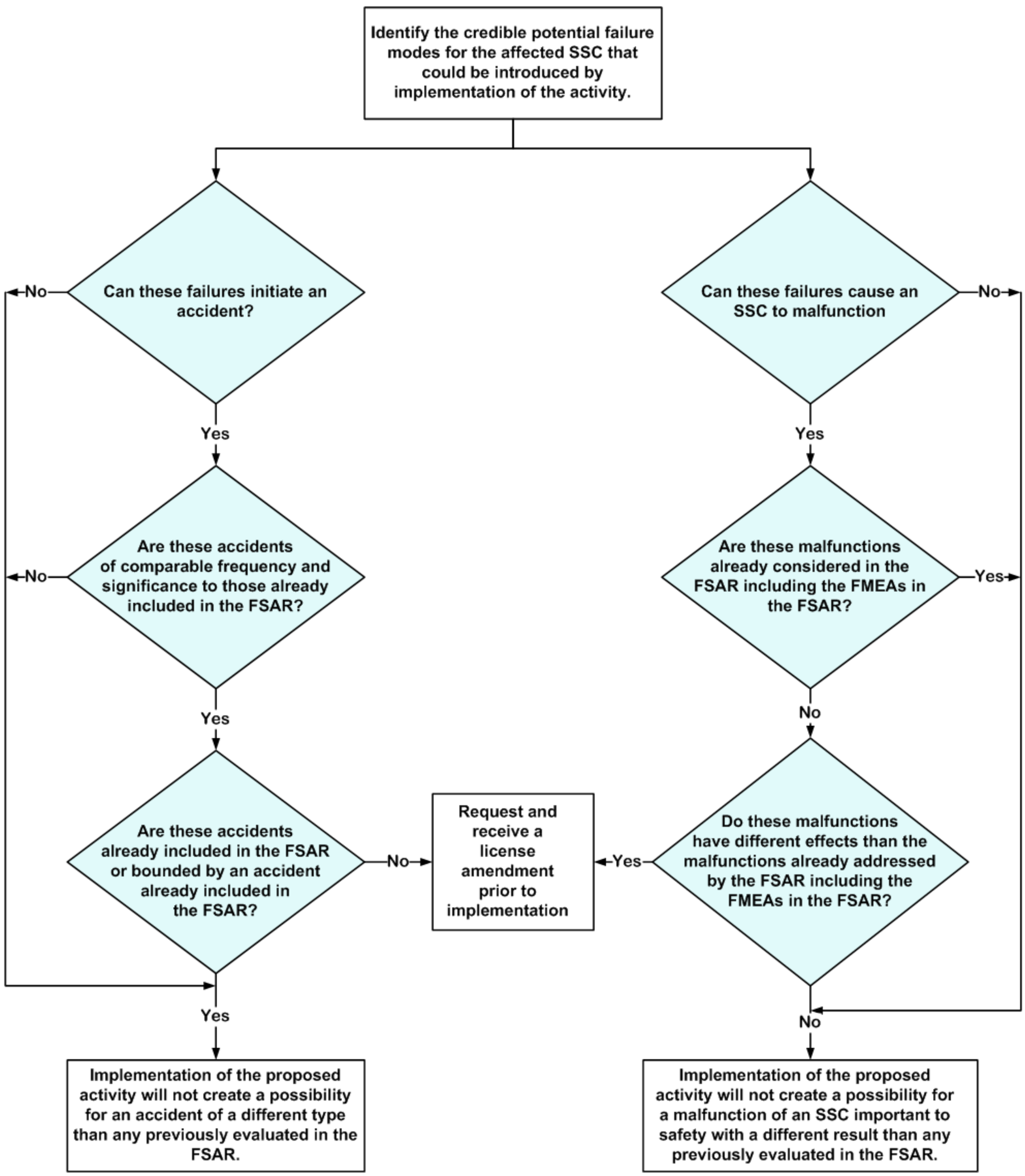


Figure 4.1-3 Accident of a Different Type/Malfunction with a Different Result

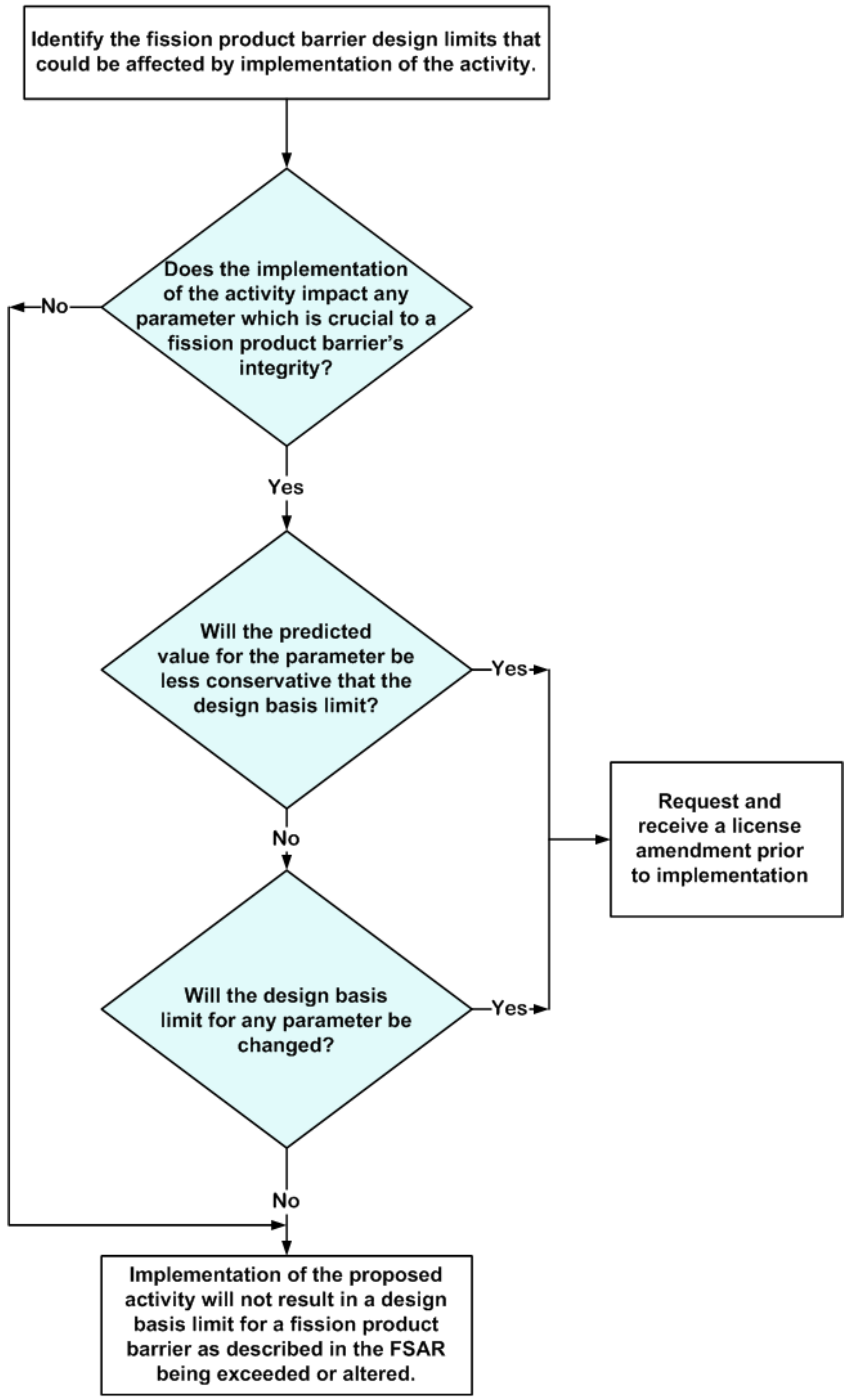


Figure 4.1-4 Fission Product Barrier Design Limit Exceeded or Altered

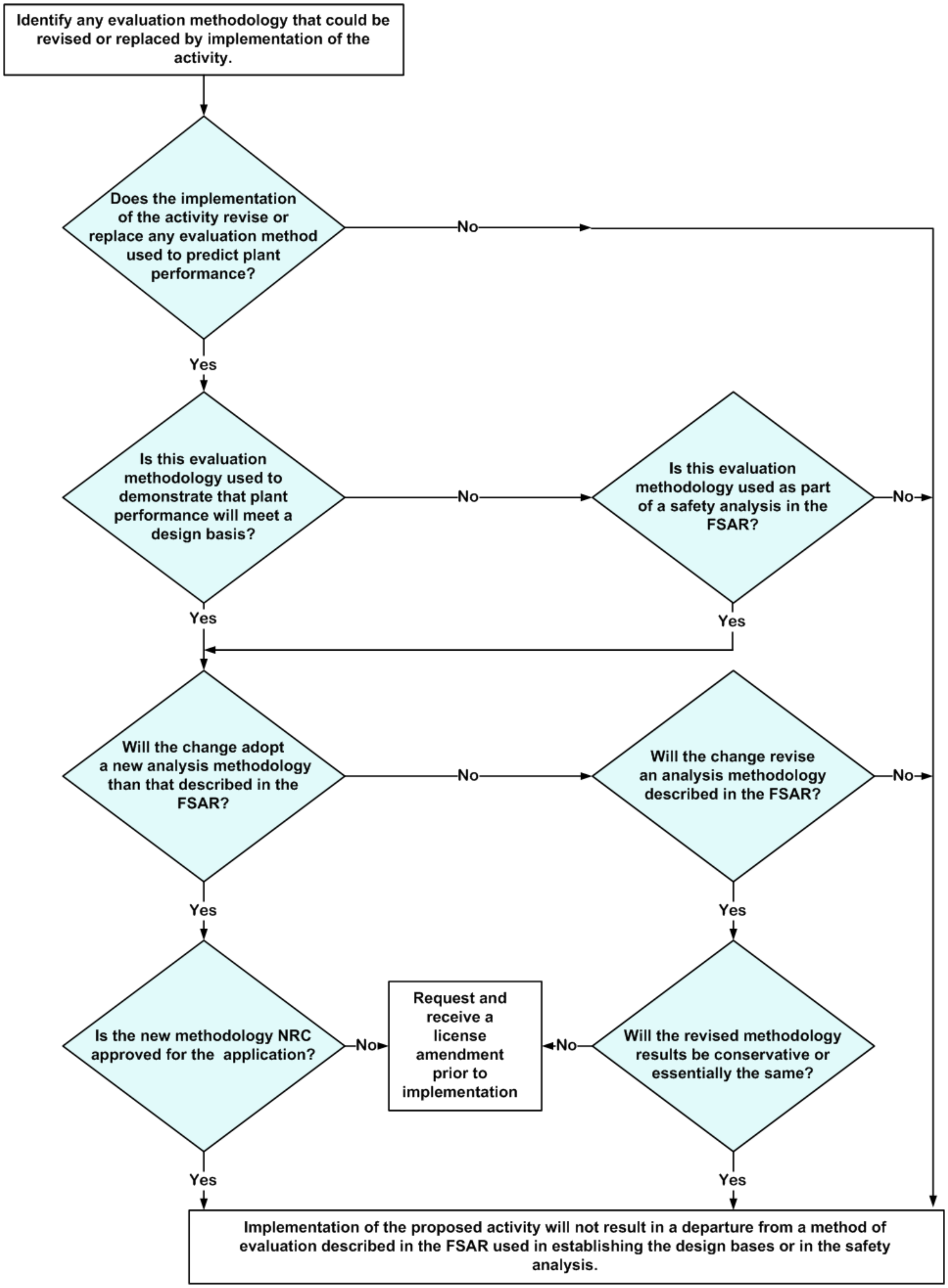
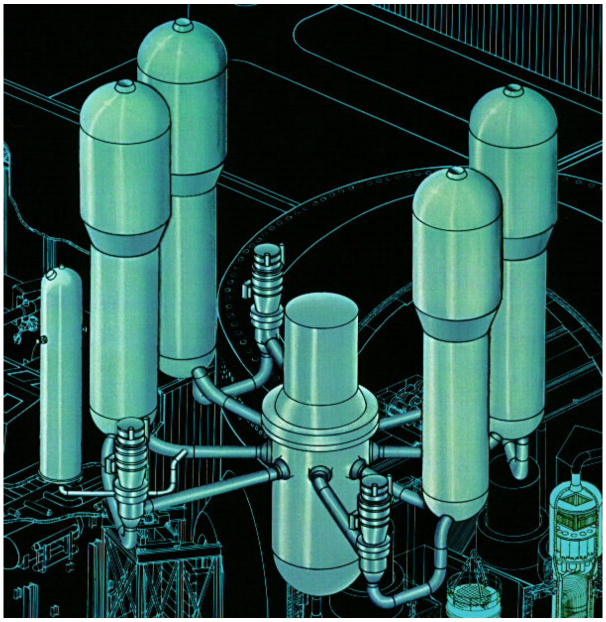


Figure 4.1-5 Departure from a Method of Evaluation



Westinghouse Advanced Technology Manual

Chapter 4.2 – Steam Generator Tube Rupture

2020

Human Resources Training & Development

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

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4.2.0 Steam Generator Tube Rupture

Learning Objectives:

1. Discuss why operator intervention is necessary to limit or prevent radiological releases during a Steam Generator Tube Rupture (SGTR) event.
2. Discuss the primary-side and secondary-side indications of an SGTR in the control room.
3. Discuss how the affected generator may be identified either prior to or following the reactor/turbine trip.
4. List the initial actions taken by the operator once the affected steam generator has been identified.
5. Discuss the actions required to stop the primary-to-secondary leakage.
6. Discuss the problems associated with the following:
    a. Secondary-to-primary leakage
    b. Steam generator overfill.
7. List the principal systems/components affected by a Loss Of Offsite Power (LOOP).
8. Discuss how plant cooldown and pressure control are accomplished with an SGTR and LOOP.
9. Discuss what affect the following events had on the SGTR transient at the Ginna plant:
    a. Tripping of the Reactor Coolant Pumps (RCPs)
    b. Failure of pressurizer Power-Operated Relief Valve (PORV)
    c. Automatic operation of letdown valves
    d. Pressurizer Relief Tank (PRT) failure
    e. Steam Generator (SG) safety valve failure.

4.2.1 Introduction

Of all the major accidents that have actually occurred at operating Pressurized Water Reactors (PWRs), Steam Generator (SG) tube failures have occurred most frequently. The nuclear industry has implemented many programs to reduce the incidents of tube failures, such as secondary side inspections, improved steam generator designs and water chemistry control, and more reliable eddy current tube inspection techniques. Nevertheless, a steam generator tube failure may remain one of the more likely accidents. Such accidents provide a direct release path for contaminated primary coolant to the environment via the secondary side safety and relief valves. Accumulation of water in the SG secondary side can also lead to an overfill condition which can severely aggravate the radiological consequences and increases the likelihood of subsequent failures.

Unlike other Loss Of Coolant Accidents (LOCA), a steam generator tube failure demands substantial operator involvement early in the event. Timely operator intervention is necessary to prevent steam generator overfill and limit the radiological releases.

The following sections describe the plant response to an actual and a postulated steam generator tube failure. A steam generator tube rupture event begins as a breach of the primary coolant barrier between the Reactor Coolant System (RCS) and secondary side of the steam generator, i.e., the steam generator tube, Figure 4.2-1. Although this relatively thin barrier is designed with substantial safety margin to preclude bursting even when subjected to full primary system pressure, the harsh secondary side environment may attack the steam generator tubes resulting in excessive tube wall thinning or cracking over time. Although improved secondary side chemistry has greatly reduced the frequency of tube failures attributed to chemical corrosion, foreign objects in the steam generator secondary have resulted in relatively rapid tube degradation and eventually tube failure (Prairie Island [1979] and Ginna [1982]). Even more recently (North Anna [1987]), tube failure was caused by flow-induced fatigue cracking.

4.2.2 Expected Plant Response to SGTR Event with Timely Operator Intervention

This section contains a description of the expected plant response to a postulated steam generator tube rupture accident and the actions, both operator initiated and automatic, which may occur during recovery. System response and recovery actions with offsite power available, section 4.2.2.1, and the effects of a loss of offsite power coincident with turbine trip, section 4.2.2.2, are discussed. As previously noted, the trends described are only representative since variations in manual actions or operable equipment as well as rupture size and specific plant design will result in slightly different system conditions. In the transient plots presented, a tube failure is to be the initiating event and it occurs when the plant is at full power.

4.2.2.1 SGTR Transient: Offsite Power Available

Since the primary system pressure (nominally 2235 psig) is initially much greater than the steam generator pressures (nominally 1000 psig) reactor coolant flows from the primary into the secondary side of the affected steam generator. In response to this loss of reactor coolant, pressurizer level and pressure decrease at a rate which is dependent upon the size and number of failed tubes, as shown in Figure 4.2-2. The Pressure decreases as the steam bubble in the pressurizer expands. Normally, charging flow will automatically increase and pressurizer heaters will energize in an effort to stabilize pressure and level. However, if leakage exceeds the capacity of the Chemical and Volume Control System (CVCS), reactor coolant inventory will continue to decrease and eventually lead to an automatic reactor trip signal. If turbine load is not reduced, reactor trip will most likely occur on Over-Temperature ΔT. For the expected case, however, turbine load will be decreased either automatically or manually so that reactor trip will occur on low pressurizer pressure. Normal letdown flow would isolate and pressurizer heaters would turn off on low pressurizer level.

On the secondary side, leakage of contaminated primary coolant will increase the activity of the secondary coolant resulting in high radiation indications from the air ejector radiation monitor and blow down line radiation monitors. Although these alarms may lag indications of a loss of reactor coolant, depending on the transport time to the radiation monitors, they have sounded nearly simultaneously with pressurizer low level indications during past tube failure events and generally provide the earliest diagnosis of a steam generator tube rupture. As primary coolant accumulates in the affected steam generator, normal feedwater flow is automatically reduced to compensate for high steam generator level. Consequently, a mismatch between steam flow and feedwater flow to the affected steam generator may be observed. This potentially provided early confirmation of a tube failure event and also identifies the affected steam generators. However, such a mismatch may not be noticeable for smaller tube failures because of the relatively large normal feedwater/steam flow rates. The water level in the affected steam generators may not be significantly greater than that of the intact steam generators prior to reactor trip as the normal feedwater control system automatically compensates for changes in steam flow rate and steam generator level due to primary-to-secondary leakage.

The time between initial tube failure and reactor trip also depends on the leak rate. In most cases sufficient time will be available (greater than three minutes) for the operator to perform a limited number of actions to either prevent or prepare for reactor trip. Such actions are likely to include starting additional charging pumps, energizing pressurizer heaters if not done automatically, reducing the load on the turbine, and possibly manually tripping the reactor. These actions, with the exception of manual reactor trip, will tend to delay an automatic trip signal. In addition, these actions can have a significant effect on the system response following reactor trip which may impact the longer term recovery. For example, as turbine run back proceeds, the mismatch between core power and turbine load causes the average coolant temperature (T_{avg}) to increase until the rod control and steam dump system actuate to restore programmed T_{avg}. A period of time may exist when T_{avg} is greater than nominal full power conditions. If reactor trip occurs during this time, the resulting cooldown of the primary system is larger when the steam dump system actuates to establish no-load conditions. The combination of a delayed reactor trip and greater shrinkage of reactor coolant may result in a significantly lower minimum RCS pressure following reactor trip. In that case RCP trip criteria may be met. This may also result in a greater steam generator inventory before recovery actions are initiated which would reduce the time available to steam generator overfill.

Following reactor trip, core power rapidly decreases to decay heat levels, steam flow to the turbine is terminated, and the steam dump system actuates to establish no-load coolant temperatures in the primary system (Figure 4.2-3). Shortly thereafter, the normal feedwater control system increases feedwater flow to compensate for shrinkage in steam generator level due to reduced steam flow. RCS pressure decreases more rapidly as energy transfer to the secondary shrinks the reactor coolant and tube rupture flow continues to deplete primary inventory. This decrease in RCS pressure results in a low pressurizer pressure Safety Injection (SI) signal soon after reactor trip. Normal feedwater flow is automatically isolated on the SI signal which also actuates the Auxiliary Feed-Water (AFW) system to deliver flow to all steam generators. For some plants, low water level is a combination of the steam generators coincident with the SI signal is required to actuate some components of the AFW system. However, since level drops below the narrow range on reactor trip from full power (Figure 4.2-4) the AFW system will also actuate on the SI signal for plants with this logic. If trip occurs at a lower power for these plants, AFW flow may not be initiated until sometime after the SI signal occurs. Eventually, manual action is required to decrease auxiliary feedwater flow to maintain the steam generator water level on the narrow range span. The expected sequence of automatic actions following reactor trip is presented in Table 4.2-1.

Secondary-side pressure will increase rapidly after reactor trip as automatic isolation of the turbine momentarily stops steam flow from the steam generators (Figure 4.2-4). Normally, automatic steam dump to the condenser will actuate to dissipate energy transferred from the primary, thereby limiting the secondary pressure increase. Since the intact and ruptured steam generators are connected via the main steam header, no significant difference in pressures will be evident at this time.

Initially, SI flow and AFW flow will absorb decay heat and decrease the reactor coolant temperature below no-load until AFW flow is manually throttled to maintain steam generator level in the narrow range. Steam flow should stop when the reactor coolant temperature decreases below no-load temperature (Figure 4.2-4) and the steam generator pressures may slowly decrease as the cold AFW flow condenses steam. At low decay heat levels or for multiple tube failures the reactor coolant temperature may continue to decrease due to SI flow even after AFW flow is throttled.

Pressurizer level decreases more rapidly following reactor trip as the reactor coolant shrinks during the post-trip cooldown and primary-to-secondary leakage continues to deplete coolant inventory. Although the minimum pressurizer level is dependent upon a number of parameters, including initial pressurizer level, initial power level, the size of the tube failure, operation of pressurizer heaters, and pre-trip operator actions, it is likely that level will be nearly off-scale low when SI is actuated. With SI actuated, the primary system will tend toward an equilibrium condition where break flow and coolant shrinkage are matched by SI flow (Figure 4.2-5). If break flow and shrinkage are initially greater than SI flow, pressurizer level and pressure will continue to decrease until quasi-equilibrium conditions are reached. In some cases, such a multiple tube failures or reduced SI capacity, RCS pressure may momentarily decrease to saturation until SI flow and AFW flow cool the primary system below the saturation temperature of the steam generators. Conversely, if SI flow exceeds primary-to-secondary leakage and coolant shrinkage, the pressurizer level and pressure will increase until equilibrium is achieved. The equilibrium RCS pressure depends on the size of the tube failures, capacity of the SI system, and cooldown rate of the primary. However, since leakage from the RCS is a function of both pressure and temperature, RCS pressure may continue to slowly decrease until reactor coolant temperatures are stabilized.

For high pressure SI plants, the pressurizer may refill to a relatively high level prior to operator intervention if the tube failure is small. However, in the more likely case, pressurizer level will return on span and will stabilize at a value significantly below nominal level, as shown in Figure 4.2-2. A point of confusion often noted occurs during simulation of a steam generator tube failure event where pressurizer level continues to increase toward an overfill condition following actuation of the SI system. While the pressurizer could fill for small tube failures in high pressure SI plants, in some cases this response has been attributed to modelling limitations of the pressurizer. The operator should be aware that although filling of the pressurizer is possible, it is not generally expected. It should also be clear that the reactor coolant temperature trend and operator actions, such as throttling AFW flow, will affect the pressurizer level.

As previously mentioned, the steam generator level may drop out of the narrow range following reactor trip, as shown in Figure 4.2-4. AFW flow will begin to refill the SGs, distributing approximately equal flow to all SGs. Since primary-to-secondary leakage adds additional inventory which accumulates in the ruptured SG, the level will return significantly earlier and will continue to increase more rapidly. This response provides confirmation of a SGTR event and also identifies the affected SG. Although these symptoms will be evident soon after reactor trip for larger tube failures, the SG level response may not be noticeably different or may be masked by non-uniform AFW flows for smaller tube failures in one or more SGs. In that case, high radiation indications may be necessary for positive identification of a ruptured SG. In such instances of smaller tube failures, the break flow would be less and, consequently, more time would be available for recovery prior to filling the affected S/G with water.

Once a tube failure has been identified, recovery actions begin by isolating steam flow from and stopping feedwater flow to the affected SGs. In addition to minimizing radiological releases, this also reduces the possibility of filling the affected SG with water by (1) minimizing the accumulation of feedwater flow and (2) enabling the operator to establish a pressure differential between the ruptured and intact SGs as a necessary step toward terminating primary-to-secondary leakage. In the analysis results, the operator was assumed to isolate the affected SG when the water level returned into the narrow range (> 15%). With steam flow and feedwater flow terminated, the affected SG pressure will slowly increase as primary-to-secondary leakage compresses the steam bubble in the SG.

High pressure SI plants would also show similar trends. Eventually an SG atmospheric relief valve would lift unless actions to stop leakage into the affected SG are completed.

After isolation of the ruptured SG, the RCS is cooled to less than saturation at the ruptured SG pressure by dumping steam from only the intact SGs. This insures adequate subcooling in the RCS after depressurization to the ruptured SG pressure in subsequent actions. With offsite power available, the normal steam dump system to the condenser provides sufficient capacity to perform this cooldown rapidly, as demonstrated in Figure 4.2-6.

RCS pressure will decrease during this cooldown as shrinkage of the reactor coolant expands the steam bubble in the pressurizer (Figure 4.2-6). For multiple tube failures, RCS pressure (Figure 4.2-7) may decrease to less than the ruptured SG pressure as steam voids, which were generated during initial RCS depressurization, condense. Reverse flow, i.e., secondary-to-primary leakage, during this time would reduce the inventory in the ruptured S/Gs and delay steam generator overfill, as shown in Figure 4.2-7.

When the cooldown is completed SI flow again increases RCS pressure toward an equilibrium value where break flow matches SI flow. Consequently, SI flow must be terminated to stop primary-to-secondary leakage. However, adequate coolant inventory must first be ensured. This includes both sufficient reactor coolant subcooling and pressurizer inventory to maintain a reliable pressurizer level indication after SI flow is stopped. Since leakage from the primary side will continue until RCS and ruptured SG pressures equalize, an excess amount of inventory is required before stopping SI flow. The “excess” amount of inventory required depends upon the RCS pressure and reduces to zero when RCS pressure equals the pressure in the ruptured SG. It is necessary to accommodate the decrease in pressurizer level after SI flow is stopped. To establish sufficient inventory, RCS pressure is decreased by condensing steam in the pressurizer using normal spray. This increases SI flow and reduces break flow, which refills the pressurizer, as illustrated in Figures 4.2-8 and 4.2-9. Note that although the cooldown of the primary side also decreased RCS pressure, the pressurizer did not refill since the net effect reduced coolant volume. Similarly, spraying the pressurizer to decrease RCS pressure concurrently with the primary side cooldown is not as effective in refilling the pressurizer, as shown in Figure 4.2-10.

For multiple tube failures, RCS pressure may decrease below the ruptured steam generator pressure before pressurizer level returns on scale. In that case, reverse flow through the failed tubes will supplement SI flow in refilling the pressurizer. Conversely, for smaller tube failures, pressurizer inventory may stay on scale and additional actions to restore inventory would not be necessary.

Previous actions were designed to establish adequate RCS subcooling, secondary side heat sink, and reactor coolant inventory to ensure SI flow is no longer required. When these actions have been completed, SI flow must be stopped to prevent repressurization of the RCS and to terminate primary-to-secondary leakage. With SI flow stopped, residual break flow will reduce RCS pressure to equilibrium with the ruptured SG, as shown in Figure 4.2-11. RCS temperature, pressurizer level, and affected SG levels will stabilize (Figure 4.2-12) and no further uncontrolled releases of radiological effluent from the ruptured SG will occur. Note that although the level in the affected steam generator may reach the top of the narrow range span, significant volume still exists before the SG fills with water.

4.2.2.2 SGTR Transient: Offsite Power Not Available

The principal systems/components affected by a loss of offsite power are the steam dump system, reactor coolant pumps, and RCS pressure control. The effect of each of these on the system response and recovery is discussed.

The steam dump system is designed to actuate following loss of load or reactor trip to limit the increase in secondary side pressure. Without offsite power available, the steam dump valves, which bypass the turbine to the condenser, will remain closed. Hence, energy transferred from the primary will rapidly increased SG pressures after reactor trip until the atmospheric relief valves lift to dissipate this energy, as shown in Figure 4.2-13. Since the secondary side temperature increase is greater, sensible energy transfer from the primary side following a reactor trip is reduced. Consequently, RCS pressure decreases more slowly, as illustrated in Figure 4.2-14, so that SI actuation and all attendant automatic actions are delayed. A typical sequence of events without offsite power available is also presented in Table 4.2-1.

RCPs trip on a loss of offsite power and a gradual transition to natural circulation flow ensues. The cold leg temperature trends toward the SG temperature as the fluid residence time in the tube region increases. Initially, the core ΔT decreases as core power decays following reactor trip and, subsequently, increases as natural circulation flow develops (Figures 4.2-15 and 4.2-16). Without RCPs running, the upper head region becomes inactive, and the fluid temperature in that region will significantly lag the temperature in the active RCS regions. This creates a situation more prone to voiding during the subsequent cooldown and depressurization.

Sufficient instrumentation and controls are provided to ensure that necessary recovery actions can be completed without offsite power available. Although the recovery methods are the same with or without offsite power available, the equipment used may be different. The RCS is cooled using the PORVs on the intact SGs since neither the steam dump valves nor the condenser would be available without offsite power. Even with one SG out of service, these valves provide sufficient capacity to complete the initial cooldown rapidly, as shown in Figure 4.2-17. Note that the hot leg temperature does not respond as quickly as the cold leg and SG temperatures since RCPs are not running.

Under natural circulation conditions subsequent actions to isolate the affected SGs and cooldown the intact RCS loops may stagnate the affected loop. Consequently, the hot leg fluid in that loop may remain warmer than the unaffected loops. Similarly, SI flow into the stagnant loop cold leg may rapidly decrease the fluid temperature in the cold leg, downcomer, and pump suction regions significantly below the rest of the RCS.

With RCPs stopped, normal pressurizer spray would not be available. Consequently, RCS pressure must be controlled using pressurizer PORVs or auxiliary spray. Although a PORV enables more rapid RCS depressurization (Figure 4.2-18), it also results in an additional loss of reactor coolant which may rupture the PRT and contaminate the containment. Auxiliary spray conserves reactor coolant but may create excessive thermal stresses in the spray nozzle which could result in nozzle failure. Auxiliary spray is recommended only if normal spray and PORVs are not available.

Since the upper head region is inactive, voiding may occur in this region during RCS depressurization. This will result in a rapidly increasing pressurizer level indication as water displaced from the upper head replaces steam released or condensed from the pressurizer. This behavior was observed during the Ginna tube failure event, when the pressurizer PORV failed to close. The extent of voiding is limited to the inactive regions of the RCS provided subcooling is maintained at the core exit. However, flashing in the inactive regions may slow further RCS depressurization to cold shutdown conditions.

Once SI flow is stopped, no additional primary-to-secondary leakage or uncontrolled radiological releases from the affected SGs should occur. This plant response is similar with or without offsite power available.

The automatic protection systems are more than sufficient to maintain adequate core cooling even for multiple tube failures. However, extensive operator actions are required to stop primary-to-secondary leakage which could lead to a steam generator overfill condition if not terminated expeditiously. The system response to a SGTR before and immediately after reactor trip has been described. From this description the symptoms which identify both the tube failure event and the affected SGs should be evident, including high or increasing secondary side radiation, and steam generator level response. These symptoms provide the basis for diagnostics in the emergency operating procedures.

It must be emphasized that although strong similarities exist, each tube failure is unique. Variations in break size and plant specific features, such as SI capacity and operator response times, will affect system conditions.

4.2.3 R.E. Ginna Tube Rupture

On January 25,1982, the R.E. Ginna Nuclear Power Plant experienced a design-basis steam generator tube rupture. This resulted in the maximum flow from a single tube.

The final safety analysis report (FSAR) assumes that the break flow is terminated by operator action within 30 to 60 minutes. The procedures available to the operators at the time proved to be inadequate to meet this time requirement. Several procedure changes have occurred because of these inadequacies. Major changes address specific guidance on safety injection reset and safety injection termination with suspected reactor upper head voiding. Also of major significance are the criteria for tripping and restarting reactor coolant pumps.

The report on the Ginna steam generator tube rupture is published as NUREG-0909. The event is described in nine phases. This nine phase description, along with an event chronology is included as Table 4.2-3 of this chapter. Note that other equipment failures made this event unique, such as PORV failure to close and SG code safety valve failure to fully reseat. Also the design of the CVCS allowed the letdown isolation valve to open, causing overpressure in the pressurizer relief tank (PRT) and release into the containment.

The R.E. Ginna Nuclear Power Plant is a 1520-MWt, two-loop PWR designed by Westinghouse. A diagram of the major plant systems and components is shown on Figure 4.2-19. Figure 4.2-20 shows the instrument locations in the reactor coolant system, pressurizer, and PRT.

4.2.3.1 Event Phase 1: Steady-State Operation (Period before 9:25 a.m., 1/25/82)

Prior to 9:25 a.m., the plant was operating at full power, steady-state conditions. The major primary and secondary system parameters and their steady-state values are listed in Table 4.2-2. These parameters indicate that the plant was in a normal full power condition. No important systems were out of service and no abnormal conditions existed in any of the major parameters.

4.2.3.2 Event Phase 2: Tube Rupture and Initial Depressurization (9:25 a.m. to 9:30 a.m.)

At 9:25 a.m., there was a sudden rupture of a single tube in the B steam generator. Detailed information from the plant process computer is available for the period beginning at 9:26 a.m. This information was used to develop the graphs of pressurizer (PZR) pressure and level versus time (Figures 4.2-21 and 4.2-22). The initial depressurization from 2197 psig to approximately 2100 psig and the associated drop in pressurizer level from 47% to 30% occurred between 9:25:25 a.m. and 9:26:30 a.m. The depressurization and level drop were terminated by automatic and manual actions to increase the charging flow from 30 gpm to at least 60 gpm (corresponding to full flow from one charging pump) and thermal expansion of the water in the reactor coolant system associated with the ordered load reduction. This indicates that the initial leak rate was approximately 750 gpm.

A level deviation alarm resulted when the water level in the B SG exceeded its setpoint of 52%. The water level increased because of the flow from the reactor coolant system to the SG through the ruptured tube. The increased water level was sensed by the feedwater control system, which reduced feedwater flow by modulating the feedwater control valve. The difference between feed flow and steam flow produced the steam flow/feed flow mismatch alarm from the B SG. Simultaneously, a radiation alarm on the air ejector indicated a leak from the reactor coolant system to the secondary system. These were important symptoms of a tube rupture in B SG.

At 9:27:11 a.m. (Figure 4.2-22) a more rapid reactor coolant system depressurization and level decrease began. This was the result of a reactor coolant cooldown and a continuing leak of approximately 750 gpm. This leak resulted in a reactor trip at 9:28 a.m. on low pressurizer pressure (~1900 psig), an automatic safety injection actuation signal on low pressurizer pressure (~1720 psig), and a containment isolation signal on safety injection actuation. The safety injection actuation signal started all three high pressure safety injection pumps and the two motor driven auxiliary feedwater pumps. The containment isolation signal resulted in the closure of all containment isolation valves, termination of main feedwater flow, and termination of charging flow. The turbine driven auxiliary feedwater pump subsequently started automatically on low water level (17%) in both steam generators. Shortly after these actuation signals, the pressurizer emptied of water, and the reactor coolant system pressure dropped to approximately 1200 psig. The minimum system pressure was apparently determined by the temperature of the hottest fluid in the reactor coolant system. This fluid would have flashed when the system pressure dropped below the saturation pressure corresponding to its temperature. This initial flashing in the reactor coolant system would have occurred when the temperatures in the pressurizer surge line and reactor vessel upper head were near or above 576°F, the saturation temperature corresponding to 1270 psig.

Immediately after the reactor, turbine, and feedwater trips, the narrow-range A and B SG water level instruments indicated a level drop from about 47% to about 10%, normal for a trip from full power, while the wide-range level instrument indicated a slight increase in level. This discrepancy was believed to result from cold calibration of the wide-range instrument and the fact that its lower pressure tap was located just above the tube sheet. The narrow-range instrument is calibrated at operating temperature of the SG and its lower pressure tap is located just above the top elevation of the tube bundle.

Approximately 50 seconds after the SI signal occurred, the reactor operators verified that the pressurizer pressure was less than 1715 psig and manually tripped the reactor coolant pumps in accordance with Ginna procedures.

During normal operations, both seal injection and component cooling water are provided to the reactor coolant pumps. The seal injection flow was terminated upon SI because the charging pumps were tripped automatically.

In addition, the piping that returns the seal water to the CVCS was isolated by the containment isolation signal. After the seal return valve closed, reactor coolant system leakage through the reactor coolant pump seals pressurized the seal return line. As shown by the pressurizer relief tank level indication, the relief valve on this line lifted. The pumps can be operated without seal injection provided component cooling water is available and the seal leakage is less than five gpm (Ginna procedure). Therefore, the reactor coolant pump trip was a result of the procedural requirement to trip the pumps to avoid exacerbating certain small-break loss of coolant accidents.

Numerous valves inside containment were affected when the instrument air was isolated at 9:28 a.m. from the containment isolation signal. The important valves for this event were the two pressurizer PORVs, the pressurizer spray valves, the CVCS charging and letdown valves, and the pressurizer auxiliary spray valve. Except for the level control valve in the CVCS, all these valves fail closed. The pressurizer PORVs have a backup nitrogen supply that is available to operate the valves.

4.2.3.3 Event Phase 3: Natural Circulation and Reactor Coolant System Repressurization (9:30 a.m. to 10:07 a.m.)

Following the initial depressurization, the SI pumps injected water into the reactor coolant system, increasing the volume of water in the system and increasing the system pressure to 1350 psig. During this period, the reactor-coolant-system-to-B-SG pressure difference was approximately 300 psi and the leakage into the B SG continued at a rate of approximately 400 gpm. Figure 4.2-23 presents estimates of SI flow and break flow versus pressure. This figure indicates that the reactor coolant system and B SG should establish a dynamic equilibrium between high pressure injection flow and break flow with a reactor coolant system pressure of 1410 psig, which corresponds to an indicated reactor coolant pressure of 1385 psig. This condition developed at approximately 10:00 a.m. during the event.

The temperature difference from the cold legs (Figure 4.2-24) to the hot legs initially decreased, since the reactor trip caused a rapid drop in the reactor core heat generation, and reached a minimum value of 20°F. Following the RCP trip at 9:29 a.m., the reactor coolant flow rates decreased. As flow decreased, natural circulation developed, with the reactor core as the heat source, and the elevated steam generators as the heat sink.

At 9:32 a.m. the turbine-driven auxiliary feedwater steam supply valve from B SG was shut in accordance with the SGTR procedure. In addition, the motor-driven auxiliary feedwater pump was isolated from the B SG. To confirm that the leak was from the B SG, as suspected, a check of B steam line radiation level was made using a portable radiation monitor. The indicated reading (approximately 30 mrem/hr) gave positive indication of the affected SG approximately 15 minutes after the initial alarms had indicated that a problem existed.

At 9:40 a.m. the B SG was isolated by closing the MSIV, and no further cooling was taking place in the B SG. This caused the flow in the B reactor coolant loop cold leg to stagnate and to reverse direction as water in the B loop cold leg was drawn toward the ruptured tube. The reverse flow in the B reactor coolant cold leg continued throughout the event.

Prior to 9:40 a.m., the reactor coolant leaking into the B SG was circulated throughout the main steam, main feedwater, and condensate systems. After 9:40 a.m. the B SG main steam isolation valve was closed and the tube leak caused an increase in the indicated steam generator water level. The pressure in the B SG began to increase when the turbine-driven auxiliary feedwater terminated at 9:46 a.m. The B SG narrow-range water level indication went off scale high at 9:55 a.m. Later the attached steam line also flooded.

Throughout this phase, the A SG continued to dump steam into the main condenser. The RCS cooldown rate during this period can be seen by observing the change in the A loop temperature versus time in Figure 4.2-24.

The only radiation alarm from the SG blowdown system occurred at 9:50 a.m., 22 minutes after the B SG blowdown piping isolation valve closed on containment isolation. The radiation monitor is located downstream of the sample line isolation valves, which were also closed upon containment isolation.

The SI signal was reset at 9:57 a.m. The containment isolation signal was also reset in order to restore instrument air and gain control of air-operated valves inside containment.

At 10:04 a.m., one charging pump was restarted, although the SGTR procedure called for starting all available charging pumps.

4.2.3.4 Event Phase 4: Pressurizer PORV Operation (10:07 a.m. to 10:15 a.m.)

Reducing the RCS pressure to reduce the tube leakage is an important step in recovery from a tube rupture event. The first attempt to reduce RCS pressure occurred at 10:07 a.m. when one PORV was opened for a few seconds. The valve was successfully cycled three times but failed to close on the fourth cycle at 10:09 a.m. The operators then closed the block valve to terminate flow through the stuck-open PORV. The normal closure time for the block valve is approximately 35 seconds. The plant process computer printout shows that pressure in the RCS was increasing at 10:11 a.m., indicating that the block valve was closed by that time. In addition, the temperature rise in the PRT terminated at 10:12 a.m.

While the PORV was open RCS pressure dropped from 1350 psig to 850 psig (Figure 4.2-25). For the period from 10:09 a.m. to 10:11 a.m. the RCS pressure was lower than the B SG pressure. This low RCS pressure caused a temporary reversal in primary-to-secondary break flow, an increase in SI flow, and flashing of water in the reactor vessel upper head and B SG tubes. While the PORV was stuck open the pressurizer level increased rapidly from 6% to 100%. The pressurizer was filled by water displaced by steam formation in the reactor vessel upper head and inside the B SG tubes, flow from the B SG into the RCS through the ruptured tube, and SI and charging flow.

The indicated rate of increase of pressurizer level, beginning at 10:09 a.m., corresponds to a computed water inventory rate of change of 405 ft^3/min. Since the PORV was opened for about two minutes after 10:09 a.m., approximately 810 ft^3 of water would have left the pressurizer. This value is reasonably close to the estimated value of water volume available, that is 765 ft^3.

Since the water volume in the pressurizer at 10:09 a.m. was approximately 100 ft^3, these calculations imply that a relatively small volume (35 to 100 ft^3) of water was discharged through the PORV after the steam in the pressurizer had been relieved.

A review of the PRT parameters (Figure 4.2-26) indicates that the four percent level increase during the PORV openings corresponds to approximately 40 ft^3 of water. Since the mass of steam in the pressurizer at 10:07 a.m. corresponds to 35 ft^3 of water at 1400°F, the indicated increase in PRT level implies that only 5 ft^3 of water was discharged through the PORV. Therefore, all the available data indicated that when the PORV failed to close it was discharging steam; that very little liquid discharge took place; and that the liquid discharge occurred at the end of the blow down while the PORV block valve was closing.

During the time when the PORV was open, the indicated cold-leg temperature in the B RCS loop decreased rapidly to 260°F and then recovered to 350°F. These changes are associated with an increase and decrease in SI flow in the B loop cold leg. The SI water was mixing with the hot water from the reactor vessel downcomer and the B loop cold-leg temperature sensor was reading a mixed fluid temperature.

After the pressurizer PORV block valve was closed, the system pressure returned to approximately 1400 psig. This pressure was slightly higher than the pressure recorded before the PORV openings. Except for forming the steam bubble in the upper head and filling the pressurizer with water, the system conditions after the block valve closure were essentially the same as before the PORV opening.

After the operator noted that the PORV block valve indicated closed on the main control board, he directed that the PORV tailpipe temperatures be monitored to insure that the block valve had fully closed and that the other PORV was not leaking. The drop in tailpipe temperature was slower than expected, so the operator closed the block valve associated with the other PORV. It was later determined that there was no leakage past the originally closed block valve or the second PORV.

Throughout this phase of the event, the RCS was being cooled by dumping steam from the A SG to the main condenser. Auxiliary feedwater for the A SG was supplied by the A motor-driven pump from the condensate storage tank.

Instrument air had been restored at 9:59 a.m., but the selected letdown orifice isolation valve (LCV-200B) and level control valve (LCV-427) remained closed because the pressurizer level was below 10%. At approximately 10:08 a.m., the pressurizer level increased above 10%, opening (LCV-427) and the selected orifice isolation valve as designed. The letdown containment isolation valve (AOV-371) remained closed, since the valve does not automatically open when the containment isolation signal is reset. Consequently, the letdown line was communicating with the RCS while the downstream portion of the letdown line remained isolated, and the relief valve opened at a set pressure of 600 psig. This valve relieves to the PRT and was a major contributor to the PRT level increase.

4.2.3.5 Event Phase 5: Prolonged Safety Injection (10:15 a.m. to 10:38 a.m.)

When the RCS pressure and the pressurizer level increased after the PORV block valve was closed at 10:11 a.m., the conditions necessary for allowing termination of SI existed. The plant operators knew; however, that a steam bubble had formed under the reactor vessel upper head and they were reluctant to interpret the high pressurizer level as a legitimate indication of having sufficient RCS inventory. As a result, the termination of SI did not occur until about 10:38 a.m., after discussions were held between control room personnel and the Technical Support Center personnel.

A detailed review of the system data indicate that PORV operation was successful in decreasing RCS pressure and in increasing the liquid inventory by SI and charging flow. Subsequently, SI increased RCS pressure to 1390 psig. SI flow could have been safely terminated immediately after the PORV block valve closed at 10:11 a.m.

After 10:11 a.m. the continued SI caused the RCS pressure to remain approximately 300 psi above the B SG pressure. This pressure differential caused the leakage to the SG to persist. As a direct result of the leakage into the B SG, the pressure increased to 1080 psig at 10:19 a.m., and the opening of a SG safety valve released steam into the atmosphere. This occurred again at 10:28 a.m. The first and second SG safety valve openings each resulted in pressure reductions of approximately 50 psi. The A and B SG valve position recorders were started by a technician earlier in the event, but the recorders failed to indicate these and subsequent valve lifts.

The repeated openings of the SG safety valve led the control room and Technical Support Center personnel to decide to terminate SI.

4.2.3.6 Event Phase 6: Safety Injection Termination and Leakage Reduction (10:38 a.m. to 11:21 a.m.)

The SI pumps were stopped at 10:38 a.m. and the RCS pressure decreased to approximately 950 psig. The secondary pressure continued to decrease to approximately 850 psig as a result of the third opening of the SG safety valve. This SG pressure reduction of approximately 200 psi is unusually large and indicates that this valve did not close normally, possibly as a result of discharging two-phase flow. With an RCS-to-SG DP of 100 psi, the leak rate was reduced to approximately 150 gpm. As a result of the continuing leakage, the pressure difference between the RCS and the B SG gradually decreased over the next 40 minutes, falling to 30 psi at about 11:19 a.m.

At about 10:40 a.m. the pressurizer heaters were re-energized to establish a steam bubble in the pressurizer. The pressurizer heaters had tripped on low pressurizer level during the initial depressurization.

At about 10:42 a.m., a second charging pump was started. As indicated in Figure 4.2-25, the equilibrium RCS pressure was approximately 40 psig above the pressure in the B SG with the two charging pumps running. Continued charging flow while letdown remained isolated caused the RCS-to-SG pressure differential to persist and the break flow to continue.

During this phase of the event, the method of dumping steam from the A SG was changed to allow steam to be vented to atmosphere through the atmospheric PORV on the A SG. The steam had been dumped to the condenser until the last operating condensate pump was secured at 10:40 a.m. Without condensate flow, the air ejector automatically secured, and the vacuum in the condenser was not maintained. The decision to stop dumping steam to the condenser was made to prevent any further contamination of the condensate system, particularly the condensate demineralizers.

Also, during this phase of the event, the RCS pressure increased from 950 to 1050 psig. Initially the increase was caused by operators throttling closed the A SG PORV with a corresponding decrease in heat removal from the RCS. After 11:07 a.m., when one of the SI pumps was restarted, the RCS pressure increased when the SI pump added water. The SI pump had been restarted as a precaution against a large pressure reduction which could be caused by the restart of the A reactor coolant pump.

One B SG safety valve opened a fourth time as a result of the RCS pressure increase caused by the operation of the SI pump.

During this phase, both the letdown line relief valve and the seal return relief valve continued to lift and discharge water to the PRT. As shown in Figure 4.2-26, the PRT water level increase indicates that the letdown relief valve was the major contributor to the tank inventory increase, which resulted in the burst of the tank rupture disc at about 10:52 a.m. The letdown relief valve remained open until 12:02 p.m. The estimated flow rate through the letdown relief valve was about 24 gpm based on the rate of change in

PRT level indication between 10:15 and 10:45 a.m., 22 gpm based on PRT and containment sump inventory balance.

4.2.3.7 Event Phase 7: Reactor Coolant Pump Restart (11:21 a.m. to 11:37 a.m.)

This phase of the event began with the restart of the A RCP at 11:21 a.m. No detailed information is available for the period immediately before or immediately after the time when the pump was restarted because of computer failure.

Although there is no computer recorded data for the period during the pump restart, later computer data (about 12 minutes after pump restart) and hand written logs of the thermocouple data indicated that the temperature reduction in the upper head region was very rapid and occurred very soon after the restart of the RCP. All the data after the time of pump restart showed that, with the exception of the pressurizer, the entire RCS was at approximately the same temperature for the rest of the event.

The reactor vessel upper head temperatures had been below the saturation temperature corresponding to the RCS pressure since 10:11 a.m. but were significantly higher than the temperatures in the remainder of the RCS, with the exception of the pressurizer. At 11:21 a.m., a steam bubble of less than 300 ft^3 may still have existed in the upper portion of the reactor vessel. There is no instrumentation at higher elevations which would detect such a bubble. After the RCP restart the indicated temperature in the upper head decreased to a value equal to the temperature in the remainder of the RCS, approximately 400°F. With the RCP running and more than 100°F of subcooling at the upper head thermocouple locations, it is unlikely that any steam existed in the upper head at this time or later.

The limited data available indicate that it is likely that a small RCS-to-SG differential pressure, perhaps 40 psid, existed throughout this period. The corresponding leak rate would be 100 gpm.

Throughout this phase of the event, one SI pump was operated as a precaution against an uncontrolled depressurization associated with the RCP restart. Such a depressurization was of concern to the plant staff because the pressurizer level was still off scale and a steam bubble was thought to exist in the reactor vessel upper head. It should be noted that the B SG would have provided water through the ruptured tube to help suppress any large pressure changes. The primary results of operating the SI pump were the two additional openings of the B SG safety valve. These openings of the valve will be discussed further in the next phase of the event. The depressurization associated with the RCP restart was limited to about 100 psi, apparently as a result of steam formation in the pressurizer (above the range of indicated levels) and increased SI flow.

4.2.3.8 Event Phase 8: Leaking Steam Generator Safety Valve (11:37 a.m. to 12:27 p.m.)

At 11:37 a.m., the B SG's safety valve opened for the fifth time, as a result of the continuing SI. The data indicated that the valve did not close until pressure in the SG decreased to 840 psig. This value is about the same as that for one of the earlier valve openings and is considerably below the pressure at which the valve would normally close. This abnormal behavior may again be attributed to the fact that the valve discharged liquid rather that the steam for which it had been designed.

After the B SG safety valve closed, the pressure differential between the RCS and the B SG was more than 100 psid.

Safety injection flow was terminated at about the same time as this last valve opened. However, the RCS to SG differential pressure was significantly higher than for the comparable conditions at 10:38 a.m. Three additional facts indicate that this phase is significantly different from earlier phases of the event. First, the reduction in B SG pressure at approximately 12:05 p.m., while the RCS pressure was more than 100 psi higher, cannot be explained unless there was significant mass or energy removal from the SG. Cooling of the B SG was in progress at this time; however, the observed rate would not support such a pressure difference. Second, the indicated differential pressure implies a large flow, estimated to be 100 to 200 gpm, into the SG over a long period of time (50 min.). Since the B SG appears to have been full at 11:37 a.m. (the time of the last valve opening), it appears very unlikely that the SG could accommodate an additional 5,000 to 10,000 gallons of water. Third, the rapid increase in B SG pressure at about 12:25 p.m. was similar to that experienced when the safety valve closed earlier in the event. These facts tend to conclude that it is very likely that the B SG safety valve failed to fully reseat following the opening at 11:37 p.m. and that the valve leaked at a rate of 100 to 200 gpm for approximately 50 min. This release rate is approximately two to four percent of the valve capacity and was probably not noticed by the plant staff because it’s noise and steam discharge were masked by the noise and steam from the nearby A SG atmospheric PORV. The mass balance also tends to support the position that the safety valve failed to properly reseat for 50 min.

At 11:52 a.m., the pressurizer level indication came back on scale. The estimated rate of leakage through the B SG safety valve and the continued plant cooldown would explain the return of the pressurizer level during the period when charging flow exceeded letdown. The maximum rate of decrease of the indicated pressurizer level agreed well with that predicted by calculations. Normal letdown had been restored at about 12:02 p.m. At about 12:12 p.m., one SI pump was restarted, apparently for the purpose of arresting the decrease in pressurizer level caused by continuing leak into the B SG. The SI pump was then operated intermittently to control pressurizer level throughout the remainder of this phase.

4.2.3.9 Event Phase 9: Leak Termination and Cooldown (12:27 p.m., 1/25/82 to 10:45 a.m., 1/26/82)

At about 12:25 p.m., the B SG safety valve appears to have seated. The SG indicated pressure then increased to a value slightly above the RCS pressure, and the RCS leak was terminated. At about 12:35 p.m., the SI pump was stopped; it was no longer needed to control pressurizer level.

The break flow was controlled by attempting to maintain the RCS pressure at about 25 psi below the B SG pressure during the RCS cooldown and depressurization. The B SG was, therefore, leaking water back into the RCS during this phase of the event. The B SG cooldown was being controlled by the heat transfer from it to the RCS.

After 12:27 p.m., the cooldown proceeded at a very slow rate, which allowed time for the RCS to be degassed before using the RHR system (the low pressure and low temperature decay heat removal system). During this phase of the event, the B SG water level indication came back on scale on the narrow-range instrument at approximately 6:40 p.m., January 25, 1982.

Estimated break flow for an indicated 25 psi differential pressure was calculated and found to be about four times larger than that expected based upon the rate of level decrease observed in the B SG. The rate of change of the B SG wide range water level indicating implies a 37 gpm leak rate. The return from being off-scale after seven hours of leakage back into the RCS implies approximately a 39 gpm leak rate. Considering the limited data available, these values are considered to be in good agreement.

Since the B SG pressure sensor is at an elevation approximately 60 ft above the elevation of the pressure sensor in the RCS loop and the SG was flooded with water, the actual pressure differential at the break would have been 28 psi greater than indicated. Therefore, an indicated SG pressure 25 psi greater than the RCS pressure would mean a break differential pressure of 53 psi, which would have supported a much larger leak rate of approximately 150 gpm. For the leak rate to have averaged 36 gpm, the pressure difference must have been less than three psi. After reviewing the reactor coolant loop pressure measurements and all three B SG pressure measurements for the cooldown phase, particularly the pressure oscillations occurring between 8:00 p.m. and 11:00 p.m., January 25 (see Figure 4.2-27), the reactor coolant loop pressure measurement was in error (too low) by approximately 50 psi. This error was recognized by the plant staff sometime during this phase and may have existed throughout the entire event, since a similar bias can be seen in the data at 9:26 a.m. An error of this magnitude is not surprising in a pressure instrument with a range of 0 to 3000 psig. (NOTE: A normal pressure instrument accuracy specification is one percent of full scale, which for this instrument is 30 psi).

The fact that the B SG pressure did not decrease to the saturation pressure corresponding to the temperature of the water being pumped through the SG tubes, indicates that thermal stratification existed in the generator and its attached main steam line. Thermal stratification is to be expected in a steam system which has been over filled, particularly for a design like that of Ginna in which the upper internals impede water volume communication and the steam line slopes downward toward the turbine and allows hot water to be trapped. This information, together with the information on the leak rate, indicates that the primary reasons for the slow depressurization of the B SG were (1) the extremely small pressure differential between the RCS and B SG, and (2) the thermal stratification of the water in the SG, which prevented complete cooling.

After 12:25 p.m., January 25 the flow through the ruptured tube was from the B SG into the RCS. Under this condition, there is concern for potential dilution of the boric acid in the RCS. The boron concentrations in the B SG and the RCS were checked before cooldown and depressurization began and at approximately half-hour intervals thereafter. The B SG samples indicated 1100 ppm boron. Because of the amount of boric acid injected into the RCS from the boric acid storage tanks and refueling water storage tank, there was never any potential for an inadvertent criticality (the boron concentration needed to maintain the required shutdown margin was approximately 700 ppm) because of boron dilution during this event.

At approximately 6:40 p.m., the B SG narrow-range water level indication was on-scale, and auxiliary feedwater was supplied for the first time since 9:32 a.m. This was done to assist in the cooldown of the B S/G and helped to degas it.

When the B SG was depressurized, a gas mixture was found that included hydrogen and gaseous fission products, such as xenon, both of which are normally found in the RCS. Some fission products are always found in PWRs. The presence of these non-condensable gases may have also contributed to the slow depressurization of the SG.

The RHR system was placed in service at about 7:00 a.m. on January 26, 1982. The plant staff chose to maintain system conditions without substantial RCS cooldown while the RCS was cleaned and degassed using the CVCS at a letdown rate of 50 to 60 gpm.

TABLE 4.2-1 Typical Sequence of Automatic Actions Following a Double-Ended SGTR

EVENT/SIGNAL	TIME (sec) OFFSITE POWER	TIME (sec) NO OFFSITE POWER
Tube Failure	0	0
Reactor Trip Signal	232	232
Loss of All A/C Power	—	232
Steam Dump Operation	233	—
Turbine Isolation	234	234
Safety Valve Operation	—	245
SI Signal	250	386
Main FW Isolation	257	393
AFW Actuation	310	446*

TABLE 4.2-2 GINNA System Parameters

Parameter	Value	Parameter	Value
General:		Auxiliary Feedwater:	
Licensed power	1520 MWt	Motor-driven	2
Plant capacity	490 MWe	capacity	200 gpm (ea)
Number of loops	2	start signals	lo-lo S/G level
Loop isolation valves	none		trip MF pumps
			SIS
Steam Generators:		Turbine-driven 1	
Secondary water volume:		capacity	400 gpm
full load	1681 cu ft	start signals	lo-lo level (both S/G's)
no load	2821 cu ft		Loss of Power
Level at full load	52%		(both 4kVbuses)
Level at no load	39%		
Secondary Steam Volume:		Standby AFW System	Manual
full load	2898 cu ft		
no load	1758 cu ft	MSIV Automatic Closure	
A S/G to MSIV	776 cu ft	Modes All Lines:	
B S/G to MSIV	1055 cu ft	(1) High-high steam flow,	
Steam Pressure at full load	755 psig	and SIS	3.6E6 lb/h
no load	1055 psig	(2) High steam flow, low	
Primary water volume	944 cu ft	Tavg and SIS	0.4E6 lb/h
U-tubes per S/G	3260	(3) High Containment	
Allowed leakage	0.1 gpm	Pressure	18.0 psig
S/G safety valves	4		
setpoints	1085 psig	MSIV closure time	1.0 sec.
3 at	1140 psig		
Flow rate each S/G	3.3E6 lb/h	Charging System :	
at 1100 psig	0.82E6 lb/h	Number of pumps	3
PORV's each S/G	1	Type	Pos. Disp.
operation	auto at > 1050	Design flow ea.	60 gpm
	psig or manual	Normal Charging Flow	30 gpm
capacity	10 % power	Normal Letdown Flow	40 gpm
		Normal RCP seal supply	16 gpm
Steam Dump Bypass:		Normal RCP seal return	6 gpm
modes	T_{avg}-T_{ref}	Automatic letdown isolation	Low Pzr Pressure
	Steam Pressure	Automatic Trip	Safety Injection
capacity	40 %		

TABLE 4.2-2 GINNA System Parameters (Continued)

Parameter	Value	Parameter	Value
Reactor Coolant System:		High Pressure Safety Injection	
Total Volume	6245 cu ft	Number of pumps	2
Total RCS Flow	64.3E6 lb/h	Type	Centrifugal
RCP thermal output	30E6 btu/h	Design flow	300 gpm
Tavg at full load	573°F	Shut-off pressure	1520 psig
		Boron Injection with SIS	Initially from BAST
no load	547°F		then RWST
Reactor vessel head temp.	590°F	Accumulators	
Nominal system pressure	2200 psig	Number	2
low pressure scram Setpoint	1873 psig	Pressure	700 psig
Pressurizer:		Refueling Water Storage Tank	
Total Volume	800 cu ft	Capacity	3.38E5 gal
Water volume@ full load	480 cu ft	Boron concentration	>2000 ppm
Total heater Capacity	800 kW	Design Pressure	121 psig
Spray nozzle ΔT Limit	320°F		
		Boric Acid Storage Tank	
Pressurizer PORV's		Number	2
Number	2	Capacity, ea	3600 gal
Set pressure	2335 psig	Boron concentration	20,000 ppm
Flow rate	1.79E6 lb/h		
		Main Feedwater Pumps	
Pressurizer Relief Tank		Number	2
Rupture Disc Design	100 psig	Type	Centrifugal
Capacity	800 cu ft	Capacity, ea	50% of FP
		Flow rate, ea	14,000 gpm
Pressurizer Safety Valves		Operating pressure	853 psig
Number	2	Shut-off head	1180 psig
Operating Pressure	2485 psig	Drives	Electric
Flow rate @ 2500 psig	0.228E6 lb/h		
		Isolation Signals	
Pressurizer Level			
		S/G high level	67 %
Full Load	47 %	SIS	
No Load	22 %		
		Trips	
Safety Injection Actuation Setpoints			
Low Pressurizer Pressure	1723 psig	1. Loss of Offsite Power	
High Containment Pressure	4 psig	2. Overcurrent	
Low Steamline Pressure	514 psig	3. Thermal Reload	

TABLE 4.2-3 GINNA Event Chronology

Time and Event	Comment
January 25, 1982	
9:22 a.m.	
Initial conditions: plant power, 100%; indicated reactor coolant system (RCS) loop pressure, 2197 psig; indicated RCS loop average temperature, 572°F; indicated pressurizer pressure, 2235 psig; other primary secondary parameters normal; primary-to-secondary leak rate, 0 gpm.	The primary-to-secondary leak rate was last calculated based on air ejector monitor indications on January 7, 1982. Air ejector radiation monitor indications had been essentially constant since January 24, 1982. No known plant operations that would have caused or affected the event were in progress.
9:25 a.m.	
The following alarms were received in the control room: charging pump speed alarm; B steam generator level deviation alarm; B steam generator steam-flow/feed-flow mismatch alarm; pressurizer level and pressure deviation alarms; air ejector radiation monitor (R-15) alarm; pressurizer low pressure alarm (Setpoint, 2185 psig).	First indications of the tube rupture in B steam generator. One charging pump, which was in automatic pressurizer level control, was now at its maximum speed. The speed of a second charging pump, which had been on manual control, was increased by the operator. The third charging pump was not operating.
9:26 a.m.	
The Shift Supervisor ordered power reduction. One operator fast closed the turbine control valves; another operator commenced normal boration.	The Shift Supervisor was initially in his office which was located off the main operating area of the control room. He was called to the control room by an operator after the first alarm annunciated.
The following alarms were received in the control room: reactor coolant loop low pressure alarm (set-point, 2064 psig); over temperature ΔT turbine runback because of decreasing pressurizer pressure; main steam dumps armed alarm.	The over temperature AT Setpoint is a computed value which is a function of pressurizer pressure and reactor coolant system average temperature.
9:27 a.m. (about)	
All eight main steam dump valves opened automatically.	Steam dump valves opened in automatic control in response to error signal derived from the difference between RCS coolant reference and average temperature.
The third charging pump was manually started by the operator.	All three charging pumps were running at this time. The RCS pressure and pressurizer level decreased as a result of flow through the rupture (break flow). The rate of indicated decrease was consistent with the break flow and the combined effects of high charging flow and the RCS swell from the turbine down-power transient.

TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
The containment fan-cooler, service-water discharge radiation monitor (R-16) alarmed.	Alarm probably resulted from the proximity of the instrument to the B main steam line in the Intermediate Building.
9:28 a.m.	
Four main steam dump valves closed automatically.	
The following also occurred: pressurizer level low alarm (Setpoint, 10.5%); automatic reactor trip on low pressurizer pressure (Setpoint 1873 psig adjusted by a rate factor); automatic safety injection as a result of safety injection actuation; main turbine automatic trip on reactor trip; A and B steam generator low level alarms; automatic start of both A and B motor-driven auxiliary feed pumps on safety injection; main feedwater automatic isolation and main feedwater pump automatic trip on containment isolation.	The steam generator low levels resulted from the combined effects of the power reduction, reactor, main turbine and main feedwater pump trips. The RCS depressurization rate increased at this time. The break flow had not increased, but the effects of increasing RCS temperature due to the turbine load reduction were no longer present. Further, all charging pumps automatically tripped as a result of safety injection actuation. Letdown isolation valve LCV427 closed on low pressurizer level; the in-service orifice isolation valve closed on interlock with LCV427 controls. The reactor coolant pump (RCP) seal return line isolated on containment isolation. Leakage through the RCP seals pressurized the seal return piping. As shown by pressurizer relief tank (PRT) level indication, the seal return relief lifted. The contribution of this relief to PRT inventory was insignificant.
9:29 a.m.	
The main electrical generator output breakers automatically tripped.	
Both RCPs were manually tripped. Pressurizer level indicated about 0%.	Ginna Emergency Procedures E-1 .1 and E- 1.4 require tripping RCPs at <1715 psig; Westinghouse Owners' Group guidance recommends a lower trip pressure. Licensee requires an RCP trip at a higher pressure because Ginna lacks an environmentally qualified pressure instrument capable of reading these lower pressures.

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TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
9:29 a.m. (about)	
Both steam supply valves to the turbine-driven auxiliary feedwater pump opened automatically because of low-low level in both steam generators.	
9:30 a.m.	
Four main steam dump valves closed automatically.	All steam dumps were now closed.
Initial RCS depressurization stopped at about 1200 psig.	Based on post-event data evaluation, the Task Force concluded a steam bubble may have formed in the reactor vessel upper head at this time. Termination of pressure drop was apparently due to the effects of the establishment of saturation conditions in the reactor vessel upper head along with safety injection.
9:32 a.m. (about)	
The B motor-driven auxiliary feedwater pump was secured manually.	
The B steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually	The turbine-driven auxiliary feedwater pump was now being supplied steam from the A steam generator only.
9:33 a.m.	
The Shift Supervisor notified the NRC Operations Center via the Emergency Notification System (ENS) phone. The Shift Supervisor reported a reactor trip from 100% power as a result of a steam generator tube rupture. The identity of the ruptured steam generator and release information was not given at this time.	The Shift Supervisor made the ENS report using the ENS phone in his office. He suspected that the B steam generator contained the fault but chose to confirm the situation before identifying the faulted steam generator to the NRC. After the initial report, a licensed reactor operator, who was not part of the on-shift crew, manned the ENS in the control room.
The Shift Supervisor declared an Unusual Event.	The Shift Supervisor declared the Unusual Event during his discussion with the NRC Headquarters Duty Officer; the Plant Superintendent was unaware of this declaration. The declaration of an Unusual Event was made in accordance with the Ginna Emergency Plan Implementing Procedures.

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TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
9:38 a.m.	
Various main steam dump valves began to cycle open and closed.	Main steam dump valves were now being operated in the pressure-control mode. The operator was manually controlling these valves to cause a plant cooldown as required by the steam generator tube rupture procedure.
9:40 a.m.	
The B main steam isolation valve (MSIV) was manually closed and the B steam generator was isolated as required by the steam generator tube rupture (SGTR) procedure. Plant cooldown was being maintained by dumping steam from A steam generator to the main condenser. The licensee declared an Alert.	Along with closing the MSIV, B steam generator isolation included automatic closure of the feedwater supply, blow down and sample valves on containment isolation, manual closure of its auxiliary feedwater supply, and manual closure of the steam supply valve from B steam generator to the turbine-driven auxiliary feedwater pump. RCS pressure and reactor vessel upper head temperature data indicated that the steam bubble in the reactor vessel upper head had been essentially collapsed by safety injection flow.
9:46 a.m.	
The A steam supply valve to the turbine-driven auxiliary feedwater pump was closed manually.	The turbine-driven auxiliary feedwater pump was now secured.
9:48 a.m.	
The A motor-driven auxiliary feedwater pump was manually stopped to control A steam generator level.	No feedwater pumps were operating at this time.
9:50 a.m.	
The steam generator blow down radiation monitor (R-19) alarmed.	R-19 monitors radiation levels on a section of the blow down system piping common to both A and B steam generators. The alarm at this time may have been caused by activity from the B steam generator spreading through the system because of steam generator sample valves that the licensee indicated had a history of leaking.

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TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
9:53 a.m. The B steam generator power-operated relief valve (PORV) was manually isolated by an auxiliary operator closing a local, upstream, manual valve.	Operators stated that they manually isolated the B steam generator atmospheric PORV to minimize the potential for a release that would result from high steam generator pressure lifting the PORV. The control room operators interpreted the step in the tube rupture procedure which directed them to place the PORV in the manual closed position to mean that the local manual PORV isolation valve should be closed. Closing this isolation valve made the PORV unavailable for use in reducing B steam generator pressure and resulted in five challenges to an unisolable steam generator safety valve.
9:55 a.m. B steam generator narrow-range level indicated off-scale high even though all feedwater supplies to the B steam generator had been isolated earlier in the event.	
9:57 a.m. Safety injection initiation circuitry was manually reset; containment isolation was then reset.	Safety injection was reset to permit resetting of the containment isolation signal. Containment isolation was reset to permit restoration of instrument air to the containment. Instrument air would be required to operate various valves inside containment, including the pressurizer power-operated relief valves.
9:59 a.m. (about) Instrument air was restored to containment.	Because letdown isolation valve LCV427 fails open on loss of instrument air pressure, it could have opened subsequent to containment isolation. If LCV427 had opened, restoration of instrument air would have caused it to close at this time.
10:00 a.m. A and C condensate pumps were manually stopped.	The B condensate pump was still running.
10:03 a.m. All main steam dump valves were now closed.	
10:04 a.m. One charging pump was manually restarted.	

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TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
10:07 a.m.	
As directed by the SGTR procedure, pressurizer PORV PCV430 controls were manually cycled open and closed twice from the control room. RCS pressure, PRT pressure, level and temperature and PORV valve position indication in the control room demonstrated the valve successfully operated.	Shortly after the PORV was operated, pressurizer level increased above the letdown isolation setpoint. Letdown isolation valve LCV427 and the selected letdown orifice isolation valve then opened. This resulting in lifting the letdown relief valve and adding water to the PRT. The Task Force determined the letdown relief valve was the major contributor to the PRT water level increase
10:08 a.m.	
Pressurizer PORV PCV430 controls were manually cycled again from the control room and the valve successfully operated.	
10:09 a.m.	
Pressurizer PORV PCV430 controls were manually cycled again. The valve opened as desired. After the operator placed the controls in the closed position, the valve started to close but then reopened and stuck open. The operator placed the PORV block valve control switch in the closed position. RCS pressure dropped to about 900 psig; pressurizer level increased rapidly. The pressurizer relief tank (PRT) high-pressure alarm was received in the control room.	The rapid rise in pressurizer level exceeded that attributable to safety injection and charging flow and was the first clear indication to the control room staff that a steam bubble had formed in the reactor vessel upper head. This was, in fact, the second time a steam bubble had formed in the upper head region. The bubble grew as RCS pressure dropped.
10:10 a.m.	
The PRT high-temperature alarm was received in the control room.	
10:11 a.m.	
PORV block valve PCV516 indicated fully closed; pressurizer level indicated	Operator also closed block valve PCV515 to isolate the other pressurizer PORV, PCV431C.
10:17 a.m.	
The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	

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TABLE 4.2-3 GINNA Event Chronology (continued)	
Time and Event	Comment
10:19 a.m. (about)	
One B steam generator safety valve lifted and closed.	Safety injection and charging flow maintained RCS pressure greater than B steam generator pressure, resulting in continued RCS in-leakage into the ruptured steam generator. RCS pressure exceeded the lowest setpoint of the B steam generator safety valves (nominally, 1085 psig). The B steam generator safety valve may have closed and then started to leak steam after this first opening.
10:26 a.m.	
The PRT high level alarm was received in the control room.	
10:28 a.m. (about)	
One B steam generator safety valve lifted and closed.	The B steam generator safety valve position recorder failed to indicate this or subsequent safety valve lifts. The operators heard these lifts from the control room and estimated their duration based on aural information.
10:29 a.m.	
The A motor-driven auxiliary feedwater pump was manually stopped.	
10:38 a.m. (about)	
One B steam generator safety valve lifted and closed.	
Safety injection was terminated by the operators to prevent further release through the B steam generator safety valve.	Charging flow was maintained.
10:40 a.m.	
The B condensate pump and the condensate system were secured; the air ejector secured automatically following loss of condensate flow. The A steam generator PORV was manually throttled open to continue the plant cooldown by relieving the A steam generator to atmosphere.	The licensee secured the condensate system to minimize the spread of radioactive contamination to the condensate storage tanks (CSTs) and the condensate demineralizer system. Securing the condensate system made the main condenser unavailable.
10:42 a.m. (about)	
A second charging pump was started.	
The pressurizer heaters were re-energized to establish a steam bubble in the pressurizer.	The pressurizer heaters tripped on low pressurizer level during the initial depressurization.

TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
10:44 a.m. The licensee declared a Site Area Emergency and executed a site evacuation .	Nonessential personnel were evacuated to the licensee's training center which was downwind of the plant and within the path of the release plume.
10:52 a.m. (about) The PRT rupture disc ruptured, releasing water to the A containment sump.	The disc ruptured primarily because of the letdown relief flow; pressurizer PORV openings and RCP seal return relief were minor contributors to the PRT level transient which finally caused the disc rupture.
10:59 a.m. The A motor-driven auxiliary feedwater pump was manually started to feed the A steam generator.	From this time in the event, until the plant was cooling down on the residual heat removal system, the A motor-driven auxiliary feedwater pump was run intermittently to control A steam generator water level.
11:07 a.m. (about) One safety injection pump was manually restarted from the control room. The safety injection pump discharge valve was locally throttled to prevent B steam generator safety valve lifts.	The safety injection pump was started in anticipation of an RCS pressure drop that might result from restarting an RCP. This action was not required by the SGTR procedure but was taken as a direct result of the inability to reestablish normal pressurizer pressure control.
11:19 a.m. (about) One B steam generator safety valve lifted and closed. The process computer failed. It remained out of service until about 11:35 a.m.	The licensee manually read reactor vessel upper head and core exist thermocouples to verify adequate core cooling and to determine subcooling in the core and reactor vessel upper head. Any remaining steam bubble in the reactor vessel upper head region, at this time, would have had a volume of less than 300 ft^3.
11:21 a.m. (about) The A RCP was restarted; reactor vessel upper head thermocouple temperatures approached core exit temperatures; pressurizer level indications remained off-scale high. One charging pump was stopped.	A steam bubble in the reactor vessel upper head region would have been condensed by the cooler loop water now forced into this region. Since the pressurizer level instruments were calibrated for operating conditions, the actual pressurizer level would have to drop below 80% before indicated level would respond. The pressurizer volume above 80% actual level is approximately 200 ft^3.

TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
11:37 a.m. (about)	
One B steam generator safety valve lifted and closed; the safety injection pump was stopped.	Based on the indicated pressure differential between the RCS and the B steam generator, and on an RCS inventory balance calculation, the Task Force determined the safety valve failed to fully reseat. It remained partially open until about 12:25 p.m., leaking water at a rate estimated to be about 100 gpm.
11:43 a.m. (about)	
The plant vent particulate radiation monitor (R-13) and the plant iodine monitor (R-10B) alarmed.	The licensee stated that the R-l3 and R-10B monitor alarms were probably caused either by increased background radiation in the vicinity of these monitors or by the Auxiliary Building ventilation system drawing outside air into the building after the steam generator safety valve lifts. It should be noted that no plant noble gas radiation monitor (R-14) alarm was received at this time. The reason this alarm did not occur has not been determined.
11:52 a.m.	
Pressurizer level indications returned on scale; a steam bubble had been reestablished in the pressurizer.	The maximum rate of change of pressurizer level indication, which occurred about 12:10 p.m., agreed well with that predicted by analysis of the effects of the existing cooldown, charging and letdown rates and the break flow predicted by the Task Force model.
12:02 p.m.	
Normal letdown was restored.	
12:12 p.m. (about)	
One safety injection pump was started from the control room.	The safety injection was restarted to terminate the rapid decrease in pressurizer level. The pump was operated intermittently over the next 23 minutes to control pressurizer level.
12:27 p.m.	
The RCS and B steam generator indicated pressures equalized.	The B steam generator pressure trend indicated that the B steam generator safety valve reseated completely.
12:34 p.m. (about)	
The RCP seal water return isolation valve was manually opened.	RCP seal return relief reseated at this time.

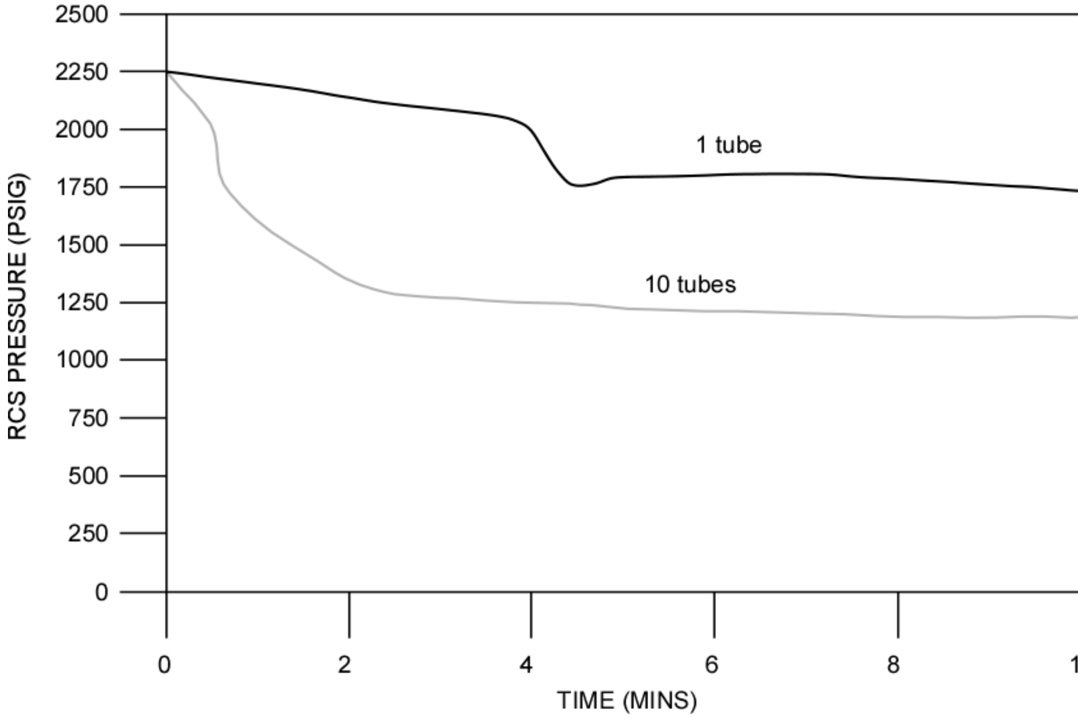
TABLE 4.2-3 GINNA Event Chronology (continued)	
Time and Event	Comment
12:35 p.m. (about) Intermittent operation of the safety injection pump was stopped.	
1:16 p.m. The A MSIV was manually closed.	
2:00 p.m. The licensee reported containment sump A level as 9.3 feet (approx. 8000 gallons); PRT level at 92%.	Containment sump A has two channels of level indication. Channel I indicated *5.3* feet (1,900 gallons); channel 2 indicated 9.3 feet (8,000 gallons). Later, it was discovered that channel 2 was in error.
6:40 p.m. (about) Narrow-range water level indication for the B steam generator returned to the indicating range. Plant cooldown continued via the A steam generator PORV with the A RCP providing flow through the A loop and back flow through the B loop. The operators maintained indicated RCS pressure 25 psi below B steam generator pressure. The B steam generator was being cooled by intermittently feeding it with auxiliary feedwater while bleeding it via the ruptured tube to the RCS.	The plant staff was concerned that water in the B main steam line might flash to steam if the steam generator was cooled and depressurized too quickly. Flashing in the main steam lines could have caused a water hammer, which could have over stressed the main steam line hangers. Therefore, the plant staff decided to pin these hangers and to conduct a slow cooldown. Because of an instrument calibration error in the RCS loop pressure instrument, the actual RCS-to-B steam generator pressure differential was about 3 psi and very little steam generator-to-RCS flow existed. To provide warning of excessive boron dilution in the RCS as a result of the B steam generator feed-and-bleed process, the plant staff sampled the RCS for boron concentration at half-hour intervals. The feed-and-bleed cooldown process caused the level in the CVCS Holdup Tanks to increase and the plant staff discussed the consequences of these tanks filling. The capacity of these tanks was not approached.
7:04 p.m. An operator again attempted to shut pressurizer PORV PCV430; the valve remained open.	
7:17 p.m. The licensee downgraded the Site Area Emergency to an Alert.	

TABLE 4.2-3 GINNA Event Chronology (continued)

Time and Event	Comment
January 26, 1982	
7:00 a.m. (about)	
The residual heat removal (RHR) system was placed in service to continue the plant cooldown. The A RCP remained in operation.	The RCP remained in operation to assist in RCS degasification and cleanup in preparation for opening the primary-side man-way on B steam generator. At low steam pressures in the A steam generator, the capacity of the A steam generator PORV had limited the plant cooldown rate.
10:45 a.m.	
The licensee downgraded the Alert to the Recovery Phase.	

TABLE 4.2-4 SGTR Accidents at Pressurized Water Reactors			
Plant	**Date**	**Leak Rate** (gpm)	**Cause**
Point Beach Unit 1	February 26, 1975	125	wastage
Surry Unit 2	September 15, 1976	330	PWSCC in U-bend
Doel Unit 2	June 25, 1979	135	PWSCC in U-bend
Prairie Island 1	October 2, 1979	390	loose parts
Ginna Unit 1	January 25, 1982	760	loose parts and tube wear
Fort Calhoun	May 16, 1984	112	ODSCC at a crevice
North Anna Unit 1	July 15, 1987	637	high cycle fatigue in a U-bend
McGuire Unit 1	March 7, 1989	500	ODSCC in the free span
Mihama Unit 2	February 9, 1991	700	high cycle fatigue
Palo Verde Unit 2	March 14, 1993	240	ODSCC
Indian Point Unit 2	February 15, 2000	150	PWSCC in U-bend

Figure 4.2-1 Closeup View of SGTR



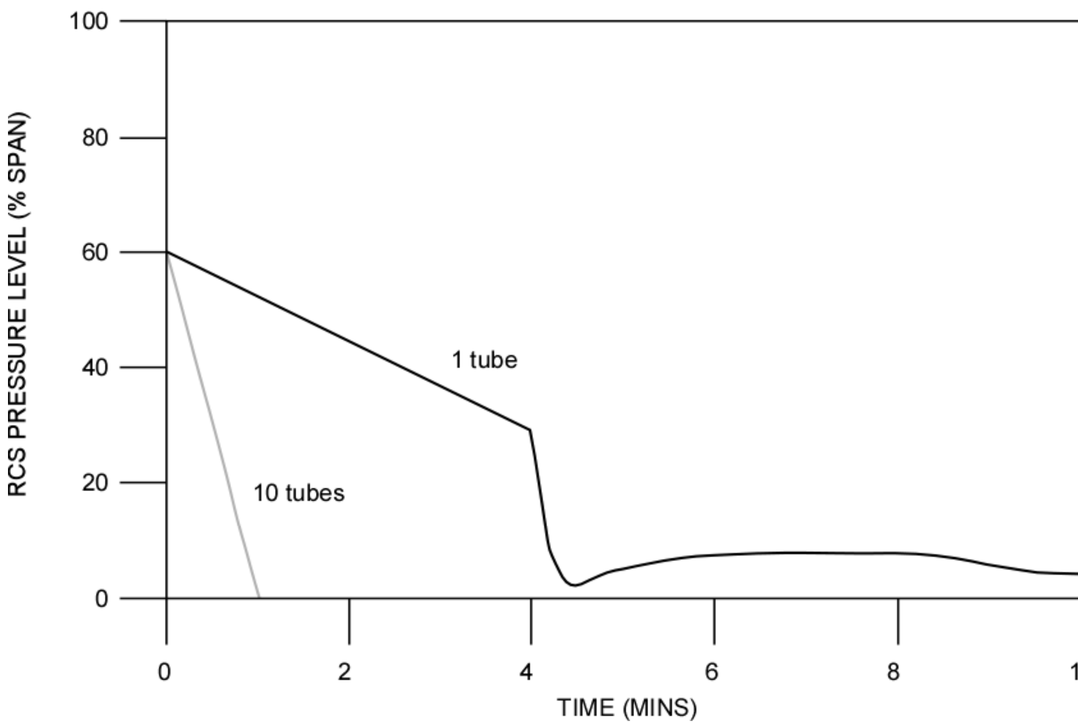


Figure 4.2-2 Initial Pressurizer Pressure and Level Response

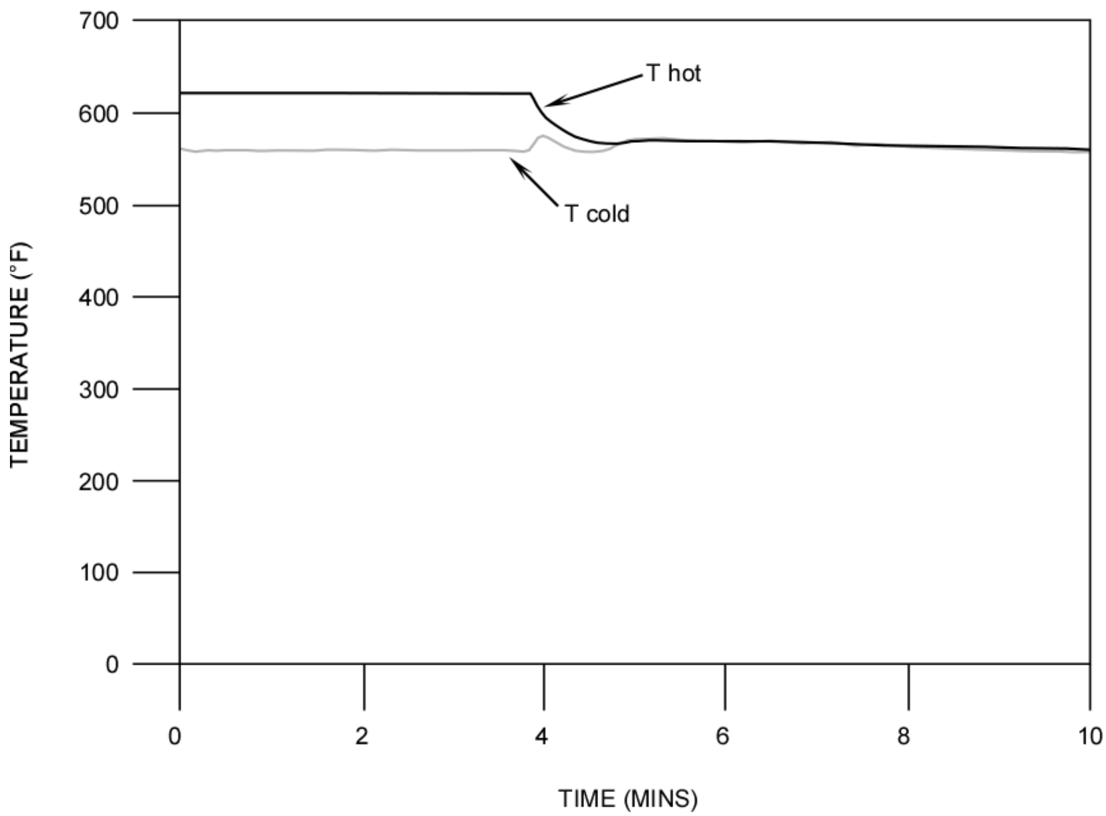


Figure 4.2-3 RCS Temperature Following Reactor Trip

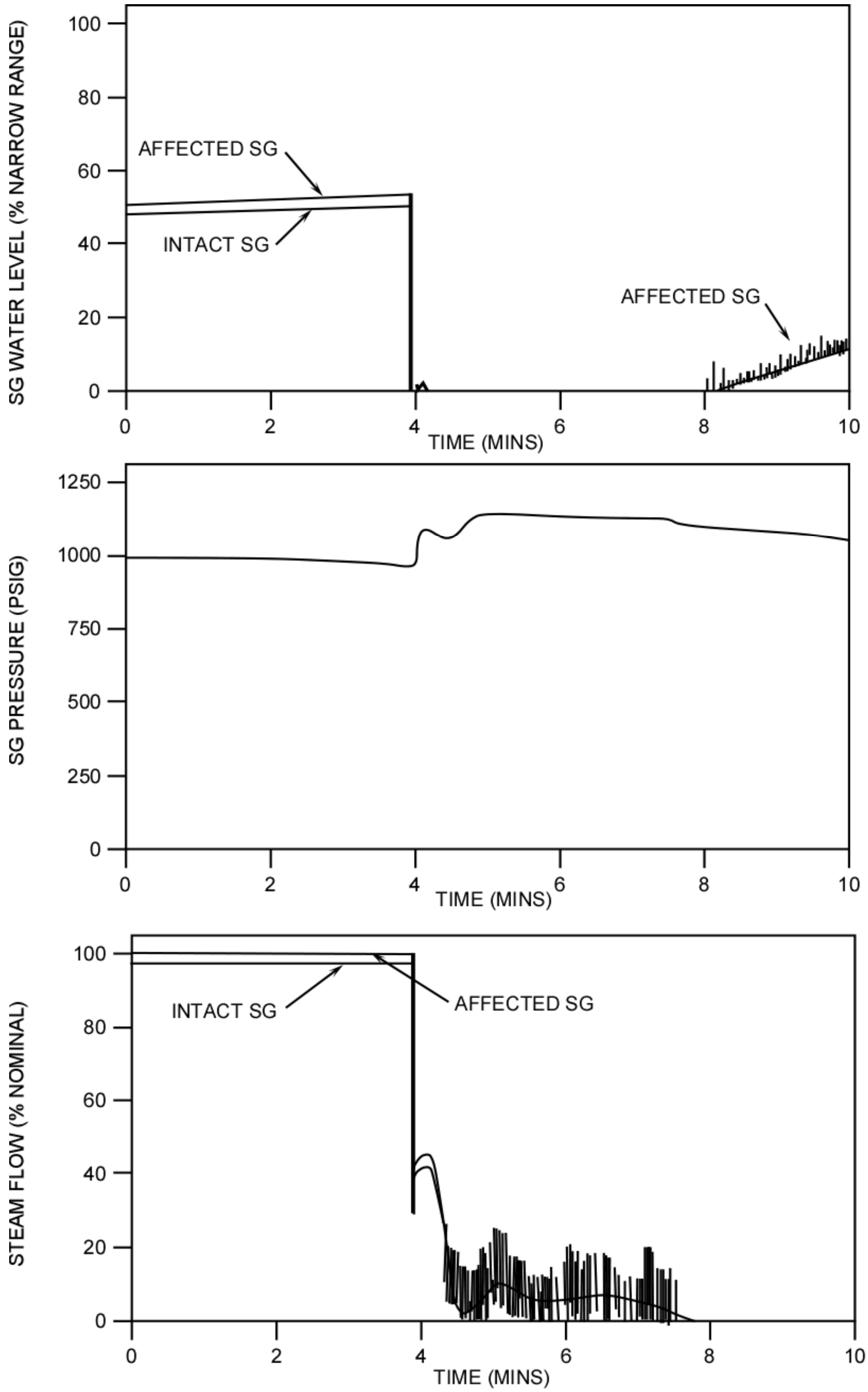


Figure 4.2-4 Steam Generator Response Following Reactor Trip

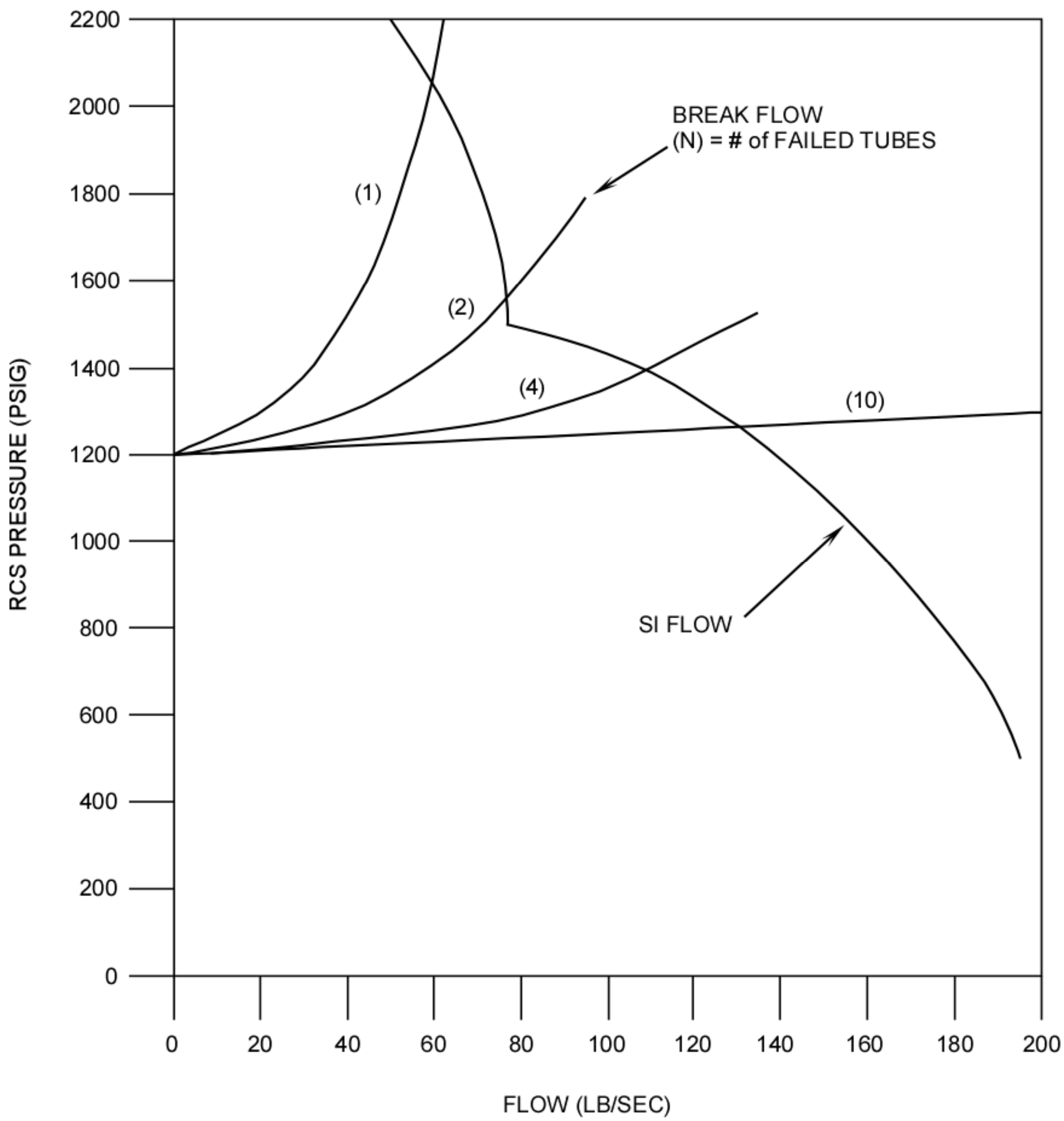
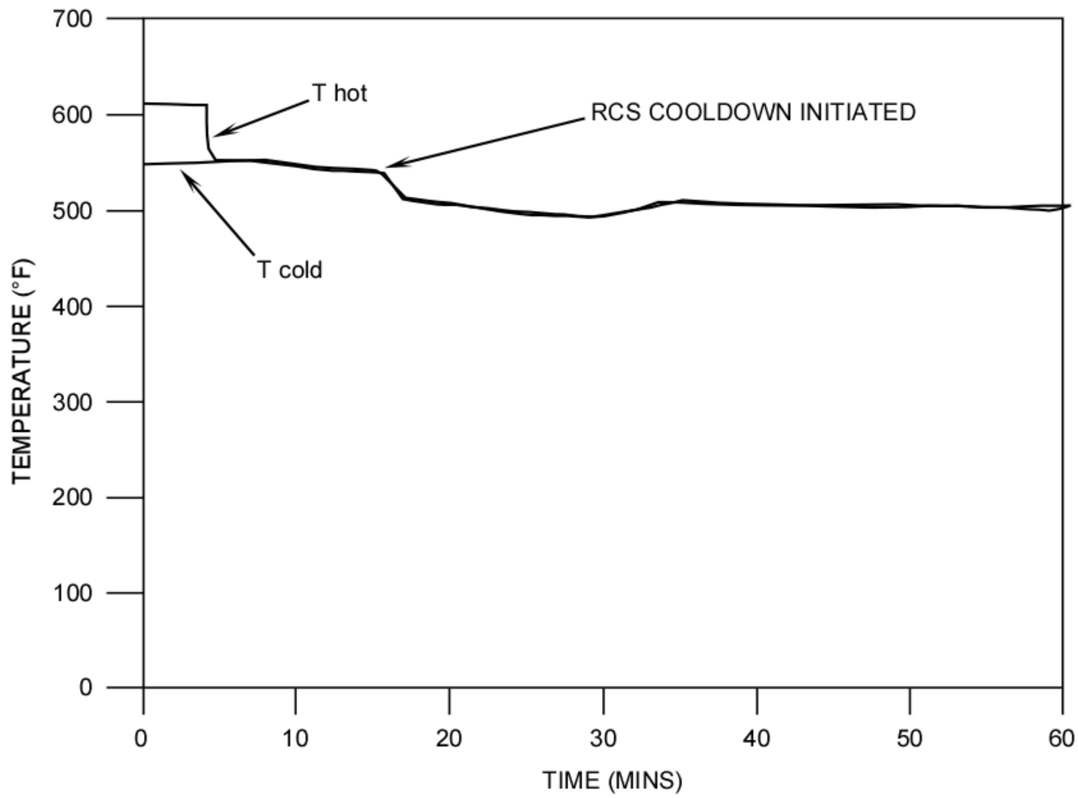


Figure 4.2-5 Equilibrium Break Flow



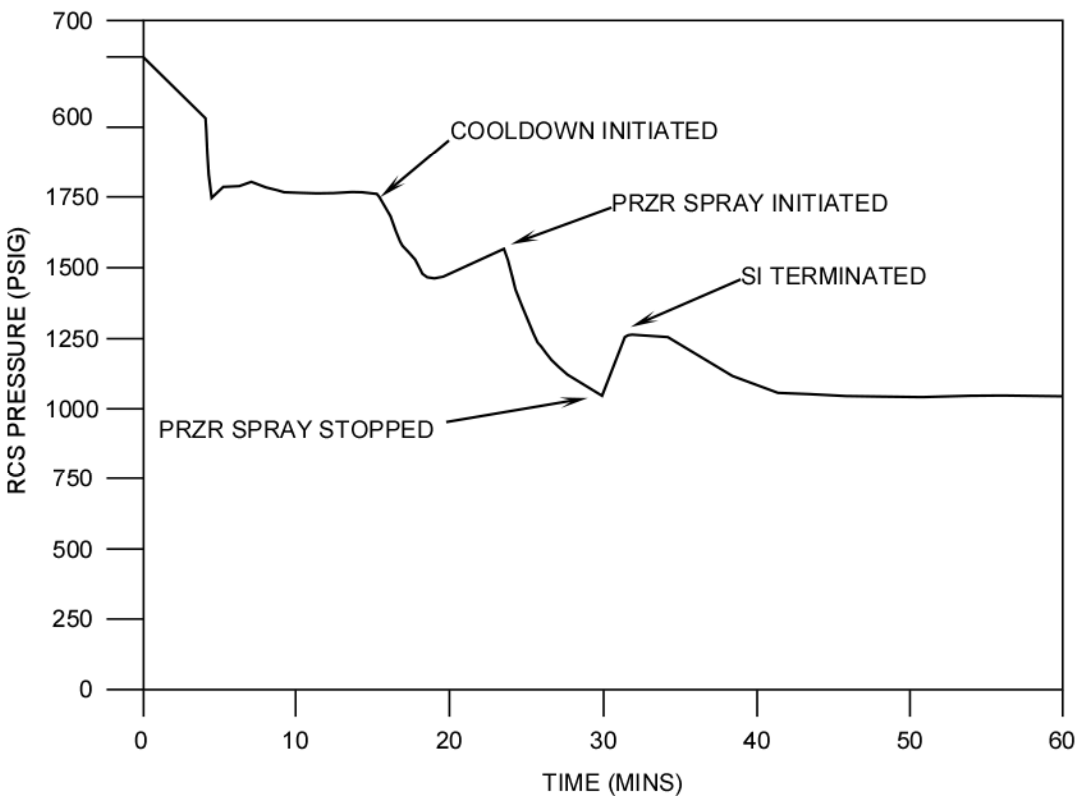
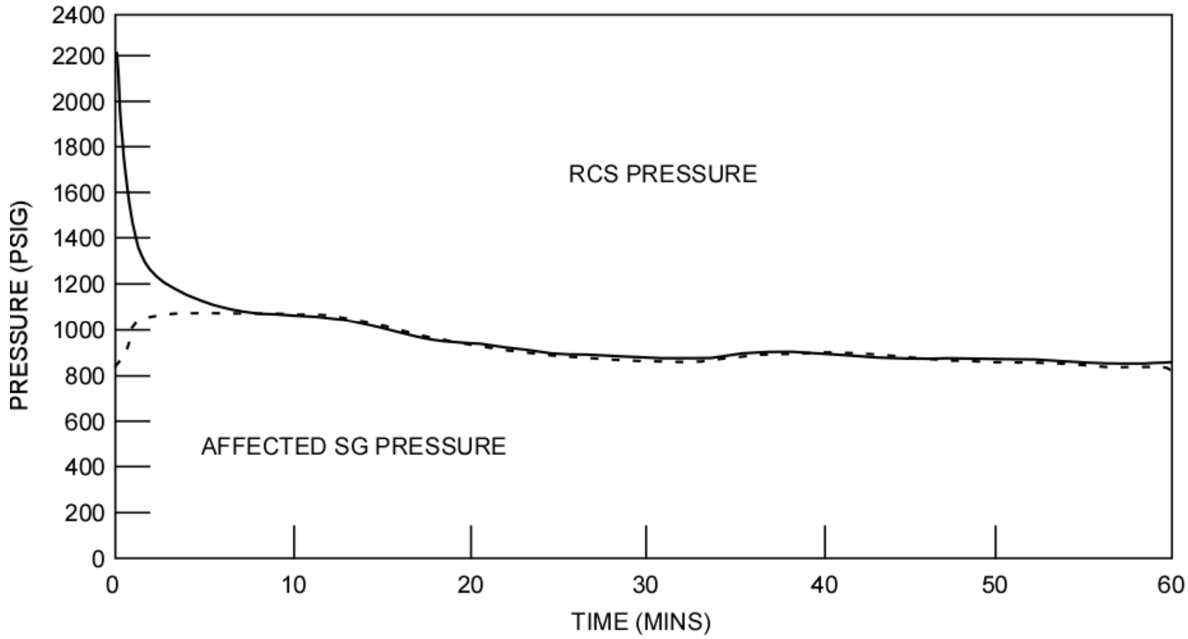


Figure 4.2-6 RCS Response – Offsite Power Available



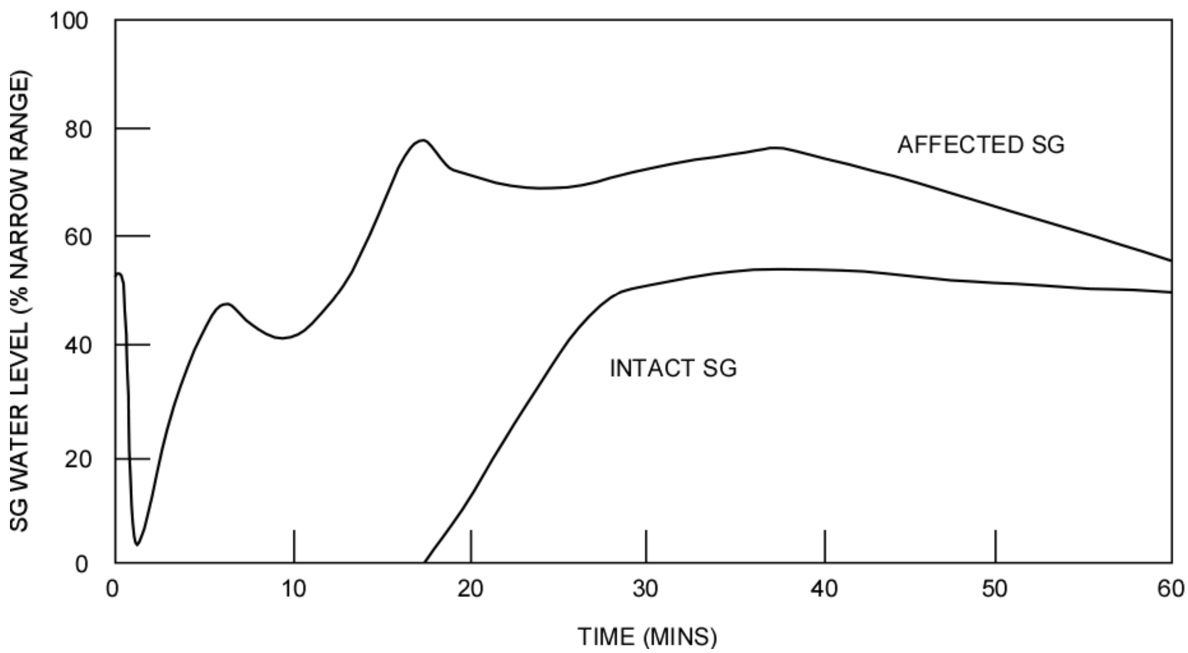


Figure 4.2-7 Multiple Tube Failure Response

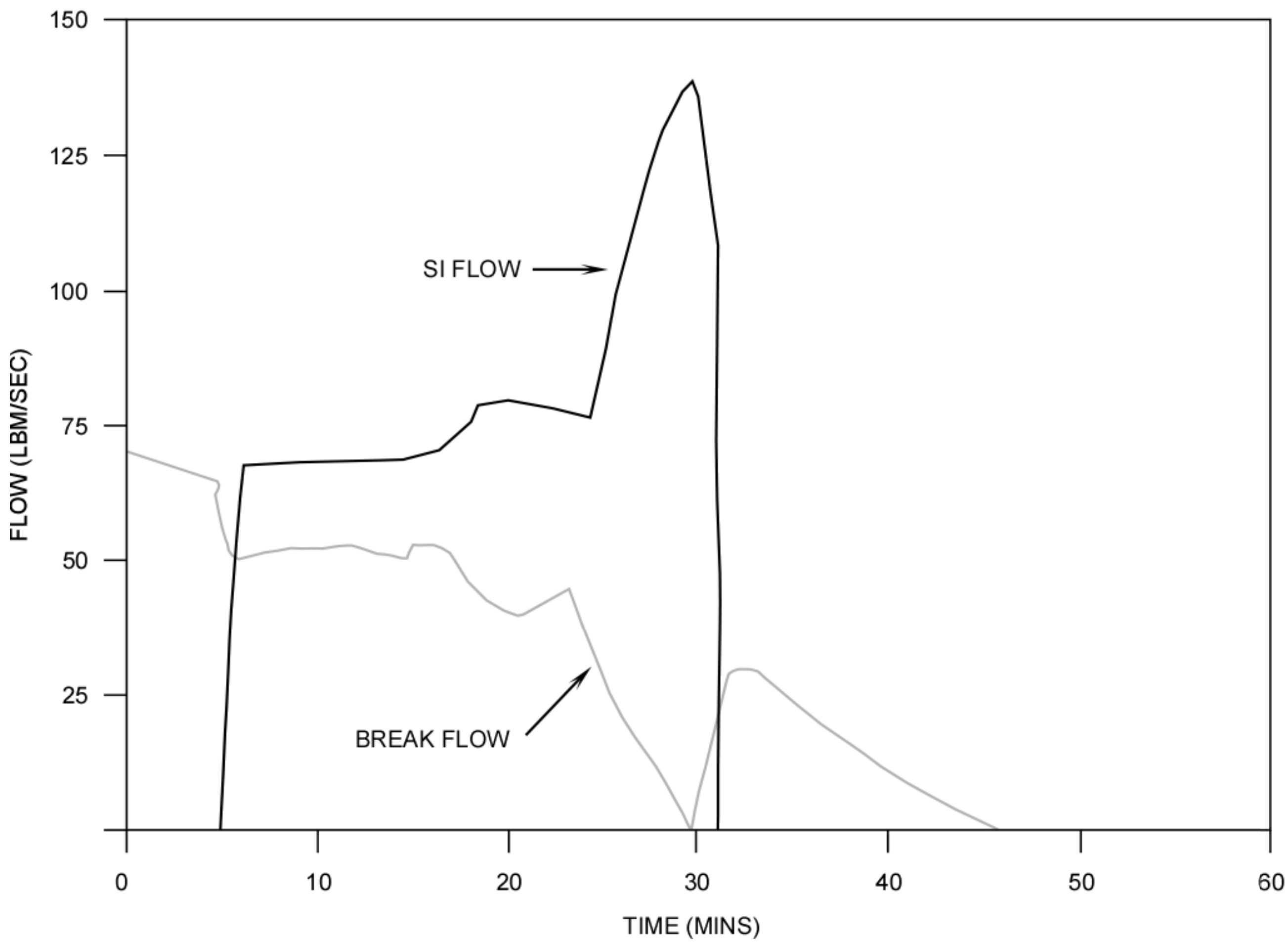


Figure 4.2-8 SI Flow and Break Flow

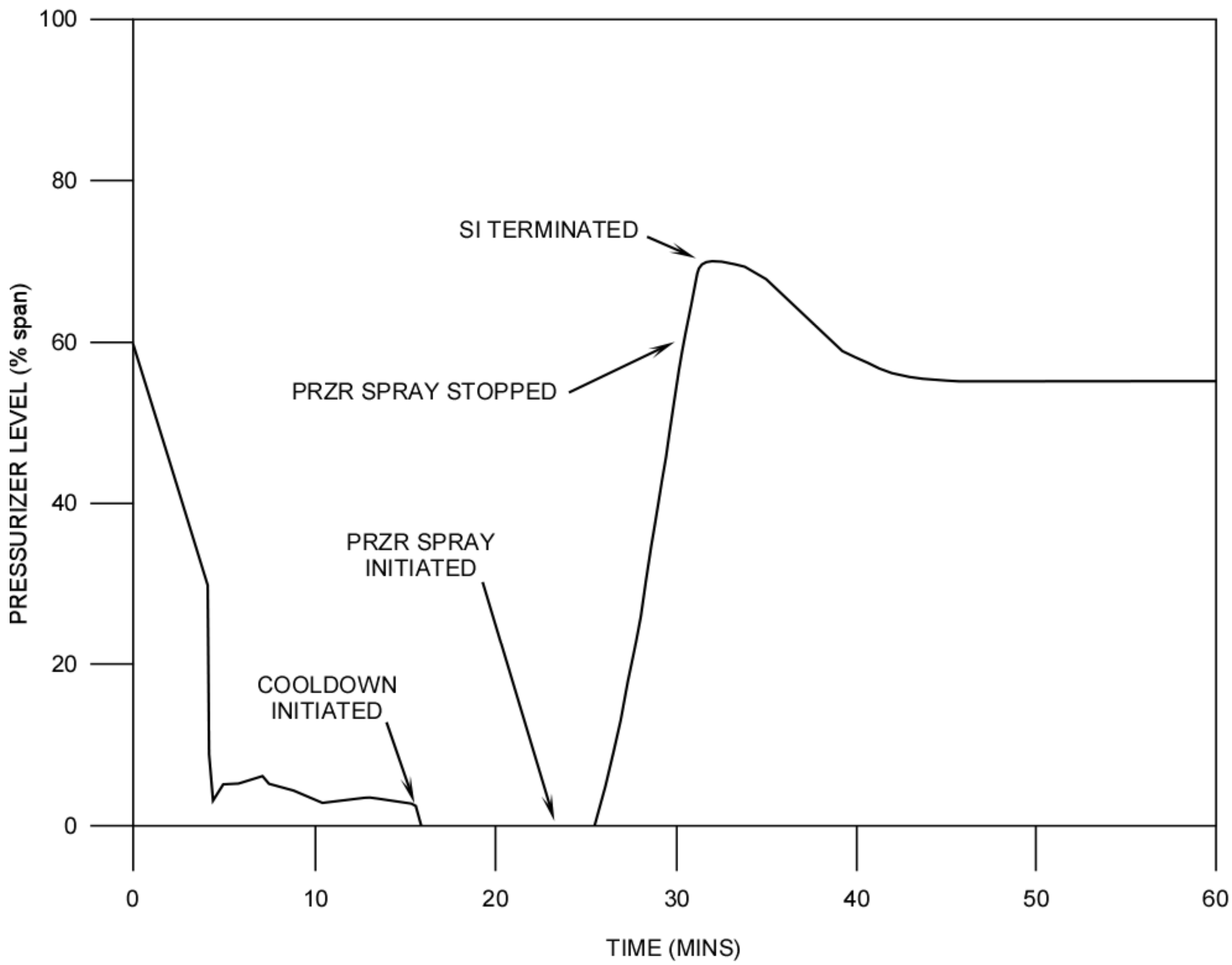


Figure 4.2-9 Pressurizer Level Response – Offsite Power Available

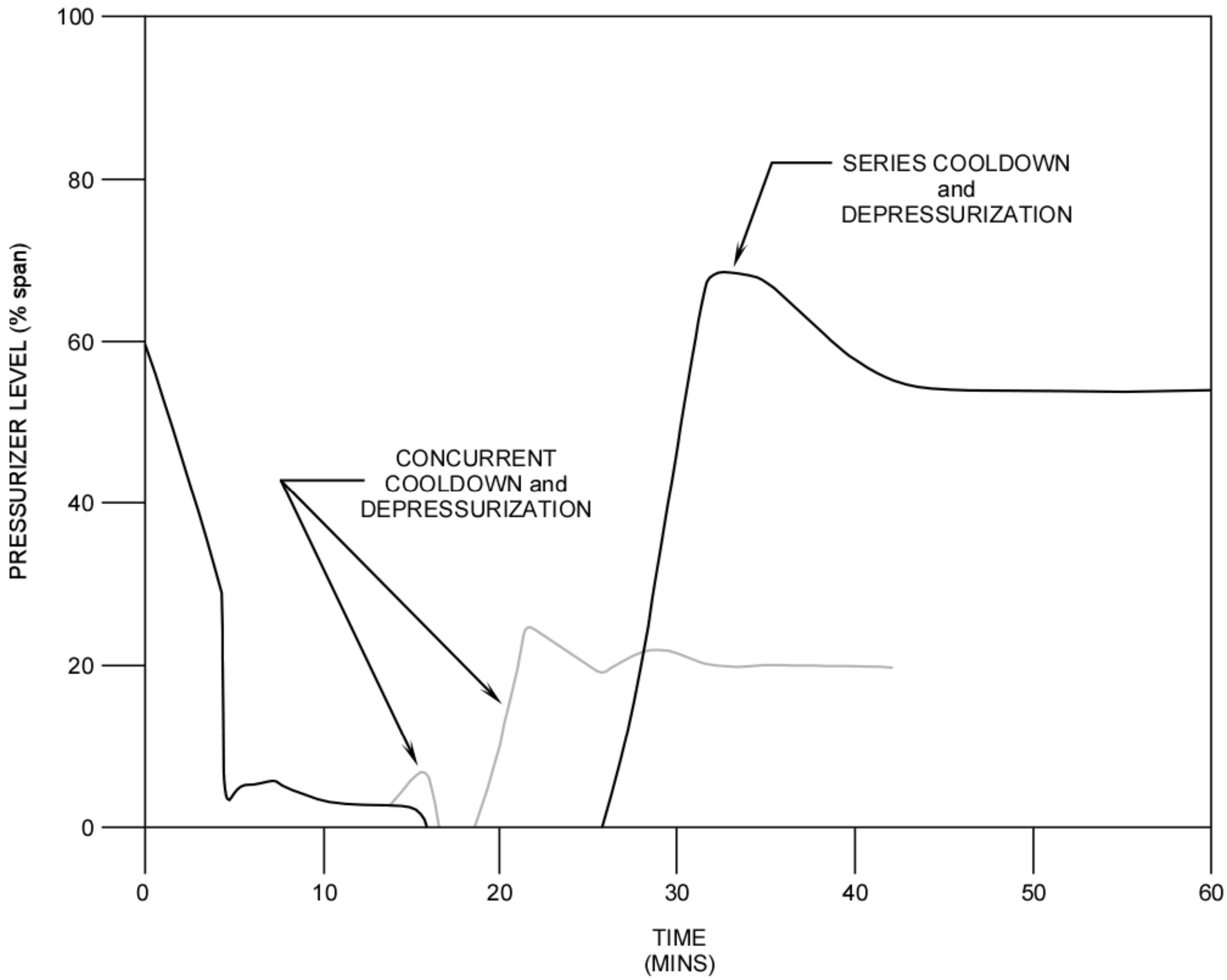


Figure 4.2-10 Pressurizer Level Response – RCS Cooldown and Depressurization

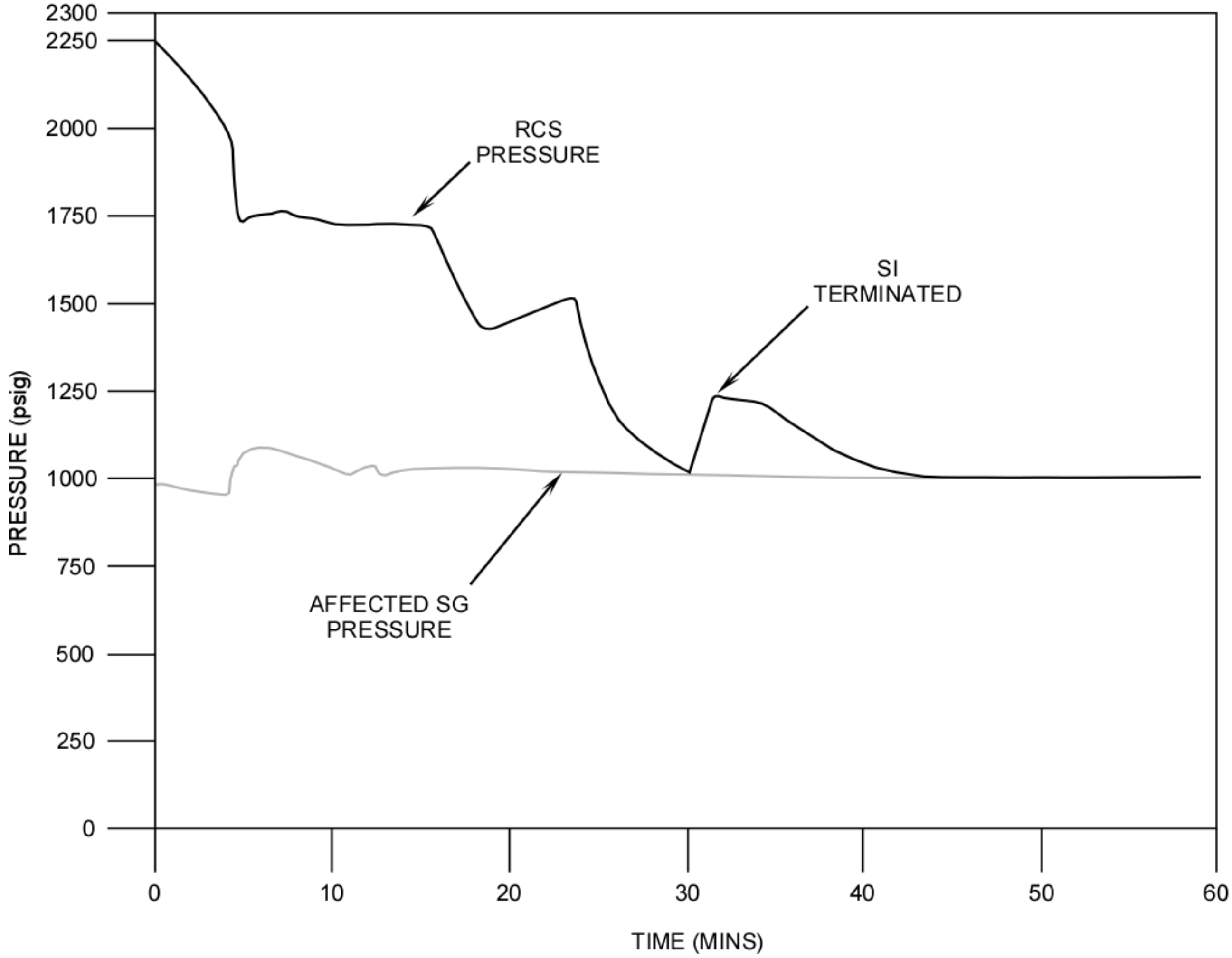


Figure 4.2-11 RCS and Ruptured SG Pressure Following SI Termination

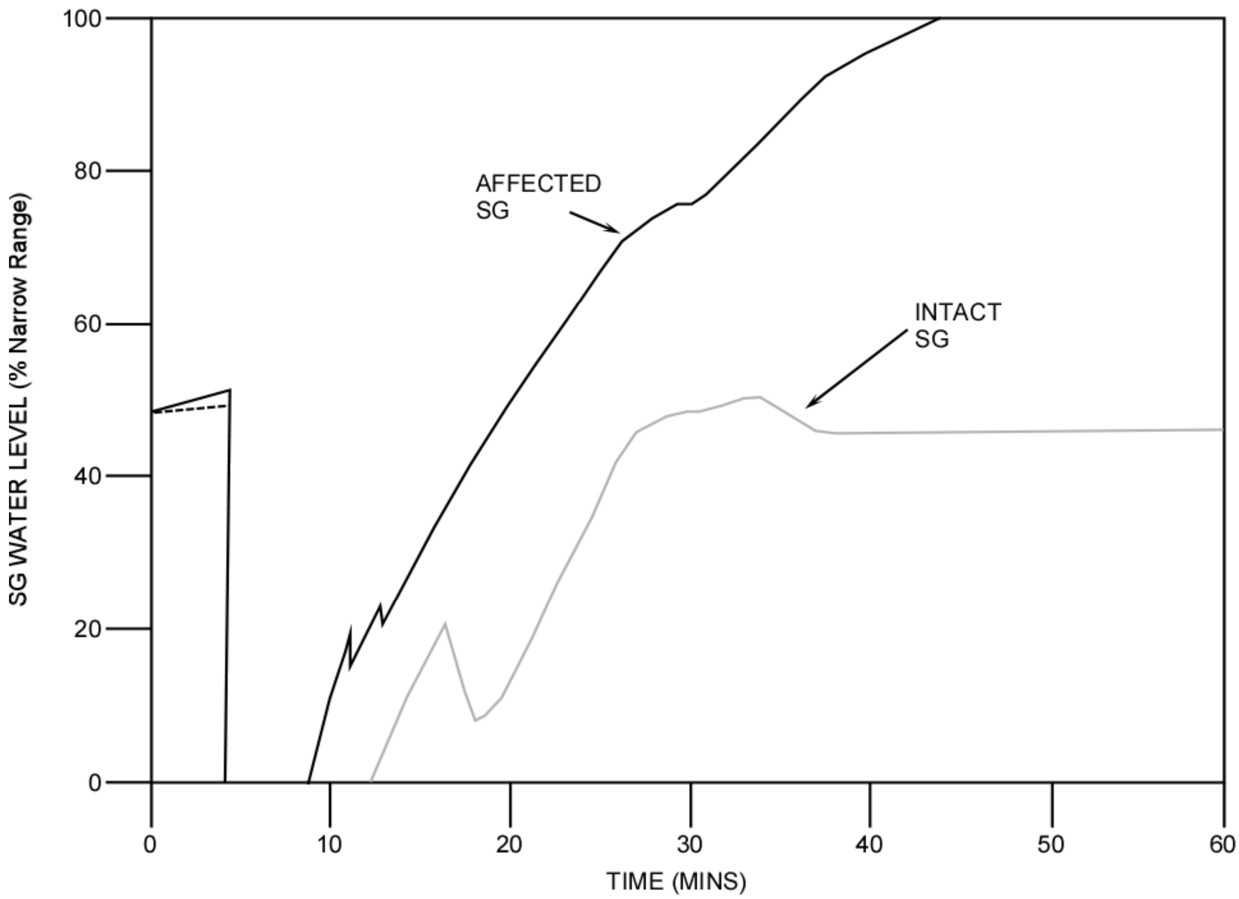
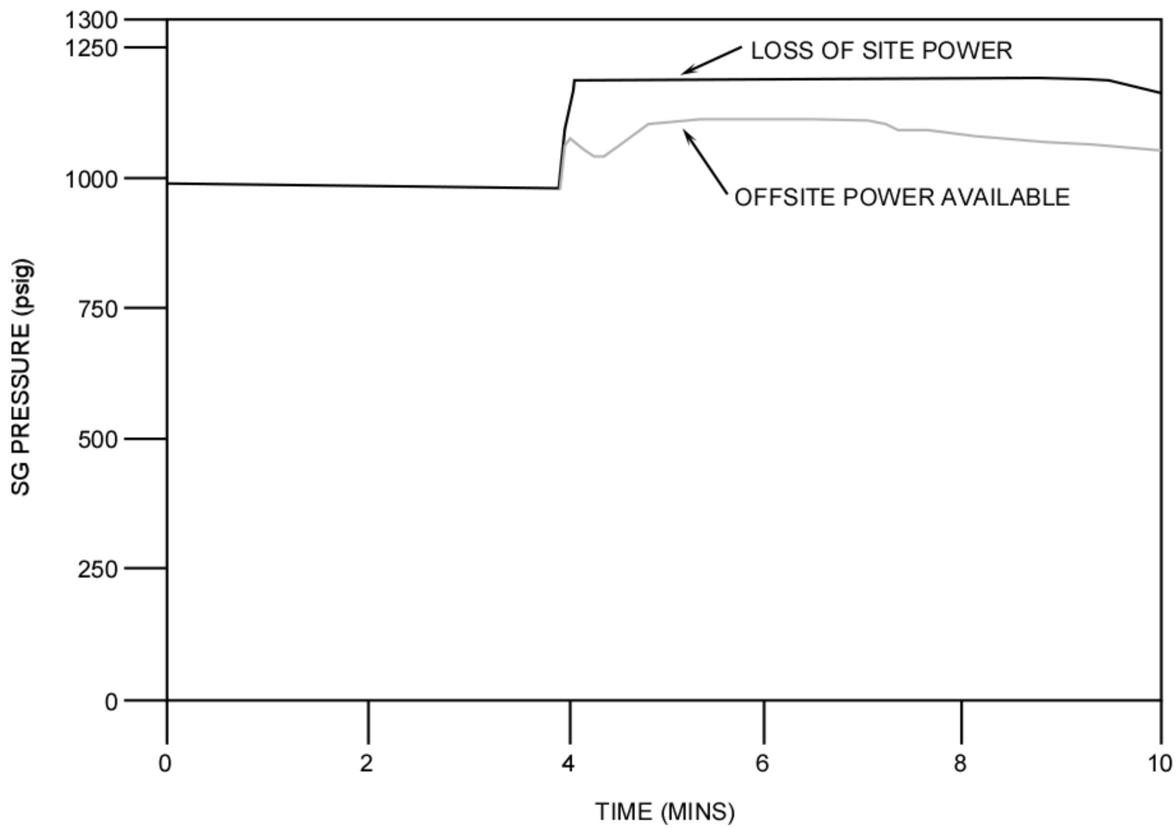


Figure 4.2-12 Steam Generator Levels



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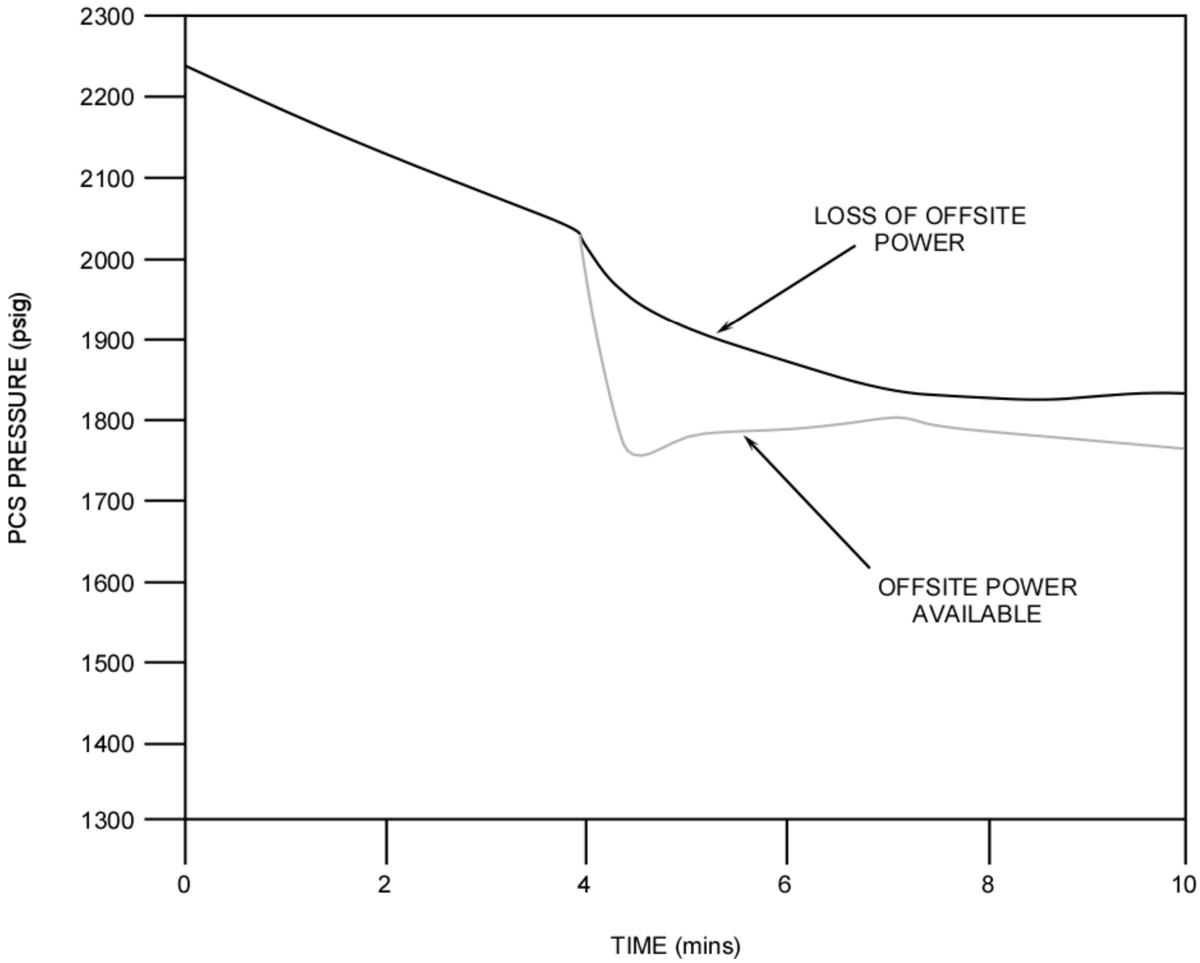

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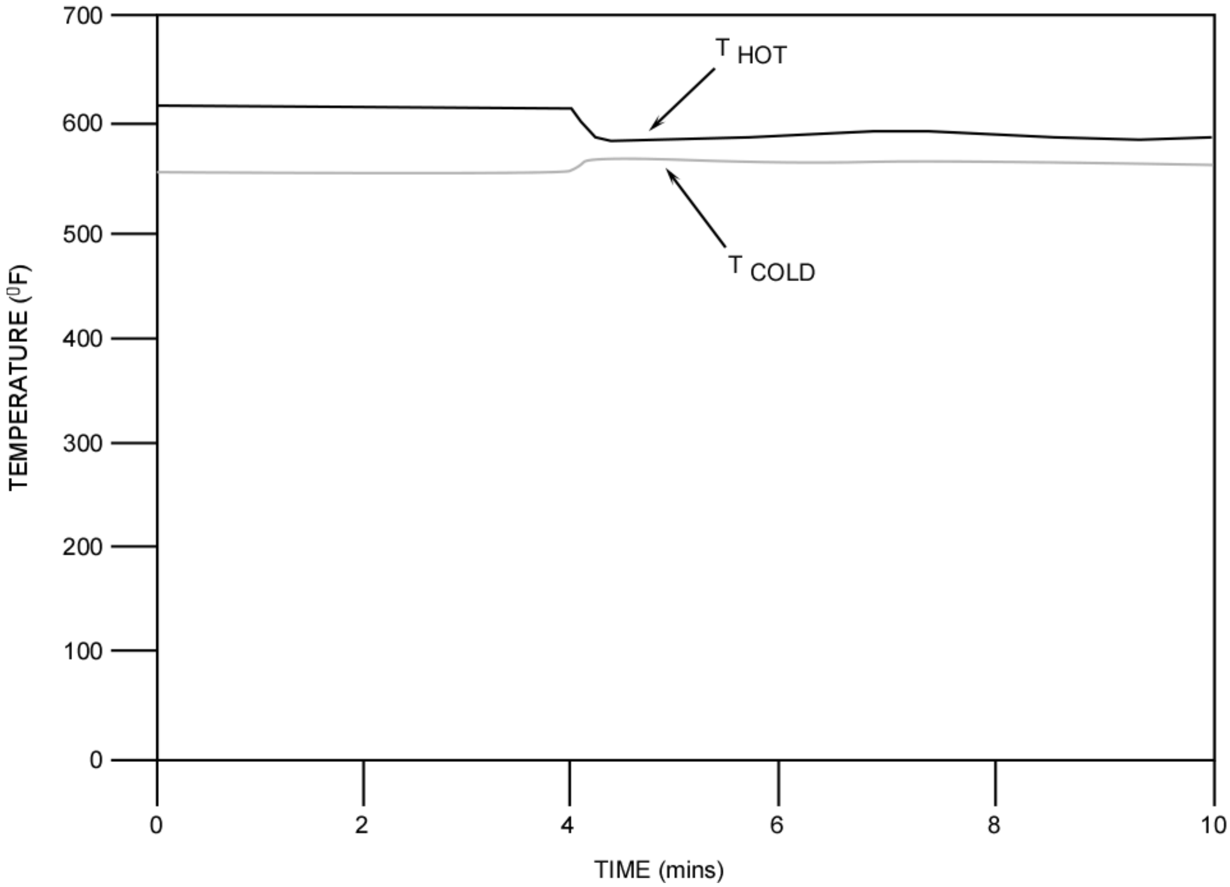

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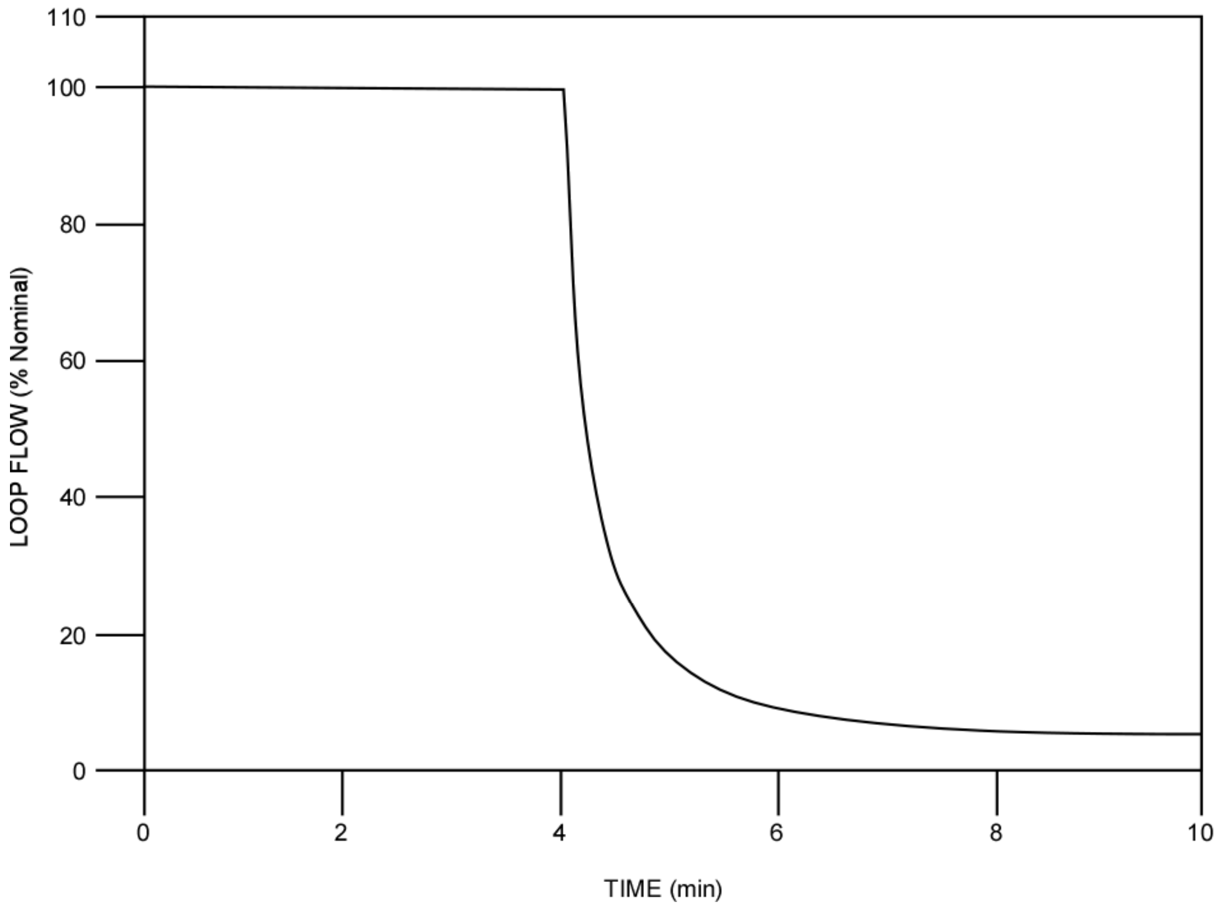

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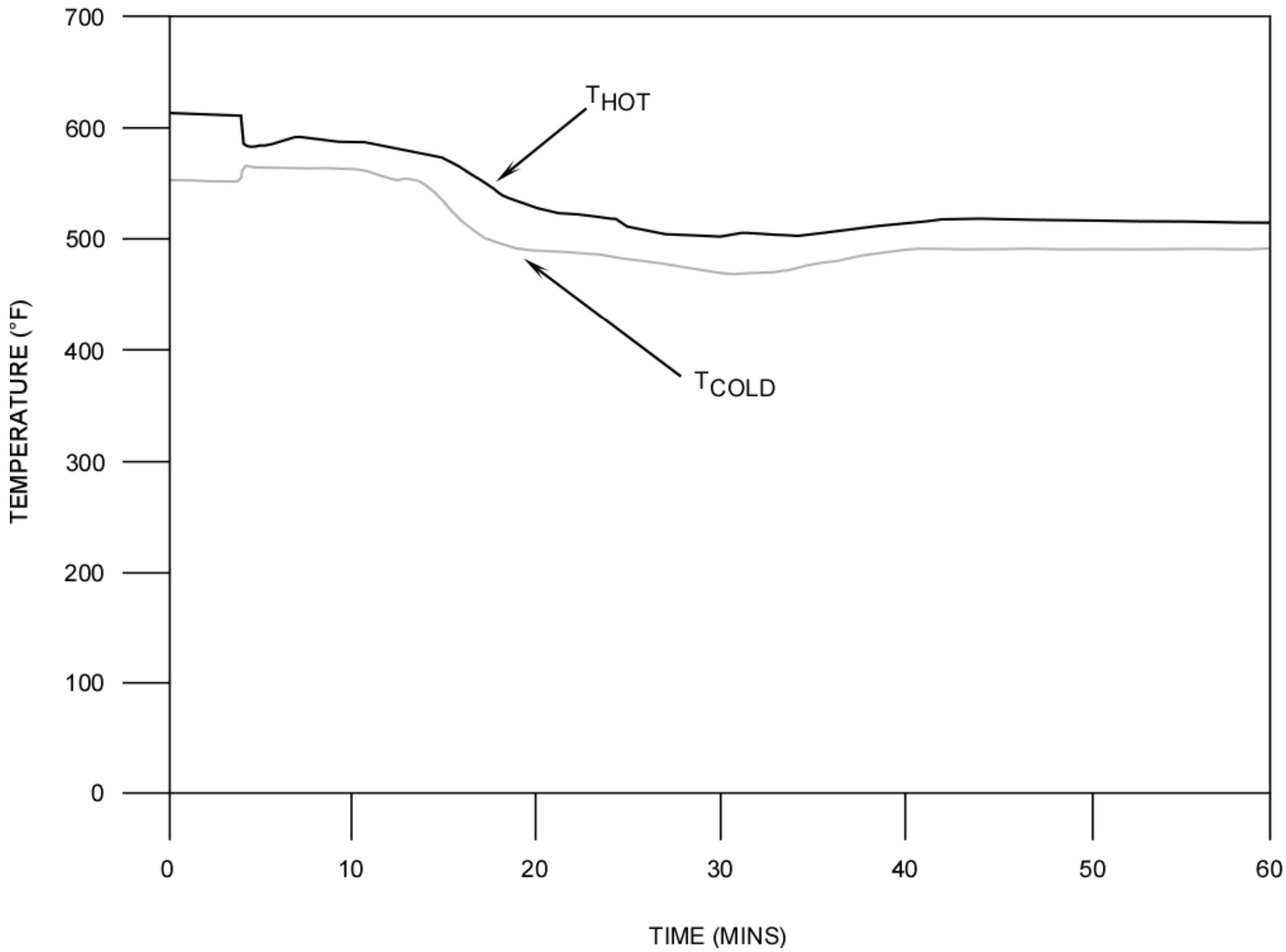

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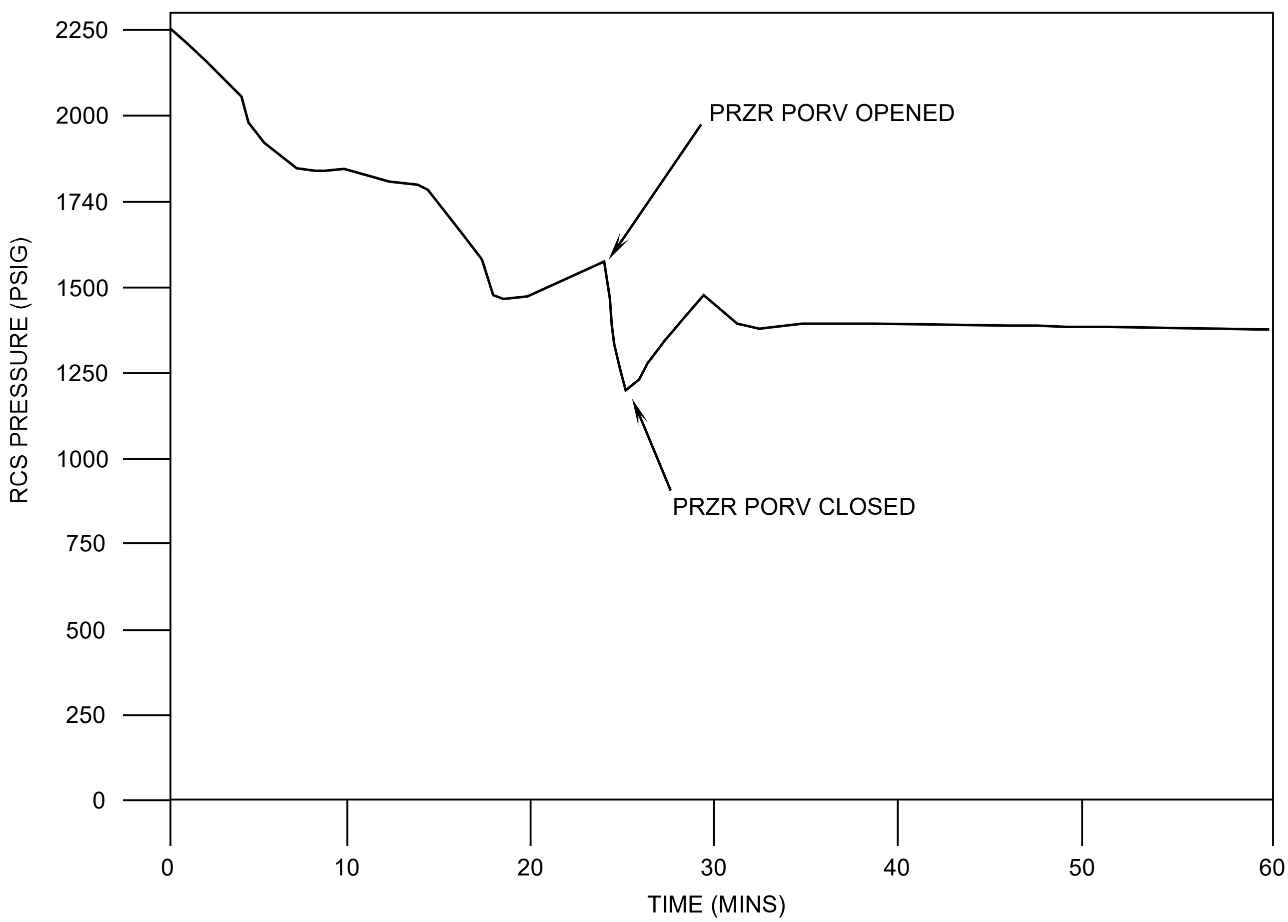

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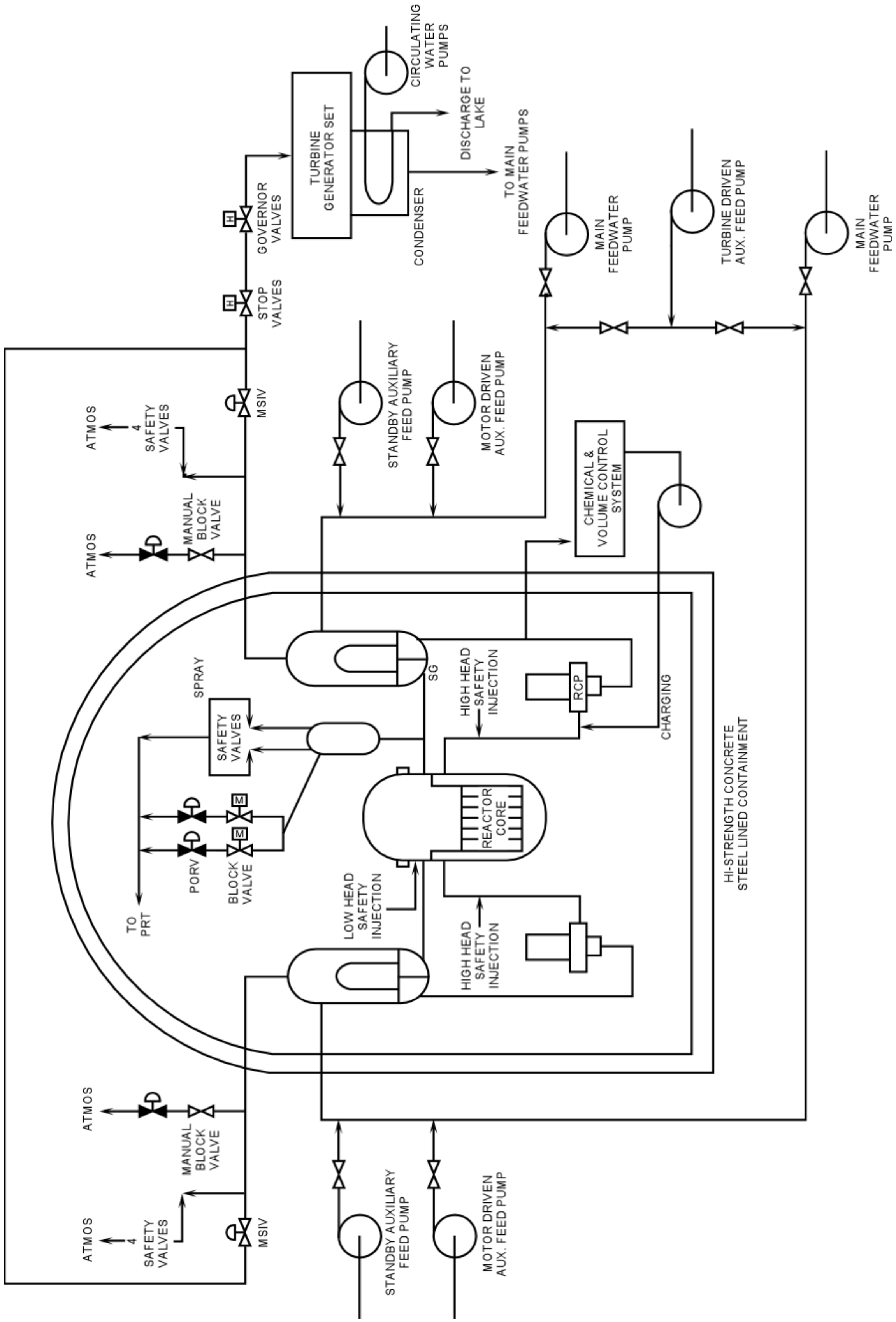

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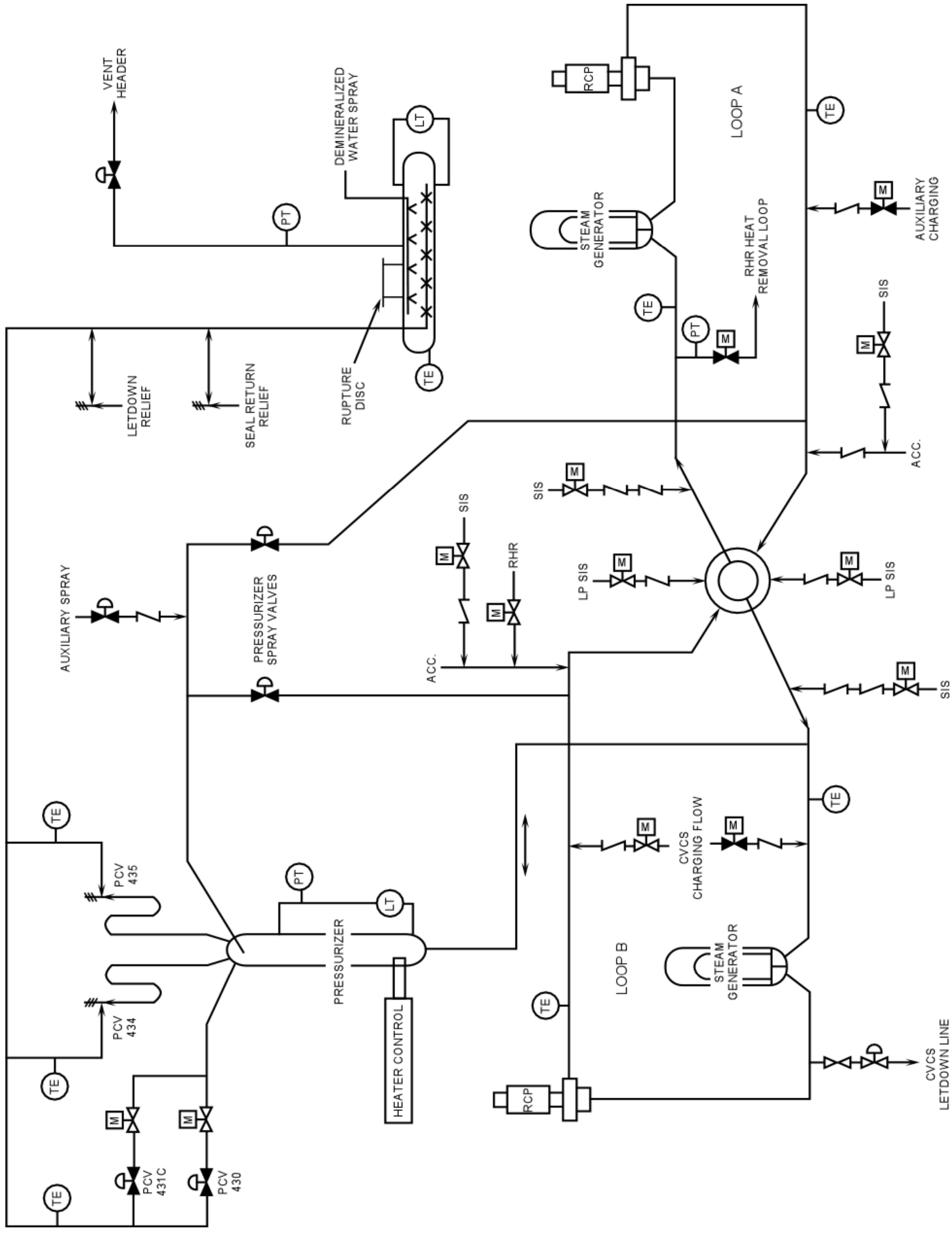

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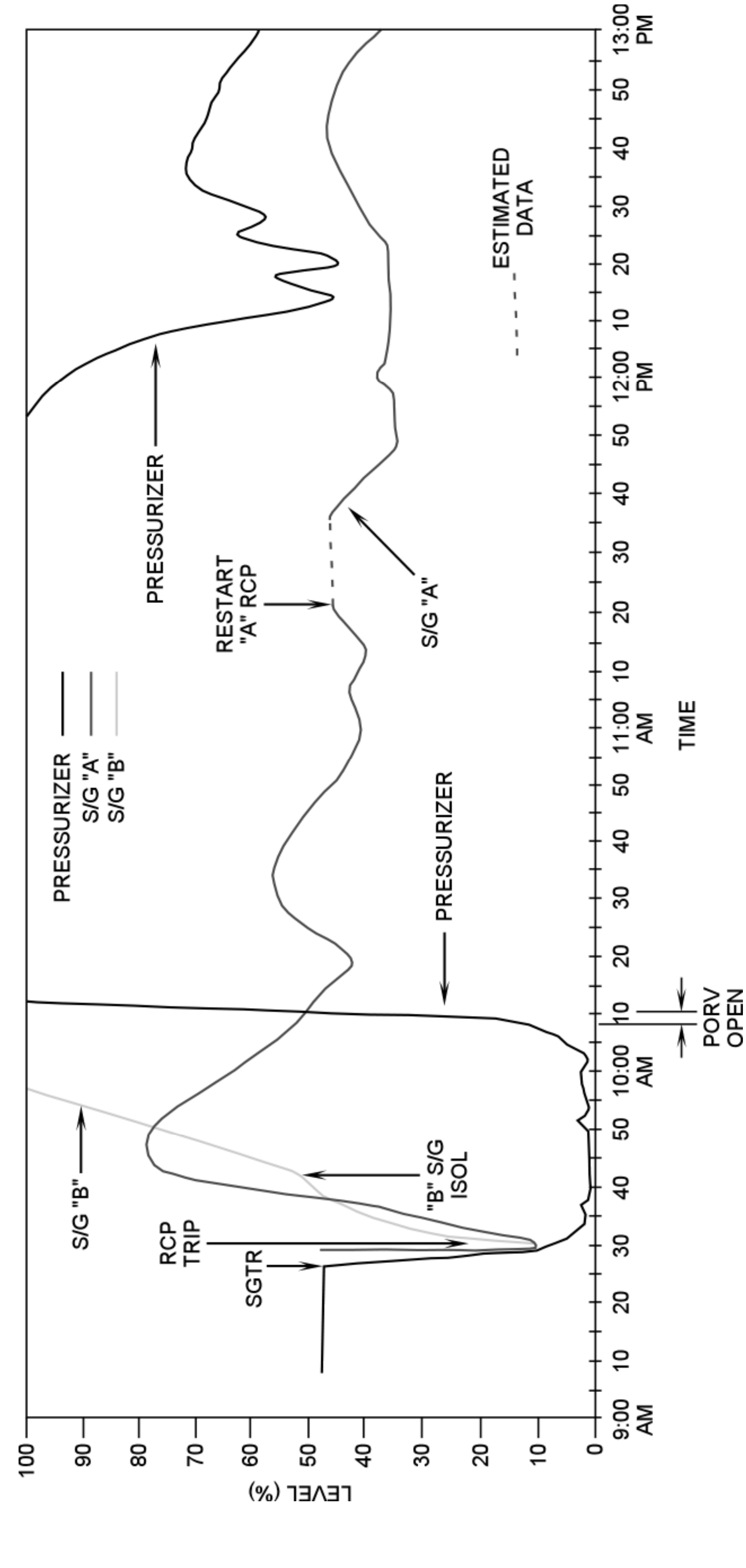

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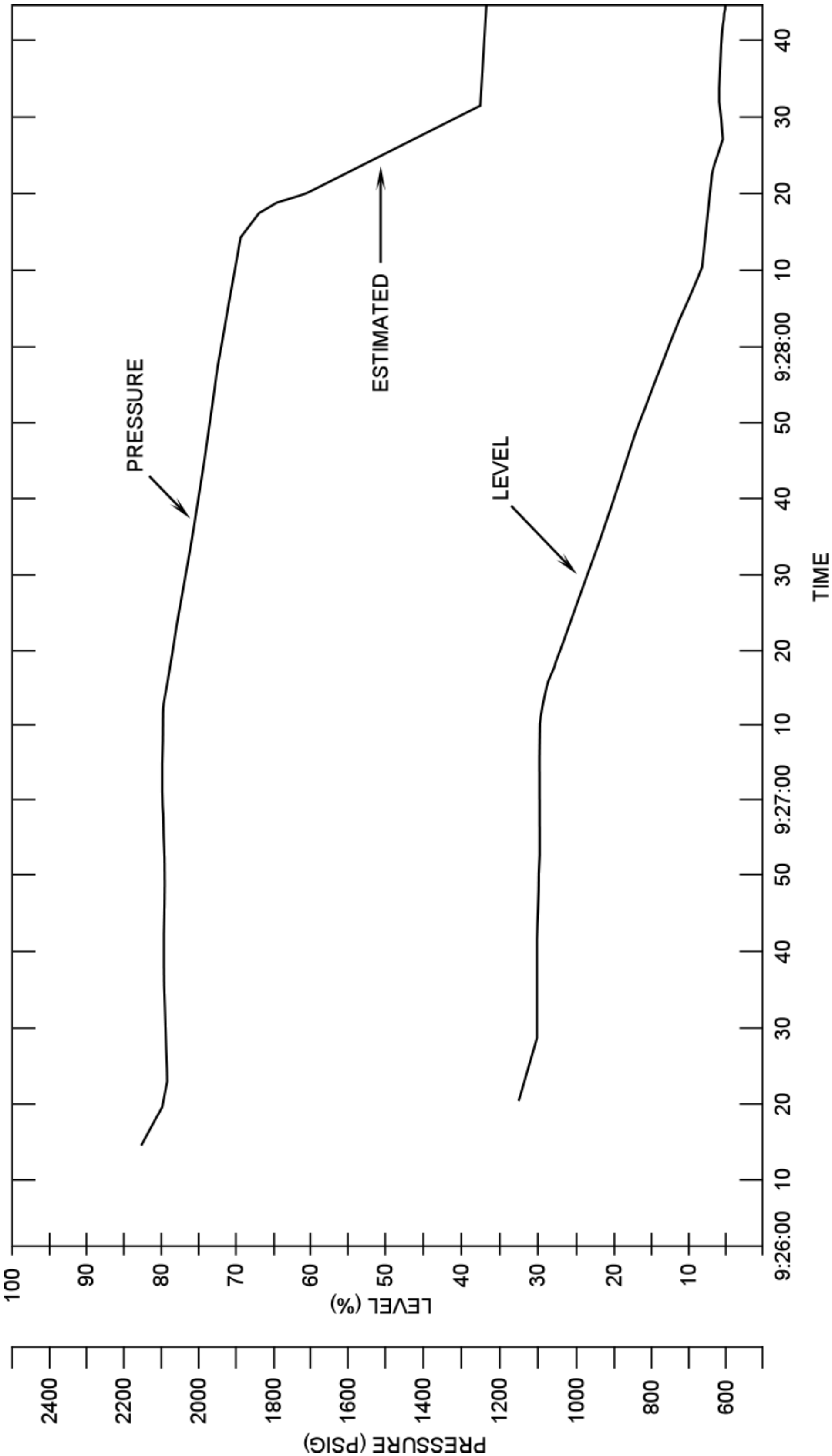

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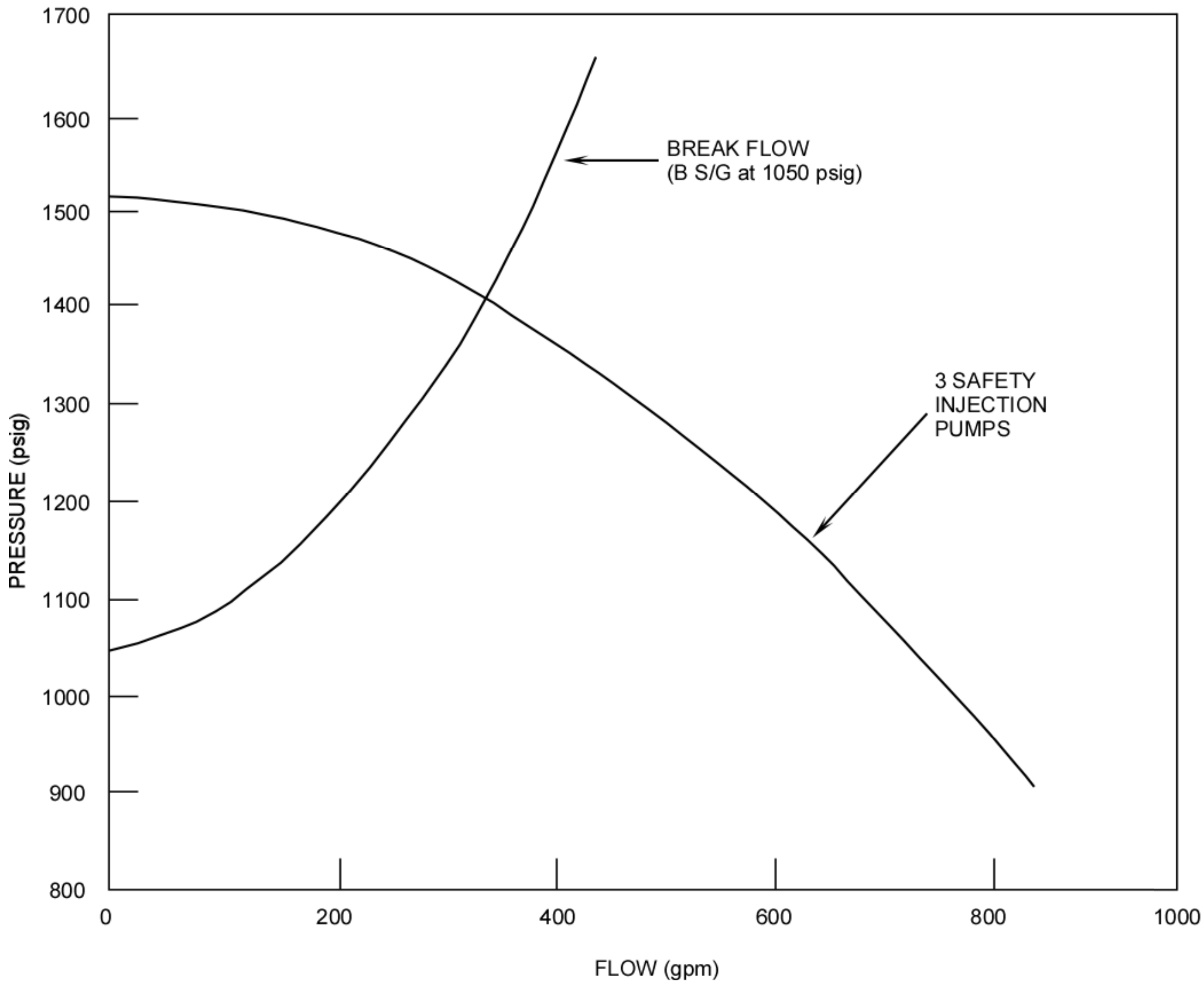

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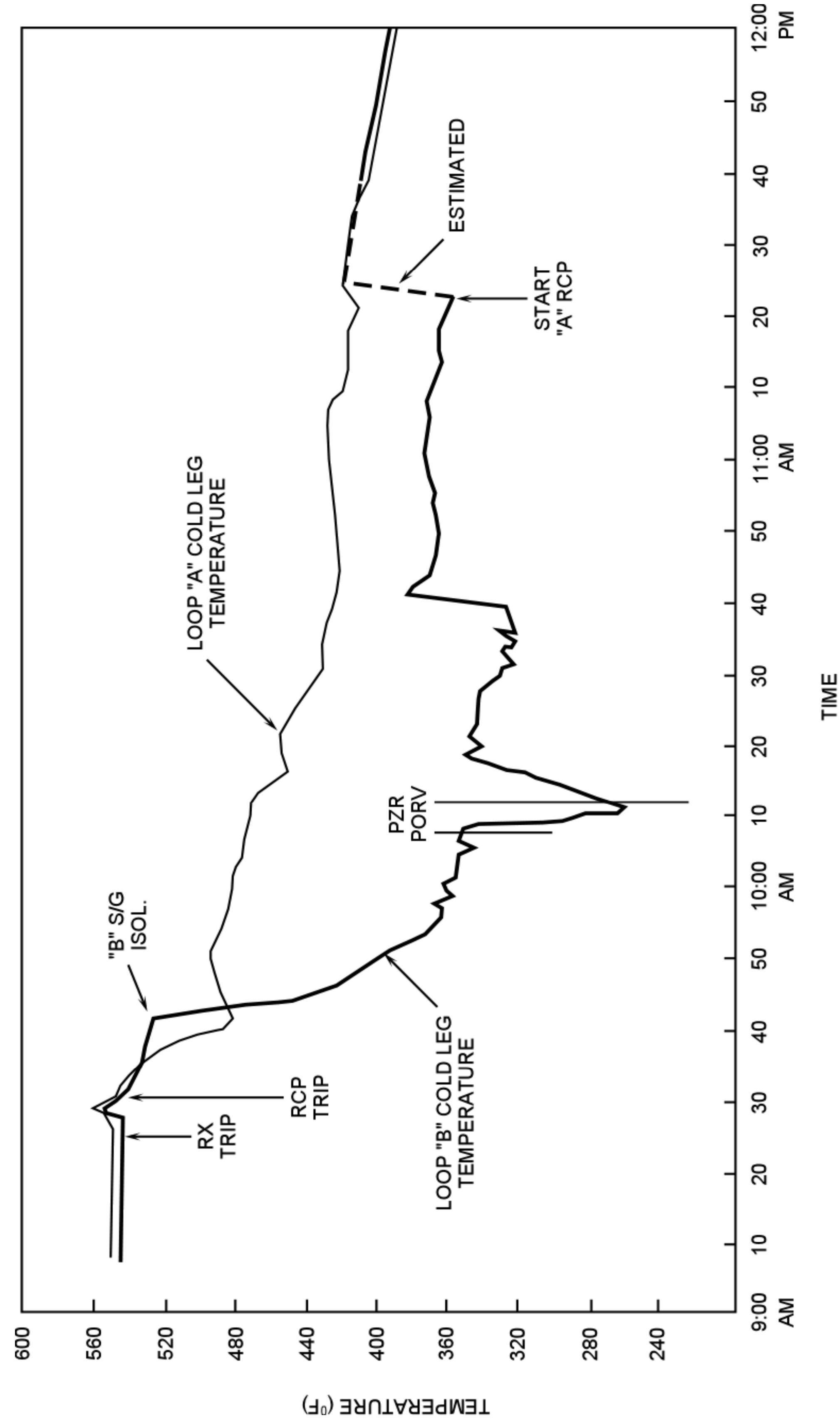

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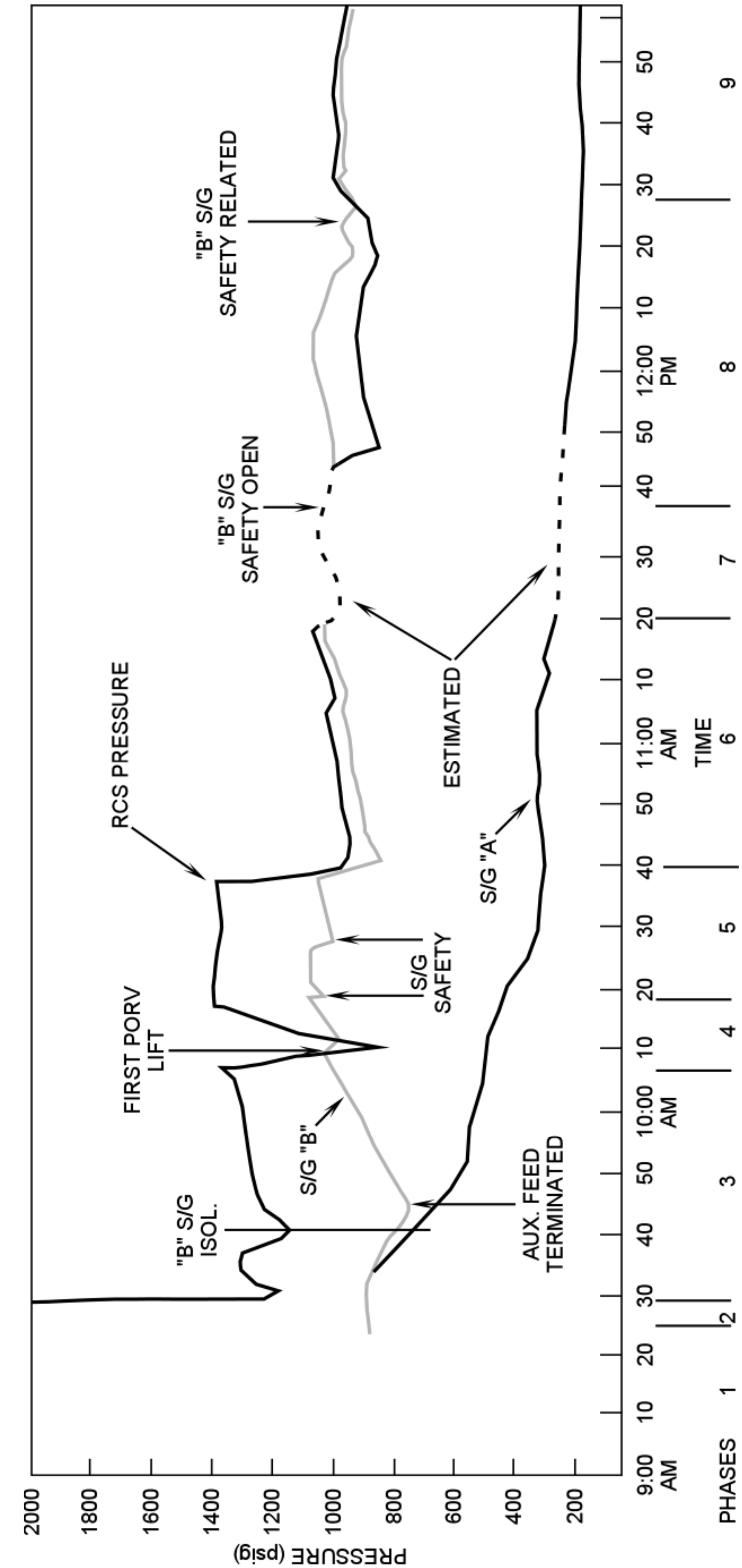

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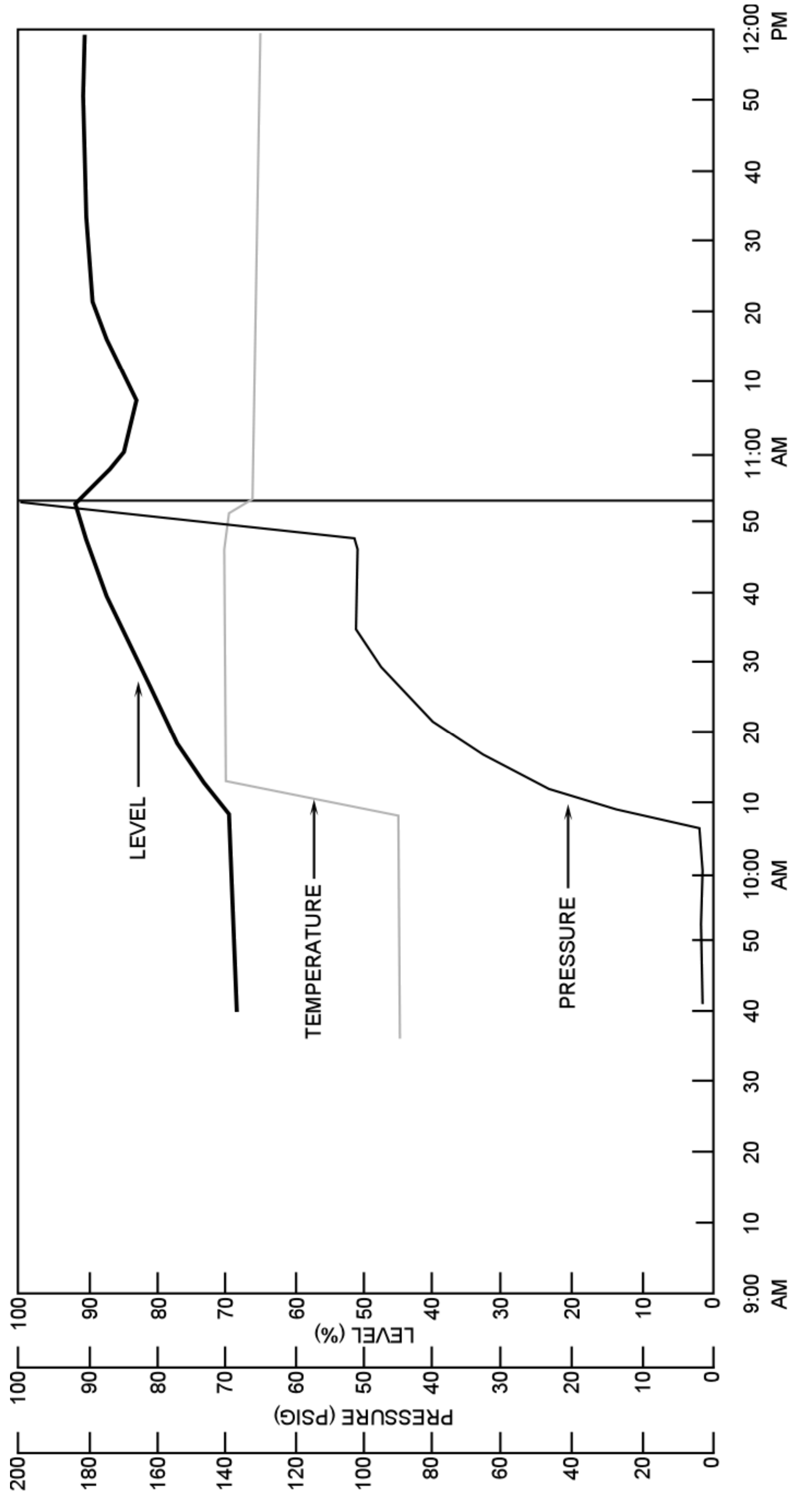

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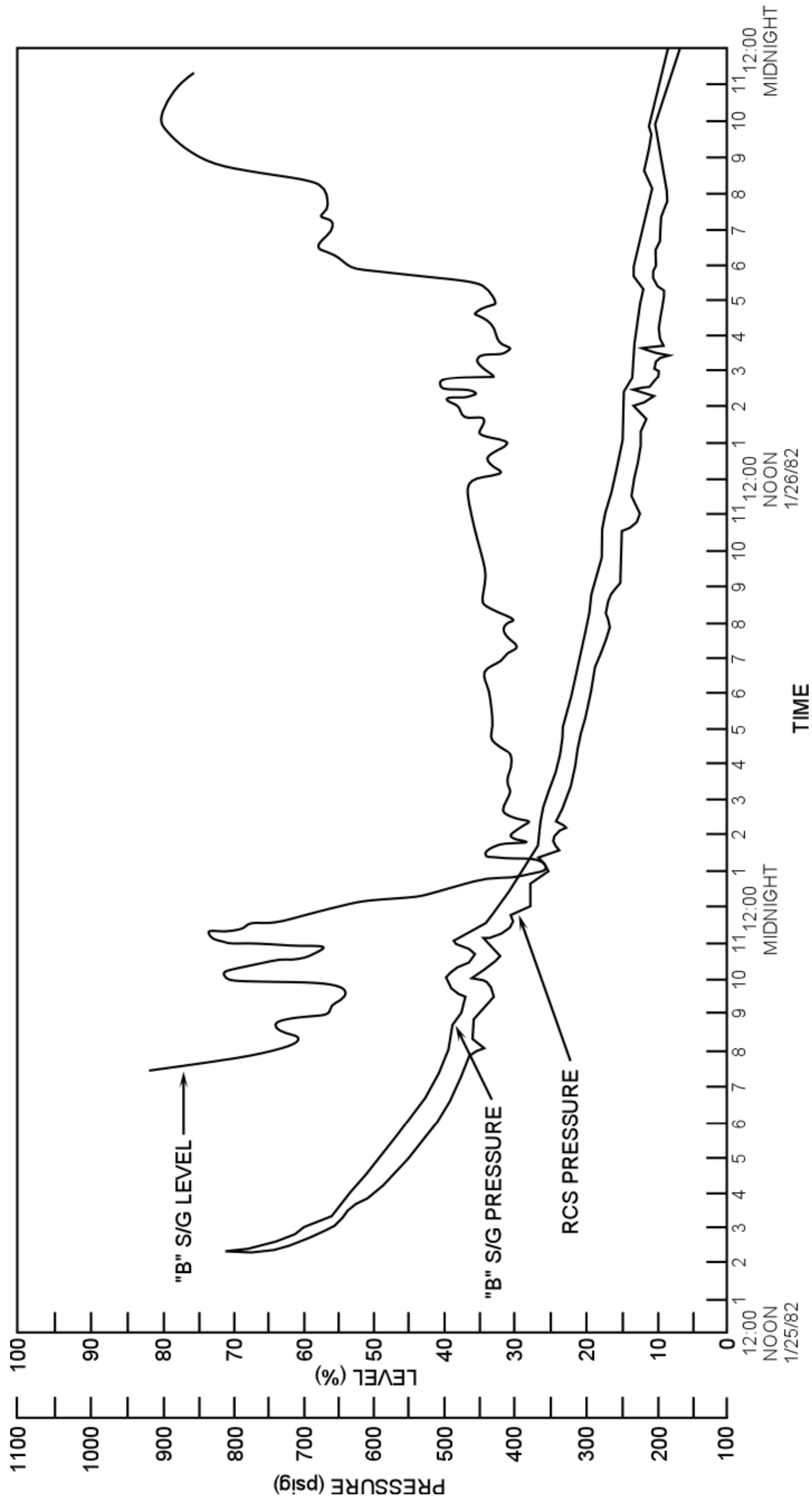

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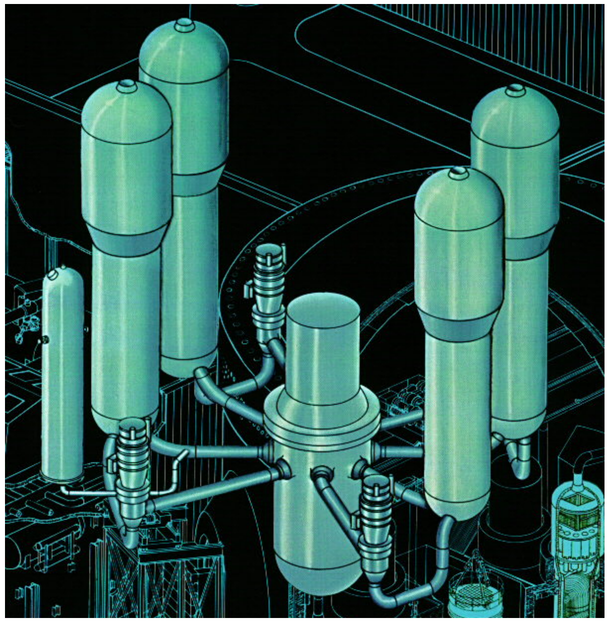

Westinghouse Advanced Technology Manual

Chapter 4.3 – Anticipated Transient Without Scram (ATWS)

2020

HRTD Human Resources Training & Development

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

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4.3.0 Anticipated Transient Without Scram (ATWS)

Learning Objectives:

1. Define the term "Anticipated Transient Without Scram" (ATWS).
2. Describe the limiting (most severe) ATWS case for a Pressurized Water Reactor (PWR).
3. Describe the parameters or components that affect a plant's sensitivity to an ATWS event.
4. Describe the modification made to Westinghouse reactor trip breakers after the Salem ATWS.
5. State the functions of the ATWS mitigation system.

4.3.1 Introduction

The definition for the term "Anticipated Transient Without Scram" can be found in 10CFR50.62, commonly known as the "ATWS rule." An ATWS is defined as an anticipated operational occurrence as defined in 10CFR50, Appendix A, followed by the failure of the reactor trip portion of the protection system specified in General Design Criterion 20 of Appendix A.

The term "transient" applies to any significant deviation from normal values of any of the key operating parameters. A transient may occur as a result of equipment failure or malfunction, or as the result of an operator error. Anticipated operational occurrences are further classified as Condition I and II events in ANSI 18.2. These events are expected to occur one or more times during the life of the plant.

Many transients are handled by various reactor control systems, which return the reactor to its normal operating condition. However, the more severe transients require that the reactor be shut down by the Reactor Protection System (RPS). As stated in the technical specification basis for reactor trip system instrumentation, the reactor trip avoids damage to the reactor fuel and cladding or to the reactor coolant system pressure boundary.

4.3.2 Reactor Protection System Design

The Westinghouse reactor protection system is shown in Figure 4.3-1. As shown, power to the Control Rod Drive Mechanisms (CRDMs) is supplied by motor generator sets through two series reactor trip circuit breakers. The opening of either reactor trip breaker de-energizes all CRDMs, and the reactor trips. This trip scheme is an example of one-out-of-two logic; it requires the actuation of only one protection train and the opening of only one reactor trip circuit breaker, at a minimum, to trip the reactor.

While this logic provides redundant means of generating a reactor trip, the testing of a reactor trip circuit breaker would result in a reactor trip without some compensating measure. Since testing is required, the RPS design includes bypass breakers that are manually installed during testing. For example, if a test of the A reactor trip breaker is required, a bypass breaker is racked in to provide a circuit path parallel to that of the A trip breaker to ensure continuity of power when the trip breaker is opened. The A bypass breaker is opened by the B protection train; therefore, during testing the reactor protection system is reduced to one-out-of-one logic.

The protection system consists of a number of analog channels. The analog section receives input signals from transmitters that sense process parameters. Each process signal is compared to a setpoint in a bistable. If the monitored parameter's input signal is equal to or exceeds the setpoint, a trip signal is generated by the bistable. The bistable trip signal is sent to redundant logic cabinets, where the reactor trip actuation signals are generated.

Each reactor trip function has a coincidence network; only one such network is shown in each protection cabinet of Figure 4.3-1. This coincidence is two-out-of-four logic. Assume that the instrument transmitters are supplying pressurizer pressure signals. If instrument transmitter 1 senses a high pressure condition (greater than the high pressure trip setpoint), its associated bistable trips. Both logic cabinets receive this signal and open the contacts associated with this channel. If no other contacts are open in this logic matrix, the undervoltage coils remain energized, and no trip occurs. If another transmitter also indicates a high pressure condition, its associated bistable trips, and now the necessary two-out-of-four logic is satisfied. When this occurs, vital power is interrupted to the undervoltage coils, allowing the reactor trip breakers to open.

4.3.3 ATWS Historical Background

The ATWS event became a possible source of concern for nuclear power plants in 1968 during discussions between the Advisory Committee on Reactor Safety (ACRS), the regulatory staff, and reactor instrument designers. There were various concerns, one of which was the possibility of interactions between control and protection functions in the instrumentation systems. After considerable discussion and some design changes, it was determined that separation of control and protection functions was being achieved to a reasonable degree, either by physical separation or electrical isolation.

The focus of interest with regard to instrumentation systems then shifted to the ability of the shutdown systems to function with the needed reliability considering common-mode failures. Common-mode failures are failures due to design deficiencies or maintenance errors that could render inoperable redundant components or portions of a safety system. At the time, it was difficult to determine whether a common-mode failure was adequately accounted for partially because the techniques to analyze such failures were not fully developed.

In 1969, the efforts to evaluate the safety concerns of the ATWS events were divided into two areas. One area was concerned with attempting to evaluate the likelihood of common-mode failures or any other failure of the reactor protection system. The second area was to analyze the consequences of various postulated ATWS events.

The ATWS event was analyzed in combination with different initiating conditions. The results showed that the worst-case ATWS initiating event for a pressurized water reactor is a loss of main feedwater.

A loss of main feedwater normally results in a reactor trip to prevent a loss of heat sink. The signal input to the reactor protection system to indicate that a loss of heat sink has occurred is a low-low level in one or more of the steam generators. However, the ATWS analysis assumes that a common-mode failure occurs which prevents the proper operation of the reactor protection system, and the reactor does not automatically trip.

With the loss of heat removal by the steam generators and the lack of a reactor trip, energy from the reactor causes a rapid increase in the reactor coolant temperature. The resultant coolant expansion causes an insurge into the pressurizer, which compresses the pressurizer steam volume. The compression of the pressurizer steam space causes the pressure in the reactor coolant system to rapidly increase. Since systems such as the rod control and pressurizer pressure control systems are not safety-grade, no credit is taken for their action. Therefore, as the temperature continues to increase, the pressure in the reactor coolant system also continues to increase.

As the primary temperature increases, the steam generator pressure increases. The increased secondary pressure causes the steam line code safety valves to open. Even though the auxiliary feedwater system is discharging to the steam generators, the feed rate is insufficient to match the rate of mass loss through the safety valves. The result of the steam generators drying out is that the reactor coolant system temperature increases at a faster rate.

For a reactor with a negative Moderator Temperature Coefficient (MTC), the increasing reactor coolant system temperature adds negative reactivity, which decreases reactor power. Unfortunately, the decrease in reactor power and resultant tempering of the coolant temperature increase are not enough to prevent the pressurizer from filling. When the pressurizer is completely filled, or becomes water solid, an increasing reactor coolant temperature results in a very high reactor coolant system pressure. For all PWR analyses, pressures in excess of 3000 psia are reached. Since this pressure is in excess of the design pressure (2500 psia) of the reactor coolant system, there is a concern about possible system damage and degradation of the emergency core cooling system interfaces.

The severity of an ATWS (peak pressure reached) initiated by a loss of feedwater is affected by the following parameters:

1. The value of the moderator temperature coefficient,
2. The size of the pressurizer,
3. The size of the pressurizer safety valves,
4. The secondary inventory, and
5. The main turbine status (operating or tripped) during the transient.

The value of the moderator temperature coefficient determines whether and how much negative reactivity is added (and the resultant reactor power decrease) as the reactor coolant temperature increases. Therefore, the worst case for the transient is at the beginning of core life (especially for high burnup cores), when the moderator temperature coefficient can be positive, or negative with a small magnitude.

The pressurizer volume is important from the standpoint of the time required to reach the solid-water condition. The size of the code safety valves determines the amount of coolant outflow when the system becomes solid. If the capacity of the code safety valves is small, then the ultimate pressure reached in the reactor coolant system will be higher.

The amount of mass in the secondary side of the steam generators determines the dry-out time of the steam generators. As previously discussed, after the steam generators dry out, the heat sink for the reactor coolant system is lost, and reactor coolant system pressure rapidly increases.

The severity of the accident is also affected by whether the main turbine is operating. It would appear that the loss of feedwater transient would be less severe if the main turbine remains in service, so that additional heat is removed from the reactor coolant system. However, this heat removal path results in a loss of steam generator inventory and decreases the time required to dry out the steam generators. A shorter dry-out time increases the pressure reached in the reactor coolant system during the loss of feedwater transient.

Intuitively, it would appear that the possibility of reaching these high reactor coolant system pressures during a loss of main feedwater is extremely small. After all, the loss of main feedwater transient and some common-mode reactor protection system failure must occur simultaneously. Electric Power Research Institute report NP-2230 (1982) calculated a frequency of 0.15/yr for total loss of main feedwater events, based on from 36 operating PWRs. The error in this data is not known, because all loss of feedwater events are not reported. The failure of the reactor trip circuit breakers, the interrupting device of the reactor protection system, has occurred many times at operating plants. Data from NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant" (1983), show that out of 16,000 breaker demands at pressurized water reactor plants, a total of 53 failures had occurred.

4.3.4 Operational Occurrences

4.3.4.1 Salem ATWS

Simultaneous failures of the reactor trip breakers occurred at the Salem nuclear plant on February 22, 1983. The unit was operating at 20% power with one main feed pump in service. The second main feed pump was at minimum speed in preparation for continued power escalation. The operators were in the process of transferring loads from offsite power to the unit generator. During the transfer, a limit switch failed, causing the loss of one of the nonvital buses. Immediate equipment losses included one reactor coolant pump, control power to the operating main feedwater pump, control room lighting, and a 125-Vac miscellaneous distribution panel.

The loss of the distribution panel caused a loss of nonvital indications in the control room, which included the main feedwater pump indications and the steam generator panel (feed flows and steam flows). However, steam generator water level indications were still available.

The loss of main feedwater resulted in decreasing steam generator levels, and the low-low level trip setpoint was reached. This resulted in a trip signal being generated by the reactor protection system. However, the two series reactor trip circuit breakers failed to open. After evaluating the deteriorating plant conditions, the operator manually tripped the plant. The operator took action 3.5 seconds after the trip signal generated by the reactor protection system, thereby masking the failure of the trip breakers to open automatically. Since the reactor tripped when the operator actuated the manual trip switch, plant personnel did not suspect a problem with the reactor trip system, and, therefore, the ATWS went unnoticed until February 25, 1983.

On February 25, 1983, Salem was operating at 12% reactor power with the feedwater system in manual control. Difficulty in controlling steam generator levels was experienced, and the level in one of the four steam generators dropped to the low-low level reactor trip setpoint. Again, the reactor trip circuit breakers failed to open. The operator, after observing the first-out annunciator, announced on the plant paging system that a plant trip had occurred.

Another operator in the control room noticed that the reactor had not tripped, as indicated by the unlit rod bottom lights. In addition, the turbine had not tripped as expected. The shift supervisor monitored the steam generator levels at this time and noticed that they were at the low-low level trip setpoint (18%). He then directed the reactor operator to manually trip the plant. The operator tripped the plant 23 seconds after the original trip signal was generated.

The shift supervisor was concerned that a failure of the first-out annunciator system or of the reactor protection system had occurred. The instrumentation department was called to perform tests to determine the apparent problem with the indications described above. After the steam generator level bistables and the protection system were verified to be operating properly, tests were performed on the reactor trip breakers. When the trip breakers failed to open when demanded by the protection system, it was determined that an ATWS had occurred.

4.3.4.2 Breaker Malfunction

In both events at Salem, the reactor trip circuit breakers failed to function as designed. Figure 4.3-2 shows the reactor trip circuit breaker design at the time of the events. During normal operations, the circuit breakers are closed, supplying power to the control rod drive mechanisms. Each circuit breaker's undervoltage coil is energized and holds the main trip shaft in position as shown. The power keeping the undervoltage coil energized is controlled by the RPS.

When a trip signal is generated through the appropriate logic (two out of three or two out of four), the RPS de-energizes the undervoltage coil, which releases the main trip shaft. The spring shown directly above the undervoltage coil pulls on the arm it is attached to, causing the main trip shaft to rotate in the counterclockwise direction. When this shaft rotates, it allows the trip spring to pull the top portion of the trip bar to the left, which opens the reactor trip breaker.

Opening the reactor trip circuit breakers removes power from the power cabinets, de-energizing the stationary and movable grippers, and allowing the rods to fall into the core. The undervoltage coil provides a fail-safe feature of the reactor protection system: if a loss of power to the reactor protection system should occur, the undervoltage coils would de-energize, and the reactor trip breakers would open as described above. In the Salem ATWS, the undervoltage coils operated properly, but because of mechanical interference, the reactor trip circuit breakers failed to open as designed.

In addition to the undervoltage coil, each reactor trip breaker has an associated shunt trip coil. The shunt trip coil is normally de-energized when the breaker is closed. To open the breaker with the shunt trip coil, it must be energized. Energizing the coil pulls the shunt trip lever down. As this lever moves down, it comes in contact with the main trip shaft, which is forced to rotate in the counterclockwise direction. As explained above, this starts the chain of events which causes a reactor trip.

In the original Westinghouse design, the remote reactor trip switch opens the reactor trip circuit breaker by energizing the shunt trip coil, while simultaneously de-energizing the undervoltage coil. This manual trip feature allowed the operator to trip the reactor from the control room during both ATWS events at Salem.

The incident that occurred at Salem resulted in increased surveillances of reactor trip breakers to ensure operability. During surveillance testing at McGuire in July of 1987, one reactor trip breaker failed to open when tripped from the control room. It was found to have a defective weld on the trip shaft, which resulted in the mechanical binding of the trip shaft. This prevented the breaker from opening.

Upon further investigation, the other trip breakers at the McGuire station were found to have defective welds on their trip shafts. NRC Bulletin 88-01 was issued on February 5, 1988, to alert utilities using Westinghouse DS model trip breakers that a potential problem existed with this design.

4.3.5 Plant Modifications

4.3.5.1 Reactor Trip Breakers

As shown in Figure 4.3-2, the original Westinghouse design provided only one means by which the RPS would automatically open the reactor trip breakers: the de-energizing of the undervoltage coils. In the aftermath of the Salem events, trip breaker operation was modified to provide redundant means of automatically opening the breakers. With the modification, shown in Figure 4.3-3, the reactor protection system both energizes the shunt trip coil and de-energizes the undervoltage coil for each breaker when trip logic is satisfied.

4.3.5.2 ATWS Rule Requirements

10CFR50.62, published in 1984 and commonly referred to as “the ATWS rule,” imposed new equipment requirements for all PWRs, as discussed in the following paragraphs.

4.3.5.3 Diverse Trip System

Combustion Engineering (CE) and Babcock and Wilcox (B&W) designed pressurized water reactors are required to have a second, diverse trip system. The system is required to be independent of the RPS from the sensor outputs to the CRDM power supplies. The diverse trip system has been imposed as a defense-in-depth measure for CE and B&W plants because of the relatively high percentage of fuel cycle time those plants are expected to operate with positive or slightly negative MTCs (in accordance with analyses performed by the reactor plant designers at the time of the ATWS rule). If an ATWS occurs when the MTC is positive or insufficiently negative to limit the reactor power and the associated increase in reactor coolant pressure, ATWS mitigation systems are likely to be ineffective. Westinghouse designed plants have been excluded from this requirement because of their larger pressurizer safety valves and relatively smaller expected percentage of fuel cycle time with positive or only slightly negative MTCs. (Refer to the discussion in section 4.3.3 of this chapter regarding the impacts of MTC and pressurizer relief valve capacity on the severity of an ATWS.)

A typical B&W diverse trip system interrupts power to the CRDMs when a very high reactor coolant system pressure setpoint has been reached. The very high pressure setpoint reflects the coolant expansion and high pressure expected during an ATWS event.

4.3.5.4 ATWS Mitigation System

Paragraph (c) of 10CFR50.62 requires each pressurized water reactor to have "equipment from sensor to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must be designed to perform its function in a reliable manner and be independent (from sensor output to the final actuation device) from the existing reactor trip system."

In response to the ATWS rule, an ATWS mitigation system has been installed in each PWR to provide a backup to the reactor trip system and the engineered safety features actuation system for initiating a turbine trip and actuating the auxiliary feedwater system in the event of an ATWS. The system is typically non-safety-related, powered by non-Class 1E source, and microprocessor based. Various signals, such as high reactor coolant system pressure and low steam generator level, can be used as indications of an ATWS event. Two examples of ATWS mitigation systems are described below.

The Trojan ATWS Mitigation System Actuating Circuitry (AMSAC), shown in Figure 4.3-4, starts the turbine-driven and diesel-driven auxiliary feedwater pumps and trips the main turbine if the narrow-range steam generator levels drop below the low-low level setpoint (11.5%) for at least 25 seconds in three of the four steam generators. This circuit is only functional when load is greater than 40% and for 6 minutes after load is reduced to less than 40%.

The Indian Point Unit 3 AMSAC (see Figure 4.3-5) performs the same functions as the system described above. However, instead of steam generator narrow-range levels, main feedwater flows are supplied as inputs. If main feedwater flows drop below 21% in three out of four channels for a preset length of time (depending on power level), and power is greater than 40% as indicated by turbine impulse pressure, the turbine is tripped, the auxiliary feedwater system is actuated, and the steam generator blowdown and sample lines are isolated. The signal is maintained for 40 seconds or for as long as the activation criteria are met. The 40-second timer maintains the AMSAC initiation signal to ensure that the necessary actions occur under changing conditions of power and feedwater flow.

Because the design of the ATWS mitigation system utilizes application software and intelligent automation controllers, problems have been encountered with the system that are unlike others traditionally experienced at nuclear plants. For example, in December of 1992, the Indian Point Unit 3 AMSAC was found to be inoperable since July of 1992 because of a software problem resulting from significant deficiencies in maintenance, testing, and quality assurance of the system. The configuration for the system is maintained on a hard drive, and it automatically loads into memory upon boot-up. The hard drive failed to reboot during a surveillance test in May of 1992. The utility reinstalled the repaired hard drive after it was returned from the vendor. The configuration files had to be rebuilt from an uncontrolled copy of the files kept by a vendor technician, because the utility had not maintained a controlled copy. During performance of post-maintenance testing on the system, the automatic reboot function was tested. However, the AMSAC developed a faulty trip signal and failed the test. Subsequent to software manipulations made by the vendor to address the faulty signal, only the reboot function was tested. During the next scheduled surveillance test in December of 1992, it was discovered that the AMSAC auxiliary feedwater initiation was inoperable due to inadvertent misplacement of the 40-second timer in the system software during the software manipulations that had been conducted during the previous July. The system software was corrected, and the AMSAC was returned to an operable status in January of 1993.

4.3.6 PRA Insights

4.3.6.1 Historical

The NRC staff evaluation of ATWS in NUREG-460, "Anticipated Transients Without Scram for Light Water Reactors" (1980), was one of the first applications of PRA techniques to an unresolved safety issue. The evaluation highlighted the relative frequency of severe ATWS events associated with various reactor types and estimated the expected reduction in frequency for various postulated plant modifications. The study also proposed quantitative goals for resolving this issue. Other notable examples of PRA applications to the ATWS issue are the NRC sponsored survey and critique of reactor protection systems (SAI, 1982), and the ATWS Task Force report summarized in SECY-83-293.

The RPS survey reviewed 16 reliability studies, most of them published PRAs, to compare the predicted failure probability per unit demand, the anticipated transient frequency, and the primary influences on RPS unavailability. There was a surprising degree of agreement among the 16 studies. A second study quantified the relative improvement to be gained by implementing a set of recommendations proposed by a utility consortium in an ATWS petition to the NRC. A third study, a value-impact evaluation of the risk reduction of generic plant classes, provided the basis for the final rule on ATWS (SECY-83-293).

A recently prepared draft NRC Office of Nuclear Regulatory Research report assesses whether the ATWS rule and other relevant Commission recommendations issued with the ATWS rule have been effective in achieving the desired outcomes. The report concludes that the ATWS rule and associated recommendations have been effective in having the required plant modifications installed, in reducing core damage frequency associated with ATWS, and in limiting the costs to licensees. Specifically:

- Hardware modifications required by the ATWS rule have been implemented at all PWRs, typically between 1986 and 1990, including the diverse means of tripping the turbine and initiating auxiliary feedwater at all plants and the diverse scram system at CE and B&W plants. The report notes that changes in fuel design to achieve longer operating cycles will result in less negative MTCs for a larger fraction of the cycle time, during which ATWS mitigation functions may be rendered ineffective. Fuel cycle changes that significantly increase the ATWS risk due to longer exposure to such MTCs may require compensatory measures consistent with the ATWS rule for Westinghouse plants.

- SECY-83-293 set a goal of 1.0E-05/RY for the core damage frequency associated with an unmitigated ATWS (referred to as P(ATWS)). This goal has been exceeded for all plant types; the average Westinghouse plant value is 6.4E-07/RY. The reduction in P(ATWS) has been greatly affected by the large decrease in the frequency of automatic trips (the initiating events for ATWSs) since the ATWS rule was invoked. Also, better than expected improvements in RPS reliability have been achieved for all reactor plant types.

- RPS reliability is related to reactor trip breaker reliability. As evidenced by NRC generic communications and industry group activities, circuit breaker problems continue to occur. Industry programs to maintain RPS reliability continue to be useful in limiting risk from ATWSs.
- However, RPS reliability estimates are subject to large uncertainties. RPS reliability requirements are so high and ATWS events are so rare that many more years of operating experience are needed to generate sufficient system demands to reduce current estimates of the uncertainty. The current uncertainty associated with RPS reliability argues for the continued application of the requirements of the ATWS rule.
- Costs associated with implementing the ATWS rule have been less than expected ($166M actual vs. $354M expected), largely due to fewer than expected spurious trips caused by ATWS mitigation equipment.

NUREG-1560, “Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance” (1997), concludes that ATWS is not an important contributor to the total core damage frequency for almost all Westinghouse plants. The core damage frequency attributable to ATWS events is small in absolute terms for almost all plants, and constitutes a significant contribution to total core damage frequency (greater than 10%) for just two plants. Each of these plants, Beaver Valley 1 and Indian Point 3, operates with some or all of its power-operated relief valve block valves closed, thereby reducing the relief capacity of the reactor coolant system during the early stages of an ATWS and thus increasing the potential peak pressure reached.

4.3.6.2 Plant Event

On June 3, 1991, a low flow reactor trip signal was generated during the calibration of a reactor coolant system flow instrument at Harris Unit 1 (LER 400/91-010). The B reactor trip breaker opened as required, but the A trip breaker failed to respond. The failure was due to a failed circuit board (a result of previous improper maintenance). The board failure prevented the occurrence of the automatic undervoltage and automatic shunt trips of the associated reactor trip breaker. A manual trip was still available.

Assuming that both reactor trip breakers had failed to open, the conditional probability of subsequent core damage was estimated at 6.6E-06 for this event. Figure 4.3-6(a) shows the relative significance of this event compared to other postulated events at Harris Unit 1.

The model used to estimate the conditional core damage probability is shown in Figure 4.3-6(b). Assuming that an ATWS occurs with no manual trip (the operator does not perform the actions as directed by the emergency procedures), four sequences have end states of core damage. The dominant sequence for core damage is sequence 2, which assumes an ATWS, no operator action to insert the control rods, that primary pressure is limited, that the auxiliary feedwater system operates, but that emergency boration is not initiated.

4.3.7 Summary

The ATWS event is an analyzed plant transient that requires the automatic shutdown of the plant, combined with the failure of the reactor protection system to respond as designed. The Code of Federal Regulations requires that each pressurized water reactor must have equipment, (diverse from the reactor trip system) that will initiate the auxiliary feedwater system and trip the turbine under conditions indicative of an ATWS. Therefore, utilities have installed ATWS mitigation systems that perform those functions.

As a result of the Salem ATWS, Westinghouse units added the automatic energizing of the shunt trip coil by the RPS. This modification provides a redundant means of opening the reactor trip breakers and potentially reduces the probability that a common-mode failure would prevent their opening.

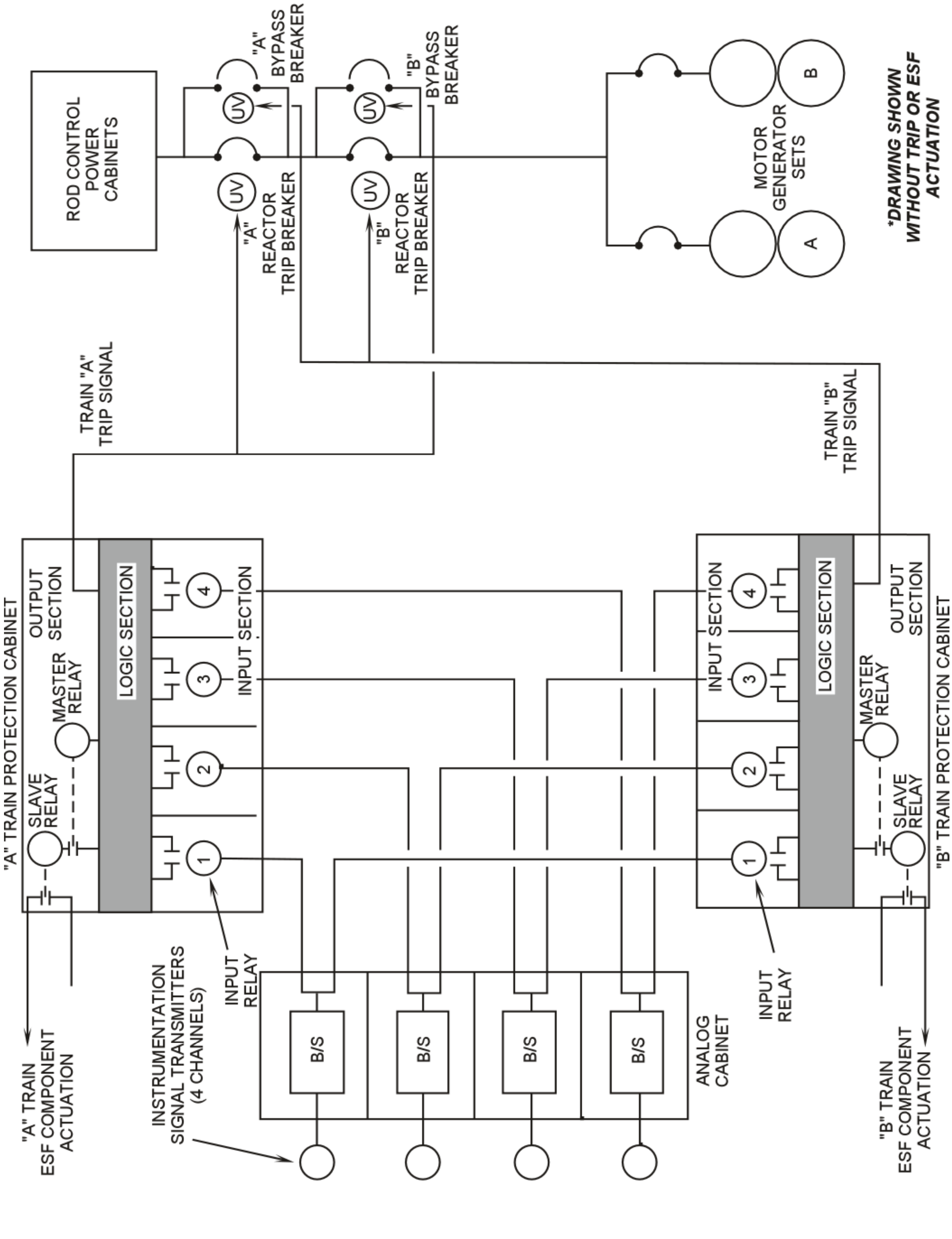


Figure 4.3-1 Solid State Protection System

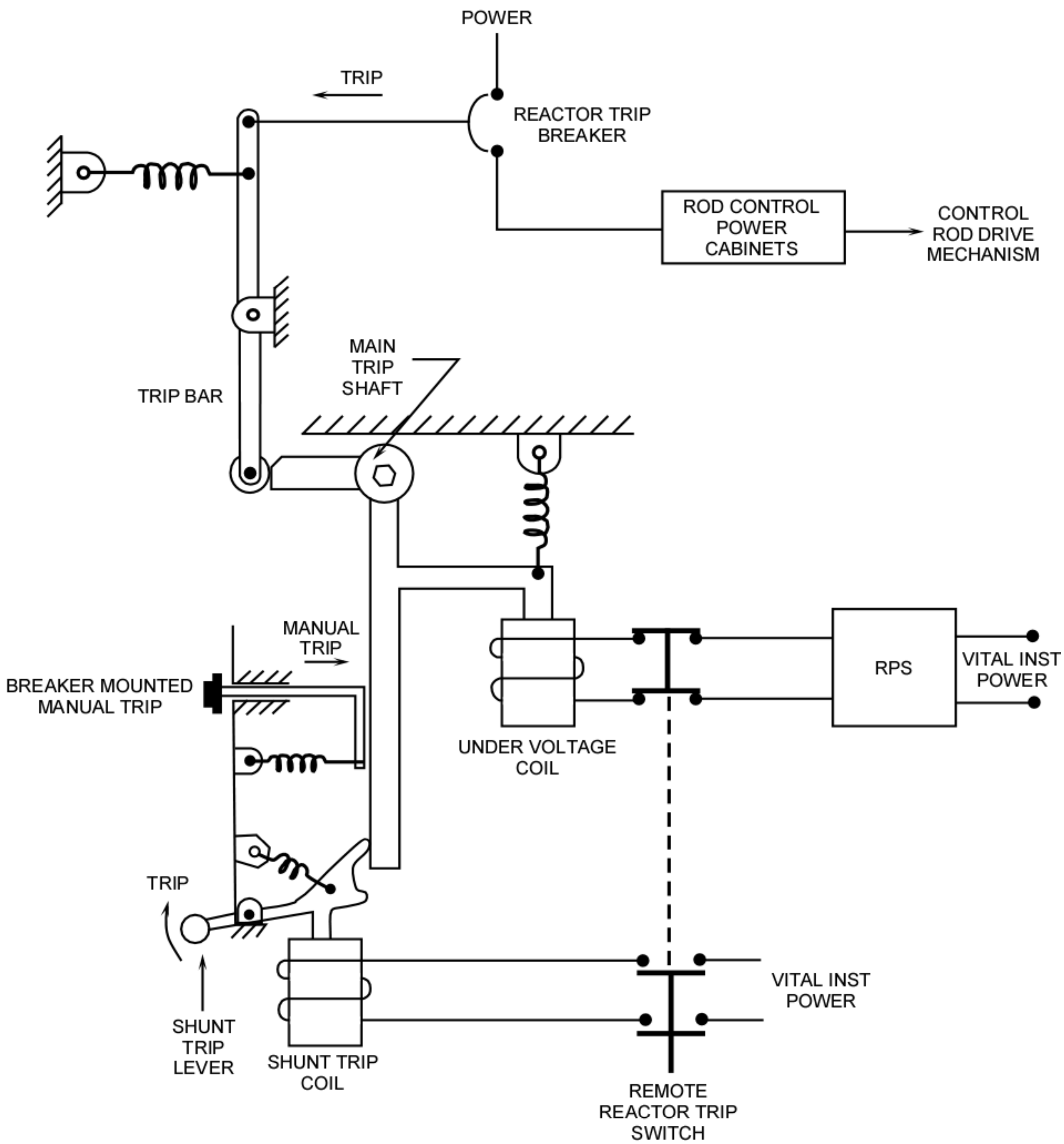


Figure 4.3-2 Reactor Trip Breaker

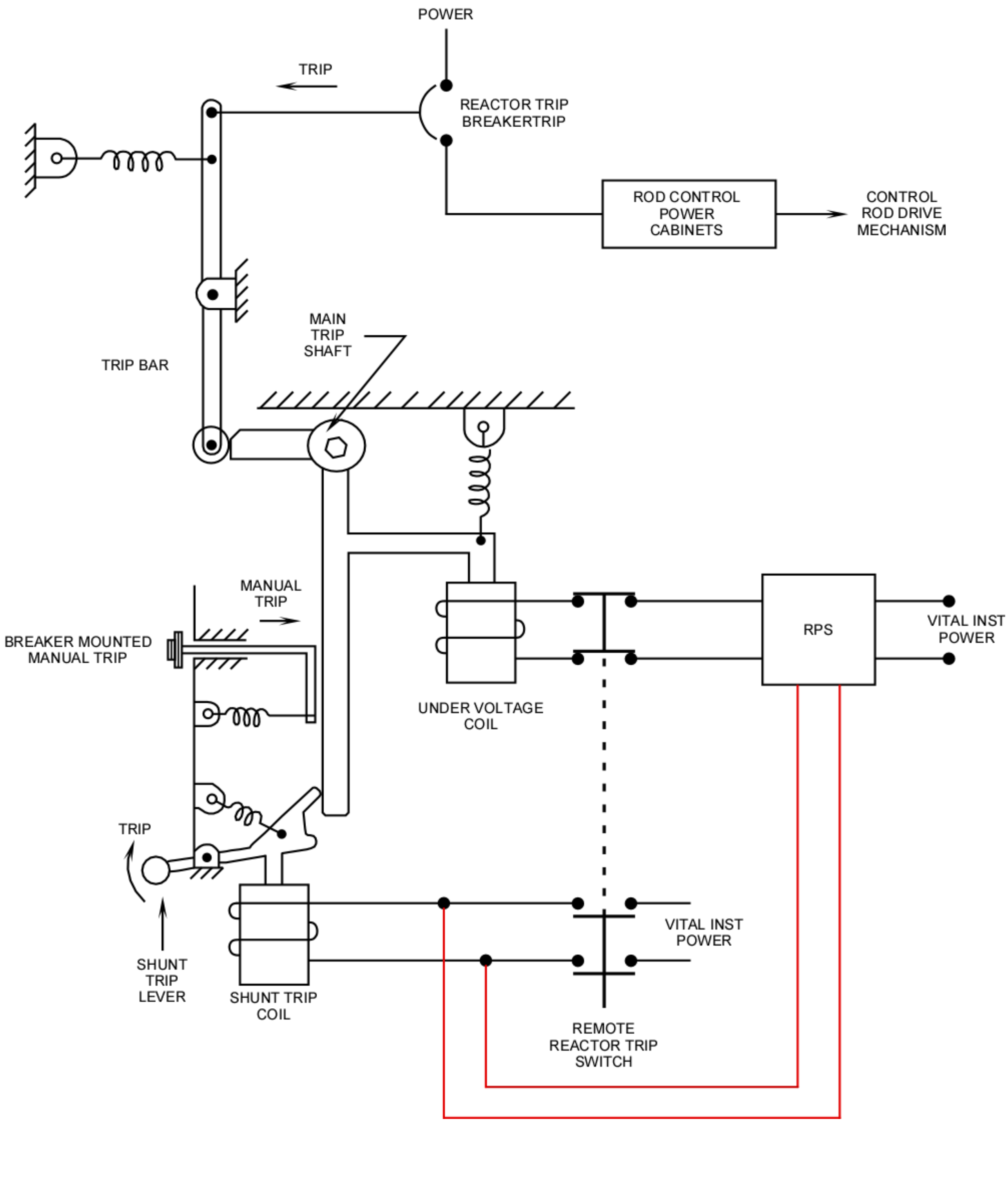


Figure 4.3-3 Reactor Trip Breaker Modification

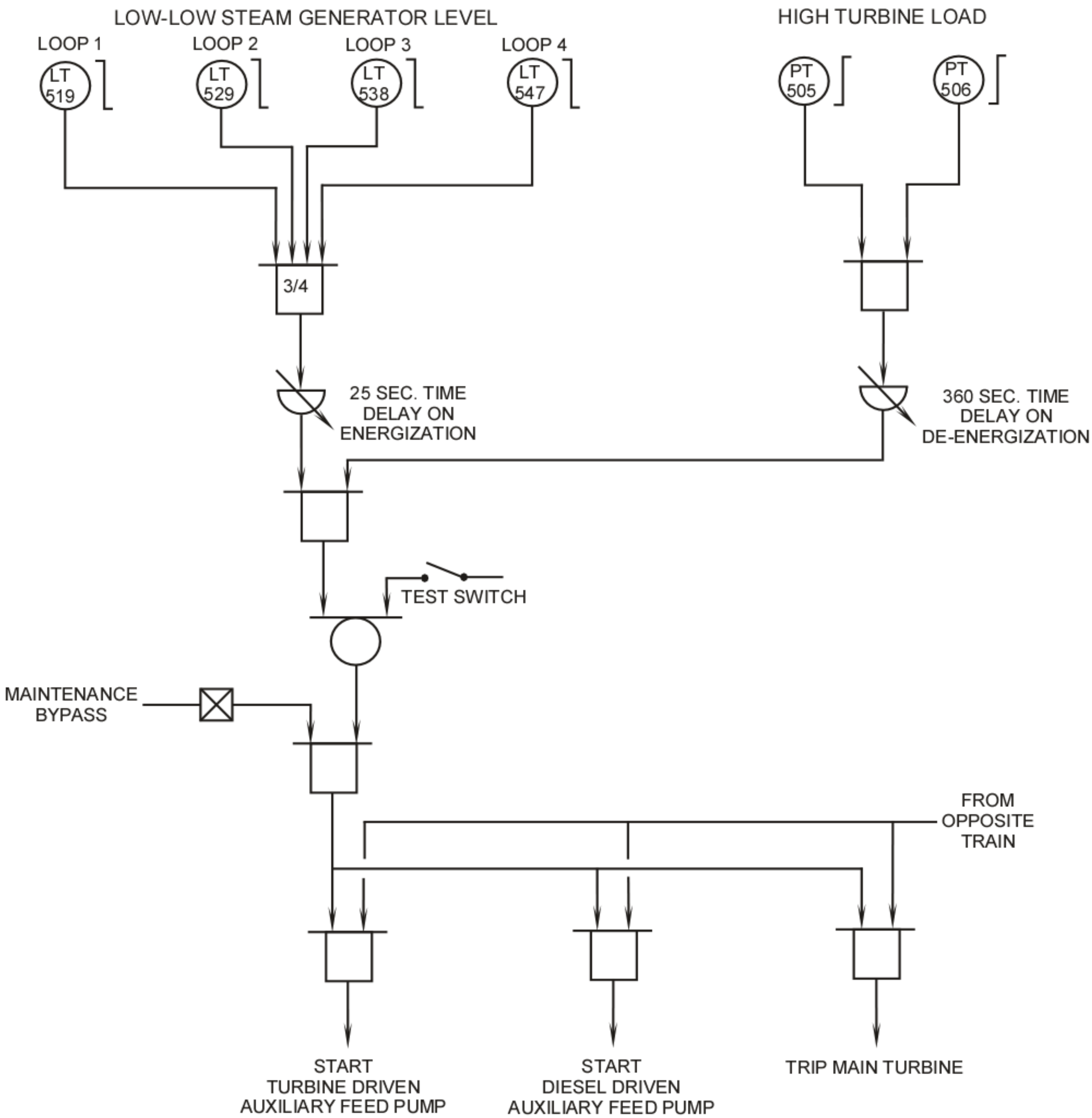


Figure 4.3-4 Trojan AMSAC Trip Circuit

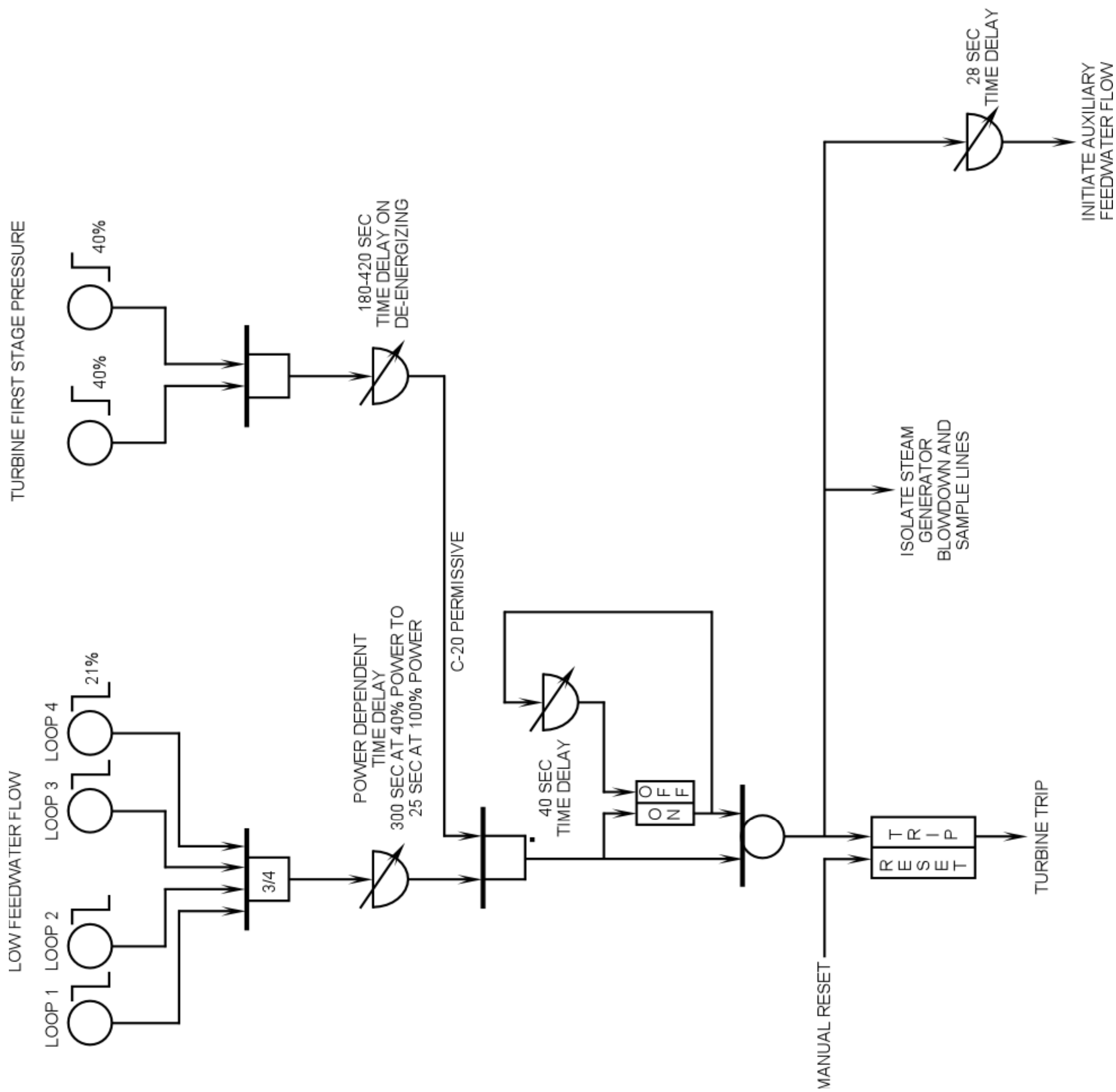


Figure 4.3-5 Indian Point Unit 3 AMSAC

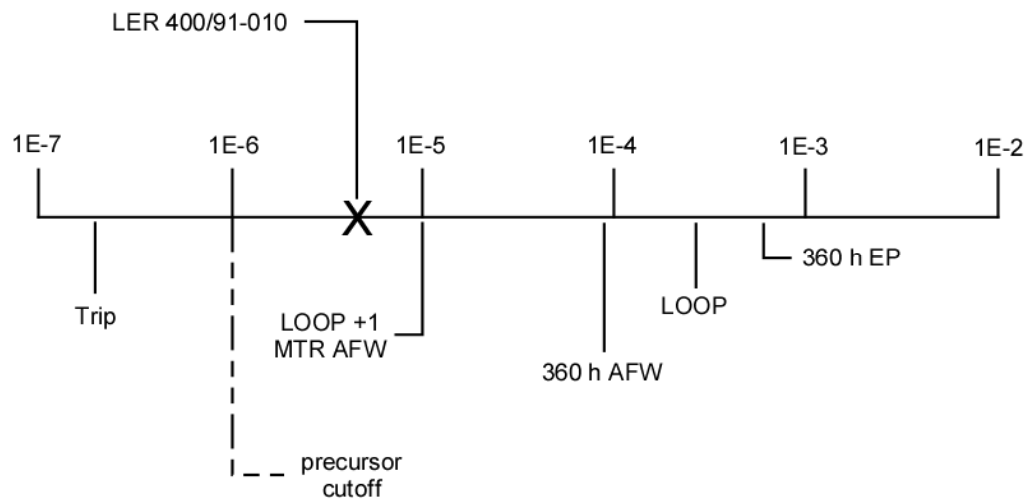


Figure 4.3-6(a) Relative Significance of Event Compared to Other Postulated Events at Harris 1

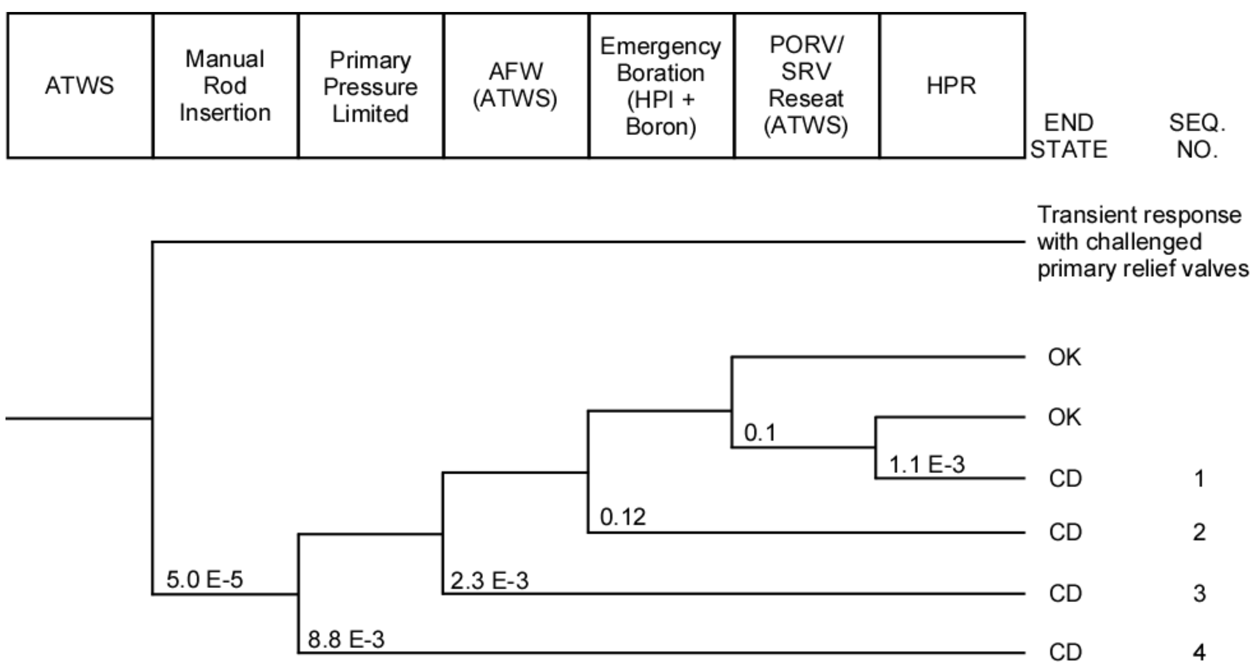
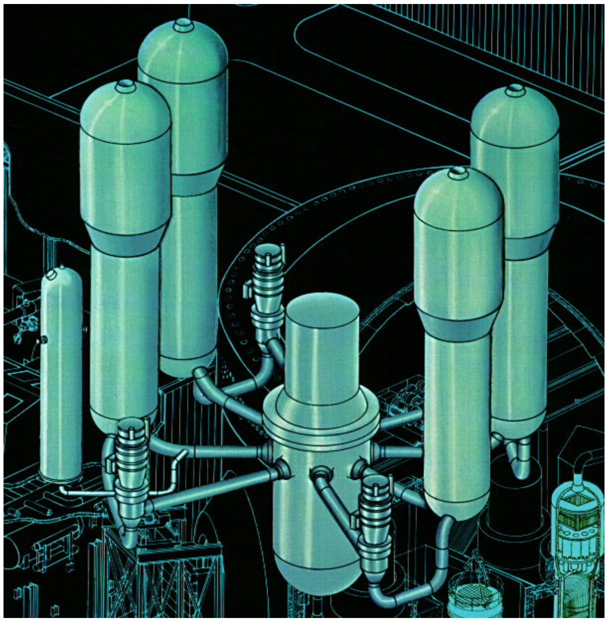


Figure 4.3-6(b) Model Used to Estimate the Conditional Core Damage Probability



Westinghouse Advanced Technology Manual

Chapter 4.4 – Loss of All AC (Station Blackout)

2020

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4.4.0 Loss of All AC Power (Station Blackout)

Learning Objectives:

1. Define the term “station blackout.”
2. Describe the initial plant response to a station blackout.
3. Describe the requirements of the blackout rule (10 CFR 50.63).
4. Describe the requirements of 10 CFR 50.155 regarding extended station blackout.
5. Describe the accident sequence that makes the loss of all Alternating Current (AC) power a major contributor to the total core damage frequency at some reactor plants.

4.4.1 Background and Basic Electrical Distribution Design

The General Design Criteria (GDC) in Appendix A of 10CFR50 establish the necessary design, fabrication, construction, testing and performance requirements for structures, systems, and components important to safety; these are the 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. GDC 17, "Electric Power Systems," requires that onsite and offsite electric power systems be provided to permit the functioning of structures, systems and components important to safety. These structures, systems, and components are required to remain functional to ensure that 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 that the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents. GDC 17 specifies additional requirements for both the onsite and offsite electrical power distribution systems to ensure both their availability and reliability.

Figure 4.4-1 shows a typical offsite power system associated with a nuclear plant. During plant operation, power is supplied to the Class 1E (onsite) distribution system by the main generator. In the event of a unit trip, the preferred source of power to the onsite distribution system would be the offsite grid. If offsite power is available, an automatic transfer to the preferred power source ensures a continuous supply of ac power to equipment required to maintain the plant in hot standby and to remove decay heat from the core. If offsite power is not available due to external causes such as severe weather or equipment failure, the undervoltage condition sensed in the onsite distribution system initiates a transfer to the onsite (standby) power source. Figure 4.4-2 shows a typical onsite ac power distribution system. In the event that an undervoltage condition is sensed on the emergency buses following a unit trip, the system is designed to ensure the opening of all supply breakers to the buses, the disconnection of all unnecessary loads, the starting of the Emergency Diesel Generators (EDG), and, when the machines have reached normal speed and voltage, the reconnection of all loads necessary to maintain the plant in a stable hot shutdown condition. If the onsite power sources are not available to re-energize the onsite distribution system, a Station Black-Out (SBO) has occurred.

An electrical distribution system in conformance with GDC 17 was once considered sufficient to ensure that a commercial nuclear power plant would be operated without undue risk to the health and safety of the public. The simultaneous loss of both the offsite and onsite sources of ac power (a station blackout) was considered incredible and therefore did not have to be considered in plant design or accident analysis.

4.4.2 Plant Response

A station blackout is defined as "the complete loss of Alternating Current (ac) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e., loss of the offsite electric power system concurrent with turbine trip and unavailability of the onsite emergency ac power system). Station blackout does not include the loss of available ac power to buses fed by station batteries through inverters or by alternate ac sources, nor does it assume a concurrent single failure or design basis accident"

(10CFR50.2). Because many safety systems required for reactor core cooling, decay heat removal, and containment heat removal depend on ac power, the consequences of a station blackout could be severe.

The immediate consequences of an SBO are not severe if it is not complicated by an accident such as a loss of reactor coolant, steam generator tube rupture, or loss of secondary coolant. If the SBO continues for a prolonged period, the potential consequences for the plant and public health and safety can be serious. The combination of core damage and containment overpressurization could lead to significant releases of fission products offsite. Any design basis accident in conjunction with an SBO would reduce the time to core damage and radioactive release.

The severity of an SBO for a Pressurized Water Reactor (PWR) depends primarily on the combination of the duration of the power outage and the response of the Reactor Coolant Pump (RCP) shaft seals (see Figure 4.4-3). During an SBO, the RCP seals undergo the simultaneous loss of high pressure seal injection and of cooling water to the RCP thermal barriers. With no seal injection, due to the loss of power to the charging pumps, reactor coolant leaks up the RCP shafts. Because the charging pumps are unavailable, this leakage cannot be replaced. The loss of cooling to the RCP thermal barriers, due to the loss of power to the component cooling water pumps, means that the leaking coolant is at very high temperatures. If the Westinghouse shutdown RCP seals have been installed, these seals are designed to automatically actuate to reduce leakage to near zero and prevent temperature degradation of the seals. If the shutdown seals are not installed, or do not operate properly, this high temperature leakage can result in degradation of the seals, which might increase reactor coolant leakage up to several hundred gallons per minute.

The severity of the loss of inventory may be mitigated through a controlled cooldown of the RCS. This evolution is covered in the Westinghouse emergency response guidelines (ECA 0.0, "Loss of all AC Power"). The RCS pressure reduction that results from coolant contraction and inventory loss through the RCP seals significantly reduces seal leakage. The cooldown can be maintained as long as natural circulation (or reflux boiling once the system becomes saturated) in the RCS transfers decay heat from the core to the steam generators. The steam generators are available as a heat sink, as long as the power-operated relief valves, the steam-driven auxiliary feed pump, and a water source are available. Manual or local operation of these components may be required to different degrees, depending on specific plant designs. Eventually, the Condensate Storage Tank (CST) will deplete, and some alternate source of water will be necessary. The normal back-up to the CST is service water, but the lack of AC power makes this source not available. When the station batteries are depleted, all remote operation and monitoring are impossible.

For all plants, if only permanently installed equipment is available, an extended station blackout will eventually result in core damage.

4.4.3 Station Blackout Rule

10CFR50.63, the station blackout rule, was added to the Code of Federal Regulations in 1988. This rule requires that each nuclear power plant be able to withstand for a specified duration and to recover from an SBO. The specified duration is to be based on the redundancy and reliability of onsite emergency ac power sources, the expected frequency of losses of offsite power, and the probable time needed to restore offsite power. The rule further requires that each plant's systems and equipment be capable of maintaining core cooling and containment integrity in the event of an SBO for the specified duration. The capability for coping with an SBO was to be determined by an appropriate coping analysis.

To comply with 10CFR50.63, each licensee was required to submit to NRR the proposed SBO duration for its plant and the justification for its selection, a description of the procedures to be implemented for SBOs, and a list of proposed modifications to equipment and procedures necessary to assure the plant's capability to cope with an SBO for the specified duration.

The station blackout rule also allows a licensee to take credit for an alternate ac source. 10CFR50.2 defines an alternate ac source as an ac "power source that is available to and located at or nearby a nuclear power plant and meets the following requirements:

(1) Is connectable to but not normally connected to the offsite or onsite emergency ac power systems;

(2) Has minimum potential for common mode failure with offsite power or the onsite emergency ac power sources;

(3) Is available in a timely manner after the onset of station blackout; and

(4) Has sufficient capacity and reliability for operation of all systems for coping with station blackout and for the time required to bring and maintain the plant in safe shutdown...."

The station blackout rule states that an alternate ac source constitutes acceptable capability to withstand an SBO provided that the licensee performs an analysis which demonstrates that the plant has this capability, that the licensee demonstrates by test the time required to start and align the source, and that the alternate ac source meets certain capacity requirements. If the alternate ac source meets those requirements and can be demonstrated to be available to power the shutdown buses within 10 minutes of the onset of an SBO, then no coping analysis is required.

Regulatory Guide 1.155, "Station Blackout," also issued in 1988, provides guidance for meeting the requirements of 10CFR50.63. The guide contains guidance on:

- Maintaining an individual emergency diesel generator target reliability of 0.95 or 0.975 per demand and assumes that, as long as the unavailability of DGs due to maintenance and testing is not excessive, the maximum DG failure rate would result in overall reliability for the emergency power system;

- Establishing a DG reliability program with test, maintenance, data collection, and management oversight elements to maintain the selected DG target reliability;

- Developing procedures and training to cope with an SBO;

- Selecting a plant-specific minimum acceptable blackout duration capability of 2, 4, 8, or 16 hours based on the reliability and redundancy of onsite emergency ac power sources, the expected frequency of losses of offsite power based on the independence of offsite power sources and the plant's susceptibility to severe weather, and the probable time needed to restore offsite power;

- Evaluating a plant's capability to cope with a blackout based on the selected duration capability; and
- Completing modifications as necessary to cope with a blackout.

The guidance is structured so that the lower emergency diesel generator target reliability (0.95) is selected at plants where the DGs are demonstrated to be relatively unreliable, and that longer blackout coping durations are selected at plants with relatively unreliable DGs and at plants that are more susceptible to losses of offsite power.

All licensees have completed actions to comply with the station blackout rule. As a result of the rule, all plants have established blackout coping and recovery procedures, completed training in accordance with these procedures, established emergency diesel generator reliability programs which have improved DG reliability, ensured a four- or eight-hour coping capability, and implemented modifications as necessary to cope with an SBO. Modifications include additional DGs (some as onsite emergency ac power sources and some as alternate ac sources); modifications to existing DGs and DG auxiliaries; the addition of or modifications to gas turbine generators, added cross-ties between buses, units, and power sources; and changes to dc load-shed procedures.

In accordance with the regulatory assessment requirement of the station blackout rule, the NRC has completed safety evaluations of licensee compliance actions for all plants. In addition, the NRC completed eight pilot inspections prior to 1995 to verify the adequacy of licensee programs, procedures, training, equipment and systems, and supporting documentation in implementing the station blackout rule. Because these inspections found only minor problems, the NRC staff concluded that additional inspections to verify adequate implementation of the rule were unnecessary.

4.4.4 Commission Order EA 2012-049 to 10 CFR 50.155

Following the reactor accidents at Fukushima Dai-ichi, the NRC Commission issued EA 2012-049, the order modifying licenses with regard to requirements of mitigation strategies for beyond-design-basis external events (BDBEE). This requires the licensees to implement and maintain strategies to mitigate a BDBEE with a simultaneous station blackout. No credit can be taken for the alternate AC source as defined in 10CFR50.63 unless it can be demonstrated that it would remain functional following the assumed BDBEE.

In essence, this requires the licensees to be able to cope with a station blackout for an unlimited period of time (in addition to the requirements of 10CFR10.63) under the severe conditions of the assumed BDBEE.

The industry developed NEI 12-06, Diverse and Flexible Coping Strategies (FLEX) Implementation Guide, to implement the requirements of EA-2012-049. The implementation will require licensees to ensure certain additional portable equipment is available, build safe storage locations for that equipment, purchase agreements with outside agencies to supply equipment during the BDBEE, and modify emergency procedures.

The Westinghouse Owner's Group (WOG) Flex procedures and most actions are complete. The acronym ELAP, (Extended Loss of AC Power), is used to designate a station black out that is expected to exceed a plant-specific time, typically one hour. At that point, the FLEX actions will be implemented.

In August 2019, the NRC amended its regulations to establish regulatory requirements for nuclear reactor applicants and licenses to mitigate beyond-design-basis events. The new rule, 10 CFR 50.155, "Mitigation of beyond deign basis events," makes NRC Order EA-12-049 "Order modifying Licenses With Regard to Requirements for Mitigation Strategies for Beyond Design Basis Event" (Mitigation Strategies Order), and Order EA 12-051, "Order Modifying Licenses With Regard to Reliable Spent Fuel Pool Instrumentation" (Spent Fuel Pool Instrumentation Order), generically applicable; establishes regulatory requirements for documentation of changes, and addresses several Petitions for Rulemaking that were submitted to the NRC following March 2011 Fukashima Dai-ichi event. The final rule was published in the Federal Register on August 9, 2019 (84 FR 39684) with an effective date of September 9, 2019. The FRN also announced the public availability of the final regulatory guidance, Regulatory Guide 1.226, "Flexible Mitigation Strategies for Beyond Design Basis Events" and Regulatory Guide 1.227, "Wide Range Spent Fuel Pool Level Instrumentation." [ADAMS Accession ML19058A006]

Each holder of an operating license for a nuclear power reactor under this part on September 9, 2019, and each holder of a combined license under part 52 of this chapter for which the Commission made the finding specified in 10 CFR 52.103(g) as 10 CFR 52.103(g) as of September 9, 2019, shall continue to comply with the provisions of paragraph (b)(2) of this section, and shall comply with all other provisions of this section no later than September 9, 2022, for licensees that received NRC Order EA–13–109 or September 9, 2021, for all other applicable licensees.
Withdrawal of orders and removal of license conditions. (1) On September 9, 2022, Order EA–12–049, ''Order Modifying Licenses With Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events,'' and Order EA–12–051, ''Order Modifying Licenses With Regard to Reliable Spent Fuel Pool Instrumentation,'' are withdrawn for each licensee or construction permit holder that was issued those Orders.

4.4.5 PRA Insights

Because of the dependence on electrical power by most of the systems involved in the mitigation of accidents, the electrical distribution system can be a major contributor to core damage frequency.

A major accident sequence has a station blackout as the initiator, followed by RCP seal failure, leading to a small-break loss of coolant accident. This sequence leads to core damage because of the unavailability of the high pressure injection system for replenishing the reactor coolant inventory.

Other sequences involving electrical power problems as initiators involve the failure of the auxiliary feedwater system, the failure of a pressurizer Power-Operated Relief Valve

(PORV) to shut, and the failure of a PORV to open to enable bleeding and feeding. Causes of loss of power initiators include:

1. The failure of DGs to start,
2. The failure of DGs to run after starting,
3. The failure to recover ac power,
4. The unavailability of DGs due to testing or maintenance, and
5. A local inverter fault which fails the automatic actuation of the auxiliary feedwater system.

A report prepared by the NRC Office of Nuclear Regulatory Research, “Final Report: Regulatory Effectiveness of the Station Blackout Rule” (2000), assesses whether the station blackout rule has been effective in achieving the desired outcomes. The report concludes that, although there are opportunities to clarify SBO-related regulatory documents, the rule is effective, and industry and NRC costs to implement the rule were reasonable. The report provides the following detailed conclusions:

- The reduction in the mean SBO-attributable core damage frequency was approximately 3.2E-05/RY, slightly better than the expected 2.6E-05/RY. As a result of improvements made to address the station blackout rule, more plants achieved a lower SBO-attributable core damage frequency than expected, and the plants with the greatest numbers of losses of offsite power from plant events and extremely severe weather conditions made the largest improvements, most by providing access to alternate ac power supplies. In addition, with some exceptions, the observed DG reliability performance exceeds the mean DG reliability assumptions of probabilistic risk assessments and individual plant examinations, indicating that SBO-attributable core damage frequencies are smaller than those stated in those risk assessments. As the blackout rule risk reduction objectives have been exceeded, further investigation of strategies for reducing SBO frequencies may not be needed.

- Before the blackout rule was issued, only 11 of 78 plants surveyed had a formal emergency DG reliability program, 11 of 78 plants had a unit average DG reliability of less than 0.95, and 2 of 78 had a unit average DG reliability of less than 0.90. Since the blackout rule was issued, all plants have established DG reliability programs which have improved DG reliability. Only 3 of 102 operating plants have a unit average DG reliability of less than 0.95, considering actual performance on demand and unavailability due to maintenance and testing with the reactor at power. However, unavailability due to maintenance and testing at power is greater than expected and explains why licensees appear to be having difficulty meeting the 0.975 target reliability. Decreased DG reliabilities and/or increased maintenance and testing unavailabilities erode the risk benefits obtained from implementing the blackout rule.

- Operating experience indicates that modifications implemented in response to the blackout rule have increased defense in depth against power interruptions. Turkey Point’s ability to ride out Hurricane Andrew in 1992 illustrates this point;

there is some likelihood that the plants would have lost all ac power during a 2.5-hour interval a few days after the storm without two emergency DGs added to address the blackout rule. Blackout-rule modifications also provide defense in depth to compensate for potential degradation of offsite ac power sources that may result from deregulation of the electric power industry or longer-than-expected times for recovery of offsite power following extremely severe weather.

- A value-impact analysis indicates that the rule's outcome was within the expected range of reductions in public dose per dollar of cost. Not expected was the addition of 19 power supplies at a cost of $174M. However, the addition of power supplies has resulted in significant plant-specific reductions in core damage frequency and has provided significant monetary benefits associated with greater operating flexibility resulting from longer allowed outage times for DGs.

The Westinghouse Electric Company (Westinghouse) has developed a Reactor Coolant Pump (RCP) Shut Down Seal (SDS) that, when actuated, is expected to restrict reactor coolant system (RCS) inventory losses to very small leakage rates during plant events that arise from the loss of all RCP seal cooling. The SDS is a thermally actuated, passive device that is to be physically installed in existing seal packages between each RCP No. 1 seal and the No. 1 seal leak-off line to provide a leak-tight seal in the event of existing seal failure due to elevated temperature conditions following the loss of RCP seal cooling. Installation of this seal may significantly reduce the risk associated with station blackout.

Figure 4.4-4 is the station blackout event tree for Farley after the shutdown seals were installed. If auxiliary feedwater flow is adequate and the pressurizer safeties and PORVs are closed, proper actuation of the shutdown seal takes the plant to an "OK" state. It is not necessary to perform the plant cooldown to ensure core cooling.

4.4.6 Plant Event

In March of 1990, Vogtle Unit 1 experienced a loss of all ac power for a period of approximately 36 minutes. The blackout was caused by a combination of human errors and equipment failures.

Prior to the loss of power, the plant was shutdown with the reactor vessel head installed, but with the head bolts de-tensioned. The reactor coolant system was drained to mid-loop for maintenance. Train A of the residual heat removal system was maintaining primary temperature. The B diesel generator was disassembled for maintenance, and the B reserve auxiliary transformer (RAT) was tagged out for maintenance. Offsite power was being supplied by the A RAT.

At approximately 9:20 a.m., a truck toppled a tower onto the A RAT, causing a loss of offsite power to Unit 1. The A diesel generator started but did not continue to run. The diesel trip signals were bypassed, and the diesel was emergency started at 9:56. During the period when ac power was not available, the reactor coolant system temperature increased by 46°F (an equivalent heatup rate of 1.3°F/min). After power was restored, the A train of the residual heat removal system was restarted to reduce the primary temperature.

The Vogtle station blackout occurred after the plant had been shut down for a period of time, so the decay heat level was very low. Had the blackout initiated with a larger decay heat load, the rate of temperature increase would have been much faster. In this case the shutdown plant conditions, and the short duration of the blackout minimized the consequences of the event (RCP seals were not threatened). Nevertheless, the Vogtle Unit 1 blackout was very similar to core damage sequences which appear in plant PRAs, and more severe initial conditions or a longer blackout duration could have resulted in core damage.

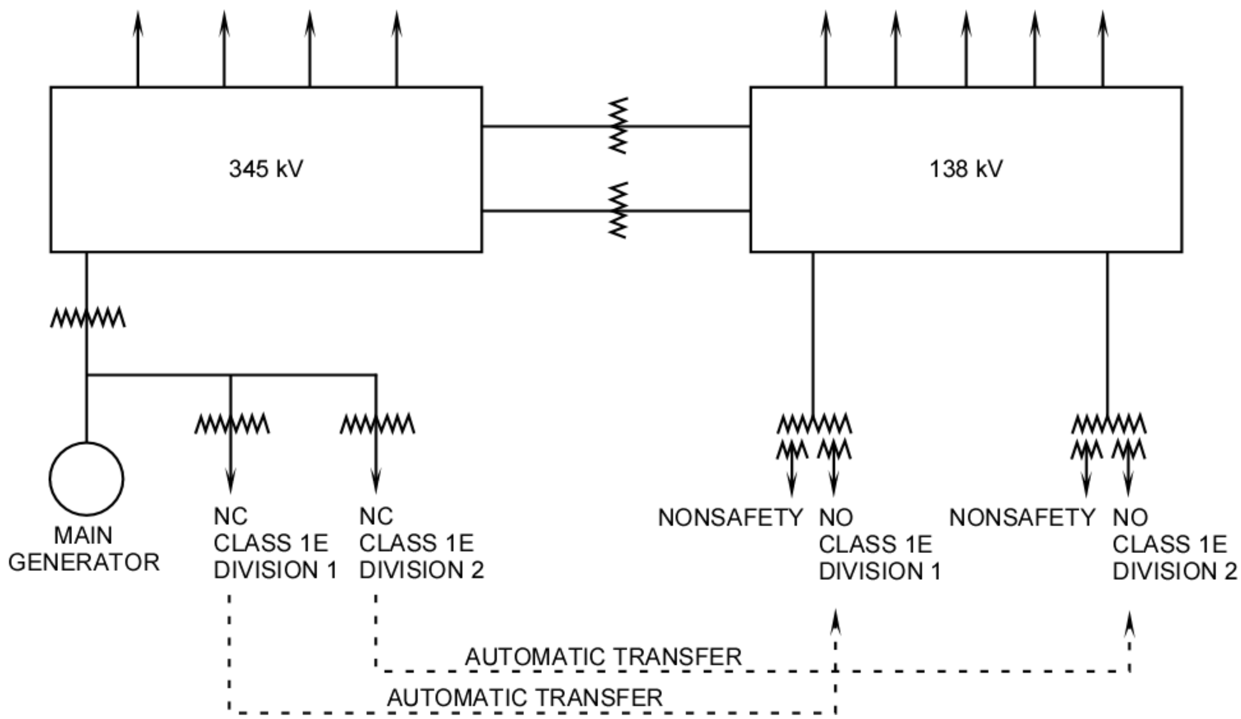


Figure 4.4-1 Typical Offsite AC Distribution

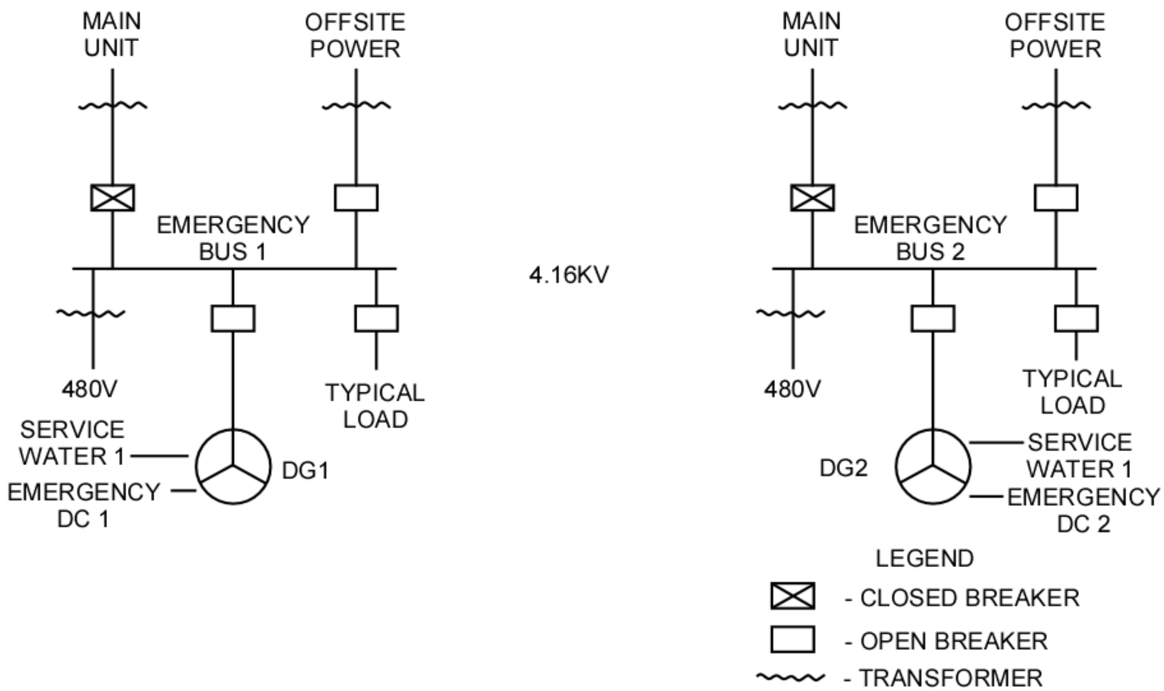


Figure 4.4-2 Typical Onsite AC Distribution System

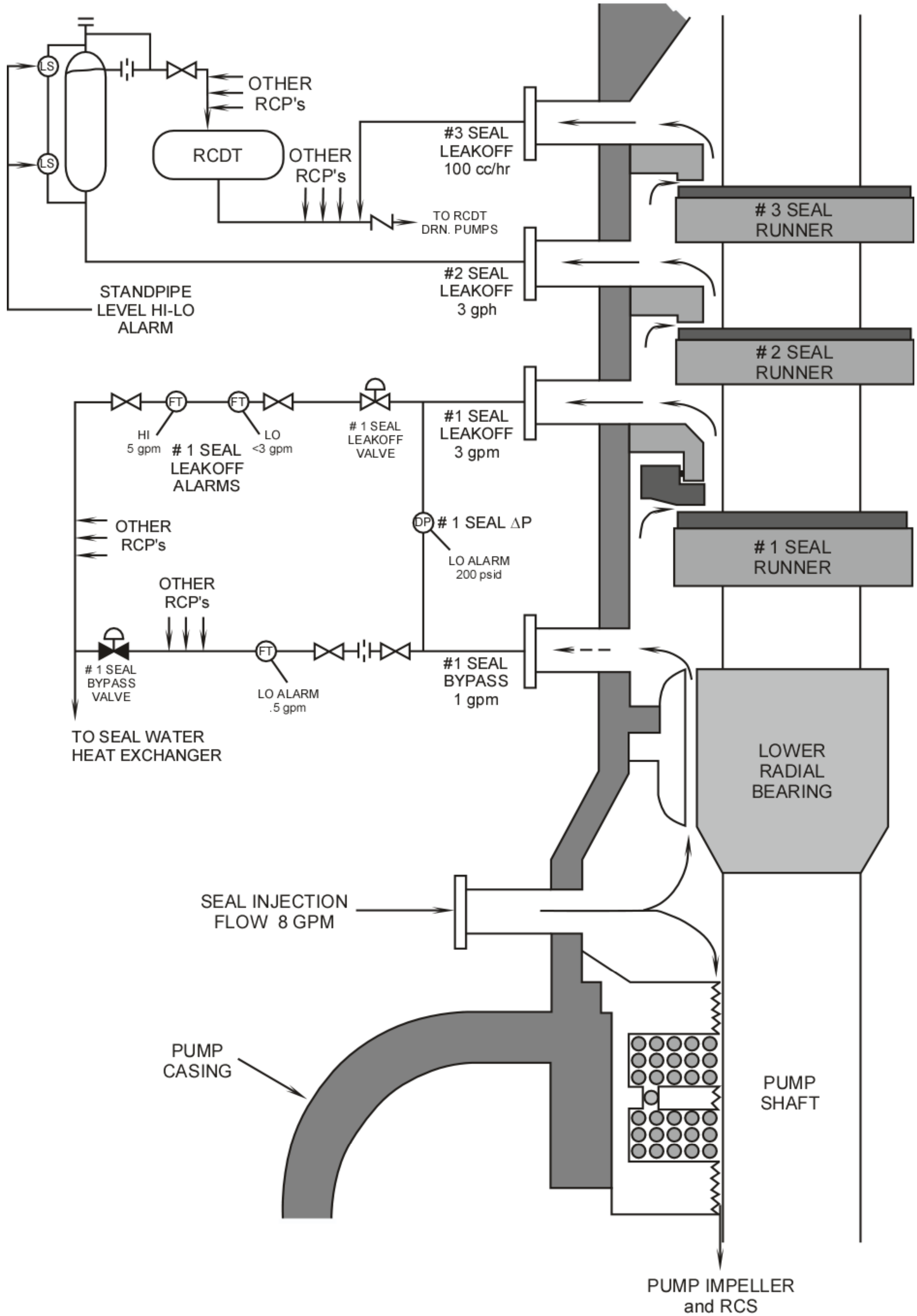


Figure 4.4-3 Seal Flow Diagram

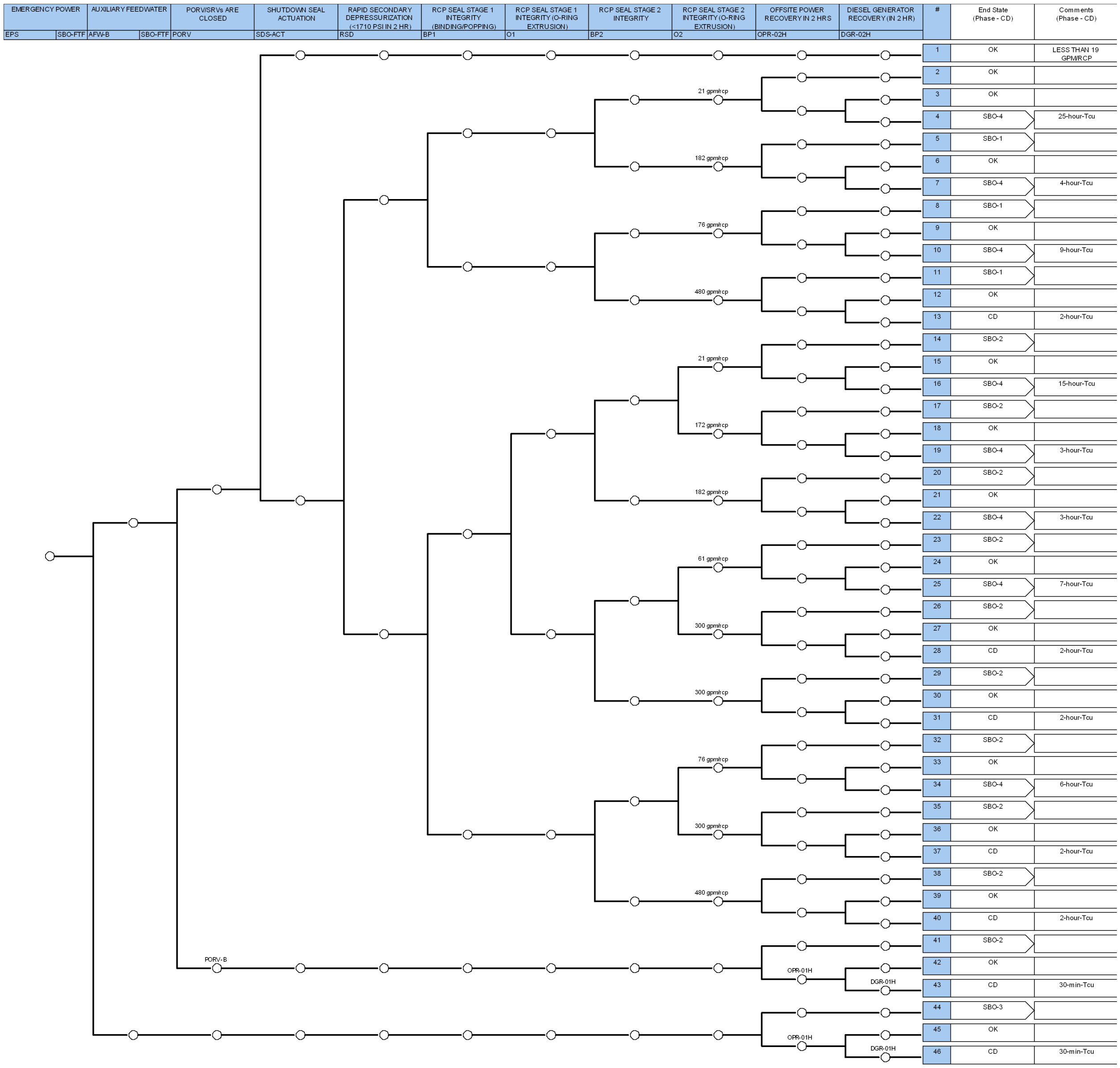
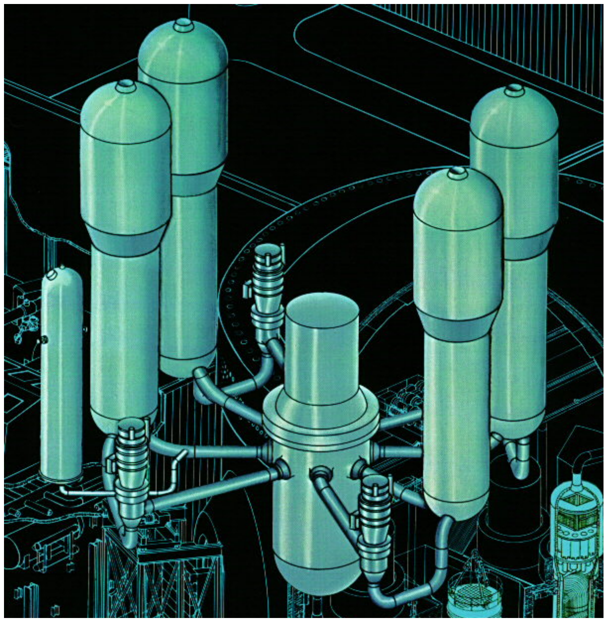


Figure 4.4-4 Farley SBO Event Tree



Westinghouse Advanced Technology Manual

Chapter 4.5 – Shutdown Plant Problems
SELF STUDY – INFO ONLY

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4.5.0 Shutdown Plant Problems

Learning Objectives:

1. State the purposes of the Residual Heat Removal (RHR) system.
2. Describe the alignment and operation of the RHR system during its shutdown cooling mode of operation.
3. Describe design features of the RHR system which could reduce its reliability when it is being used for decay heat removal.
4. Describe the consequences of losing decay heat removal capability when the reactor is in cold shutdown.

4.5.1 Introduction

One of the most significant problems associated with a shutdown reactor is the removal of the heat being produced by radioactive decay of the fission products produced during reactor operation. The General Design Criteria in Appendix A of 10CFR50 address this problem by requiring a residual heat removal system to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded. Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capability 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.

The core damage frequency associated with the inability to remove decay heat from the reactor core was demonstrated to be significant in the results of the Reactor Safety Study (WASH-1400). The overall probability of core damage in the first generation of large commercial power reactors was higher than had been expected (about 5×10^{-5} as compared to 1×10^{-6} per reactor year). Inadequate reliability of the decay heat removal system (specifically following a small-break loss of coolant accident) was shown to be responsible for a substantial portion of the overall probability of core damage. This fact, combined with repetitive events resulting in the inadequate or complete loss of decay heat removal capability in operating plants, led the NRC to designate shutdown decay heat removal requirements as an Unresolved Safety Issue (USI A-45). Under the established task action plan, the NRC has studied the adequacy of systems for safely removing decay heat from a reactor core during shutdown and to assess the value and the impact of alternative measures for improving the reliability of the decay heat removal function.

4.5.2 RHR System Description

The purposes of the residual heat removal system are as follows:

1. Removes decay heat from the core and reduces the temperature of the Reactor Coolant System (RCS) during the second phase of plant cooldown,
2. Serves as the low pressure injection portion of the Emergency Core Cooling Systems (ECCSs) 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 shutdown plant operations, the RHR system is used to remove the decay heat from the core and to reduce the temperature of the reactor coolant to the cold shutdown temperature (less than 200°F). The cooldown performed by the RHR system (from 350°F to less than 200°F), is referred to as the second phase of cooldown. The first phase of cooldown is accomplished by the Auxiliary Feed-Water (AFW) system, the steam dump system, 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.

The residual heat removal system, as shown in Figure 4.5-1, consists of two heat exchangers, two residual heat removal pumps, and the associated piping, valves, and instrumentation necessary for operational control. The inlet line to the residual heat removal system for the second phase of cooldown is 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 pump suction line from the reactor coolant system is normally isolated by two series motor-operated valves (8701 and 8702). The suction line has a relief valve located downstream of the isolation valves; all three valves are located inside the containment. Each RHR supply to the RCS cold legs is isolated from the reactor coolant system by two check valves located inside the containment, and each RHR pump discharge line is can be isolated by a normally open motor-operated valve (8809A or 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 cool down the plant is not compromised; however, the time required for the cooldown is extended. The water chemistry requirements for the residual heat removal system are the same as those for 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 in each residual heat removal train between the pump and its associated heat exchanger.

To ensure 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.

4.5.2.1 Component Description

4.5.2.1.1 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 suctions for pump cooling. A control valve located in each minimum flow line (610 or 611) is regulated by a signal from the flow transmitter located in each pump discharge header. Each control valve opens when the RHR pump discharge flow is less than 500 gpm and the pump is running and closes 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.

4.5.2.1.2 Residual Heat Removal Heat Exchangers

Two heat exchangers are installed in the system. The heat exchanger design is based on the heat load and the temperature difference between the reactor coolant and component cooling water 20 hours after the reactor has been shut down. The temperature difference between these two systems at that time is at its minimum, thus accounting for 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.

4.5.2.1.3 Residual Heat Removal System Valves

Each valve that performs a modulating function is equipped with two stem packing glands and an intermediate leakoff 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 back-leakage through the check valves which separate the residual heat removal system from the reactor coolant system.

The residual heat removal system includes two isolation valves (8701 and 8702) in series in 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. Many plants have removed this automatic closure in response to recommendation #5 of the 1985 AEOD report referred to in section 4.5.3.

4.5.2.2 System Features and Interrelationships

4.5.2.2.1 Plant Cooldown

The initial phase of reactor cooldown is accomplished by transferring heat from the RCS to the steam and power conversion system via the steam generators. 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 the 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.

The 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 heat exchangers coincident with manual adjustment of the heat exchanger bypass valve (HCV-618).

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. These lines 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.

4.5.2.2.2 Solid Plant Operations

The residual heat removal system is used in conjunction with the chemical and volume control system (see Figure 4.5-2) during cold shutdown operations (less than 200°F) to maintain reactor coolant chemistry and pressure control. Solid plant operations (no 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. The term "solid plant" refers to the fact that the reactor coolant system is completely filled to the top of the pressurizer with coolant.

The RHR system is used to circulate 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 accompany small temperature changes. Volume control of the reactor coolant is preferred because of the faster response and because any desired pressure change can be obtained within controllable limits. Since control of the mass in the RCS is the preferred means of pressure control, a portion of the RHR flow is diverted to the chemical and volume control system through valve HCV-128.

The flow diverted to the CVCS is controlled by the position of the backpressure control valve PCV-131, which is located downstream of the letdown heat exchanger. During solid plant operations the flow water returned to the reactor coolant system is determined by the charging rate, which is controlled through manual positioning of 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 (via 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 between the charging and letdown flow rates. Pressure regulation is necessary to maintain the pressure in the RCS to a selected range dictated by the fracture prevention criteria requirements of the reactor vessel.

4.5.2.2.3 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 and 8702) are closed, and the isolation valve from the refueling water storage tank (8812) is opened. The reactor vessel head is lifted slightly, and refueling water is pumped into the reactor vessel through the normal RHR system return lines and then into the refueling cavity through the open reactor vessel. The reactor vessel head is gradually raised as the water level in the refueling cavity rises. 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 valve is 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 refueling, the RHR system is used to return the water from the refueling cavity to the refueling water storage tank via manual valve 8735. The water level is drained to the level of the reactor vessel flange. The remainder of the water in the refueling cavity is removed through drains located in the bottom of the refueling canal.

4.5.2.3 System 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 operation 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 RHR system utilizes the containment sump as a source of water, and the RHR heat exchangers to cool the water prior to returning the water 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.

4.5.2.4 Consequences of Loss of RHR

After the fission process is stopped (i.e., the reactor is shutdown) the continuing radioactive decay of fission products and irradiated core materials produces a significant amount of heat. For a typical 3411-MWt nuclear plant, the power associated with this decay heat is about 20 MWt, 24 hours after shutdown from full power. If a means to remove this heat that is being generated in the core is not available, it is obvious that the temperature of the fuel and fuel cladding will increase. Even if the plant is in a cold shutdown condition, the fuel and clad temperature will continue to increase until the point is reached that clad oxidation and fuel melting can occur.

If the plant is in cold shutdown to perform maintenance or refueling, it is very likely that the RCS will be open with steam generator primary manways removed, the pressurizer relief valves open, the pressurizer safety valves and manways removed, or the reactor vessel head vented. When the plant is in mode 5 (cold shutdown), the technical specifications do not require that containment integrity be maintained. The containment equipment hatch and personnel airlocks could be open, and the positions of containment isolation valves could be indeterminate.

Because of the possibilities for system status and alignment during cold shutdown, the time available to replace lost RCS inventory and to re-establish decay heat removal before bulk boiling, core uncovery and fuel damage takes place will vary from plant to plant. The consequences can be severe because of the inability to contain the radioactive fission products that are released once fuel degradation begins.

4.5.3 NRC and Industry Studies

In addition to the studies being performed in conjunction with the resolution of USI A-45, other studies of decay heat removal capabilities have been conducted by independent NRC and industry nuclear safety groups.

A study published by the Nuclear Safety Analysis Center (NSAC) in 1983, "Residual Heat Removal Experience Review and Safety Analysis" (NSAC Report 52), concludes that the "reliability of shutdown decay heat removal could be an important generic safety issue." The study compiled information on over 250 pressurized water reactor (PWR) events involving RHR systems. Over 100 of the events involved an actual loss or significant degradation of decay heat removal capability when it was required to be operable. The results of the events that had specific safety implications fell into three categories:

(1) Loss of reactor coolant inventory via the RHR system,

(2) Over pressurization of the RCS, and

(3) Loss of long-term decay heat removal capability due to RHR system failures.

Even though loss of RCS inventory during cold shutdown conditions might have previously been thought to be unimportant, the analysis by the NSAC concluded that, in certain instances, the loss of inventory combined with the degraded condition of other systems (permitted by technical specifications) needed to replace the lost RCS coolant demonstrated the potential for core uncovery. In one event, if timely operator action had not been taken, core uncovery could have taken place in about 25 minutes (Sequoyah Unit 1, February 11, 1981).

Because of previous repressurization events that have occurred during cold shutdowns at PWRs, the NRC has required that automatic protective systems to prevent cold overpressure be installed. Improper operation and maintenance of these systems can still render them ineffective. Malfunctions or personnel errors during cold shutdown can result in repressurization of the RCS to the setpoint pressure of the pressurizer code safety valves. High pressures could have significant implications regarding reactor vessel brittle fracture limitations.

Many events have taken place that caused the complete loss of the ability to remove decay heat during shutdown. Even though the majority of the events have taken place long enough after shutdown such that sufficient time existed for recovery, the potential exists for decay heat removal losses that could result in bulk boiling conditions in the core. Coolant boiling could create a significant hazard for personnel working in the area as well as lead to core damage.

The NSAC report concludes that significant improvements in decay heat removal capabilities could be made by simply upgrading plant procedures and administrative controls used during plant shutdown. Historically, utilities have emphasized stringent controls and procedural requirements during power operation. The assumption was that during cold shutdown, the plant was in a "safe" condition and that strict controls and safety equipment operability were not necessary. The results of analysis of repetitive events involving decay heat removal systems have demonstrated that this is not necessarily the case.

Some of the recommendations made in the NSAC report include:

1. Improvements in training and procedures related to loss of RCS coolant during RHR system operation (when automatic ECCS is not required to be available by technical specifications), cold overpressure protection, RCS void formation during cold shutdown, long-term unavailability of the RHR system, restoration of air-bound RHR pumps, and inadvertent automatic RHR system isolation;
2. Better administrative controls for maintenance and surveillance during cold shutdown, vessel level monitoring during partially drained operations, critical valve positioning and status control, outage control by operation personnel, and maintenance prioritization; and
3. Minor hardware modifications including better control room indications and alarms for low RHR system flow, actual valve position, valve controls, and shutdown reactor vessel level monitoring systems, and improved instrumentation, data collection and human engineering for shutdown reactor plant operations.

A case study prepared by the NRC office for Analysis and Evaluation of Operational Data (AEOD), "Decay Heat Removal Problems at U.S. Pressurized Water Reactors" (AEOD/C503), was published in December 1985. This study concludes that "for certain postulated events, unless timely corrective actions are taken, core uncovery could result on the order of one to three hours. To date, no serious damage has resulted from the loss-of-DHR [decay heat removal]-system events that have occurred at U.S. PWRs. However, many of the events which have occurred thus far may serve as important precursors to more serious events."

The study's analysis indicates that the underlying or root causes of most of the loss-of-DHR-system events were related to human-factors deficiencies involving procedural inadequacies and personnel error. The majority of the errors were committed during maintenance, testing, and repair activities in shutdown plants. The leading cause of loss of decay heat removal capability was inadvertent automatic closure of the suction isolation valves as a result of human error.

The results of the AEOD analysis show that, in losses of the DHR system occurring during the early stages of shutdown (e.g., within 24 hours after a reactor trip), with the RCS partially drained, or shortly after activation of the DHR system before the primary system is drained, corrective actions must be taken promptly (i.e., within less than two hours unless a loss of RCS inventory is involved) to either restore the DHR system or to implement alternate methods for removing reactor decay heat. This analysis emphasizes the fact that a loss of decay heat removal capability can lead to a safety-significant event unless timely recovery actions are taken.

The AEOD recommendations for improving the reliability of decay heat removal systems include:

1. Improving human factors by upgrading coordination, planning, and administrative control of surveillance, maintenance, and testing operations which are performed during shutdowns;
2. Providing operator aids to assist in determining the time available for DHR recovery and to assist operators in trending parameters during loss-of-DHR events;
3. Upgrading the training and qualification requirements for operations and maintenance staff;
4. Requiring the use of reliable, well-analyzed methods for measuring reactor vessel level during shutdown modes;
5. Modifying plant design to remove automatic closure interlocks and/or power to the DHR suction isolation valves during periods which do not require valve motion; and
6. Clarifying plant technical specifications to eliminate ambiguities associated with operating mode definitions.

4.5.4 Plant Events

4.5.4.1 Diablo Canyon Unit 2 (4/10/87)

On April 10, 1987, Diablo Canyon Unit 2 experienced a loss of decay heat removal capability in both trains. The reactor coolant system had been drained to the midpoint elevation of the hot-leg piping in preparation for the removal of the steam generator manways. During the 85-minute period that the heat removal capability was lost, the reactor coolant temperature increased from 87°F to the boiling point, steam vented from an opening in the reactor vessel head, water spilled from the partially unsealed manways, and the airborne radioactivity levels in the containment rose above the maximum permissible concentration of noble gases allowed by 10CFR20. The reactor, which was undergoing its first refueling, had been shut down for seven days at the time, and the containment equipment hatch had been opened.

Erroneous level indication, inadequate knowledge of pump suction head/flow requirements, incomplete assessment of the behavior of the air/water mixture in the system, and poor coordination between control room operations and containment activities all contributed to the event. Under the conditions that existed, the system that measured the level of coolant in the reactor vessel indicated erroneously high and responded poorly to changes in the coolant level. In addition, the intended coolant level was later determined to be below the level at which air entrainment due to vortexing was predicted to commence. At the time of the event, the plant staff believed that the coolant level was six inches or more above the level that would allow vortexing.

The event began when a test engineer, in preparation for a planned containment penetration local leak rate test, began draining a section of the reactor coolant pump leakoff return line, which he believed to be isolated. However, because of a leaking boundary valve, this action caused the volume control tank fluid to be drained through the intended test section to the reactor coolant drain tank. The control room operators, who were not aware that the engineer had begun conducting the test procedure, increased makeup flow to stop the level reduction in the volume control tank. A few minutes later, the operators were informed that the reactor coolant drain tank level was increasing, but they could not determine the source of the leakage. Although the actual level of coolant in the reactor vessel was apparently dropping below the minimum intended level, the indication of level in the vessel remained within the desired control band. Subsequently, the electrical current to the operating RHR pump was observed to be fluctuating. The second pump was started, and the running pump was shut down. The current to the second pump also began to fluctuate, so it was immediately shut down as well.

The operators did not immediately raise the water level in the reactor because they still did not know the source of the leakage, the true vessel level, or the status of the work on the steam generator manways. Operators were sent to vent the RHR pumps. One pump was reported to be vented, and a few minutes later an attempt was made to restart the pump. The electrical current to the motor again began to fluctuate, and the pump was secured. During this period the operators did not know the temperature of the coolant in the reactor vessel because the core-exit thermocouples had been disconnected in preparation for the planned refueling. Within an hour, airborne activity levels in the containment were increasing, and personnel began to evacuate from the containment building.

When the operators learned that the steam generator manways had not been removed, action was initiated to raise the reactor vessel water level by adding water from the refueling storage tank. About 10 minutes later, the test engineer identified the source of the leakage and stopped it. When vessel level had been raised sufficiently, one of the RHR pumps was started, and the indicated pump discharge temperature immediately rose to 220°F. At this time the reactor vessel was slightly above atmospheric pressure, and steam was venting from an opening in the reactor vessel head.

Following the loss of decay heat removal capability at Diablo Canyon, the utility took a number of actions to prevent loss of RHR suction during low level operation and to improve recovery should such a loss occur. These actions included the following: (1) evaluation of the reactor vessel level indicating system to determine the level at which vortexing would occur and the effect of vortexing on level measurement; (2) enhancements of instrumentation to provide accurate level measurement, alarm capability, and core-exit temperature measurement during low level operation; (3) enhancement of procedures to include requirements for verifying proper RHR pump suction before starting the second RHR pump; (4) precautions specifying minimum vessel levels as a function of RHR flow; (5) improvements in work planning, control, and communication to include restriction of the work scope to items that do not have the potential to reduce RCS inventory; and (6) improvement of operator training, including a discussion of the potential causes of RHR flow loss, as well as recovery procedures.

Information Notice 87-23 was subsequently issued by the NRC to alert other licensees to the event, and Generic Letter 87-12 was issued to (1) assess safe operation of PWRs when the reactor coolant system water level is below the top of the reactor vessel; (2) determine whether the RHR system meets the licensing basis of the plant, such as GDC 34 and the technical specifications, in this condition; (3) determine whether there is a resultant unanalyzed event that may have an impact on safety; and (4) determine whether any threat to safety that warrants further NRC attention exists in this condition.

4.5.4.2 North Anna Unit 1 (6/27/87)

On June 21, 1987, North Anna Unit 1 operators discovered that approximately 17,000 gallons of reactor coolant had been lost from the RCS while the unit was in cold shutdown. The delay in discovering the inventory loss resulted from the use of pressurizer level as an indication of reactor coolant inventory, failure to use all available indications, and failure to perform a mass inventory balance.

On June 17, 1987, during preparations for a startup following a refueling outage, a problem developed with a reactor coolant pump motor, requiring removal of the motor. When the problem was discovered, the unit was at approximately 195°F and 325 psig, with a bubble in the pressurizer. In order to establish plant conditions for removal of the motor (which may involve leakage from the RCS), the plant would normally have been cooled to less than 140°F and drained to the midpoint level of the hot-leg nozzle, and the residual heat removal system would have been placed in operation. In order to expedite the work, the plant was cooled to 110°F, and the pressurizer was cooled by filling the pressurizer while venting it via the Power-Operated Relief Valves (PORVs). The pressurizer level was lowered to 80% with the PORVs open. The PORVs were then shut because the vapor-space temperature led the operators to believe that a bubble still existed, and the level was further lowered to 20%. This evolution was conducted in accordance with a procedure that was not specifically intended for draining the system. The operators did not realize that lowering the level with the PORVs shut and then subsequently cooling the pressurizer would cause a vacuum to form in the pressurizer and cause the level to hold at 20%.

On June 18, 1987, the pump motor was uncoupled, and a small amount of expected leakage (estimated at 2 gpm) up the pump shaft was encountered. This leakage was relatively clean water from the seal injection line past the pump seals, which did not provide a tight seal when the motor was uncoupled. Makeup to the RCS was from the Volume Control Tank (VCT). The VCT level was maintained, with the VCT pressure greater than the RCS pressure. The operators believed that maintaining the pressurizer and VCT levels would maintain the reactor coolant inventory by making up for any losses with flow from the VCT to the RCS. Voids consisting of noncondensible gases and vapor formed in the RCS and collected in the system high points (reactor vessel head and steam generator tubes). The voids were not indicated by any decrease in pressurizer level.

On June 21, 1987, a decision was made to reduce the pump shaft leakage by raising the pressurizer level, cycling the PORVs to vent the pressure, and then lowering the pressurizer level to draw a slight vacuum in the pressurizer. This was a condition that already existed, but the operators were unaware of it. When the PORVs were cycled, the pressurizer relief tank pressure dropped, as well as the pressurizer level, indicating that a vacuum already existed in the pressurizer. The reactor vessel level indicating system (RVLIS) indication at this time was 79%; however, the operators were not monitoring this indication because the system had been modified during the previous outage and the operators thought it would be unreliable. Because of the recorder scale and the time span visible on the RVLIS trend recorder, the change in the level indication would only have been noticed by comparing it with a separate plot or by rolling it back 12 to 24 hours to compare it with the present indication. When the condition was discovered, the operators took action to provide makeup to the RCS and to vent the reactor vessel head, as well as to check other available information to account for the system inventory. A total of 17,000 gallons of borated water was required to reestablish the RCS inventory.

The procedure used to establish plant conditions for removing the RCP motor did not contain appropriate instructions for monitoring and maintaining the RCS inventory. The licensee changed the procedure to require a review of the reactor coolant system inventory and routine surveillance of all available level indications, including that from the RVLIS.

4.5.5 Summary

In presenting its proposed resolution of USI A-45 in SECY-88-260, the staff recognized the ongoing actions in implementing the Commission's Severe Accident Policy, one of which was a generic letter to require all plants in operation or under construction to undergo a systematic examination termed the Individual Plant Examination (IPE) to identify any plant-specific vulnerabilities to severe accidents. The IPE analysis is intended to examine and understand the plant emergency procedures, design, operations, maintenance, and surveillance to identify vulnerabilities. The analysis will examine both the DHR systems and those systems used for other functions. It is anticipated that a future extension of the IPE program will require examination of externally-initiated events, some of which significantly contribute to DHR failure-related core damage frequency.

To resolve USI A-45, one of the alternatives proposed by the staff was to have each licensee perform a risk assessment for its plant. This assessment would be done in conjunction with the IPE program. Available options for acceptable risk assessments include performing a Level-1 PRA (enhanced) or performing an analysis using the IDCOR IPEM. Thus, USI A-45 was RESOLVED with the requirement for plant-specific analyses to be conducted under the IPE program.

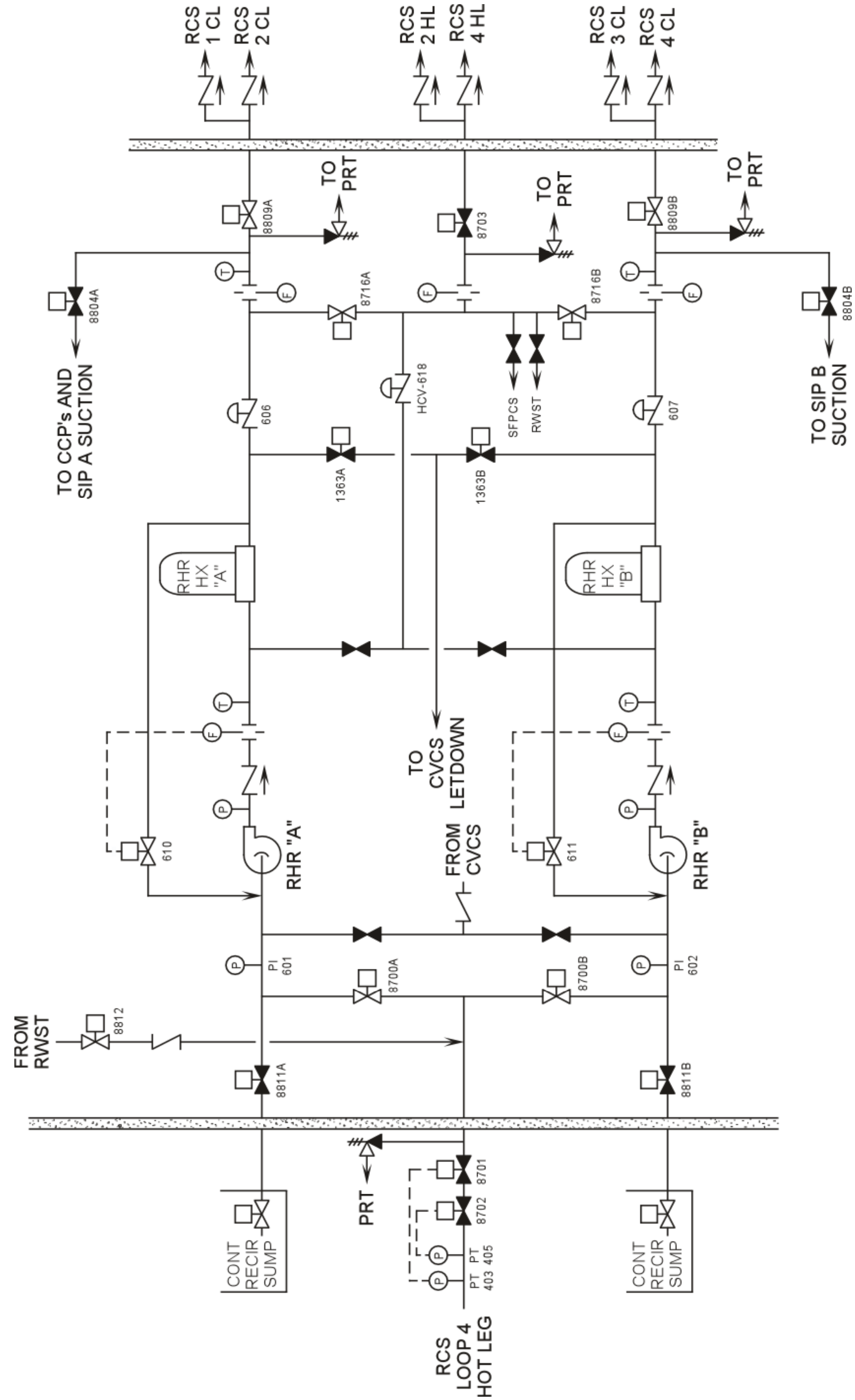


Figure 4.5-1 Residual Heat Removal System

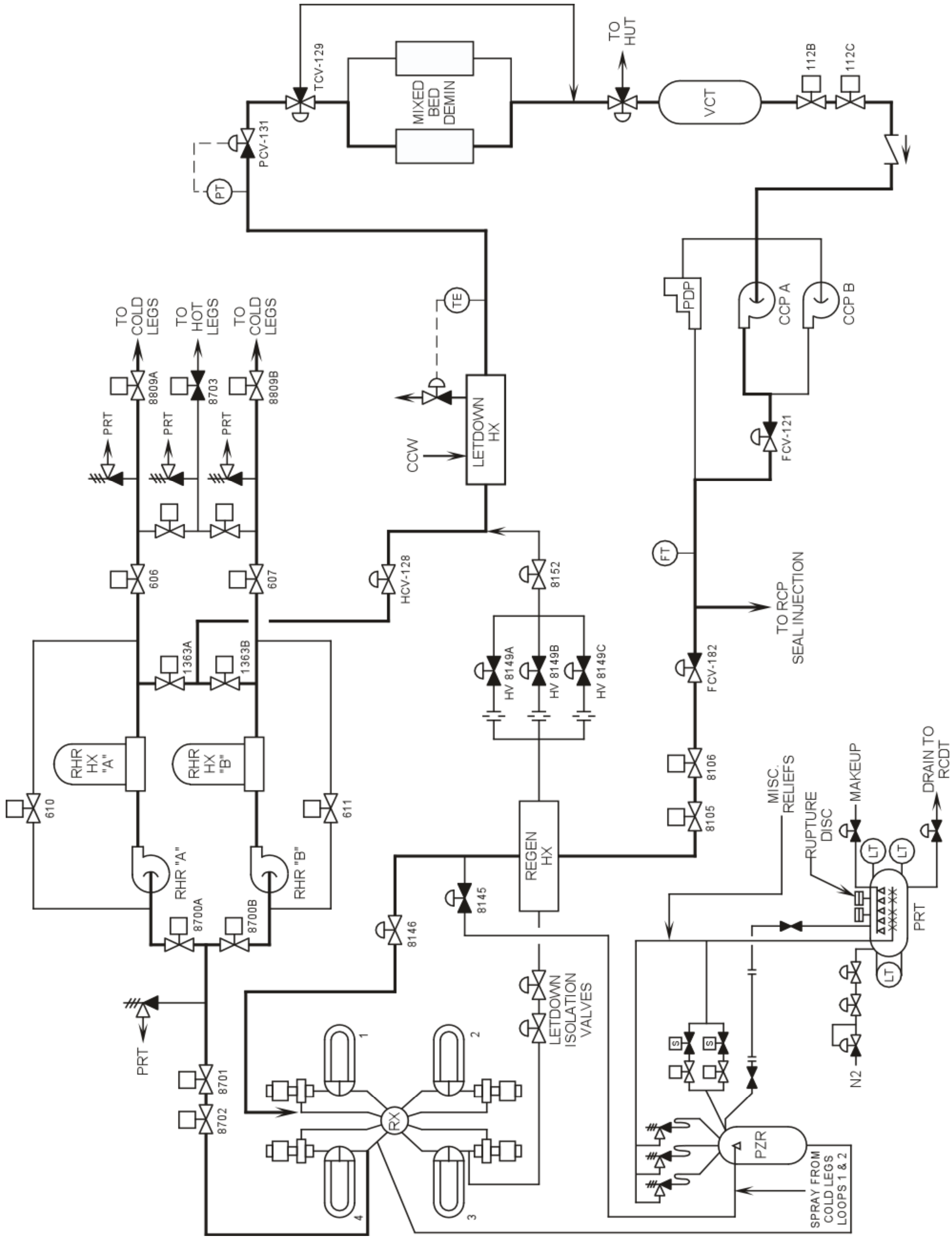
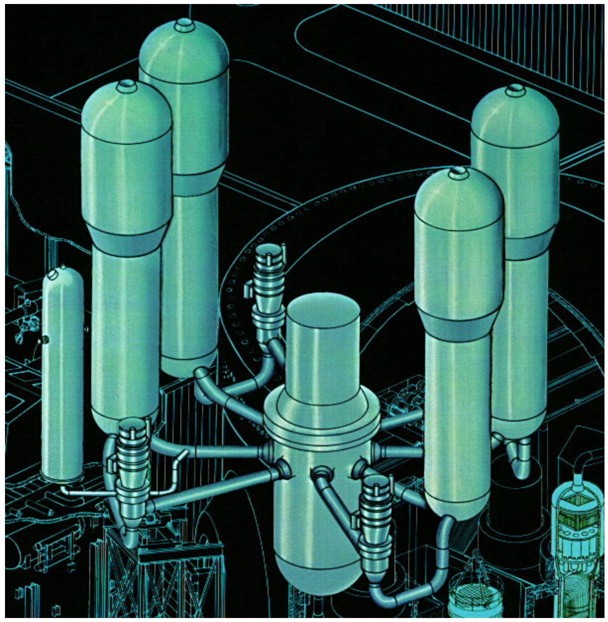


Figure 4.5-2 Solid Plant Pressure Control



Westinghouse Advanced Technology Manual

Chapter 4.6 – Voided Piping Concerns

2020

Human Resources Training & Development

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

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4.6.0 VOIDED PIPING CONCERNS

Learning Objectives:

1. Describe the causes of voided piping.

2. Describe the potential consequences of voided piping.

3. Describe licensee actions to minimize the consequences of voided piping.

4.6.1 Introduction

Voided piping has been a recurring problem throughout the nuclear industry and has been the topic of several NRC and INPO publications. Voided piping can lead to the loss of function of safety-related systems, and this loss of function is often not detected by surveillance activities. Because the causes of voiding are varied and often subtle, constant vigilance is required to prevent and mitigate voided piping.

4.6.2 Causes of Voided Piping

The following is a discussion of some common causes of voided piping. This list is not comprehensive.

4.6.2.1 Leakage from Safety Injection Accumulators

Accumulator pressure is maintained by a volume of high pressure nitrogen (650 psig) in approximately the top half of an accumulator tank. Some nitrogen is absorbed by the accumulator water. Leakage of water from this source into the lower pressure components of the ECCS can release gas, as the nitrogen comes out of solution at the lower pressure.

In 2005, a leak from an accumulator at Indian Point 2 caused the inoperability of one safety injection pump due to the pump casing being filled with gas. The inspection team concluded that the other two safety injection pumps would not have functioned 75% of the time in response to certain loss-of-coolant accidents (Reference 1).

In January 1995, Residual Heat Removal (RHR) pipe supports at Sequoyah were found to be damaged. The cause was determined to be water hammer that occurred during RHR pump testing. Large gas pockets composed of 99 percent nitrogen were later found in the RHR lines; they probably resulted from leakage of water from a cold-leg accumulator tank (Reference 2).

On three occasions in November and December of 1996, water hammer occurred in the Low Pressure Safety Injection (LPSI) system at Waterford when the LPSI pumps were started. The licensee determined that the large pressure transients were caused by the presence of a nitrogen gas volume in the pump discharge lines. The gas had come out of solution when nitrogen-saturated, 600-psig water leaked from the safety injection tanks into the lower pressure LPSI piping. When the pumps started, the compressible gas volume created a transient pressure surge in the LPSI system (Reference 3).

4.6.2.2 Check Valve Leakage from High Temperature/High Pressure Systems into Lower Pressure Systems

In 1985, San Onofre Unit 1 experienced multiple check valve failures in the feedwater lines. The feedwater lines voided with steam due to the leakage through the failed check valves. When auxiliary feedwater was subsequently introduced into the feedwater lines, the rapid condensation of the steam voids produced a severe water hammer event (Reference 4).

INPO SOER 84-3 (Reference 5) documents several examples of Auxiliary Feed-Water (AFW) pumps disabled by steam binding after leakage of hot feedwater into AFW lines through check valves.

4.6.2.3 Evolution of Dissolved Gas Due to Pressure Changes

The following discussion is from SOER 97-1, "Potential Loss of High Pressure Injection and Charging Capability from Gas Intrusion" (Reference 6).

Units designed with centrifugal charging pumps are often equipped with minimum flow recirculation lines that are routed to the reactor coolant pump seal return line and from there back to the common charging pump suction header. During normal operation, the pressure-reducing orifices in these recirculation lines have allowed gases to be stripped from the recirculating liquid. This gas is then directed back to the charging pump suction header. Two units have reported discovering gas pockets and indications of gas binding in the charging pumps as a result of gases stripped from the fluid in the pump recirculation header.

At Beaver Valley 2, longstanding design weaknesses in the charging / High Head Safety Injection (HHSI) system piping configuration and ineffective corrective actions caused at least two pump shaft failures and resulted in periodic pump unavailability over a 10-year period. The failures and unavailability resulted from the accumulation of gas bubbles in the suction piping and subsequent ingestion of gas into the pumps during pump starts. The station tolerated periodic venting to minimize the potential for pump damage, effectively implementing a workaround to compensate for system design inadequacies. System venting became an accepted practice over time and was performed at a set frequency and prior to pump starts (including starts for surveillance tests), masking potentially degraded pump performance. The manual venting process was not fully effective and occasionally little, or no gas was actually vented. After Unit 2 experienced an HHSI pump shaft failure on September 12, 1997, and several subsequent gas binding events occurred, station management finally assembled a team to determine the root cause for the ineffective resolution of the gas binding (Reference 7).

On January 11, 2008, Wolf Creek was shut down because voids were identified in multiple locations in ECCS piping. The shutdown was required by TS 3.0.3 because two trains of ECCS were inoperable. RHR became a source of voids when the RHR system was removed from service. Gases that had been entrained in coolant circulated by the RHR system at a higher pressure came out of solution when the system was isolated and depressurized (Reference 8).

4.6.2.4 Failure to Properly Vent When Filling System

Reference 8 also identifies that at Wolf Creek the section of piping between the RHR pump discharge and the SI and charging pump suctions (called the piggyback line) contained excess air and some hydrogen partly because the pipe sloped the wrong way and could not be properly vented.

On July 28, 2004, the Palo Verde licensee identified that ECCS suction piping voids in all three Palo Verde units could have resulted in a loss of the ECCS during transfer to the recirculation mode for some Loss-Of-Coolant Accident (LOCA) conditions. The condition had existed since plant startups in 1986, was contrary to the Palo Verde Final Safety Analysis Reports (FSARs), and would not have been identified during testing because water is not drawn from the containment emergency sumps during tests (Reference 9).

4.6.2.5 Failure of Level Instruments to Indicate Correct Level

In May 1997 at Oconee Nuclear Station Unit 3, hydrogen ingestion during a plant cooldown damaged and rendered nonfunctional two high-pressure injection (HPI) pumps. The level instrumentation on the B&W equivalent of the volume control tank had a common reference leg which developed a leak. The resulting false high level indication led to depletion of tank inventory and subsequent hydrogen binding of the HPI pumps. If the operators had started the remaining HPI pump, it too would have been damaged. The NRC responded with an augmented inspection team (Reference 10). The NRC team reported that there had been a total lack of HPI capability during power operation, a failure to meet Technical Specification (TS) HPI operability requirements, design deficiencies, inadequate maintenance practices, operators who were less than attentive to plant parameters, a failure to adequately assess operating experience, and a violation of Criterion III of Appendix B to 10 CFR Part 50.

4.6.2.6 Column Separation

Column separation refers to the breaking of liquid columns in fully filled pipelines. When the pressure in a pipeline drops to the vapor pressure at specific locations, liquid columns are separated by a vapor cavity or cavities. This may result in water hammer, in which the collision of two liquid columns, or of one liquid column with a closed end, may cause a large and nearly instantaneous rise in pressure. This pressure rise travels through the entire pipeline and forms a severe load for hydraulic machinery, individual pipes and supporting structures.

On November 9, 1999, the vacuum break check valve for the "C" SW pump at Beaver Valley Unit 2 failed to open, causing a water hammer event (Reference 11). The service water pumps draw from a water source that is ~ 30 feet below the pump location. If the vacuum breaker fails to open when the pump is stopped, the static column of water draws a vacuum in the suction pipe, causing the formation of low temperature steam. This steam provides virtually no flow resistance when the pump is started, leading to a severe water hammer event. The water hammer caused deformation of an expansion joint downstream of the "C" SW pump which rendered the pump inoperable.

4.6.2.7 Vortexing in Suction Sources

There are many instances of RHR suction vortexing with the RCS in reduced inventory operation. This phenomenon can lead to gas binding of an RHR pump leading to the loss of RHR cooling. Chapter 4.9 of this manual has more information on this topic.

4.6.3 Safety Consequences of Voided Piping

The following are six examples of how voiding can have safety implications. This information is from Generic Letter 2008-1 (Reference 12).

4.6.3.1 Air Binding of Pumps

Gas binding of a centrifugal pump is a condition in which the pump casing is filled with gases or vapors to the point that the impeller is no longer able to contact enough fluid to function correctly. The impeller spins in the gas bubble, but it is unable to force liquid through the pump. This can lead to cooling problems for the pump's packing and bearings.

Air binding can render more than one pump inoperable when pumps share common discharge or suction headers, or when gas accumulation affects more than one train, greatly increasing the risk significance. Such a common-mode failure would result in the inability of the ECCS or the decay heat removal (DHR) system to provide adequate core cooling and in the inability of the containment spray system to maintain the containment pressure and temperature below design limits. An air-bound pump can become damaged quickly, eliminating the possibility of recovering the pump during an event by subsequently venting the pump and suction piping.

The amount of gas that can be ingested without a significant impact on pump operability and reliability is not well established.

A single-stage pump with significant clearances between moving parts, can often withstand a large slug of gas that completely stops flow, and the pump may be restored to operation when the gas is removed. However, in some cases, physical pump failure has occurred after gas ingestion. A similar no-flow or reduced-flow condition in a multistage pump that has close tolerances between moving parts, such as the multi-stage pumps used in the ECCS, will likely cause permanent damage.

At reduced flow rates even small gas ingestion rates can be a problem, as gas can accumulate with time and the pump can eventually become gas bound. Gas binding because of this effect is a potential concern since ECCS pumps are often initially operated at low flow rates when the gas volume passing through the pump may be at a maximum.

4.6.3.2 Reduced Pump Capacity

All pumps exhibit a loss of developed head when exposed to gas at the pump impeller.

Gas introduced into a pump can render the pump inoperable, even if the gas does not air bind the pump, because the gas can reduce the pump discharge pressure and flow capacity to the point that the pump cannot perform its design function. For example, an HPI pump that is pumping air-entrained water may not develop sufficient discharge pressure to inject under certain small-break LOCA scenarios.

4.6.3.3 Water Hammer

Gas accumulation can result in water hammer or a system pressure transient, particularly in pump discharge piping following a pump start, which can cause piping and component damage or failure. Gas accumulation in the DHR system has resulted in pressure transients that have caused DHR system relief valves to open. In some plants, the relief valve reseating pressure is less than the existing RCS pressure, a condition that complicates recovery. This was encountered, for example, during an event at Sequoyah in which a pressure pulse resulting from gas in RHR discharge piping caused a relief valve to open and rendered both RHR trains inoperable for 6 hours because the relief valve failed to reseat.

4.6.3.4 Premature Failure of Pumps

(1) Unbalanced loads caused by entrained gas and or (2) the reduction in inlet pressure at a pump because of gas in a vertical suction line that causes pump cavitation can result in additional stresses that lead to premature failure of pump components.

4.6.3.5 Interruption of Natural Circulation Flow in the Reactor Coolant System

Gas accumulation can result in pumping noncondensible gas into the reactor vessel or coolant loops that may affect core cooling flow.

4.6.3.6 Delay in Flow Delivery

The time needed to fill voided discharge piping can delay the delivery of water beyond the time frame assumed in the accident analysis.

4.6.4 Control of Voiding

In the Westinghouse improved standard Technical Specifications, surveillance requirement 3.5.2.3 requires the licensee to “Verify ECCS piping is full of water” with a 31-day frequency. This verification usually involves a combination of ultrasonic testing and venting.

Venting of affected systems has often been difficult, mostly where the vent valves are not located at system high points. These locations can sometimes be cleared of voids with a high flow rate of circulating fluid to sweep the gas from the high points. Some licensees have installed additional vent valves to enable proper venting. Generic Letter 2008-1 says “No specific NRC requirement mandates the installation of vent valves on the subject systems. However, failure to translate the design basis of assuring the system is maintained sufficiently full of water to maintain operability into drawings, specifications, procedures, and instructions is a violation of Criterion III in Appendix B to 10 CFR Part 50."

Steam generator water hammer is the specific type of water hammer experienced by San Onofre and others (Reference 4) caused by the introduction of cold feedwater to a feedwater line voided by steam. This was a significant problem in the mid-1970s, but has been well controlled by a combination of design and procedure changes.

The steam voiding of auxiliary feedwater (AFW) has been controlled through check valve improvements and monitoring of AFW piping temperatures.

4.6.5 Summary

Voided piping is a longstanding NRC concern. Voiding can lead to damaged safety-related equipment and loss of safety function. Licensee diligence is required to control voiding in safety-related piping systems.

4.6.6 References

1. Indian Point 2 – NRC Inspection Report 05000247/2005006 Preliminary White Finding, Accession No. ML051680119

2. NRC IR 50-327, Accession No. 9503080217

3. LER 1997-002-00 Potential Common Mode Failure ff Shutdown Cooling, Waterford

4. NUREG-1190, Loss of Power and Water Hammer Event at San Onofre, Unit 1, on November 21, 1985, Accession No. ML063560431

5. SOER 84-3, Auxiliary Feedwater Pumps Disabled by Back leakage

6. INPO SOER 97-1, Potential Loss of High Pressure Injection and Charging Capability from Gas Intrusion, Accession No. ML081980741

7. INPO Significant Event Notification 179, Long-Standing Design Weaknesses and Ineffective Corrective Actions Cause Gas Binding Failures of High Head Safety Injection Pumps

8. Wolf Creek Generating Station – NRC Special Inspection Report 5000482/2008007, Accession No. ML081160060

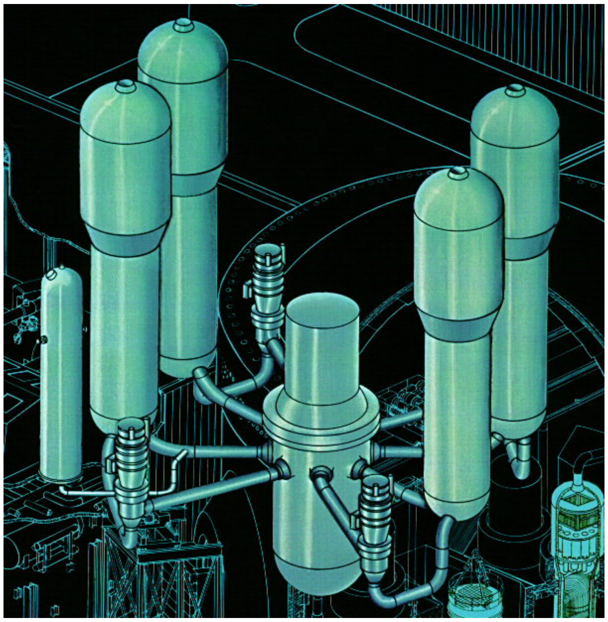
9. Palo Verde Nuclear Generating Station, NRC Special Inspection Report 05000528/2004014, 05000529/2004014, AND 05000530/2004014; Preliminary Greater Than Green Finding, Accession No. ML050050287

10. IN 97-38, Level-Sensing System Initiates Common-Mode Failure of High-Pressure-Injection Pumps, June 24, 1997, Accession No. ML031050514

11. LER 99-011-01, 10 CFR 50.73(a)(2)(i)(B) and 10 CFR 50.73(a)(2)(ii)(B), Inoperability of Service Water System Train B Due to Deformed Discharge Expansion Joint on In-Service Pump 2SWS*P21C, Accession No. ML003700492

12. NRC Generic Letter 2008-01: Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems, Accession No. ML072910759

13. NRC Information Notice 97-40 Potential Nitrogen Accumulation Resulting from Back leakage from safety Injection tanks, Accession No. ML031050497



Westinghouse Advanced Technology Manual

Chapter 5 – Transients

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5.0 Power Changes

5.0 Westinghouse Four-Loop Design Transients

Learning Objectives:

1. Given a set of transient curves and Table 5-1, demonstrate an understanding of plant characteristics and control, protection, and safeguards systems by:
    a. Explaining why the parameter values are trending as shown at selected numbered portions of the curves,
    b. Explaining plant effects caused by parameters reaching certain values at selected numbered points, and
    c. Explaining the cause(s) of the reactor trip and/or Engineered Safety Features (ESF) actuation, if either occurs.

5.1 Introduction

The transient curves contained in this chapter were compiled and analyzed by staff members of the NRC's Technical Training Center (TTC). They were produced from the dynamic responses of the Trojan (a Westinghouse four-loop reactor plant) training simulator. Specific parameter responses of the simulator were recorded by a data acquisition program and then graphed with a graphics program.

The instructor explanations provided in class for these curves are the results of analysis by the TTC staff during the actual simulator "runs" and during subsequent staff seminars. For each transient, the sequence of numbered points has been established to aid the instructor's classroom presentation.

Caution is advised when trying to apply these simulator curves to any operating plant. Even relatively minor changes in setpoints, capacities, or plant configurations could cause significant differences in indicated responses.

During analysis and study of the curves, the student should concentrate on explaining the changes in various parameters caused by the initiating event and by the subsequent operation of control, protection, and safeguards systems. When explaining a numbered point, the student should always try to relate "cause" and "effect" (e.g., pressurizer level is increasing because the reactor coolant system [RCS] average temperature is increasing, and the coolant is expanding into the pressurizer). Do not place too much emphasis on an isolated portion of or a minor deviation in the graph of a particular parameter unless it is associated with a numbered point. Generally, a numbered point will bracket a portion of a curve, indicating that the student should try to explain why a parameter is trending or changing in the bracketed area. If a numbered point is associated with a reactor trip or engineered safety features actuation, the student should attempt to explain not only that the protective action has occurred but also what reactor trip signal or ESF actuation signal is present.

The following general notes are applicable to all transients unless other information is provided:

1. Pressurizer pressure is from one of the four pressurizer pressure instruments. In a few transients, wide-range RCS pressure from one of the pressure detectors on the residual heat removal (RHR) system suction line is also provided.
2. Bank D rod position is actual rod position (shows every step change and the results of a reactor trip or rod drop).
3. Nuclear power is from one of the four excore nuclear instruments.
4. Generator load is in electrical MW.
5. Average RCS temperature (T_{avg}) is the T_{avg} from one of the four coolant loops, derived from the narrow-range resistance temperature detectors (RTDs). The programmed T_{avg} for a particular turbine load (T_{ref}) is a function of turbine impulse pressure.
6. Pressurizer level is from one of the three pressurizer level detectors.

7. Charging flow is from the flow transmitter downstream of the charging pumps and includes flow supplied to both the normal charging line and to reactor coolant pump seal injection.

8. Steam dump demand is the ouput of either the loss-of-load, the turbine trip, or the steam pressure controller, whichever is in service.

9. Steam flow (W_s) is the flow in one of the four main steam lines but is indicative of total steam flow.

10. Feedwater flow (W_f) is the flow supplied to one of the four steam generators but is indicative of total feedwater flow.

11. Steam generator level is from one of the three narrow-range level detectors on one of the four steam generators but is indicative of the level in any steam generator.

12. Steam pressure (P_{stm}) is from one of the three pressure detectors on one of the four main steam lines but is indicative of the pressure in any steam line.

13. Additional parameters are monitored and graphed if they are pertinent to the transient analysis.

14. When a transient is caused by a control system response to an instrument failure, the output of a redundant instrument is graphed to display the actual changes in the parameter of interest.

15. Initial plant conditions not available from the transient curves are given by the instructor during the introduction to the transient and listed in a box adjacent to the transient curves. For transients used on the final exam, the initial conditions are given as part of the problem statements.

5.2 Transient Analysis

The following sections discuss various aspects of transient analysis.

5.2.1 Energy Equilibrium

Transient analysis begins with an examination of the stored energy of the reactor coolant. As shown in Figure 5-1, the internal energy of the reactor coolant is dependent on two factors, the energy input from the core and the energy removal by the secondary system (steam generators). If the energy input equals the energy removal, then the internal energy of the reactor coolant is not changing. Therefore, the average coolant temperature is stable. However, if an upset in the energy equilibrium occurs, then the internal energy of the reactor coolant changes, resulting in a change in coolant temperature. When a change in coolant temperature occurs, the density of the reactor coolant changes. The changes in temperature and density affect several of the parameters that are shown in the transient curves of this chapter.

Assume that with an initial equilibrium between energy production and energy removal, a transient occurs that results in a reduction in the rate of energy removal (e.g., a turbine load reduction). Since the rate of energy production (reactor power) can not immediately drop, the internal energy of the reactor coolant increases, and the average coolant temperature increases. When the coolant temperature increases, the density of the coolant decreases. This decrease in density results in an increase in the volume of the reactor coolant, causing an insurge into the pressurizer and an increase in pressurizer level. The pressurizer level insurge compresses the steam bubble, and pressurizer pressure increases.

Now consider an increase in the rate of energy removal by the secondary system (e.g., a turbine load increase) from equilibrium conditions. Initially, the rate of energy removal from the reactor coolant exceeds the rate of energy production by the reactor, the internal energy of the reactor coolant decreases, and the average coolant temperature decreases. When the coolant temperature decreases, the density of the coolant increases. The immediate consequence of an increase in coolant density is an outsurge from the pressurizer and a corresponding decrease in pressurizer level. When the pressurizer level decreases, the volume of the steam bubble increases. The expanding steam bubble results in a decrease from the initial pressurizer pressure.

In each of the examples discussed above, the reactor coolant temperature and density and the pressurizer level and pressure change as a result of a change from an initial equilibrium between the energy input to and energy removal from the reactor coolant.

A change in the stored energy of the reactor coolant can be identified by comparing the reactor power and the steam demand on the steam generators. Generally, if the turbine load is less than the reactor power, then the average coolant temperature is increasing, and conversely, if the turbine load is greater than the reactor power, then the average coolant temperature is decreasing. Any time the turbine is not in service or an additional steam demand from steam dump operation or a steam break is present, a comparison of steam flow and reactor power leads to the same conclusions. Once the direction of the energy mismatch is known, the changes in coolant temperature and in pressurizer level and pressure can be explained.

The two examples in the previous discussion are representative of two types of transients. In the first type, reactor power exceeds the rate of energy removal by the secondary; if the mismatch is extreme, the transient is referred to as an overheating event. This type of transient includes turbine trips, load rejections, and normal power decreases. In the second type, the rate of energy removal by the secondary exceeds reactor power; if the mismatch is extreme, the transient is referred to as an overcooling or excessive heat transfer event. Examples of this type of transient are normal power increases, steam dump operation, steam generator power-operated relief valve (PORV) openings, turbine valve failures, and steam line breaks.

In addition to determining the direction and magnitude of the energy input/energy removal mismatch, the student must analyze the responses of the control systems. If nuclear power exceeds turbine load, T_{avg} increases. If T_{avg} increases above T_{ref}, then the control rods are inserted by the rod control system (assuming automatic operation). Also, the pressurizer level increases. If the increase in level exceeds the increase in the pressurizer level setpoint, the pressurizer level control system decreases charging flow. The accompanying increase in pressurizer pressure is compared to the pressure setpoint in the pressurizer pressure control system. The control system reduces the output of the proportional heaters and, if the pressure error is large enough, opens the spray valves. Finally, if the increase in pressurizer pressure is large enough, the pressurizer PORVs open. The rod control system and the pressurizer level and pressure control systems will react in similar but opposite fashions to a transient in which turbine load exceeds nuclear power.

5.2.2 Reactivity Balance

Transient analysis also involves an examination of the reactivity balance. The transients in this section can involve changes in fuel temperature, moderator temperature, and control rod position, any of which can add positive or negative reactivity to an initial state of equilibrium reactivity ($\rho = 0$). For the transients of this section, the fuel and moderator temperature coefficients of reactivity are always negative. No transient time span is long enough for changes in fission product (poison) concentrations to significantly affect reactivity, and no transient involves an operator-controlled change in boron concentration. If the transient terminates at a new steady-state endpoint without a plant trip, the positive reactivity added by one source must be completely balanced by the negative reactivity added by another.

During a normal load change, reactivity will be added by the power defect and compensated by a change in control rod position. The power defect (the power coefficient integrated over a power change) accounts for the change in reactivity associated with the changes in fuel temperature and moderator temperature, with the moderator temperature assumed to be maintained at programmed values. When the operator changes the turbine load at the turbine electrohydraulic control (EHC) station, the resulting primary-to-secondary mismatch causes the average coolant temperature to initially increase or decrease. The rod control system (if in automatic) responds to the T_{avg}/T_{ref} error and the power mismatch associated with the load change by inserting or withdrawing rods. When the new steady state has been reached at the end of the load change, the reactivity balance ($\rho = 0$) is restored, with the reactivity associated with the power defect completely balanced by the reactivity added by the change in control rod position.

As an example, consider a turbine load reduction with the rod control system in automatic. Initially, the drop in load relative to the unchanged nuclear power causes the average reactor coolant temperature to increase, and the temperature and power mismatch circuits of the rod control system call for control rod insertion. The control rod insertion suppresses nuclear power and drives down T_{avg} to match the decreasing T_{ref}. Meanwhile, the fuel temperature is decreasing with the decrease in nuclear power. When the load change is complete, the primary power again equals the secondary load, and the positive reactivity addition associated with the power defect (both fuel and moderator temperatures are lower at the transient endpoint) is completely balanced by the negative reactivity added by the control rod insertion.

Next, consider the load reduction with the rod control system in manual. The primary-to-secondary power mismatch increases the coolant temperature and thereby adds negative reactivity. The negative reactivity addition decreases reactor power. The decrease in reactor power adds positive reactivity via the fuel temperature coefficient (the fuel temperature is decreasing), resulting in a dampening of the power decrease. As long as the rate of reactor energy production is greater than the rate of energy removal by the turbine, the coolant temperature continues to rise. The transient is terminated when the rate of energy input to the coolant by the reactor exactly matches the rate of energy removal by the secondary system, and the positive reactivity addition associated with the decrease in fuel temperature exactly matches the negative reactivity addition associated with the increase in coolant temperature. The endpoint conditions are equal values of reactor and secondary power and a T_{avg} that is higher than that at the start of the transient.

The examples discussed above involve changes initiated by the secondary plant. However, transients can be initiated in the primary system. An uncontrolled rod withdrawal and a dropped rod are two examples. However, the considerations of any existing energy mismatch, control system actions, and the effects of reactivity coefficients remain applicable. For the transients in this section, the moderator and fuel temperature coefficients and the reactivity changes associated with rod motion account for the changes in reactor power. In actual plant operation, long-term changes in the concentrations of fission product poisons and operator-controlled changes in the boron concentration must also be considered.

5.2.3 Steam Generators

Another consideration in the analyses of transients involves the changes that occur in steam generator level and pressure. The initial changes in steam generator level that are caused by changes in steam flow from the steam generator are called "shrink" and "swell." It is important to recognize that such a change in indicated level is not caused by a change in steam generator inventory. Recall that SG level is measured in the downcomer, not the tube bundle region. Water flows from the downcomer to the tube bundle region by gravity.

The static pressure of the water column in the downcomer must be greater than the static pressure of the water/steam mixture in the tube bundle region to induce flow from the downcomer to the tube bundle region. This pressure difference requires a difference in the water levels in the two regions. (The level in the tube bundle region is an effective level because the fluid volume there is partially steam.) In a static condition (no flow), these two levels would be equal. As steam flow from the turbine increases (as with a turbine load increase), the rate of steam formation in the tube bundle region increases. The increased steam fraction of the tube bundle fluid volume increases the resistance to flow (head loss) between the downcomer and the tube bundle region; the increased flow resistance requires a greater difference in the effective levels of those two areas. The result is a rise in the downcomer water level. Conversely, for a decrease in steam flow from the SG, the flow resistance between the downcomer and the tube bundle region drops, resulting in a reduced downcomer level.

In summary, with an increase in steam flow, indicated level inherently rises. This is called swell. With a drop in steam flow, indicated level inherently drops. This is called shrink. The change in indicated level is due to a change in the flow resistance between the downcomer and the tube bundle region. The change in indicated level is not due to a change in steam generator inventory.

Following the initial change in level, the Steam Generator Water Level Control System (SGWLCS) returns the level to the normal programmed value through a change in feedwater flow.

For reasons not fully understood, the wide range level indication is generally not affected by shrink and swell.

5.2.4 Instrument Failures

A knowledge of control system functions and actions that are taken at particular setpoints is necessary to analyze instrument failure transients. A failure of an instrument which feeds an input to a control system can be analyzed by asking the following questions:

1. What is the function of the control system?
2. What actions does the control system take to accomplish its function?
3. What actions are taken if the actual value of the parameter is above or below the setpoint value?

In short, if the output of a failed instrument is supplied to a control system, the student should determine the response of the control system and how the controlled component changes plant conditions.

As an illustration of this technique, consider the case of a failure of the median select value of steam generator level failing low. The inaccurate level is provided to the SGWLCS. The function of the SGWLCS is to maintain the steam generator level at the setpoint value. The first question in the above list is now answered. The SGWLCS controls the steam generator level at setpoint by controlling the position of the main feedwater regulating valve. The second question is now answered. Finally, if the steam generator level is low, the feedwater regulating valve opens further to increase the level in the steam generator. Since the SGWLCS has no way of "knowing" that it has a faulty input, this response occurs even with an initially normal steam generator level. Now consider the resulting effects. Feedwater flow now exceeds steam flow, and the steam generator level increases. This example illustrates the basic questions to be kept in mind for analyses of transients initiated by instrument failures.

5.2.5 Accidents

Analyses of accidents generally involve the trends in primary and secondary levels and pressures and the responses of plant safeguards systems. In the case of a Loss Of Coolant Accident (LOCA), the pressurizer pressure and level drop, but the steam generator pressures and levels are largely unaffected. Since a Steam Generator Tube Rupture (SGTR) is a special form of LOCA, the primary conditions will change similarly during an SGTR, while the level in the affected steam generator increases with the influx of reactor coolant through the rupture. Steam line breaks can be grouped into breaks upstream of the Main Steam Isolation Valves (MSIVs) and downstream of the MSIVs. During a break upstream of the isolation valves, the steam pressure in the affected steam generator decreases more rapidly than the pressures in the unaffected steam generators. Following isolation of the faulted steam generator by its check valve, the pressures in the intact steam generators should recover, while the affected steam generator blows down to atmospheric pressure. A break downstream of the MSIVs results in equal pressure drops in all steam generators, which are terminated by MSIV closure. Of course, the overcooling of the reactor coolant caused by a steam break also lowers pressurizer pressure and level.

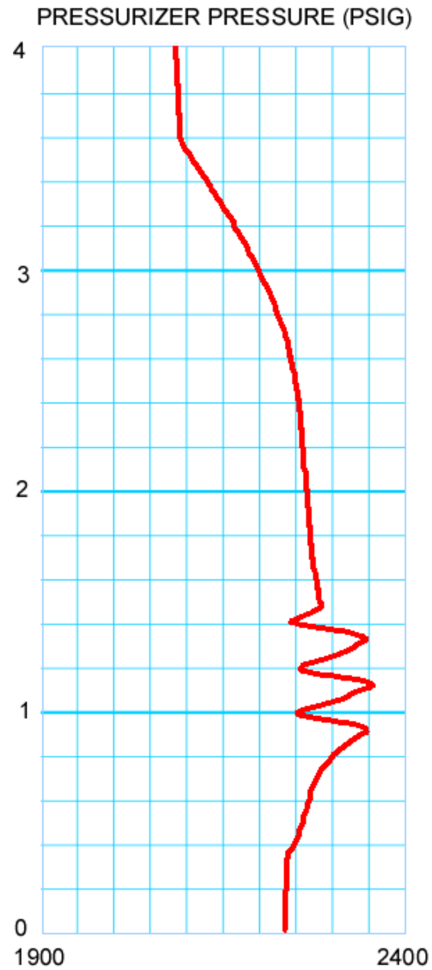
For any accident, a Safety Injection (SI) actuation is indicated by the change in charging flow upon the isolation of normal charging and the initiation of high head injection, and by the change in feedwater flow upon the isolation of main feedwater and the initiation of the Auxiliary Feedwater System (AFW). During steam line breaks and some small LOCAs, high head injection eventually reverses the drop in pressurizer level caused by overcooling of the reactor coolant or by inventory loss. For some transients, plots of high, intermediate, and low head injection are provided to illustrate the responses of the Emergency Core Cooling Systems (ECCS) to an SI actuation and plant conditions, and plots of containment pressure are provided to illustrate the progress of the accident and the response of containment pressure suppression systems.

In an actual reactor plant, indications of accidents would include the responses of radiation detectors. Elevated containment radiation levels would result from a LOCA, and higher secondary radiation indications would result from a primary-to-secondary leak. No radiation indications are included as part of the transient curves provided in this manual.

5.2.6 Trend Format

The trends in this chapter present data in a way that may be unfamiliar to the student. Traditionally, parameter change vs. time is displayed in a format where time is the parameter associated with the horizontal (X) axis. However, in the trends for this course, time is on the vertical (Y) axis, and the parameter value of interest, which is graphed as a function of time, is on the horizontal (X) axis. This convention was established by the control room chart recorders initially installed in the units. The paper strip moved down as the pen recorded the value, leaving the most recent value at the top of the chart. Since operators were accustomed to this format, this convention was retained in digital replacements. We present the data in the same format as that displayed on control room trend recorders.

On the graph to the right, for instance, pressurizer pressure is plotted versus time over a four-minute interval. The scale for pressurizer pressure, as shown at the bottom of the graph, is 1900 – 2400 psig.

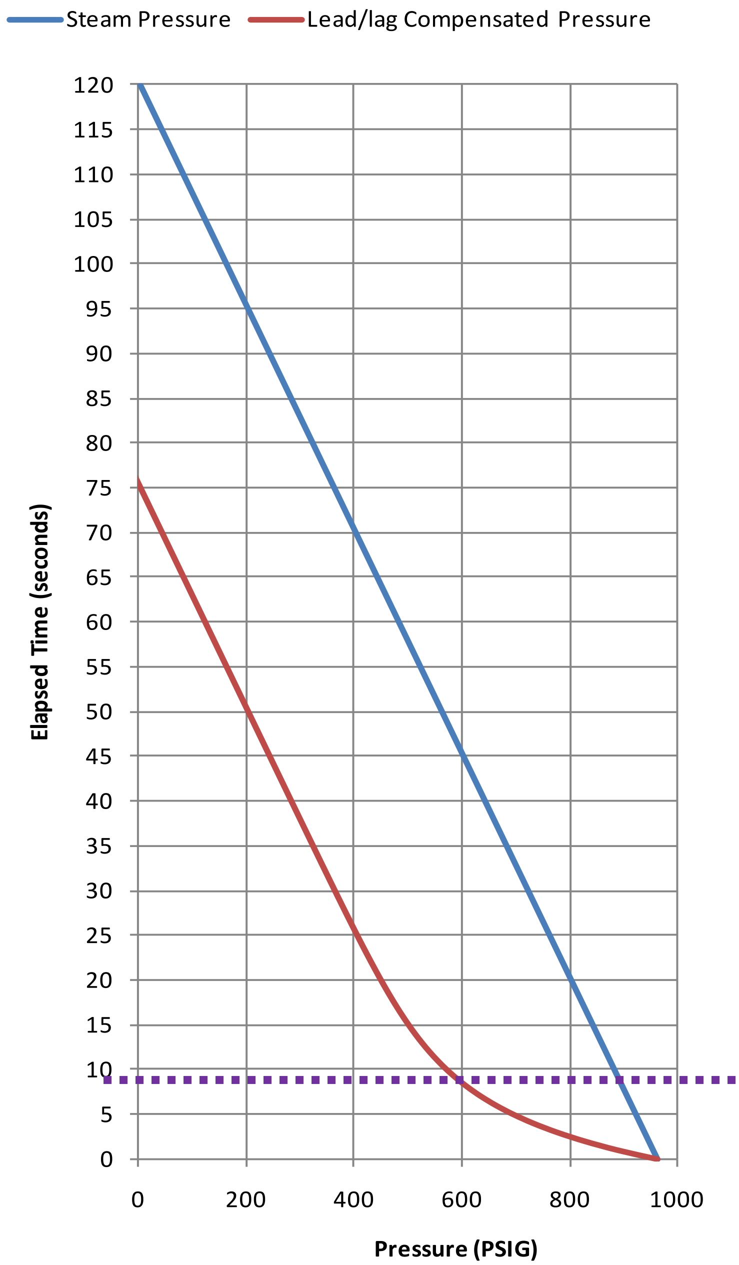


5.3 Signal conditioning

Some process control circuits contain components which modify the signal measurement.

5.3.1 Lead/Lag Compensation

The figure to the right illustrates the effect of a lead/lag circuit where the lead time constant is 50 seconds, (τ_1), and the lag time constant is 5 seconds, (τ_2). These are the time constants associated with the modified steam pressure signal which is an input to the low steam pressure bistables in the reactor protection system. The associated low steam pressure bistable does not "see" the measured steam pressure; it only "sees" the output of the lead/lag unit. In this example, if steam pressure drops at a constant rate, the output of the lead/lag function eventually resolves to a linear function where the output reaches a specific value 45 seconds (lead minus lag) before the actual parameter reaches that value. For example, the lead/lag output reaches 400 psig at time 25 seconds, and the actual parameter reaches 400 psig 45 seconds later (70 seconds). It takes about 5 lag time constants to resolve to a linear function.

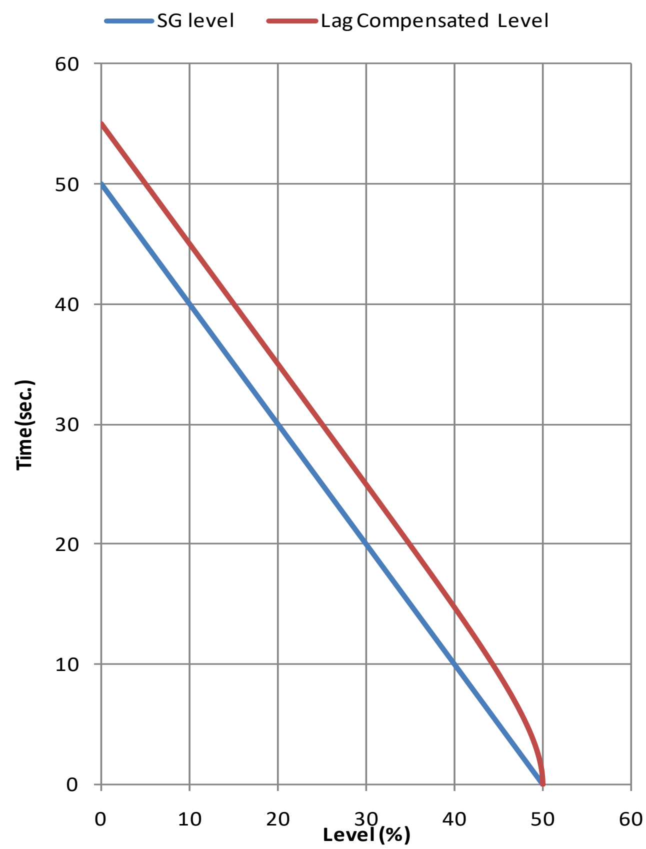


If steam pressure follows this trend, the low pressure bistable, with a trip setpoint of 600 psig, trips at an indicated pressure of ~875 psig.

The lead/lag function is represented on plant instrument diagrams by $\frac{1+\tau_1 s}{1+\tau_2 s}$.

5.3.2 Lag Compensation

The figure to the right illustrates the effect of a lag circuit, where the lag constant is 5 seconds, (τ_1), as in the level input to the steam generator level control system. In this example, if steam generator level drops at a constant rate, the output of the lag function eventually resolves to a linear function where the output reaches a specific value 5 seconds after the actual parameter reaches that value.

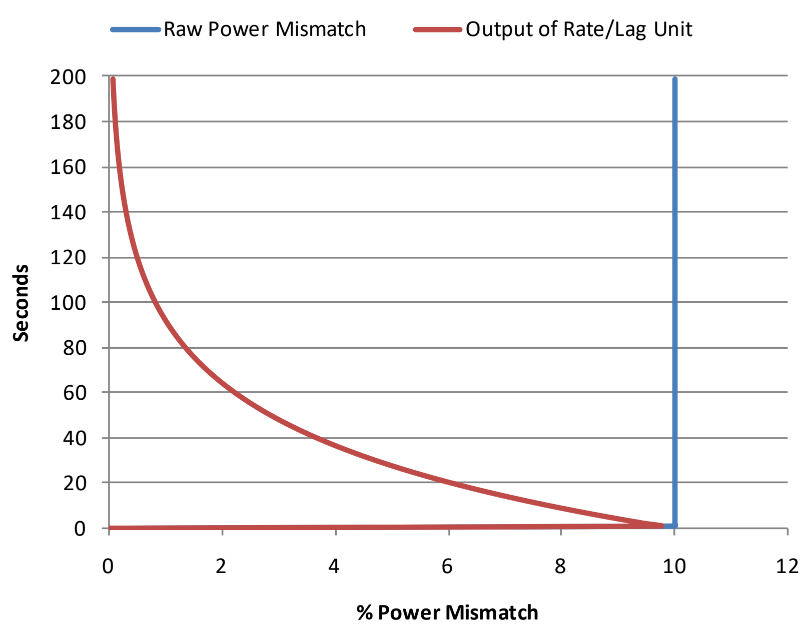


When steam generator level begins to change, the steam generator level control system does not immediately "see" this change. This prevents an inappropriate response to shrink and swell.

The lag function is represented on plant instrument diagrams by $\dfrac{1}{1+\tau_1 s}$.

5.3.3 Rate/Lag Compensation

The figure to the right illustrates the effect of a rate/lag circuit where the rate time constant, (τ_1), is 40 seconds, and the lag time constant, (τ_2), is 40 seconds, as in the rod control power mismatch unit. The rate/lag unit output is only generated in response to changes in the input. The figure shows the effect of a step change in the power mismatch, from 0% to 10% at time zero. This results in a step change in the rate-lagged signal. When the power mismatch stays constant, the output of the rate/lag unit decays to zero in about 5 lag time constants. The rate/lag function is represented on plant instrument diagrams by $\dfrac{\tau_1 s}{1+\tau_2 s}$.



5.4 Parameter Behavior During Transients

The following descriptions of parameter behavior during transients are provided in the order with which the graphs of the parameters are presented.

5.4.1 Pressurizer Pressure

1. Pressurizer pressure is affected by components controlled by the pressurizer pressure control system. This is particularly evident during transients involving the failure of the controlling pressure channel.
2. A rapid change in pressurizer level can have such a large effect on the dimensions of the pressurizer steam bubble and, as a result, on pressurizer pressure that the pressurizer pressure control system cannot immediately restore pressure to setpoint.
3. This parameter is an input into the OTΔT trip and turbine runback setpoint calculations and can cause the setpoints to increase or decrease. Evidence of a turbine runback can be seen on the generator load plot.

5.4.2 Bank D Rod Position

1. Bank D rod position is affected by the power mismatch and temperature mismatch inputs to the rod control system.
2. It is possible for the power mismatch circuit output to be equal and opposite to the temperature mismatch circuit output. This condition results in no rod motion, even though a T_{ref} - T_{avg} difference exists.
3. The failure of an the input to the power mismatch circuit causes rapid rod motion initially due to the high rate of change of nuclear power relative to turbine load; the output of the power mismatch circuit then decays exponentially, allowing any existing temperature mismatch to gradually increase its impact on rod control.
4. A step drop in bank D rod position to 0 steps is indicative of a reactor trip.

5.4.3 Nuclear Power

Nuclear power responds to reactivity effects associated with fuel temperature, moderator temperature, and control rod position. No transient time span is long enough for changes in fission product (poison) concentrations to significantly affect reactivity. No transient involves an operator-controlled change in boron concentration; changes in the coolant boron concentration occur only during transients involving significant injection of the refueling water storage tank contents.

5.4.4 Generator Load

1. During power level changes, the change in generator load is usually the initiating event. A load change can be input gradually by the operator with the selection of a new demanded load and loading rate or rapidly via operation of the control valve position limiter.
2. The Trojan GE turbine EHC system generates a demanded control valve position for a given demanded load and does not incorporate MW or impulse pressure feedback. Thus, once the control valves reach their demanded positions, they will not respond to load changes if the demanded load remains unchanged. The

throttle pressure compensation circuit will attempt to maintain constant steam flow over the range of no-load (~1020 psig) to full-load (~930 psig) throttle pressure. Throttle pressure changes inside this band only produce minor changes in generator load. Throttle pressure changes outside this band cause significant changes in generator load. For example, RCS temperature changes initiated from 50% power do not cause significant changes in generator load, since throttle pressure compensation is in the center of its operating band. Cooldown transients initiated from rated thermal power MAY cause generator load to drop if throttle pressure drops below the range of throttle pressure compensation.

3. The Trojan GE EHC system includes an initial pressure limiter which closes the control valves when throttle pressure drops below 90% of the throttle pressure for rated power

4. A turbine runback is indicated by an abrupt change in load to a new lower value.

5. A step drop in generator load to 0 MW is indicative of a turbine trip.

5.4.5 T_{ref}/T_{avg}

1. Since T_{ref} varies linearly with impulse pressure, it reflects changes in generator load.

2. T_{avg} is generated from the hot-leg and cold-leg temperatures (T_H and T_c) measured by resistance temperature detectors (RTD). There is an inherent delay in measuring temperature because of the heat transfer required to heat the RTD through a thermal well. There is also a delay due to loop transport time. Therefore, during a rapid transient, pressurizer level provides a better initial indication of a coolant temperature change (see section 5.3.6 below).

3. T_{avg} is a reflection of the balance between the rate of energy production in the primary and the rate of energy removal by the secondary. If the two are equal, T_{avg} will remain constant. Any imbalance, whether initiated in the primary or secondary, causes a change in T_{avg}.

5.4.6 Pressurizer Level

1. A change in pressurizer level is often a direct reflection of a change in reactor coolant density and thus provides an indication of a primary temperature change.

2. A decrease in pressurizer level can be indicative of a loss of coolant inventory.

3. A somewhat small but visible change in pressurizer level can result from a change in coolant density associated with a moderately large pressure change.

5.4.7 Charging Flow

1. Generally, charging flow varies with the position of charging flow control valve FCV-121, which responds to the output of the pressurizer level control system (all transients begin with charging flow supplied by one centrifugal charging pump). Charging flow increases when the pressurizer level is less than the level setpoint and decreases when the level is greater than the setpoint. Often during a transient the pressurizer level and the level setpoint (a function of auctioneered high T_{avg}) are

changing in the same direction simultaneously but not in step, so that charging flow undergoes "swings" in which it first increases and then decreases, or vice versa.

2. An SI actuation signal causes a characteristic perturbation in charging flow during which the second centrifugal charging pump starts, the normal charging line isolates, and charging flow becomes seal injection only. This perturbation appears on the charging flow plot as a "zigzag." The steady-state charging flow after an SI actuation depends on the RCS pressure and the position of FCV-121, which continues to modulate in response to pressurizer level control system commands.

5.4.8 Steam Dump Demand

During power operation a steam dump demand indication reflects a T_{avg} - T_{ref} difference of greater than 5°F (the loss-of-load controller is in service). The T_{avg} signal is rate compensated, so if T_{avg} is rising quickly, the demand signal may be generated at an indicated ΔT of < 5°F. Following a turbine trip, an existing demand indicates that T_{avg} exceeds the no-load T_{avg} (the turbine trip controller is in service). During plant heatups and startups, an existing demand indicates that steam pressure exceeds the no-load steam pressure setpoint of 1092 psig. A demand indication does not necessarily mean that the steam dumps are opening; an arming signal must also be present. The best confirmation of steam dump operation is a change in steam flow. When steam dump demand is indicated, an increase in steam flow indicates that dump valves are open.

5.4.9 Steam Flow

Steam flow responds to changes in turbine control valve position, steam generator PORV operation, steam generator safety valve operation, and steam dump operation. Since steam flow is density compensated, indicated steam flow changes as measured steam pressure changes, especially when the associated steam pressure channel fails.

5.4.10 Feedwater Flow

1. Feedwater flow is governed by the position of the main feedwater regulating valves and the speed of the feedwater pumps, which are controlled by the SGWLCS.
2. At the outset of a transient, the change in feedwater flow is governed by the feed flow/steam flow mismatch. As the transient progresses and the level error has a chance to build, the level error signal will dominate feedwater flow changes.
3. Feedwater flow often undergoes many oscillations during a transient. Large swings in feed flow correspond to significant changes in main feed regulating valve position; small-amplitude fluctuations in feed flow may be considered as normal steady-state operation.
4. The feedwater flow indication following the isolation of main feedwater reflects auxiliary feedwater addition to the steam generator. In the control room, main feedwater flow and auxiliary feedwater flow are indicated on separate meters.

5.4.11 Steam Generator Level

1. A rapid change in steam demand causes a shrink or swell to occur (see section 5.2.3). Wide range steam generator level, which is displayed for some transients, is generally not affected by shrink or swell.

2. A change in the reactor coolant temperature, especially a decrease, can result in a change in the secondary temperature of the steam generators and changes in steam density and steam generator level.
3. Following the isolation of main feedwater, level is affected by auxiliary feedwater addition.

5.4.12 Steam Pressure

1. In general, steam pressure increases with a load decrease and decreases with a load increase.
2. Steam pressure can be affected by a change in T_{avg} if the change is large enough to affect the conditions governing primary-to-secondary heat transfer (see section 5.3.11).
3. A rapid drop in steam pressure can reflect operation of the steam generator PORVs and safety valves and steam line breaks.

TABLE 5-1 TRANSIENT INFORMATION

I. Setpoints

A. Reactor Coolant Temperature (°F)

564	Low T_{avg}
557 - 585	T_{avg} program from 0% to 100% power
553	Low-low T_{avg} (P-12)

B. Pressurizer Level (% level)

92	High level reactor trip
25 - 61.5	Level program from 0% to 100% power
17	Low level heater cutoff and letdown isolation

C. Pressurizer Pressure (psig)

2485	Code safety valves open
2385	High pressure reactor trip
2335	PORVs open
2235	Nominal operating pressure
1915	Low pressure SI block permissive (P-11)
1865	Low pressure reactor trip
1807	Low pressure SI actuation

D. Steam Generator Level (% level)

69	High level turbine trip, feedwater isolation, trip of main feed pumps (P-14)
33 – 44	Level program from 0% to 20% power
11.5	Low-low level reactor trip, AFW actuation

E. Volume Control Tank level (% Level)

41 – 54	Auto Makeup
64 - 94	Divert to hold up tank
1.4	Transfer to RWST.

F. Steam Dump System Controller Inputs (°F)

5 - 16.4	Generates 0 - 100% output from loss-of-load controller
0 - 27.7	Generates 0 - 100% output from turbine trip controller

G. Nuclear Instrumentation

1. Source Range (cps)

10^5	High flux reactor trip

2. Intermediate Range

25% current equivalent	High flux reactor trip
20% current equivalent	High flux rod stop
10^{-10} amps	Source range block permissive (P-6)

3. Power Range (% power)

109	High flux, high setpoint reactor trip
103	High power rod stop
39	Loss of loop flow permissive (P-8)
25	High flux, low setpoint reactor trip
10	Nuclear at-power block permissive (P-10)
+5 (w/ 2-sec time constant)	Positive high flux rate reactor trip
-5 (w/ 2-sec time constant)	Negative high flux rate reactor trip

H. Main Steam Pressure (psig)

1170 -1230	Range of code safety valve lift setpoints
1125	Atmospheric relief valve lift setpoint
600	Low steam pressure SI actuation (with high steam flow)

I. ESF Actuation Signals

Refer to Technical Specification Table 3.3.2-1

II. Significant Parameters (Typical Values)

A. Reactivity Values

1. Moderator Temperature Coefficient (no-load)

   BOL: -4 pcm/°F (1500 ppm boron)
   EOL: -26 pcm/°F (0 ppm boron)

2. Doppler-Only Power Coefficient

   BOL: -13 pcm/% power
   EOL: -11 pcm/% power

3. Power Defect at 100% power

   BOL: -1500 pcm
   EOL: -2400 pcm

4. Control Rod Worths

   Bank: 1000 pcm
   Individual: 150 pcm
   Differential worth: 4 to 12 pcm/step

5. Xenon Reactivity (BOL)

   Equilibrium at 100% power: -2741 pcm
   Peak following reactor trip: -5200 pcm

6. Reactor Makeup Parameters

   Boric acid worth: 8 pcm/ppm (BOL)
   Maximum dilution rate: 120 gpm
   Maximum boration rate: 40 gpm (4 weight % boric acid)
   Automatic makeup rate: 80 gpm total blended flow

B. System and Component Parameters

1. RCS

   Range of ΔT from 0% to 100% power: 0 - 59°F

2. Pressurizer

   1% change in level per °F change in T_{avg}
   130 gal per % level
   10 psi change in pressure per % change in level
   10 psi change in pressure per °F change in T_{avg}

3. Main Steam System

   No-load pressure (corresponds to T_{avg} of 557°F): 1092 psig
   Steam flow per generator (100% power): 3.77×10^6 lbm/hr
   Total steam flow (100% power): 15.07×10^6 lbm/hr

4. ECCS Maximum Pressures for Injection (psig)

   2670 HPI pumps
   1520 SI pumps
   650 Cold-leg accumulators
   200 RHR pumps

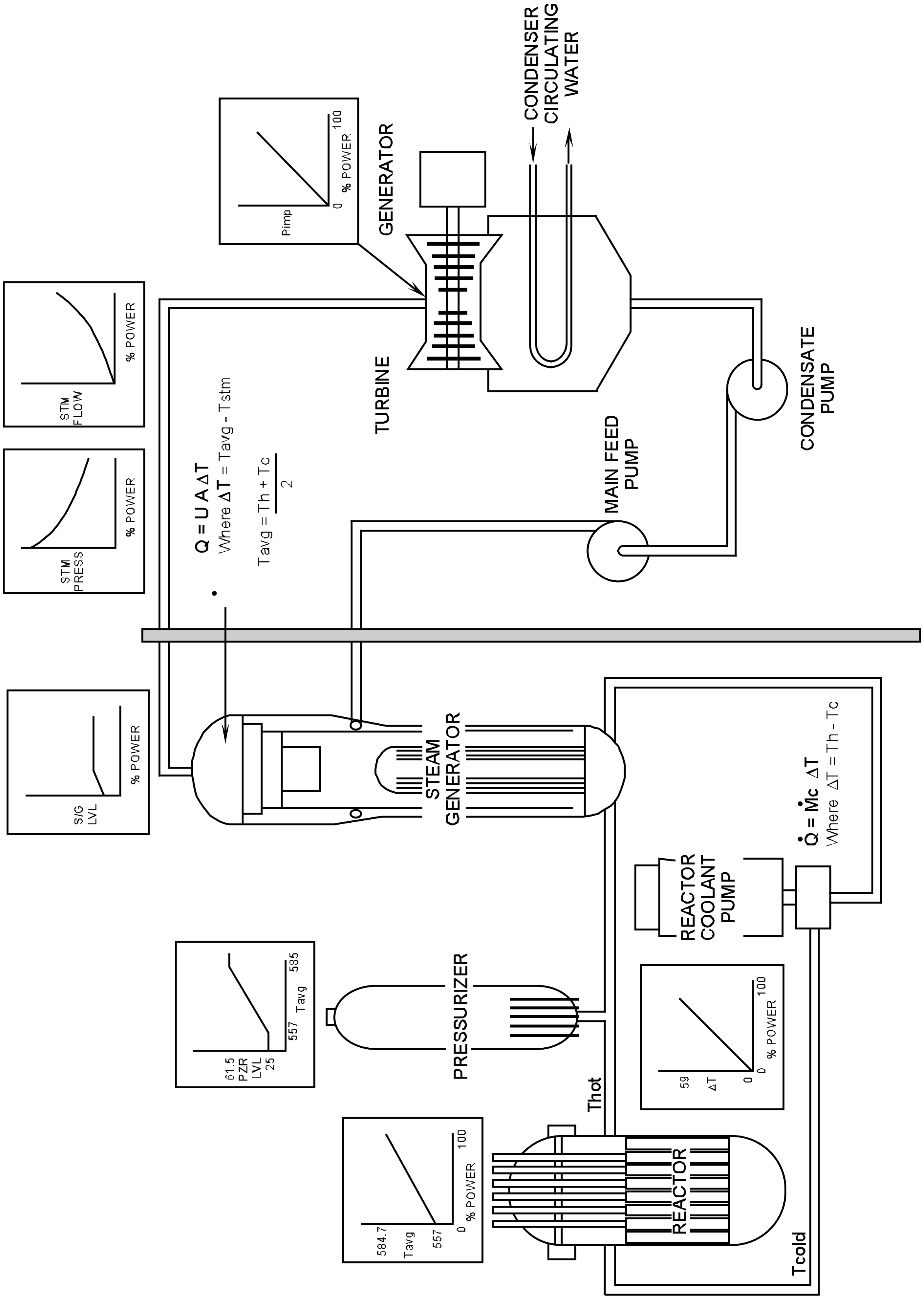


Figure 5-1 NSSS Response

Transient 5.01 Ramp Load Increase

Initial Conditions:

BOL
Nuclear Power: 55%

Initiating Event: 5%/min load increase

Point Explanation

1. **Generator load** increases as the turbine control valves open in response to the 5%/min load increase command input by the operator at the turbine EHC station. The increase in the mechanical work of the turbine is converted to electrical energy in the generator.

2. **Bank D rod position** increases as outward motion is called for by the power mismatch (turbine load increasing relative to nuclear power) and temperature mismatch ($T_{ref} > T_{avg}$) circuits of the rod control system.

3. **Nuclear power** increases in response to the positive reactivity added by rod withdrawal. Note that power would have risen even if the rods did not move, but in that case, the positive reactivity would have come from the drop in Tavg.

4. **Pressurizer level** rises mostly because of the rise in T_{avg}. The changes in pressurizer level and level setpoint are similar but not exact. The level program is linear, but the change of water density vs. temperature is not linear. The program approximates a constant RCS mass.

5. **T_{avg}** increases as the rods are withdrawn and nuclear power increases. Over the time interval in which T_{avg} is increasing, nuclear power exceeds turbine load. When the control rods are in automatic, reactor power does not "follow" the secondary power (i.e. it does not lag the change in secondary power, but leads the change). It is the action of the automatic rod control system that causes T_{avg} to follow the program.

6. **T_{ref}** increases with generator load (T_{ref} varies linearly with turbine P_{imp}).

7. **Charging flow** responds to the integrated value of the difference between PZR level and level program, but during this interval, charging flow is at its minimum value. The pressurizer level controller is calling for reduced charging flow, but the charging flow control valve has a minimum valve position set on its controller to prevent flashing in the letdown line.

Point Explanation

8. **Steam flow** increases as the control valves open to increase load. **Feed flow** lags the changes in steam flow in response to the demand from the steam generator water level control program.

9. **Steam generator level** remains near its programmed value because of the action of the steam generator level control system. Even though level remains relatively constant, the mass in the steam generator drops. A steam generator contains the most mass hot zero power. This is why the bounding steam line break is analyzed from hot zero power.

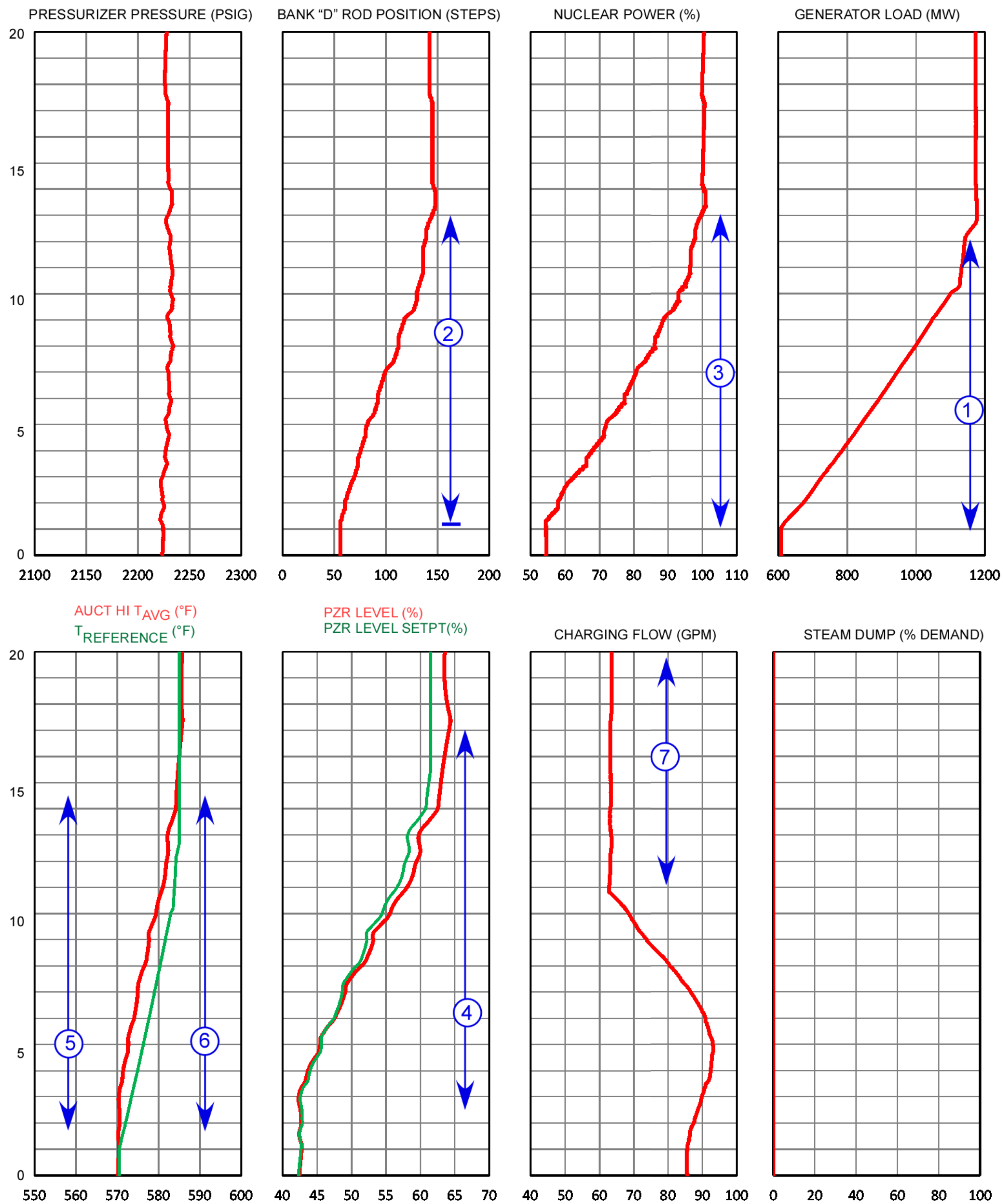
10. **Steam pressure** decreases as the control valves are opened. $Q = UA(T_{avg} - T_{stm})$; T_{avg} is increasing and T_{stm} (also P_{stm}) is decreasing throughout the load change as $\dot{Q}$ increases.

Note 1: The starting bank D rod position is below the rod insertion limit and would not be typical for a plant operating at 50% power. The rods were initially diluted in to their starting positions so that the power change could be completed with all control systems in automatic and with T_{avg} maintained on program throughout.

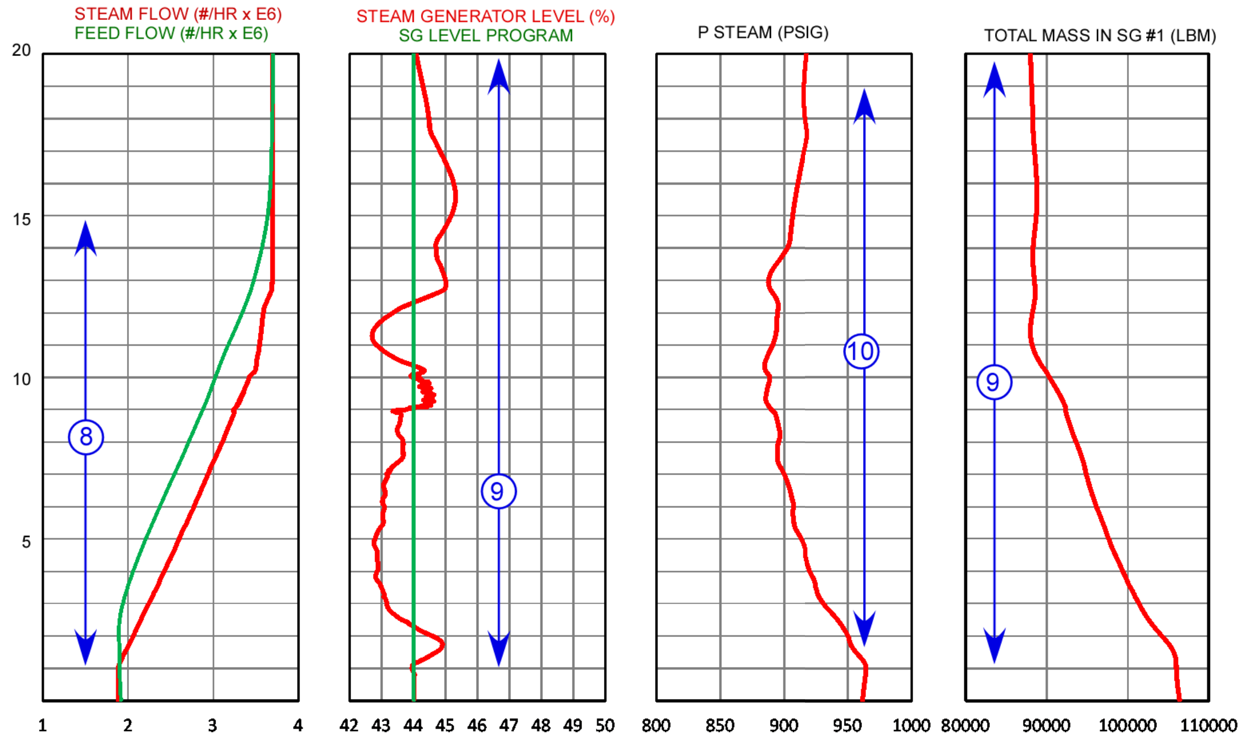
Note 2: At steady state at the end of the transient, nuclear power = secondary load, so Tavg is unchanging. As for the reactivity balance, the negative reactivity added by the power defect associated with the power change is balanced by the positive reactivity added by the rod withdrawal, so that the net endpoint $\rho = 0$.

What this transient illustrates:

1. The plant response to a normal power increase controlled at the turbine EHC system station.
2. The actions of the rod control and pressurizer level control systems.
4. The programmed increase in T_{avg} and decrease in steam pressure associated with a power increase.



Transient 5.01 Ramp Load Increase



TRANSIENT 5.01
RAMP LOAD INCREASE.

Initial Conditions
BOL
Nuclear Power: 55%

Initiating Event:
5%/min. load increase

Transient 5.01 Ramp Load Increase

Transient 5.02 Ramp Load Decrease

Initial Conditions:

BOL
Rated Thermal power

Initiating Event: 5%/min load decrease

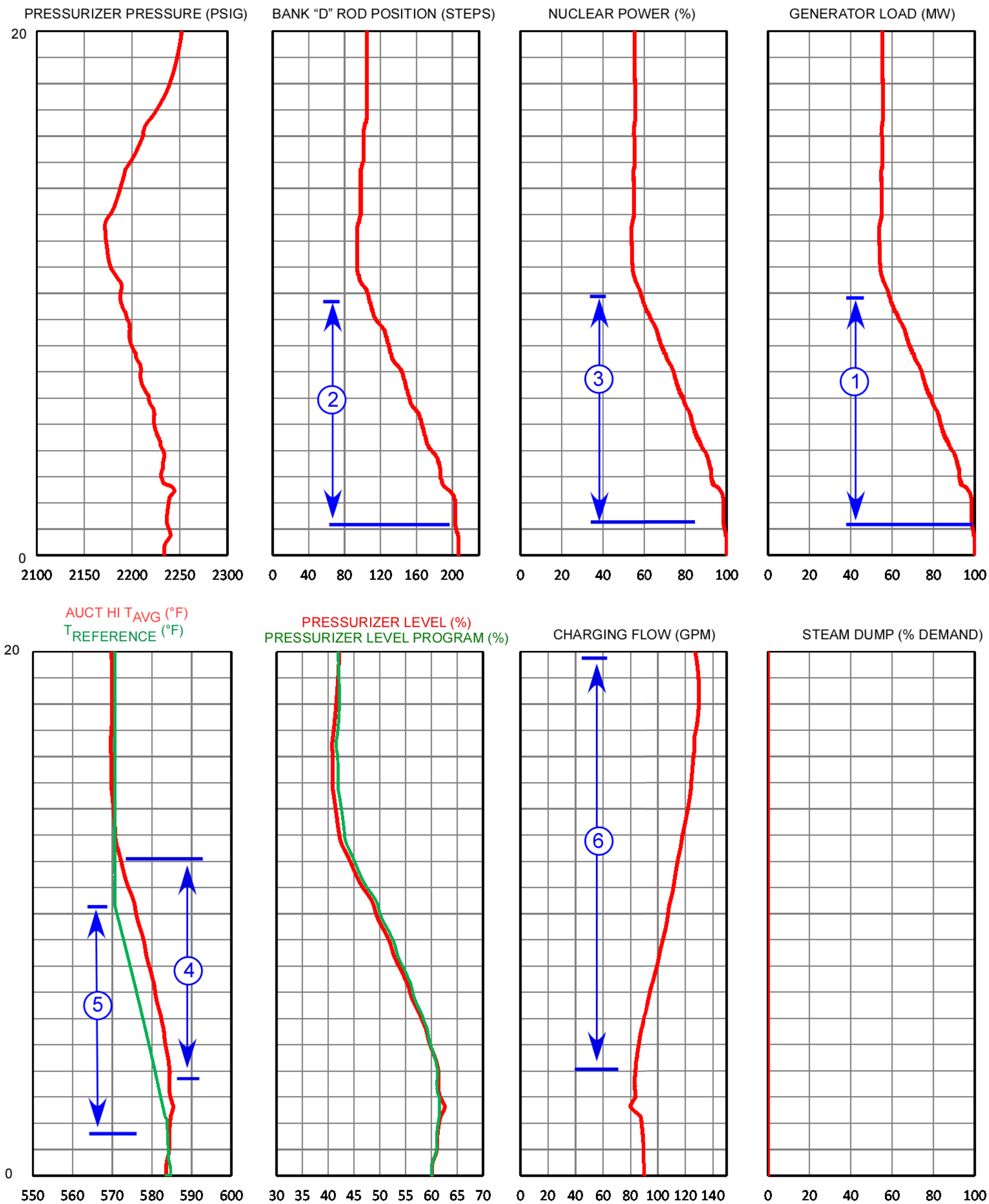
Point **Explanation**

1. **Generator load** decreases as the control valves close in response to the 5%/min load decrease command input by the operator at the turbine EHC station.
2. **Bank D rod position** decreases as inward motion is called for by the power mismatch (turbine load decreasing relative to nuclear power) and temperature mismatch ($T_{ref} < T_{avg}$) circuits of the rod control system.
3. **Nuclear power** decreases in response to the negative reactivity added by rod insertion.
4. $\mathbf{T_{avg}}$ decreases as the rods are inserted and nuclear power decreases. Over the time interval in which T_{avg} is decreasing, nuclear power is less than turbine load.
5. $\mathbf{T_{ref}}$ decreases with generator load (T_{ref} varies linearly with turbine P_{imp}).
6. **Charging flow** changes due to small differences between Pressurizer level and program level. The level program approximates constant mass, but, since the density of water vs. temperature is not linear, the linear program results in small charging flow deviations during large temperature changes.
7. **Steam flow** decreases as the control valves close to decrease load. **Feed flow** closely tracks steam flow as the steam generator water level control system keeps steam generator level on (or near) the program value.
8. **Steam pressure** increases as the control valves close. $\dot{Q} = UA(T_{avg} - T_{stm})$; T_{avg} is decreasing and T_{stm} (also P_{stm}) is increasing throughout the load change as $\dot{Q}$ decreases.

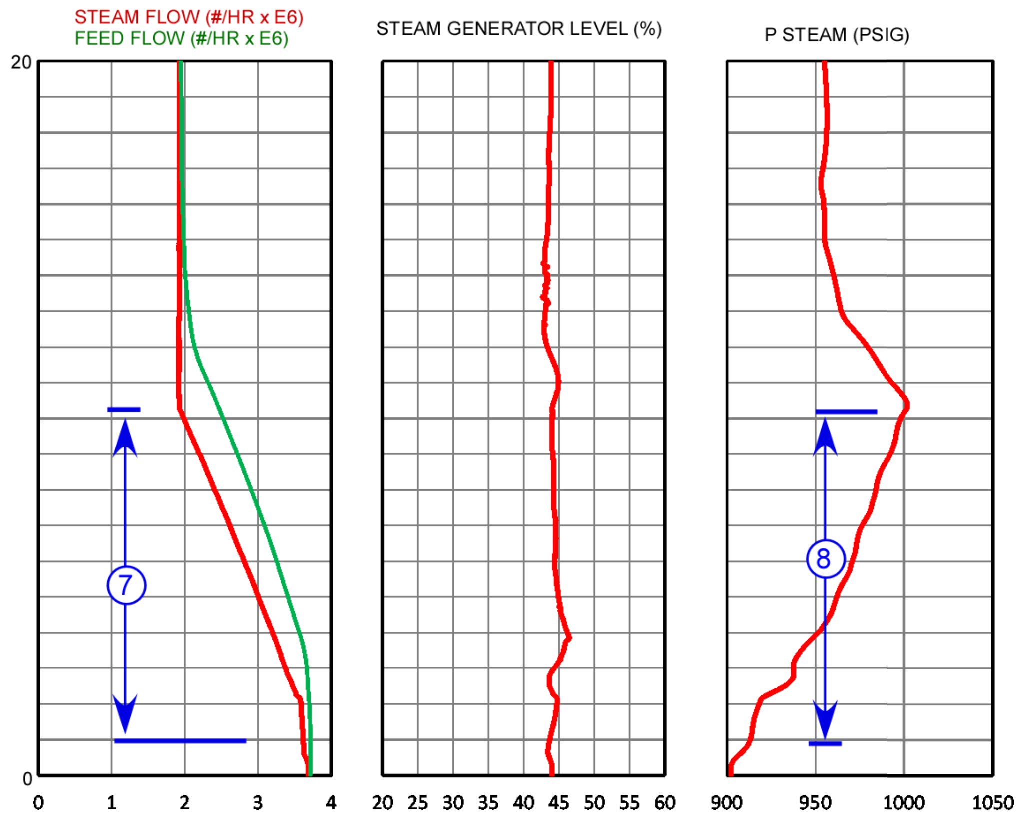
Note 2: At steady state at the end of the transient, nuclear power = secondary load, so T_{avg} is more or less unchanging. As for the reactivity balance, the positive reactivity added by the power defect associated with the power change is balanced by the negative reactivity added by the rod insertion, so that the net endpoint $\rho = 0$.

What this transient illustrates:

1. The plant response to a normal power decrease controlled at the turbine EHC system station.
2. The actions of the rod control and pressurizer level control systems.
3. The programmed decrease in T_{avg} and increase in steam pressure associated with a power decrease.



Transient 5.02 Ramp Load Decrease



TRANSIENT 5.02
RAMP LOAD DECREASE, 100-50%
@ 5%/MIN.

Initial Conditions
BOL
Rated Thermal Power

Initiating Event:
5%/min. load decrease

Transient 5.02 Ramp Load Decrease

Transient 5.03 Rapid Load Decrease, 100 - 90%

Initial Conditions:

BOL
Rated Thermal Power

Initiating Event: Rapid closure of turbine control valves with the valve position limiter

Point **Explanation**

1. **Generator load** decreases as the control valves close in response to the rapid reduction in steam flow to the turbine.
2. **T_{ref}** decreases with generator load (T_{ref} varies linearly with turbine P_{imp}).
3. **Bank D rod position** decreases at or near the maximum rate (72 steps/min) as rapid inward rod motion is called for by the power mismatch (turbine load decreasing relative to nuclear power) and temperature mismatch ($T_{ref} < T_{avg}$) circuits of the rod control system.
4. **Nuclear power** decreases in response to the negative reactivity added by rod insertion and (to a small extent) by the increase in reactor coolant temperature (discussed in point 6 below).
5. **Pressurizer level** increases at the start of the transient due to the heatup of the reactor coolant caused by the power mismatch, with turbine load < nuclear power.
6. **T_{avg}** increases at the start of the transient due to the power mismatch, with turbine load < nuclear power. Note that, although it is somewhat difficult to see on the plots, the increase in the T_{avg} indication lags the increase in pressurizer level (which indicates the increase in actual T_{avg}) because of the inherent delay in temperature measurement.
7. **Charging flow** initially decreases as the pressurizer level rises relative to the level setpoint (which is unchanged at the start of the transient with T_{avg} > full-load T_{avg}).
8. **Steam flow** decreases as the control valves close to decrease load.
9. **Feed flow** decreases as the steam generator water level control system closes the main feed regulating valves to match steam and feed flows.
10. **Steam generator level** initially shrinks with the load decrease.

Point Explanation

11. **Feed flow** increases in response to the level error resulting from the initial shrink.

12. **Steam pressure** increases as the control valves close. $\dot{Q} = UA(T_{avg} - T_{stm})$;

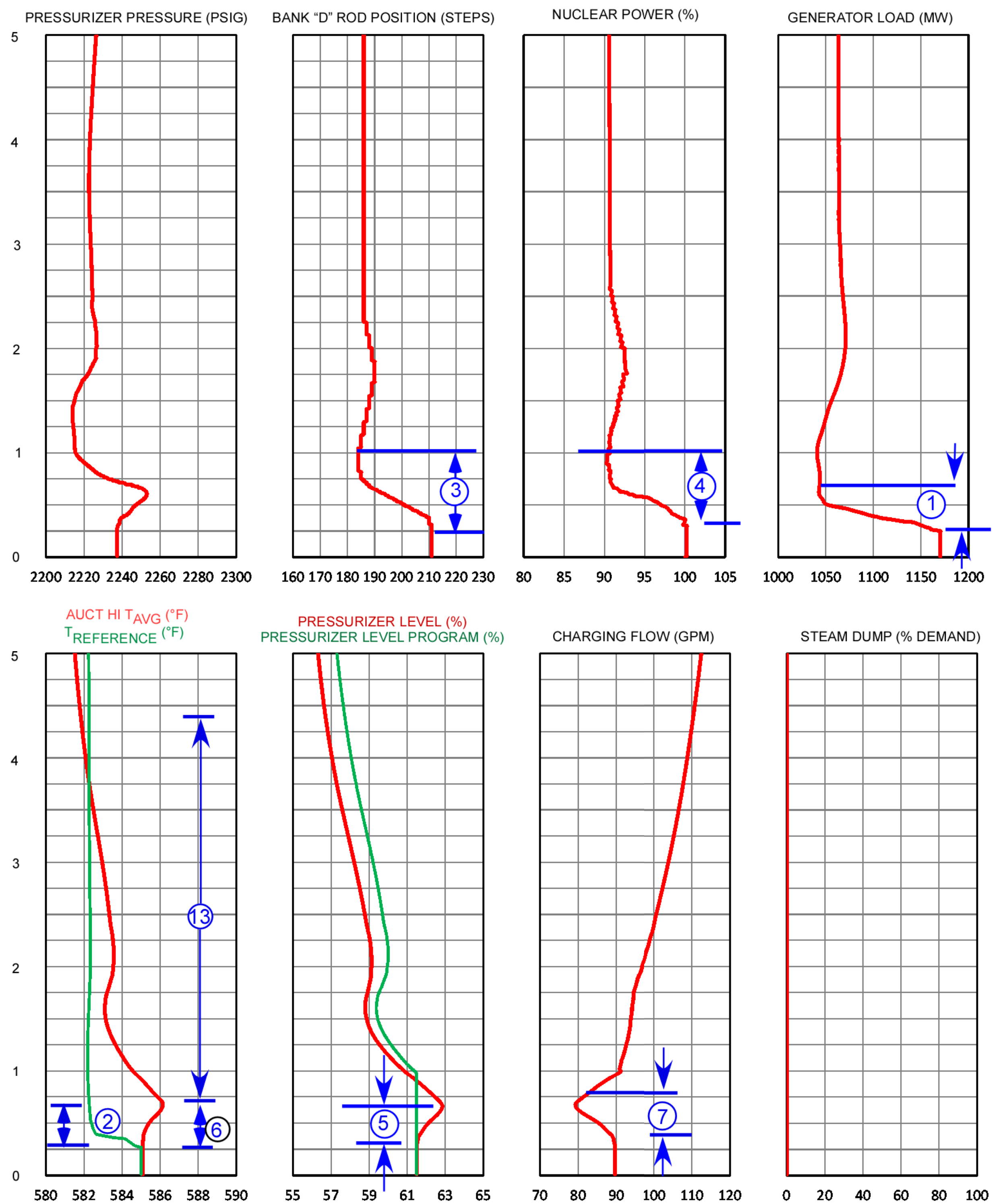
    T_{stm} (also P_{stm}) is increasing as the turbine load (and $\dot{Q}$) is decreased. The increase in T_{stm} is exaggerated a bit by the increase in T_{avg}.

13. Rod insertion produces a small mismatch between nuclear power and secondary load to bring $\mathbf{T_{avg}}$ down toward T_{ref}.

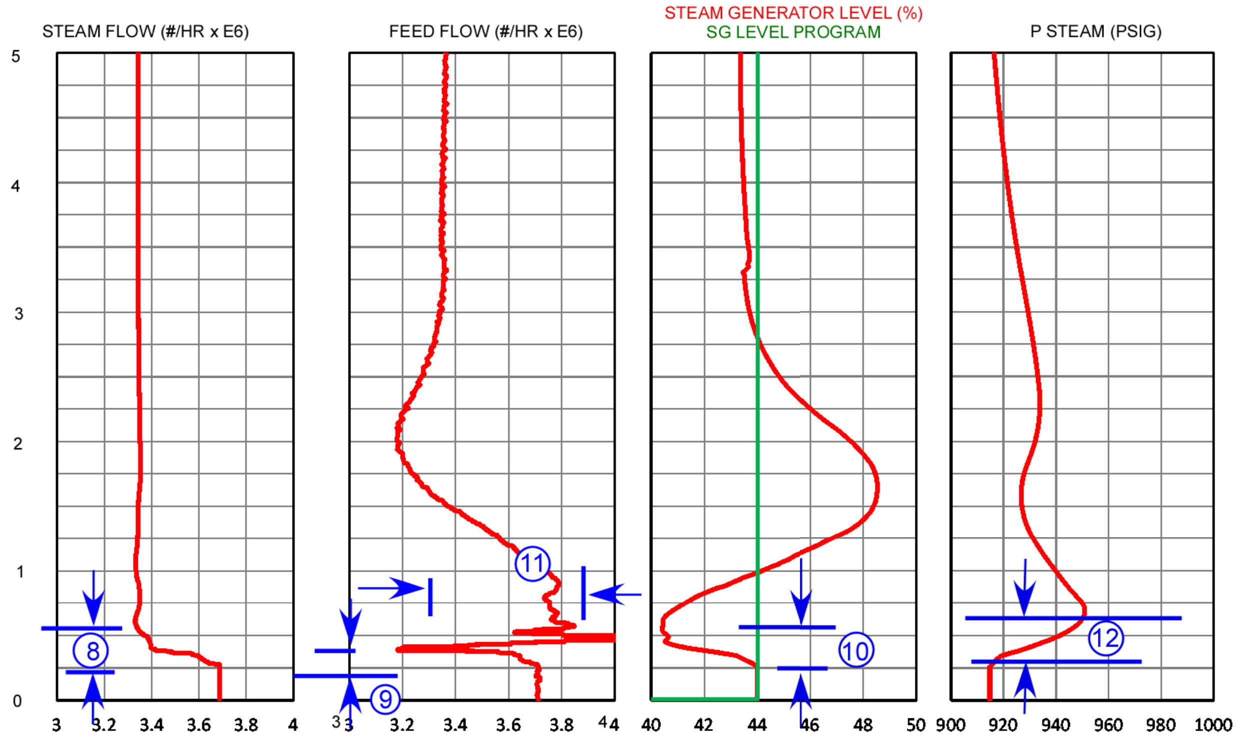
Note: At steady state at the end of the transient, nuclear power = secondary load, so T_{avg} is more or less unchanging. As for the reactivity balance, the positive reactivity added by the power defect associated with the power change is balanced by the negative reactivity added by the rod insertion, so that the net endpoint $\rho = 0$.

What this transient illustrates:

1. The plant response to a short, rapid power decrease initiated at the turbine EHC system station with the valve position limiter.
2. The actions of the rod control and pressurizer level control systems.
3. The initial shrink in steam generator water level associated with a power decrease, and the response of the steam generator water level control system.
4. The programmed decrease in T_{avg} and increase in steam pressure associated with a power decrease.



Transient 5.03 Rapid Load Decrease, 100 - 90%



TRANSIENT 5.03
RAMP LOAD DECREASE, 100-90%

Initial Conditions
Rated Thermal Power
BOL

Initiating Event:
Rapid closure of the turbine control valves with the valve position limiter

Transient 5.03 Rapid Load Decrease, 100 - 90%

Transient 5.04 Rapid Load Decrease, 100 - 50%

Initial Conditions:

BOL
Rated Thermal Power

Initiating Event: Rapid closure of turbine control valves with the valve position limiter

Point Explanation

1. **Generator load** rapidly decreases as the control valves close in response to the rapid reduction of the valve position limiter potentiometer setpoint by the operator at the turbine EHC station.

2. **T_{ref}** decreases with generator load (T_{ref} varies linearly with turbine P_{imp}).

3. **Bank D rod position** decreases at the maximum rate (72 steps/min) as rapid inward rod motion is called for by the power mismatch (turbine load decreasing rapidly relative to nuclear power) and temperature mismatch ($T_{ref} << T_{avg}$) circuits of the rod control system.

4. **Nuclear power** decreases rapidly in response to the negative reactivity added by rod insertion and by the increase in reactor coolant temperature, as discussed in point 7.

5. **Pressurizer level** increases at the start of the transient due to the heatup of the reactor coolant caused by the power mismatch, with secondary load < nuclear power.

6. **Pressurizer pressure** rises as the steam bubble is squeezed by the thermal expansion of the reactor coolant. Spray flow terminates the pressure rise.

7. **T_{avg}** increases at the start of the transient due to the power mismatch, with secondary load < nuclear power. The increase in T_{avg} is limited by the actuation of the steam dumps, which limits the total primary-to-secondary power imbalance.

8. **Charging flow** initially decreases sharply as the pressurizer level rises relative to the level setpoint (which is unchanged at the start of the transient with T_{avg} > full-load T_{avg}).

9. **Steam dump demand** increases rapidly with the rapid reduction in T_{ref} (the T_{avg} - T_{ref} difference rapidly increases). All 12 steam dump valves open fully, as discussed in point 13.

Point Explanation

10. **Steam flow** initially decreases rapidly as the control valves close to decrease load.

11. **Feed flow** decreases as the steam generator water level control system closes in response to the rapidly changing steam flow.

12. **Steam generator level** initially shrinks with the rapid load decrease.

13. **Steam flow** increases as all steam dump valves open fully with a loss-of-load arming signal (from the rapid reduction in turbine load) and maximum demand.

14. **Feed flow** rapidly increases in response to the rapid increase in steam flow and to the level error resulting from the initial shrink.

15. **Steam pressure** increases as the control valves close. $\dot{Q} = UA(T_{avg} - T_{stm})$; T_{stm} (also P_{stm}) is increasing as the turbine load (and $\dot{Q}$) is decreased. Note that the rise in steam pressure is limited by steam dump operation; while the dumps are open, total secondary load is always > turbine load.

16. **Bank D rods** momentarily stop. This transient includes a graph of rod control system inputs. There is no control board indication of these inputs, but they are included for training purposes. At this point, the initial large input to the power mismatch circuit from the reduction in turbine load has died off, nuclear power has been decreasing faster than turbine load, and the power mismatch calls for control rod withdrawal. The total error to the rod control system (the combination of power mismatch and temperature error) is < 1°F, and rod motion stops. The temperature error to rod control is not the raw difference between T_{avg} and T_{ref}, but undergoes Lead/Lag compensation. The polarity convention is such that a negative error results in rod insertion.

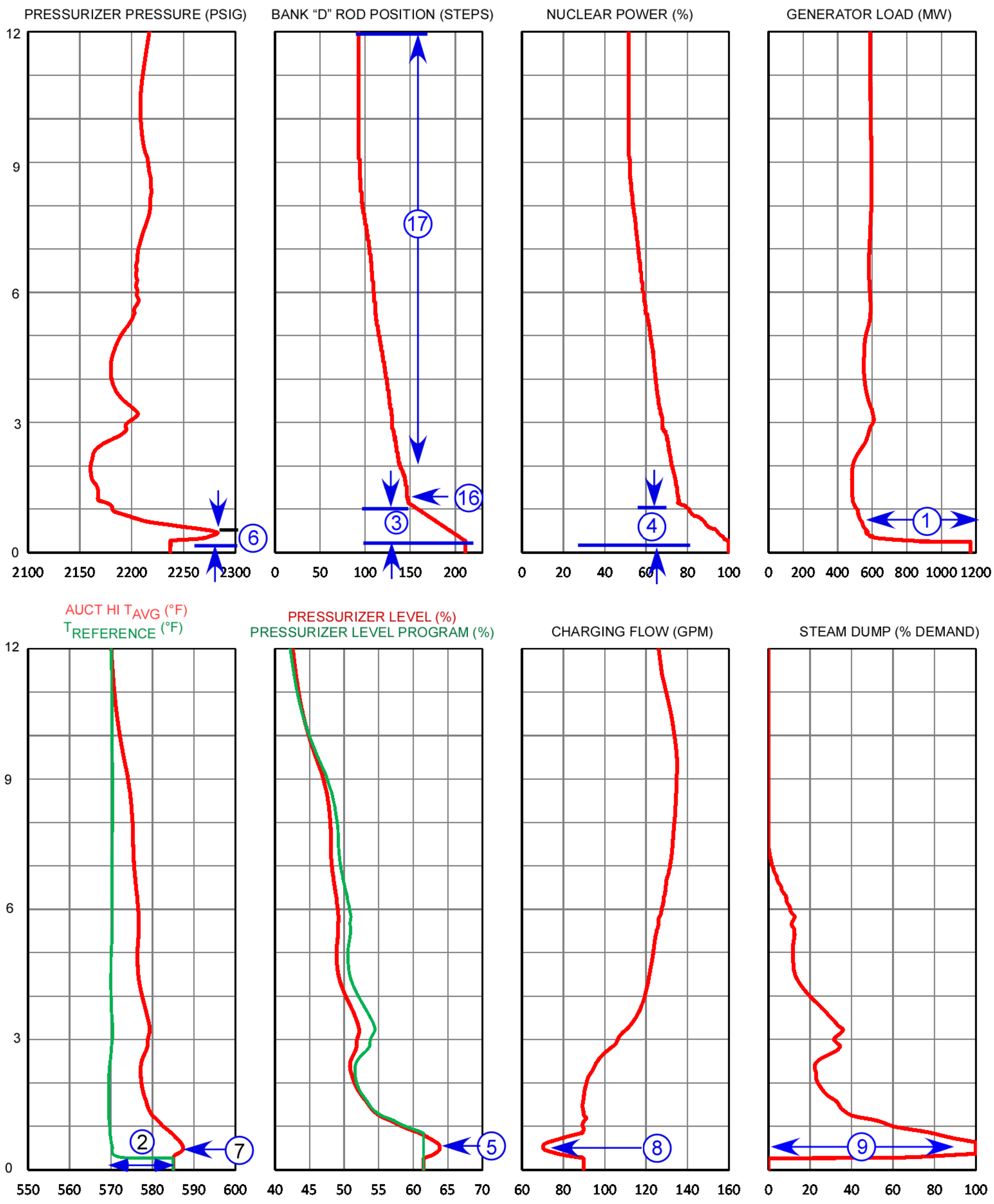
17. **Bank D rod position** decreases again, at a slower rate than earlier in the transient, with $T_{avg} > T_{ref}$. Even though the temperature error is large, the power error cancels out most of the temperature error. The negative reactivity from rod insertion causes reactor power to be lower than secondary power, which reduces T_{avg}. When T_{avg} drops to within 5°F of T_{ref}, the steam dumps fully close. Control rod motion has the overall effect of closing the steam dump valves.

Note 1: As T_{avg} decreases, the steam dump demand trends toward 0, and secondary load returns to turbine load only. The steam dumps have been armed by a loss-of-load arming signal and will remain armed until they are reset by the operator.

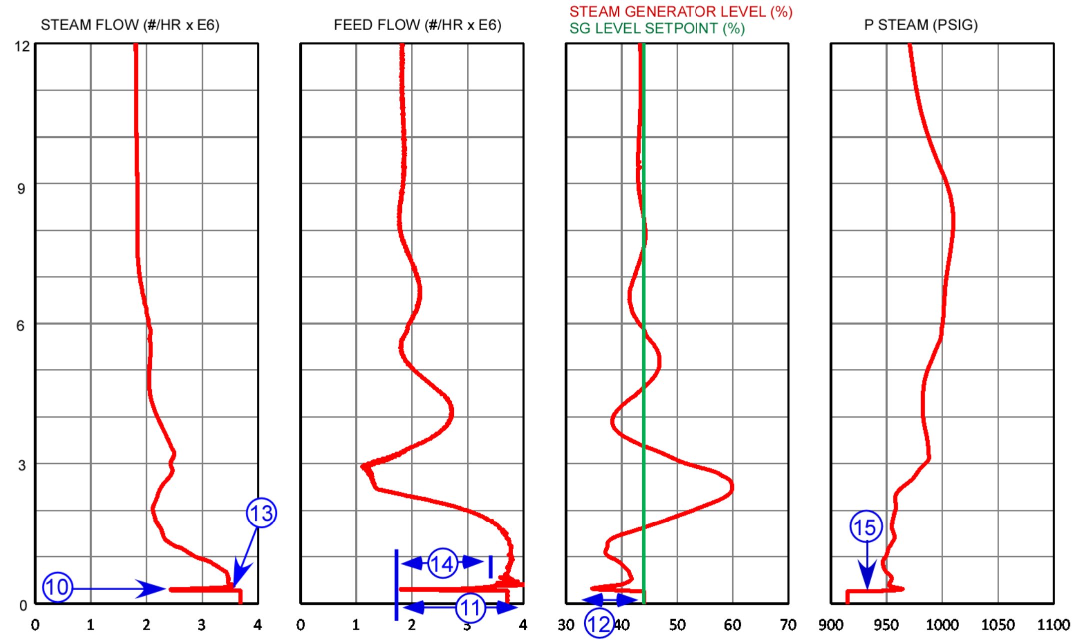
Note 2: This transient is at the limit of the design of the system. Automatic control rod motion is designed to accommodate a 10% step change and the steam dumps have a 40% capacity. Plant response to a larger load rejection may result in a plant trip.

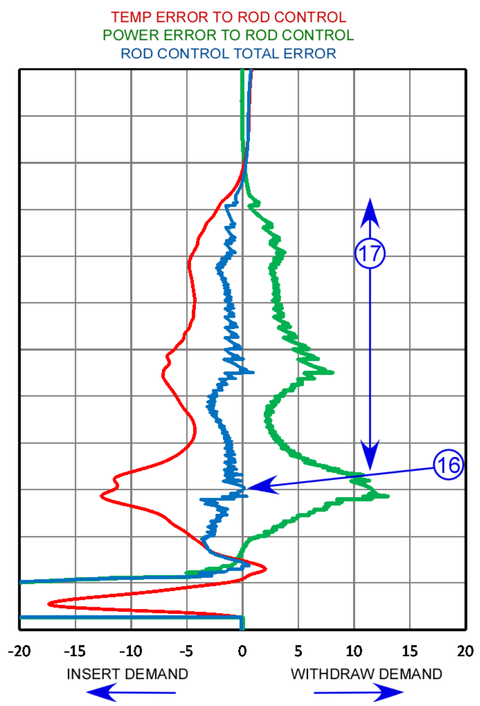
What this transient illustrates:

1. The plant response to a rapid power decrease initiated at the turbine EHC system station with the valve position limiter.
2. The actions of the rod control ,pressurizer level control, and pressurizer pressure control systems.
3. The initial shrink in steam generator water level associated with a power decrease, and the response of the steam generator water level control system.
4. The actions of the steam dump control system in response to a large loss of load.
5. The increase in T_{avg} when nuclear power > secondary load.
6. The programmed decrease in T_{avg} and increase in steam pressure associated with a power decrease.
7. Control rod motion (or some negative reactivity) is necessary to cause the steam dump valves to close after a load rejection causes them to open. The steam dumps only act to limit the rise in T_{avg}.



Transient 5.04 Rapid Load Decrease, 100 - 50%





TRANSIENT 5.04
RAPID LOAD DECREASE, 100-50%

Initial Conditions
BOL
Rated Thermal Power

Initiating Event:
Rapid closure of the turbine control valves.

Transient 5.04 Rapid Load Decrease, 100 - 50%

Transient 5.11 Manual Reactor Trip

Initial Conditions:

BOL	Bank D Rod Position: 221 steps
Nuclear Power: 100%	Normal operating temperature and pressure
All control systems in automatic	

Initiating Event: Operator depresses manual trip pushbutton

<u>Point</u> **<u>Explanation</u>**

1. **Bank D rod position** falls to 0 in ~ 2 sec when the opening of the reactor trip breakers kills power to all rod drive system coils.

2. **Nuclear power** initially decreases rapidly in concert with the prompt drop in neutron flux associated with the trip. At ~ 15 sec, the rate of power decrease follows the decay of delayed neutron precursors.

3. **Generator load** decreases rapidly to 0 when the turbine trips. The turbine trip input comes from the P-4 contact of the reactor protection system.

4. **Pressurizer level** decreases with the increase in reactor coolant density. Reactor coolant temperature is decreasing rapidly in response to the mismatch between nuclear power (decreasing to decay heat level with the trip) and secondary load (momentarily at maximum steam dump capacity.

5. The decrease in **pressurizer pressure** reflects the expansion of the steam bubble associated with the drop in pressurizer level.

6. **Charging flow** initially rises in response to the large drop in pressurizer pressure. The charging flow controller converts the output of the master pressurizer level controller to a flow demand. When charging flow rises, the charging flow controller responds by rapidly closing FCV-121 in response to the flow error.

7. **Steam dump demand** follows the T_{avg} - 557°F (no-load T_{ref}) difference. The turbine trip causes the output of the turbine-trip controller to be selected as steam dump demand. The steam dump demand increases to maximum immediately after the trip with the large T_{avg} – 557°F difference, then decreases as the steam dump actuation reduces T_{avg} below the no-load T_{ref} value.

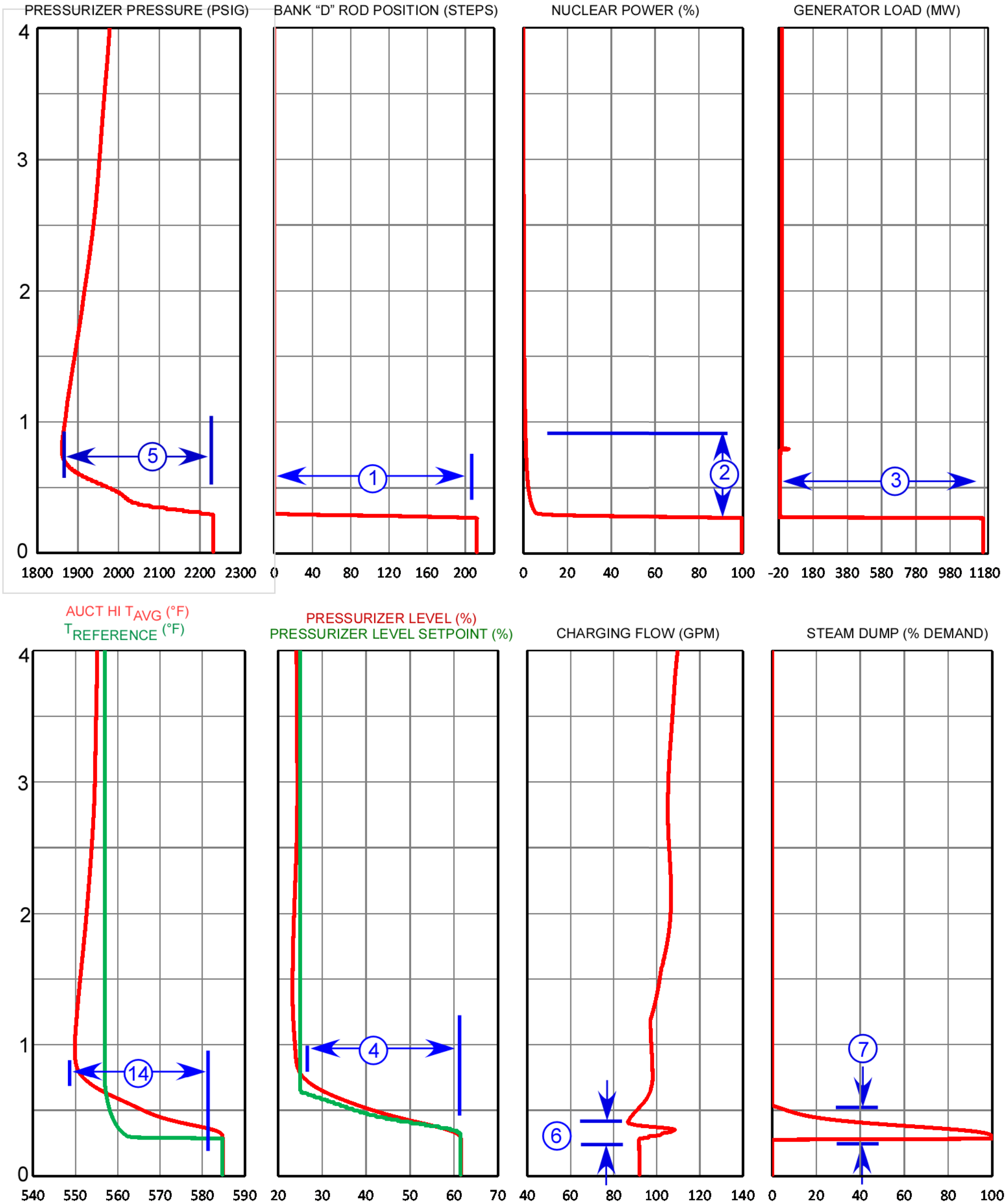
8. **Steam flow** (1) decreases as the turbine steam admission valves close with the turbine trip, then (2) increases as the steam dump valves blast open in response to the turbine trip arming signal and large demand, and finally (3) returns to 0 as the steam dump valves modulate closed in response to the reduction in demand.

<u>Point</u> <u>Explanation</u>

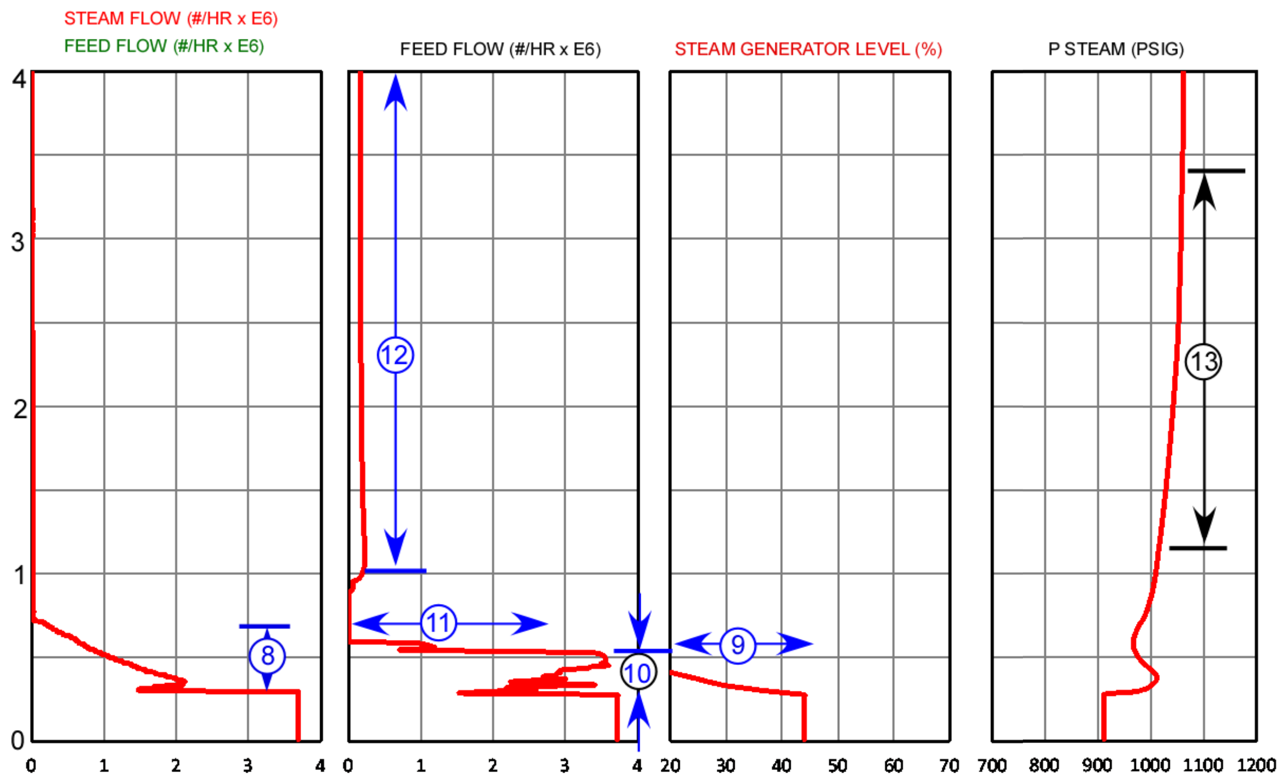
9. **Steam generator level** shrinks with the closure of the turbine steam admission valves.
10. The steam generator level control system at first decreases **feed flow** in response to the reduction in steam flow with the trip, and then increases feed flow in response to (1) the increase in steam flow with steam dump actuation and (2) the steam generator level error (level < setpoint) resulting from the trip-induced shrink.
11. The rapid reduction in **feed flow** reflects feedwater isolation on reactor trip coincident with low T_{avg} (564°F).
12. The indicated **feed flow** reflects operation of the AFW system.
13. **Steam pressure** tracks toward P_{sat} (1092 psig) for no-load T_{avg}. Decay heat and reactor coolant pump heat increase the reactor coolant temperature and, in turn, steam pressure.
14. **T_{avg}** drops because the rate of heat removal from the steam dump operation exceeds the post-trip core heat input.

What this transient illustrates:

1. The plant response to a reactor trip.
2. The actions of the pressurizer level control system.
3. The initial shrink in steam generator water level associated with a turbine trip, and the response of the steam generator water level control system.
4. The actions of the steam dump control system in response to a turbine.



Transient 5.11 Manual Reactor Trip



TRANSIENT 5.11
MANUAL REACTOR TRIP

Initial Conditions
BOL
Normal operating temperature and pressure
Rated Thermal Power

Initiating Event:
Operator manually actuates reactor trip

Transient 5.11 Manual Reactor Trip

Transient 5.12 Rapid Load Decrease, 100 - 50%, Rods In Manual

Initial Conditions:

BOL Nuclear Power: 100%
Rod bank selector switch placed in manual

Initiating Event: Rapid closure of turbine control valves with the valve position limiter

<u>**Point**</u> <u>**Explanation**</u>

1. **Generator load** rapidly decreases as the control valves close in response to the rapid reduction of the valve position limiter potentiometer setpoint by the operator at the turbine EHC station.

2. **T_{ref}** decreases with generator load (T_{ref} varies linearly with turbine P_{imp}).

3. **Bank D rod position** does not change with the rod control system in manual.

4. **Pressurizer level** increases at the start of the transient due to the heatup of the reactor coolant caused by the power mismatch, with secondary load < nuclear power.

5. **Pressurizer pressure** rises as the steam bubble is squeezed by the thermal expansion of the reactor coolant. Spray operation mitigates the pressure rise.

6. **T_{avg}** increases at the start of the transient due to the power mismatch, with secondary load < nuclear power. The increase in T_{avg} is limited by the actuation of the steam dumps, which limits the total primary-to-secondary power imbalance.

7. **Nuclear power** drops due to the rise in T_{COLD}. However, the excore indication of reactor power is initially affected by the drop in density of the water in the reactor vessel downcomer. When T_{COLD} rises, the lower density in the reactor vessel downcomer allows more neutrons to reach the detector, indicating a rise in reactor power even though it is not rising. Eventually, the rise in T_{COLD} adds enough negative reactivity to overcome this measurement error. Nuclear power stabilizes out at a little less than its original value. The steam dumps have picked up most of the missing load.

   Final reactor power is a function of turbine power, steam dump operation, and reduced secondary efficiency at the lower power (less extraction steam and feedwater preheat).

8. **Charging flow** initially decreases sharply as the pressurizer level rises relative to the level setpoint (which is unchanged at the start of the transient with T_{avg} > full-load T_{avg}).

9. **Steam dump demand** increases rapidly with the rapid reduction in T_{ref} (the T_{avg} - T_{ref} difference rapidly increases). The maximum steam dump demand (T_{avg} - T_{ref} = 16.4°F) is reached quickly. All 12 steam dump valves open fully, as discussed in point 13.

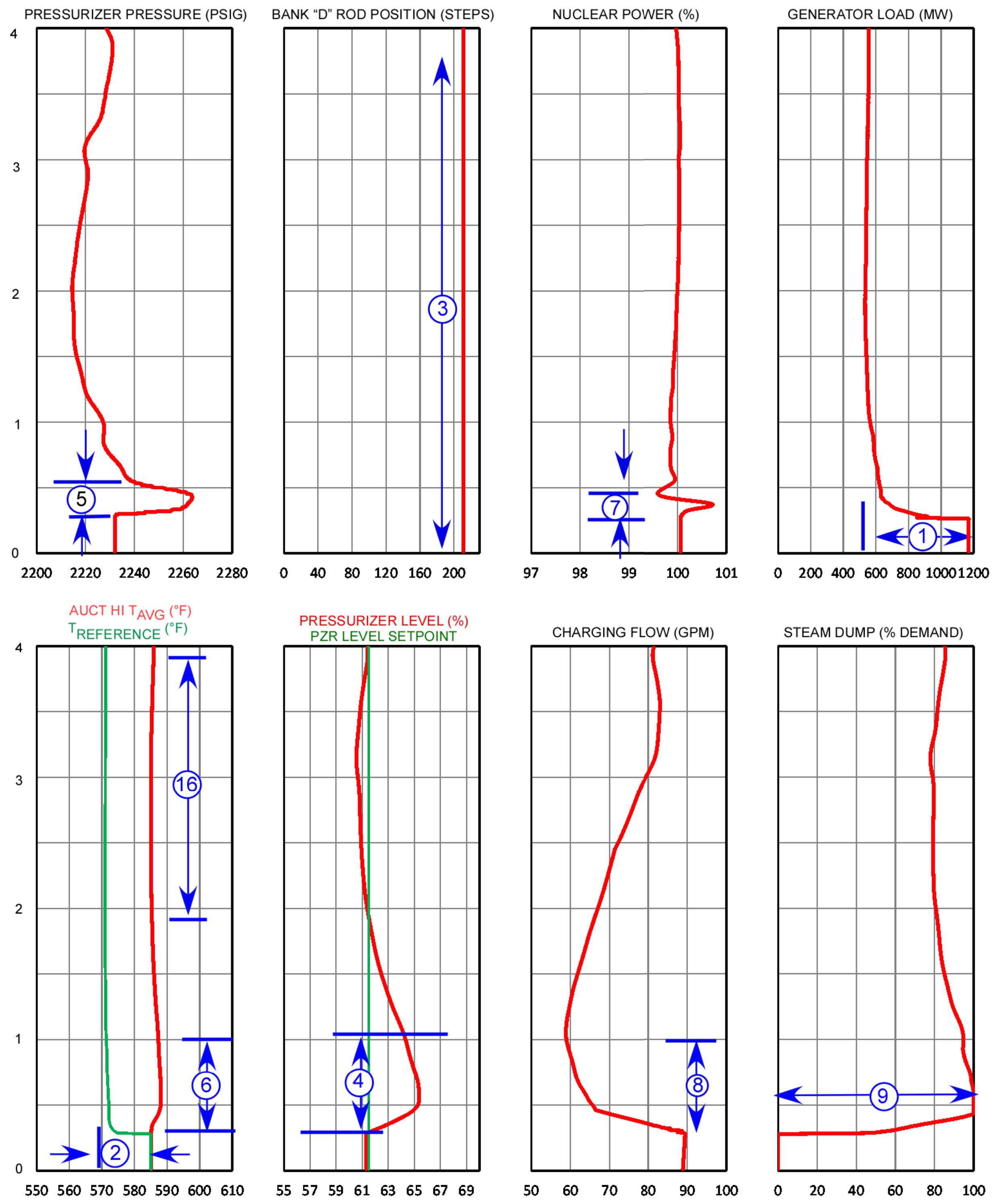
Point Explanation

10. **Steam flow** initially decreases rapidly as the control valves close to decrease load.
11. **Feed flow** decreases as the steam generator water level control system closes the main feed regulating valves to match steam and feed flows.
12. **Steam generator level** initially shrinks with the rapid load decrease.
13. **Steam flow** rapidly increases as all steam dump valves open fully with a loss-of-load arming signal (from the rapid reduction in turbine load) and maximum demand.
14. **Feed flow** rapidly increases in response to the rapid increase in steam flow and to the level error resulting from the initial shrink.
15. **Steam generator level** increases with the increased feed flow in response to the low level after the initial shrink.
16. $\mathbf{T_{avg}}$ (and $\mathbf{T_{avg} - T_{ref}}$) stays relatively constant over the last minutes of the transient, as nuclear power is equal to total secondary load. The remaining temperature fluctuations are due to the feedwater control system slowly establishing an equilibrium steam generator level on program. At the end of the transient, total secondary power is a little less than 100%.

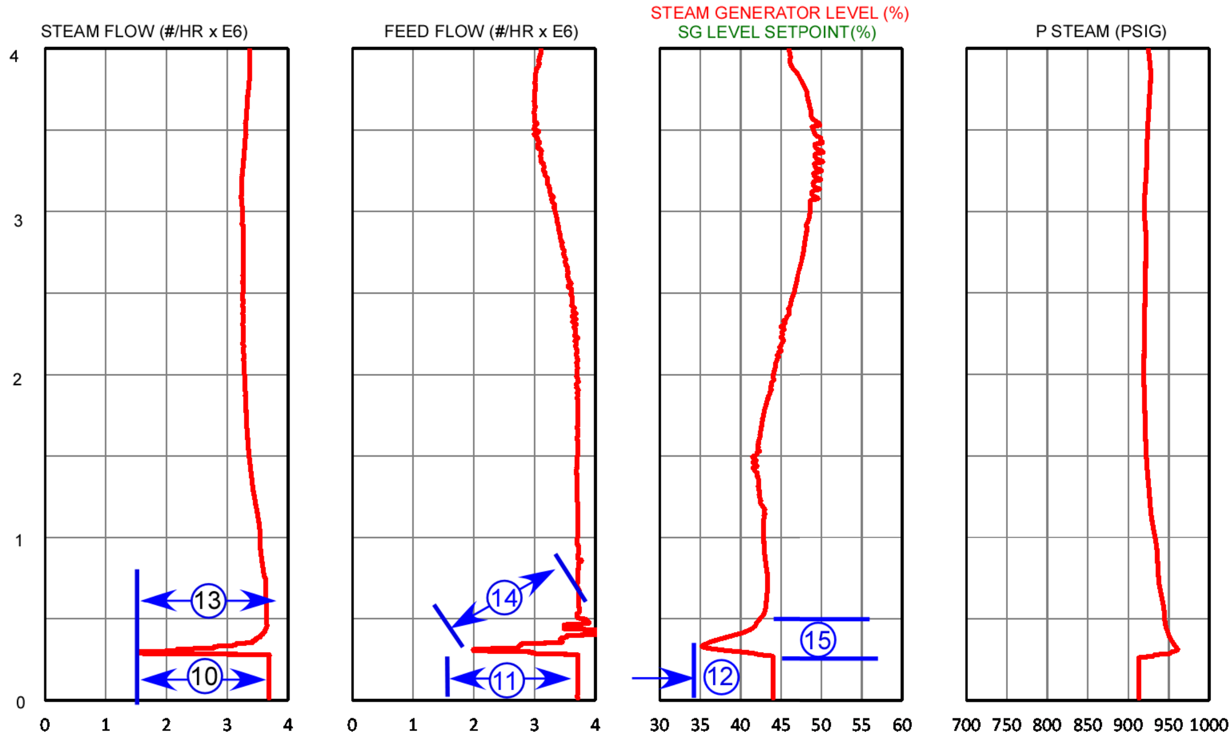
Note: At steady state at the end of the transient, the positive reactivity added by the decrease in fuel temperature associated with the relatively small power change is balanced by the negative reactivity added by the increase in coolant temperature, so that the net endpoint $\rho = 0$.

What this transient illustrates:

1. The generator load response to a rapid power decrease initiated at the turbine EHC system station with the valve position limiter.
2. The actions of the pressurizer level control and pressurizer pressure control systems.
3. The initial shrink in steam generator water level associated with a power decrease, and the ensuing recovery in SG level.
4. The actions of the steam dump control system in response to a large loss of load, and steam dumps serving as a significant portion of total secondary load. The steam dumps do not restore T_{avg} to program value, they only limit the rise in T_{avg}. Adding negative reactivity will restore T_{avg} and close the steam dumps.
5. The increase in T_{avg} when nuclear power > secondary load.



Transient 5.12 Rapid Load Decrease, 100 - 50%, Rods In Manual



TRANSIENT 5.12
RAPID LOAD DECREASE, 100-50%
RODS IN MANUAL

Initial Conditions
BOL
Nuclear Power: 100%
Rod bank selector switch placed in manual

Initiating Event:
Rapid closure of the turbine control valves with the valve position limiter

Transient 5.12 Rapid Load Decrease, 100 - 50%, Rods In Manual

Transient 5.13 Rapid Load Decrease, 100 - 50%, Steam Dumps Off

Initial Conditions:

BOL | Rated Thermal Power
Steam dump turned off

Initiating Event: Rapid closure of turbine control valves with the valve position limiter

Point **Explanation**

1. **Generator load** rapidly decreases as the control valves close in response to the rapid reduction of the valve position limiter potentiometer setpoint by the operator at the turbine EHC station.
2. **Bank D rod position** decreases at the maximum rate (72 steps/min) as rapid inward rod motion is called for by the power mismatch (turbine load decreasing rapidly relative to nuclear power) and temperature mismatch ($T_{ref} << T_{avg}$) circuits of the rod control system.
3. **Pressurizer level** increases greatly at the start of the transient due to the heatup of the reactor coolant caused by the power mismatch, with turbine load < nuclear power.
4. **Pressurizer pressure** rises as the steam bubble is squeezed by the thermal expansion of the reactor coolant. The pressure increase is controlled by PORV lifts.
5. **T_{avg}** increases at the start of the transient due to the power mismatch, with turbine load < nuclear power. Rod insertion is not as effective as steam dump actuation in limiting the increase in T_{avg}.
6. **Nuclear power** decreases in response to the negative reactivity added by the rod insertion and the increase in T_{avg}.
7. **Steam dump demand** increases rapidly to maximum with the rapid reduction in T_{ref} (the T_{avg} - T_{ref} difference rapidly increases). No steam dump valves open, as shown by the steam flow trace, as the steam dump bypass interlock switches have been placed in the off positions.
8. **Steam flow** initially decreases rapidly as the control valves close to decrease load. Steam flow rises slightly after the load reduction due to the rise in steam pressure with constant turbine valve position.
9. **Steam generator level** initially shrinks with the rapid load decrease.

Point Explanation

10. **Steam pressure** increases rapidly with the closure of the turbine control valves and the large increase in T_{avg}.

11. **Steam generator level** increases with the increased feed flow in response to the low level after the initial shrink.

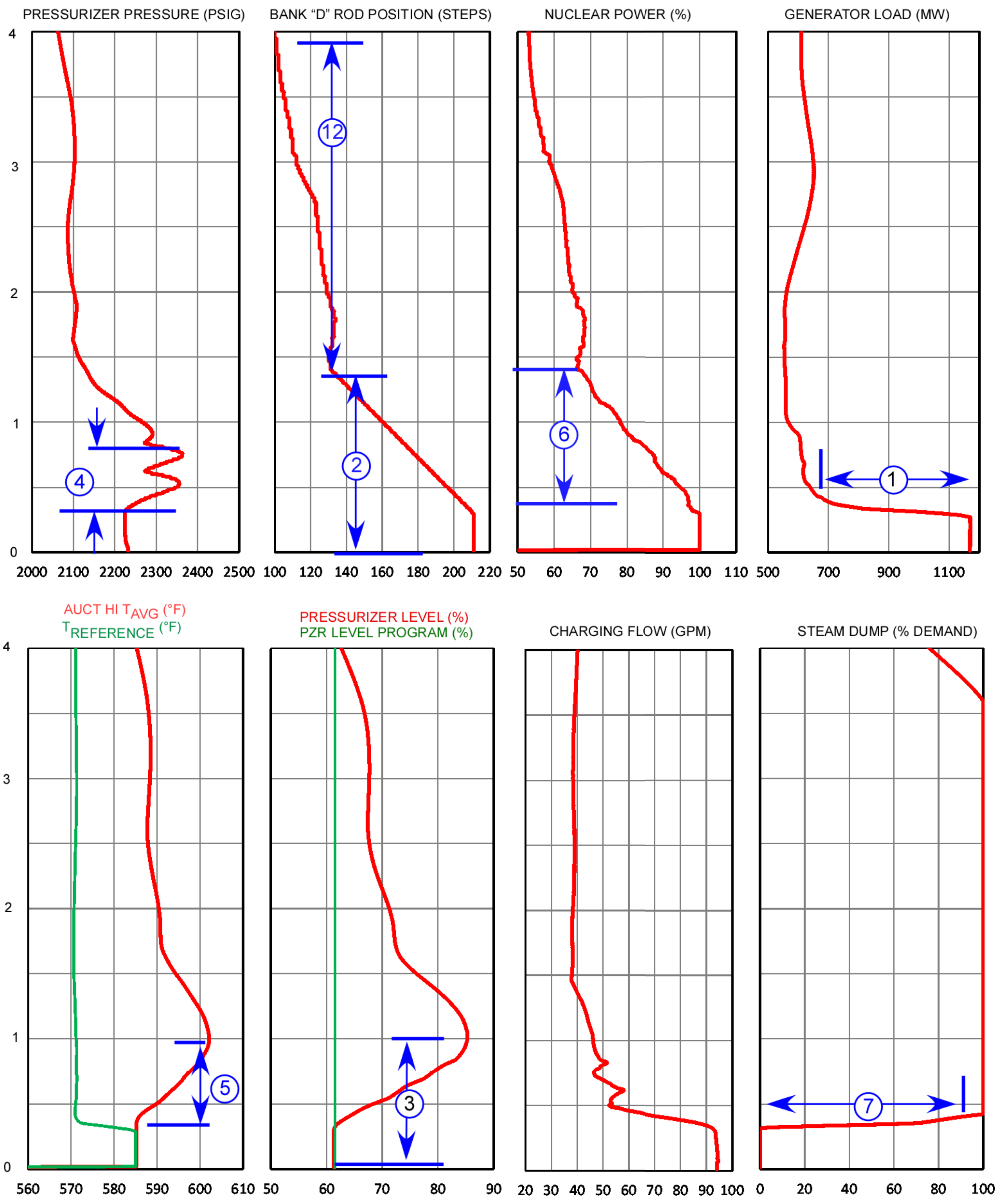
12. C**ontrol rod** insertion slows as a function of the interaction between the power mismatch and temperature mismatch components of automatic rod control. During this interval, the power mismatch is calling for withdrawal, and the temperature mismatch is calling for insertion.

13. **Feed flow** initially drops in response to the drop in steam flow, then responds to the SG level error.

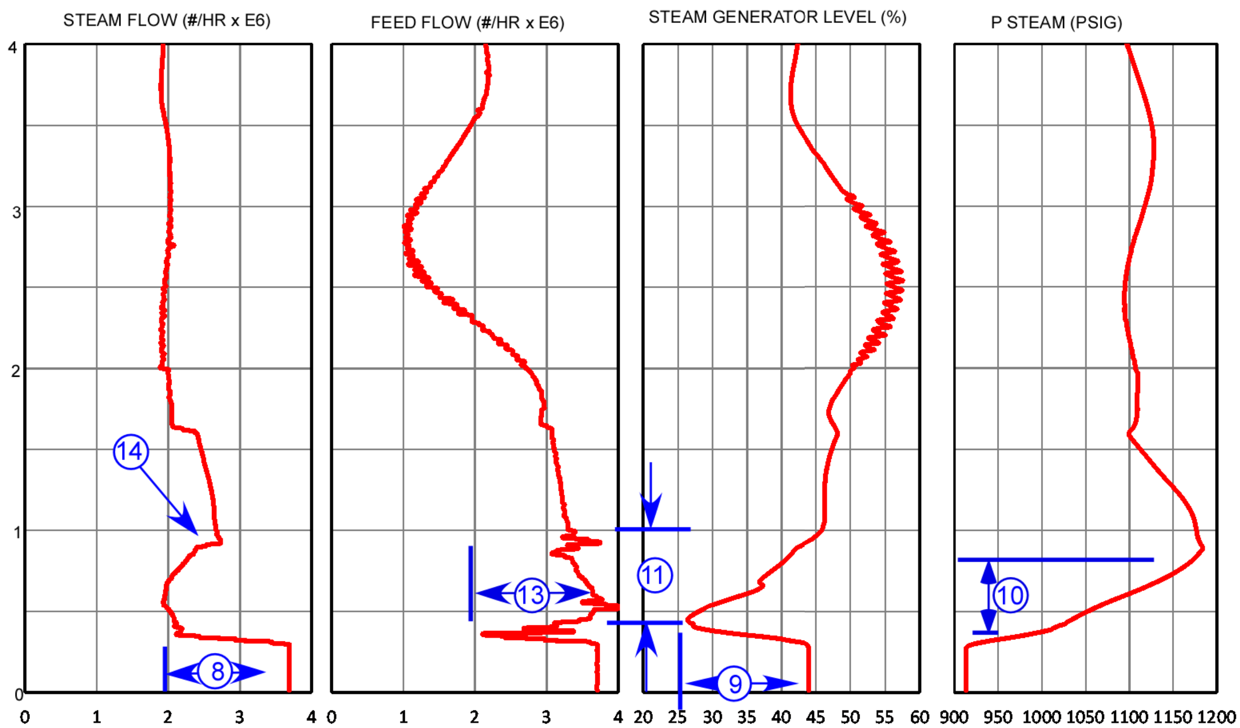
14. The PORVs and safeties act similarly to steam dumps in limiting the rise in T_{avg}.

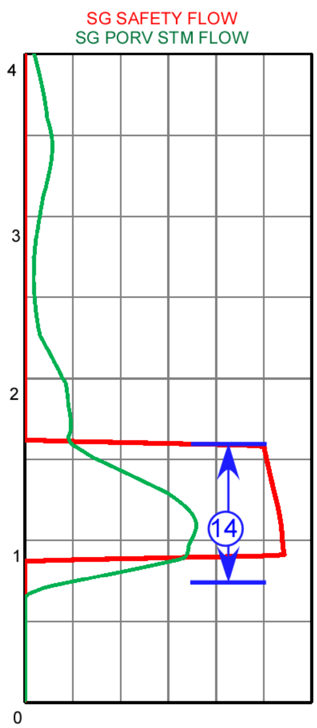
What this transient illustrates:

1. The generator load response to a rapid power decrease initiated at the turbine EHC system station with the valve position limiter.
2. The actions of the rod control, pressurizer level control, and pressurizer pressure control systems.
3. The initial shrink in steam generator water level associated with a power decrease.
4. The increase in T_{avg} when nuclear power >> secondary load.
5. Rod insertion (starting with bank D rods almost completely withdrawn) is not as effective as steam dump actuation in limiting the increase in T_{avg} with nuclear power >> secondary load.



Transient 5.13 Rapid Load Decrease, 100 - 50%, Steam Dumps Off





TRANSIENT 5.13
RAPID LOAD DECREASE, 100-50%
STEAM DUMPS OFF

Initial Conditions
BOL
Rated Thermal Power
Steam dumps turned off

Initiating Event:
Rapid closure of the turbine control valves with the valve position limiter

Transient 5.13 Rapid Load Decrease, 100 - 50%, Steam Dumps Off

Transient 5.14 Rapid Load Decrease, 100 - 50%, Steam Dumps Off, Rods In Manual

Initial Conditions:

BOL
Rated Thermal Power
Steam dump bypass interlock switches placed in off position
Rod bank selector switch placed in manual

Initiating Event: Rapid closure of turbine control valves with the valve position limiter

Point **Explanation**

1. **Generator load** rapidly decreases as the control valves close in response to the rapid reduction of the valve position limiter potentiometer setpoint by the operator at the turbine EHC station.

2. **Pressurizer level** increases greatly at the start of the transient due to the heatup of the reactor coolant caused by the power mismatch, with secondary load < nuclear power.

3. **Pressurizer pressure** rises as the steam bubble is squeezed by the thermal expansion of the reactor coolant. The second pressure rise reaches the high pressurizer pressure trip setpoint.

4. **T_{avg}** increases at the start of the transient due to the power mismatch, with secondary load < nuclear power.

5. The reactor trips due to high pressurizer pressure.

6. **Steam flow** initially decreases rapidly as the control valves close to decrease load.

7. **Steam generator level** initially shrinks with the rapid load decrease.

8. **Steam pressure** increases rapidly with the closure of the turbine control valves and the large increase in T_{avg}.

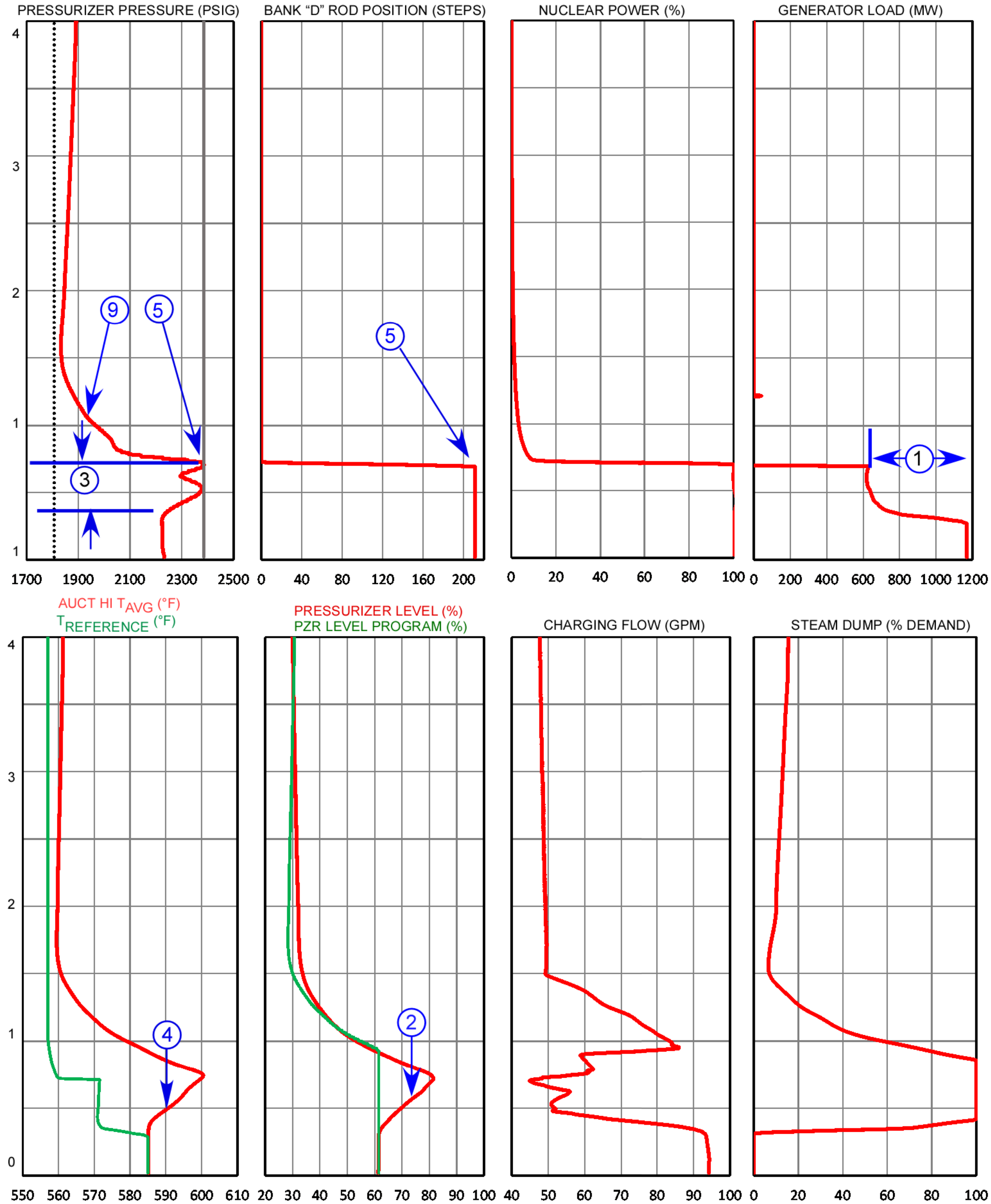
9. **Pressurizer pressure** drops after the reactor trips. The PORV lifts have taken energy out of the pressurizer, so that post-trip pressure drops lower than normal. It is a characteristic of a PWR that a heatup followed by a cooldown causes a low pressure condition in the RCS.

<u>Point</u> <u>Explanation</u>

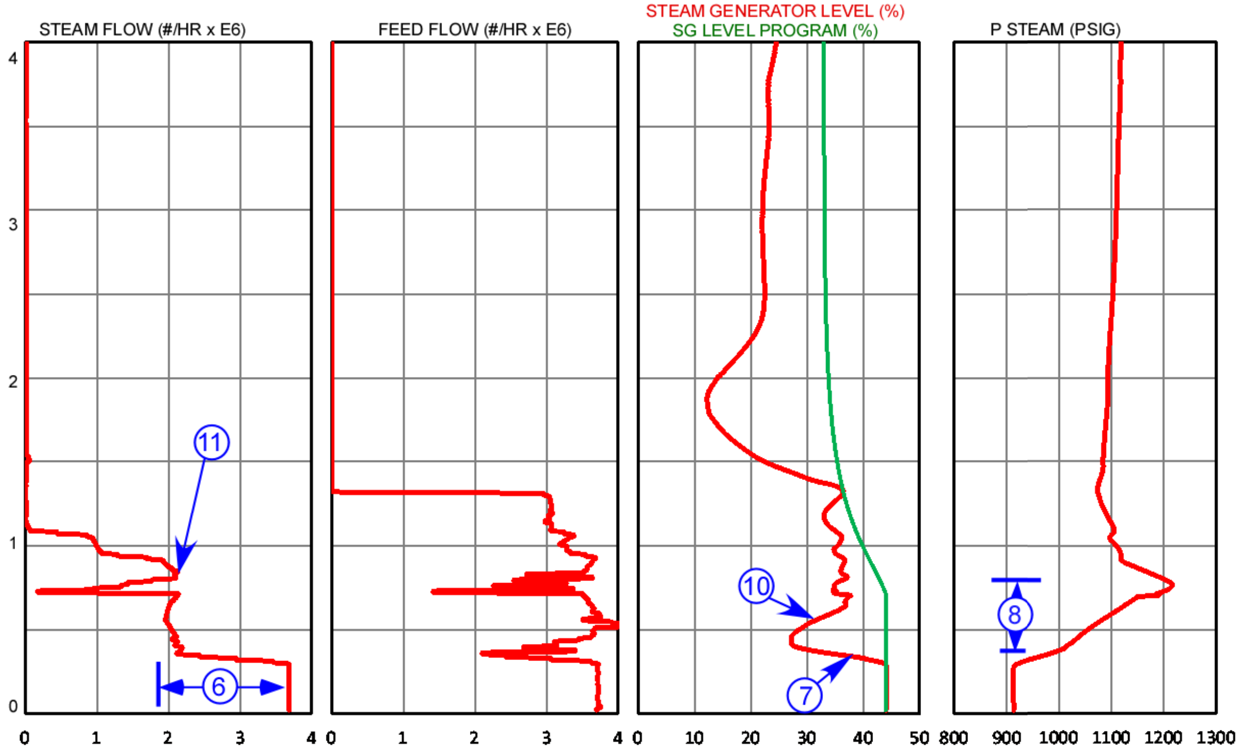
10. **Steam generator level** increases with the increased feed flow in response to the low level after the initial shrink.
11. The large increase in **steam flow** reflects openings of the PORVs and safety valves.

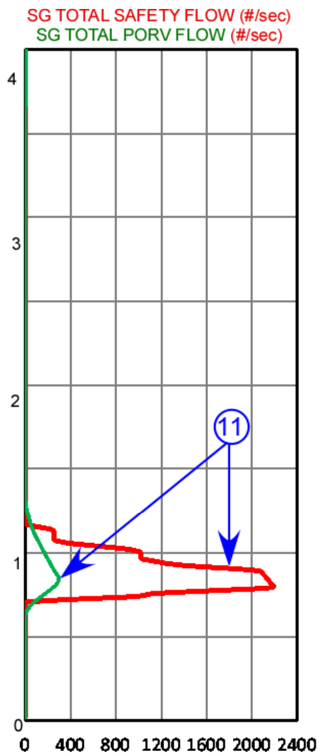
What this transient illustrates:

1. The only difference between this transient and transient 5.13 is that control rods are in manual. This causes the heat-up to be more severe.
2. The SG PORVs and safeties act similarly to steam dumps in limiting the rise in T_{avg}.



Transient 5.14 Rapid Load Decrease, 100 - 50%, Steam Dumps Off, Rods In Manual





TRANSIENT 5.14
RAPID LOAD DECREASE, 100-50%
STEAM DUMPS OFF, RODS IN MANUAL

Initial Conditions
BOL
Rated Thermal Power
Steam dumps turned off
Control rods in manual

Initiating Event:
Rapid closure of the turbine control valves
with the valve position limiter

Transient 5.14 Rapid Load Decrease, 100 - 50%, Steam Dumps Off, Rods In Manual

Transient 5.21 Dropped Rod (Control Bank D Rod D-12)

Initial Conditions:

BOL
Normal temperature and pressure
Nuclear Power: 100%   All control systems in automatic

Initiating Event: Control bank D rod D-12 drops completely into the core

<u>Point</u> <u>Explanation</u>

1. **Nuclear power** drops in response to the negative reactivity insertion associated with the dropped rod. Of the two power range channels plotted, the power drop is greatest on channel NI-42 because it is closest to the dropped rod and measuring power in the most affected quadrant of the core. (Control bank D rod D-12 is very close to the core “corner” adjacent to NI-42. See the attached core map.)

2. **Bank D rod position** increases with the temperature mismatch circuit of the rod control system calling for outward rod motion. The rod motion stops when C-11, Control Bank Withdrawal Interlock is reached.

3. **T_{avg} (all loops)** decreases with the power mismatch caused by the dropped rod, with nuclear power < turbine load. The decrease in T_{avg} continues until enough positive reactivity has been added from MTC to make nuclear power = to turbine load. (The drop in coolant temperature and the positive reactivity associated with it indicate that the positive reactivity associated with the rod withdrawal of point 2 above is not enough to counteract the negative reactivity of the dropped rod.) Note the spread in the loop temperatures: loop #4, closest to the dropped rod, is affected the most. The temperature spread graphically illustrates that complete coolant mixing in the reactor and in the reactor vessel upper plenum does not occur.

4. The positive reactivity from the coolant temperature drop and (to a small extent) from the rod withdrawal increases **nuclear power**.

Point **Explanation**

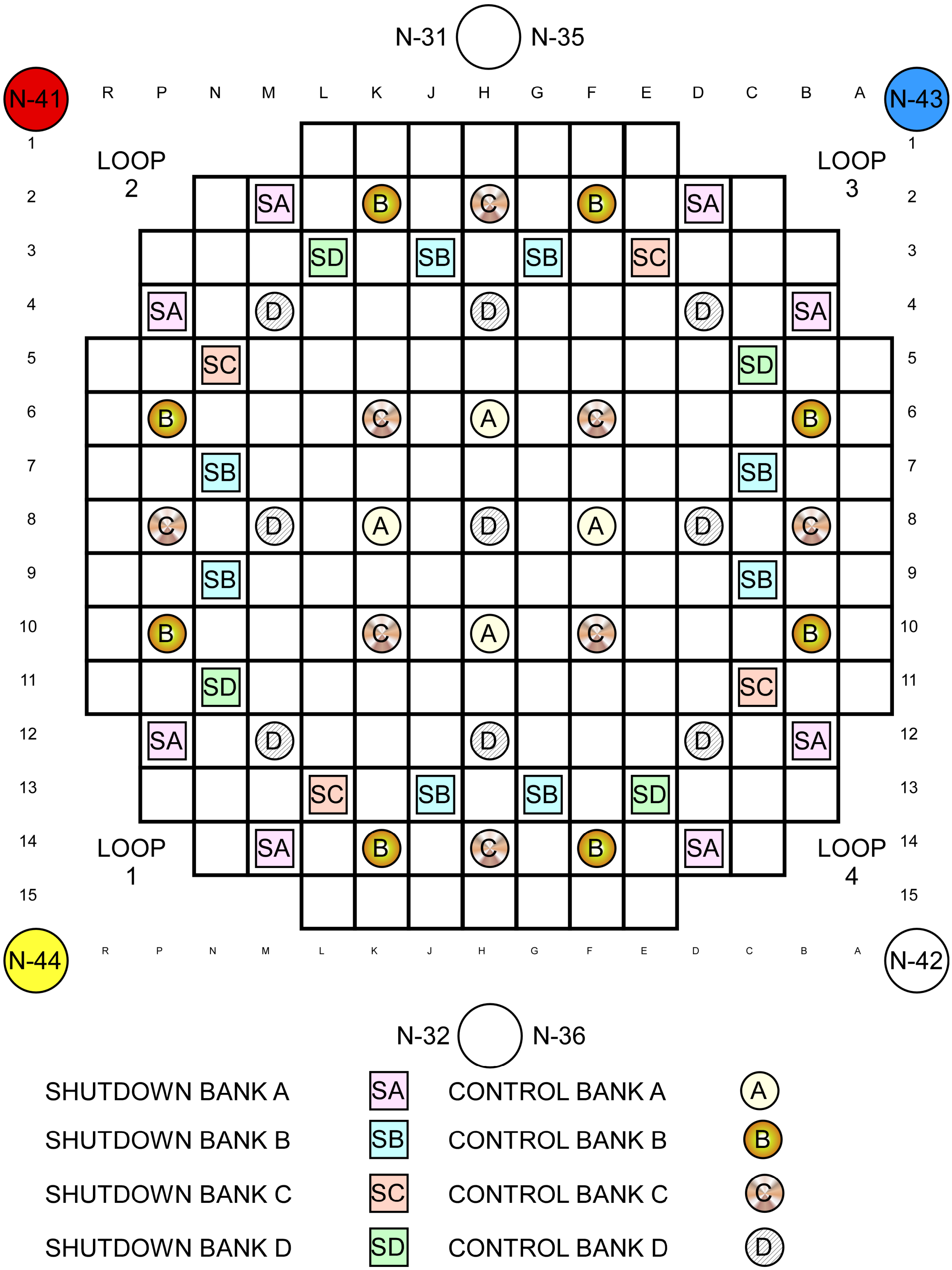
5. **Steam pressure** drops as heat transfer conditions in the SGs change due to the reduced T_{avg}. The lower T_{avg} cannot continue to support steam pressure at its initial value. $\dot{Q} = UA(T_{avg} - T_{stm})$; $\dot{Q}$ is essentially constant, so T_{stm} (and P_{stm}) is gradually decreasing to maintain the same ΔT across the SG tubes.

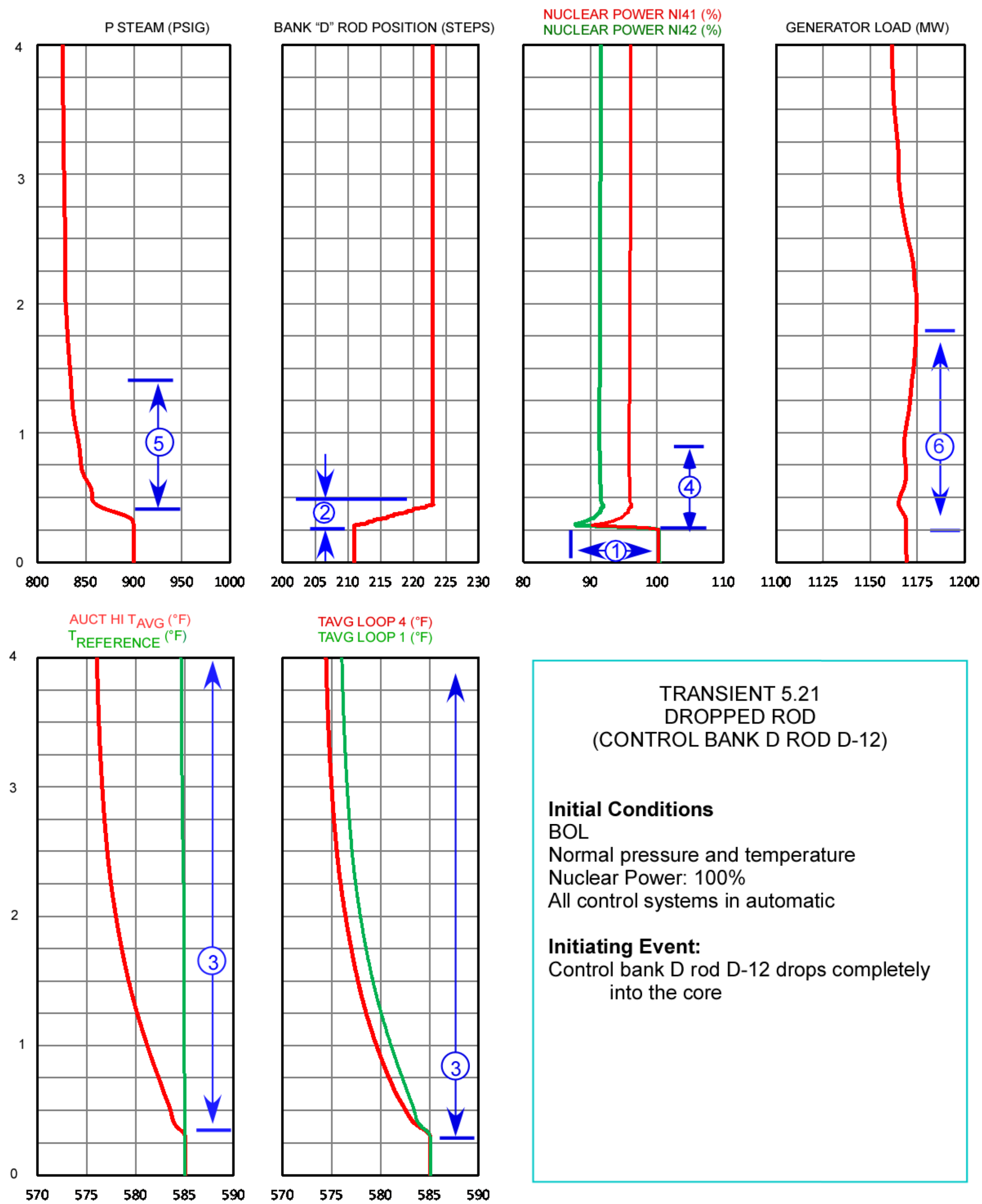
6. **Generator load** remains approximately constant as steam pressure drops due to the action of throttle pressure compensation.

What this transient illustrates:

1. The negative reactivity associated with a dropped rod.
2. The spread in coolant temperatures between core quadrants, illustrating that the dropped rod affects the portions of the core closest to it the most.

Transient 5.21 Dropped Rod (Control Bank D Rod D-12) (cont'd)





Transient 5.21 Dropped Rod (Control Bank D Rod D-12)

Transient 5.22 Fast Rod Withdrawal, 50% Load

Initial Conditions:

BOL
Nuclear Power: 50%

Initiating Event: Rod control system failure withdraws control rods at 72 steps/min

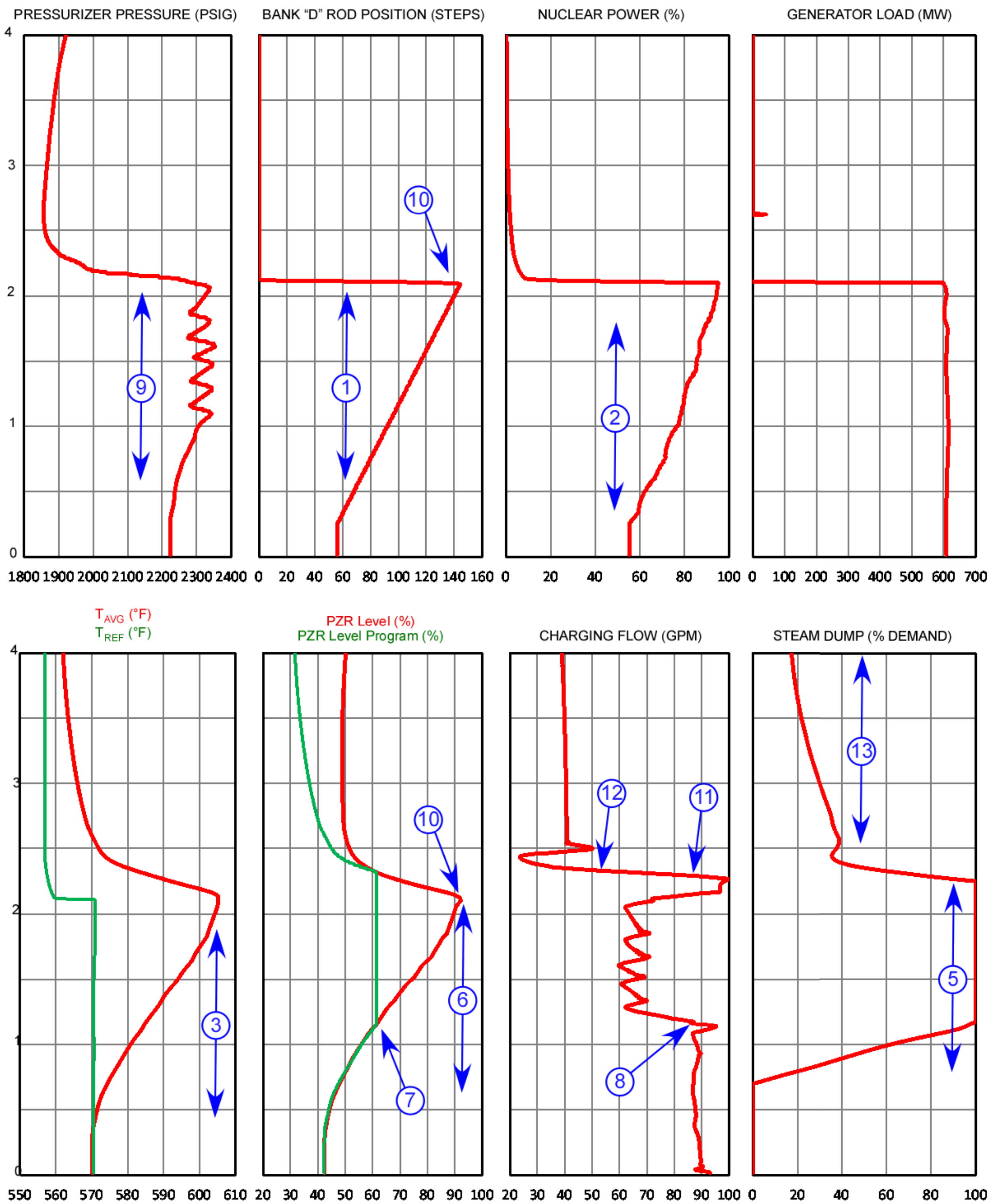
<u>**Point**</u> <u>**Explanation**</u>

1. **Bank D rod position** increases at 72 steps/min in response to the controller failure. Bank C also moves consistent with overlap requirements.
2. **Nuclear power** increases with the positive reactivity associated with the rod withdrawal. The rise in fuel temperature and moderator temperature is adding negative reactivity, but they cannot overcome the effect of the rods.
3. **T_{avg}** increases with the power mismatch caused by the rod withdrawal, with nuclear power > turbine load. The increase in T_{avg} is also evident in the increase in pressurizer level.
4. **Steam pressure** increases as heat transfer conditions in the SGs change due to the increased power and the increased T_{avg}. $\dot{Q} = UA(T_{avg} - T_{stm})$. $\dot{Q}$ is rising as additional paths for steam flow are created (safeties and SG PORVs). T_{avg} is also rising, so T_{stm} (and P_{stm}) is increasing.
5. **Steam dump demand** steadily increases to maximum with $T_{avg} >> T_{ref}$. Steam dump actuation does not initially occur (there is no corresponding change in steam flow), as there is no arming signal. The steam dumps will not arm until the turbine trips.
6. **Pressurizer level** increases because of the decrease in reactor coolant density (T_{avg} is increasing). Level continues to rise to the reactor trip setpoint.
7. The **PZR level program** stops rising when it reaches its maximum value.
8. **Charging flow** drops rapidly when PZR level exceeds its maximum program value. This corresponds to Tavg exceeding its maximum program value.
9. **Pressurizer pressure** rises as the steam bubble is compressed by the thermal expansion of the reactor coolant. The PORVs cycle several times.

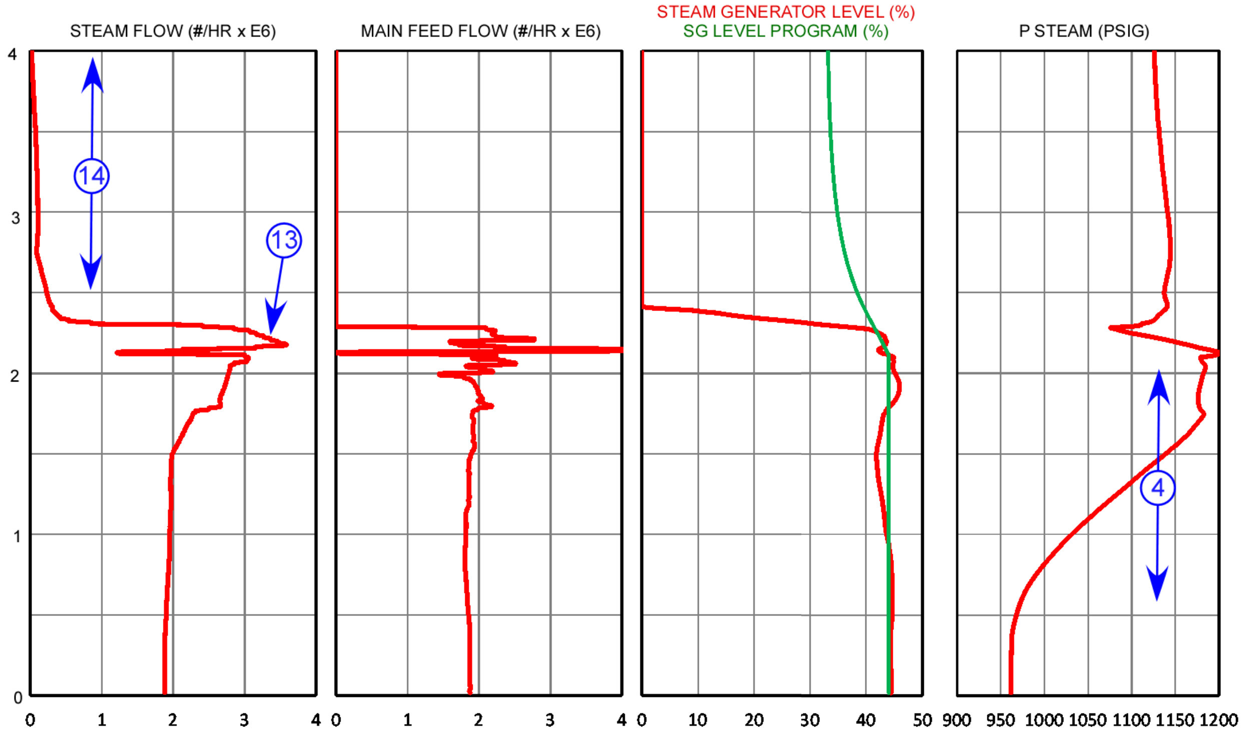
<u>Point</u>	<u>Explanation</u>
10.	**Pressurizer level** rises to the reactor trip setpoint.
11.	**Charging flow** rises rapidly when the reactor trips. This is due to the large drop in pressurizer pressure. Since the charging pumps are centrifugal pumps, the flow is always a function of the pump head. The flow controller rapidly lowers this flow by throttling down on the flow control valve.
12.	**Charging flow** shows the characteristic trace for SI actuation. Flow increases due to automatic start of the standby charging pump. Flow then drops as the normal charging flowpath isolates and the remaining charging flow is all going to the RCP seals.
13.	**Steam flow** rises to a very large value when the reactor trips. When the steam dumps arm on the turbine trip, the full capacity of the steam dumps is added to the steam flow from SG PORVs and SG safeties. This momentary high steam flow causes a rapid reduction in steam pressure, leading to a safety injection on high steam flow coincident with low steam pressure. The steam pressure signal has a large lead component which causes it to trip the low pressure bistable at a pressure well above the setpoint.
14.	The combination of **steam dump demand** and **steam flow** shows that the MSIVs are closed. This is evidence that the cause of the SI is high steam flow coincident with low steam pressure.
15.	The reason that **steam flow** does not go to zero as soon as the MSIVs close is steam flow through the SG PORVs.

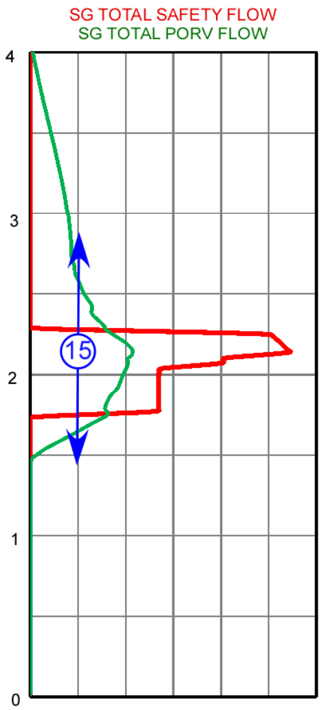
What this transient illustrates:

1. The response of the plant to a fast rod withdrawal at power, particularly the increases in reactor coolant temperature, pressurizer level, and steam pressure.
2. The throttle pressure compensator keeps generator load fairly constant as steam pressure changes, since pressure remains in the operating band of the throttle pressure compensation circuit.
3. The control rods are deeply inserted at the onset of this transient to see the maximum reactivity effect of the rod withdrawal at power. This is not an expected rod position at 50% power.



Transient 5.22 Fast Rod Withdrawal, 50% Load





TRANSIENT 5.22
FAST ROD WITHDRAWAL FROM 50%

Initial Conditions
BOL
50% RTP

Initiating Event:
Control rods withdraw in sequence at 72 steps/minute

Transient 5.22 Fast Rod Withdrawal, 50% Load

Transient 5.23 Fast Rod Withdrawal From 10^{-8} amps in IR

Initial Conditions:

BOL
Critical at 10^{-8} amps in the intermediate range.

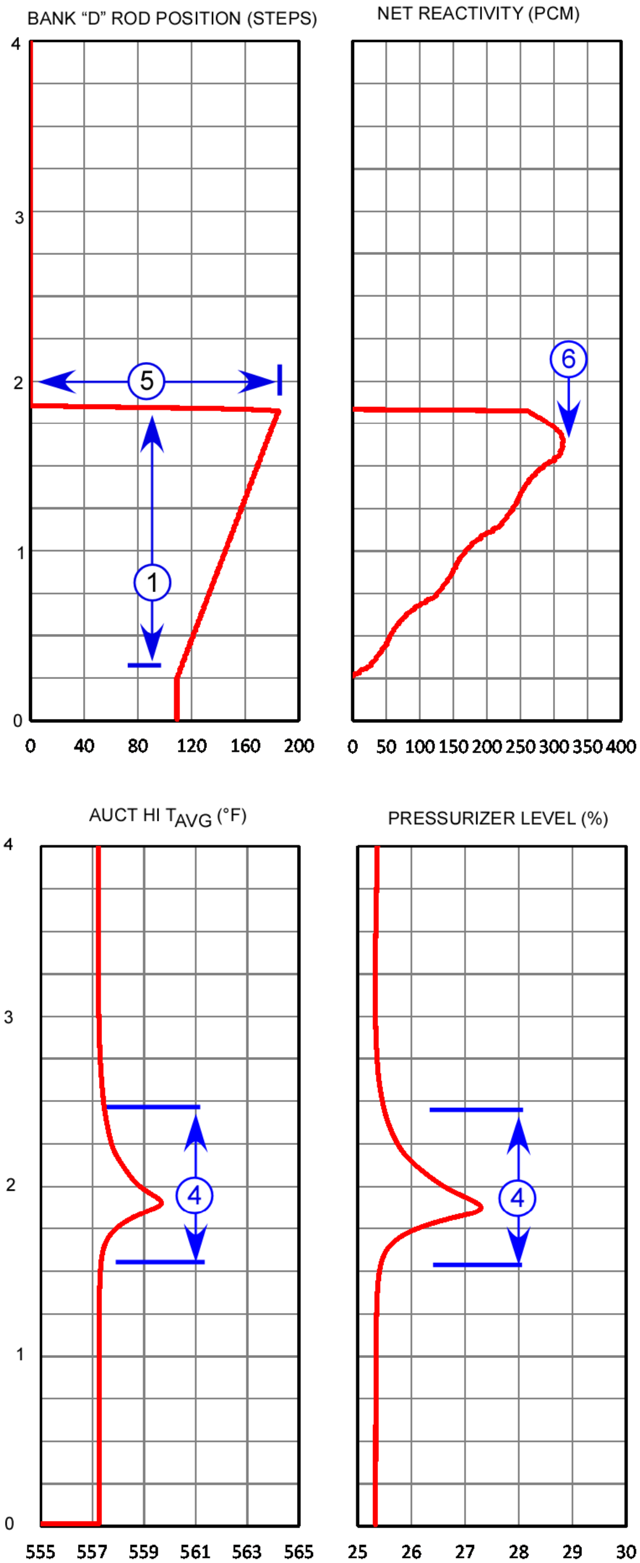
Initiating Event: Rod control system controller failure withdraws bank D rods at 72 steps/min

<u>Point</u> **<u>Explanation</u>**

1. **Bank D rod position** increases at 72 steps/min in response to the controller failure.
2. **Intermediate range power** increases with the positive reactivity associated with the rod withdrawal.
3. **Nuclear power (power range)** gets on scale when rod withdrawal has increased neutron flux sufficiently. Peak power exceeds the P-10 setpoint (10%), so the reactor trip based on a turbine trip above P-7 is activated.
4. **Pressurizer level** and **T_{avg}** increase after the point of adding heat has been reached. During most of the transient there is no significant reactivity feedback from the fuel or the moderator. The point of adding heat corresponds roughly to the power range coming on scale.
5. The reactor trip (indicated by the step drop in **bank D rod position**) is caused by a turbine trip > P-7.
6. The effect of being above the point of adding head can be seen in that the **net positive reactivity** in the core begins to reduce prior to the reactor trip, even though the rods continue to withdraw.

What this transient illustrates:

1. The response of the plant to a fast rod withdrawal starting below the point of adding heat.
2. There is no significant (visible) reactivity effect of heating the fuel or moderator until power is approximately at the power range.



TRANSIENT 5.23
FAST ROD WITHDRAWAL
FROM 10^{-8} amps IR

Initial Conditions
BOL
Critical at 10^{-8} amps in IR

Initiating Event:
Rod control system controller failure withdraws bank D rods at 72 steps/min.

Transient 5.23 Fast Rod Withdrawal From 10^{-8} amps in IR

Transient 5.31 Loop #1 Cold-Leg RTD Fails High

Initial Conditions:

BOL
Rated Thermal Power

Initiating Event: Loop #1 cold-leg RTD fails high

<u>Point</u> **<u>Explanation</u>**

1. **Auctioneered high T_{avg}** rises to > 620°F. The loop #1 T_{avg} becomes auctioneered high T_{avg}; that loop has a T_c of 630°F (the upper limit of the instrument range) because of the failed-high cold-leg RTD and a T_H of > 610°F (normal).

2. **Bank D rod position** shows CRDMs initially inserting at the maximum rate (72 steps/min) because of the large temperature mismatch input to the rod control system.

3. **Nuclear power** decreases due to the negative reactivity associated with rod insertion. The positive reactivity insertion resulting from the decrease in reactor coolant temperature and the decrease in power is not enough to counteract the effect of the rod motion.

4. **Actual T_{avg}** decreases due to the large imbalance between nuclear power and secondary load, with nuclear power decreasing rapidly. The loop 3 T_{avg} (the blue trace) is representative of loops 2, 3 and 4.

5. The **pressurizer level** decrease reflects the reduction in reactor coolant volume caused by the decrease in coolant temperature.

6. **Charging flow** increases with pressurizer level low relative to the level setpoint, which remains at the maximum value (61.5%) with auctioneered high T_{avg} > 585°F.

7. **Steam dump** demand increases to 100% with the RTD failure. The T_{avg} - T_{ref} input to the loss-of-load controller is maximized with $T_{avg} \gg T_{ref}$. Note that no dump valves initially open. There is no arming signal until the initial pressure limiter acts to lower turbine load and arm the dumps on loss of load.

8. **Pressurizer pressure** drops as the pressurizer steam bubble expands with reactor coolant contraction. Note that the lead/lag pressure (the one used for low pressurizer pressure reactor trip) does not drop below the low pressure setpoint until after the trip.

Point Explanation

9. **Steam pressure** drops as heat transfer conditions in the SGs change due to the reduced T_{avg}. $\dot{Q} = UA(T_{avg} - T_{stm})$; $\dot{Q}$ is essentially constant, so T_{stm} (and P_{stm}) is gradually decreasing to maintain the same ΔT across the SG tubes. The lead/lag steam pressure signal drops below the SI low steam pressure setpoint when the steam dump valves open. This makes up ½ of the SI actuation logic. The other ½ is met when steam flow exceeds the high steam flow setpoint.

10. **Generator load** falls off with the degraded steam pressure. When the cooldown begins, the throttle pressure compensation keeps load fairly constant. Shortly before the trip, the initial pressure limiter begins to close turbine control valves in response to the low throttle pressure. This actuates the loss of load (C-7) which arms the steam dumps.

11. **Steam flow** initially drops as steam pressure drops.

12. The reactor trip (indicated by the step drop in **bank D rod position**) is caused by a safety injection actuation on high steam flow coincident with low steam pressure. Action of the initial pressure limiter has lowered turbine load enough the arm the steam dumps on C-7 (loss of load). This increase in steam flow leads to the high steam flow coincident with low steam pressure safety injection and steam line isolation signal.

13. The **charging flow** perturbation reflects the SI actuation. This flow indication does not include BIT flow. Flow settles at a value that reflects RCP seal injection only.

14. **Steam Flow** rises when the steam dump valves open. When the high steam flow setpoint is exceeded, the second half of the SI logic is met. The other half of the logic is met when the lead/lag steam pressure drops to < 600 psig.

15. **Steam Flow** drops to zero because the MSIVs shut at the time of the trip.

16. **Pressurizer level** recovers with ECCS flow and letdown isolation following the SI actuation.

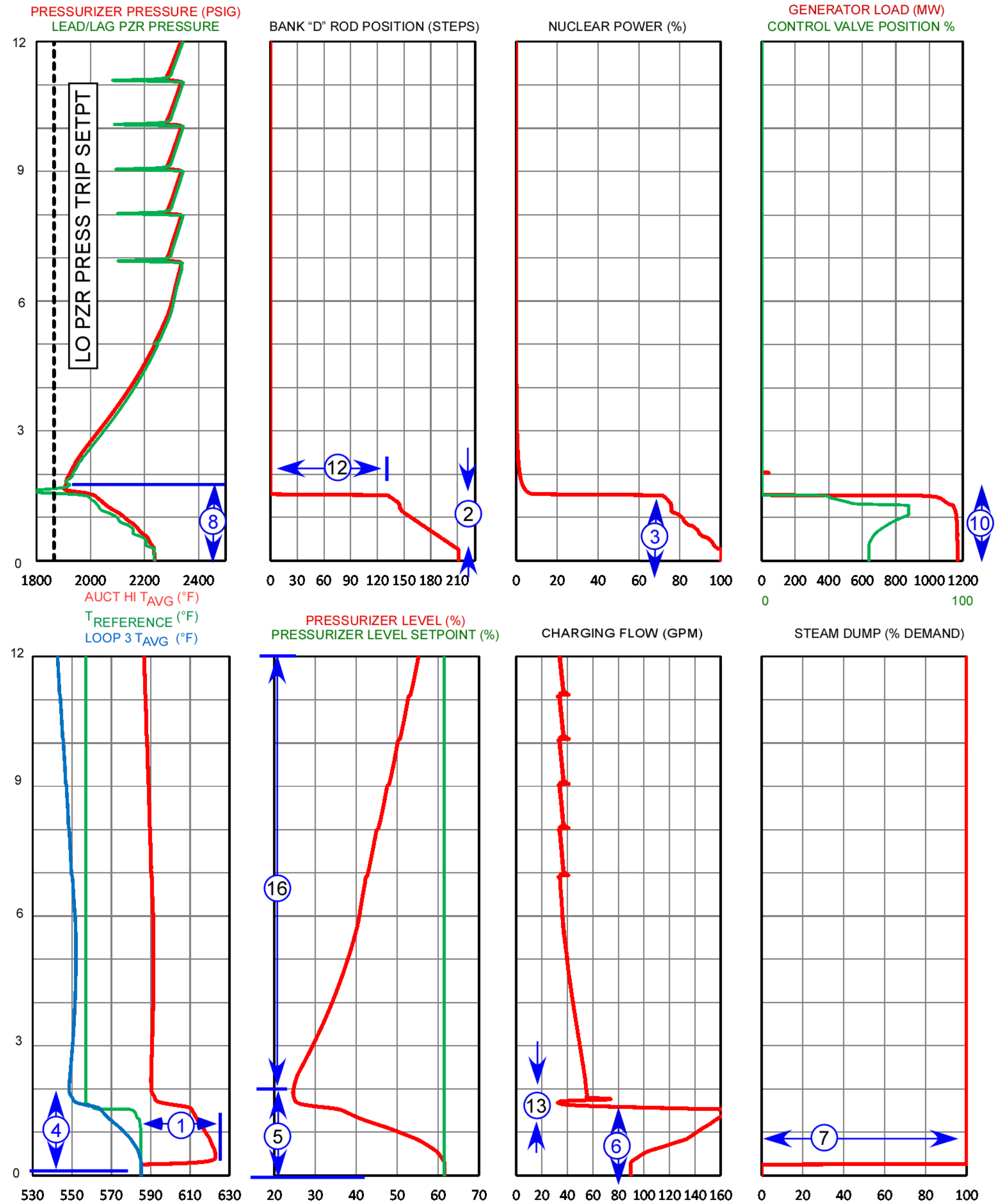
Point **Explanation**

17. **Total Feed flow** after the trip reflects the main feedwater isolation followed by AFW actuation.

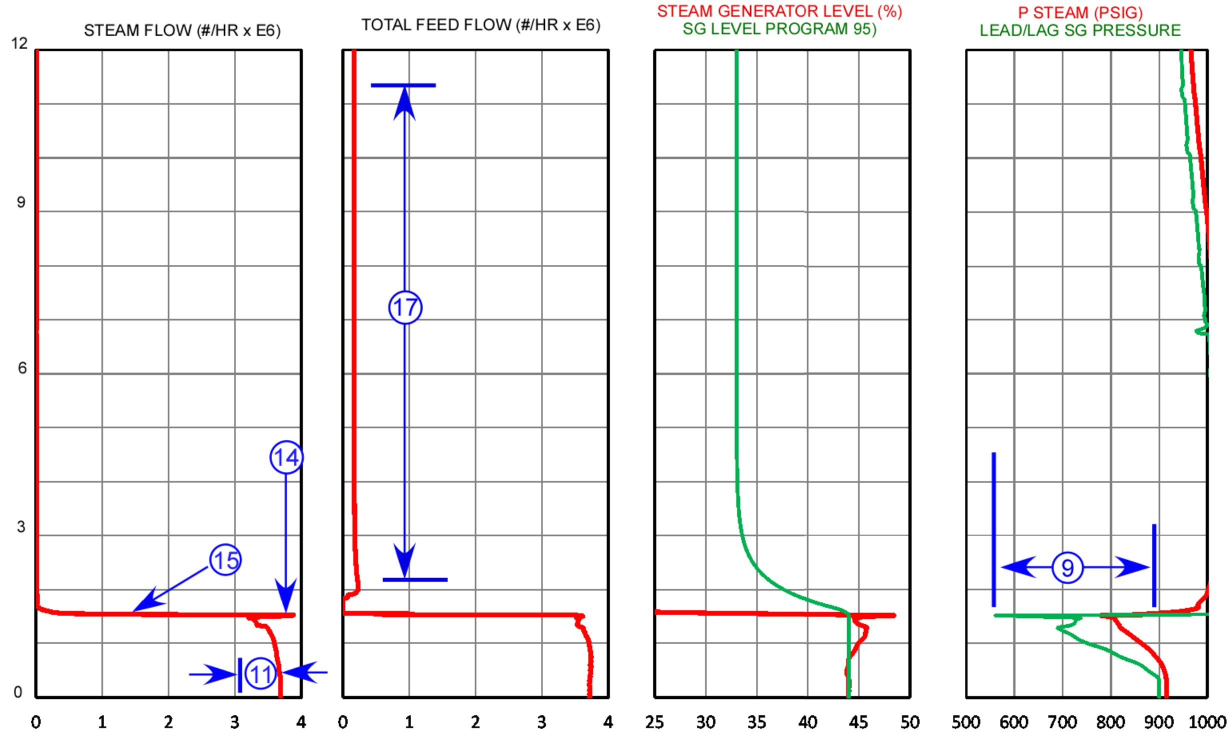
Note 1: The "blip" in generator load shortly before 3 min reflects the voltage/current spike accompanying the opening of the output breakers.

What this transient illustrates:

1. The responses of the rod control, pressurizer level control, and steam dump control systems to a failed-high cold-leg RTD.
2. The decrease in T_{avg} when nuclear power << secondary load.
3. Plant response to an uncontrolled cooldown.



Transient 5.31 Loop #1 Cold-Leg RTD Fails High



TRANSIENT 5.31
LOOP #1 COLD-LEG RTD FAILS HIGH

Initial Conditions
BOL
Rated Thermal Power

Initiating Event:
Loop #1 cold-leg RTD fails high

Transient 5.31 Loop #1 Cold-Leg RTD Fails High

Transient 5.32 Loop #1 Hot-Leg Signal Fails High, ~ 20% Load

Initial Conditions:

BOL
Nuclear Power: 20%
Steam dumps armed due to previous load rejection

Initiating Event: Loop #1 hot-leg signal fails high.

<u>Point</u> **<u>Explanation</u>**

1. **Auctioneered high T_{avg}** increases rapidly to ~ 600°F. The loop #1 T_{avg} becomes auctioneered high T_{avg}; that loop has a T_H of 650°F (the upper limit of the instrument range) because of the failed hot-leg signal, an increase of some 80°F above its initial value. This increase in T_H increases T_{avg} by ~ 40°F.

2. **Charging flow** increases with pressurizer level low relative to the level setpoint, which has increased to the maximum value (61.5%) with auctioneered high T_{avg} > 585°F.

3. **Steam dump demand** increases to 100% with the RTD failure. The T_{avg} - T_{ref} input to the loss-of-load controller is maximized with $T_{avg} >> T_{ref}$. As discussed in point 4 below, the dump valves open immediately, as the steam dump control system is already armed in the T_{avg} mode.

4. **Steam flow** increases sharply. With the dumps already armed and a 100% demand, all 12 dump valves blast open.

5. **Steam pressure** decreases sharply with all 12 dump valves opening and relieving steam to the condenser.

6. The reactor trip (indicated by the step drop in **bank D rod position**) is caused by a safety injection actuation on high steam flow plus low steam pressure. The high steam flow setpoint is reached with the steam dump valves blasting open, and the safety injection signal is generated when two lead/lag compensated steam pressure signals drop to < 600 psig. Actual steam line pressure is > 950 psig at the time of the trip, but the rate of decrease causes the compensated signal to rapidly drop.

Point Explanation

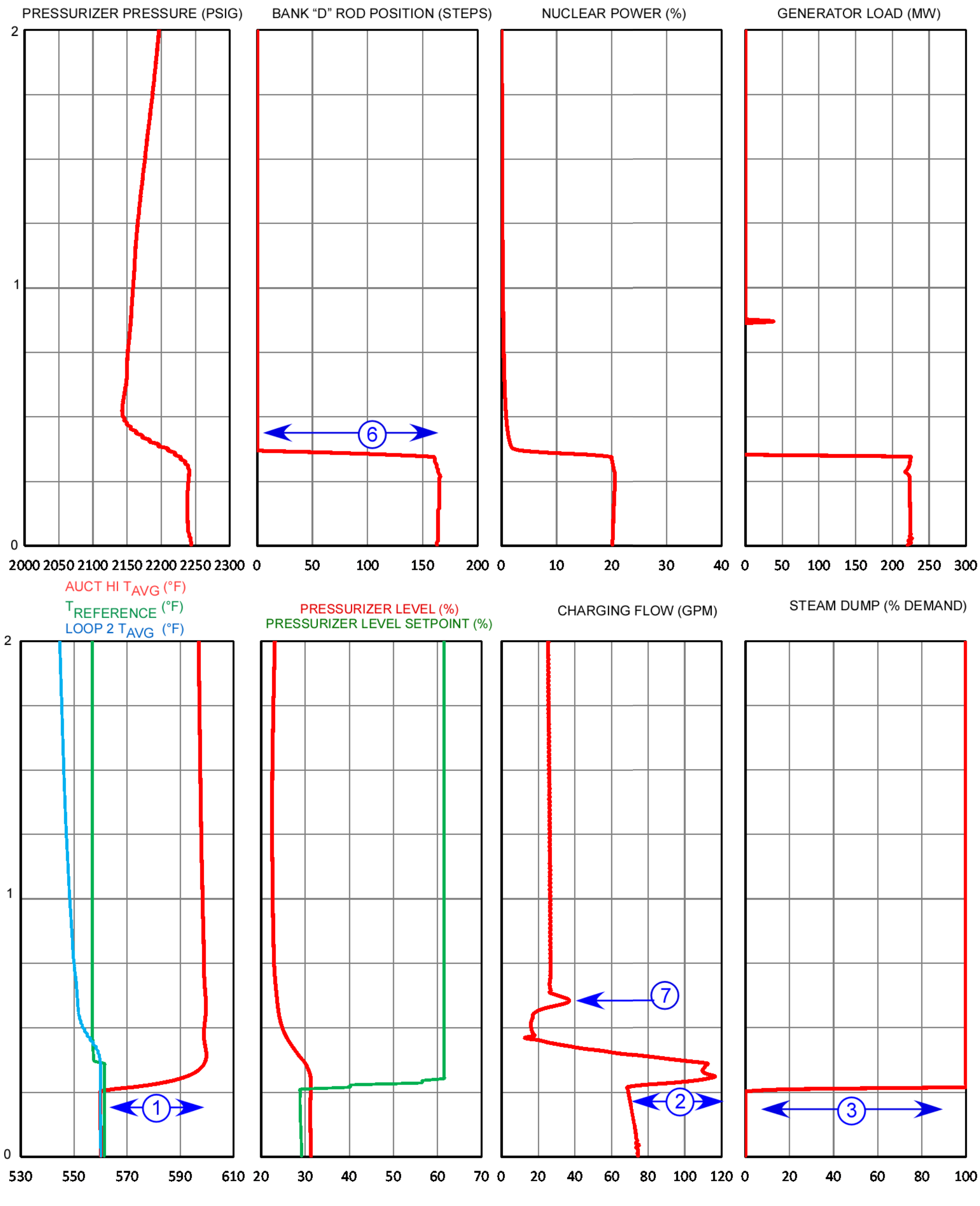
7. The **charging flow** perturbation reflects the safety injection actuation. The initial drop in flow reflects charging line isolation; the flow settles at the relatively high value governed by the maximum opening of charging flow control valve FCV-121 (the pressurizer level is below the setpoint level [61.5%] throughout the transient) and the flow restriction of the RCP seals (the only path left for injection from the CVCS).

8. **Steam flow** decreases to 0, reflecting the MSIV closure associated with the high steam flow safety injection actuation.

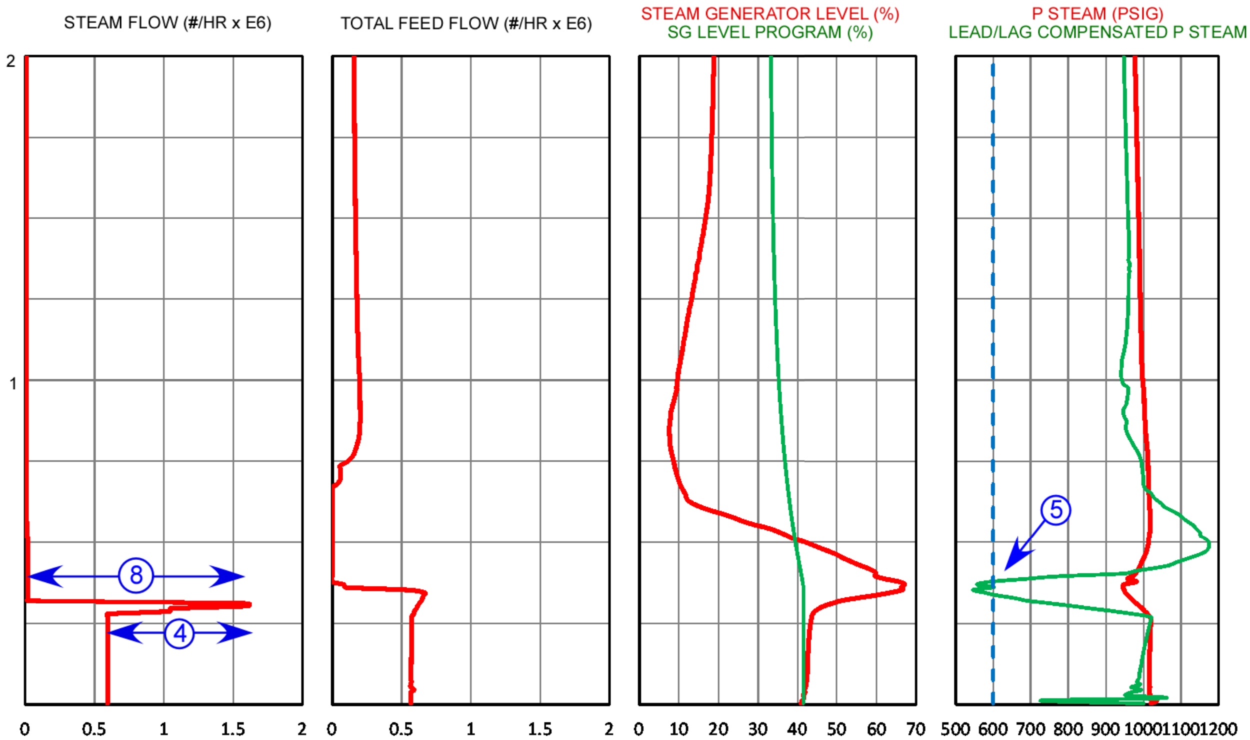
Note 1: The "blip" in generator reflects the voltage/current spike accompanying the opening of the output breakers.

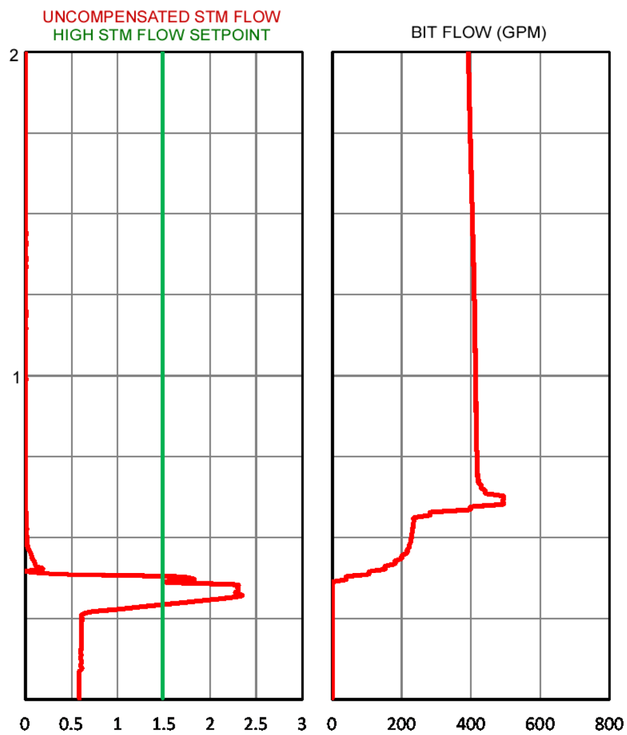
What this transient illustrates:

1. The responses of the plant to excessive steam demand.
2. Lead/lag compensation of the low steam pressure signal.



Transient 5.32 Loop #1 Hot-Leg Signal Fails High, ~ 20% Load





TRANSIENT 5.32
LOOP #1 HOT-LEG SIGNAL FAILS HIGH,
20% LOAD

Initial Conditions
BOL
Nuclear Power: 20%
Steam dumps armed due to previous load rejection

Initiating Event:
Loop #1 hot-leg signal fails high

Transient 5.32 Loop #1 Hot-Leg Signal Fails High, ~ 20% Load

Transient 5.33 Power Range Channel NI-41 Fails High

Initial Conditions:

BOL
Normal Temperature and pressure
Nuclear Power: 100%
All control systems in automatic

Initiating Event: Power range channel NI-41 fails high

Point **Explanation**

1. **Nuclear power (from NI-41)** increases to maximum (initiating event).

2. **Bank D rod position** decreases at the maximum rate (72 steps/min). The failed-high power range channel becomes auctioneered high nuclear power, and its step increase relative to a constant turbine load develops a large rod insertion signal in the power mismatch circuit of the rod control system. This transient includes a graph of rod control system inputs. There is no control board indication of these inputs, but they are included for training purposes.

3. Actual **reactor power** as measured by the excores and core ΔT decreases due to the negative reactivity associated with rod insertion. The positive reactivity insertion resulting from the decrease in reactor coolant temperature, as discussed in point 4 below, is not enough to counteract it during this phase of the transient.

4. $\mathbf{T_{avg}}$ decreases due to the large imbalance between nuclear power and turbine load, with nuclear power decreasing rapidly. To maintain turbine load, energy must be taken from the reactor coolant, reducing its temperature. The dominant effect of control rod motion is to change RCS temperature, not plant power.

5. **Steam pressure** drops as heat transfer conditions in the SGs change due to the reduced T_{avg}. The lower T_{avg} cannot continue to support steam pressure at its initial value. $\dot{Q} = UA(T_{avg} - T_{stm})$; $\dot{Q}$ is relatively constant.

6. **Generator load** initially falls off with the degraded steam pressure. The initial pressure limiting circuit acts to partially close control valves when throttle pressure drops to the setpoint.

7. **Bank D rod position** stops decreasing. Over the first minute or so of the transient, the large negative input to the rod control system from the initial "spike" in auctioneered high nuclear power has been decaying off, while a large positive input due to the decrease in auctioneered high T_{avg} relative to T_{ref} has been building in. These inputs essentially cancel at ~ 1 min, and rod motion stops. For several seconds prior to this point, the rod insertion speed is slowing, showing that the total error calling for rod insertion has decreased greatly from the initial error associated with the NI-41 failure.

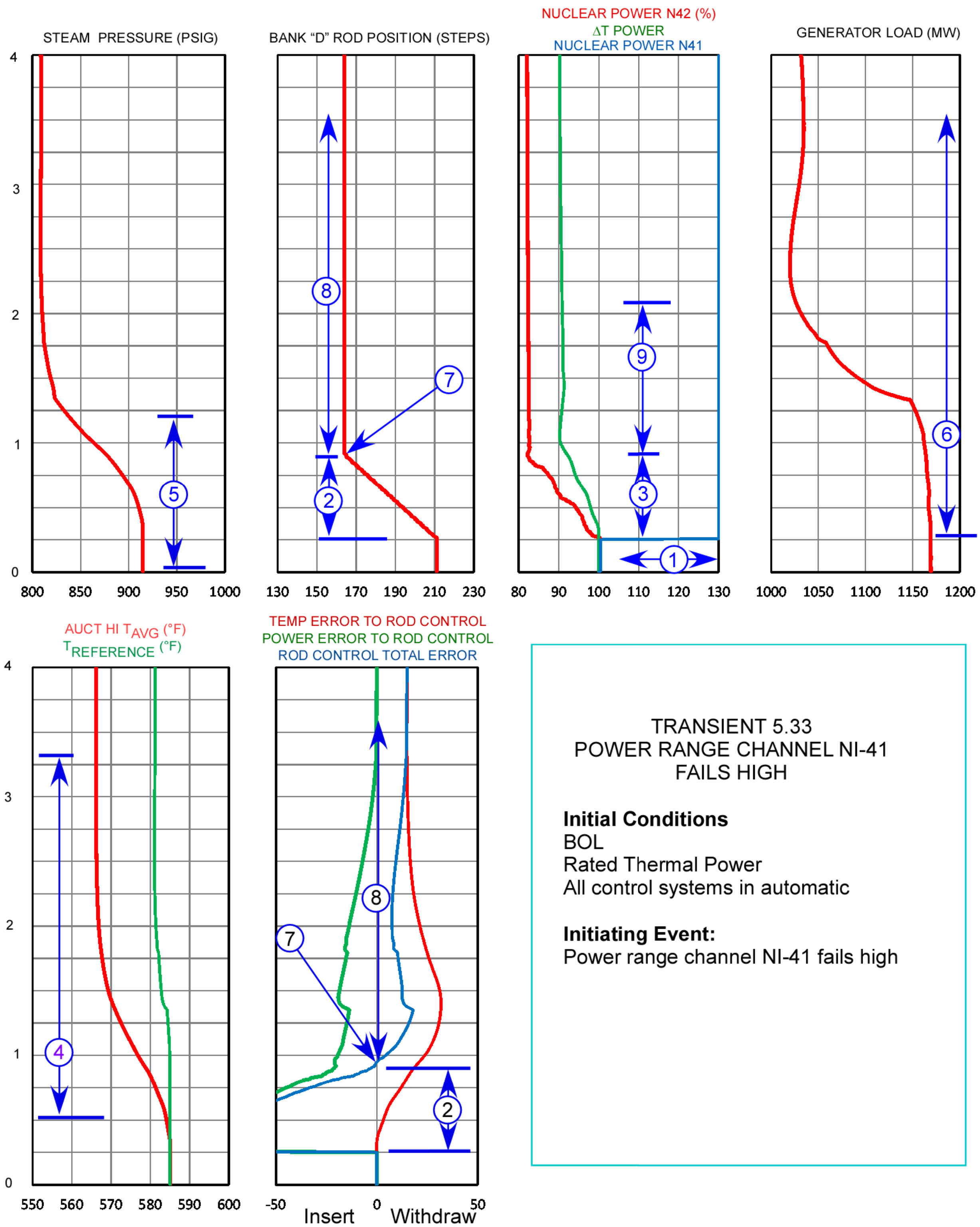
Point Explanation

8. **Bank D rod position** remains constant over the last three min of the transient. Ordinarily, outward rod motion would result from the continued decrease in T_{avg} and the continued decay of the nuclear power spike, but the failed channel exceeds the overpower rod stop setpoint (103%), and this rod stop requires only a one-out-of-four coincidence.

9. The power measurements diverge. The excore neutron detectors are partially shielded by the drop in RCS cold leg temperature. During this time, ΔT is a more accurate measurement of reactor power.

What this transient illustrates:

1. The response of the rod control system to a failed-high power-range NI.
2. The decrease in T_{avg} when nuclear power < secondary load.
3. An overpower rod stop.
4. The dominant effect of control rod motion is to change RCS temperature. The final value of plant power is very close to the initial value, but T_{avg} has dropped. The only way to practically change power at a PWR involves changing turbine load.
5. The shielding of the excore neutron detectors by a drop in RCS cold leg temperature.



Transient 5.33 Power Range Channel NI-41 Fails High

Transient 5.34 Steam Dump Loss-Of-Load Controller Fails To Maximum Demand

Initial Conditions:

BOL
Rated Thermal Power
Steam dumps armed due to previous load rejection

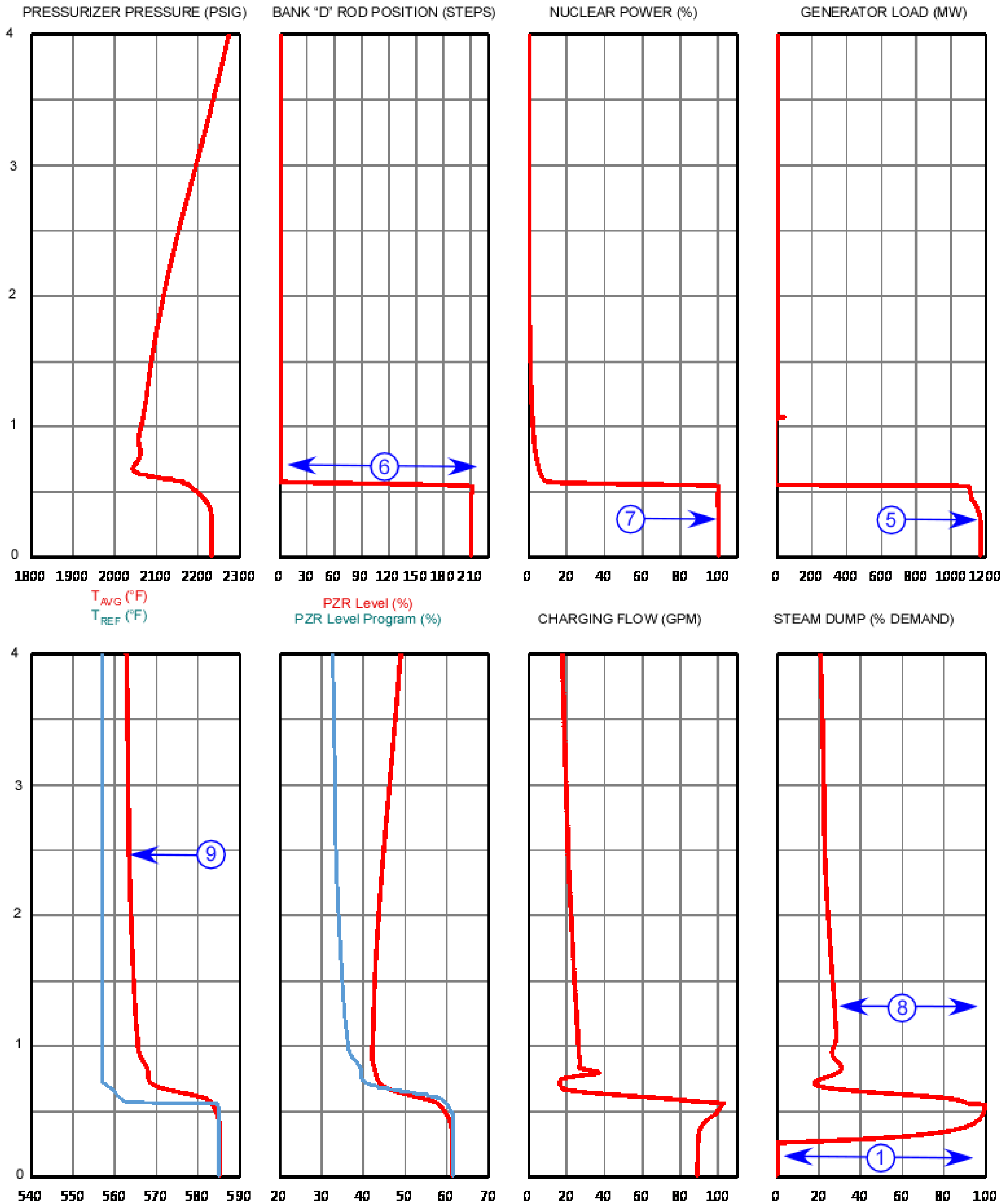
Initiating Event: Steam dump loss-of-load controller fails to maximum demand

<u>Point</u> **<u>Explanation</u>**

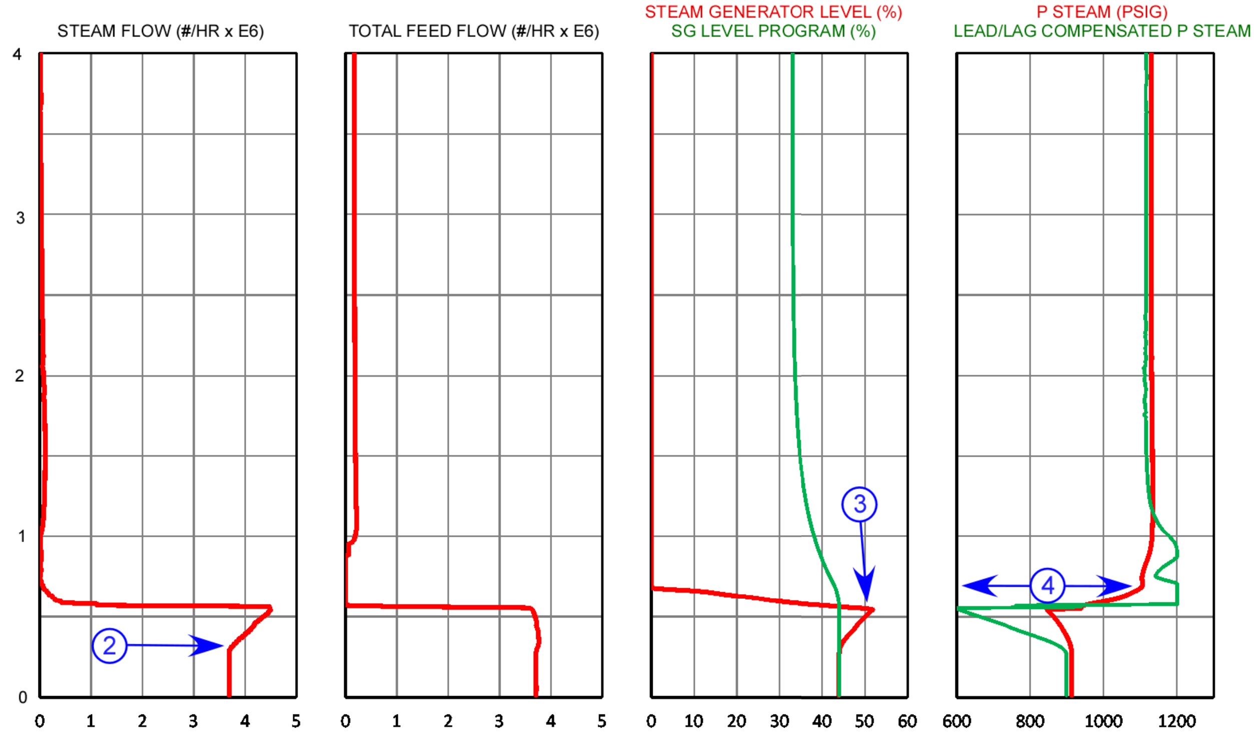
1. The initiating event increases **steam dump demand** to 100%.
2. **Steam flow** increases sharply as the steam dump valves open. The dumps are already armed, and the 100% demand resulting from the controller failure causes all 12 dump valves to blast open.
3. **Steam generator level** swells as the steam dump valves open.
4. **Steam pressure** drops with the additional steam release associated with steam dump operation. The lead/lag compensated steam pressure rapidly drops to the low steam pressure setpoint [600 psig]. This combines with the high steam flow condition to initiate safety injection (SI) and steamline isolation.
5. **Generator load** lowers due to degraded steam pressure.
6. The reactor trip (indicated by the step drop in **bank D rod position**) is caused by the SI actuation.
7. The transient is terminated too quickly to see any effect on **reactor power** prior to the reactor trip. Due to loop transit times
8. **Steam dump demand** lowers after the turbine trip. The turbine trip which accompanies the reactor trip puts the turbine trip controller in service, and the steam dump demand falls as T_{avg} drops.
9. **T_{AVG}** remains above **T_{REF}** because RCS temperature is being controlled by the SG PORVs due to MSIV closure.

What this transient illustrates:

1. The response of the (already armed) steam dump control system to a loss-of-load controller demand failure.
2. Post-trip T_{AVG} is higher when RCS temperature is controlled by the SG PORVs.



Transient 5.34 Steam Dump Loss-Of-Load Controller Fails To Maximum Demand



TRANSIENT 5.34
STEAM DUMP LOSS-OF-LOAD
CONTROLLER FAILS TO 100%

Initial Conditions
BOL
RTP

Initiating Event:
Steam dump loss-of-load controller fails to 100% with steam dumps armed.

Transient 5.34 Steam Dump Loss-Of-Load Controller Fails To Maximum Demand

Transient 5.35 Impulse Pressure Channel Pt-505 Fails Low

Initial Conditions:

BOL
Normal pressure and temperature
Nuclear Power: 100%   All control systems in automatic

Initiating Event: Impulse pressure channel PT-505 fails low

Point **Explanation**

1. $\mathbf{T_{ref}}$ undergoes a rapid decrease to its minimum value of 557°F (programmed T_{avg} for no load).

2. **Bank D rod position** decreases at the maximum rate (72 steps/min) because of the large temperature mismatch ($T_{ref} << T_{avg}$) and large power mismatch (turbine load decreasing rapidly relative to nuclear power) inputs to the rod control system calling for fast rod insertion. The large mismatches result from the failed-low impulse pressure channel.

3. **Nuclear power** decreases due to the negative reactivity associated with the rod insertion. The positive reactivity insertion resulting from the decrease in reactor coolant temperature and fuel temperature is not enough to counteract it. The excore NIs are partially shielded by the colder water entering the reactor vessel downcomer, so they become increasingly inaccurate as RCS temperature drops. The **Loop ΔT Power** indication is a more accurate measure of reactor power when RCS temperature is not at its programmed value.

4. $\mathbf{T_{avg}}$ decreases due to the large imbalance between nuclear power and turbine load, with nuclear power decreasing rapidly. To maintain turbine load, energy must be taken from the reactor coolant, reducing its temperature.

5. The **pressurizer level** decrease reflects the reduction in reactor coolant volume caused by the decrease in coolant temperature. As long as T_{avg} remains in its program band, the level program and level follow closely.

6. **Steam dump demand** increases to 100% with the impulse pressure failure. The T_{avg} - T_{ref} input to the loss-of-load controller is maximized with $T_{avg} >> T_{ref}$. Note that the dumps do not actuate, as there is no arming signal.

7. **Pressurizer pressure** drifts lower as the pressurizer steam bubble expands with reactor coolant contraction. The pressurizer heaters cannot maintain normal operating pressure.

8. **Steam pressure** drops as heat transfer conditions in the SGs change due to the reduced T_{avg}. The lower T_{avg} cannot continue to support steam pressure at its initial value. $\dot{Q} = UA(T_{avg} - T_{stm})$; $\dot{Q}$ is essentially constant with the turbine control valve position unchanging, so T_{stm} (and P_{stm}) is gradually decreasing to maintain the same ΔT across the SG tubes.

Point Explanation

9. **Steam generator level** decreases with the reduction in feed flow (the failed-low impulse pressure channel has driven the steam generator water level setpoint to its minimum programmed value, so feed flow is decreased to bring level down to the new setpoint). The reason that the level setpoint changes gradually in response to a step change in impulse pressure is that the level setpoint has a 30 second lag circuit.

10. **Generator load** initially remains fairly steady as steam pressure due to the action of throttle pressure compensation opening the control valves.

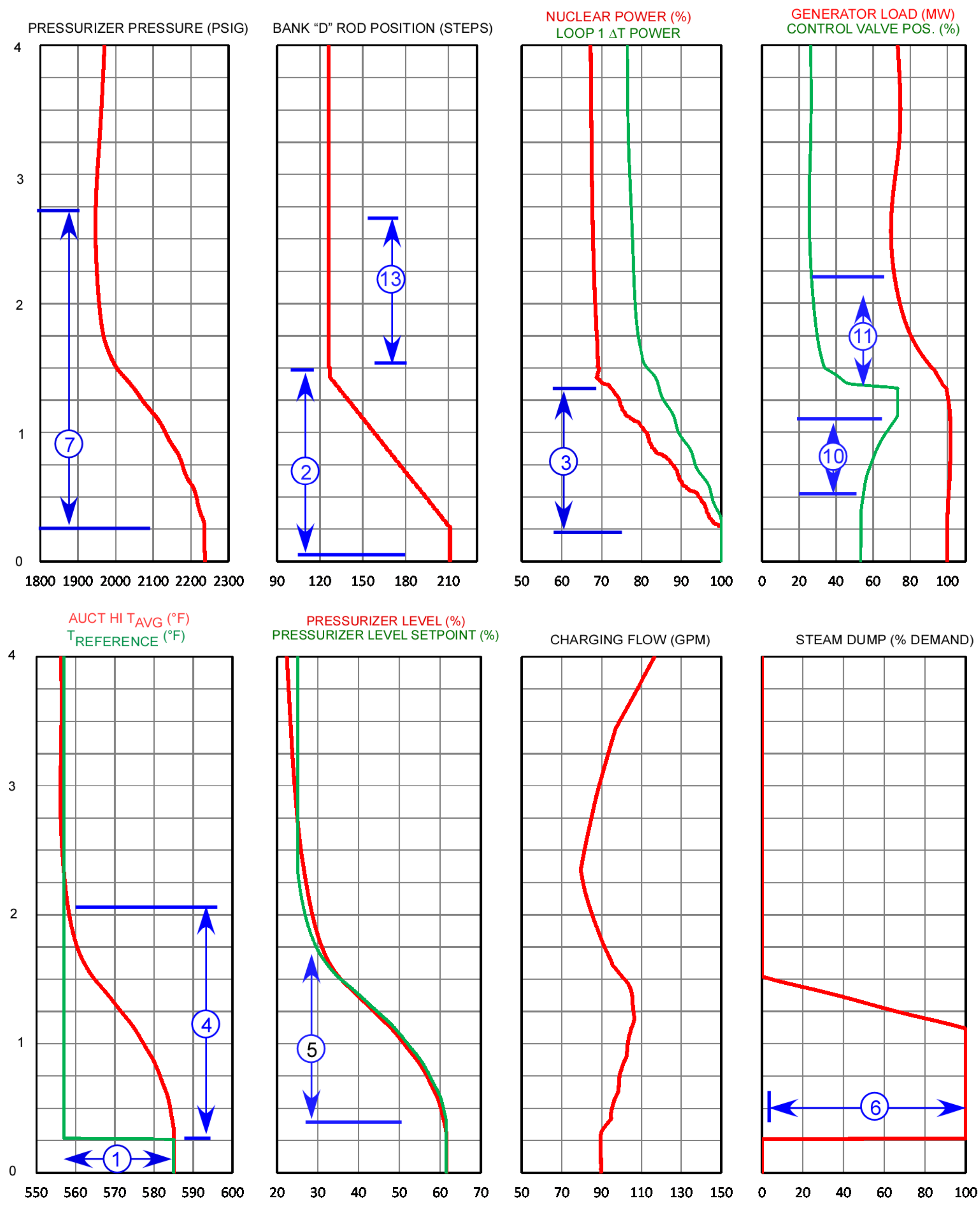
11. **Generator load** is reduced by the action of the initial pressure limiter. This feature is designed to reduce steam demand when steam pressure at the turbine throttle valves drops to 90% of its rated value.

12. **Steam flow** decreases because of the action of the initial pressure limiter.

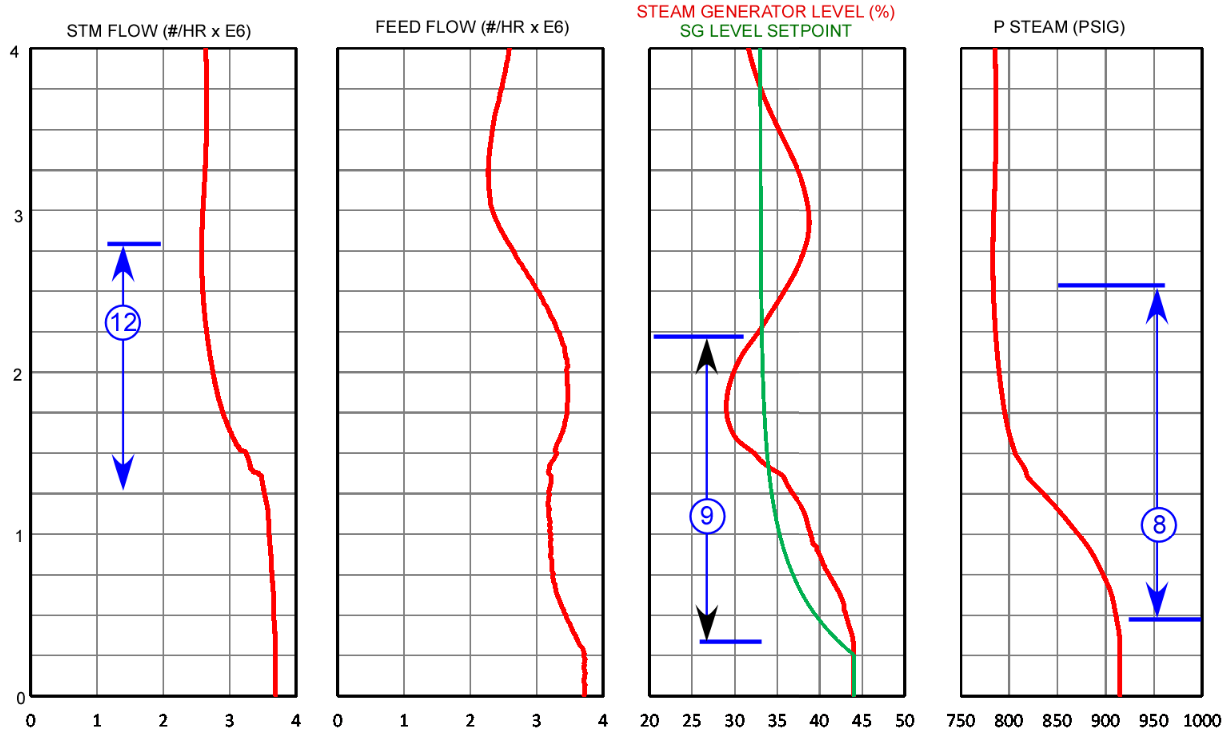
13. When the total error input to the rod control system drops below 1°F, rod motion stops. Also, even if the total error demanded rod withdrawal, rod withdrawal is blocked by the C-5 (auto rod withdrawal block) interlock (the input to C-5 is from the failed-low channel).

What this transient illustrates:

1. The responses of the rod control and steam dump control systems to a failed-low impulse pressure channel.
2. The decrease in T_{avg} when nuclear power < secondary load.



Transient 5.35 Impulse Pressure Channel Pt-505 Fails Low



TRANSIENT 5.35
IMPULSE PRESSURE CHANNEL
PT-505 FAILS LOW

Initial Conditions
BOL
Rated Thermal Power

Initiating Event:
Impulse pressure channel PT-505 fails low

Transient 5.35 Impulse Pressure Channel Pt-505 Fails Low

Transient 5.36 Impulse Pressure Channel PT-505 Fails High

Initial Conditions:

BOL
Nuclear Power: 55%
All control systems in automatic

Initiating Event: Impulse pressure channel PT-505 fails high

Point **Explanation**

1. **T_{ref}** undergoes a rapid increase to its maximum value of 585°F (programmed T_{avg} for full load).
2. **Bank D rod position** increases at the maximum rate (72 steps/min) because of the large temperature mismatch (T_{ref} >> T_{avg}) and large power mismatch (turbine load increasing rapidly relative to nuclear power) inputs to the rod control system calling for fast rod withdrawal.
3. **Nuclear power** increases due to the positive reactivity associated with the rod withdrawal. The negative reactivity insertion resulting from the increase in reactor coolant temperature and fuel temperature is not enough to counteract it.
4. **T_{avg}** increases due to the large imbalance between nuclear power and turbine load, with nuclear power increasing rapidly. As the turbine load is essentially unchanging, energy must be added to the reactor coolant, increasing its temperature.
5. The **pressurizer level** increase reflects the expansion in reactor coolant volume caused by the increase in coolant temperature.
6. **Charging flow** decreases greatly when pressurizer exceeds the maximum program value. This corresponds to T_{avg} exceeding its maximum program value.
7. **Pressurizer pressure** increases as the pressurizer steam bubble is squeezed by the reactor coolant expansion. Pressurizer spray is inadequate to control pressure but the pressure rise is mitigated by multiple pressurizer PORV cycles.

Point **Explanation**

8. **Steam pressure** increases as heat transfer conditions in the SGs change due to the increased T_{avg}. $\dot{Q} = UA(T_{avg} - T_{stm})$; $\dot{Q}$ is essentially constant with the turbine control valve position unchanging, so T_{stm} (and P_{stm}) is gradually increasing to maintain the same ΔT across the SG tubes.

9. The **steam dump demand** increase indicates that the increase in nuclear power has driven T_{avg} higher than T_{ref} in excess of the loss of load controller deadband. Since the T_{avg} signal to the steam dumps is lead/lag compensated, the heatup rate causes this to occur at an indicated ΔT of about 3°F (instead of 5°F). Note that the dumps do not open, as there is no arming signal.

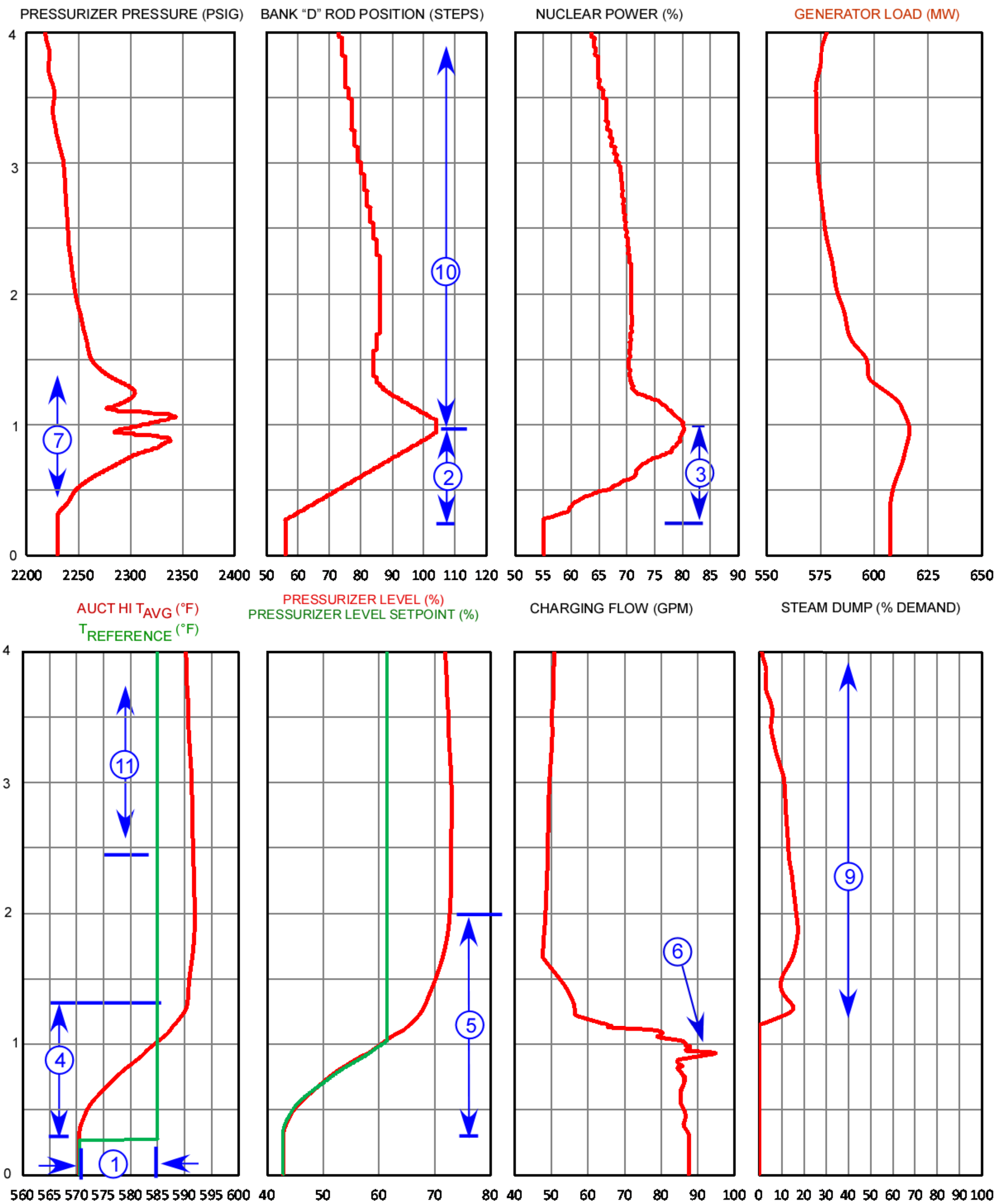
10. **Bank D rod position** decreases as Tavg overshoots. The large power mismatch error from the initial failure has died off and the total error now calls for insertion.

11. **T_{avg}** is decreasing as the rod insertion decreases nuclear power and narrows the primary-to-secondary power mismatch. At steady-state (not yet reached at 4 min), nuclear power will have been made equal to turbine load, and the plant will be operating at ~ 55% power with the full-load programmed T_{avg} value. The new steady state will involve both a higher bank D rod position and a higher coolant temperature, with the associated reactivity changes canceling each other.

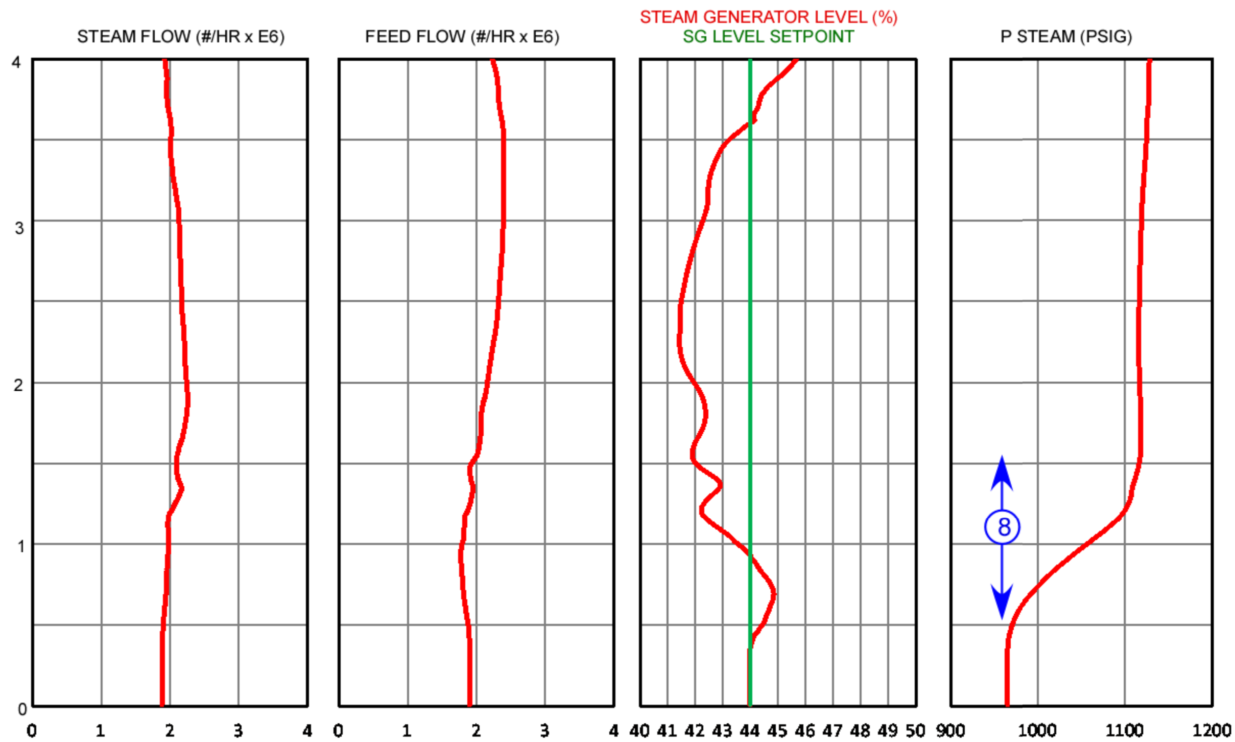
Note 1: The starting bank D rod position not typical for a plant operating at 55% power. The rods were initially diluted in to their starting positions so that the response to the failure would be more dramatic. If this transient is started from the normal 100% conditions, the rods would be withdrawn to the auto withdrawal limit and then stop, and the slight change in reactivity would minimally affect other plant parameters, making for quite a mild transient.

What this transient illustrates:

1. The responses of the rod control and steam dump control systems to a failed-high impulse pressure channel.
2. The increase in T_{avg} when nuclear power > secondary load.
3. The throttle pressure compensation circuit keeps generator load fairly constant over a range of steam pressures.



Transient 5.36 Impulse Pressure Channel Pt-505 Fails High



TRANSIENT 5.36
IMPULSE PRESSURE CHANNEL
PT-505 FAILS HIGH

Initial Conditions
BOL
Nuclear Power: 55%
All control systems in automatic

Initiating Event:
Impulse pressure channel PT-505 fails high

Transient 5.36 Impulse Pressure Channel Pt-505 Fails High

Transient 5.41 Controlling Pressurizer Pressure Channel Fails High

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

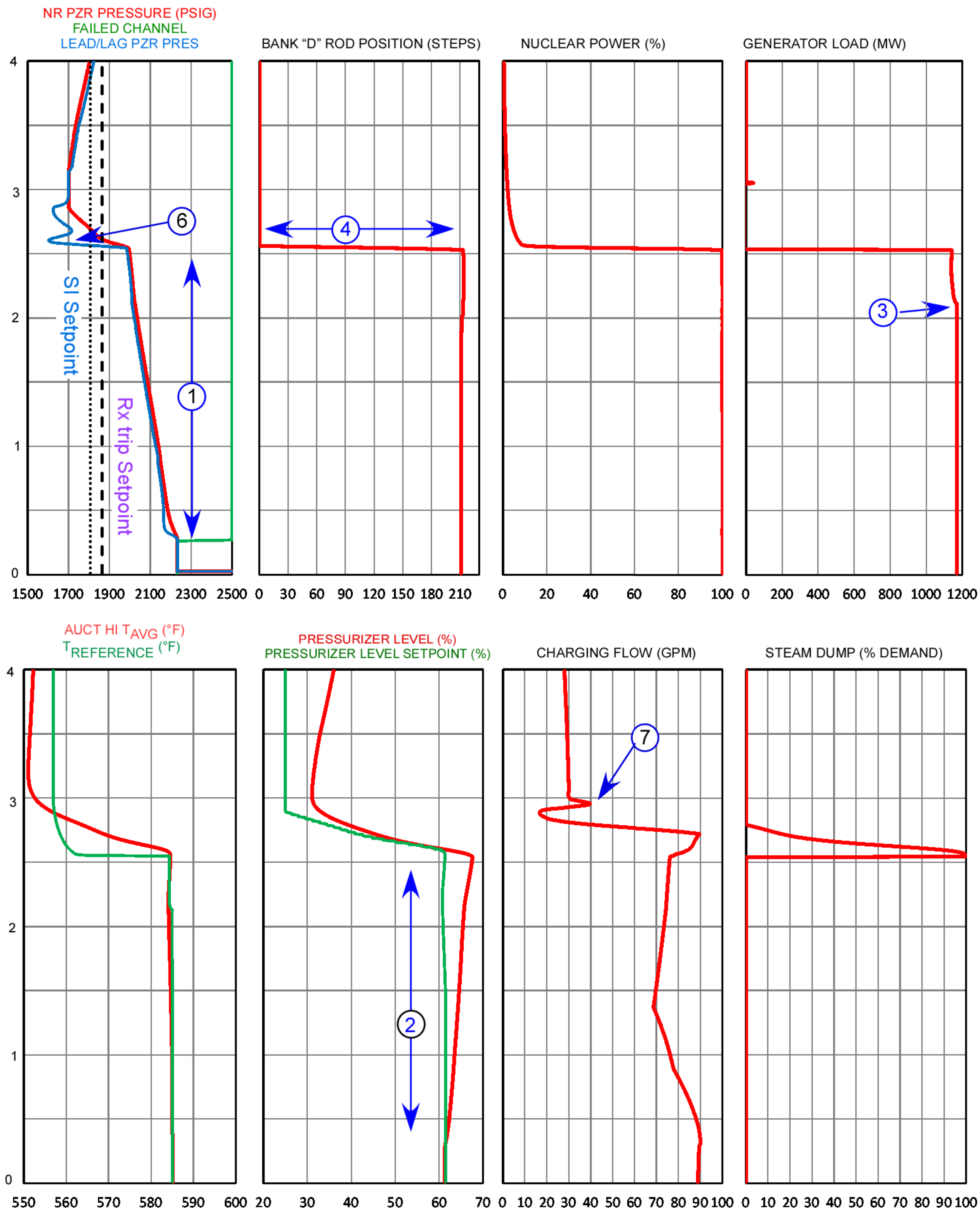
Initiating Event: Controlling pressurizer pressure channel (PT-455) fails high

Point **Explanation**

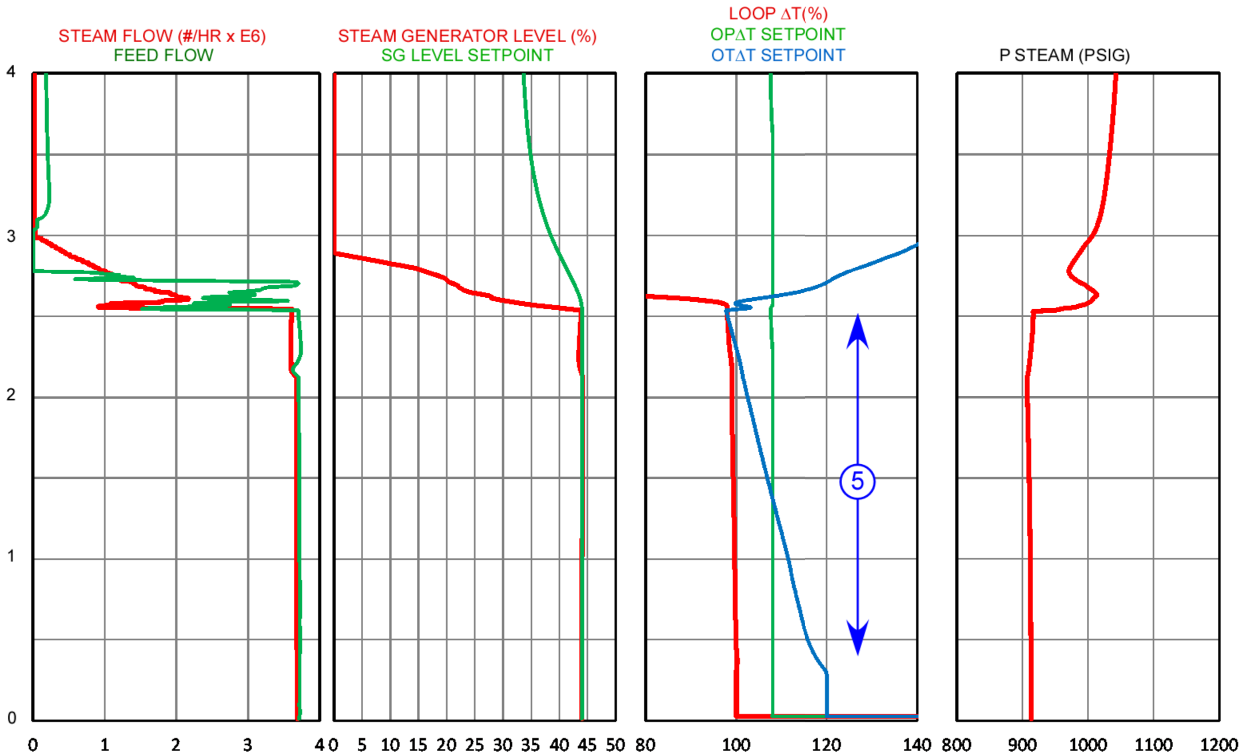
1. Actual **pressurizer pressure** trends down with maximum pressurizer spray. The pressurizer pressure control system is responding to a pressure input of 2500 psig (well above the pressure setpoint of 2235 psig) from the failed channel.
2. The **pressurizer level** increase prior to the reactor trip is due to an insurge as RCS water expands. Water is slightly compressible. RCS compressibility is enhanced by nucleate boiling in the core.
3. **Generator load** decreases due to an OTΔT runback. The decreasing pressure on the three “good” channels is lowering the OTΔT trip and runback setpoints.
4. The reactor trips (indicated by the step drop in **bank D rod position**) on OTΔT.
5. The OTΔT trip setpoint drops in response to lowering Pzr pressure, causing a turbine runback first. The effect of the runback can be seen in a small drop in ΔT. The setpoint continues to drop until a trip is generated.
6. The low **pressurizer pressure** SI actuation setpoint is reached shortly after the reactor trips.
7. **Charging flow** makes its characteristic response to an SI actuation.

What this transient illustrates:

1. The response of the pressurizer pressure control system (maximum spray) to a failed-high controlling pressurizer pressure channel.
2. An increase in indicated pressurizer level with a decrease in pressurizer pressure.
3. AN OTΔT reactor trip and SI actuation.



Transient 5.41 Controlling Pressurizer Pressure Channel Fails High



TRANSIENT 5.41
CONTROLLING PRESSURIZER PRESSURE
CHANNEL FAILS HIGH

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Controlling pressurizer pressure channel fails high

Transient 5.41 Controlling Pressurizer Pressure Channel Fails High

Transient 5.42 Controlling Pressurizer Level Channel Fails Low

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

Initiating Event: Controlling pressurizer level channel (LT-459) fails low

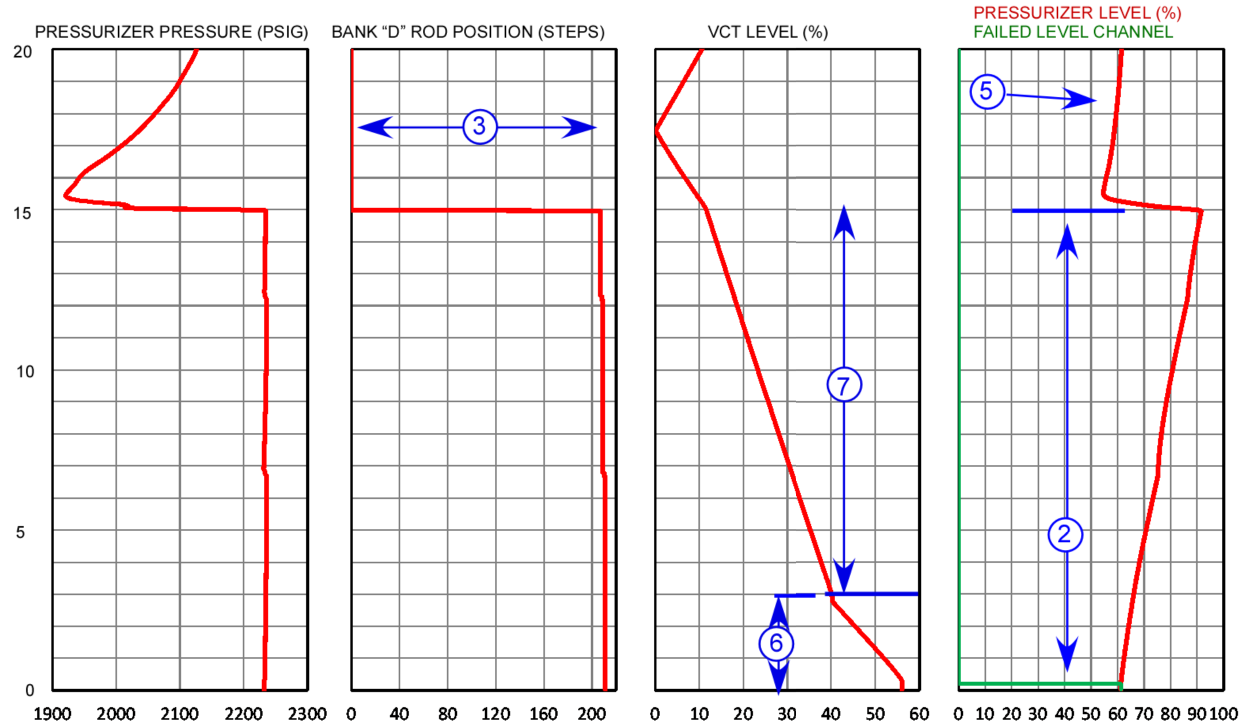
Point **Explanation**

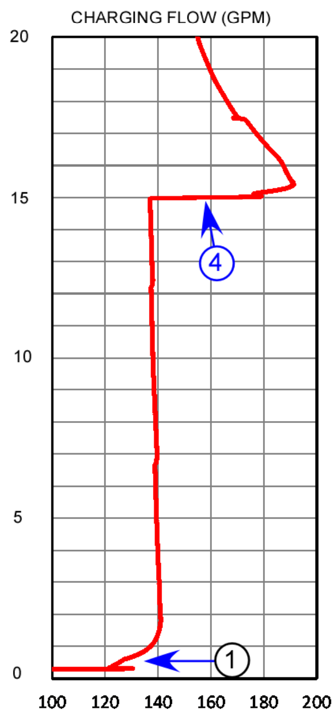
1. **Charging flow** increases to maximum as charging flow control valve FCV-121 opens fully. The pressurizer level control system is responding to a level input of 0%, which is well below the level setpoint of 61.5%.
2. **Pressurizer level** increases rapidly with maximum charging and no letdown (letdown is isolated in response to the < 17% level of the failed channel).
3. The reactor trip (as indicated by the step drop in **bank D rod position**) is caused by high pressurizer level, as indicated by the 2 "good" level channels.
4. **Charging flow** increases after the trip because plant pressure drops as T_{avg} decreases to < no-load T_{avg}. The operating charging pump's output increases when the discharge pressure drops (characteristic of centrifugal pump operation). The flow control valve has been fully open since the initial instrument failure, so the increase in flow is due solely to the drop in RCS pressure.
5. **Pressurizer level** recovers after the trip due to continued charging with letdown isolated and plant heatup. With no operator action, the pressurizer will eventually fill.
6. **VCT level** drops because maximum charging and isolated letdown are depleting the VCT inventory.
7. The change in slope of **VCT level** indicates initiation of automatic makeup, which slows but does not stop the VCT level decrease.

Point **Explanation**

What this transient illustrates:

1. The response of the pressurizer level control system to a failed-low controlling pressurizer level channel.
2. A high pressurizer level reactor trip.
3. The depletion of VCT level.





TRANSIENT 5.42
CONTROLLING PRESSURIZER LEVEL
CHANNEL FAILS LOW

Initial Conditions
Rated Thermal Power
All control systems in automatic

Initiating Event:
Controlling pressurizer level fails low

Transient 5.42 Controlling Pressurizer Level Channel Fails Low

Transient 5.43 Controlling Pressurizer Pressure Channel Fails Low

Initial Conditions:

BOL
Normal temperature and pressure
Nuclear Power: 100%   All control systems in automatic

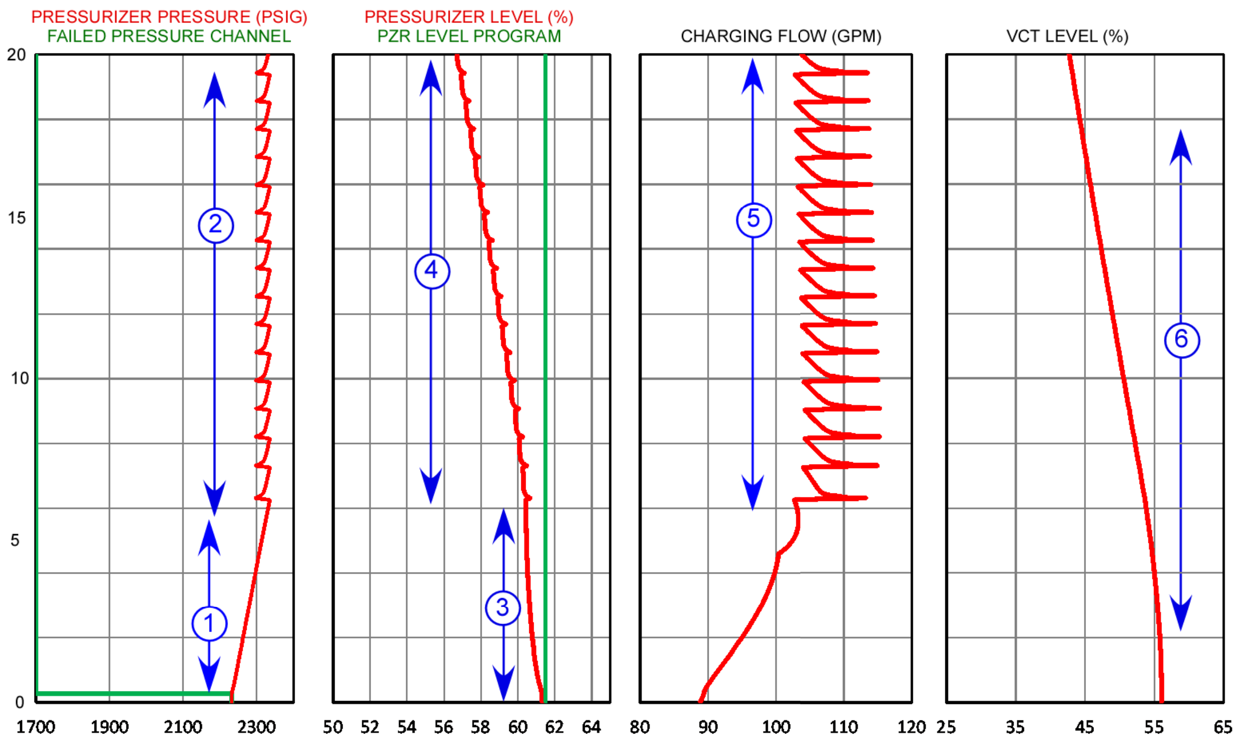
Initiating Event: Controlling pressurizer pressure channel (PT-455) fails low

Point Explanation

1. Actual **pressurizer pressure** trends up with maximum heater output from both variable and backup heaters. The pressurizer pressure control system is responding to a pressure input of 1700 psig (well below the pressure setpoint of 2235 psig) from the failed channel.
2. **Pressurizer pressure** repeatedly increases to the PORV lift setpoint. Only PORV PCV-456 lifts; the 2-out-of-2 coincidence for PCV-455A cannot be met with one of its inputs (pressure channel 455) failed low. With each PORV lift, pressure drops about 40 psig, the PORV recloses in a few seconds, and the upward trend in pressure resumes with maximum heater output.
3. The initial decrease in **pressurizer level** reflects a pressurizer outsurge. Water is slightly compressible. RCS compressibility is enhanced by nucleate boiling in the core.
4. The short-term increases ("blips") in **pressurizer level** are coincident with the PORV lifts. Each PORV lift results in a decrease in reactor coolant density and corresponding increase in pressurizer level.
5. The general trend of **Charging Flow** is to make up for the lost inventory associated with cycling of the pressurizer PORV. Also, it is apparent that the charging flow changes as its discharge pressure changes. This is a characteristic of a centrifugal pump. At this elevated pressure charging flow does not match the rate of coolant loss.
6. Slow losses of RCS inventory show up as a drop in **VCT level**.

What this transient illustrates:

1. The response of the pressurizer pressure control system (maximum heaters) to a failed-low controlling pressurizer pressure channel.
2. The responses of pressurizer pressure, pressurizer level, and charging flow to several PORV lifts.
3. The response of charging flow and VCT level to small losses of RCS inventory.



TRANSIENT 5.43
CONTROLLING PRESSURIZER PRESSURE
CHANNEL FAILS LOW

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Controlling pressurizer pressure fails low

Transient 5.43 Controlling Pressurizer Pressure Channel Fails Low

Transient 5.51 Median Select Steam Generator Level Fails Low

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

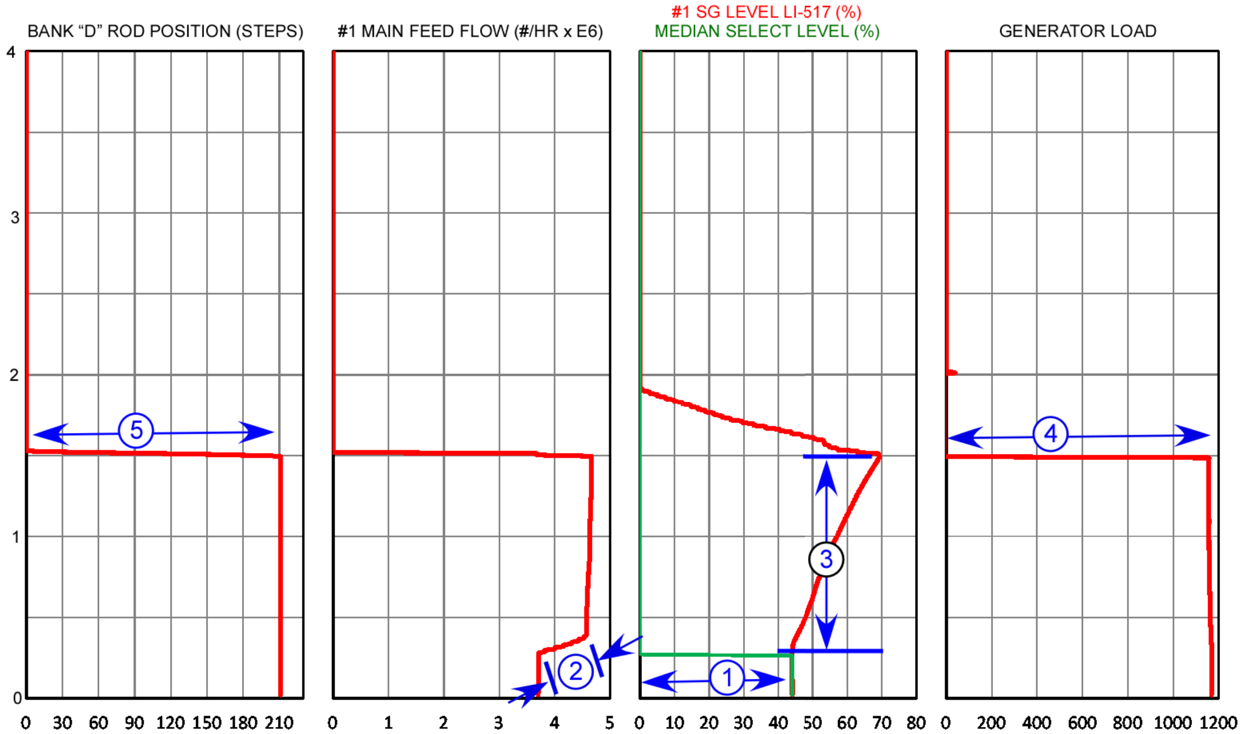
Initiating Event: Median Select SG #1 level fails low

Point Explanation

1. Initiating event - Median Select SG #1 level fails low.
2. **Feed flow to SG #1** increases to maximum as the main feed regulating valve opens in response to the controlling level input falling low.
3. **Steam generator level in SG #1** increases rapidly with the feed flow increase and no change in steam flow.
4. The turbine trip (as indicated by the step drop in **generator load**) is caused by high steam generator water level (the level measured by the two "good" level detectors on SG #1 reaches the turbine trip setpoint).
5. The reactor trip (as indicated by the step drop in **bank D rod position**) is caused by the turbine trip with plant power above the P-7 setpoint.

What this transient illustrates:

1. The response of the steam generator water level control system (maximum feed regulating valve position) to a failed-low median select steam generator level.
2. A turbine trip on high SG level.
3. A reactor trip on a turbine trip + P-7.



TRANSIENT 5.51
STEAM GENERATOR MEDIAN SELECT
LEVEL FAILS LOW

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Steam Generator #1 median select level fails low

Transient 5.51 Median Select Steam Generator Level Fails Low

Transient 5.52 Median Select Steam Generator Level Fails High

Initial Conditions:

Normal Temperature and Pressure
Nuclear Power: 100%
All control systems in automatic

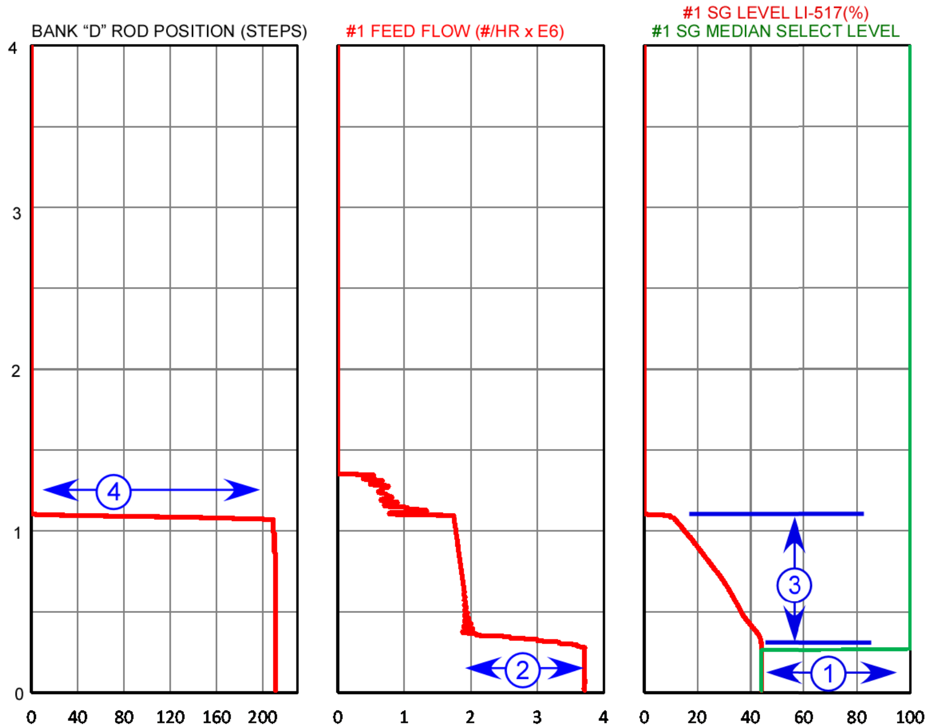
Initiating Event: Median Select SG #1 level fails high

Point **Explanation**

1. Initiating event - Median Select SG #1 level fails high.
2. **Feed flow to SG #1** decreases to minimum as the main feed regulating valve closes in response to the controlling level input rising well above the level setpoint.
3. **Steam generator level in SG #1** decreases rapidly with the feed flow decrease and no change in steam flow.
4. The reactor trips (as indicated by the step drop in **bank D rod position**) on low steam generator water level.

What this transient illustrates:

1. The response of the steam generator water level control system (minimum feed regulating valve position) to a failed-high median select steam generator level.
2. A reactor trip on low SG level.



TRANSIENT 5.52
STEAM GENERATOR MEDIAN SELECT
LEVEL FAILS HIGH

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Steam Generator #1 median select level
fails high

Transient 5.52 Median Select Steam Generator Level Fails High

Transient 5.53 Controlling Steam Generator Feed Flow Channel Fails Low

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

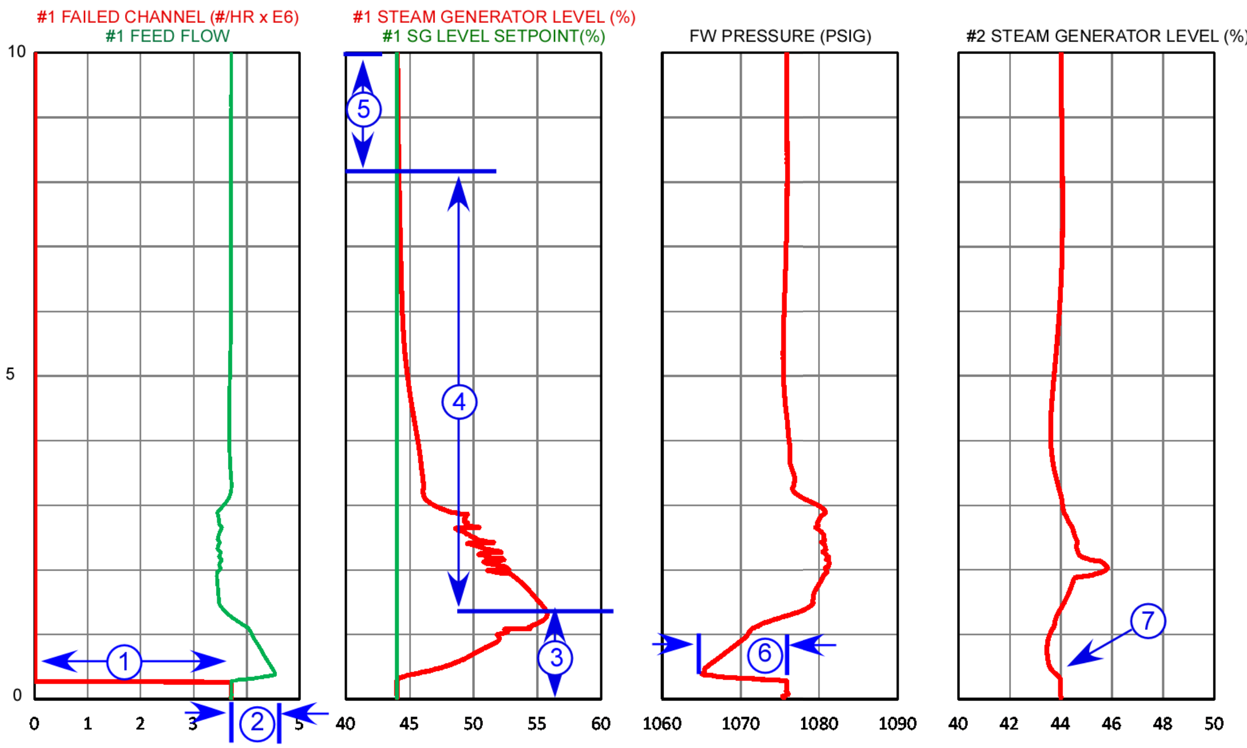
Initiating Event: Controlling SG #1 feed flow channel (FT-510) fails low

Point Explanation

1. Initiating event – FT-510 fails low.
2. **Feed flow to SG #1** increases to maximum as the main feed regulating valve opens in response to the large steam flow/feed flow mismatch (feed flow < steam flow) input to the steam generator water level control system.
3. **Steam generator level in SG #1** increases with the feed flow increase and no change in steam flow. Even after feed flow begins to decrease, steam generator level continues to rise as long as feed flow exceeds steam flow.
4. The large (integrated) level error causes **feed flow to SG #1** to decrease, overriding the still-present steam flow/feed flow mismatch. This trend in feed flow illustrates that steam generator water level control is level dominant.
5. **Steam generator level in SG #1** will eventually settle out at setpoint. When level is stable at setpoint, the integrated level error has canceled out the flow error.
6. The opening of the #1 feedwater regulating valve causes **feedwater pressure** to drop.
7. The drop in feedwater pressure causes all of the **"unaffected" steam generator levels** to drop.

What this transient illustrates:

1. The response of the steam generator water level control system to a failed-low controlling steam generator feed flow channel.
2. That steam generator water level control is a level-dominant system.
3. Changes in one feedwater regulating valve position affects all steam generator levels because of the change in feedwater pressure.



TRANSIENT 5.53
STEAM GENERATOR CONTROLLING
FEED FLOW CHANNEL FAILS LOW

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Steam Generator #1 controlling feed flow
transmitter fails low

Transient 5.53 Controlling Steam Generator Feed Flow Channel Fails Low

Transient 5.54 Controlling Steam Generator Feed Flow Channel Fails High

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

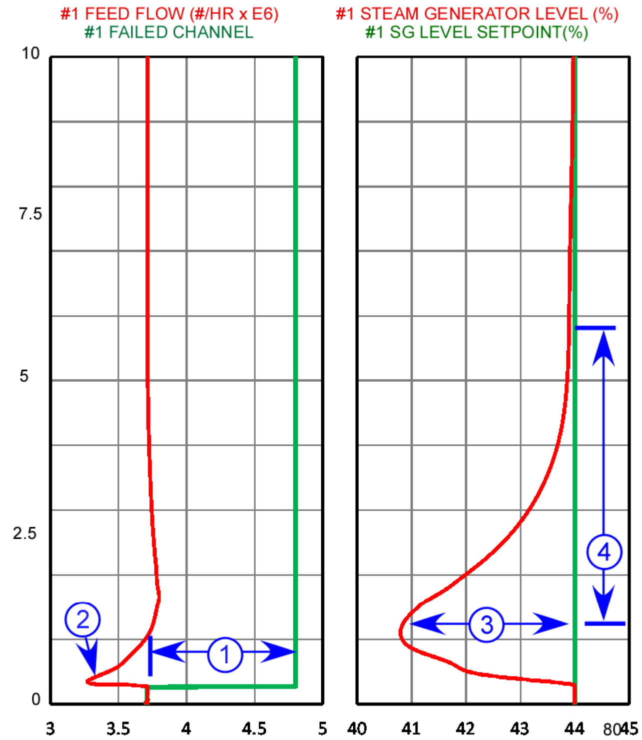
Initiating Event: Controlling SG #1 feed flow channel (FT-510) fails high

Point **Explanation**

1. Initiating event – FT-510 fails high.
2. **Feed flow to SG #1** decreases as the main feed regulating valve closes in response to the large steam flow/feed flow mismatch (feed flow > steam flow) input to the steam generator water level control system.
3. The (integrated) level error causes **feed flow to SG #1** to increase, overriding the still-present steam flow/feed flow mismatch. This trend in feed flow illustrates that steam generator water level control is level dominant.
4. **Steam generator level in SG #1** increases with feed flow greater than steam flow. The level error input to steam generator water level control brings level back to setpoint.

What this transient illustrates:

1. The response of the steam generator water level control system to a failed-high controlling steam generator feed flow channel.
2. That steam generator water level control is a level-dominant system.



TRANSIENT 5.54
STEAM GENERATOR CONTROLLING
FEED FLOW CHANNEL FAILS HIGH

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Steam Generator #1 controlling feed flow transmitter fails high

Transient 5.54 Controlling Steam Generator Feed Flow Channel Fails High

Transient 5.61 Trip Of #1 Main Feed Pump

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

Initiating Event: #1 main feed pump trips

<u>Point</u> <u>Explanation</u>

1. **#1 MFP flow rate** decreases to 0 with the trip of the pump.
2. **#2 MFP flow rate** increases to compensate for the tripped pump. With the loss of discharge pressure from the #1 pump, the ΔP across the main feed regulating valves decreases, and the feed pump speed control system increases the speed of the still operating pump to boost feedwater pressure and regulating valve ΔP.
3. **Generator load** decreases rapidly to less than 60% on the loss-of-feed-pump turbine setback.
4. **Bank D rod position** decreases at the maximum rate (72 steps/min) in response to the power mismatch circuit (turbine load decreasing rapidly) and temperature mismatch circuit ($T_{ref} < T_{avg}$) of the rod control system.
5. **Nuclear power** decreases in response to the negative reactivity added by rod insertion and, to a small extent, by the increase in T_{avg}.
6. **Steam dump demand** increases to a large value with the drop in T_{ref} accompanying the turbine setback and the increase in T_{avg} resulting from the power mismatch (nuclear power > secondary load).
7. **Steam flow** decreases in response to the closure of the turbine control valves resulting from the setback, then increases with steam dump actuation. The steam dumps are armed by the setback-induced rapid load reduction, and a large demand exists, as described in point 6 above.
8. **Steam dump demand** decreases, first rapidly and then steadily, as rod insertion brings T_{avg} down to T_{ref}.

Transient 5.61 Trip Of #1 Main Feed Pump (cont'd)

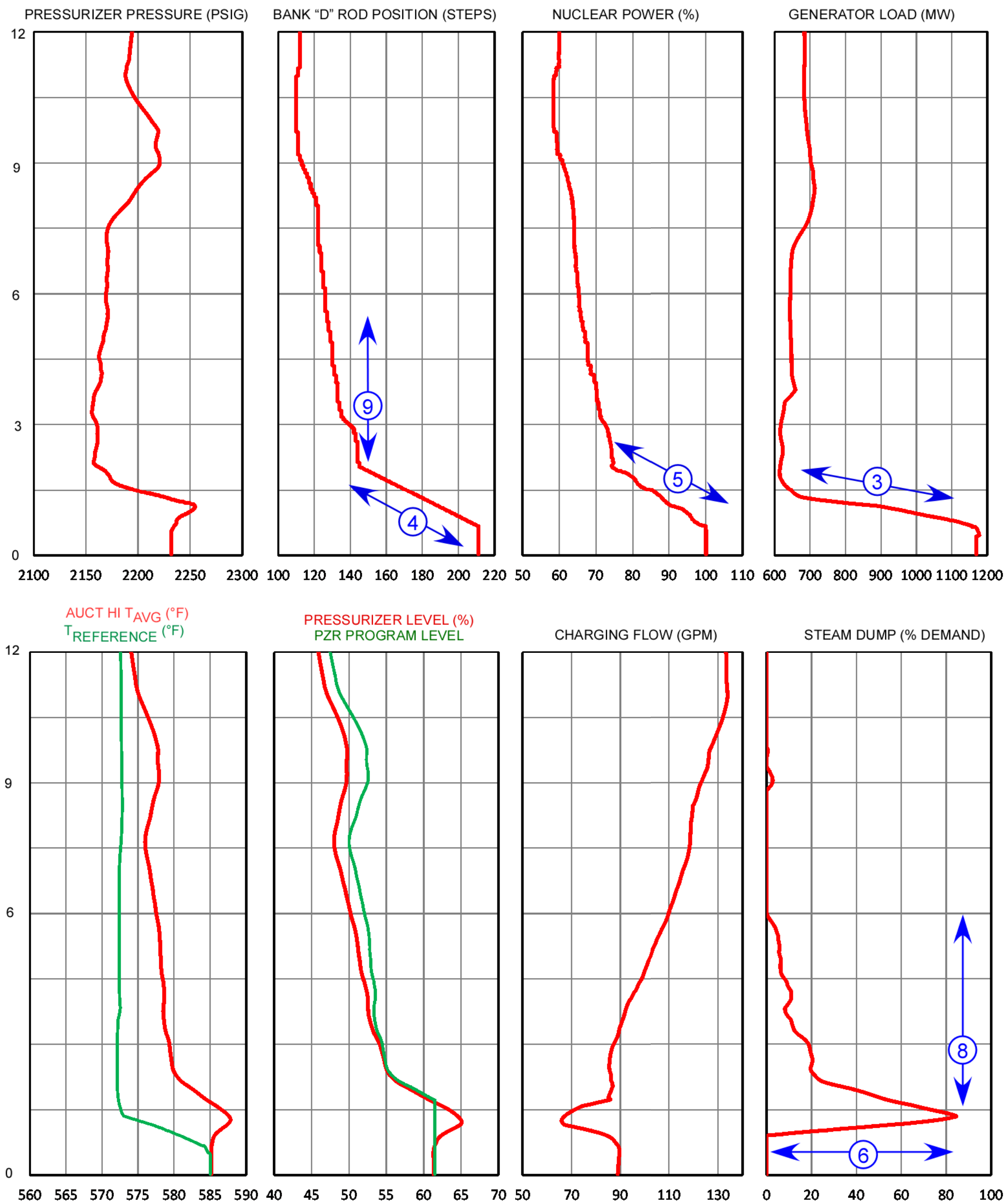
Point **Explanation**

9. The change in **bank D rod position** slows as the inputs to the rod control system from the temperature and power mismatch circuits almost cancel. T_{avg} is > T_{ref}, so the temperature mismatch circuit is calling for rod insertion, but nuclear power has been decreasing with turbine load constant, so the power mismatch circuit is calling for rod withdrawal.

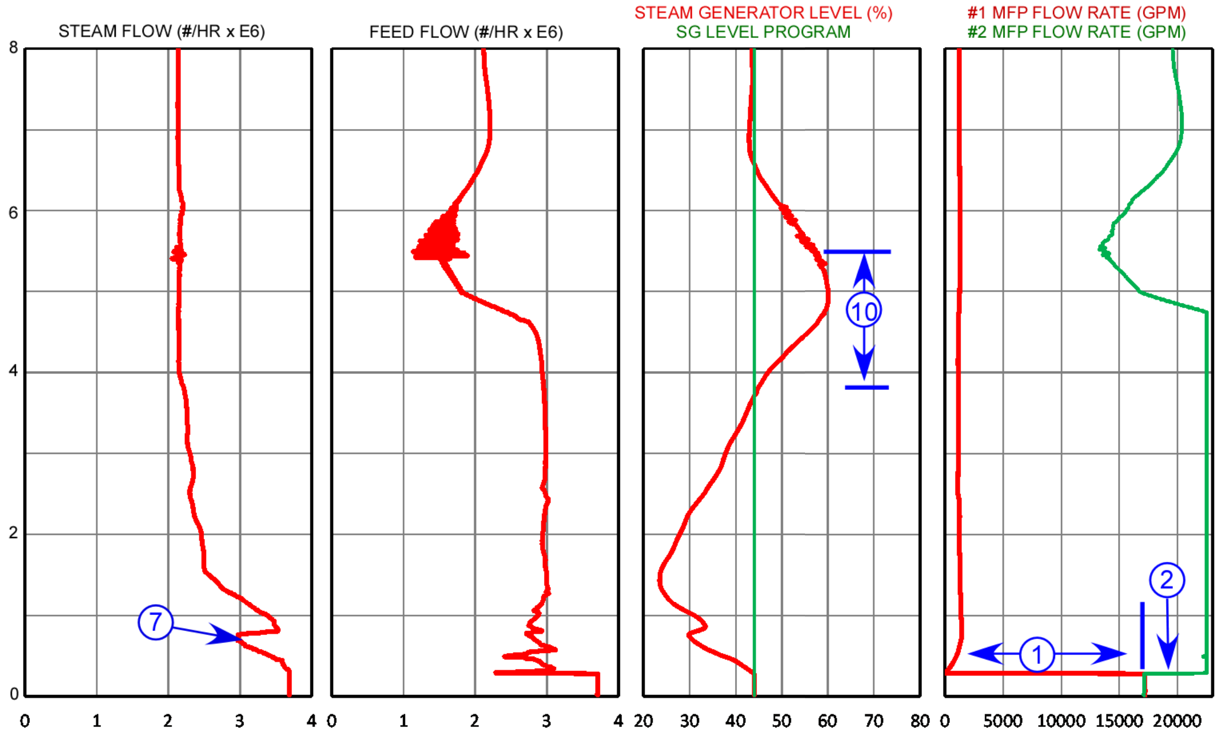
10. Steam generator level continues to rise above the setpoint because of the large integral signal that built into the steam generator water level control system while level was below setpoint. This is called controller "windup" and is a feature of integral controllers in the Westinghouse design. Operator intervention is necessary to prevent a large overshoot on this transient.

What this transient illustrates:

1. A loss-of-feed-pump turbine setback.
2. Steam dump actuation to handle the difference between nuclear power and secondary load.
3. Controller windup.



Transient 5.61 Trip Of #1 Main Feed Pump



TRANSIENT 5.61
TRIP OF #1 MAIN FEED PUMP

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
#1 main feed pump trips

Transient 5.61 Trip Of #1 Main Feed Pump

Transient 5.62 Inadvertent MSIV Closure

Initial Conditions:

BOL
Nuclear Power: 50%
All control systems in automatic

Initiating Event: The MSIV in the main steam line from the #1 SG inadvertently shut

<u>**Point**</u> <u>**Explanation**</u>

1. **Steam flow from the #1 SG** initially decreases to near 0 as the MSIV shuts. The following rise in steam flow reflects SG #1 PORV releases.

2. **Steam generator level in the #1 SG** shrinks in response to the large reduction in steam demand from that SG with the MSIV closure.

3. **Feed flow to the #1 SG** initially drops as the #1 SG water level control system responds to the rapid drop in steam flow. But when #1 SG pressure rises above feed pressure, feed flow drops to zero.

4. **Steam pressure in the #1 main steam line** increases rapidly, as steam is bottled up in the #1 SG and its associated main steam line. The SG PORV opens to relieve steam from the #1 SG.

5. The removal of flow resistance associated with the isolation of the #1 main steam line causes **steam flow from the #4 SG** (as well as from the #2 and #3 SGs) to increase.

6. **Steam generator level in the #4 SG** (as well as in the #2 and #3 SGs) swells in response to the increase in steam demand from that SG.

7. **Feed flow to the #4 SG** (as well as to the #2 and #3 SGs) increases as the #4 SG water level control system responds to the increase in steam flow by opening the #4 SG main feedwater regulating valve.

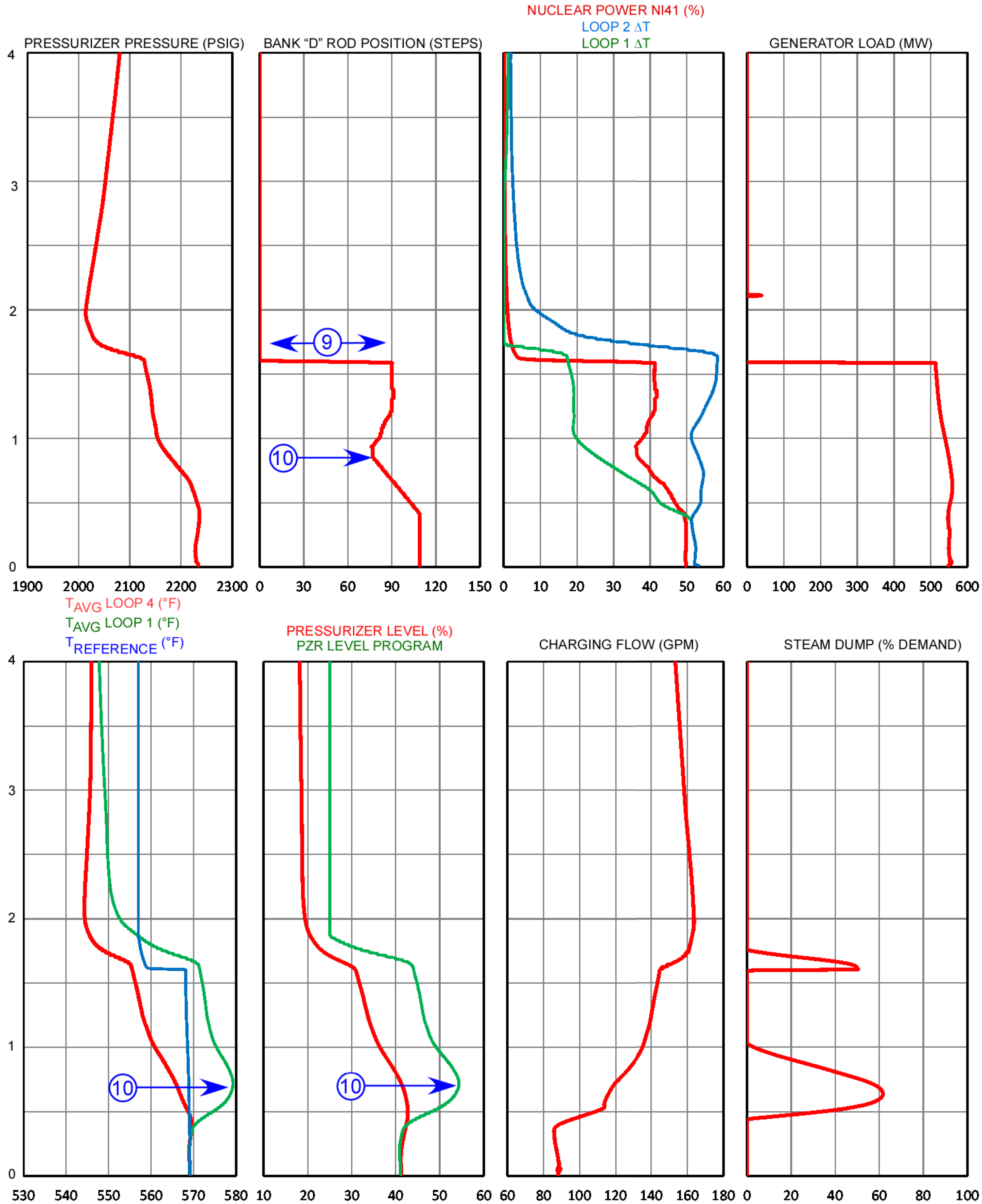
8. **Steam pressure in the #4 main steam line** (as well as in the #2 and #3 main steam lines) decreases in response to the increased heat transfer in (and increased steaming from) that SG. The 3 unaffected SGs are attempting to maintain the turbine load at the original level and cannot support the necessary steam flow at the original steam pressure.

9. The reactor trips (as indicated by the step drop in **bank D rod position**) on low steam generator water level in the #1 SG. Since steam pressure is greater than feed pressure, feed flow is zero. SG PORV flow on the #1 SG deplete inventory in the #1 SG.

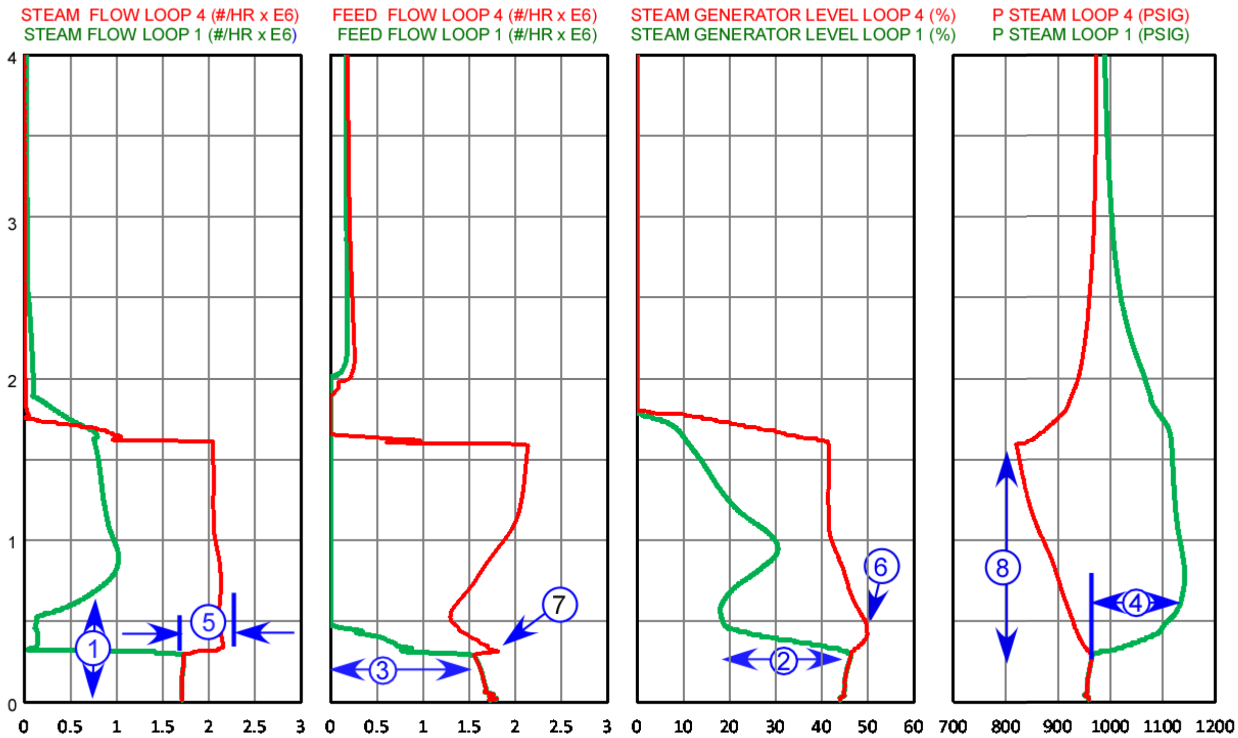
10. Loop #1 T_{avg} rises as its SG takes less heat. This causes loop #1 to become the auctioneered high T_{avg}, even though it is not representative of RCS temperature. This leads to inappropriate responses from the pressurizer level control system and the automatic rod control system.

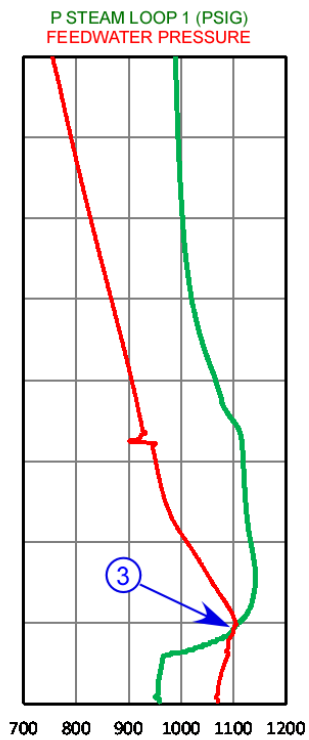
What this transient illustrates:

1. The effects of a closed MSIV: reduced steam flow, SG level shrink, increased steam pressure.
2. Increased steam flow from the other 3 main steam lines to "pick up the slack."
3. Assymetric loop temperatures.



Transient 5.62 Inadvertent MSIV Closure





TRANSIENT 5.62
INADVERTENT MSIV CLOSURE

Initial Conditions
BOL
Nuclear Power: 50%
All control systems in automatic

Initiating Event:
The MSIV in the main steam line from the #1 SG inadvertently shuts

Transient 5.62 Inadvertent MSIV Closure

Transient 5.63 RCP Trip

Initial Conditions:

BOL
Nuclear Power: 28%
All control systems in automatic

Initiating Event: The RCP in loop #1 trips

Point **Explanation**

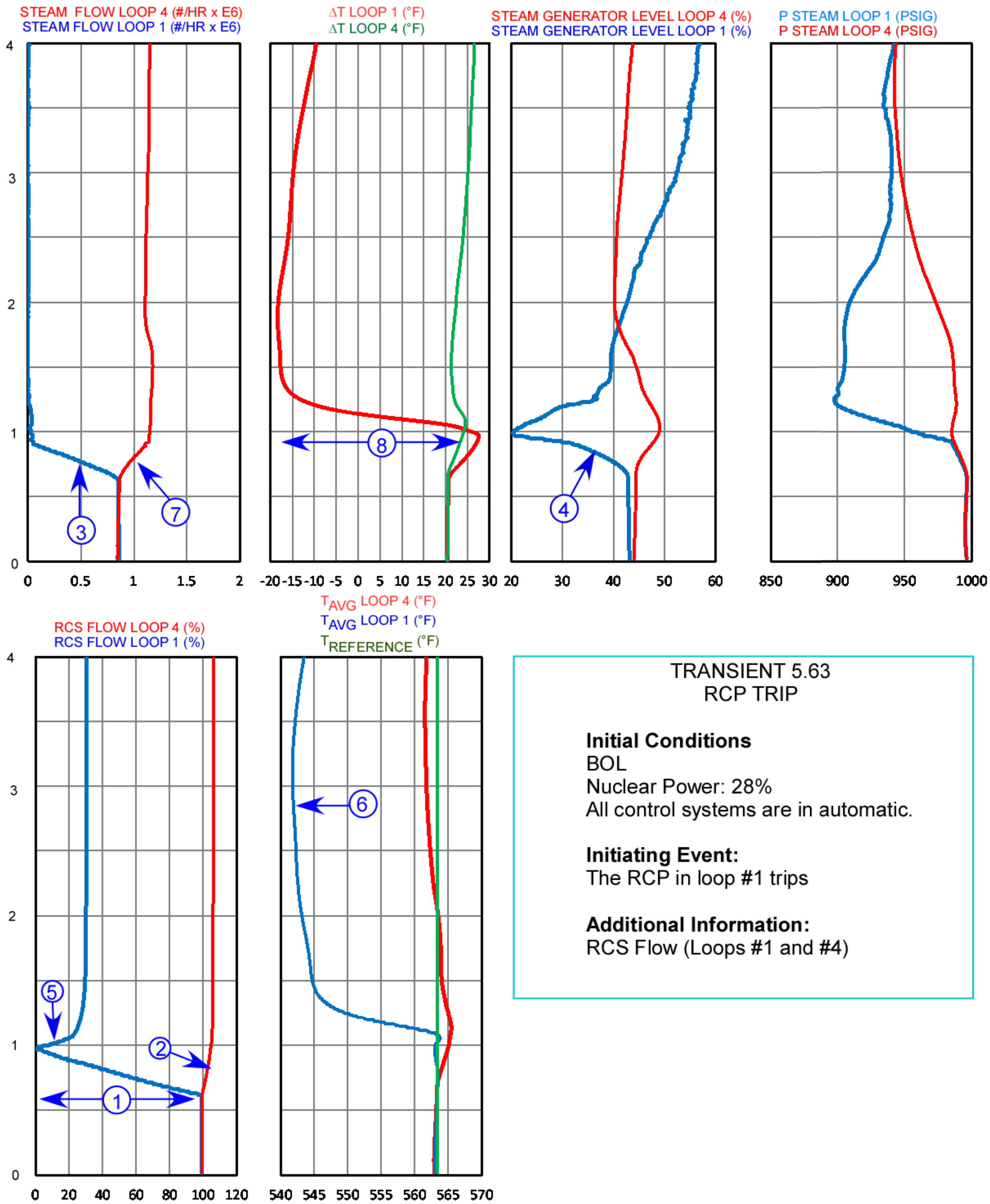
1. **RCS flow in loop #1** decreases to 0 as the reactor coolant pump coasts down with flywheel inertia.
2. **RCS flow in loop #4** (as well as in loops #2 and #3) increases with the decrease in flow resistance from loop #1 and the development of reverse flow in that loop supplied by the discharge of the 3 running pumps.
3. The reduction in **steam flow in steam line #1** reflects the degradation of heat transfer in SG #1. The reactor coolant pump had been "delivering" water at the core exit temperature (T_{hot}) to the steam generator. When the reactor coolant pump stops, the flow in that loop reverses, and T_{cold} enters that SG on the primary side. This greatly reduces the heat transfer in that steam generator.
4. SG#1 level shrinks as steam flow drops. The relative absence of boiling in SG #1 and its associated flow resistance allows feedwater to flow into the tube bundle region from the downcomer (where SG level is measured), and the drop in **steam generator level in the #1 SG** results. Contributing to the level drop is the reduction in recirculation flow from the moisture separators to the downcomer with the reduction in steam flow.
5. The increase in **RCS flow in loop #1** reflects the development of reverse flow in that loop. The elbow tap flow measurement system is not direction sensitive. Discharge from the 3 running pumps is supplied to the cold leg of the idle loop via the reactor vessel annulus.
6. The decreased value of **loop #1 T_{avg}** that exists at the end of the 4 plotted minutes also reflects the development of reverse flow in that loop. Once reverse flow in the idle loop is fully developed, the flow in that loop enters the SG (from the cold leg) with a temperature ~ equal to the T_c of the other 3 loops and exits (to the hot leg) a little colder.
7. **Steam flow in steam line #4** (as well as in steam lines #2 and #3) increases as heat transfer in the SGs in the loops with the running RCPs increases to maintain the unchanged turbine load. The increased steam flow is supported by a core ΔT which is a few degrees larger than its initial value now that the core mass flow rate has decreased to ~ 3/4 of its initial value ($\dot{Q} = \dot{M} c_p [T_H - T_c]$).

8. **ΔT in Loop 1** becomes negative as flow reverses in the loop. The water in the cold leg passes through the SG and gives up some heat, resulting in the coolant in the "hot leg" being colder than the coolant in the "cold leg".

<u>Point</u> <u>Explanation</u>

What this transient illustrates:

1. The reduction in RCS loop flow associated with an RCP trip and the subsequent development of reverse flow in that loop.
2. The shrink in SG level in the loop with the tripped RCP.



Transient 5.63 RCP Trip

Transient 5.71 SG Safety Valve Fails Open

Initial Conditions:

BOL
Nuclear Power: ~10^{-8} amps in I.R.
Normal plant configuration for startup

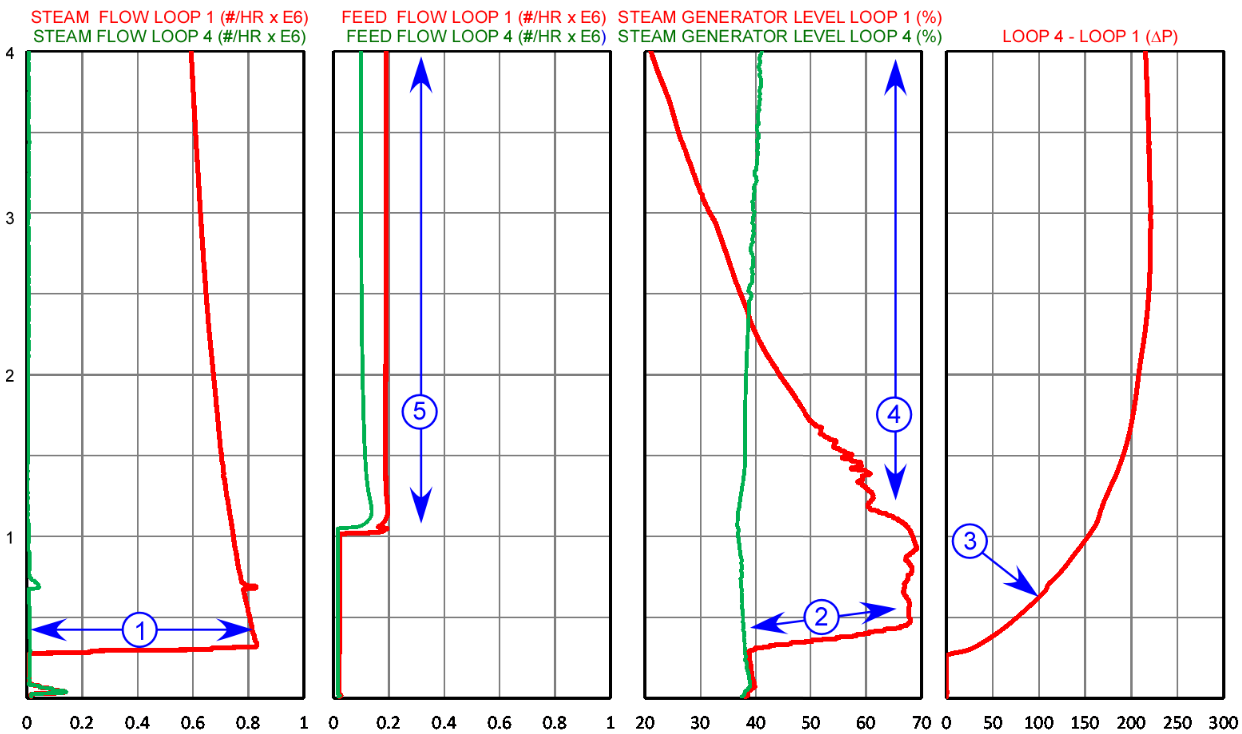
Initiating Event: One safety valve on main steam line #1 fails to 100% open

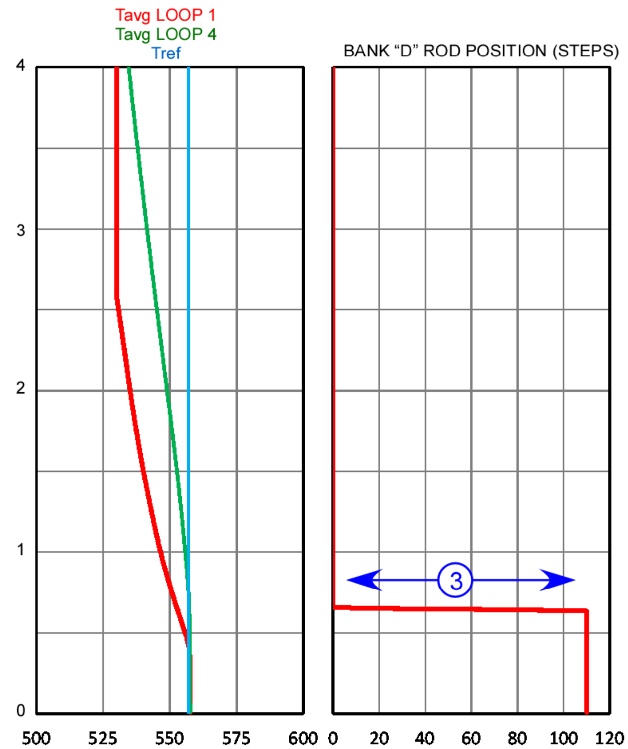
<u>Point</u> **<u>Explanation</u>**

1. **Steam flow in main steam line #1** increases to the safety valve capacity for no-load steam pressure.
2. **Steam generator level in SG #1** swells with the surge in steam demand associated with the safety valve failing open.
3. The reactor trip (indicated by the step drop in **bank D rod position**) is caused by a safety injection actuation, which is caused by high steam line ΔP.
4. The decrease in **steam generator level in SG #1** reflects dissipation of that SG's inventory through the failed-open safety valve.
5. **Feed flow** during the latter few minutes of the transient reflects AFW system operation. The AFW system actuation is caused by the SI. The AFW flow to SG #1 is a little larger than that to the other 3 SGs because of the lower pressure in SG #1.

What this transient illustrates:

1. The relatively slow dissipation of one SG's inventory through a failed-open safety valve.
2. The isolation of the steam break from the other 3 SGs by the faulted SG's check valve.
3. A steam-break-induced cooldown of the RCS.
4. A high steam line ΔP SI.





TRANSIENT 5.71
SG SAFETY VALVE FAILS OPEN

Initial Conditions
BOL
Nuclear Power: ~10^{-8} amps in I.R.
Normal plant configuration for startup.

Initiating Event:
One safety valve on main steam line #1
fails to 100% open

Transient 5.71 SG Safety Valve Fails Open

Transient 5.72 Double-ended Shear of Main Steam Line Inside Containment With LOOP, 10^{-8} Amps In I.R.

Initial Conditions:

BOL
Nuclear Power: ~10^{-8} amps in I.R.
Normal plant configuration for startup

Initiating Event: Doubled-ended shear on main steam line #1 and LOOP occur simultaneously at ~5 sec

Point Explanation

1. **Indicated steam flow in main steam line #1** spikes high with the steam break. The pressure transmitter used for density compensation is quickly disconnected from the SG because it is downstream of the location of the double-ended shear of the steam line. Actual flow falls off more gradually as the SG depressurizes.
2. **Steam generator level in SG #1** swells with the surge in steam demand associated with the steam break.
3. **Indicated Steam pressure in main steam line #1** suddenly drops to containment pressure because the transmitter is downstream of the double-ended shear of the steam line. Actual pressure drops more slowly as the SG loses energy out the break.
4. **Steam pressure in main steam line #4** (as well as the other intact main steam lines) drops more slowly than line #1. The steam break is cooling the entire RCS and the intact SGs are cooling off as a result. Loops 2, 3, and 4 cannot feed the break because the check valve in main steam line #1 prevents backflow.
5. **Wide-range loop #1 T_c** decreases due to the cooldown of the reactor coolant caused by the steam break, which is in steam line #1 and affects loop #1 the most.
6. **Charging flow** decreases to 0 very rapidly with the LOOP; the CCP which has been operating is now unpowered.
7. The reactor trip (indicated by the step drop in **bank D rod position**) is caused by the SG ΔP safety injection actuation. The loss of offsite power would also cause the rods to drop, but the large flywheels on the rod drive motor generators keep the stationary grippers engaged for about 9 seconds after a loss of power.

Transient 5.72 Double-ended shear of main steam line Inside Containment With LOOP, 10^{-8} Amps In I.R. (cont'd)

Point Explanation

8. **Charging flow** returns after the emergency diesel generators have started and attained rated speed, the EDG output breakers have closed, and the CCPs have restarted. The CCPs are now operating in the HPI mode; the plotted charging flow reflects seal injection to the RCPs (normal charging is isolated) and a constant charging flow control valve position

9. **Feed flow to SG #1** increases with actuation of the AFW system (the AFW system is actuated by the SI actuation). The flow to that SG is initially higher than that to the other three SGs because of its lower pressure. The AFW flow to SG #1 then decreases when the "B" train of AFW isolates in response to exceeding the high flow setpoint of 500 gpm in that train. The "A" train of AFW was being used during startup, so these throttle valves were barely open. The "A" train of AFW is never isolated, because the "A" train does not reach the high flow setpoint. The procedure would direct the crew to isolate AFW flow to the faulted SG, but this transient is run with no operator action.

10. The decrease in **steam flow in main steam line #1** reflects the decrease in driving force for steam flow with the reduction in steam pressure in that steam line and the increase in containment pressure. The magnitude of the flow is inaccurate (see point 1), but the trend is still useful.

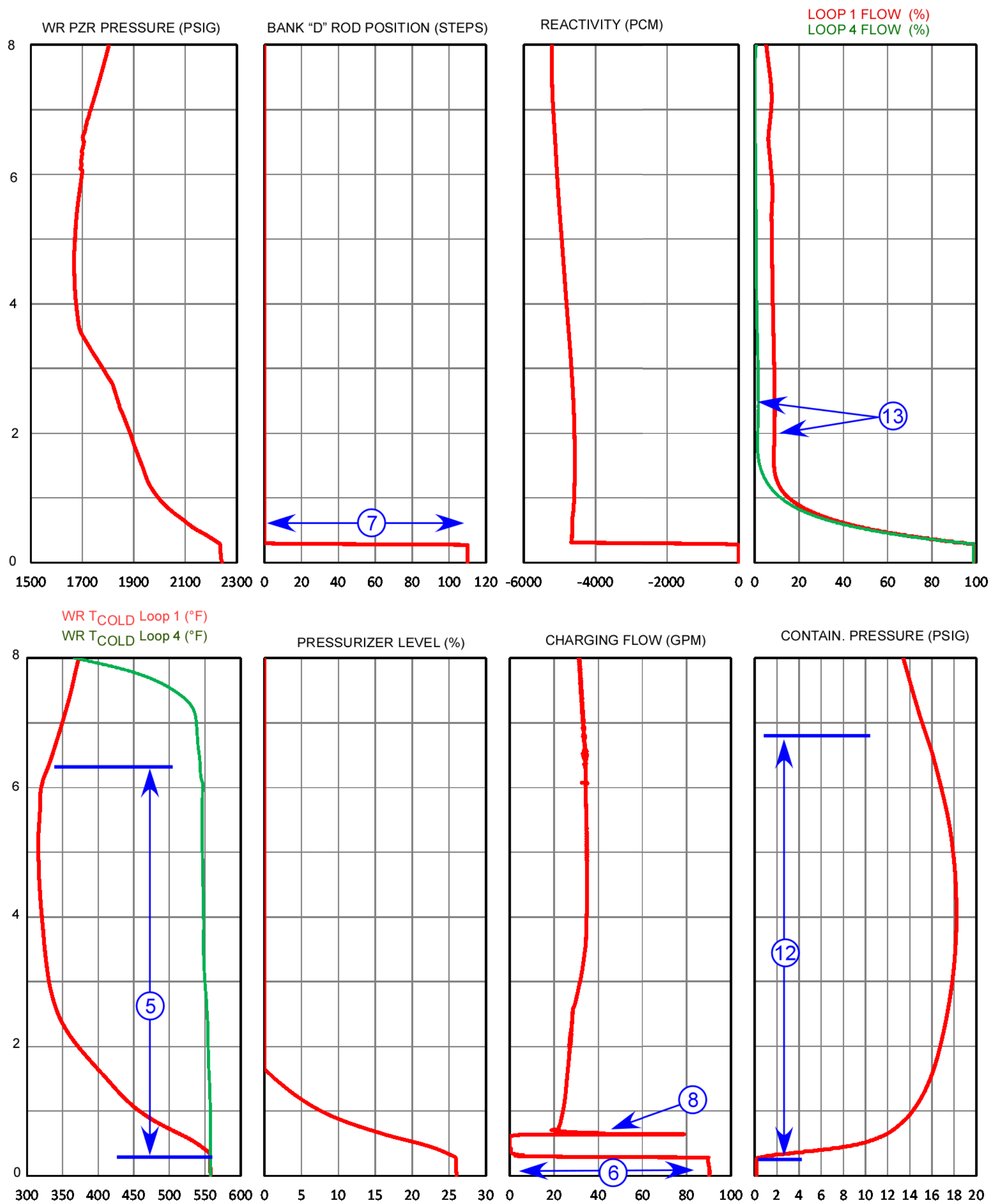
11. The decrease in **steam generator level in SG #1** reflects the dissipation of that SG's inventory through the steam break.

12. **Containment pressure** increases as steam is discharged from main steam line #1 to the containment atmosphere. The pressure increase is mitigated by containment fan cooler operation.

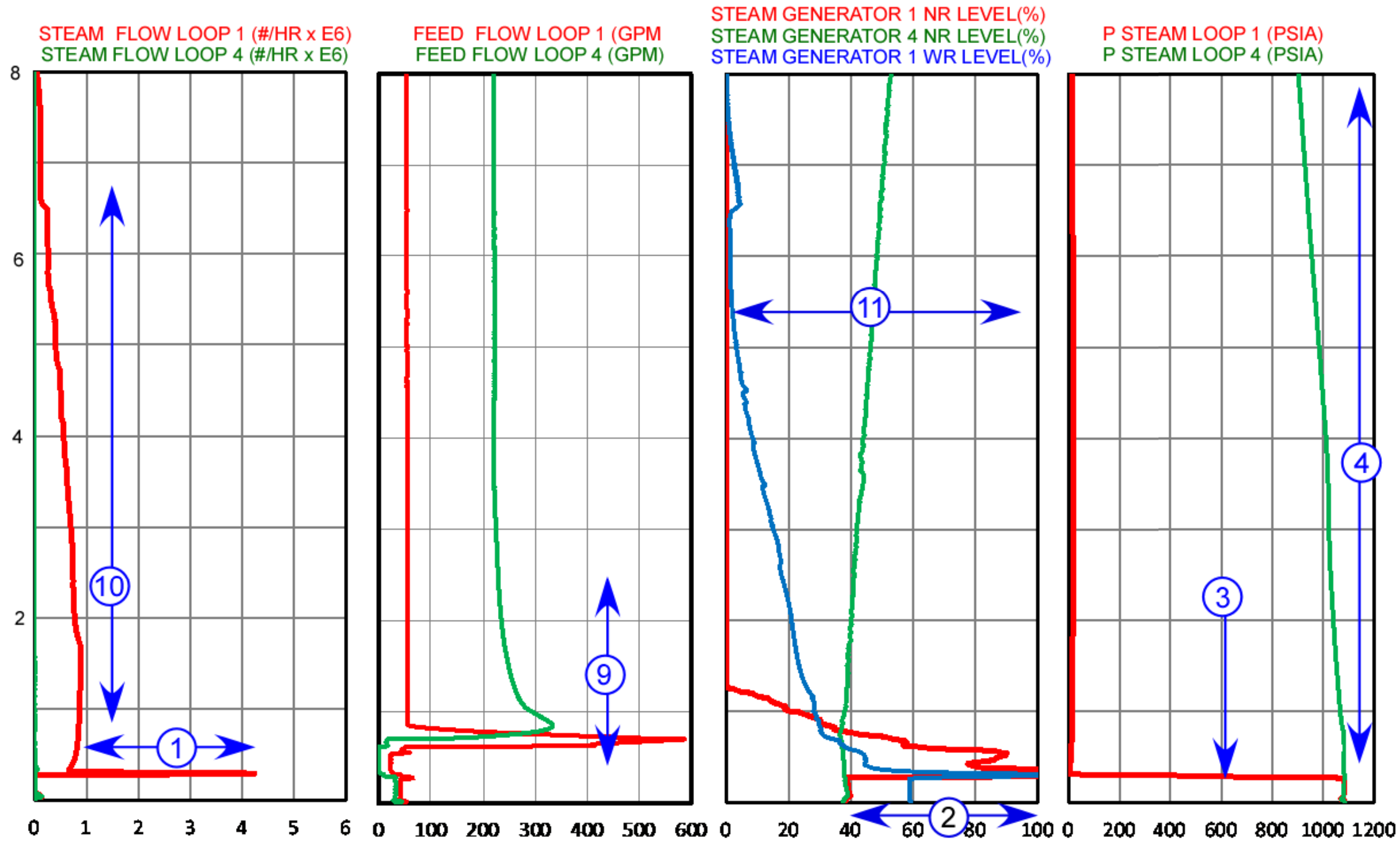
13. Loop #1 flow reflects the natural circulation flow in that loop. The loops associated with the intact SGs are essentially stagnant.

What this transient illustrates:

1. The depletion of one SG's inventory through an unisolable break upstream of the MSIV.
2. The isolation of the steam break from the other 3 SGs by the faulted SG's check valve.
3. A steam-break-induced cooldown of the RCS.
4. A high steam line ΔP ESF actuation and the characteristic response of charging flow.
5. LOOP-induced effects: the delay in starting the charging pumps after the SI actuation and the controller responses.
6. The Feed-Only-Good-Generator (FOGG) feature of the AFW flow control valves.



Transient 5.72 Double-ended shear of main steam line Inside Containment With LOOP, 10^{-8} Amps In I.R.



TRANSIENT 5.72
Double-ended shear of main steam line
Inside Containment With LOOP, 10-8 Amps In I.R

Initial Conditions
BOL
Nuclear Power: ~10^{-8} amps in I.R.
Normal plant configuration for startup.

Initiating Event:
Double-ended shear on main steam line #1 and loss of offsite power occur simultaneously.

Transient 5.72 Double-ended shear of main steam line Inside Containment With LOOP, 10^{-8} Amps In I.R.

Transient 5.73 Large Steam Break Inside Containment, 100% Power

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

Initiating Event: Large break on main steam line #1 (8 X 10^6 lbm/hr) inside containment

Point **Explanation**

1. **Steam flow in all steam generators** initially increases with the steam break. When #1 SG pressure drops enough to close its steam line check valve, only #1 SG feeds the break.

2. **Steam generator level in SGs #1** swells with the surge in steam demand associated with the steam break.

3. **Steam pressure in main steam line #1** decreases as steam is discharged to the containment atmosphere. The intact steam lines depressurize much more slowly because the closing of the #1 steam line check valve prevents the other three generators from steaming out the break.

4. **Steam flow** momentarily rises in the intact SGs as the steam dumps respond to the reactor trip. This is evidence that the MSIVs did not close at the time of the trip. This rules out high steam flow + low steam pressure SI as the cause of the plant trip.

5. The reactor trip (indicated by the step drop in **bank D rod position**) and SI actuation (indicated by the characteristic perturbation in **charging flow**) is caused by high steam line ΔP. The high steam flow setpoint is exceeded in all steam generators, but only #1 lead/lag steam pressure reaches the low pressure setpoint (this requires 2/4 for actuation).

6. The closure of the #1 steam line check valve causes **steam pressure** in the intact SGs to momentarily rise following the reactor trip.

7. **Wide-range loop #1 T_c** decreases due to the cooldown of the reactor coolant caused by the steam release through the break. The cooldown in RCS loop #1 (which contains the SG which is feeding the break) leads the cooldowns in the other loops. The cooldown stops when the steam generator is effectively empty.

Point Explanation

8. **Feed flow to SG #1** increases with actuation of the AFW system (the AFW system is actuated by the SI actuation). The flow to that SG is initially higher than that to the other three SGs because of its lower pressure. The AFW flow to SG #1 decreases to 0 in two steps when each AFW flow control valve to that SG closes in response to the high flow (> 500 gpm) sensed in its supply line to that SG. The two steps are due to the train A and train B valves closing at different times.

9. The decrease in **steam flow in main steam line #1** reflects the decrease in driving force for steam flow with the reduction in steam pressure in that steam line and the increase in containment pressure.

10. The decrease in **steam generator level in SG #1** reflects the rapid dissipation of that SG's inventory through the steam break.

11. **Containment pressure** increases as steam is discharged from main steam line #1 to the containment atmosphere. The pressure increase is mitigated by containment fan cooler operation.

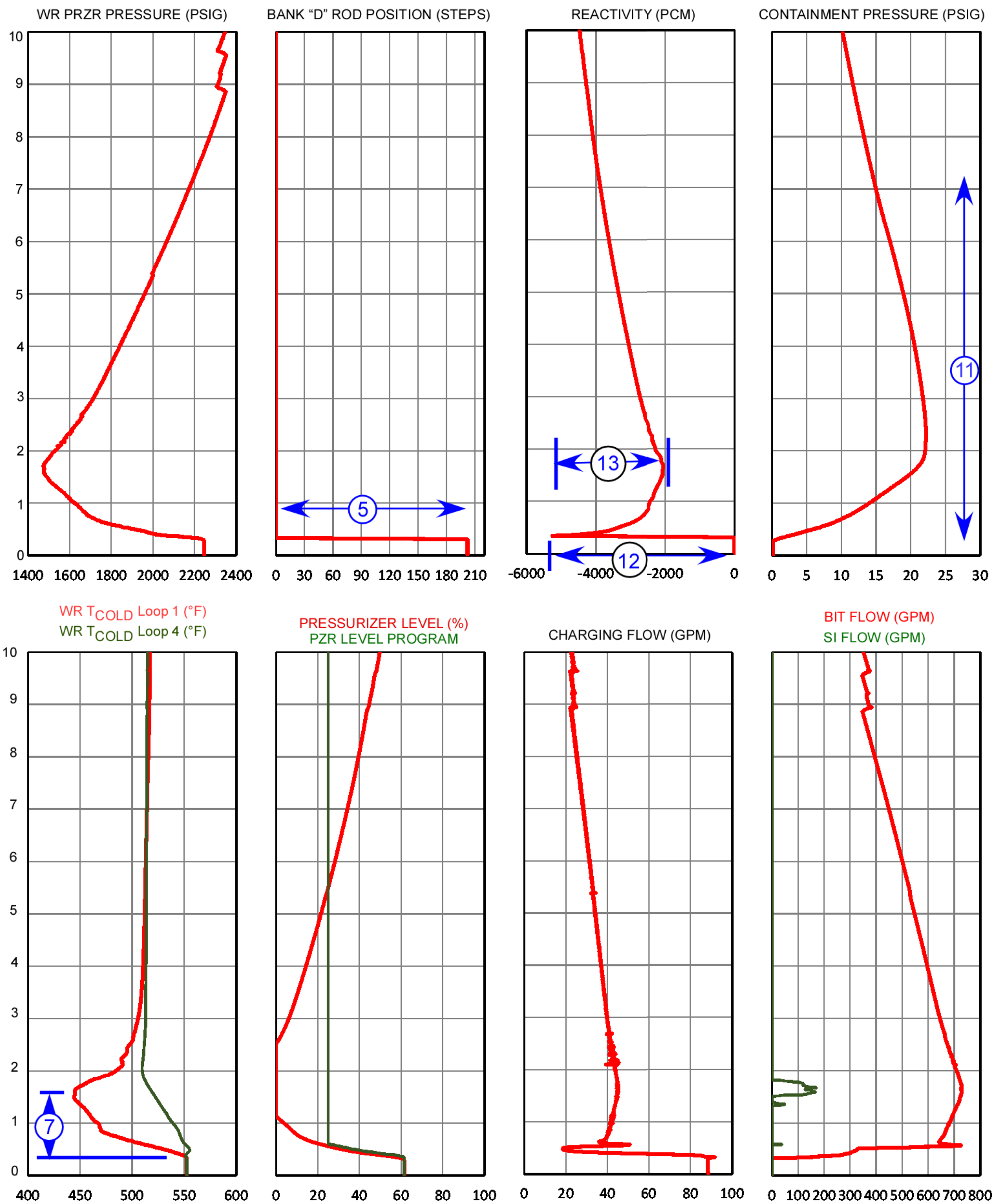
12. The reactor is made subcritical by the amount of total rod worth minus power defect.

13. The positive reactivity added by the RCS cooldown is mitigated by ECCS flow.

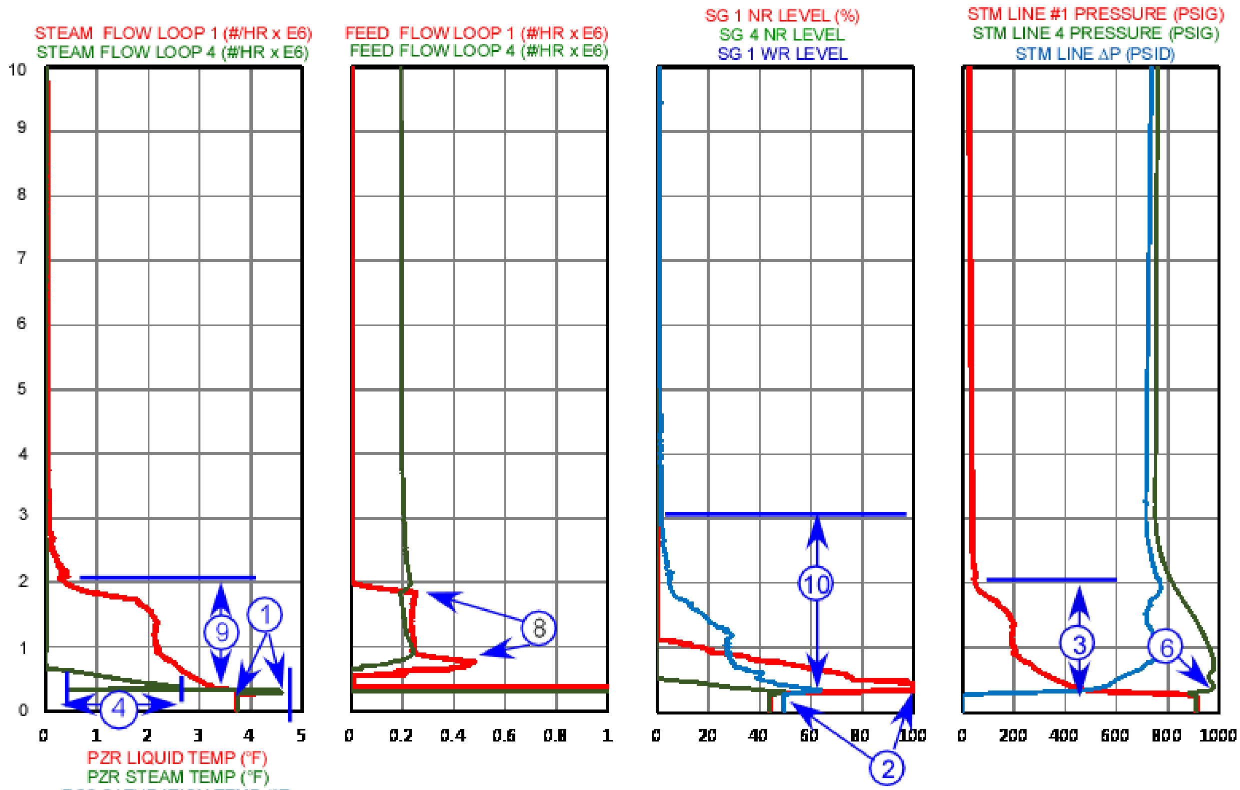
14. When the PZR refills, the water is coming from the loop 2 hot leg, so PZR liquid temperature approaches the loop 2 hot leg temperature. The compression of the steam causes it to be superheated. At the end of this transient, the PZR is not at saturation conditions. The liquid is subcooled and the steam is superheated.

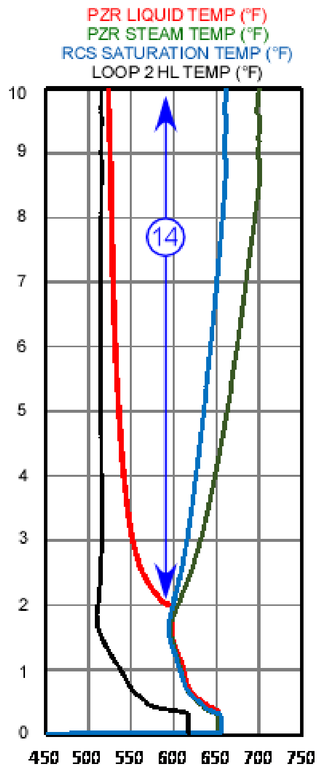
What this transient illustrates:

1. The dissipation of one SG's inventory through an unisolable break upstream of the MSIV.
2. The isolation of the steam break from the other 3 SGs by the faulted SG's check valve.
3. A steam-break-induced cooldown of the RCS.
4. A SG ΔP SI actuation and the characteristic response of charging flow.
5. The "feed-only-good-generator" feature of the AFW flow control valves.
6. PZR liquid and steam temperature response to a large insurge.



Transient 5.73 Large Steam Break Inside Containment, 100% Power





TRANSIENT 5.73
LARGE STEAM BREAK INSIDE CONTAINMENT

Initial Conditions
EOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Large break on main steam line #1
(8 x 10^6 lbm/hr)

Transient 5.73 Large Steam Break Inside Containment, 100% Power

Transient 5.74 Large Steam Break Downstream Of MSIVs, 10^{-8} Amps In I.R.

Initial Conditions:

BOL
Nuclear Power: ~10^{-8} amps in I.R.
Normal plant configuration for plant startup

Initiating Event: Large break (8.72×10^6 lbm/hr) downstream of the MSIVs

<u>Point</u> **<u>Explanation</u>**

1. **Steam flow** (all main steam lines) increases rapidly with the steam break. The high steam flow setpoint is exceeded on all steam lines, providing half of the SI/Steam line isolation actuation.

2. **Steam pressure** decreases with the unrestricted steam flow through the break. Note that the lead/lag steam pressure to the low steam pressure bistables drops below the SI setpoint, providing the second half of the SI/Steam Line Isolation signal.

3. The reactor trip (indicated by the step drop in **bank D rod position**) is caused by an SI actuation on high steam flow plus low steam pressure. Note that the SI actuation takes place when the steam pressure is well above 600 psig; the input to the low steam pressure bistable reaches the low steam pressure setpoint because of the lead-lag circuit through which the steam pressure signal is processed. Note also that the other SI actuation signals are not possible: pressurizer pressure and T_{avg} are not low enough yet, and, because the break is downstream of the MSIVs, there is no steam line ΔP, and it does not cause containment pressure to increase.

4. The **charging flow** perturbation reflects the SI actuation (isolation of normal charging and diversion of some HPI flow through the seal injection lines).

5. The additional steam flow through the break cools the reactor coolant; the **pressurizer level** decrease reflects the reduction in reactor coolant volume caused by the decrease in coolant temperature.

6. **Steam flow** decreases to 0, reflecting the MSIV closure associated with the high steam flow SI actuation.

7. **Source range power** comes on scale when both source range detectors are energized by both I.R. channels reaching the P-6 reset setpoint following the trip.

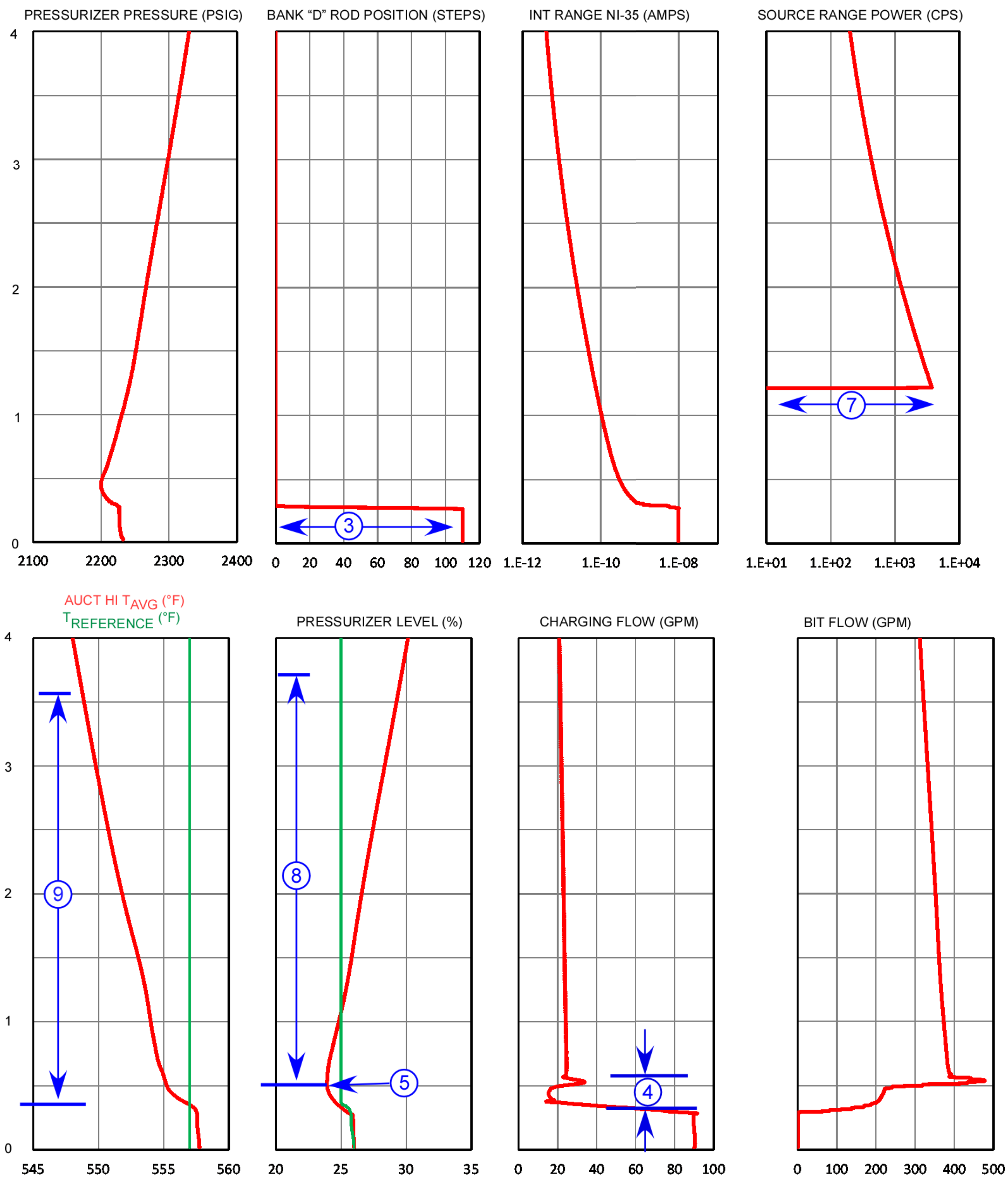
8. **Pressurizer level** increases with injection from the CCPs and letdown isolated following the SI actuation.

9. **Tavg** continuously drops because of the combination of cold ECCS water entering the RCS and auxiliary feedwater flow.

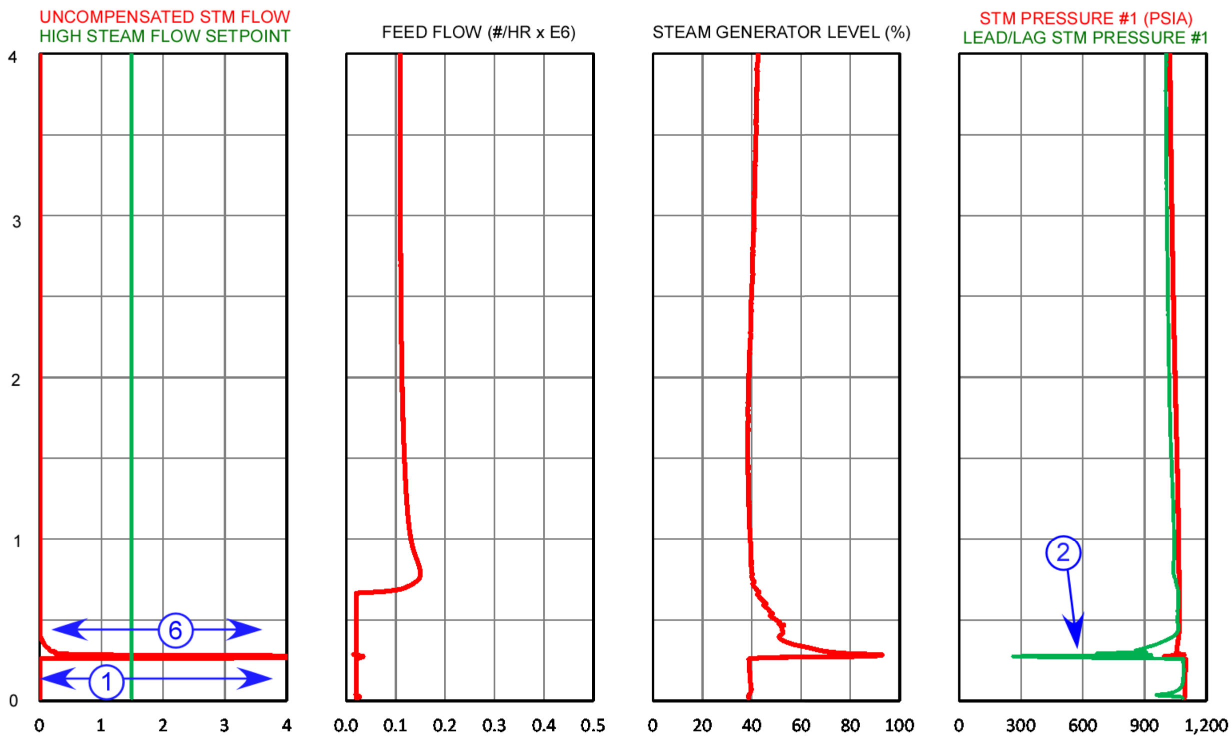
Transient 5.74 Large Steam Break Downstream Of MSIVs, 10^{-8} Amps In I.R. (cont'd)

What this transient illustrates:

1. The feeding of a steam break downstream of the MSIVs by all SGs.
2. A high steam flow + low steam pressure SI actuation and the isolation of all main steam lines.
3. A steam-break-induced cooldown of the RCS.
4. The energizing of the source range detectors when intermediate range power reaches the P-6 setpoint.



Transient 5.74 Large Steam Break Downstream Of MSIVs, 10^{-8} Amps In I.R.



TRANSIENT 5.74
LARGE STEAM BREAK DOWNSTREAM
OF MSIVs

Initial Conditions
BOL
Nuclear Power: ~10^{-8} amps in I.R.
Normal plant configuration for startup

Initiating Event:
Large break (8.72 x 106 lbm/hr) downstream
of the MSIVs

Transient 5.74 Large Steam Break Downstream Of MSIVs, 10^{-8} Amps In I.R.

Transient 5.75 SGTR In SG #1

Initial Conditions:

BOL
Rated Thermal Power
All control systems in automatic

Initiating Event: Tube rupture in SG #1

Point Explanation

1. **Pressurizer level** drops with the loss of coolant inventory from the RCS.
2. **Pressurizer pressure** decreases with the expansion of the pressurizer steam bubble associated with the inventory loss. This trend continues until the low pressurizer pressure reactor trip setpoint is reached.
3. **Charging flow** increases to a very high value as the pressurizer level control system opens charging flow control valve FCV-121 in response to the low level, and the discharge flow from the operating CCP is enhanced by the low RCS pressure.
4. **Steam generator level in SG #1** increases by a few percent with the leakage of reactor coolant into that SG. The level is brought back to setpoint as the level error input to the SG water level control system reduces feed flow to SG #1 (see point 5).
5. **Feed flow to SG #1** decreases in response to the level error input to the SG water level control system. The steady-state feed/steam error is equal to the primary-to-secondary leak rate.
6. **Generator load** decreases in response to OTΔT runbacks. The OTΔT setpoint is greatly reduced by the decrease in pressurizer pressure. In the turbine EHC system each runback is accomplished by the reduction of the load demand by ~ 5% in a 2.3-sec interval; runbacks continue every 30 sec as long as the runback condition persists.
7. The reactor trips (indicated by the step drop in **bank D rod position**) on low pressurizer pressure. The OTΔT trace shows that the OTΔT setpoint was not exceeded.
8. The low pressurizer pressure (1807-psig setpoint) SI actuation (as indicated by the perturbation in **charging flow**) occurs a few seconds after the reactor trip.

Point Explanation

9. **Pressurizer pressure** decreases even faster after the pressurizer empties. Also contributing to the pressure drop at this point are the continued inventory loss and coolant volume contraction as T_{avg} is brought to the no-load value.

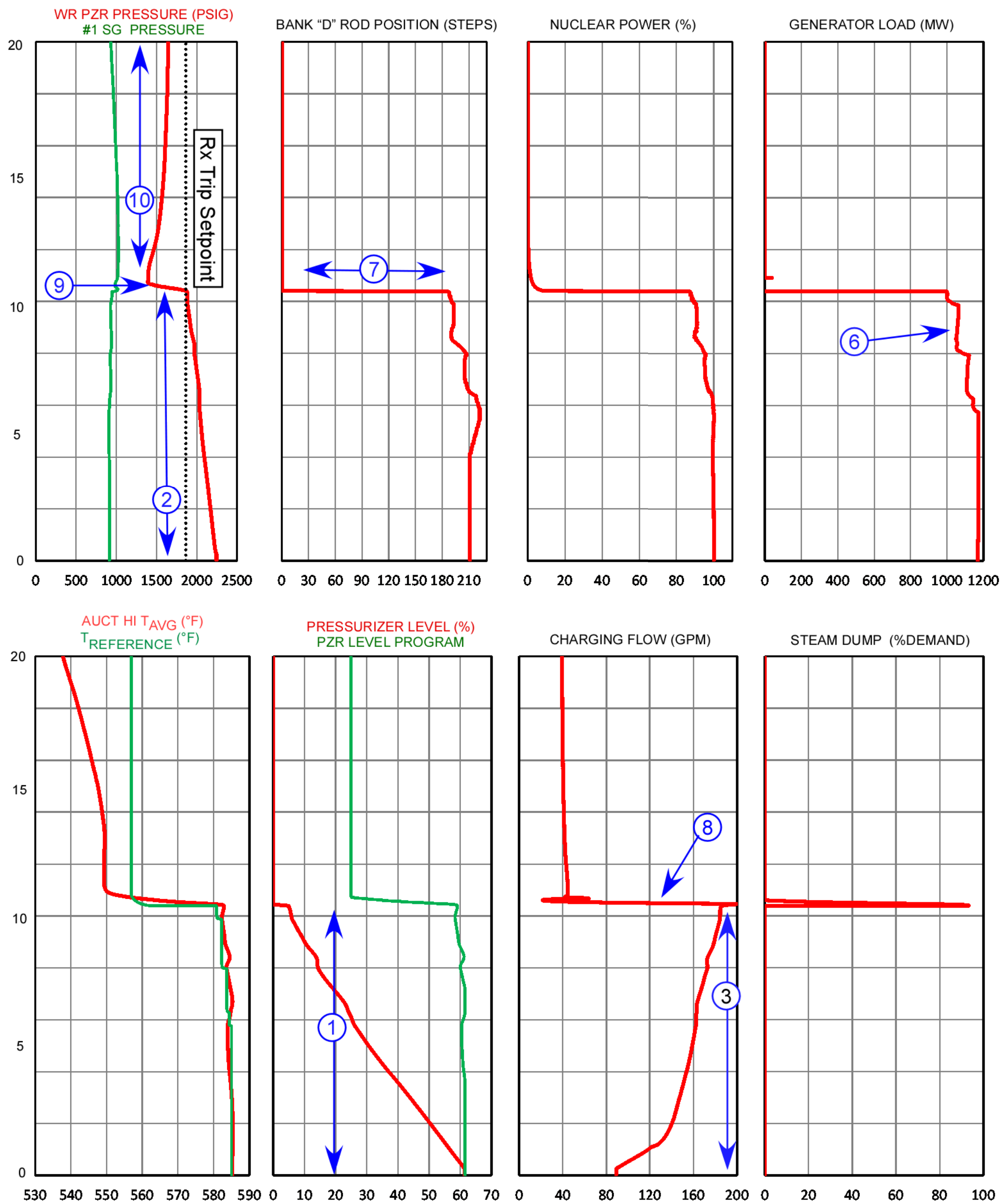
10. **Pressurizer pressure** recovers as total ECCS flow from the CCPs and the safety injection pumps exceeds the flow through the tube rupture. The decrease in RCS pressure has both increased injection flow and reduced the driving force for tube leakage.

11. **BIT flow** and **RCS leak flow** are approaching an equilibrium where RCS leak flow will equal ECCS flow.

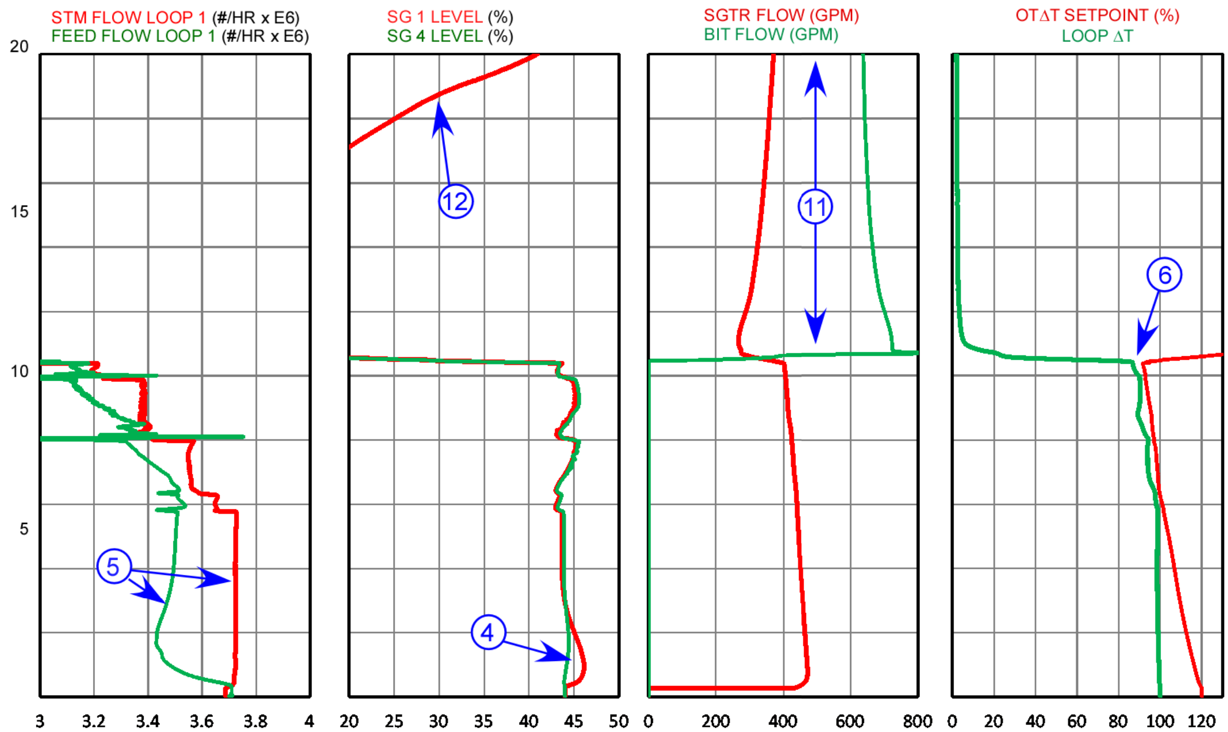
12. **Steam generator level in SG #1** increases faster than the other steam generators because it is filling with AFW flow and reactor coolant leakage, while the other 3 SGs are filling with AFW flow alone.

What this transient illustrates:

1. The loss of inventory from the RCS and the reduction in RCS pressure associated with an SGTR, and the resulting protection system responses.
2. A low pressurizer pressure SI actuation and the characteristic response of charging flow.
3. OTΔT runbacks.
4. The filling of the RCS and the SGs by ESF systems.
5. Pressurizer pressure reaches an equilibrium after the trip where RCS leak flow = ECCS flow.



Transient 5.75 SGTR In SG #1



TRANSIENT 5.75
SGTR IN SG 1

Initial Conditions
BOL
Rated Thermal Power
All control systems in automatic

Initiating Event:
Tube rupture in SG 1

Transient 5.75 SGTR In SG #1

Transient 5.76 Cold-Leg Break

Initial Conditions:

BOL
Rated Thermal power
All control systems in automatic

Initiating Event: 10,000-gpm break in cold leg of loop #1

Failure of fast transfer to offsite power when the main generator trips

Point **Explanation**

1. **Pressurizer level** drops rapidly with the loss of coolant inventory from the RCS.
2. **Pressurizer pressure** decreases rapidly with the expansion of the pressurizer steam bubble and then complete emptying of the pressurizer.
3. The reactor trips (indicated by the negative reactivity) on low pressurizer pressure. The low pressurizer pressure reactor trip uses a lead/lag compensated signal. The first 30 second close-up shows that the lead/lag signal reaches the trip setpoint of 1865 psig when PZR pressure is still well above 2100 psig.
4. **Wide Range RCS pressure** "hangs up" at ~ 1000 psig. The saturation temperature for this pressure is ~ 540°F; a great deal, if not all, of the reactor coolant has reached saturation. This means that flashing is occurring in the RCS, and the formation of steam bubbles holds up the pressure decrease.
5. **RCS pressure** drops below the pressure of the steam generators, indicating that the steam generators are hotter than the RCS. The steam generators are a heat source, not a heat sink. Decay heat is being removed by a combination of break flow and ECCS flow.
6. **Liquid break flow** drops as break begins to vent steam. (The break "uncovers.")
7. Full Range RVLIS shows that some core uncovery is required to vent steam out the break when the break is in the cold leg. Note that venting steam out the break causes some recovery in core level. Also, the additional energy release from the steam flow begins an RCS cooldown (WR T_{cold}), which allows RCS pressure to drop.
8. B**reak flow** and **makeup flow** reach an equilibrium where break flow equals makeup flow.
9. **Containment pressure** increases rapidly as the hot coolant is released into the containment volume.

Point Explanation

10. **Containment pressure** decreases as the containment fan coolers remove heat from and condense steam in the containment volume.

11. **BIT flow** shows sequential starts of the HHSI pumps. The first start occurs when SI is first initiated. The pumps then trip on loss of offsite power and subsequently start as loads are sequenced on the emergency diesel generators.

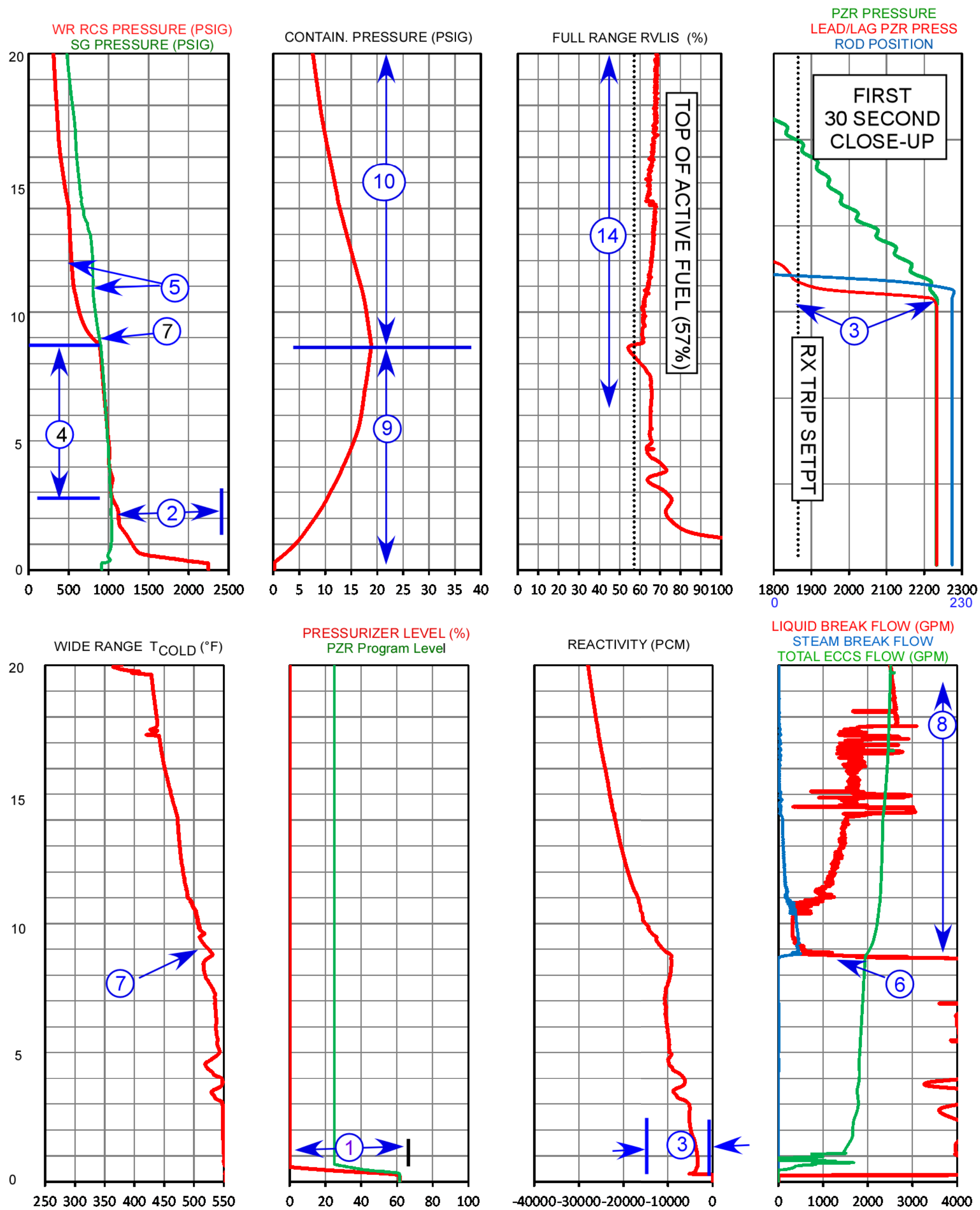
12. **Safety injection system flow** at first increases rapidly with the initiation of safety injection. The RCS depressurizes quickly such that both CCPs and SI pumps are injecting. SI system flow then gradually increases as the pump discharge pressure decreases (characteristic of centrifugal pumps).

13. The drop in **cold-leg accumulator level** reflects the discharge from the accumulators when the RCS pressure falls below the accumulator nitrogen cover pressure (600 psig).

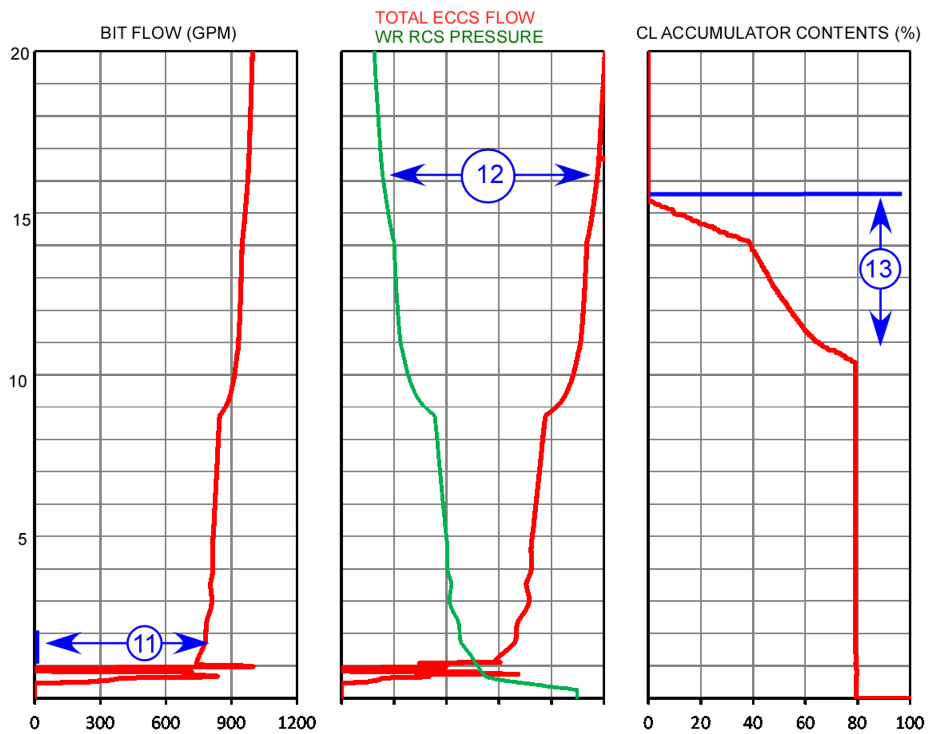
14. **Full Range RVLIS** shows that RCS inventory is at an equilibrium where break flow equals makeup flow. The core is in a pool boiling regime where the only water entering the core from the vessel downcomer is replacing the water that is boiled away. The great majority of ECCS flow is bypassing the core and going out the break. During a cold leg LOCA, boric acid concentration builds up as a result of the pool boiling regime until hot leg injection begins.

What this transient illustrates:

1. The loss of inventory from the RCS and the reduction in RCS pressure associated with a LOCA, and the resulting protection system responses.
2. For larger RCS breaks, the SGs no longer serve a heat removal function. This condition occurs when RCS pressure drops below SG pressure. At this point, natural circulation of water through the SGs stops.
3. The development of saturated conditions in the RCS.
4. The beneficial effect of venting steam out the break.
5. The responses of the ECCSs and the different pressures at which they inject.
6. The reduction in containment pressure due to containment fan cooler operation.
7. Pool boiling in the core following a LOCA in the cold leg.



Transient 5.76 Cold-Leg Break



TRANSIENT 5.76
COLD LEG BREAK

Initial Conditions
BOL
Normal operating temperature and pressure
Rated Thermal Power

Initiating Event:
10,000-gpm break in cold leg of loop #1
Failure of fast transfer to offsite power when the main generator trips

Transient 5.76 Cold-Leg Break

Transient 5.77 Loss-Of-Feedwater ATWS

Initial Conditions:

BOL
Rated Thermal Power
Reactor trip breakers are failed in the closed position
All control systems in automatic

Initiating Event: Feedwater isolation

Point **Explanation**

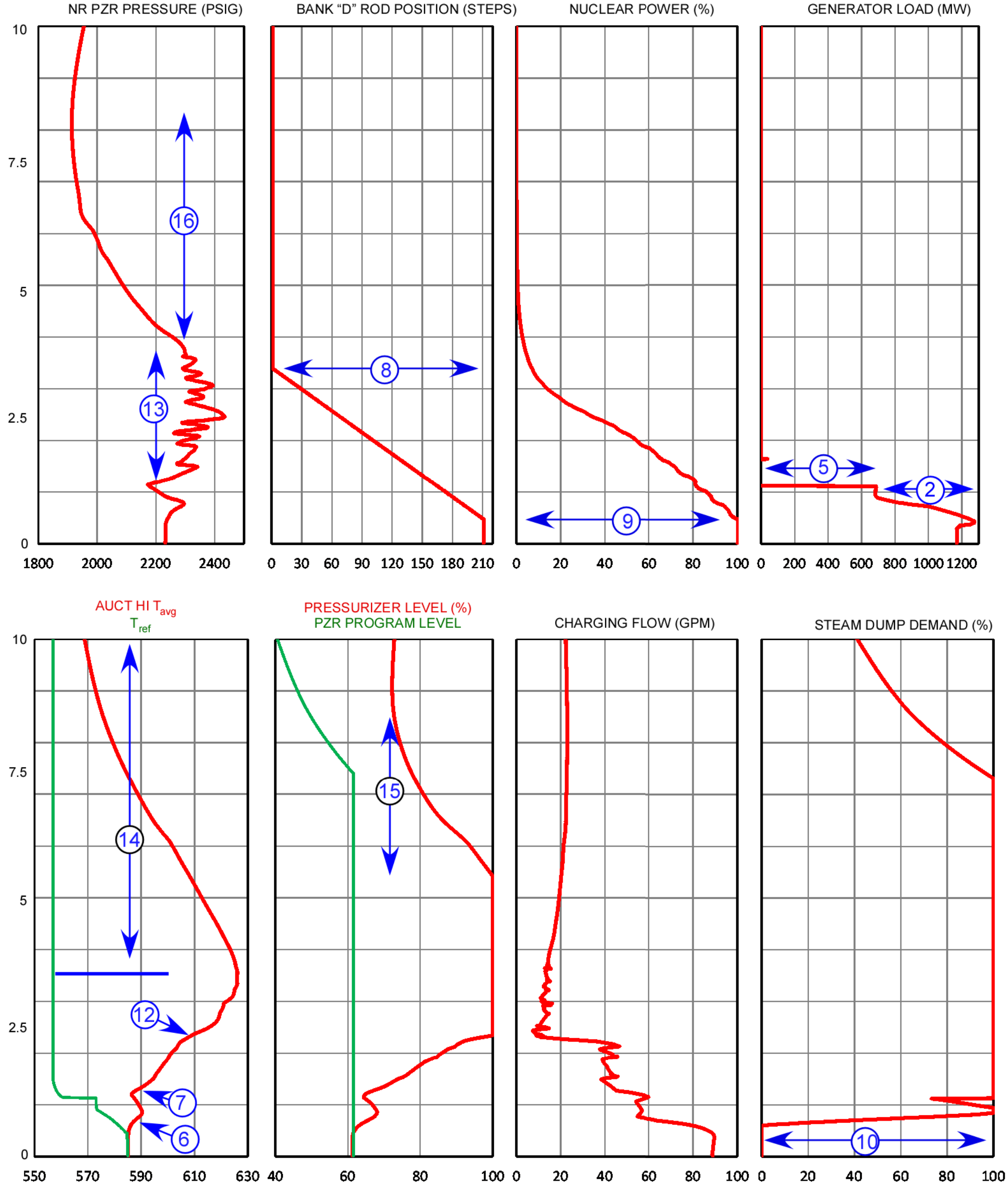
1. **Feed flow** drops to 0 rapidly with the feedwater isolation.
2. **Generator load** decreases rapidly with the turbine setback (acts through the load limit circuit) initiated by the feed pump trips.
3. **Steam generator level** rapidly decreases as a result of the stoppage of feed flow and continued steaming.
4. **Feed flow** comes back on scale with the initiation of AFW on the trip of both main feed pumps.
5. **Generator load** drops to 0 when the turbine is tripped by the ATWS mitigation system actuation circuit (AMSAC). 25 sec after 3 of the SG levels reach the low-low level setpoint, AMSAC trips the turbine and actuates AFW.
6. **T_{avg}** increases with the power mismatch resulting from continued nuclear power generation and the turbine setback, then drops because of control rod insertion.
7. **T_{avg}** increases the 2nd time when the turbine trips.
8. **Bank D rod position** decreases as the rod control system inserts the rods at the maximum rate (72 steps/min) in response to large inputs from the power mismatch circuit (setback and turbine trip) and from the temperature mismatch circuit ($T_{avg} >> T_{ref}$).
9. **Nuclear power** decreases rapidly due to the negative reactivity associated with the rod insertion and the coolant temperature increase.
10. **Steam dump demand** rapidly increases to maximum with the large T_{avg} - T_{ref} difference. The steam flow graph indicates that the dumps are armed by a loss-of-load arming signal.
11. **Steam flow** and **steam pressure** decrease as the SG inventories are boiled off to near empty. The rapid rate of the pressure drop causes the lead/lag steam pressure to drop below 600 psig. This, combined with the steam flow through the steam dumps causes a safety injection and a steam line isolation.
12. The increase in **T_{avg}** accelerates as the SG heat sink is almost completely gone.

Point Explanation

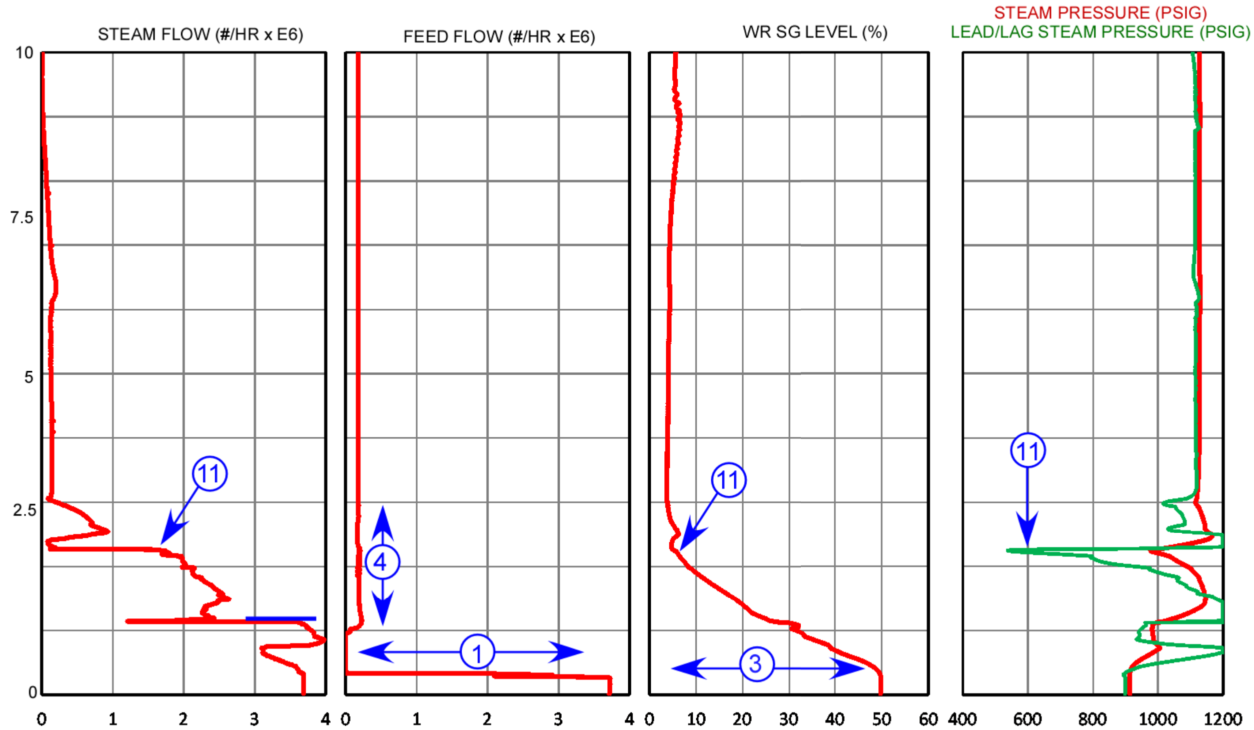
13. **PZR pressure** reflects PORV lifts as the pressurizer is full or nearly full and coolant temperature is still increasing.
14. **T_{avg}** decreases when control rod insertion lowers reactor power to < the capacity of the AFW system (~7%). The steam generators are now able to remove the heat produced by the core.
15. **Pressurizer level** drops back to the indicating range due to the RCS cooldown. The cooldown is reducing RCS volume faster than BIT flow can overcome.
16. **PZR pressure** drops when Tavg begins to drop.
17. The rapid increase in **BIT flow** reflects the SI actuation.
18. Control rod motion eventually drives the reactor substantially subcritical. BIT flow assists in driving the reactor subcritical. Note that early in the transient it is hard to get the reactor to deviate from criticality as doppler resists the change in power (DOPC adding $+\rho$). It isn't until the rapid heatup that net reactivity becomes significantly negative.

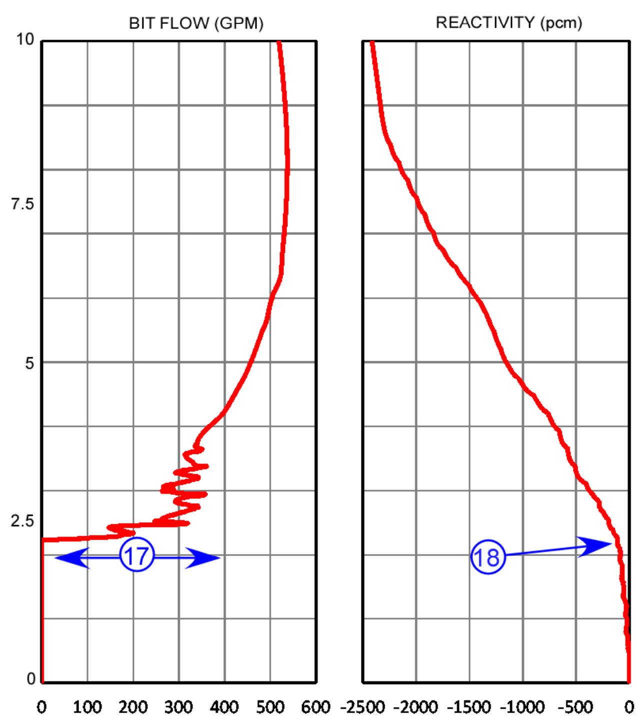
What this transient illustrates:

1. The large reduction in heat removal capability with the loss of main feedwater, and the inability of AFW alone to hold T_{avg} at normal operating values at high reactor powers.
2. A Safety Injection actuation and the responses of ESF systems.
3. The development of solid plant conditions due to overheating and overfilling of the RCS.
4. A turbine setback caused by the loss of a main feed pump.
5. The reactor achieves and maintains subcriticality even with the failure of the reactor protection system and no operator action. The safety significance of this transient is the challenge to RCS integrity due to the severe overpressure transient during the initial RCS heatup. Fuel integrity is not challenged in this event.



Transient 5.77 Loss-Of-Feedwater ATWS





TRANSIENT 5.77
LOSS OF FEED ATWS - BOL

Initial Conditions

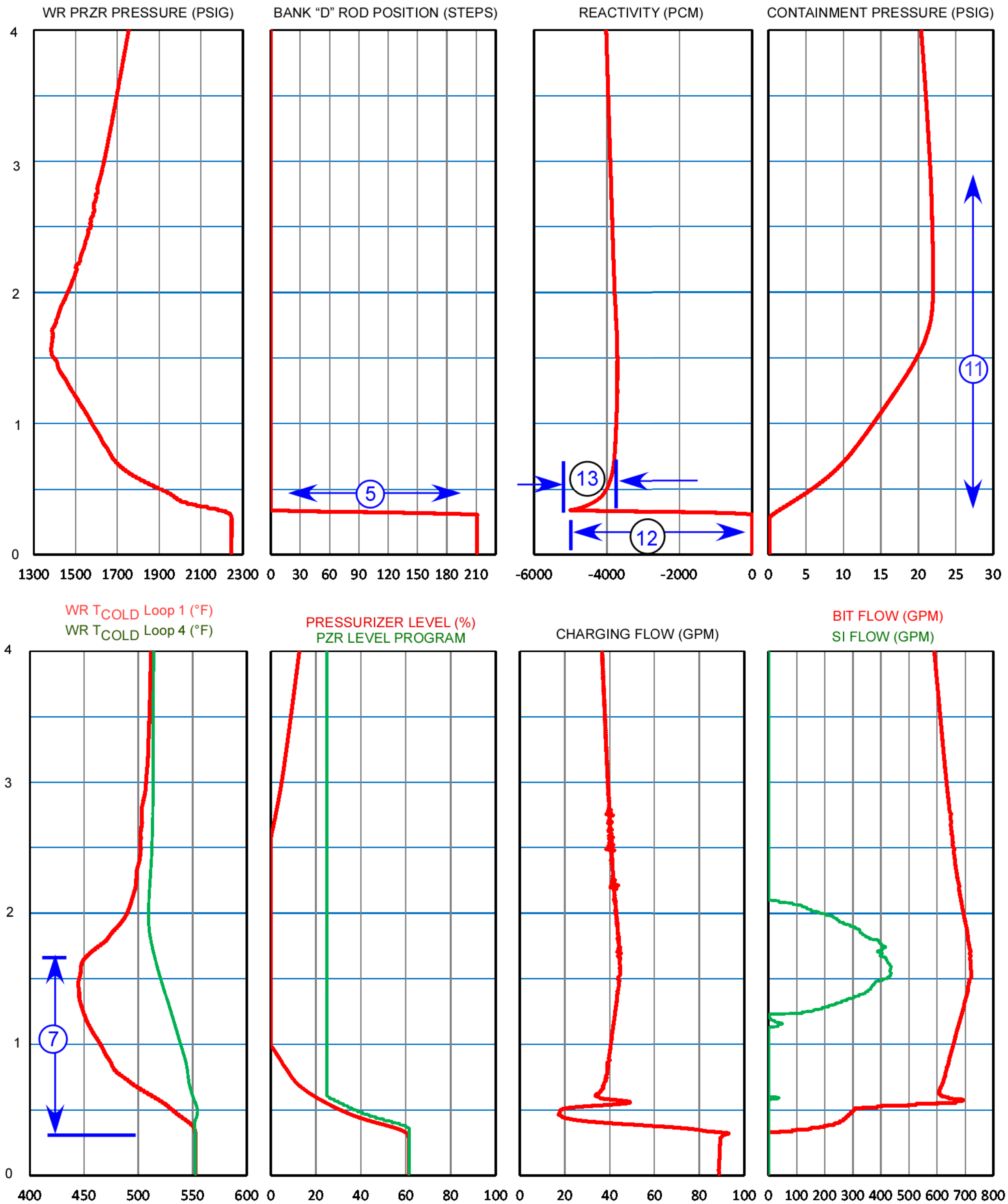
BOL
Rated thermal power
All control systems in automatic
Reactor trip breakers are failed in the closed position

Initiating Event:

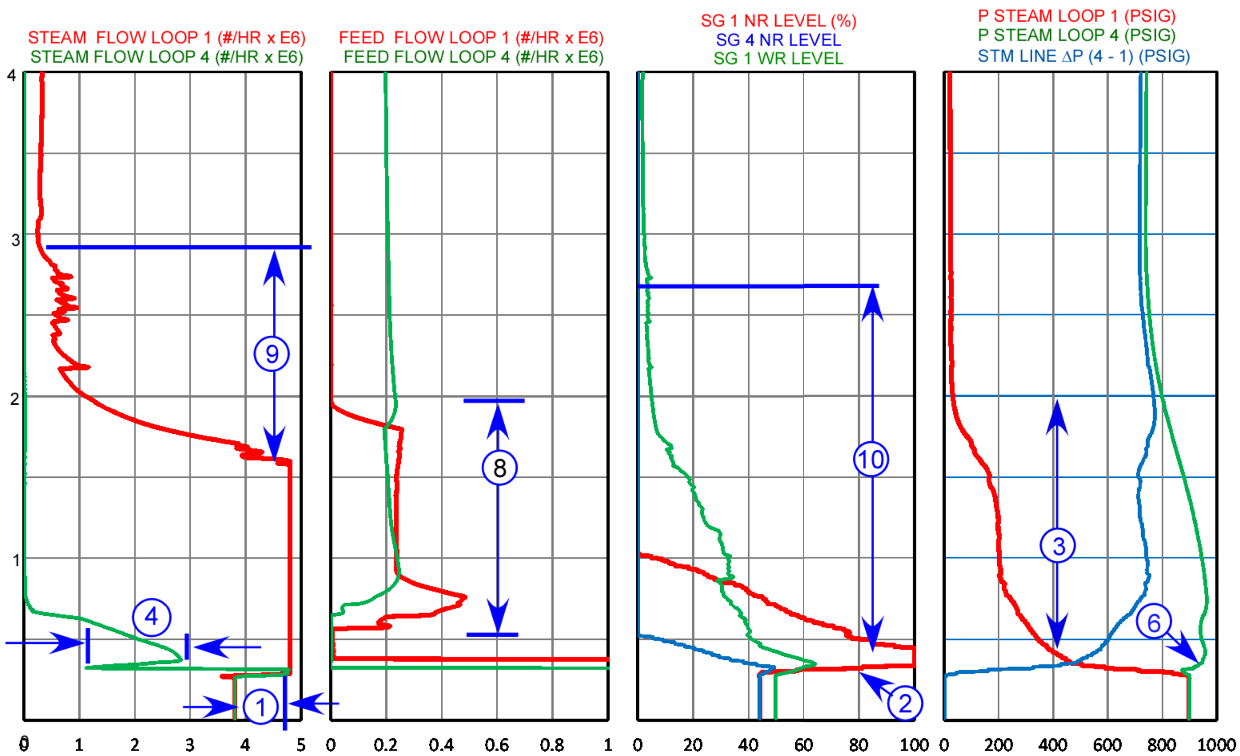
Feedwater isolation

Transient 5.77 Loss-Of-Feedwater ATWS

Exercise 1


WR PRZR PRESSURE (PSIG)
BANK "D" ROD POSITION (STEPS)
REACTIVITY (PCM)
CONTAINMENT PRESSURE (PSIG)
4
3
2
1
0
1300 1500 1700 1900 2100 2300
0 30 60 90 120 150 180 210
-6000 -4000 -2000 0
0 5 10 15 20 25 30
5
13
12
11
WR TCOLD Loop 1 (°F)
WR TCOLD Loop 4 (°F)
PRESSURIZER LEVEL (%)
PZR LEVEL PROGRAM
CHARGING FLOW (GPM)
BIT FLOW (GPM)
SI FLOW (GPM)
7
400 450 500 550 600
0 20 40 60 80 100
0 20 40 60 80 100
0 100 200 300 400 500 600 700 800

Exercise 1 (cont.)



What was the initiating event?

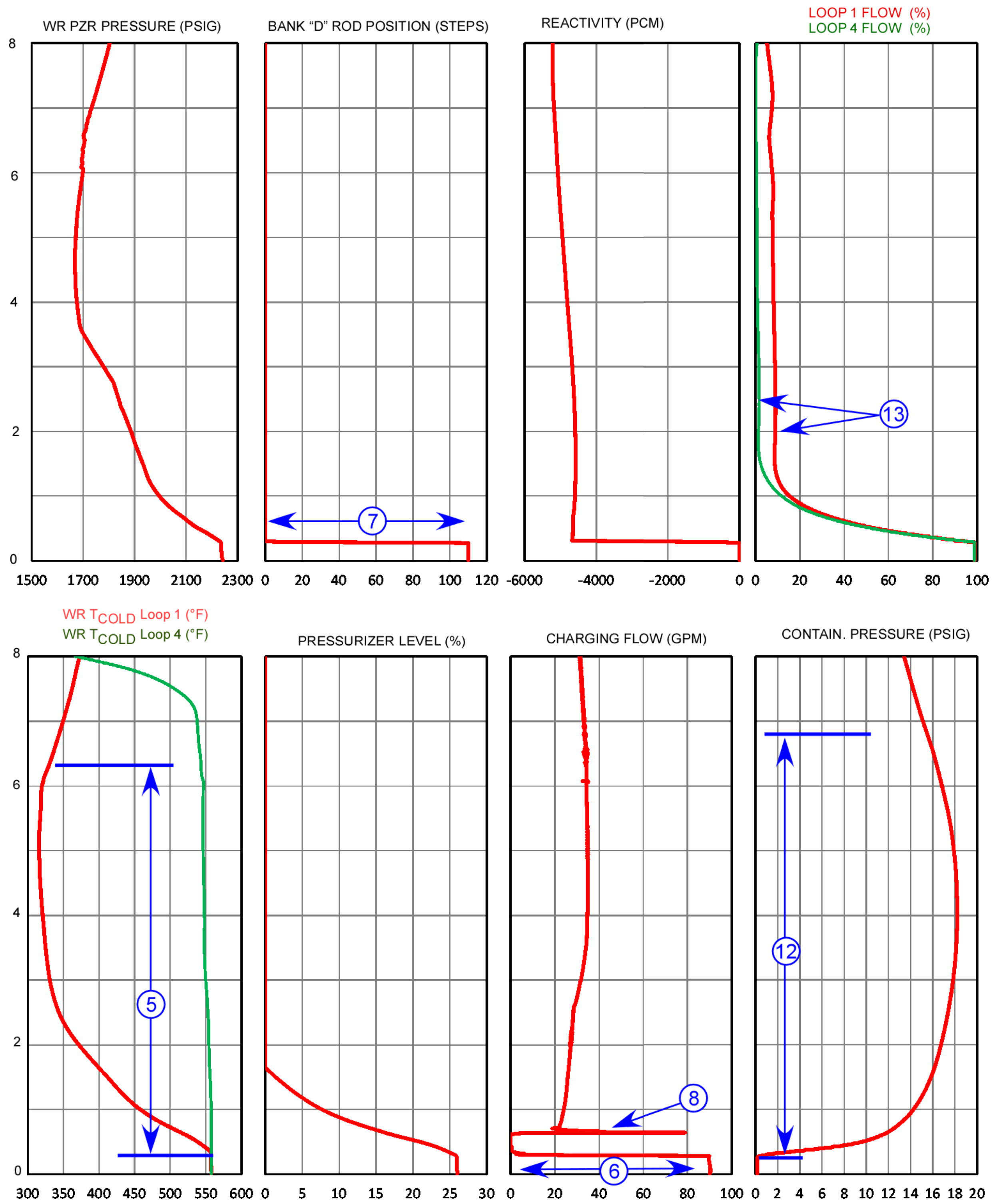
What signal caused the reactor trip?

What evidence supports your conclusion in the previous question?

At one point, Loop 4 cold is 514°F with a saturation pressure of 841 psia. At the same time, Loop 4 SG pressure is 900 psia. What is the significance of this?

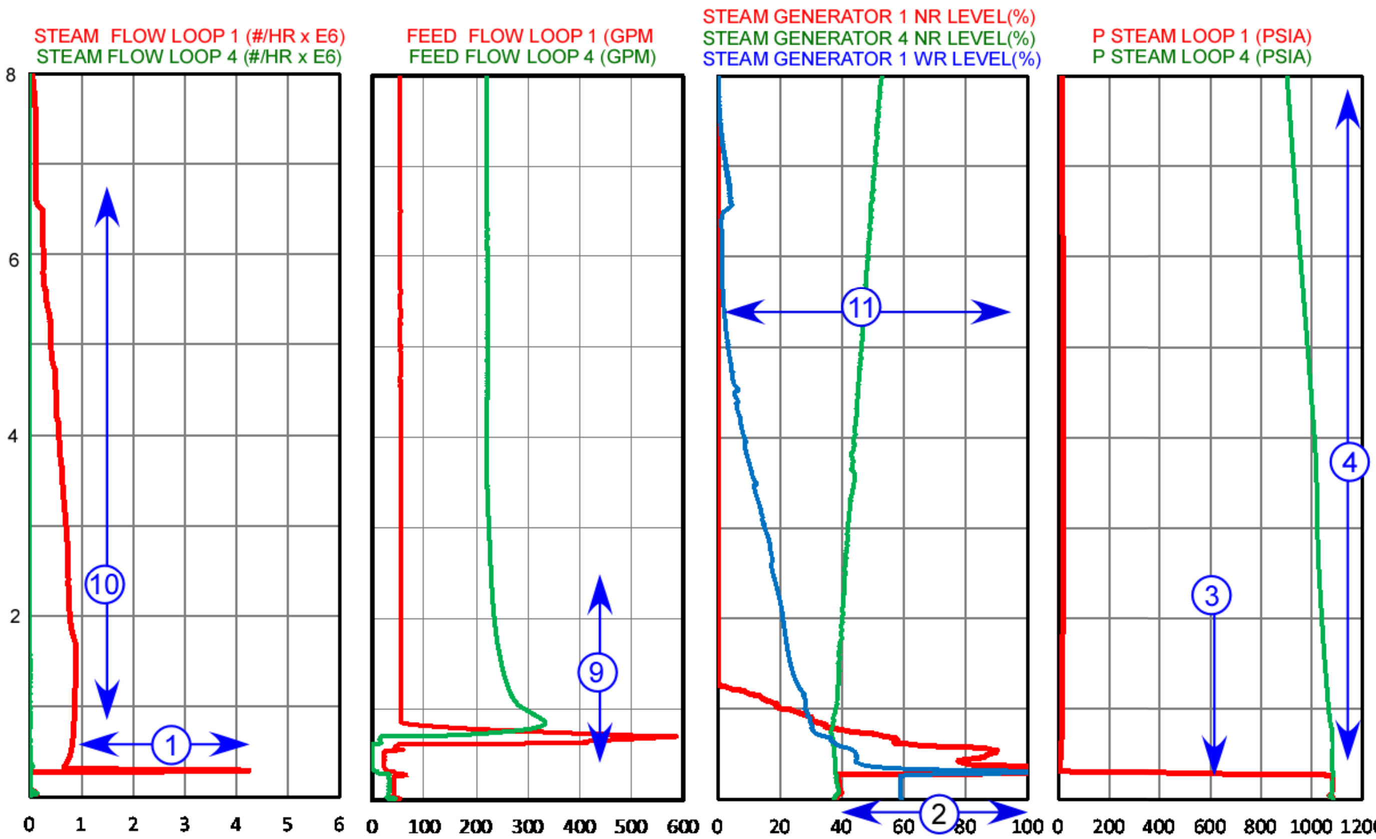
Explain the trend at each numbered point.

Exercise 2



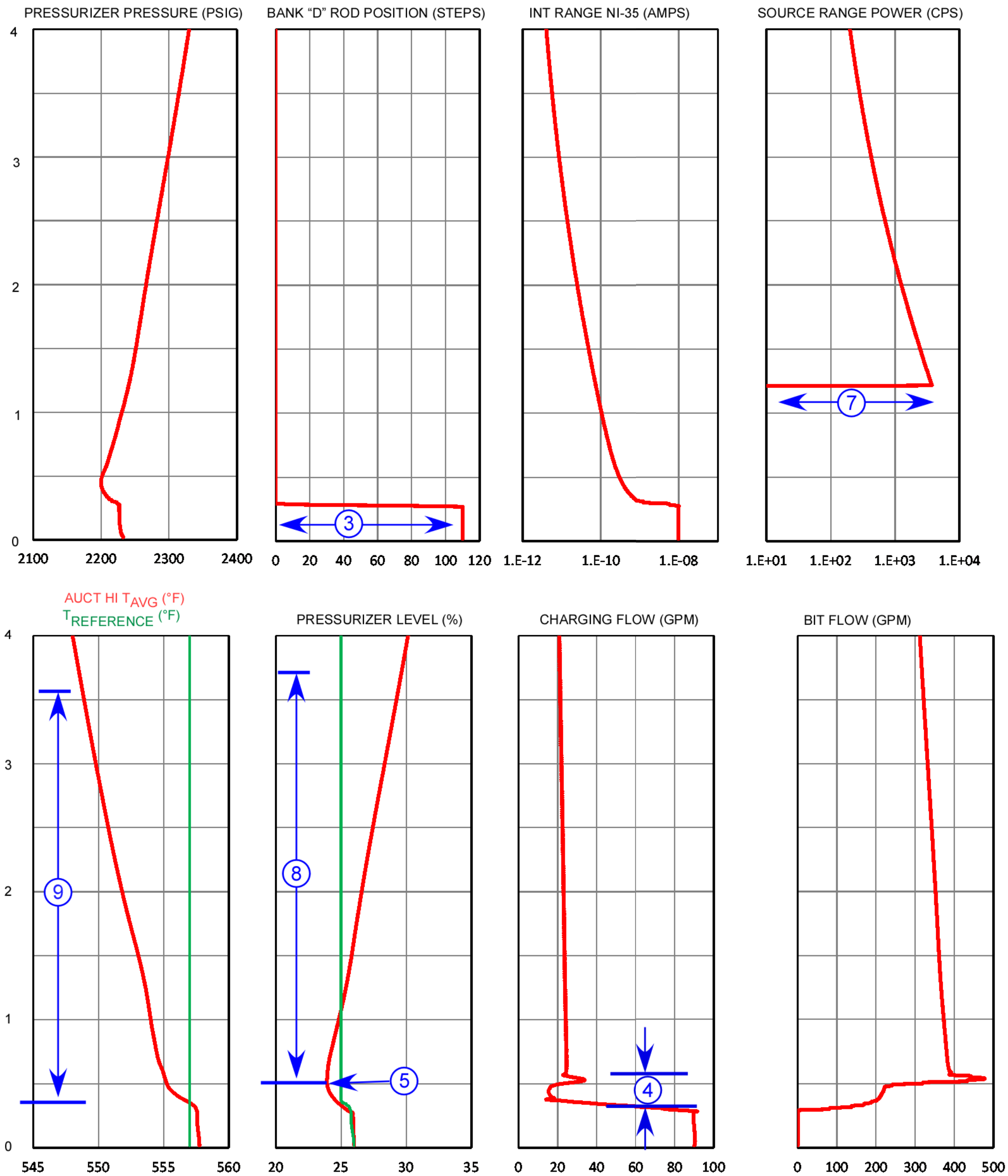
WR PZR PRESSURE (PSIG)
BANK "D" ROD POSITION (STEPS)
REACTIVITY (PCM)
LOOP 1 FLOW (%)
LOOP 4 FLOW (%)
8
6
4
2
0
1500 1700 1900 2100 2300
0 20 40 60 80 100 120
-6000 -4000 -2000 0
0 20 40 60 80 100
7
13
WR TCOLD Loop 1 (°F)
WR TCOLD Loop 4 (°F)
PRESSURIZER LEVEL (%)
CHARGING FLOW (GPM)
CONTAIN. PRESSURE (PSIG)
300 350 400 450 500 550 600
0 5 10 15 20 25 30
0 20 40 60 80 100
0 2 4 6 8 10 12 14 16 18 20
5
8
6
12

Exercise 2 (cont.)



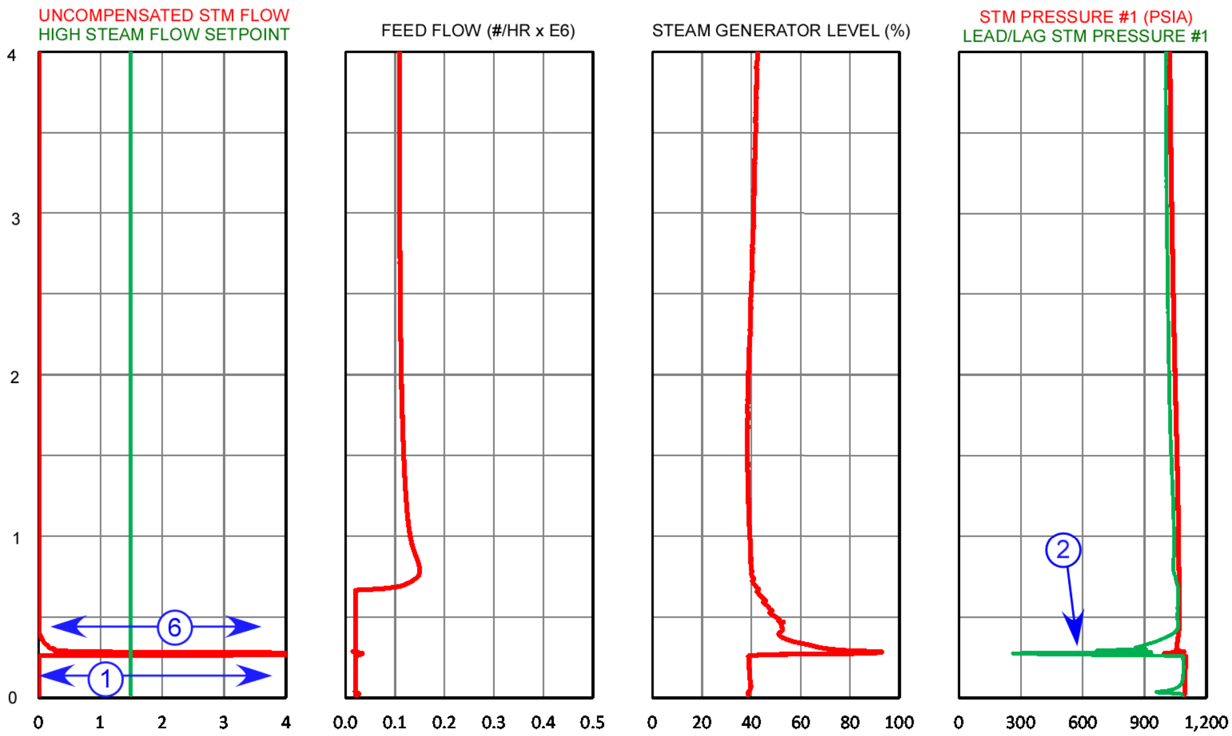
How is the initiating event different than in Exercise #1?
Why is the cooldown so much larger than in Exercise #1
Compare the elapsed time with Exercise #1. Why so slow?
Explain the trends at the numbered points.

Exercise 3



PRESSURIZER PRESSURE (PSIG)
BANK "D" ROD POSITION (STEPS)
INT RANGE NI-35 (AMPS)
SOURCE RANGE POWER (CPS)
4
3
2
1
0
2100
2200
2300
2400
0
20
40
60
80
100
120
1.E-12
1.E-10
1.E-08
1.E+01
1.E+02
1.E+03
1.E+04
3
7
AUCT HI T_{AVG} (°F)
$T_{REFERENCE}$ (°F)
PRESSURIZER LEVEL (%)
CHARGING FLOW (GPM)
BIT FLOW (GPM)
545
550
555
560
20
25
30
35
0
20
40
60
80
100
0
100
200
300
400
500
9
8
5
4

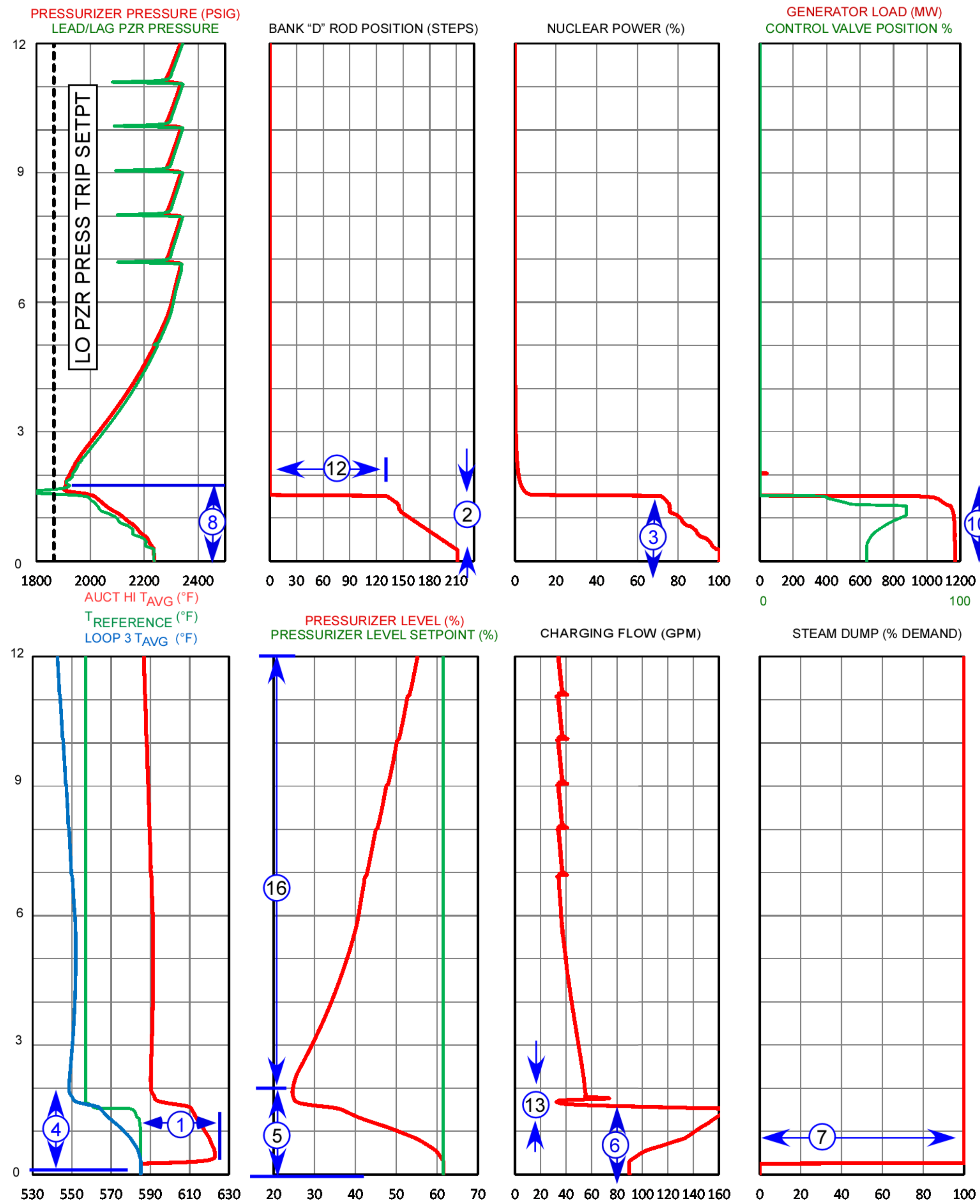
Exercise 3 (cont.)



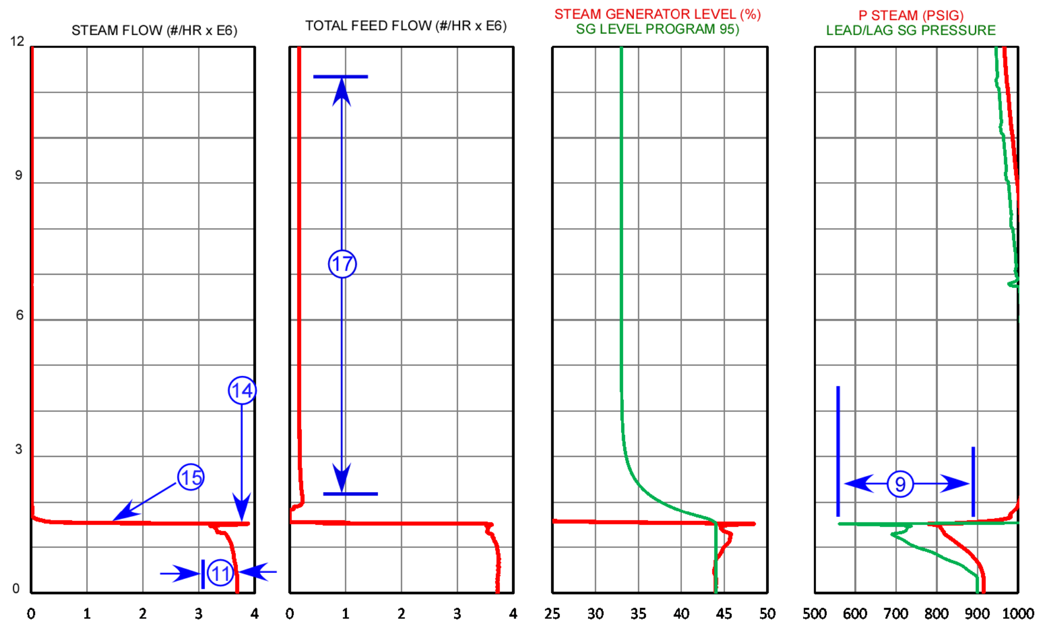
What is the initiating event?

Explain the trends at the numbered points.

Exercise 4


PRESSURIZER PRESSURE (PSIG)
LEAD/LAG PZR PRESSURE
LO PZR PRESS TRIP SETPT
BANK "D" ROD POSITION (STEPS)
NUCLEAR POWER (%)
GENERATOR LOAD (MW)
CONTROL VALVE POSITION %
AUCT HI TAVG (°F)
TREFERENCE (°F)
LOOP 3 TAVG (°F)
PRESSURIZER LEVEL (%)
PRESSURIZER LEVEL SETPOINT (%)
CHARGING FLOW (GPM)
STEAM DUMP (% DEMAND)
1
2
3
4
5
6
7
8
10
12
13
16

Exercise 4 (cont.)

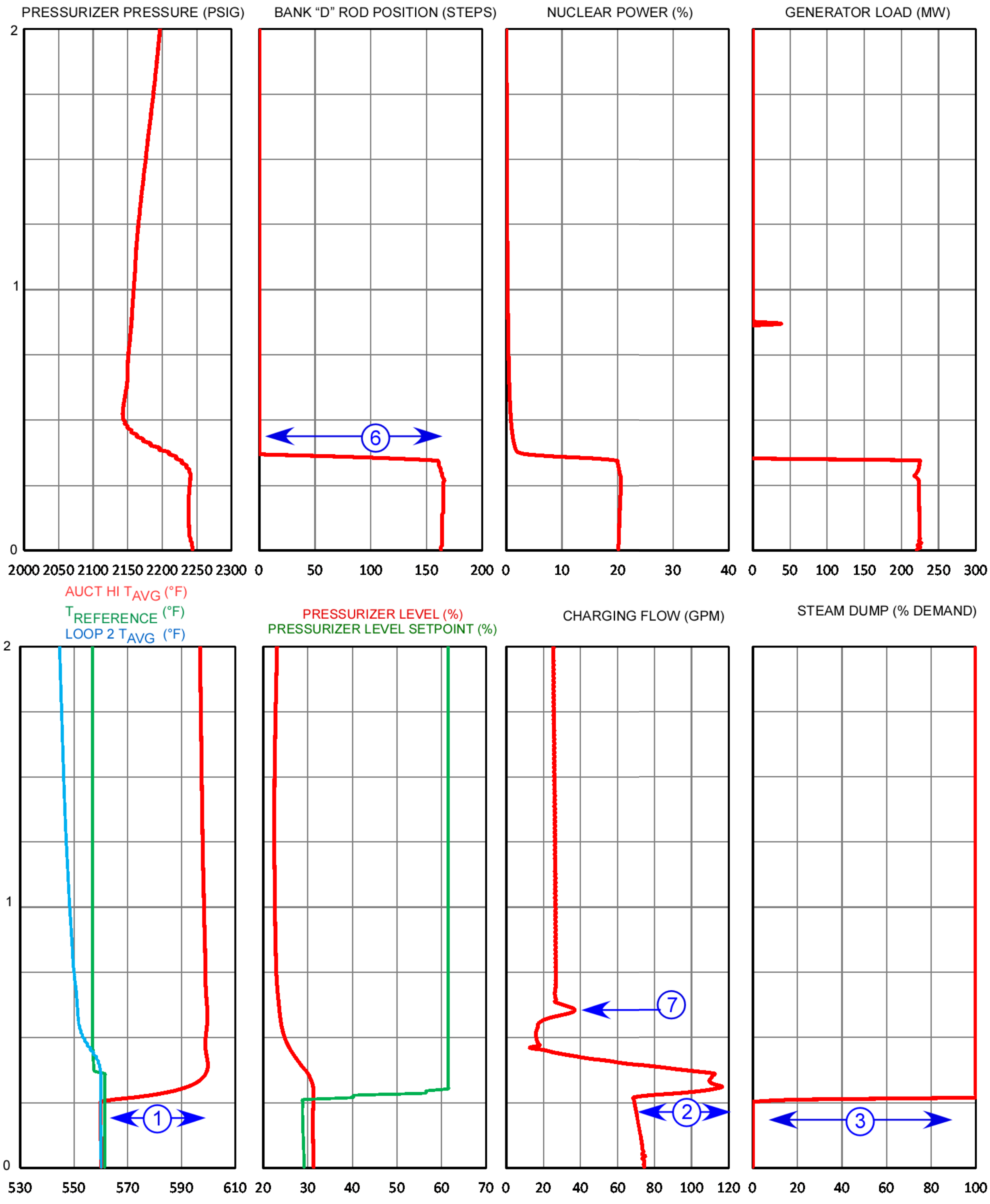


What was the initiating event?

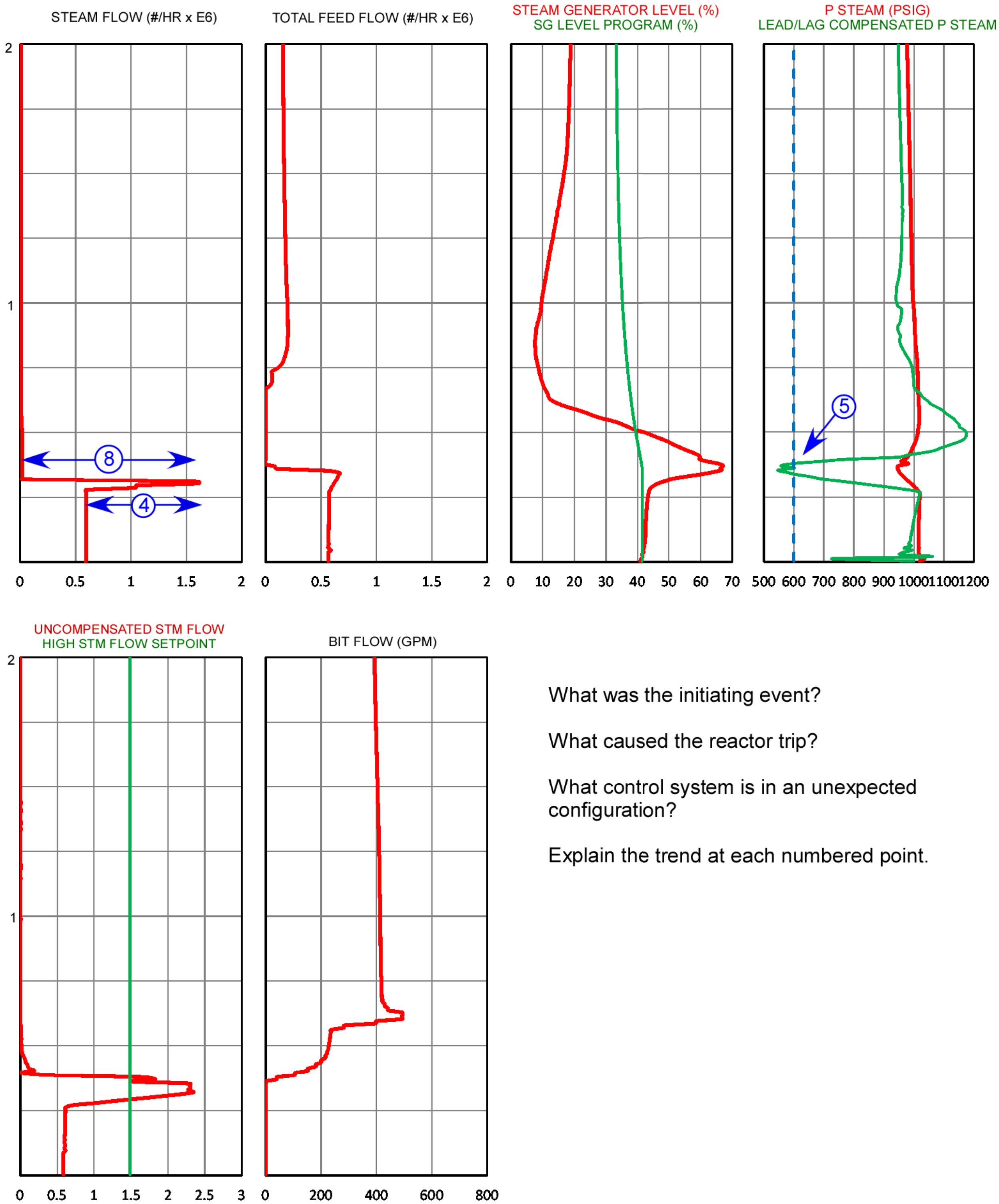
What was the cause of the reactor trip?

Explain the trends at each numbered point.

Exercise 5


PRESSURIZER PRESSURE (PSIG)
BANK "D" ROD POSITION (STEPS)
NUCLEAR POWER (%)
GENERATOR LOAD (MW)
2
1
0
2000 2050 2100 2150 2200 2250 2300
0 50 100 150 200
0 10 20 30 40
0 50 100 150 200 250 300
6
AUCT HI TAVG (°F)
TREFERENCE (°F)
LOOP 2 TAVG (°F)
PRESSURIZER LEVEL (%)
PRESSURIZER LEVEL SETPOINT (%)
CHARGING FLOW (GPM)
STEAM DUMP (% DEMAND)
530 550 570 590 610
20 30 40 50 60 70
0 20 40 60 80 100 120
0 20 40 60 80 100
1
2
3
7

Exercise 5 (cont.)



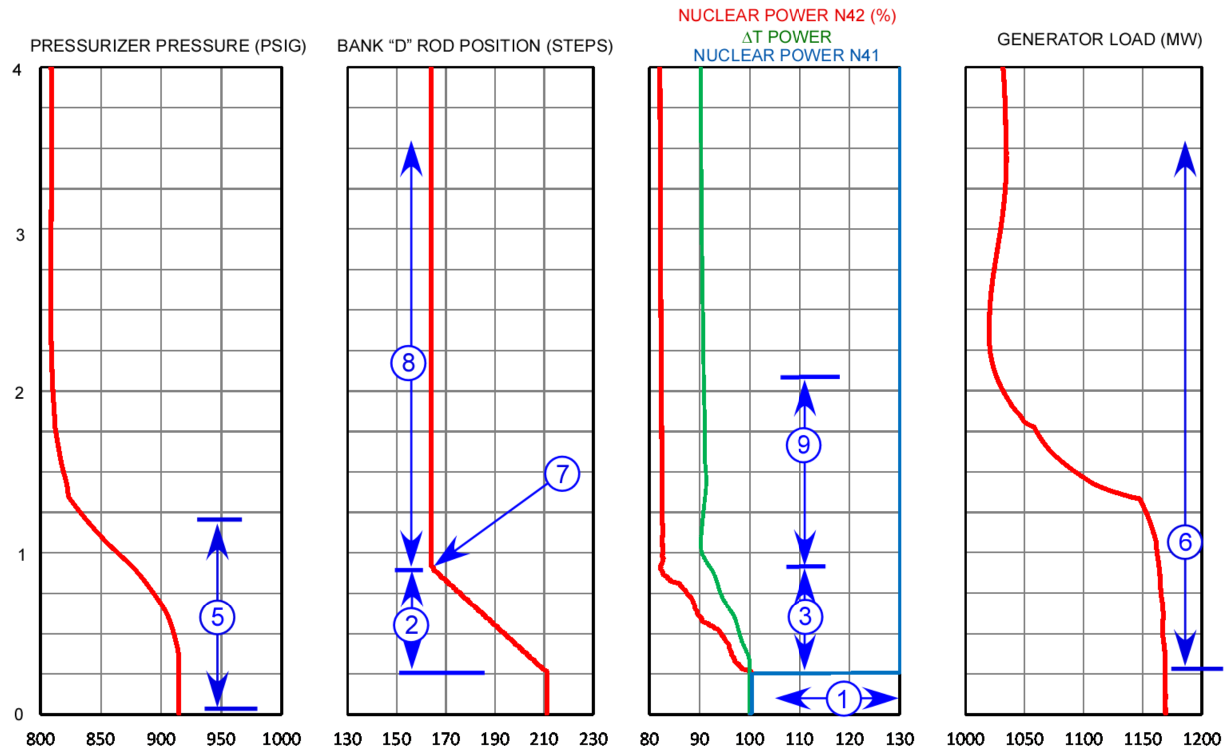
What was the initiating event?

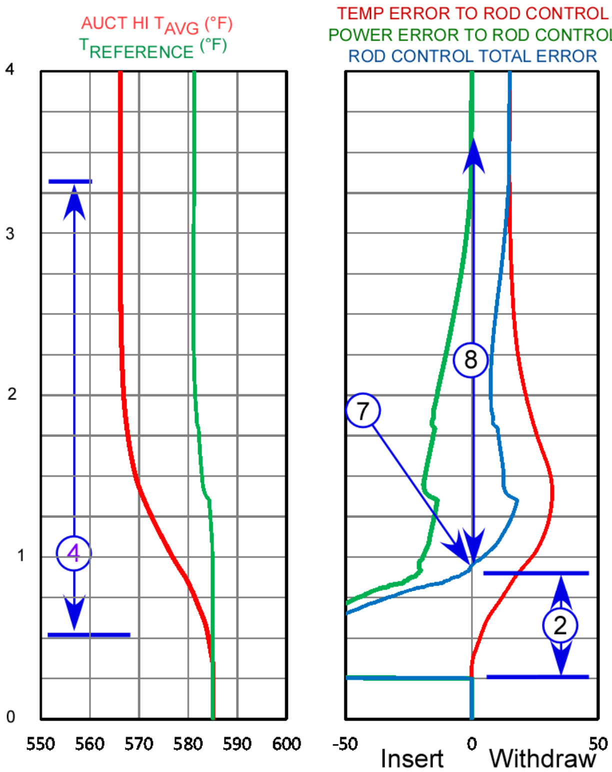
What caused the reactor trip?

What control system is in an unexpected configuration?

Explain the trend at each numbered point.

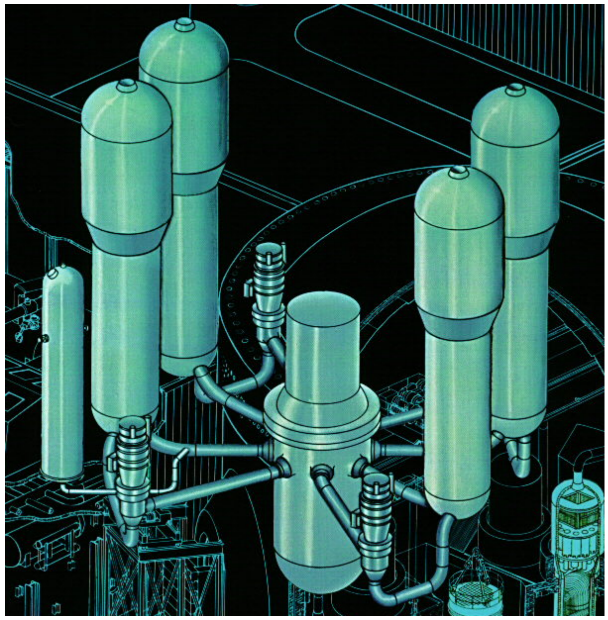
Exercise 6





What was the initiating event?

Explain the trend at each numbered point.



Westinghouse Advanced Technology Manual

Chapter 7.1 – Events That Shaped the Nuclear Industry

2020

HRTD Human Resources Training & Development
U.S.NRC UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Chapter 7.1 – Events That Shaped the Nuclear Industry

Learning Objectives:

1. Briefly discuss these events.
2. Explain the causes of the events.
3. Explain the safety implications of the events.
4. Explain what industry or regulatory changes occurred as a result of the events.

Top Industry-Shaping Events

Individuals are who they are because of many influences - heredity, environment, experiences, and others. Similarly, nations and cultures respond to influences. For example, the U.S. has been shaped by the American Revolution, the War Between the States, the Great Depression, and the attacks on the World Trade Center.

Industries also grow and evolve in response to events.

The question we are attempting to answer here is, "What shaped the U.S. nuclear industry?" Answering this succinctly is a tall order, but the answer is important, especially to the worker that is new to the nuclear industry. Many relevant external factors, such as domestic and international political will, public acceptance, regulation, timing, and momentum will be excluded from the answer, though clearly there is value in considering them for a complete picture. Rather, we focus on the industry's response to its own performance by identifying key events that sparked substantial change.

The 24 events included here occurred after 1975, during a time of great industry growth, consolidation, and maturation. These events caused reaction across the industry - they could not be ignored, and industry leaders consider themselves vulnerable to similar occurrences. The events were significant enough that to allow them to happen again for lack of response was unacceptable. Hence, remarkable actions were taken to prevent recurrence.

The descriptions of these events do not include much detail. Indeed, the purpose of each article is not to expound upon the event but rather to show how the nuclear industry changed as a result. The descriptions are short enough to hold the reader's attention, long enough to convey the significance of the issue, and interesting enough to prompt the reader reaction "tell me more." Our desire is for this project to be used across the nuclear industry to help shape the culture of a new workforce and to remind the existing workforce of how and why we are what we are.

Events That Shaped the Industry

Listed by Event Date

1970s
Browns Ferry 1 - Fire results in the loss of safety-related components. (March 1975)

TMI 2 - Loss of coolant accident with major fuel damage. (March 1979)

1980s
Crystal River - Improper SG level control, loss of heat sink, and operator uncertainty following loss of instrumentation power supply and stuck-open PORV. (February 1980)

St. Lucie 1 - Natural circulation cooldown. (June 1980)

Browns Ferry 3 - Control rods fail to insert following a scram. (June 1980)

Salem 1 - Reactor trip breakers fail to actuate. (February 1983)

ANO 1 - Improper rod recovery leads to fuel damage. (September 1983)

Connecticut Yankee - Reactor cavity seal failure. (August 1984)

V.C. Summer - Premature criticality during startup because of inaccurate ECT and monitoring. (February 1985)

Davis-Besse - Loss of main and auxiliary feedwater. (June 1985)

Chernobyl 4 - Reactor Explosion. (April 1986)

Surry 2 - Feedwater line rupture. (December 1986)

Diablo Canyon 2 - Extended loss of RHR during steam generator maintenance. (April 1987)

LaSalle 2 - Scram following neutron flux oscillations. (March 1988)

Connecticut Yankee - Significant fuel damage. (October 1989)

1990s
Vogtle 1 - Loss of shutdown cooling due to switchyard work. (March 1990)

Nine Mile 1 - Special testing of the main turbine. (August 1990)

Palo Verde 2 - Steam generator tube rupture. (March 1993)

Millstone 2 - Repeated sealant injections to repair an unisolable primary system valve. (August 1993)

Salem 1 - Reactor scram and safety injection following marsh grass blockage of intake. (April 1994)

Zion 1 - Reactivity mismanagement during a shutdown. (February 1997)

Oconee 3 - Potential loss of high pressure injection and charging from gas intrusion. (March 1997)

2000s
Browns Ferry 3 - Four electricians injured while placing grounds inside a 4kV unit board. (March 2002)

Davis-Besse - Undetected leak and degradation in the reactor vessel head. (March 2002)

Events That Shaped the Industry

Listed by Event Topic

Maintenance and Testing
Browns Ferry 1 - Fire results in the loss of safety-related components. (March 1975)

Salem 1 - Reactor trip breakers fail to actuate. (February 1983)

Surry 2 - Feedwater line rupture. (December 1986)

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Operations and Training
TMI 2 - Loss of coolant accident with major fuel damage. (March 1979) St. Lucie 1 - Natural circulation cooldown. (June 1980)

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1

Fire Results in Loss of Safety-Related Components

March 22, 1975 - Browns Ferry 1 (BWR)

Imagine...It was early in the morning, as plant workers were driving to work. A pall of black smoke hung over the trees. As the plant came into view, the source of the smoke became apparent...it was Browns Ferry Unit 1. One engineer recalled, "I had a sick feeling in the pit of my stomach when I saw the plant. I'll never forget that feeling."

A fire in a cable tray between the Unit 1 reactor building and the cable spreading room caused significant damage to cables related to the control of Unit 1. To a lesser degree, Unit 2 was also affected. The fire resulted in failures of safety systems, and led to the shutdown of both units.

Browns Ferry 1 cable spreading room with melted aluminum cable conduit.

Additional Resources

- INPO 87-014, Material For A Case Study On An In-Plant Cable Fire

This event resulted in new federal regulations for fire protection, entitled 10CFR50, Appendix R - a significant change to the industry.

How It All Started

An engineer used a candle to check for air leaks through a firewall penetration seal in the cable spreading room to the reactor building. Slight deflections in the candle flame indicated air flow associated with leaks. In this case, the penetration seal had been breached for a design modification and was being checked for leaks through a temporary seal before the permanent sealing material was installed. After inserting foam into a noted leak, the engineer placed the candle approximately 1 inch from the foam to check the effectiveness of the added sealant. The airflow from a continuing leak pulled the candle flame into the foam, which sizzled and began to burn. Attempts to extinguish the fire at its origin in the spreading room were ineffective; and the fire, fanned by the draft through the leaking penetration, quickly spread to the reactor building side of the wall.

Effects on Plant Operations

The first indication of the fire's effect was the simultaneous receipt of several alarms in the Unit 1 control room about 20 minutes after the fire started. These alarms confused operators because they conflicted with other indications in the control room. Several safety systems actuated without valid signals. Control board indicating lights pulsated. Smoke came from beneath the control panel. Operators attempted to shut down unneeded equipment, but the equipment restarted. When reactor power on Unit 1 was affected, the operator scrammed the reactor. Following the scram, all capability to monitor core power was lost as the vital power supply electrical control boards were lost. All emergency core cooling

systems were lost because their motor-operated valves lost power and could not be operated. Control power for some equipment and controls was established using temporary jumpers.

Fighting the Fire

Initially, workers fought the fire in the cable spreading room but soon left to fight the fire inside the reactor building. When they arrived at the penetration in the reactor building, they discovered that the fire had spread into the cable tray system about 20 feet above the floor. Their attempts to extinguish the fire were unsuccessful. Community firefighters were delayed helping the station fire fighters while obtaining temporary radiation monitoring badges. They did not arrive at the scene of the fire for 45 minutes after being called. The workers and firefighters initially used carbon dioxide and dry chemicals to try to smother the fire, but it didn't work because of the air flow through the penetration. The fire was subsequently fought on both sides of the reactor building and cable spreading room wall and extinguished, but not before significant damage occurred to cables related to the control of Unit 1 and, to a lesser degree, Unit 2.

How This Event Shaped the Nuclear Power Industry

- Regulations were established in 10CFR50, Appendix R for physical separation of safeguards equipment trains so that failure of one train would not affect the other.
- Stations adopted extensive training programs for employees performing fire watches, whose only function is to observe maintenance activities, such as welding and grinding, that have the potential for starting a fire.
- Measures were put in place to expedite issuance of radiation monitoring badges for fire-fighting and other emergency personnel.

Core Damaging Loss of Coolant Event

March 28, 1979 - Three Mile Island 2 (PWR)

This was the worst accident at a U.S. commercial nuclear power plant, resulting in the meltdown of half of the reactor core and permanent closure of the plant. Although no injuries occurred, public confidence in the nuclear industry was severely shaken. Sweeping changes in emergency planning, operator training, emergency procedures, human factors engineering, regulatory oversight, and a number of other areas were the result. Nuclear utilities formed the Institute of Nuclear Power Operations to promote excellence in utility operations of nuclear power plants.

Additional Resources

- Material For a Case Study on Three Mile Island Unit 2 Accident

How It All Started

The accident occurred when an open power-operated relief valve failed to reset during a plant transient, and operators did not realize it was open. This caused the core to overheat because reactor coolant escaped through the open valve. Operators were confused by the many alarms in the control room and took a series of actions that made plant conditions worse by reducing coolant flow through the core. As the core overheated, the zirconium fuel cladding ruptured and the fuel pellets began to melt.

What Happened

At 4 a.m. on March 28, 1979, the plant experienced a loss of main feedwater during a simple maintenance activity while at 100 percent power. Safety systems automatically shut down the main turbine and started the emergency feedwater pumps. However, the emergency feedwater pumps failed to pump water to the steam generators because system valves were inadvertently left closed after an earlier test. With no feedwater, the steam generators eventually stopped removing heat from the reactor, causing the temperature and pressure of the reactor coolant to increase, which resulted in the power-operated relief valve opening to relieve pressure. Instead of closing as it should have, the valve remained open. There was no indication of the actual position of the power-operated relief valve in the control room, so operators did not recognize that it was open. As a result of the open relief valve, system pressure decreased to the point where the safety injection system automatically initiated. Operators erroneously thought the core was covered with coolant because of pressurizer level, so they drastically reduced injection flow. They did not realize that a steam void had formed in the reactor vessel head, which grew to the point of uncovering fuel. Over half the core melted as a result. The reactor was permanently shut down and defueled, after only three months of operation.

Ironically, a similar event had happened two years earlier at Davis-Besse, except that the open power-operated relief valve was recognized and closed by operators, stopping the event with no consequences. Weaknesses in industry programs for sharing information prevented the Three Mile Island operating crews from benefitting from the lessons learned from Davis-Besse.

How This Event Shaped the Nuclear Power Industry

- Many plant design and equipment requirements were implemented, including piping systems, auxiliary feedwater systems, containment isolation, and automatic shutdown and accident mitigation capabilities. The process of implementing the modifications took years.
- Public confidence in nuclear power was badly shaken, and support for nuclear projects evaporated. Utilities suspended plans for new nuclear projects, and some plants under construction were not completed.
- Many improvements in human factors design within the control rooms were made to assist operators in diagnostics and discernment.
- Operator training was substantially strengthened. Physics, math, and other fundamentals became requirements of operator training, and site-specific simulators were adopted to further enhance the knowledge and skills of licensed operators.
- Symptom-based emergency operating procedures were developed to ensure operators could effectively diagnose and respond to emergency and abnormal situations.
- Many changes in emergency preparedness standards were made, including prompt regulator notification of problems.
- Substantial changes to regulatory oversight were made, including inspection standards, how performance is determined, periodic reports, and analysis of vulnerabilities.
- The Institute of Nuclear Power Operations (INPO) was established to promote excellence in operations and to provide for sharing of lessons.

3

Loss of Instrument Power

February 26, 1980 - Crystal River 3 (PWR)

The industry responded to this event with design modifications to instrumentation to ensure that the effects of lost power to instrumentation are less severe. In this case, lost power to indicators challenged the operators, caused systems to operate erratically, and substantially complicated the transient. Guidance and training were also provided to ensure operators know how to respond.

What Happened

When 24-volt power was lost to nonnuclear instrumentation (NNI), a reactor scram and turbine trip occurred. Also, a power-operated relief valve (PORV) stuck open after the loss of power, and a safety valve lifted, resulting in a discharge of about 40,000 gallons of water into the containment sump. Following the NNI power failure, many instruments failed mid-scale and much of the control room indication was lost. Of the instrumentation that remained operable, transient conditions made their indications questionable to the operators, and the plant's integrated control system (ICS) complicated the transient as a result of the erroneous instrumentation signals. The erroneous signals led to a reduction of feedwater concurrent with a turbine header pressure error that opened turbine valves and resulted in a loss of heat sink. A failure of the steam generator A level transmitter closed associated feedwater and steam block valves, causing steam generator A to boil dry.

How It All Started

The event began when an instrument and control technician inserted a circuit card into an inservice module. The connection pins did not properly align, creating a short circuit, and the resulting loss of power caused the loss of several control and indication parameters. The loss of control parameters provided erroneous signals to the ICS. This opened the PORV, caused withdrawal of control rods to increase reactor power, and reduced feedwater flow, resulting in a loss of heat sink and a high reactor coolant system (RCS) pressure condition.

Effects on Plant Operation

The effect of erroneous ICS signals established conditions for a reactor scram, turbine trip, and engineered safeguards actuation, which dumped approximately 40,000 gallons of primary coolant on the floor of the containment building.

Additional Resources

- SOER 81-1, Improper Steam Generator Level Control and Loss of Heat Sink Due to a Partial Loss of Instrumentation
- SOER 81-2, System Response and Operator Uncertainty Due to Failed Instrumentation
- SOER 81-3, Loss of 24VDC Non-Nuclear Instrumentation Power Supply

Nuclear Note:

Emergency feedwater is an important safety system that provides the feedwater to steam generators under several accident conditions to remove heat from the reactor. In this event, the steam generators were drained by the transient, and the integrated control system prevented auxiliary feedwater from being used. As a result, an important way of removing heat from the reactor was not available.

The ICS responded to the faulty inputs from the instruments by throttling down feedwater flow resulting in a level decrease in both steam generators. The emergency feedwater system, which is also controlled by the ICS, did not respond to the loss of feedwater because the midrange failures of steam generator level instrumentation were higher than actual levels. The steam generator rupture protection system further aggravated the incident by isolating the steam and preventing their use for removing decay heat.

Many important indicators in the control room needed by operators failed to the midscale position. Since midscale is typically where normal values indicate, this challenged the operators making it difficult to determine a valid indication from a failed indication. Operators took conservative actions based on operating experience, including prompt isolation of the open PORV, closure of all non-essential reactor building isolation valves, and continuation of coolant injection when the lack of instrumentation affected their ability to confirm core cooling.

How This Event Shaped the Nuclear Power Industry

The industry responded to this event with equipment modifications, procedure enhancements, and operator training. In addition, this was the first event for which the NRC required the industry to conduct a failure modes and effects analysis (FMEA).

Specific changes that the industry adopted include the following:

- Modifications were made in the following areas:
  - The potential for midscale failures of instrumentation was eliminated.
  - The potential for losses of power to instrumentation buses to interfere with the operation of auxiliary feedwater systems was eliminated.
  - Automatic bus transfer capability was added to ensure power to instruments is available when normal power is lost.
- Improved abnormal and emergency procedure guidance was provided for switching power supplies and restoring power to affected buses when power is lost to instrumentation.

4

Natural Circulation Cooldown

June 11, 1980 - St. Lucie 1 (PWR)

After losing component cooling water, operators scrammed the reactor and tripped all reactor coolant pumps. With the reactor cooled by natural circulation, operators were challenged in their ability to control core cooling and flow because of limitations in instrumentation and guidance. A void developed in the reactor vessel head. This important event prompted four separate INPO Significant Operating Experience Reports to be written, including better response to pressurizer level anomalies, modifications to reduce the impact of reactor coolant pump loss, additional instrumentation, and additional operator training.

Additional Resources

- SOER 81-5, Instrumentation to Conduct Natural Circulation Cooldown
- SOER 81-6, Unanalyzed Conditions Encountered During a Natural Circulation Cooldown

Nuclear Note: *Under normal conditions, increasing charging flow would cause an increase in pressurizer level. However, with a steam void in the reactor vessel head, the increased pressure effect from increased charging flow compressed the void in the vessel head, and a decrease in pressurizer level resulted. Also, the depressurization effect of spraying the pressurizer caused the voids in the vessel head to expand, thus increasing pressurizer level.*

How It All Started

On June 11, 1980, a component cooling water containment isolation valve failed closed, causing a total loss of cooling to all the reactor coolant pump seals. The reactor was manually scrammed, and all the reactor coolant pumps were manually tripped. Operators started to cool the reactor using natural circulation. Approximately four hours into the cooldown, a steam void began to form in the reactor vessel head as the pressurizer cooled down. This occurred as the reactor became the hottest part of the system, which resulted in water being displaced from the reactor coolant system into the pressurizer.

The reactor vessel head had little or no coolant flow during natural circulation, which allowed it to become hotter than the pressurizer. Pressurizer level indication anomalies that occurred included decreasing pressurizer level while operators were adding water and increasing pressurizer level while they were spraying the pressurizer.

Operators did not have indication of temperature in the vessel head after hot leg temperature instrumentation reached the low end of its range of 515oF. As a result, they did not realize that the vessel head had become the hottest part of the system.

Masking Another Problem

When shutdown cooling was initiated using one shutdown cooling loop, a reactor coolant loss from the shutdown cooling loop to the refueling water tank developed. However, the pressurizer level anomalies and low-pressure safety injection masked the reactor coolant loss. The most probable path for the coolant was through the mini-recirculation valves of the low-pressure safety injection pumps to the refueling water tank after shutdown cooling was initiated. Both the loss of coolant and the collapsing reactor

vessel head void caused primary pressure to decrease and resulted in the operation of one shutdown cooling train in the shutdown cooling mode and the other in the low head safety injection mode.

How This Event Shaped the Nuclear Power Industry
This event shaped the nuclear power industry by sparking significant improvements in the quality of procedures and training, as well as improvements in reactor coolant system temperature and vessel level instrumentation. It raised industry awareness of weaknesses in reactor coolant temperature instrumentation, procedure guidance on natural circulation verification and cooldown, and operator training on natural circulation and cooldown.

5

Nuclear Note:

An "anticipated transient without scram" event is one in which conditions for a scram exist but the scram does not occur. In such cases, other measures to shut down the reactor must be taken.

Failure of Control Rods to Insert

June 28, 1980, Browns Ferry 3 (BWR)

Additional Resources

- SOER 80-6, Partial Failure of Control Rods to Insert

A key element of nuclear safety is to be able to rapidly and completely shut down the reactor when needed. Control rods are the principal means of achieving this. In this anticipated transient without scram (ATWS) event, 76 of 185 control rods failed to fully insert during a scram. Water had accumulated in the scram discharge volume piping in such a way as to remain undetected by the scram discharge instrument volume (SDIV) instrumentation. This water accumulation caused premature pressurization of the scram discharge volume, thereby affecting control rod motion when the rods were scrammed. Three additional scrams - one automatic - were necessary to fully insert the control rods. In response to this event, the NRC issued guidance for both equipment capability and emergency procedures to ensure plants are able to be rapidly shut down if an ATWS occurs.

What Happened

On June 28, 1980, Browns Ferry 3 was being shut down in preparation for repairs to the feedwater system. The reactor was manually scrammed at 30 percent power, but 76 control rods associated with the east scram discharge volume (SDV) did not fully insert. The scram discharge volume was drained for a short time, a second manual scram was inserted, and all partially inserted rods were driven inward, although 59 rods still remained partially withdrawn. A manual scram was again inserted after the scram discharge volume was briefly drained; 47 rods remained partially withdrawn. After a longer drain of the scram discharge volume, an automatic scram occurred (because of the scram discharge volume tank high water level signal existing when the scram reset switch was placed in the Normal position). All remaining control rods fully inserted at this point. The total time elapsed from the initial manual scram to the time that all rods inserted following the automatic scram was approximately 15 minutes.

The control rods failed to insert because of a significant amount of water in the east bank scram discharge volume. In addition, the potential existed for water to accumulate within the scram discharge volume piping so as to remain undetected by the scram discharge instrument volume (SDIV) instrumentation. This water accumulation resulted in premature pressurization of the scram discharge volume, thereby affecting control rod insertion upon a scram.

How This Event Shaped the Nuclear Power Industry

The Nuclear Regulatory Commission prescribed a series of actions for boiling water reactor operators to evaluate the susceptibility of their systems and the adequacy of station emergency operating procedures for

responding to this type of event. Additionally, requirements for periodic checks for water accumulation in scram discharge volume were prescribed. Similar design weaknesses at other plants that could result in similar ATWS events were identified and corrected.

The specific measures taken included the following:

- The design of scram discharge instrument volume (SDIV) water detection instrumentation was strengthened to provide direct indication of the amount of water in the scram discharge volume.
- Procedures for responding to ATWS were developed.
- Guidance for using the standby liquid control system (an alternate system for shutting down the reactor) was expanded to facilitate prompt actuation, if needed.
- Significant Operating Experience Report 80-6, Partial Failure of Control Rods to Insert, was issued, with 10 recommendations that addressed procedures and modifications necessary to prevent having to avoid and mitigate the ATWS conditions of this event.

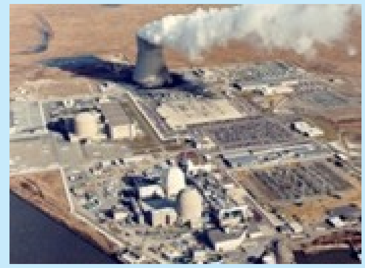
6

Reactor Trip Breaker Failures

February 22 and 25, 1983 - Salem 1 (PWR)

Nuclear Note:
Reactor trip breakers supply the power to the rod control system and are designed to open on receipt of a scram signal to facilitate the dropping (insertion) of control rods into the reactor core, thereby promptly shutting down the reactor.

On two separate occasions, both reactor trip breakers failed to open following receipt of a trip signal from the reactor protection system. On both occasions, the reactor was tripped manually from the control console.



Additional Resources

- SOER 83-8, Reactor Trip Breaker Failures

What Happened

On February 22, 1983, while Unit 1 was at 20 percent power during a unit startup, 4-kV bus power from the station to the auxiliary transformer was being transferred. A faulty limit switch resulted in deenergizing the 4-kV bus during the transfer attempt and several loads including control power to a main feedwater pump was lost. The resulting loss of main feedwater caused a steam generator low-low level reactor trip setpoint to be reached. At about the same time the trip demand signal was received, the shift supervisor directed the reactor operator to manually trip the reactor. After a short delay, the reactor was manually tripped.

At the time of the manual trip, control room personnel were unaware that the automatic reactor trip demand setpoint had been reached and that the reactor trip breakers had failed to open. The unit was subsequently restarted without detecting that the reactor trip breakers had failed to open automatically following receipt of a trip demand signal. Review of the computer sequence of events recorder four days later identified that the actual reactor scram was the result of the manual trip initiation and had occurred approximately 3.6 seconds after the low-low steam generator level scram demand signal had been received from the reactor protection system.

On February 25, 1983, after synchronizing the generator to the grid, reactor power was at 12 percent and increasing. The feedwater system was in manual control, and operators were experiencing difficulties in maintaining steam generator levels because of control instabilities at low steam and feedwater flow rates. A low-low steam generator reactor scram signal resulted from the level control problems. Another operator in the control room noted that the reactor had not scrammed and called out that information to the other operators. The reactor was then manually scrammed at the direction of the shift supervisor. Approximately 25 seconds elapsed between the automatic scram signal and the manual scram. Subsequent testing of the reactor trip breakers indicated that both breakers had failed to open, apparently because of mechanical binding in the undervoltage trip mechanisms.

Effects on Plant Operation

Fortunately, there was no consequence to the reactor in these events. However, failure of the reactor trip breakers to open when required poses a significant challenge to plant safety, and prompt and correct operator action is required to terminate a transient.

How This Event Shaped the Nuclear Power Industry

- Stations throughout the U.S. industry implemented a broad number of changes to preventive and corrective maintenance programs and testing for reactor trip breakers.
- Processes and practices involving post-trip reviews were strengthened to ensure that all aspects of the transients are recognized and evaluated prior to restart of the units. This failure had not been realized by station personnel until four days later when a review of the sequence of events recorder identified that the automatic trip had not occurred.
- Emergency operating procedure guidance was reviewed throughout the industry and strengthened, where needed, to include action requirements to scram the reactor in the event of failure of the automatic trip system.

7

Core Damage From Control Rod Misalignment

September 26, 1983 - Arkansas Nuclear One 1 (PWR)

Operating the reactor within the design specifications such as power level, rod configuration, and temperature and pressure, is vital to protecting the fuel. At Arkansas Nuclear One, Unit 1 was operated inadvertently with a control rod in a misaligned configuration for 12 days. When the misalignment was recognized, operators realigned the rod with the reactor operating at 100 percent power, which caused xenon oscillations and localized power peaking. Damage to the fuel cladding resulted, thereby breaching the first barrier to release of fission products.

Additional Resources

- SOER 84-2, Control Rod Mispositioning
- SER, 84-83, Control Rod Misalignment

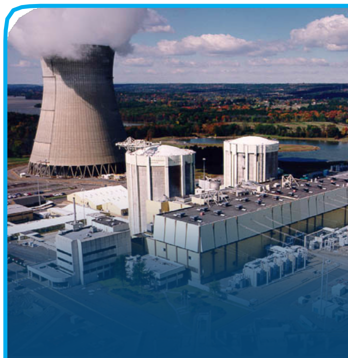
This event prompted the industry to establish guidelines for realigning mispositioned rods to protect the fuel from localized power spikes that can lead to fuel-cladding failure. Nuclear engineering involvement was mandated to ensure that core conditions are understood and that the core is protected during recovery.

What Happened

During a plant startup on September 11, 1983, the absolute position indication for control rod assembly 10 in the regulating group sporadically dropped to zero percent and then returned to normal. This was attributed to sticking reed switches in the absolute position indication, so power escalation was continued. The reed switches weren't a problem - the control rod was stuck.

Nuclear engineers monitored in-core detector signals and gross quadrant power tilt, but they did not detect any power asymmetries that would indicate rod misalignment because the misaligned rod was located near the center of the core. This location made it difficult to detect rod misalignment using gross quadrant tilt.

On September 26, the axial power shapes for the fuel assembly with control rod assembly 10 were measured and showed a misalignment of approximately 90 inches from the rest of the group. Operators promptly raised and aligned the control rod assembly with its group while operating at 100 percent power. This maneuver was performed without evaluating the effects on local power distribution. Additionally, the operators did not consult with station nuclear engineers prior to withdrawing the misaligned rod. The rapid rod withdrawal caused flux oscillations and localized power peaks that resulted in fuel cladding damage.



The rapid restoration of the out-of-position control rod at the high power level established the core conditions for the fuel failure. Operating procedures in place at the time of the event did not address recovery from long-term control rod misalignment. If the operators had reduced power and withdrawn the control rod at a slower rate, the resultant xenon oscillations and localized power peaking could have been controlled, reducing the probability of fuel damage.

How This Event Shaped the Nuclear Power Industry

This event raised the industry's sensitivity to the importance of exercising great care in operating the core, particularly when off-design conditions are encountered. Significant Operating Experience Report 84-02 established requirements for measured responses that involve analyzing the condition of the core, establishing recovery parameters, and training personnel. Station nuclear engineering involvement and support were mandated for recovery from off-normal core conditions such as this to ensure core conditions are known and recovery parameters, such as power level and control rod movements, are applied appropriately. Power reductions were specified, when necessary, prior to recovery to reduce the potential for excessive power peaking and to limit the rate of control rod movement during recovery.

8

Nuclear Note:

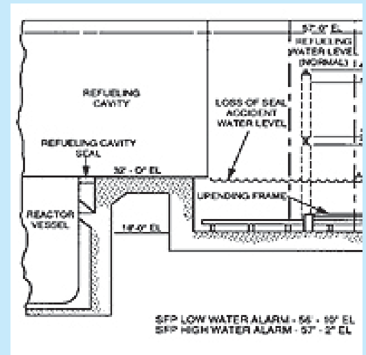
The reactor cavity is a cavernous space from which the reactor vessel is accessed during refueling. The cavity is flooded with borated water during refueling so that when fuel is moved into or out of the vessel it remains covered with water. The cavity seal keeps the water from draining through the annulus between the reactor vessel flange and the reactor cavity floor.

Reactor Cavity Seal Failure

August 12, 1984 - Connecticut Yankee (PWR)

This event shaped the industry by increasing the importance of reviews of failure modes during the design process. The term “failure modes and effects” became commonly used after this event.

A new design for the reactor cavity seal was not reviewed adequately for possible failure modes before it was implemented. This design included an inflatable bladder that, under normal circumstances, provided a tight seal, preventing leaks. However, the bladder failed, creating a large leakage path for water in the reactor cavity to drain to the containment floor. It was very fortunate that fuel was not being moved when the reactor cavity seal failed in this event. If irradiated fuel had been in the cavity when the seal failed, it could have been uncovered.



Additional Resources

- SOER 85-1, Reactor Cavity Seal Failure

What Happened

While preparing for refueling, the reactor cavity seal was installed, the reactor vessel head was removed, the refueling cavity was nearly full with borated water, and the refueling support systems were tested. The transfer tube valves between the spent fuel pool and the refueling cavity were closed, and preparations for removing the upper internals were under way.

On August 12, 1984, without warning, approximately 25 percent of the outer inflated bladder slipped through the 2-inch annulus, creating a leak path of several square feet. The water in the refueling cavity dropped over 20 feet as 200,000 gallons of borated water drained through the annulus during the 22-minute event. The containment floor was covered with 18 inches of contaminated water from the cavity.

How It All Started

The design of this reactor cavity seal was used for the first time during the previous refueling, and a new outer air bladder was being used for the first time during this refueling. The modified seal was used as a result of previous excessive leakage that occurred while using the original seal. The new seal could have failed from over- or underinflation, punctures, temperature increases, and seal misalignment. These “failure modes” should be considered during design, and the effects of the failures need to be determined before a design is adopted.

How This Event Shaped the Nuclear Power Industry

- Fundamental improvements were adopted by the industry during design change safety reviews to ensure the full range of possible failure modes and their effects are considered. These considerations are termed "failure modes and effects analyses."
- Design reviews were conducted to assess susceptibility to losses of refueling cavity water. Actions were taken to reduce the potential for and consequence of inadvertent cavity draindown events such as the following:
  - steam generator nozzle dam failures
  - inadvertent opening of loop isolation valve with an open steam generator or disassembled

    reactor coolant pump
  - losses of coolant through the residual heat removal system
  - failures of boiling water reactor main steam line plugs used to isolate main steam lines from the refueling cavity
  - failure of reactor vessel nozzle inspection covers and instrumentation port covers
  - inadvertent opening of a refueling cavity drain valve
  - failures of the seals on refueling or spent fuel pool gates

9

Premature Criticality

February 28, 1985 - VC Summer (PWR)

Controlling reactivity is extremely important to nuclear safety. In this event, an alarmingly high neutron startup of 17 decades per minute was achieved as control rods were continuously withdrawn through the point of criticality. Fortunately, the reactor automatically scrammed without consequence. The reactor had achieved criticality earlier than operators expected because of errors in the estimated critical position. As a result of this event, the industry strengthened operator practices for how reactor startups are conducted by ensuring multiple indications are used, avoiding continuous rod withdrawals, and controlling distractions in the control rooms during startups.

Station's Reactor Control Pan

Additional Resources

- SOER 88-2, Premature Criticality Events During Reactor Startup

How It All Started

On February 27, 1985, with VC Summer plant shut down for repairs, an estimated critical position was calculated. The reactor was brought to a critical condition on the following morning but was shut down after only three hours of operation. A subsequent calculation was performed using the power history and other information from that morning's criticality. The estimated critical rod position was 168 steps on control bank D.

A second reactor startup was initiated later that day by a trainee under the direct supervision of a shift supervisor. The shift supervisor planned to stop rod withdrawal at 100 steps to check rod position indication and nuclear instrumentation; however, the reactor automatically scrammed on high flux positive rate. It was later determined that criticality had occurred at approximately 40 steps on control bank D and a reactor startup rate of 17 decades had been achieved - much higher than the .5 to 1 decade per minute that is normally allowed.

The method used to calculate the estimated critical position (ECP) was inaccurate because of the rapidly changing xenon and samarium poison concentrations resulting from a complicated power history over the preceding 48 hours. Operators had assumed a much higher level of poisons than actual existed at the time of the reactor startup. In addition, the licensed operators who performed the calculations used middle-of-life rod worth curves instead of the beginning-of-life curves appropriate for the existing core time-in-life.

Nuclear Note:

An "estimated critical position" calculates the expected rod positions at which a reactor should go critical. It is used to help operators approach criticality cautiously and identify when the core responds differently than expected. The calculation uses estimated fission poison concentrations of xenon, samarium, and soluble boron to determine either control rod position or boron concentration for criticality. The previous power history is used to estimate the poison concentrations. Graphs (curves) for xenon and samarium concentrations based on core time-in-life are used, applying the time after previous shutdown to determine concentrations.

In addition to inaccuracies in the estimated critical position, the approach to criticality was not made cautiously enough. The operators performing the reactor startup did not sufficiently monitor nuclear instruments or startup rate during the reactor startup. Additional monitoring tools such as inverse count ratio (1/M plotting) or count rate doubling methods that help identify proximity to criticality were not employed.

How This Event Shaped the Nuclear Power Industry

This event set in motion a series of actions to formalize approaches to criticality and improve the quality of tools used to predict when criticality would occur. The emphasis on the operator monitoring nuclear instruments, being prepared for criticality at any time, and using methodical, slow rod movements has become part of fundamental operator startup techniques.

Specific actions taken by the industry include the following:

- Operator actions when criticality is achieved outside allowable tolerance band of the ECP were specified.
- Expectations were established for monitoring the approach to criticality with nuclear instruments, audio count rate speakers, and calculations such as inverse count rate or count rate doubling methods.
- Hold points or periodic pauses during control rod withdrawal were mandated to allow stabilization of neutron level and data collection for projecting criticality.
- Improved industry standards for control room formality and distractions during startups were established.

10

Loss of All Feedwater

June 9, 1985 - Davis-Besse (PWR)

Nuclear Note:
Auxiliary (or emergency) feedwater is supplied to steam generators under abnormal or emergency conditions and is needed to remove heat from the reactor. Auxiliary feedwater systems are safety-related, whereas main feedwater systems are not.

This event had a substantial impact on the operation and testing of industry standby turbines in both PWRs and BWRs and in the setting of motor-operated valve torque switches. The event involved the temporary loss of all feedwater and the subsequent loss of level in both steam generators, thereby eliminating them as the normal means of cooling the reactor following the scram. Both auxiliary feedwater pump turbines tripped on overspeed as a result of accumulated condensation in the steam supply lines following a trip of a main feedwater pump and reactor scram. Inadvertent isolation of auxiliary feedwater occurred when containment isolation valves were closed; the valves were delayed in reopening because of problems with their motor-operator torque switch settings.

AFW pump trip and throttle valve

Additional Resources

- SOER 86-01, Reliability of PWR Auxiliary Feedwater Systems
- SER 29-85, Loss of Main and Auxiliary Feedwater (06-19-1985)

How It All Started
Following a main feedwater pump trip at 90 percent reactor power, the reactor scrammed on high pressure. Immediately after the scram, a spurious closure of the main steam isolation valves isolated the steam supply to the other operating turbine-driven main feedwater pump.

Both turbine-driven AFW pumps started automatically from a steam or feedwater rupture control system (SFRCS) signal because of low level in one steam generator. Almost simultaneously with this automatic actuation, a control room operator, intending to manually initiate SFRCS for steam generator low level, mistakenly initiated both channels of SFRCS for low steam generator pressure. This closed the containment isolation valves for both auxiliary feedwater trains (low pressure in a steam generator prompts a different SFRCS response than low steam generator level).

When the AFW pumps were started by the SFRCS signals, they accelerated and tripped on overspeed. The overspeed trips were the result of water slugs in the steam supply piping that came from residual condensation. The condensation flashed to steam as it passed the turbine governor valve and caused turbine overspeed.

About one minute after the manual SFRCS initiation, the operator recognized the manual initiation error and took corrective actions. However, the motor-operated containment isolation valves did not reopen because their torque switch bypass settings were incorrect. As a result, operators had to manually move the valves off their seats before their motor operators would work.

Feedwater was restored when the operators manually reset the auxiliary feedwater pump turbines and manually controlled the acceleration to full speed with the trip throttle valves.

How This Event Shaped the Nuclear Power Industry
This important event shaped the industry in several ways:

- It brought into focus the importance of ensuring turbine-driven standby pumps are capable of their design functions. Requirements were made for adding steam traps to eliminate the problem of accumulated condensation, which had caused the auxiliary feedwater pump turbines to trip on overspeed during the starting sequence. Testing practices that involved preconditioning the systems by draining piping of accumulated water or exercising valves were changed so that as-found conditions are tested.
- The importance of motor-operated valves operating when called on prompted reviews of maintenance programs for motor-operated valves in the AFW system, which included verification of torque and limit switch settings.

11

Reactor Destruction

April 26, 1986 - Chernobyl 4 (RBMK)

This reactor accident was the worst accident in the history of nuclear power. The Chernobyl 4 disaster caused the devastation that many detractors of nuclear power feared - loss of life, widespread contamination, and long-term effects. It was initiated by an improperly performed test and occurred as the result of a flawed reactor design. As a result of this horrific event, the need for worldwide collaboration among nuclear operators was recognized, resulting in the formation of the World Association of Nuclear Operators.

Additional Resources

- SOER 87-1, Core Damaging Accident Following an Improperly Conducted Test

The accident was the result of a test being performed with safety features disabled. The reactor achieved prompt criticality, which caused a steam explosion and fire that released significant levels of contamination from the destroyed core into the environment over parts of the Western Soviet Union, Europe, and Eastern North America. Large areas of the Ukraine, Belarus, and Russia were badly contaminated, resulting in the evacuation and resettlement of more than 336,000 people. Twenty-eight people died within four months of the accident from radiation or thermal burns; 19 others have subsequently died, and there are additional reports of fatalities from thyroid cancer and leukemia apparently caused by the accident.

What Happened

During the performance of a turbine-generator coastdown test on April 26, 1986, Unit 4 experienced a severe reactivity excursion that, with the accompanying pressure surge and fire, destroyed the reactor and breached the surrounding building. The test procedure had not been adequately reviewed for safety. Management control of the evolution was not maintained, the test procedure was not followed, several critical safety functions were bypassed, and control rods were misoperated. Operators lost control of the reactor during the performance of the test.

How It All Started

On April 25, 1986, prior to routine shutdown, a test was scheduled to determine how long turbines would spin and supply power to the reactor's safety systems in the event of a loss of external electric power. A series of operator actions, including the disabling of automatic shutdown mechanisms, preceded the attempted test. Test preparations included gradual reduction of reactor power.

The test was conducted on backshift by an inexperienced crew that misunderstood the test schedule, which had been changed as a result of external utility demands. Ill-advised changes in power were used to achieve initial conditions, which caused a buildup of core poisons that affected the ability to achieve required power levels. To increase the power to the desired level, automatic control rods were pulled out of the reactor beyond what was allowed by safety regulations. In addition, as part of the test, the water pumps that were to be driven by the turbine generator were turned on, increasing the water flow beyond what is specified by safety regulations. The increase in the water flow made it necessary to withdraw manual control rods to increase power. These control rod conditions created the unstable operating situation that directly caused the disaster. It did not appear that control room personnel were aware of any danger.

Steam to the turbines was shut off and, as the momentum of the turbine generator drove the water pumps, the water flow rate decreased, which decreased the absorption of neutrons by the coolant. The turbine was disconnected from the reactor, increasing the level of steam in the reactor core. As the coolant heated, pockets of steam formed voids in the coolant lines. Because of the design of the RBMK reactors, the steam bubbles increased the power of the reactor rapidly, and the reactor operation became progressively less stable. As the reaction continued, the excess xenon poison was depleted, increasing core power and leading to a significant power excursion. Tragically, when operators scrammed the reactor, a control rod design flaw caused an additional power surge. The reactor jumped to about 30,000 megawatts, 10 times the normal operational output. A huge steam explosion occurred, which displaced and destroyed the reactor lid, ruptured coolant tubes, and then blew a hole in the reactor building roof.

How This Event Shaped the Nuclear Power Industry
As a result of this accident, the need for international collaboration in setting and implementing high standards for operating nuclear facilities was recognized. The World Association of Nuclear Operators was formed as a result.

The industry recognized that the accident occurred because of improper or inappropriate operator actions during the event and breakdowns in management/administrative controls. Management controls were mandated in Significant Operating Experience Report 87-1, *Core Damaging Accident Following an Improperly Conducted Test* for special tests and other nonroutine plant evolutions. These controls included clear delineation of responsibilities for those involved in special tests, reviews of procedures for the conduct of special tests by individuals with necessary technical expertise, and ensuring plant operators are prepared prior to special testing.

12

Feedwater Line Rupture

December 9, 1986 - Surry 2 (PWR)

This pipe rupture event at Surry 2 was the first case of extensive single-phase erosion/corrosion in condensate and feedwater piping among domestic light water reactors. Four people lost their lives in this event, and others were injured, some seriously. The rupture was caused by wall thinning in carbon steel piping from erosion/corrosion. Because of this event, the industry instituted extensive inspection and replacement of susceptible piping in high-energy systems.

Additional Resources

- SOER 87-3, Pipe Failures in High Energy Systems Due to Erosion Corrosion

What Happened

Unit 2 was operating at 100 percent power when a main steam isolation valve closed. Steam generator levels dropped, causing a reactor scram. Approximately 35 seconds after the reactor scram, an elbow in the suction pipe to the A main feedwater pump ruptured. Eight contract personnel working in the area were burned by the escaping steam and water, and four of them subsequently died. About 30,000 gallons of feedwater were released, flashing to steam and causing equipment damage and electrical malfunctions in some systems.

The rupture occurred at the inlet to an 18-inch, 90-degree elbow. The elbow was located immediately downstream of a tee connection off the 24-inch main feedwater suction header. Severe wall thinning had occurred throughout the elbow and the 18-inch outlet of the tee. Wall thicknesses as low as 0.120 inches were found in the general area where the rupture began. Also, small localized areas had thicknesses as low as 0.048 inches. The original nominal wall thickness was 0.5 inches. Thinning occurred around the entire circumference of the elbow and tee connection outlet. Subsequent inspection of the corresponding piping section on Surry Unit 1 showed similar but less extensive thinning.

The cause of the wall thinning was single-phase water erosion/corrosion. High local turbulence caused by the piping elbow immediately downstream of the tee connection had greatly accelerated the erosion/corrosion process. Water temperature, pH, and oxygen content contributed to the high erosion/corrosion rate.

Collateral effects of the rupture included 62 sprinkler heads discharging in the Unit 2 turbine building. Water from this suppression system entered open electrical conduit, caused short circuits in control systems, and initiated the Halon and Cardox fire suppression systems in the emergency switchgear and cable tray rooms. The discharged Halon leaked into the control room through floor penetrations, and several individuals reported shortness of breath, dizziness, and nausea.

How This Event Shaped the Nuclear Power Industry

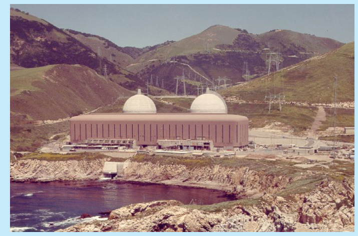
Until this event, many stations piping inspection programs included only steam and two-phase flow areas, such as extraction steam and steam drain piping, and did not include single-phase flow areas such as feedwater piping. After this event occurred, piping inspection programs were expanded substantially, and ongoing inspections that provided trend information were instituted. Comprehensive engineering review programs identified systems and pipe sections most susceptible to erosion/corrosion.

13

Extended Loss of Residual Heat Removal

April 10, 1987 - Diablo Canyon 2 (PWR)

As a result of this event, the industry realized increased risks associated with reduced inventory or mid-loop level operations and outage-related activities that could potentially interrupt heat removal capability or reactor coolant system inventory while in this "higher-risk" condition. The event highlighted the importance of minimizing time spent and carefully controlling work activities while in this condition.



Additional Resources

- SOER 85-4, Loss or Degradation of Residual Heat Removal Capability at PWRs
- SOER 88-3, Losses of Residual Heat Removal with Reduced Reactor Vessel Water Level at PWRs

What Happened

An extended loss of residual heat removal capability occurred while the reactor coolant system was at mid-loop level. The low reactor coolant system level allowed air to become entrained in the residual heat removal system pump suction, which disabled the residual heat removal system. Localized boiling, void formation, and pressurization of the reactor coolant system further exacerbated the loss of coolant inventory through the steam generator manway seals. Delays in raising coolant level occurred because of concerns for the safety of personnel working on the steam generator manways.

How It All Started

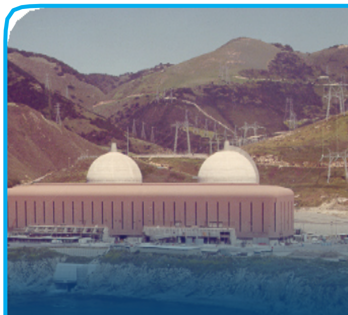
On April 10, 1987, Unit 2 had been shut down for seven days, and the reactor coolant system level had been drained to mid-loop level to permit the removal of the steam generator primary-side manways for nozzle dam installation. The installed nozzle dams would permit work in the steam generators while the refueling cavity was flooded for refueling. Reactor coolant system level was monitored using a temporary water level indication system.

Mid-loop level in reactor coolant system hot leg is the minimum level that ensures adequate residual heat removal pump net positive suction pressure.

The event started when an engineer, preparing for a local leak rate test in a portion of the chemical and volume control system, opened a vent and drain valve to drain water from a previously isolated line. He then left the area because of high radiation levels and did not monitor the draining activity. One of the tagging boundary isolation valves leaked through, resulting in the volume control tank level being lowered. The engineer had not briefed the on-duty operating shift before starting this activity.

Nuclear Note:

The residual heat removal system is used to remove decay heat while the unit is shut down and depressurized.



Believing the drop in level was caused by an imbalance between charging and letdown flows, control room operators responded to the volume control tank level drop by increasing letdown flow. Increasing letdown flow caused reactor coolant system level to decrease, eventually causing air entrainment in the residual heat removal system through a vortex at the suction nozzle resulting in air binding and cavitation of the residual heat removal pump.

The residual heat removal pump was stopped, and the standby pump was started. The standby residual heat removal pump was then shut down because of similar erratic pump indications.

When the residual heat removal pumps were shut down, reactor coolant system cooling was lost, and the reactor coolant system temperature began to rise from 87F to 220F because of decay heat from the fuel. Reactor coolant system pressure increased from atmospheric to approximately 10 psig. Steam vented into containment through a reactor vessel head plastic vent line that had melted and ruptured because of the temperature and pressure increase. Concerns over conditions in containment prompted a containment evacuation until the conditions could be assessed and the safety of all workers could be ensured.

When the decreasing reactor vessel water level was recognized, operators isolated letdown flow, stopping the loss of inventory from the reactor coolant system. After residual heat removal flow was secured, the shift foreman sent an operator into containment to see if the steam generator manways were in place so the reactor coolant system level could be raised. The shift foreman did not learn that the manways were still in place for 75 minutes, which delayed level restoration and prolonged the event.

How This Event Shaped the Nuclear Power Industry
This important event shaped the industry in several ways:

- As a result of this and other events involving loss of residual heat removal, NRC Generic Letter 88-17, Loss of Decay Heat Removal, was issued to establish requirements for maintaining adequate hot leg venting while in a reduced inventory condition. Great care is now taken to know and understand reactor vessel level during reduced inventory conditions.
- Most stations modified the processes for disconnecting core exit thermocouples to ensure some thermocouples are available as long as possible so that core temperatures can be monitored under these conditions.

14

Neutron Flux Oscillations

March 9, 1988 - LaSalle 2 (BWR)

Station confidence in current operating procedures was seriously undermined because of a March 9, 1988 high neutron flux scram caused by power oscillations following trips of both reactor recirculation pumps. The neutron flux oscillations had been identified as a big concern elsewhere in the industry, but this event caused LaSalle to reassess and revise its operating protocols involving immediate operator actions to avoid or exit the operating region of instability.

Additional Resources

- SER 14-88, Scram Caused by Neutron Flux Oscillations

How It All Started

An instrument valving error during surveillance testing caused a false reactor pressure vessel low level signal, and both reactor recirculation pumps tripped. Reactor power rapidly dropped to 40 percent, and the reactor continued to operate on natural circulation. Five minutes later, indicated power on the average power range monitors began to oscillate on a period of approximately two seconds, causing downscale and upscale local power range monitor alarms.

Attempts to restart a recirculation pump were unsuccessful, and the oscillations continued for an additional two minutes until an automatic reactor scram was actuated on a high neutron flux signal of 118 percent. The recirculation pump could not be started because of a low feedwater flow interlock that had been actuated by a feedwater transient during the event. The interlock had not been reset prior to an attempt to start a pump. If it had been reset, and feed flow restored, the plant would have been in a more favorable location on the power-to-flow map, and neutron flux oscillations would have ceased.

When entering the power-to-flow region susceptible to core instability as a result of the loss of forced recirculation flow, the immediate action recommended by General Electric is to insert control rods to reduce power and exit the region of potential instabilities. This action was not included in the applicable procedures at LaSalle for responding to the loss of recirculation flow. Also, operator training at the station did not cover detailed guidance for neutron flux oscillation.

It was believed that flux oscillations were unlikely for LaSalle's core configuration, and operator actions to dampen oscillations would, therefore, not be a substantial concern.

Stability analyses previously performed by General Electric indicated that flux oscillations for the LaSalle core would rapidly decay to a steady-state value. However, the calculation assumed steady-state conditions and a fixed value for such variables as core flow, feedwater temperature, and reactor vessel level. In this event, however, the plant experienced several transient effects. Feedwater temperature decreased because of the rapid power reduction and feedwater heater isolations, and the colder temperature caused a small increase in power that drove the core operating conditions further into the instability region. Also, reactor vessel level and core flow were oscillating on a 30 to 40 second period, and the neutron flux oscillation amplitude demonstrated a sensitivity to core flow. Because of these transient conditions, the actual decay ratio for the core under these conditions was higher than anticipated.

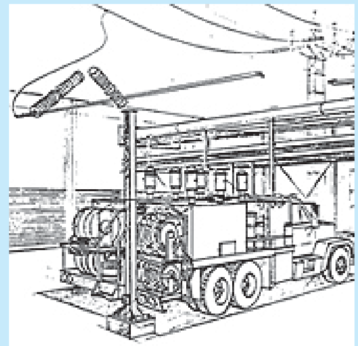
How This Event Shaped the Nuclear Power Industry
This event brought to light the importance of prompt actions by operators if the reactor entered the power-flow instability region. The industry adopted operating standards that mandated immediately placing the plant in a known safe condition. Conditions under which the reactor is to be scrammed were established. Additionally, enhanced licensed operator training and operating procedures at BWRs focused on core instability concerns and actions to be taken when operating in the region of core instability.

15

Loss of Off-site Power During Reduced Reactor Coolant Inventory

March 20, 1990 - Vogtle 1 (PWR)

Prior to this event, there were few restrictions on what other work was performed concurrently with reduced inventory operations. There was little consideration regarding scheduling outage-related work activities that could potentially impact or interrupt decay heat removal if problems were encountered. This pivotal event brought into focus the importance of scheduling outage work that could affect key outage safety functions such as shutdown cooling for periods that would minimize the effects of problems.



Additional Resources

- IN 90-25, Loss of Vital AC Power With Subsequent Reactor Coolant System Heat-up

What Happened

On March 20, 1990, with Unit 1 in a refueling outage and Unit 2 at full power, a fuel truck in the low-voltage switchyard backed into a support column for an off-site power feed to the Unit 1A and Unit 2B operating reserve auxiliary transformers. A phase-to-ground fault occurred, and the feeder breakers for the Unit 1 and Unit 2 auxiliary transformers deenergized. Power was lost to both the Unit 1 safety buses that were cross-tied, and Unit 2 automatically scrammed following the loss of power to a reactor coolant pump bus. Unit 2 was stabilized in hot standby; however, Unit 1 experienced major complications because of ongoing outage maintenance activities.

In Unit 1, reactor vessel water level had been lowered to mid-loop to perform various maintenance tasks. The reactor vessel head was in place, and the first tensioning pass of the head bolts had been completed. All steam generator manways were in place but were not fully closed. The pressurizer manway and the containment personnel and equipment hatches were open. One emergency diesel generator and one reserve auxiliary transformer were removed from service for maintenance. The other reserve auxiliary transformer was providing power to both safety-related buses.

When off-site power was lost, the operating reserve auxiliary transformer was lost, which deenergized both vital buses. This caused the operating residual heat removal (RHR) pump to be lost. Because the Unit 1B emergency diesel generator was tagged out of service and disassembled for maintenance, the emergency power supply for the B vital bus was unavailable and the standby B RHR pump could not be started.

Nuclear Note:

Reduced inventory operations are when reactor vessel water level is lowered for work such as installing steam generator nozzle dams or removing the reactor vessel head. Installing nozzle dams requires reactor vessel level to be lowered to the center line of the reactor coolant system piping, which makes the shutdown cooling system susceptible to vortexing and loss of flow.

The operable diesel generator started and energized its safety bus for approximately one minute, but then tripped. It tripped two more times after operators tried to start it. Finally, it was started in the emergency mode, 36 minutes after the loss of power. During the 36 minutes without power, reactor coolant temperature increased from 90oF to 136oF. A site area emergency was declared for this event.

Human error caused the loss of off-site power at a time when the electrical distribution system was most vulnerable to a single fault. The only available diesel generator started but tripped, removing all power sources to the safety buses - there was no defense-in-depth. In addition, the containment equipment and personnel hatches were open, which resulted in an unobstructed radiological flowpath to the environment in the event boiling in the reactor coolant system occurred.

How This Event Shaped the Nuclear Power Industry

This event shaped the U.S. nuclear power industry by mandating sequencing of work during outages to ensure sufficient defense-in-depth is available. An important document that described key outage safety functions that ensure defense-in-depth was initiated. This document is entitled NUMARC 91-06, and all nuclear utilities have committed to following its guidance for providing defense-in-depth.

In addition, strong controls were placed on work in the switchyard, including access to the switchyard, controls on vehicle movement, and controls on material storage. Up until this point, operators were often not even aware of work being conducted in the switchyard, and communication between transmission and distribution personnel and the nuclear staff was typically weak.

16

Significant Fuel Damage

November 17, 1989 - Connecticut Yankee (PWR)

Consequences of plant operation with failed fuel include increased airborne activity, radiation levels throughout the primary system, and loose surface contamination. These conditions result in increased radiological dose to station workers, unplanned radiation exposures, personnel contaminations, and an increased potential for off-site releases. Fuel failures of this magnitude are enormously expensive to deal with and represent breaching of the first level of containment - the fuel clad.

Additional Resources

- SOER 90-2, Nuclear Fuel Defects

In this significant event, Connecticut Yankee experienced failures of nearly 85 percent of its 157 fuel assemblies, for a total of 456 failed fuel rods. The primary cause of the failures was debris that became lodged between the lower fuel assembly nozzle and the first spacer grid. As a result of this event, the industry strengthened fuel management policies, and each plant developed "failed fuel action plans" to provide escalating activities in the event of fuel problems.

How It All Started

A restart from a previous plant refueling was made with two known defective fuel rods. Based on the size of the expected leaks, it was anticipated that the beginning of the cycle iodine-131 activity levels would stabilize at approximately 5.0 x E-3 microCuries/milliliter. However, during the startup, the activity increased to five times the estimated level and stabilized at this value for most of the remaining operating cycle. The primary coolant activity data indicated that there were between 9 and 12 defective fuel rods and that the defects were probably hairline cracks or pinholes in high burnup fuel.

After a month of operation, the plant was shut down for reactor coolant pump maintenance. During this outage, there were no water chemistry indications of new problems with the fuel, so the plant was restarted and it operated continuously for 461 days. When the plant was shut down and depressurized to enter the subsequent refueling outage, iodine-131 activity increased and peaked at more than 10 times the technical specification limits. Inspection of fuel assemblies revealed 448 fuel rods with defects through the fuel clad walls in 133 fuel assemblies. Many other fuel rods had damage that did not penetrate the clad wall. The defects were caused by impingement, or fretting of small metal chips at the bottom of the fuel rods, approximately 1 inch above the bottom plate. In addition to the fretting failures, some pellet-clad interaction (PCI) defects occurred during the operating cycle.

The debris that caused the fretting came from machining conducted on the thermal shield during the previous refueling outage. The machining debris was a by-product of thermal shield support system repairs during the outage.

Between 600 and 900 fuel rods with partial through-wall debris-induced wear were reinserted into the reactor for the next operating cycle. Specialized equipment for detailed visual fuel inspection and debris removal was mobilized, and approximately 500 pieces of debris were removed.

Connecticut Yankee had a foreign material exclusion program in place during the outage, and efforts were made to limit the amount of debris introduced into the reactor vessel during the thermal shield repairs. Although three days were spent cleaning up debris from the work following the repair, these efforts were not enough to prevent the extensive damage that ensued.

Following the fuel failures and prior to core reload, the reactor vessel was thoroughly vacuumed. other debris in systems that connect to the reactor cooling system was also removed.

How This Event Shaped the Nuclear Power Industry

This event, and others like it, was the starting point of the industry's efforts to operate with zero fuel defects. The industry realized that current programs designed to preclude the introduction of foreign materials into the reactor vessel or spent fuel pool during maintenance activities were in need of significant improvements. Equally important, the industry needed to institute ways of responding to fuel failures. As a result, failed fuel action plans were instituted for every station that provided escalating responses to indications of fuel problems. Expectations for investigation of fuel failures were established so that lessons could be learned.

17

Special Test of the Main Turbine

August 17, 1990 - Nine Mile Point 1 (BWR)

A key term that has been adopted by every U.S. nuclear station as a result of this event is "infrequently performed test or evolution," or IPTE. No utility is unfamiliar with the term, and few managers have not provided oversight of IPTE briefings. This event is important for one key reason - inadequate controls were provided for an important test of the main turbine. In this event, test preparations and testing of the main turbine were continued even though unexpected plant and equipment responses were encountered and significant procedural inadequacies existed. The purpose of the test was to determine the precise locations of the turbine-generator rotor system torsional resonance frequencies. A manual reactor scram was required to slow the main turbine after it had been tripped to prevent damage from excessive vibration.

Additional Resources

- SER 18-90, Problems Experienced During a Special Test of the Main Turbine
- SOER 91-1, Conduct of Infrequently Performed Tests or Evolutions (06- 20-1991)

How It All Started

A main turbine torsional test was scheduled during power ascension at Nine Mile Point 1 in August 1990. The plant had completed extensive work on the turbine during the outage and the turbine vendor recommended that this test be performed. The test involved rolling the turbine to approximately 1945 RPM (within 5 RPM of the overspeed trip setpoint) at an acceleration rate of 7 RPM per minute. During that time, generator excitation voltage was to be applied in a controlled manner and turbine torsional loads were to be measured.

Over two days of testing, substantial problems were experienced with the test setup, including temporary alterations to a 345 kV breaker and a load limit motor that did not work properly, and performance monitoring indications in the test center that did not work. These problems were resolved before the test was conducted, but appropriate managers were not made aware of the problems being experienced.

After the test started, turbine vibrations that exceeded the 10 mil limit recommended by the system engineer occurred several times, yet the test was continued. When vibration on one turbine bearing reached 10 mils and was sustained, the turbine was manually tripped. During subsequent turbine coastdown, a bearing vibration level increased to over 15 mils, at which time the reactor was scrammed so that the condenser vacuum could be lowered to allow a faster slowdown of the turbine.

At this point, the turbine torsional test was postponed until the test methodology and procedural problems could be resolved.

How This Event Shaped the Nuclear Power Industry
Many of the causes and contributors to the Chernobyl disaster were present on a smaller scale in this event. There were similar lack of testing controls and time pressures on operating and testing personnel. Testing activities were inadequately controlled and were allowed to continue even though unexpected plant and equipment responses were encountered and significant procedural inadequacies existed. The industry responded with one of the key Significant Operating Experience Reports, SOER 91-1, Conduct of Infrequently Performed Tests or Evolutions.

SOER 91-1 required a number of important actions, including the following:

- Establish controls that ensure management expectations are met during tests that could significantly degrade the plant's margin of safety.
- Specify the requirements for the nature and quality of test guidance so that limits and actions to take if problems are experienced are clearly specified.
- Senior line managers are expected to brief operating and testing personnel on expectations before they perform the activity.

18

Steam Generator Tube Rupture

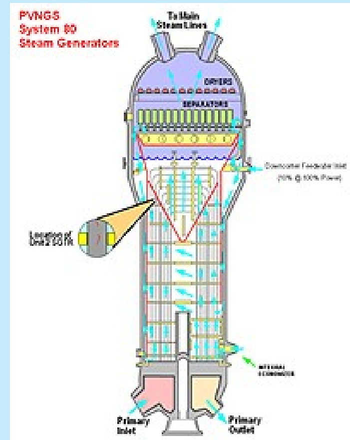
March 14, 1993 - Palo Verde 2 (PWR)

Nuclear Note:

The main steam line radiation monitors are sensitive to high-energy N-16 gamma created during the fission process. The high energy-gamma is then negated by the scram. Training did not prepare operators to expect this response.

Steam generator tube rupture events significantly increase the risk of uncontrolled radiological releases to the environment. Cleanup and repairs are difficult and costly and take a long time. Also, plants live with the effects of contaminated secondary systems for years.

In this event, operators had difficulty diagnosing the source of the leak, which caused delays in isolating the 240 gallon-per-minute steam generator tube rupture. As a result, 750,000 gallons of water in the secondary system were contaminated, and 48,000 gallons spilled from overfilling the condenser. There were leaks into the surrounding yard areas from the turbine building. The industry responded by restructuring emergency operating procedures to strengthen diagnostics.



Additional Resources

- SOER 93-1, Diagnosis and Mitigation of Reactor Coolant System Leakage Including Steam Generator Tube

How It All Started

A tube rupture on Unit 2 caused an immediate decrease in pressurizer pressure and level. Within seconds, the associated main steam line radiation monitor alarmed. However, neither the condenser exhaust monitor nor the steam generator blowdown radiation monitor alarmed because of transit time and high alarm setpoints. This confused operators because tube rupture training taught crews to expect alarms on the condenser exhaust and steam generator blowdown, but not the main steam line radiation monitor alarm.

As pressurizer level decreased, the crew isolated reactor coolant letdown and a started another makeup pump. At this point, the location of the leak was not apparent to the crew. As a precaution, the crew diverted condensate from the hotwell to the condensate storage tank, thereby preventing contamination of the tank. Following these actions, pressurizer level decreased at a slower rate; however, the level decrease continued. The reactor was manually scrammed at 25 percent level. Cooldown from the scram caused a quick drop in pressurizer level and pressure, and safety injection automatically initiated, causing a containment isolation. This isolated steam generator blowdown and the associated radiation monitors. After the scram, the main steam line radiation monitor alarm cleared.

Attempts to diagnose the event using the postscram diagnostic flowchart were unsuccessful because the flowchart indications of a tube rupture no longer existed (blowdown, main steam line, and condenser exhaust radiation monitor alarms). The functional recovery procedure was entered.

As directed by the functional recovery procedure, operators restored flow to the blowdown radiation monitors, which alarmed several minutes later. The condenser exhaust radiation monitor subsequently alarmed. These alarms, received approximately one hour after the onset of the SGTR, provided the indications needed by the diagnostic flowchart for a tube rupture; however, procedural rules of use required that the functional recovery procedure be continued until a designated exit point is reached. A sense of urgency did not exist because steam generator level, pressurizer pressure and level, and reactor coolant system temperature were generally stable and under control.

Two hours after the tube rupture occurred, the source was identified as No. 2 steam generator. Because of the delays isolating the steam generator, 750,000 gallons of water in the secondary systems became contaminated. Over the next five days, contamination levels were reduced by recirculating the condensate-feedwater systems through the full-flow condensate polishers. However, unknown to the operators at the time, additional water continued to enter the condenser from the gland seal steam exhaust that was in operation to maintain condenser vacuum. The condensate divert from the condenser to the condensate storage tank had previously been isolated, and condenser level increased to 22 feet above normal. Level eventually reached the suction of the condenser vacuum pumps. As a result, vacuum pumps were secured and condenser vacuum was lost. Contaminated water leaked from multiple locations in the condensate system, overfilled the turbine building sumps, and spilled onto the turbine building floor. An estimated 48,000 gallons of condensate, contaminated with low levels of radioactive material, was lost. Approximately 16,000 gallons of the spilled water reached areas outside the turbine building through doorways.

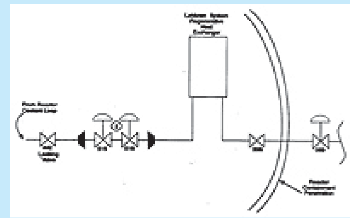
How This Event Shaped the Nuclear Power Industry
Significant improvements were made in diagnostic guidance included within emergency operating procedures and rules of usage. Additionally, licensed operator simulator training and simulator modeling were strengthened to better prepare licensed operators for emergency operations, and in particular, steam generator tube ruptures.

19

Repeated Sealant Injections

August 5, 1993 - Millstone 2 (PWR)

In this event, station management allowed operation of Millstone 2 to continue without properly addressing chronic leakage from a small manual valve (2CH-442) that was an unisolable part of the reactor coolant pressure boundary. As many as 30 attempts to stop the leakage with leak sealant were made, which ultimately caused the leakage to increase, thereby forcing the shutdown of the unit.



Additional Resources

- SER 28-93, Increased Leakage from an Unisolable Reactor Coolant Leak After Repeated Sealant Injections (11-30-1993)

This event is often called the "442" event, referring to the designation of the leaking valve. Management justified its decision to operate with the temporary repairs without considering the potential for problems. As a result, management lost sight of nuclear safety, and a non-isolable reactor coolant system boundary valve was damaged.

What Happened

In May 1993, two small steam plumes were noted coming from a 2-inch letdown isolation manual valve, coming from a body-to-bonnet flange joint. This valve is a non-isolable valve at reactor coolant system pressure. The valve's body-to-bonnet studs were tightened, but the leakage continued. There was no engineering analysis of the adequacy of the body-to-bonnet stud torque values or the possibility of using higher torque valves. In fact, it was later discovered that the torque values on the vendor-supplied drawing used during this maintenance were below the value required to assure joint tightness. The leakage did not exceed regulatory limits, so the reactor was returned to 100 percent power.

Station management decided to use on-line leak sealant injections to stop the flange leakage because of past success with the method. This involves drilling holes in the component body and injecting a paste-like substance that hardens in the presence of steam to stop the leakage. It was later determined that the torque values on the vendor-supplied drawing used were below the value required to ensure joint tightness.

The initial leak repair effort was made in early June. The leak stopped for about an hour, so a second hole was drilled in the valve so more sealant could be injected. In addition to these two injections, over the next two months, 28 other sealant injections were made because of recurring leakage. In addition, the valve flange was peened several times using a pneumatic peening tool. Although peening is an acceptable practice for capturing the leak sealant, caution must be exercised to prevent damage to the component. Precautions and limitations on the use of peening were not defined in the work package.

On August 5, during another injection of sealant into the valve, the reactor coolant leak rate suddenly increased to a value greater than allowed, and the unit was manually shut down. Inspection of the valve following unit shutdown indicated that one of the four body-to-bonnet studs had failed as a result of tensile overload caused by peening of the valve body-to-bonnet joint during the repair attempts. In addition, the sealant injection ports had been improperly drilled.

Other Issues

During the multiple attempts to repair the valve, a stress analysis of valve structural integrity was performed to evaluate for acceptable drilled-hole locations and sealant injection pressures. However, safety evaluations for modifications to the valve were not performed to assess the overall impact on plant safety, including the consequences of valve failure or the prudence of repeated sealant injections and peening operations.

On several occasions during the repair activities, personnel involved in the sealant injection work raised questions regarding valve integrity and brought them to the attention of supervisors. At one point, a through-wall crack in the valve body was suspected, and a recommendation was made to shut down the plant. Additional evaluation of the through-wall indication determined that the leakage path was the stud hole in the valve bonnet. The technical aspects of component integrity were addressed; however, the nuclear safety aspects of an unisolable reactor coolant leak were not fully considered.

How This Event Shaped the Nuclear Power Industry

This event brought into focus the dangers of emphasizing production over nuclear safety. A key lesson was the importance of senior nuclear managers periodically emphasizing to personnel that nuclear safety considerations always take priority over production goals and that decisions must always reflect an overriding emphasis on protecting the reactor core.

In addition, tighter controls on temporary leak sealing processes were instituted.

20

Reactor Scram and Safety Injection

April 7, 1994 - Salem 1 (PWR)

Nuclear Note: *Operators should move control rods only in a controlled, deliberate manner, carefully monitoring indications as reactivity is changed.*

This event resulted in the phrase "conservative decision-making" and the issuance of one of the most important SOERs: red-tabbed SOER 94-1, Nonconservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety Injections, and Water-Solid Conditions.

Travelling Screen

Additional Resources

- SOER 94-1, Rev. 1, Nonconservative Decisions and Equipment Performance Problems Result in a Reactor Scram, Two Safety (02-14-1995)

Operators at Salem had experienced the initiating conditions before. High tides on the Delaware River sometimes brought heavy accumulations of dead reeds and grasses from nearby marshes, which accumulated on circulating water intake travelling screens. This problem required rapid load reductions because the traveling screens could not handle this volume of debris. Operators were often praised for their ability to keep the plant on line under such adverse conditions. In this event, the nonconservative attempts by operators to keep the plant on line created the conditions for the multiple problems experienced.

What Happened

On April 7, 1994, operators rapidly reduced power at Salem Unit 1 because marsh grass was clogging the circulating water intake screens, causing the circulating water pumps to trip. The operating crew had difficulties in balancing reactor power reduction with the turbine load reduction, making it hard to control reactor coolant temperature. At one point, the reactor coolant temperature dropped below the allowable minimum temperature for criticality. Reactor coolant pressure and pressurizer level decreased rapidly, causing a letdown isolation. The pressurizer heaters deenergized because of low pressurizer level. In addition, condenser backpressure exceeded limits for continued turbine operation. Nevertheless, turbine operation was continued as the crew attempted to raise reactor coolant temperature and recover circulating water flow.

Operators were distracted throughout the transient. At one point, the operator at the reactor controls portion of the console was sent to another part of the control board to change the electrical alignment. This left important indications and controls inadequately tended.

In the effort to restore temperature to the range required for critical operation, control rods were withdrawn continuously for about 55 seconds, until this action was terminated by an automatic reactor scram at the 25 percent low-power high-flux scram setpoint that was unanticipated by the crew. The scram was followed immediately by a partial safety injection and partial main steam isolation.

Subsequent to the reactor scram, the reactor coolant system temperature increased after the main steam isolation valves were closed. The reactor coolant temperature was not stabilized, and the main steam atmospheric dump valves failed to operate as designed to limit the temperature increase. The reactor coolant temperature increase, combined with a partial safety injection, raised pressure and increased pressurizer level to water-solid conditions. This resulted in repeated, rapid opening and closing of the pressurizer power-operated relief valves.

The reactor coolant system heatup increased secondary-side pressure and resulted in actuation of several main steam safety valves. Steam released through the main steam safety valves and the resulting cooldown caused the water-solid reactor coolant system to depressurize rapidly and resulted in a second automatic safety injection actuation. The reactor coolant system was repressurized, resulting in additional cycles of the pressurizer power-operated relief valves.

How This Event Shaped the Nuclear Power Industry

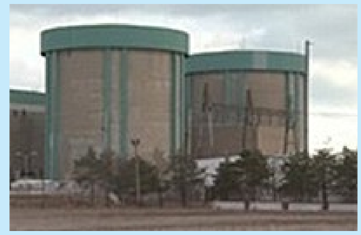
Many important lessons were learned; however, the key message of the event is that operators, when faced with unexpected or uncertain conditions, must place the plant in a safe condition and must not hesitate to reduce power or scram the reactor. The industry also began to place a high priority on resolving equipment problems - operator burdens - that complicate the operator’s ability to control the plant during transients.

Condenser Tube Sheet

21 Reactivity Mismanagement During Shutdown

February 21, 1997 - Zion 1 (PWR)

This event sharpened the industry's view of reactivity control and set a course of escalating standards in expectations for control room conduct during reactivity changes. Distractions to operators in the control room were also addressed. Now, reactivity changes are done in careful, deliberate actions. The control room is ordinarily quiet, and business is conducted outside the control room proper.



Additional Resources

- SER 9-97, Unrecognized Reactivity Mismanagement During a Reactor Shutdown

In this event, control rods were moved in lengthy steps without proper regard for the amount of reactivity being changed. There was insufficient monitoring by the operator of reactor power, and insufficient oversight by shift management. Operators and supervisors were distracted by the many activities in the control room.

What Happened

With Unit 1 at power and Unit 2 in an outage, the common control room was busy on February 21, 1997. The shift supervisor divided his time between the two units coordinating testing and maintenance activities. During the Unit 1 shutdown, the crew had to deal with many distractions, including radiation monitor system and other surveillance testing activities, equipment troubleshooting, auxiliary boiler startup, a liquid waste discharge, and air compressor maintenance.

On that morning, Unit 1 had been required by technical specifications to shut down within four hours because of an inoperable containment spray pump. Reducing power to comply was delayed by 90 minutes because the unit was already at a lowered power level (42 percent) start with, and there was ample time to comply.

When power was reduced to 7 percent and preparations were being made to trip the main turbine, the shift supervisor decided to keep the reactor critical in mode 1 to conduct required maintenance. The shift supervisor instructed the control room supervisor to maintain the reactor critical after the turbine was manually tripped; however, he did not tell him to remain in mode 1. After the turbine was tripped, the control room supervisor instructed the reactor operator to insert control rods and stabilize reactor power at 2.5 E-2 percent (the point of adding heat). The reactor operator inappropriately interpreted this step to mean he should insert control rods continuously until power reached 2.5E-2 percent. The reactor operator then continuously inserted control rods.

Over the next four minutes, the reactor operator inserted the control rods at 30 inches per minute, adding a large amount of negative reactivity to the core. Reactor power decreased to the point of adding heat at a negative .33 decade per minute startup rate. When the reactor operator stopped inserting the rods, reactor power continued to decrease because of the large amount of negative reactivity added. Neither the control room supervisor nor the shift supervisor had been monitoring the reactor operator, and neither was aware how far the control rods had been inserted. At this point, the reactor was essentially shut down. Unit 1 reactor power continued to decrease. The reactor operator then began continuously withdrawing the control rods for nearly two minutes in an attempt to maintain power at the point of adding heat. This constituted an unauthorized startup of the reactor.

The reactor operator stopped withdrawing the control rods when the shift supervisor ordered a reactor scram because the containment spray pump limiting condition for operation was about to expire. Station personnel later determined the positive reactivity added during the control rod withdrawal resulted in an unauthorized mode change and startup of the reactor.

A reactor engineer was the only person in the control room who observed the inappropriate control rod movements, but he did not effectively communicate his concerns over the reactor operator's actions to control room supervision. Shortly after the RO began withdrawing the control rods, the reactor engineer commented to the operator, "I don't like this." The operator responded, "I don't like this either." Managers and other personnel present in the control room were unaware that a reactivity transient had occurred.

How This Event Shaped the Nuclear Power Industry

After this event, the industry brought great focus to control room conduct, particularly around reactivity management, control rod manipulations, oversight, and activities in the control room. Prior to this event, the control room was a hub of many other activities in addition to operating the reactor plant - it was a place for meetings, work preparation, work authorization. Since this event, these distractions have all but disappeared. Oversight is provided during reactivity changes, and expectations for how this oversight is exercised by shift management is clear.

Nuclear Note:

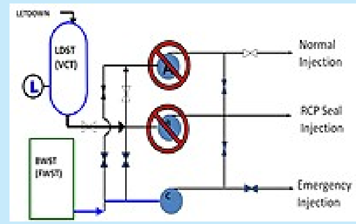
The LDST provides the common source of water for all HPI pumps.

22

Potential Loss of High-Pressure Injection from Gas Intrusion

May 1997 - Oconee 3 (PWR)

A leak in the common reference leg for both letdown storage tank (LDST) level transmitters at Oconee 3 resulted in gas binding and damage to two high pressure injection (HPI) pumps during a plant cooldown. All charging and HPI capability would have been permanently lost if operators had started the third HPI pump or if a safety injection had occurred.



Additional Resources

- SOER 97-1, Potential Loss of High Pressure Injection and Charging Capability From Gas Intrusion
- High-Pressure Injection Pumps Unavailable for Emergency Core Cooling Operation

This event is significant because the probability of fuel damage increases substantially if the HPI pumps are unavailable during a small-break loss-of-coolant accident (LOCA). With the HPI system unavailable, and if break flow is insufficient to depressurize the reactor coolant system to allow low-pressure injection systems to restore core cooling and replenish reactor vessel inventory, operator actions might not be successful in preventing core damage.

Because of this event, measures were taken to prevent or eliminate gasses from collecting in standby safety systems. These measures involved modifications to systems and better ways of filling and venting the systems.

How It All Started

Operators began cooling down Oconee Unit 3 on May 2, 1997. The 3B HPI pump was in operation to provide reactor coolant system makeup and reactor coolant pump (RCP) seal injection. The 3A pump was in standby, aligned for automatic start on low RCP seal injection flow. As the reactor coolant contracted during the cooldown, operators periodically made up to the letdown storage tank from the holdup tanks or boric acid storage tanks. Approximately 16,000 gallons of makeup were added to the LDST during the evening of May 2 and the morning of May 3. After shutdown cooling was placed in service, the cooldown continued at approximately 10oF per hour. No additional makeup was added to the LDST, and its level slowly decreased as the pressurizer level was kept within the prescribed operating band.

The indicated level in the LDST stopped decreasing at 7:45 a.m., although the actual level in the LDST had slowly decreased. Indicated level actually slowly increased because of a leak in the common reference leg. Control room personnel did not notice the slight changes in LDST level and pressure because the leak rate was small.

At 9:13 a.m., an HPI low discharge pressure alarm actuated. At this time, the LDST and 3B HPI pump suction piping were essentially empty and the 3B pump was beginning to cavitate. The 3A HPI pump started automatically on low RCP seal injection flow. With two pumps running, HPI pressure and seal injection flow were restored. The flow from the 3A HPI pump was provided by the water in its suction piping. The operator stopped the 3A pump after seal injection flow was restored. HPI flow and pressure became unstable immediately after the 3A pump was shut down.

The operator restarted the 3A pump, and HPI discharge pressure and RCP seal injection flow returned to normal. Pump motor current was higher on the 3A pump, and the operator tripped the 3B pump. A short while later, 3A HPI pump failed catastrophically, shearing the pump-to-motor coupling. The 3B HPI pump also suffered damage, albeit minor.

How This Event Shaped the Nuclear Power Industry

Because of this event, many measures were taken in the industry to eliminate gas voids in important standby systems, such as improving venting and filling practices, installing more and better high-point vents, and rerouting piping systems. SOER 97-1, Potential Loss of High Pressure Injection and Charging Capability from Gas Intrusion, was written to address PWR gas binding issues. Further efforts were undertaken to reduce gas binding in other systems, such as BWR safety systems. Although failures of safety systems dropped since the corrective measures were taken from this event, the attention brought to the issue has uncovered other problems with gas intrusion into important systems that are continuing to be addressed.

23 Electrical Workers Seriously Injured While Installing Grounds

March 26, 2002 - Browns Ferry 3 (BWR)

Calorie suits. Live-dead-live checks. Arc flash. These terms came to the forefront of nuclear electrical maintenance as a result of this significant event and several others that preceded it. As a result of this event, stations instituted sweeping changes to safety requirements during electrical maintenance. In extensive engineering studies, it was determined that workers could be adequately protected from the energies associated with switchgear in the event of arc flash.

The four electrical workers who were involved in an arc flash event at Browns Ferry 3 on March 26, 2002, while installing grounding cables in a breaker cubicle were very lucky. Not much would have had to have been different for there to be loss of life.

4-kV Switchgear at Browns Ferry 3

Additional Resources

- SER 4-02, Recurring Events: Electrical Workers Severely Injured While Performing Maintenance on Medium-Voltage Switchgear (4-kV to 13-kV)
- SEN 232, Recurring Event-Four Electricians Injured While Placing Grounds Inside a 4-kV Unit Board

What Happened

Grounding cables were being installed in preparation for isolation of the main generator and the station service transformers. The cables were being placed in five 4-kV circuit breaker cubicles and electricians were working the normal bus supply breaker in the last cubicle. The bus was energized.

The breaker cubicle has a shutter designed to prevent access to the energized source and load connection stabs. Two electricians, one on each side of the cubicle, held the shutter open, exposing both the source and load connection stabs. The upper row of stabs was energized, and the lower row (approximately 10 inches below) was not. The workers had attached one end of each of three grounding cables to a station grounding plat on the floor of the cubicle. The other ends of the cables were attached to a connecting rod (one at a time) that could be mated to a stab in the cubicle. A third electrician positioned in front of the cubicle used a voltage detector to confirm the bottom stabs were deenergized.

One of electricians picked up the grounding cable connecting rod and started to place it (inappropriately) on one of the energized stabs. One electrician holding the shutter saw this and shouted a warning while the other attempted to close the shutter. An electrical flash occurred. The arc flash burned the faces and arms of the three electricians at the breaker cubicle, and a fourth electrician watching the activity from several feet away received burns.

The worker applying the ground had become briefly disoriented and went to the wrong (energized) stab; the other two workers were unable to intervene in time. These workers were fortunate - the outcome could have been much worse. Weaknesses in prejob briefings, supervisory oversight, and self-checking practices contributed to this event.

The accident investigation team concluded that weaknesses in the use of error prevention techniques by the workers, primarily self-checking, led to the event. Additionally, weaknesses in the use of personal protective equipment (PPE), such as fire retardant clothing, appropriate gloves, and face shields, as well as a failure to establish exclusion boundaries, contributed to the extent and severity of the injuries sustained. The investigation team also recognized that a switching jacket worn by one of the workers probably saved that person's life.

How This Event Shaped the Nuclear Power Industry

Many aspects of worker and equipment protection needed improvement. This event set the following measures into motion: an expansion of the use of physical and administrative barriers, clear definitions of safe work zones, purchases of electrical flash protection equipment, and protective clothing requirements. Design groups calculated energies associated with busses and breakers. Additionally, considerable enhancements in electrical safety training provided to nuclear plant workers resulted.

24

Reactor Vessel Head Wastage

March 2002 - Davis-Besse (PWR)

Since the Chernobyl 4 reactor explosion, no other event has been as worrisome as the Davis-Besse head wastage event. This event brought safety culture to the forefront of discussions about plant performance. Safety culture principles were established, and plant staffs examined themselves against these principles.

This event is significant because the reactor vessel head had experienced so much corrosion around a control rod drive penetration that only the thin stainless steel liner remained to form the pressure boundary. Failure of that thin clad would have resulted in a large, unisolable loss-of-coolant accident.

Additional Resources

- SOER 02-4, Reactor Pressure Vessel Head Degradation at Davis-Besse Nuclear Power Station

How It All Started

On March 6, 2002, a cavity was discovered in the reactor pressure vessel (RPV) head adjacent to control rod drive mechanism (CRDM) nozzle 3 at Davis-Besse Nuclear Power Station. The cavity was discovered during an ultrasonic inspection of the CRDM penetration on the reactor pressure vessel (RPV) head. The cavity was created by boric acid corrosion of the carbon steel from CRDM nozzle leakage. The cavity extended approximately 7 inches from the nozzle and, at its widest point, was approximately 6 inches. The wastage extended into the base metal of the head, eventually reaching the nominal 3/8-inch stainless steel cladding on the inside of the head.

Davis-Besse had experienced ongoing problems with CRDM flange leaks since 1990. Chronic flange leaks and the perceived inaccessibility to the upper portions of the RPV head (there is only a 2-inch clearance between the head and the permanent insulation at the top of the head) made inspection of the upper head area and removal of boron accumulation very difficult. Over the years, station personnel began to believe that leakage in the RPV head area was most likely caused by a CRDM flange leak. Corrective actions associated with the boric acid corrosion control program focused almost exclusively on CRDM flange leakage and did not consider CRDM nozzle cracking as a potential source of leakage.

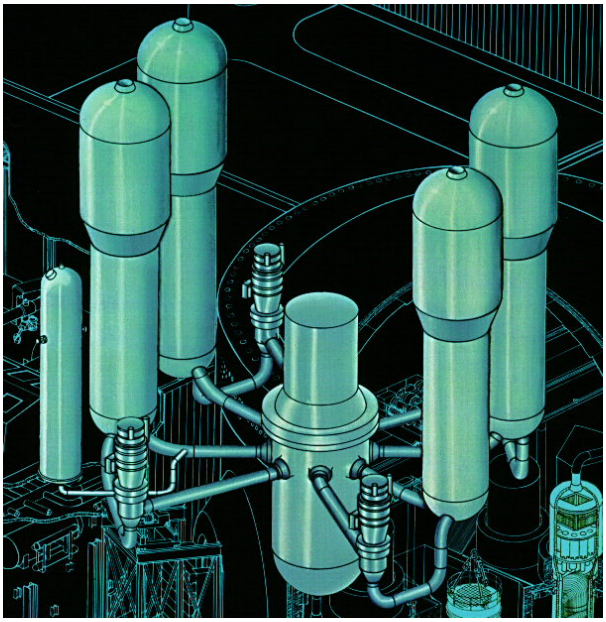
As early as 1998, solidified boric acid was observed flowing from the weep holes in the service structure to the RPV flange, and stalactites and stalagmites had formed under the RPV head insulation and on the CRDM nozzles. During the 1998 and 2000 outages, significant deposits of boron were noted. Also, the characterization of the deposits changed from predominantly porous, white deposits to hard, rust-colored deposits, indicating the acid was attacking metal.

Other indications of leakage began to show. Ferric oxide particulates (rust) were found in the containment radiation monitor filters in 1999, indicating that carbon steel corrosion was occurring in the containment. Reactor coolant unidentified leak rate increased from .1 to .9 gallons per minute from 1998 to 1999. In addition, the containment atmosphere radiation monitor filters began clogging from boron crystals to the point of needing replacement every one to two weeks. In June and July 1999, the containment air coolers began fouling, and rust deposits were found on the tubes. The significance of these indications was not recognized.

A major contributor to this event was a shift in the focus at all levels of the organization from implementing high standards to justifying minimum standards. This reduction in standards resulted from an excessive focus on meeting short-term production goals, a lack of management oversight, symptom-based problem-solving, justification of plant problems, isolationism, ineffective use of operating experience, and a lack of sensitivity to nuclear safety. In addition, workers did not raise questions about abnormal conditions that pointed to the snowballing problem.

How This Event Shaped the Nuclear Power Industry

The industry changed its thinking about the importance of carefully examining safety culture. Until this time, safety culture was rarely discussed because of the negative stigma associated with having a "safety culture problem." Since this event, open and frequent discussions of safety culture occur, and measures to shape and improve safety culture are taken. Safety culture principles have been defined. The red-tabbed SOER 02-4, Reactor Pressure Vessel Head Degradation at Davis-Besse Nuclear Power Station was issued, which required self-assessments of each station's safety culture and reviews of any conditions that could not be explained.



Westinghouse Advanced Technology Manual

Chapter 7.2 – V.C. Summer Inadvertent Criticality

Reference Read Only

HRTD Human Resources Training & Development
U.S.NRC UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

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7.2.0 V. C. SUMMER INADVERTENT CRITICALITY

Learning Objectives: (Covered in Ch 7.1 Events that Shaped the Nuclear Industry)

1. Briefly discuss the V. C. Summer startup accident.
2. Explain the causes of the accident.
3. Explain the safety implications of the accident.
4. Explain what procedural limitations and administrative controls should have prevented this accident.

7.2.1 Introduction

V. C. Summer Nuclear Station is a single-unit three-loop Westinghouse plant located in Fairfield County, South Carolina, and operated by South Carolina Electric and Gas Co. The plant began commercial operation on January 1, 1982.

On February 28, 1985, during a startup, the reactor experienced an inadvertent criticality which resulted in a reactor trip. A combination of errors associated with improper operation, inadequate supervision of an operator trainee, and miscalculation of the Estimated Critical Rod Position (ECRP) led to the inadvertent criticality. The event could have been easily prevented by better training, supervision and procedural control. The reactor protection system functioned as designed to shut the reactor down before any fuel damage was experienced.

The startup was being conducted by a reactor operator trainee under the supervision of a Senior Reactor Operator (SRO). The ECRP was determined to be 168 steps on Control Bank D (CBD). The trainee was instructed to withdraw the control banks until the CBD position reached 100 steps. It was thought that this would provide a convenient stopping point with a sufficient margin prior to criticality. Based on calculations after the event, the reactor actually went critical when CBD reached about 40 steps, but no one in the control room realized that the reactor had attained criticality. The trainee continued to add positive reactivity after the reactor was critical with continued rod withdrawal. The SRO blocked the source range reactor trip when the P-6 permissive was received without noticing the rate at which reactor power was increasing. Without the 10^5 cps trip from the source range instruments to stop the power increase, reactor power increased to approximately 6% of rated thermal power with a startup rate of about 16-17 decade-per-minute (dpm) (based on post-accident calculations) before the reactor tripped on high positive flux rate in the power range. Control bank D was at about 76 steps when the trip occurred.

7.2.2 Causes

The reactor startup which took place around 1:30 p.m. on February 28 followed intermittent operation of the unit during the previous month. One of the primary causes of the inadvertent criticality was the incorrect calculation of the ECRP. The calculation for the startup used the power block method of predicting xenon and samarium reactivity worths, which can produce significant errors if the power history is intermittent. The ECRP calculation was made based on a brief period (three hours) of power operation earlier in the day rather than on previous periods of extended operation. Another problem with the calculation involved using middle of life (MOL) rod worth curves rather than beginning of life (BOL) curves, which would have been more appropriate. The licensee’s procedure lacked any guidance regarding when the change should have been made to the MOL curves.

The operator performing the startup was a trainee and did not have an NRC license. This is allowable if the trainee has received sufficient training to be able to perform the task normally performed by licensed personnel and is directly supervised by a licensed operator. The trainee apparently had not received appropriate training because he did not know what the indications of reactor criticality are and he did not know that plant procedures required that the Excore instrumentation should be monitored for indications of criticality any time positive reactivity is being added to the core.

Supervision of the trainee was inadequate, even though several reactor operators and senior reactor operators were in the control room performing other tasks related to the startup. None of the licensed operators recognized criticality and the supervising senior operator even blocked the source range trip as reactor power was increasing into the intermediate range.

7.2.3 Safety Implications

An event more severe than the February 28 inadvertent criticality is analyzed in the V. C. Summer final safety analysis report. The uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition (a Condition II fault of moderate frequency) is analyzed to determine if acceptable fuel limits are maintained during the transient. The event is initiated with a simultaneous withdrawal of two sequential control banks having a maximum combined worth at a maximum speed of 105 pcm/sec (the addition rate was determined to be 10 pcm/sec for the 2/28/85 event). The analysis determined that the power range neutron flux trip (low setpoint) would activate at 35% power (the positive rate trip is not assumed to activate). The peak power attained, limited by the fuel doppler coefficient, is about 600% of rated thermal power (the energy release from an instantaneous power pulse would be very low). No fuel or clad damage results, and the departure from nucleate boiling ratio remains greater than 1.3, according to the analysis. The V. C. Summer inadvertent criticality event was bounded by the accident analysis with considerable margin.

7.2.4 Generic Implications

The inability to accurately predict criticality is a safety concern because technical specifications require that the calculation be performed to verify that the reactor will be critical with rods withdrawn above the rod insertion limit. This is necessary to ensure that there is enough negative reactivity available from the control rods that the reactor can be made subcritical from all operating conditions assuming the worst case conditions.

Even though the inadvertent criticality event was bounded by an analyzed accident, it demonstrated significant weaknesses in the utility’s procedures and training for licensed operators. The plant procedure did not provide adequate guidance for the calculation of an ECRP during a period of unstable or unpredictable xenon behavior. Adequate guidance on the correct source of data was not available as demonstrated by the use of the incorrect rod worth curves.

The major contributor to the incorrect ECRP calculation at Summer was the incorrect determination of the reactivity worth of xenon. Summer and other licensees typically used the power block history method to calculate the equivalent power for determining xenon and samarium reactivity worths. With this method the core power level readings are logged periodically in order to describe the previous core power history. Xenon reactivity is based on the hourly average core power for the 36 hours prior to shutdown. Samarium reactivity is based on the daily average power for the eight days prior to shutdown. In determining the reactivity worth of xenon and samarium, each logged entry has a different coefficient or multiplier associated with it. The entries nearest to the time of shutdown are the most heavily weighted. The power block method of determining the equivalent power level for estimating xenon and samarium reactivities is not very accurate when previous reactor operation is intermittent at widely varying power levels. It was determined that some of the ECRP calculations were in error by more than 50 rod steps when non-equilibrium critical data were used.

Other methods, such as computer programs, are available to determine xenon and samarium worths for use in ECRP calculations. Although potentially more accurate and not subject to calculation errors, problems are still possible with computer programs. Improper data input and software errors during development and updating of the software can introduce problems during use.

Similar instances of incorrect ECRP calculations have occurred on numerous occasions at Westinghouse plants, but proper monitoring of available indications have prevented uncontrolled criticalities and power excursions. Table 7.2-1 is a partial listing of similar events.

7.2.5 Corrective Actions

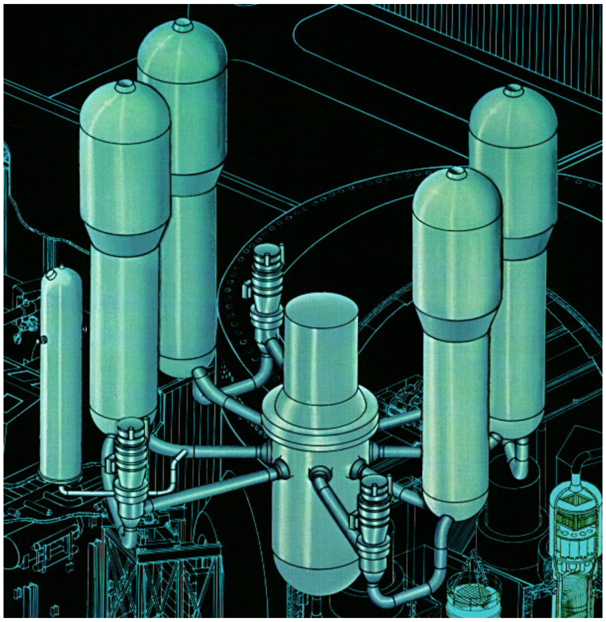
Following the incident at V. C. Summer, the licensee initiated corrective actions to prevent recurrence. Procedural inadequacies were addressed, and inverse multiplication plots were used for subsequent startups to predict criticality and to verify the accuracy of ECRPs. These actions did not prevent the problem that occurred on 5/11/85. Administrative controls on the conduct of training were improved to ensure proper supervision of on-the-job training.

Following a special inspection by USNRC Region II, enforcement action was taken for the procedural violations and inadequacies. In additon, the licensed operator supervising the evolution received a letter of reprimand.

7.2.6 Summary

The major contributor to the incorrect ECRP calculation at V. C. Summer was the incorrect determination of the reactivity worth of xenon. Similar instances of incorrect ECRP calculations have occurred on numerous occasions at Westinghouse plants. The use of inverse multiplication plots to predict criticality and to verify the accuracy of ECRPs and the proper monitoring of available indications help to prevent uncontrolled criticalities and power excursions.

TABLE 7.2-1 Incorrect ECRPs		
Date	**Plant**	**Primary Cause**
5/11/85	V.C. Summer	Incorrect ECRP, went critical below the RIL, inverse multiplication plot failed to identify error.
5/17/85	McGuire 2	Incorrect ECRP, went critical below the RIL, error caused by incorrect Xenon worth program.
8/23/84	Turkey Point 3	Incorrect ECRP, went critical 85 steps below ECRP, calculation error.
5/12/84	Turkey Point 3	Incorrect ECRP, went critical 145 steps below ECRP, calculation error.
10/31/84	Turkey Point 4	Unable to achieve criticality, calculation error resulted in improper boron addition to RCS.
5/15/85	Turkey Point 3	Incorrect ECRP, used wrong RCS temperature in calculation (525°F vs. 535°F)



Westinghouse Advanced Technology Manual

Chapter 7.3 – Water Hammer at San Onofre

2020

Human Resources Training & Development

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

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7.3.0 Water Hammer at San Onofre

Learning Objectives: (Reference Read Only)

1. Describe three types of water hammer and their causes.
2. Describe corrective actions that were taken to prevent previous steam generator water hammer problems.
3. Describe the damage caused by the water hammer event at San Onofre Nuclear Generating Station Unit 1 (SONGS-l).
4. Describe how multiple check valve failures contributed to the initiation of the water hammer at SONGS-1.
5. Discuss how check valve testing required by the American Society of Mechanical Engineers Boiler and Pressure Vessel Code could have prevented the SONGS-1 water hammer incident.

7.3.1 History of Water Hammer at Nuclear Power Plants

During the early 1970s, the NRC became aware of the increasing frequency of water hammer events in nuclear power plant systems and became concerned about the potential challenges to system integrity and operability that could result from these incidents. For pressurized water reactors, the major contributor to these incidents was a phenomenon called Steam Generator Water Hammer (SGWH). Although the significance of these events varied from plant to plant, the NRC was concerned that a severe SGWH could cause a complete loss of feedwater and affect the ability of a plant to remove decay heat and cool down after a reactor trip.

Following the SGWH that occurred at Indian Point Unit 2 in 1972, which resulted in a circumferential weld failure in one of the feedwater lines, the NRC required all utilities to submit design and operational information describing design features for avoiding SGWH. In 1978, the generic subject of water hammer was classified as an unresolved safety issue (USI A-1) and received increased NRC and industry attention.

SGWH can occur following a reactor trip when the steam generator top feedring drains and refills with cold auxiliary feedwater. NRC attention was directed at the feedring design and internal steam generator (SG) components near the feedwater (FW) nozzle. Experience had revealed that internal damage to the feedring and supports could occur. Modifications implemented to prevent SGWH generally involved installation of J-tubes to prevent the draindown of feedrings, short horizontal runs of FW piping adjacent to SG feedwater nozzles to minimize the magnitude of water hammers, and limits on auxiliary feedwater (AFW) system flow rates to avoid the rapid refill of SGs with cold water. In general, attention focused on the internal structure and design of the steam generator rather than on conditions in the FW lines and flow control components.

The NRC was aware of the possibility of developing condensation-induced water hammer extending back into the feedwater piping as a result of line voiding because of a water hammer occurrence at the KRSKO plant in Yugoslavia in 1979. Limited information on that event suggests that leaky check valves or pre-operation pump testing (i.e., start and trip test), or both, were the underlying causes. Similar occurrences had not been reported for U.S. plants, and apparently check valve failures were not considered a significant contributor to feedwater system water hammer by the NRC. Implicit in the reliance the NRC placed on J-tubes to prevent steam generator feedring voiding to prevent SGWH, was the assumption that feedwater system check valves do not leak. It appears that the NRC did not consider feedwater piping water hammer due to failed check valves to be a substantial contributor and did not pursue this issue further.

7.3.2 Water Hammer

This section discusses the water hammer which occurred at SONGS- 1, its underlying causes, and the damage incurred. Since failed check valves in the feedwater piping were the underlying cause, this section also discusses valve maintenance and inservice testing related to these valves. To clarify the discussions that follow, a brief review of water hammer phenomena and commonly accepted definitions are provided.

Hydraulic instabilities occur frequently in piping networks as a result of changes in fluid velocity or pressure. Some of the better understood occurrences include induced flow transients due to starting and stopping pumps, opening and closing valves, water filling voided (empty) lines, and pressure changes due to pipe breaks or ruptures. As a consequence of the change in fluid velocity or pressure, pressure waves are created which propagate throughout the fluid within the piping network and produce audible noise, line vibrations and, if sufficient energy transfer occurs between the pressure wave and the pressure boundary, structural damage to piping, piping supports, and attached equipment. More specifically, this pressure transient is a fluid shock wave in which the pressure change is the result of the conversion of kinetic energy into pressure waves (compression waves) or the conversion of pressure into kinetic energy (rarefaction waves). Regardless of the underlying causes, this phenomenon is generally referred to as water hammer.

A water hammer event can be characterized as one of the following three major types:

1. “Classical water hammer” generally identifies a fluid shock, accompanied by noise, which results from the sudden, nearly instantaneous stoppage of a moving fluid column. Unexpected valve closures, backflow against a check valve, and pump startup into voided lines where valves are closed downstream are common underlying causes of classical water hammer and are generally well understood.

   Analytical methods have been developed to predict loads for this type of fluid hammer and include the effects of initial pressure, fluid inertia, piping dimensions and layout, pipe wall elasticity, fluid bulk modulus, valve operating characteristics (time to open or close), etc.

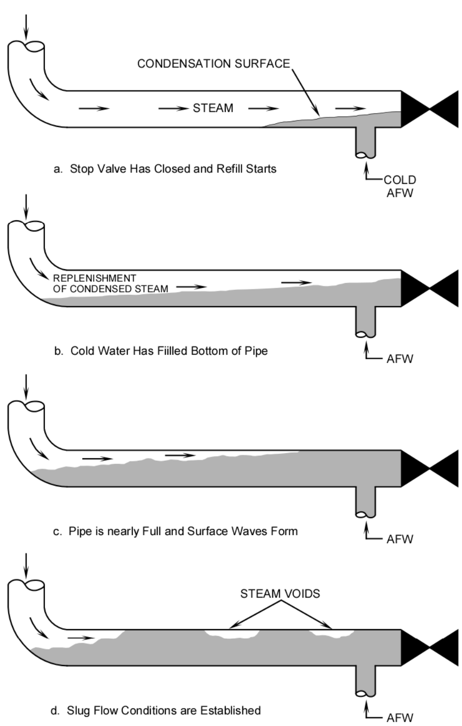


Figure 7.3-1 Filling of a Voided Feedwater Line

2. “Condensation-induced water hammer” results when cold water (such as auxiliary feedwater) comes in contact with steam. Conditions conducive to this type of water hammer are an abundant steam source and a long empty horizontal pipe run being refilled slowly with cold water. The cold water draws energy from the steam, with the rate of energy transfer being governed by local flow conditions. As the steam condenses, additional steam will flow countercurrent to the cold water, and as the pipe fills up (i.e., the void decreases) the steam velocity increases, setting up waves on the surface of the water, eventually entraining water and causing slug flow. Slug flow entraps steam pockets and promotes significant heat transfer between the steam and colder water. Figure 7.3-1 illustrates in simplified form the flow conditions which would

come about during the refilling of a voided horizontal feedwater line. Once slug flow conditions commence, a steam pocket will suddenly condense, creating a localized depressurization instantaneously. The resulting pressure imbalance across the slug (approximately 700 psi at SONGS-1) causes the slug to accelerate away from the source of pressure and toward the region of condensation.

Condensation is extremely rapid, and predicting its exact location is impossible. When the water slug suddenly strikes water in a previously filled pipe, it produces a traveling pressure wave which imposes loads of the magnitude that would be induced by classical water hammer in the piping network. This phenomenon, called condensation-induced water hammer, occurred at SONGS-1.

Predicting loads associated with this type of water hammer is extremely difficult because of the interactive and complex hydrodynamic and heat transfer phenomena which precede the sudden condensation. Void fraction (or how empty the pipe is) and subcooling (or how much colder the water is than the saturation temperature of the steam when steam and water come in contact) are two important parameters currently used in models for predicting this type of water hammer occurrence and its associated loads.

3. “Steam generator water hammer” is a condensation-induced water hammer which has occurred principally in pressurized water reactors (PWRs) with steam generators having top feedrings for feedwater injection. The underlying causes are similar to those discussed above (i.e., the voiding of the horizontal feedring and feedwater piping immediately adjacent to the steam generator and the subsequent injection of cold water). Damage from SGWH has generally been confined to the feedring and its supports and to the steam generator feedwater nozzle region. However, damage to feedwater line snubbers and supports has also occurred. An SGWH resulted in a fractured weld in a feedwater line at Indian Point Nuclear Power Plant Unit 2 in 1972.

7.3.3 San Onofre Water Hammer Incident

San Onofre Nuclear Generating Station (SONGS) Unit 1, operated by the Southern California Edison Company (SCE), is a 450-MWe Westinghouse pressurized water reactor located on the Pacific Ocean, approximately four miles south of San Clemente, California. The plant received an NRC operating license in 1967.

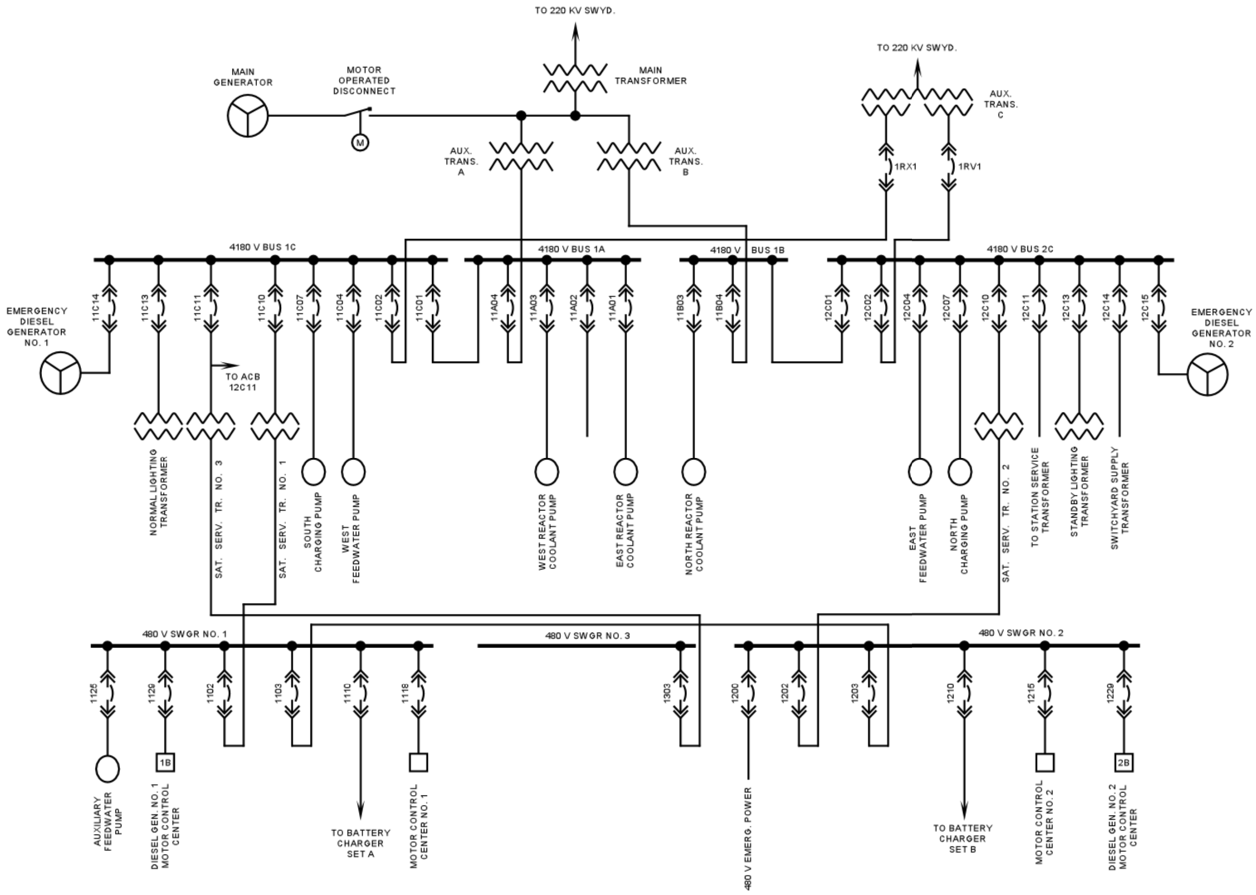


Figure 7.3-2 San Onofre Electrical System

At 4:51 a.m. on November 21, 1985, with the plant operating at 60 percent power, a ground fault was detected by protective relays associated with a transformer which was supplying power to one of two safety-related 4160-V electrical buses (see Figure 7.3-2). The resulting isolation of the transformer caused the safety-related bus to de-energize and tripped all feedwater and condensate pumps on the east side of the plant. The pumps on the west side of the plant were unaffected, since their power was supplied from another bus. The continued operation of the west feedwater and condensate pumps, in combination with the failure of the east feedwater pump discharge check valve to close, resulted in the overpressurization and rupture of an east-side flash evaporator low pressure heater unit. The operators, as required by emergency procedures dealing with electrical systems, tripped the reactor and turbine-generator. As a result, the plant experienced its first complete loss of steam generator feedwater and in-plant ac electrical power since it began operation.

The subsequent four-minute loss of in-plant electrical power started the emergency diesel generators (which by design did not load), deenergized all safety-related pumps and motors, significantly reduced the number of control room instruments available, produced spurious indications of safety injection system actuation, and caused the NRC red phone on the operator’s desk to ring. Restoration of in-plant electric power was delayed by the unexpected response of an automatic sequence that should have established conditions for delayed remote-manual access to offsite power still available in the switchyard.

The loss of steam generator feedwater was the direct result of the loss of power to the two main feedwater and one auxiliary feedwater pump motors, and the designed three-minute startup delay of the steam-powered auxiliary feedwater pump. The loss of the feedwater pumps, in combination with the failure of four additional feedwater check valves to close, allowed the loss of inventory from all three steam generators and the partial voiding of the long horizontal runs of feedwater piping within the containment building. The subsequent automatic start of feedwater injection by the steam-powered auxiliary feedwater pump did not result in the recovery of steam generator levels because the backflow of steam and water to the leak in the evaporator carried the auxiliary feedwater with it.

Later, operators isolated the feedwater lines from the steam generators, as required by procedure, which resulted in refilling the feedwater lines in the containment building. Before all feedwater lines were refilled, a severe water hammer occurred that bent and cracked one feedwater pipe in the containment building, damaged its associated pipe supports and snubbers, broke a feedwater control valve actuator yoke, and stretched the studs, lifted the bonnet, and blew the gasket of a four-in. feedwater check valve. The damaged check valve developed a significant steam/water leak, the second leak in the event.

Despite these problems, operators later succeeded in recovering level indications in the two steam generators not directly associated with the feedwater piping leak. With the re-establishment of steam generator levels, the operators safely brought the plant to a stable cold shutdown condition, without a significant release of radioactivity to the environment (an existing primary-to-secondary leak was not exacerbated) and without significant additional damage to plant equipment.

A brief description of how the SONGS-I mechanical and electrical systems involved in this event function and interact is provided. Understanding the major differences between this plant and more recently designed pressurized water reactors will clarify the basis for operator actions.

7.3.4 Plant Conditions Leading to Water Hammer

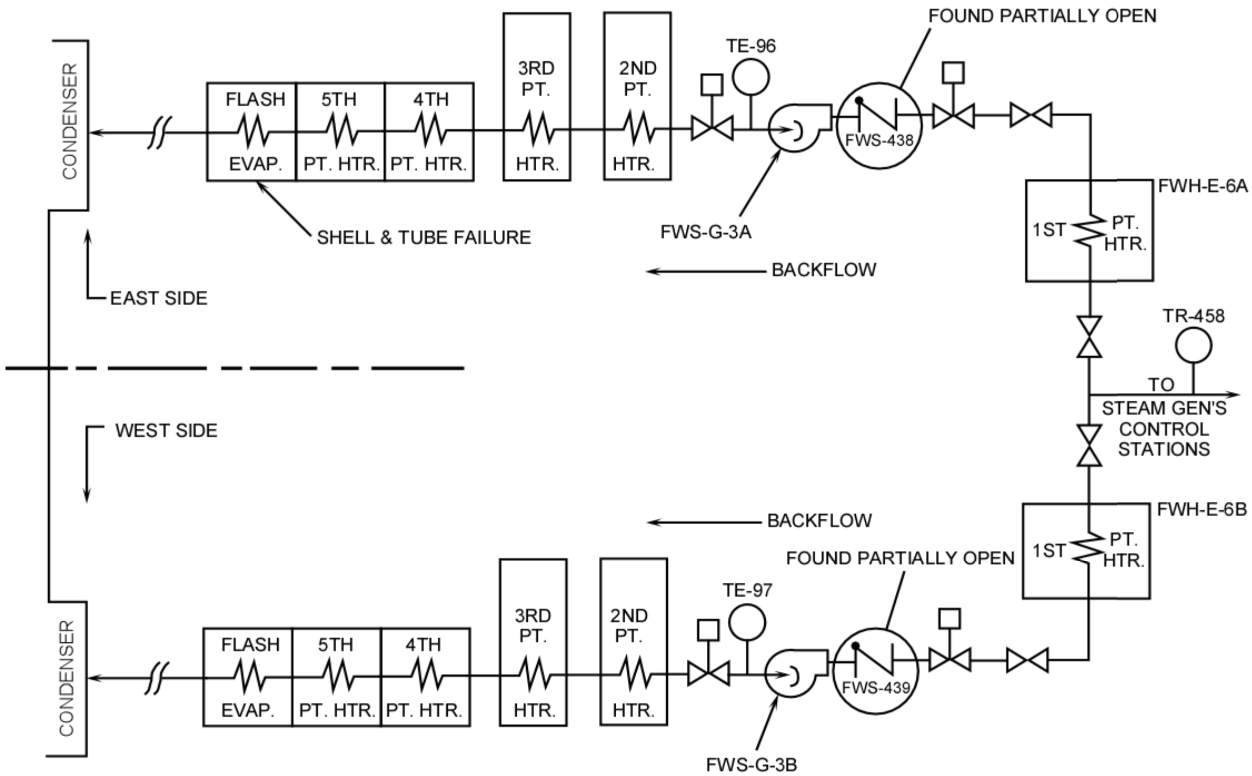


Figure 7.3-6 SONGS-1 Feedwater Flow Diagram

The plant conditions at SONGS-1 which led to a steam condensation-induced water hammer included the voiding of long horizontal lengths of feedwater lines, which allowed the backflow of steam from all steam generators before operators isolated the FW lines (by closing motor-operated valves MOV-20, 21, and 22), and the subsequent refilling of the FW lines with relatively cold (i.e., less than 100^0F) AFW. Figures 7.3-3, 7.3-4, 7.3-5, 7.3-6, 7.3-7 and 7.3-8 illustrate the flowpaths, valves and other equipment affected by this water hammer.

Upon detection of the fault on the C auxiliary transformer, relay protection de-energized 4.16-kV bus 2C, de-energizing east-side main feedwater (MFW) pump FWS-G-3A. The continued operation of west-side MFW pump FWS-G-3B, due to the unusual electrical alignment, combined with the failure of east-side MFW pump discharge check valve FWS-438 to seat, resulted in the overpressurization and failure of the east flash evaporator tube and shell. The subsequent unit trip de-energized the west-side MFW pump and denied power to electric-driven AFW pump AFW-G-IOS. With the cessation of flow to the steam generators, the failure of check valve FWS-438, and the failure of the check valves in the SG feedwater supply lines (valves FWS-346, FWS-345, and FWS-398), a path was provided for the blowdown of all three steam generators through their respective feedwater lines to the atmosphere through the failed flash evaporator.

The drop in the steam generator water levels following the unit trip initiated the AFW system, but the electric pump was de-energized, and steam-driven AFW pump AFW-G-10 took 3.5 minutes to deliver flow because of a programmed warmup period for the turbine. Thus, for three to four minutes no flow was being provided to the steam generators, and the leaking check valves permitted the horizontal feedwater lines to void. Further, the initiation of AFW flow at a rate of about 135 gpm from the steam-driven pump was not effective in halting the voiding, because flow was being carried away from the steam generators by the steam blowing down through the failed check valves in all three FW control stations and out the leak in the flash evaporator.

Following restoration of unit power, the motor-driven AFW pump started automatically, increasing the indicated AFW flow rate to a preset rate of 155 gpm per steam generator. However, all three steam generator levels continued to drop since the FW check valves remained open, the main steam system had not been isolated, and steam generator blowdown had not been isolated. Subsequently, in accordance with an emergency operating procedure for reactor trip response, operators isolated the failed FW check valves by shutting the three FW control isolation valves, MOV-20, 21, and 22, at approximately 4:55 a.m. Isolation of the feedwater trains occurred before the water hammer in the FW line to 8GB.

Subsequent to the isolation of the main FW lines, and recognition in the control room that both AFW pumps were delivering water, the operators became concerned about overcooling of the reactor coolant system and the decrease in pressurizer level. The operators decreased the AFW flows from 155 gpm to zero, and then increased them to 40 gpm. Refilling the FW lines downstream of the flow control stations was thus halted and then resumed at a much lower flow rate.

The slow refilling of the FW lines within the containment building continued from when AFW flow was first throttled to when the water hammer was reported to have occurred seven minutes later by a plant equipment operator. As noted previously, conditions conducive to steam condensation-induced water hammer in the feedwater lines were present for quite some time.

The gross failure of upstream check valves, which permitted water to drain from the feedwater lines and be replaced with steam, was the underlying cause for water hammer. Leaky check valves have been previously cited in reports of other water hammer occurrences. Five check valves are known to have been failed during the SONGS-1 event.

7.3.5 Water Hammer-Induced Damage

The following sections detail water hammer-induced damage to loop B feedwater piping and supports, to the loop B FW flow control station, and to the loop B AFW piping and describe the existing damage to feedwater system check valves.

7.2.5.1 Piping and Piping Support Damage

Damage to the loop B FW piping was confined to plastic yielding of the northeast elbow and to a visible crack on the outside of the pipe, extending approximately 80 inches axially. The crack penetrated approximately 30 percent of the pipe wall at its deepest point from the outside and approximately 25 percent on average. Damage to supports was severe in some instances. This section provides a description of the damage visible after the FW piping insulation was removed.

Figure 7.3-9 shows the loop B FW piping layout and identifies the piping support stations where damage occurred. This figure also provides directional orientation and indicates piping dimensions. Figure 7.3-10 shows principal areas of damage and indicates how the pipe moved.

The water hammer forces were sufficiently large to damage pipe supports and piping and to transmit loads through the containment building penetration structure outward to the loop B feedwater regulating station. No damage was evident to the steam generator B feedring or nozzle region that can be attributed to water hammer, nor was there evident damage to or movement of the piping between support HOOC and the steam generator B feedwater nozzle. Table 7.3-1 and Figures 7.3-9 and 7.3-10 illustrate the piping and support damage.

7.2.5.2 Feedwater Loop B Flow Control Station Damage

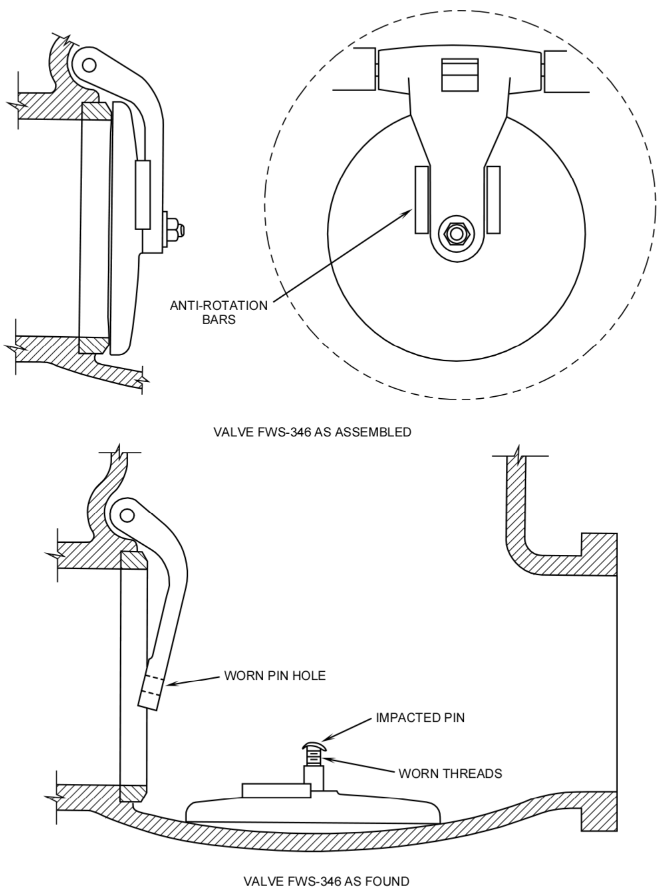


Figure 7.3-12 Check Valve FWS-346

Figure 7.3-11 shows the typical internal arrangement of a swing check valve. The water hammer originating in the feedwater line within the containment building generated a water slug which transmitted a pressure wave upstream to the loop B flow control station. Check valves FWS-346 and FWS-378, downstream of the control valves, were designed to prevent backflow, although post-event inspection revealed that the closure disk for FWS-346 (see Figure 7.3-12) was lying in the bottom of the valve chamber. Thus, any closed valve upstream of the check valve would be subjected to the water hammer loads. In addition to check valve FWS-378, flow control valve FCV-457 and motor-operated valve MOV-20 were subjected to the water hammer loads, because they had been closed by operators following the emergency operating procedures.

Because check valve FWS-378 was intact and operational, it was subjected to water hammer loads and absorbed much of the water hammer energy, whereupon the bonnet studs yielded and the gasket was forced outward against the studs. The failure of the gasket relieved much of the internal pressure, thereby minimizing damage to other equipment and valves at this station. Valve FCV-457 did incur damage to the flow actuator yoke and a bent valve stem.

7.2.5.3 AFW Piping Damage

The AFW injection points to the main feedwater piping at SONGS-1 lie in the "breezeway" upstream of the containment building steel shell. The AFW lines run horizontally and then vertically to tie into the main feedwater lines. Water hammer loads were imposed on AFW loop B piping. Although pipe movement extended several hundred feet upstream, there was no evidence of piping damage.

7.2.5.4 Valve Malfunctions

Post-event disassembly and examination of valves that contributed to water hammer conditions confirmed that check valve failures were the underlying causes for the occurrence of water hammer. Inspection findings identified the valve conditions listed in Table 7.3-2.

7.3.6 Valve In-Service Testing

The ASME Boiler and Pressure Vessel Code, Section XI, which specifies valve In-Service Testing (IST) requirements for valves like the SONGS-1 feedwater check valves, states:

> Valves shall be exercised to the position required to fulfill their function unless such operation is not practical during plant operation. Valves that cannot be exercised during plant operation shall be specifically identified by the owner and shall be full-stroke exercised during cold shutdowns. Full-stroke exercising during cold shutdowns for all valves not full-stroke exercised during plant operation shall be on a frequency determined by the intervals between shutdowns as follows: for intervals of 3 months or longer, exercise during each shutdown; for intervals of less than 3 months, full-stroke exercise is not required unless 3 months have passed since last shutdown exercise.

Additionally, the NRC staff position on cold shutdown testing of valves is as follows:

1. The licensee is to commence testing as soon as the cold shutdown condition is achieved, but not later than 48 hours after shutdown, and continue until complete or until the plant is ready to return to power.
2. Completion of all valve testing is not a prerequisite for returning to power.
3. Any testing not completed during one cold shutdown should be performed during any subsequent cold shutdowns, starting from the last test performed at the previous cold shutdown.

All feedwater system check valves are periodically tested in the closed position. The main and bypass feedwater regulating check valves are normally tested in cold shutdown (mode 5) and the feedwater pump discharge check valves are tested in hot standby (mode 3).

There are 121 valves that are subject to IST during cold shutdown. Although IST was performed during each outage, all of the valves were not tested. Consequently, the feedwater valves had been tested only one time since October 1984. The available opportunities for valve IST were not always fully utilized due to higher priority operational requirements.

Surveillance test procedures for verification of check valve closure for the main feed pump discharge check valves (FWS-438 and FWS439) require one main feed pump to be running while the other pump is stopped. The discharge valve at the idle pump is then opened and the pressure is monitored between the pump and its discharge check valve. An increase in pressure or an operator observation that the pump is rotating backwards would indicate that the check valve is not closed. While providing reasonable assurance of check valve closure, this testing method also subjects the low pressure pump suction piping to some relatively high pressures if the check valve fails to close (as in the November 1985 event), and thus damage is possible to such components as the flash evaporator. Testing with the idle pump suction valve shut would provide a more rigorous test.

Surveillance test procedures for verifying closure of other main feedwater check valves require testing to be performed during cold shutdown with the steam generators filled to a level above the feedrings. The motor-operated valve upstream of each check valve is closed, and the drain valve between this valve and the associated check valve is opened. The column of water in the steam generator provides approximately *4.5* psi of differential pressure across the valve to provide the closing force on the check valve disc. The procedure states that the section of piping between the motor-operated valve and check valve is to be drained, and that “little or no flow” from the drain should be verified. This test procedure leaves the surveillance operator to make the decision about how much flow is “little” and thus indicative of positive verification of check valve closure. The IST records do not provide a means of determining whether flow occurs or its extent, or for verifying complete valve cavity drainage before a determination is made that “little or no flow” has occurred.

Valves FWS-345 and FWS-346 failed the IST on February 24, 1985, when tested during mode 5 (cold shutdown). Maintenance work orders were prepared to repair both valves. However, on February 26, 1985, “Non-routine and Increased Frequency IST” was performed during mode 3 (hot standby), and the valves passed. During mode 3 the steam generator pressure increased the differential pressure available to seat the check valves (to approximately 700 psi) and thereby enabled them to pass. The work orders were then cancelled, and no corrective maintenance was performed.

7.3.7 Valve Failure Findings

Check valve failures caused by partial disassembly while in service do not appear to be unique to SONGS-1 or to the valve manufacturer (MCC Pacific). A limited review of licensee event reports (LERs) indicates that these valve failures are not unique.

Failures of FWS-438 and FWS-439, the main feed pump discharge check valves, may have been due to inadequate valve design, since the disc-retaining nut of each valve was not provided with a positive locking device that should have reduced the probability of the disc working loose, wedging into the valve seat, and failing open. Additionally, excessive clearances between the hinge and disc assemblies allowed the discs to rotate past the anti-rotation devices.

The failure of FWS-346, the B feedwater header check valve, may have been caused by the inadequate hardness of the disc-attaching stud, which allowed the threads to strip and the end to mushroom over, conditions contributing to the ultimate valve failure. However, the service conditions (i.e., flow-induced vibration) experienced by this valve may also have been a major contributor to failure. The failures of FWS-345 and FWS-398, the A and C feedwater header check valves, may have been due to similar service conditions.

The cracks in the seating surface of FWS378, the four-in, check valve in the B loop bypass line, appear to be service related. However, these cracks may have been caused by the significant forces on the valve from the water hammer.

Failure of the yoke of FCV-457, the loop B feedwater regulating valve, was probably due to lack of sufficient support or bracing of the valve operator during the pipe movement caused by water hammer loading.

7.3.8 Flash Evaporator Unit

During the event, the east condensate header was overpressurized, resulting in catastrophic failure of the east flash evaporator tubes and shell. The evaporator unit is in a shell which also houses two stages of low pressure feedwater heaters and drain coolers. The flash evaporators had not been used for several years, and extraction steam to them had been isolated. The evaporator condenser is part of the condensate system flowpath. The design pressure of the flash evaporator condenser and fourth- and fifth-point low pressure feedwater heater tubes is 350 psig, while the shell-side design pressure is 15 psig. The low pressure feedwater heaters were in service during the water hammer event.

When bus 2C was de-energized and the east main feed pump tripped, failed discharge check valve FWS-438 allowed the west main feedwater pump to pressurize the east condensate header.

This pressure caused a tube failure in the east evaporator condenser. The flash evaporator shell was subsequently overpressurized, resulting in the failure of the shell. After the loss of all in-plant ac power, the remaining (west) main feed pump coasted down, and the failed main feedwater regulating valve check valves (FWS345, 346, and 398) allowed backflow from all steam generators through failed valve FWS-438 to the failed tube in the east flash evaporator condenser. This backflow continued until the operators closed motor-operated feedwater header isolation valves MOV-20, 21, and 22, and main feedwater regulating valves FCV-456, 457, and 458.

Helium leak checks were performed on all east feedwater heaters, revealing no leakage beyond that expected from normal operation. The west feedwater heaters were leak tested before the unit was returned to service. The failure of the flash evaporator had no direct safety significance.

7.3.9 Turbine Breakable Diaphragms (Rupture Disks)

During the event, steam was observed issuing from the low pressure turbine breakable diaphragms. Each low pressure turbine has four breakable diaphragms designed to protect the turbine casing from overpressurization. The diaphragms, made of thin lead, are designed to break if the turbine exhaust pressure, normally subatmospheric, reaches 5 psig. The diaphragms are supported against external atmospheric pressure and normally seal the turbine casing against air in-leakage. All diaphragms were intact prior to the water hammer event.

Four of the diaphragms ruptured during the event, three on low pressure turbine 1 and one on low pressure turbine 2. Rupture of the diaphragms is not considered unusual for conditions existing after a loss of all ac power with continued energy addition into the main condenser and is of no safety significance.

7.3.10 Summary

On November 21, 1985, Southern California Edison's San Onofre Nuclear Generating Station Unit 1, located south of San Clemente, California, experienced a partial loss of in-plant ac electrical power while the plant was operating at 60 percent power. Following a manual reactor trip, the plant lost all in-plant AC power for four minutes and experienced a severe incidence of water hammer in the feedwater system which caused a leak, damaged plant equipment, and challenged the integrity of the plant's heat sink. The most significant aspect of the event involved the failure of five safety-related check valves in the feedwater system. These failures appeared in less than a year, without detection, and jeopardized the integrity of safety systems. The event involved a number of equipment malfunctions, operator error, and procedural deficiencies.

TABLE 7.3-1 Description of Feedwater Pipe Damage Following SONGS-1 Water Hammer	
Support Locations	Description of Component, Damage, Motion. Etc.
HOOC HOOB HOOA	This snubber station, the closest to the SG B, showed no visible damage or pipe movement. The feedwater pipe turns vertically, and at an angle, to rise approximately 10 feet to mate with the SG feedwater inlet nozzle.
HOOD HOO5 HOO6	These support stations were the first that showed damage (or movement) caused by water hammer. Dent in pipe that resulted when the pipe hit the concrete corner and then rebounded.
HOOG	Movement of approximately 12 inches, slippage of vertical support pads off channel beam structures and downward drop of FW pipe.
HOOH	Horizontal and vertical support pads displaced southward approximately 12 inches.
120	Evidence of first lateral motion (eastward); deformed vertical structure, and then axial rebounding which displaced pipe supports approximately 12 inches southward.
HOOK	Damage incurred at the support structure downstream of the southeast elbow. The damage incurred by the structure illustrates the magnitude of pipe motion which occurred during the water hammer pulse.
HOOL	Lateral movement (westward) of pipe which resulted in sheared vertical support structure. Concrete and support plate damaged by water hammer, nuts were loosened and bolts were missing in wall plates.
HOOM	Piping and support damage just downstream of where FW B line takes a 90-degree bend to exit the containment building.

TABLE 7.3-2 Inspection Findings		
Valve	Description	As Found
FWS-345 SG A	MFW Reg Check	Disc separated from hinge arm, disc stud broken (threaded portion).
FWS-346 SG B	MFW Reg Check	Disc separated from hinge arm, disc stud deformed.
FWS-398 SG C	FW Reg Check	Disc nut loose. Disc partially open. Disc caught inside of seat ring.
FWS-438	FWP Discharge Check	Disc nut loose. Disc partially open. Disc caught inside of seat ring. (Figure 7.3-13)
FWS-439	FWP Discharge Check	Disc nut loose. Disc partially open. Anti-rotation lug lodged under hinge arm.

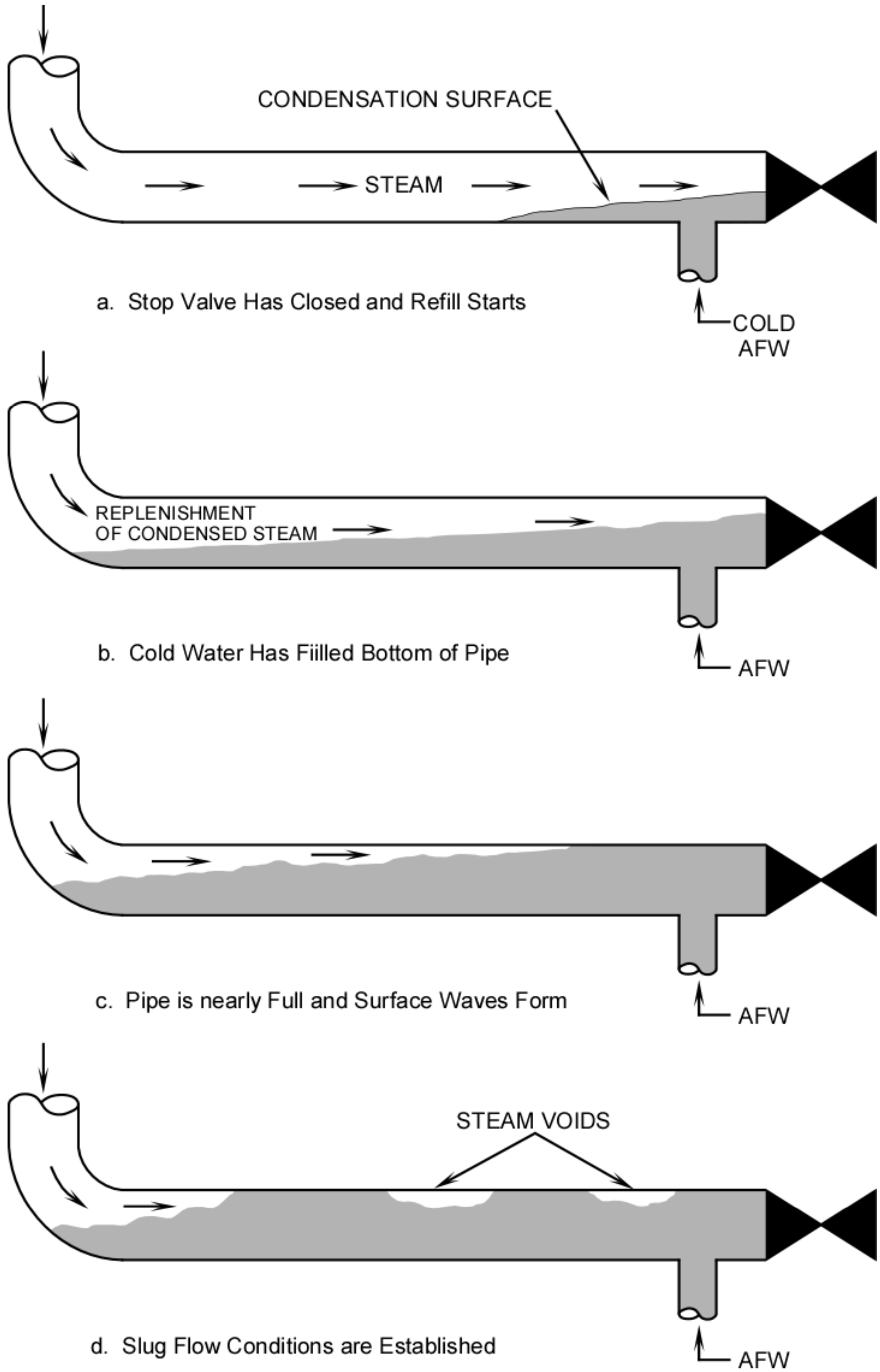


Figure 7.3-1 Filling of a Voided Feedwater Line

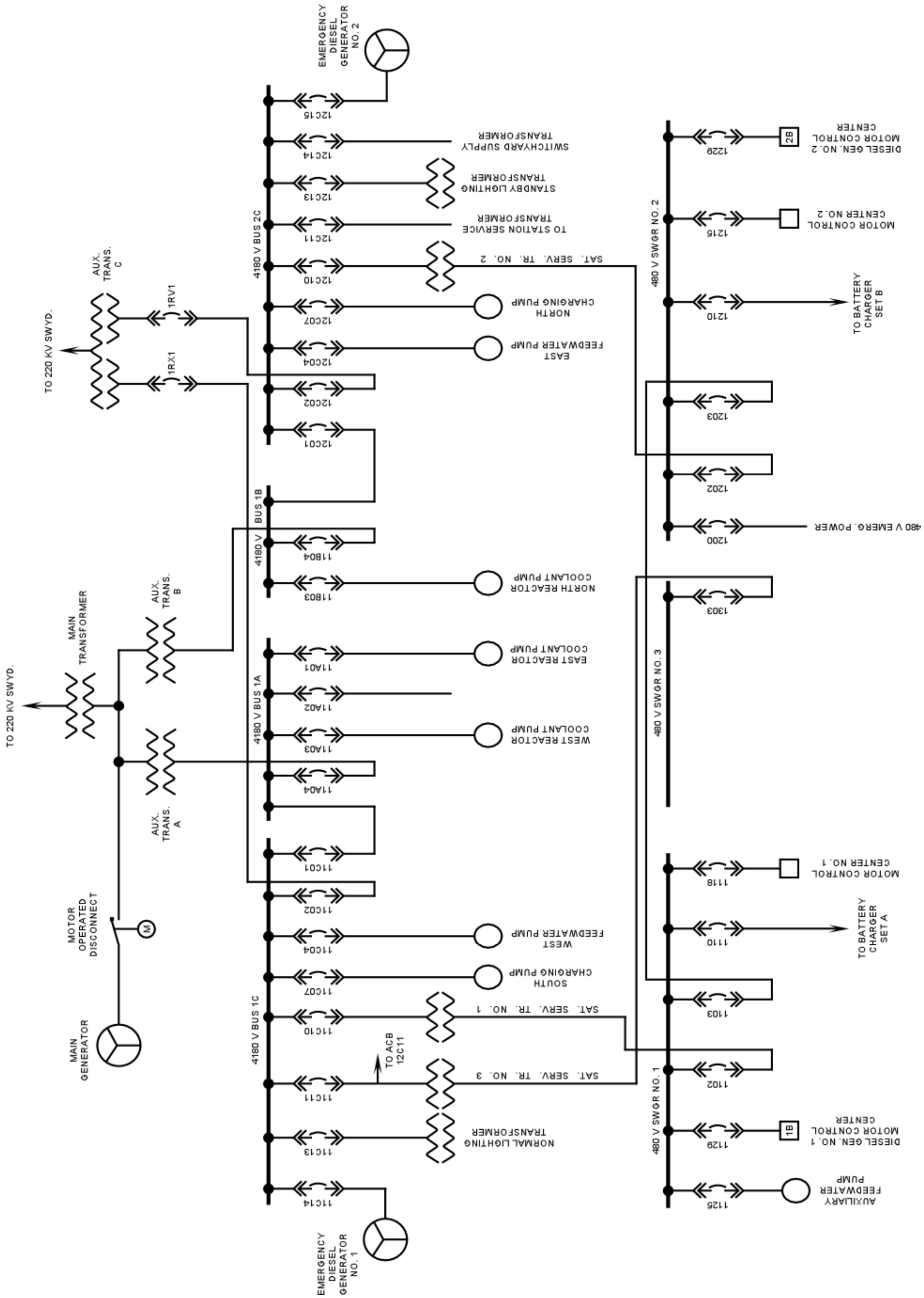


Figure 7.3-2 San Onofre Electrical System

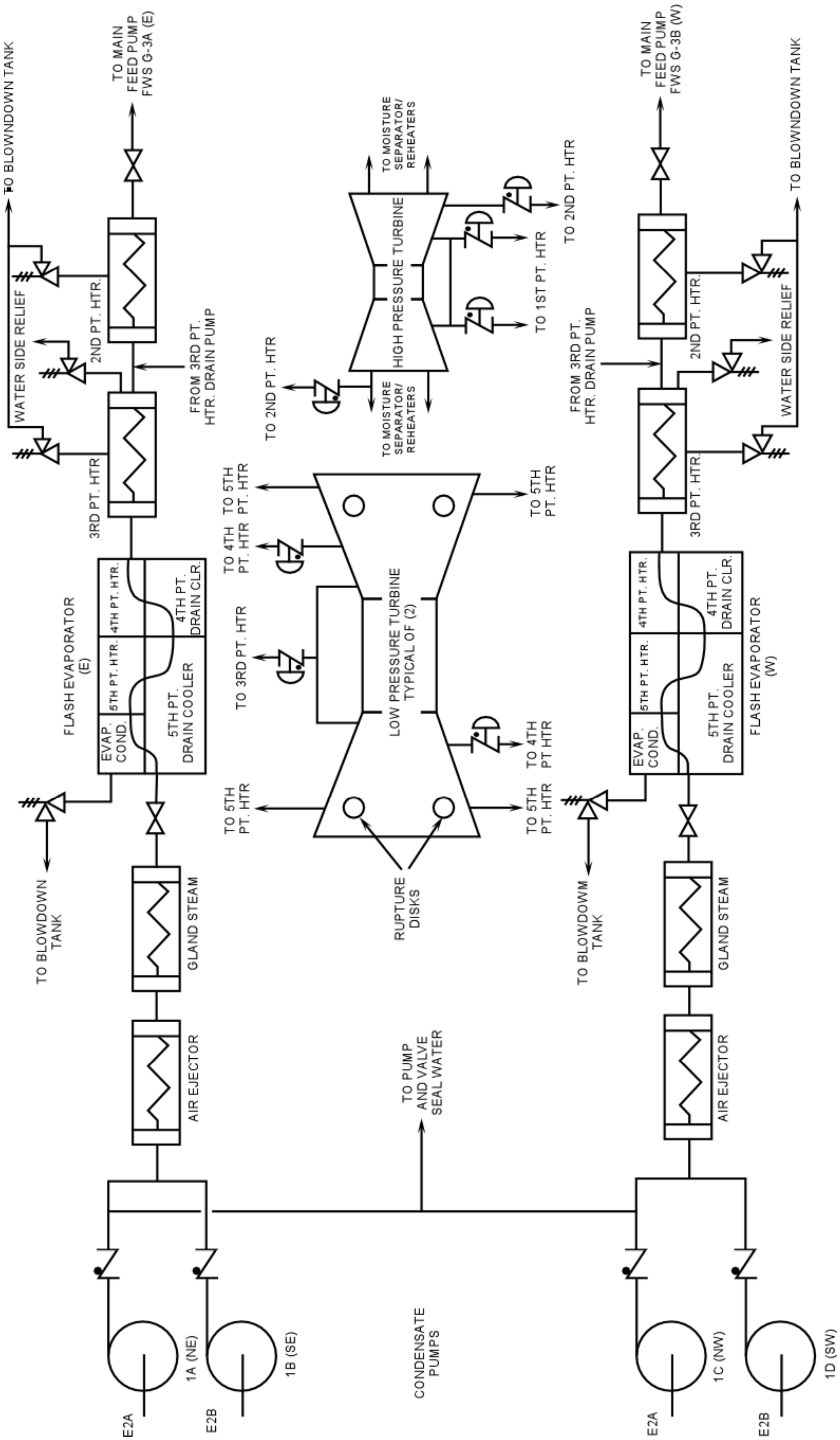


Figure 7.3-3 Condensate System

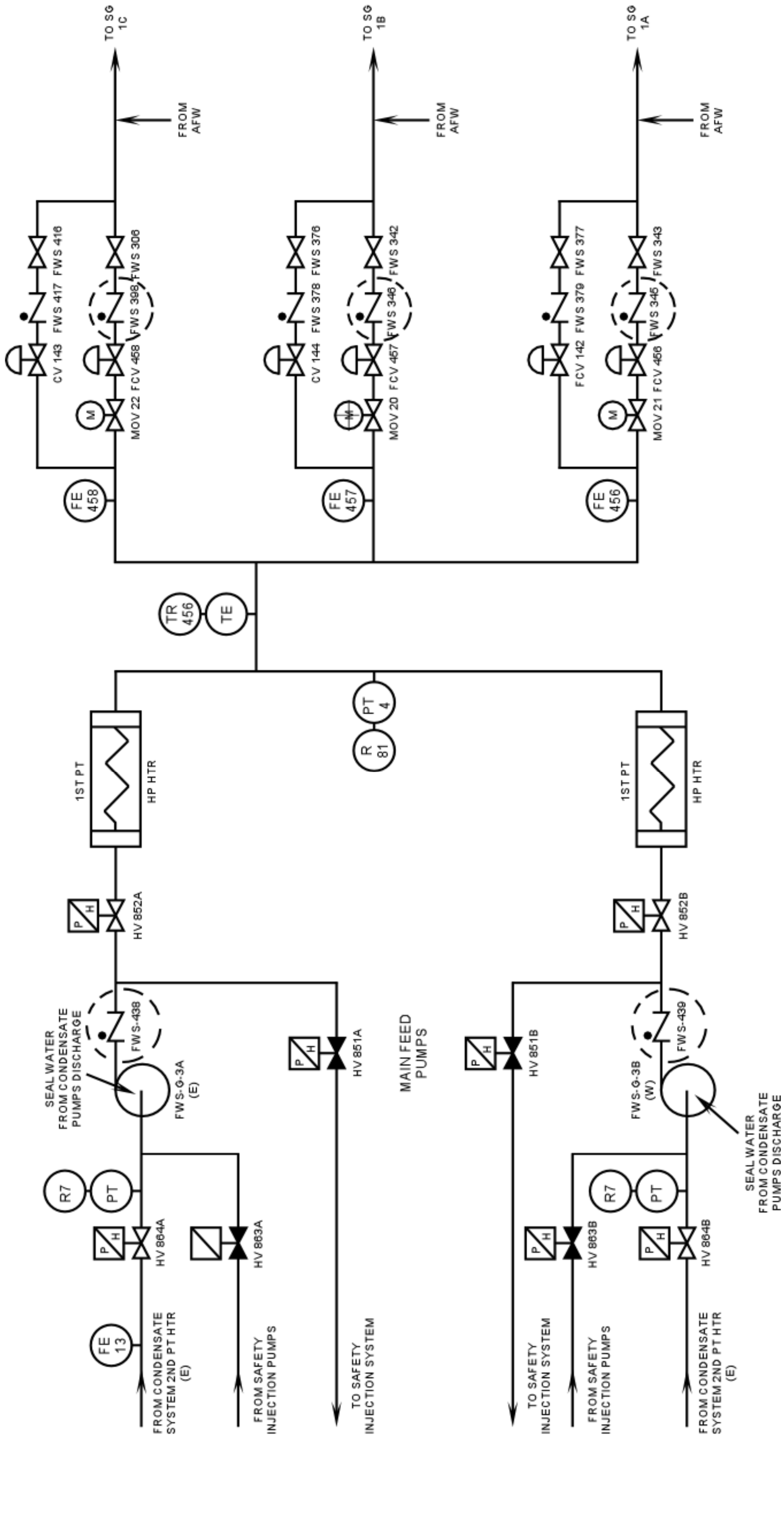


Figure 7.3-4 Main Feed System

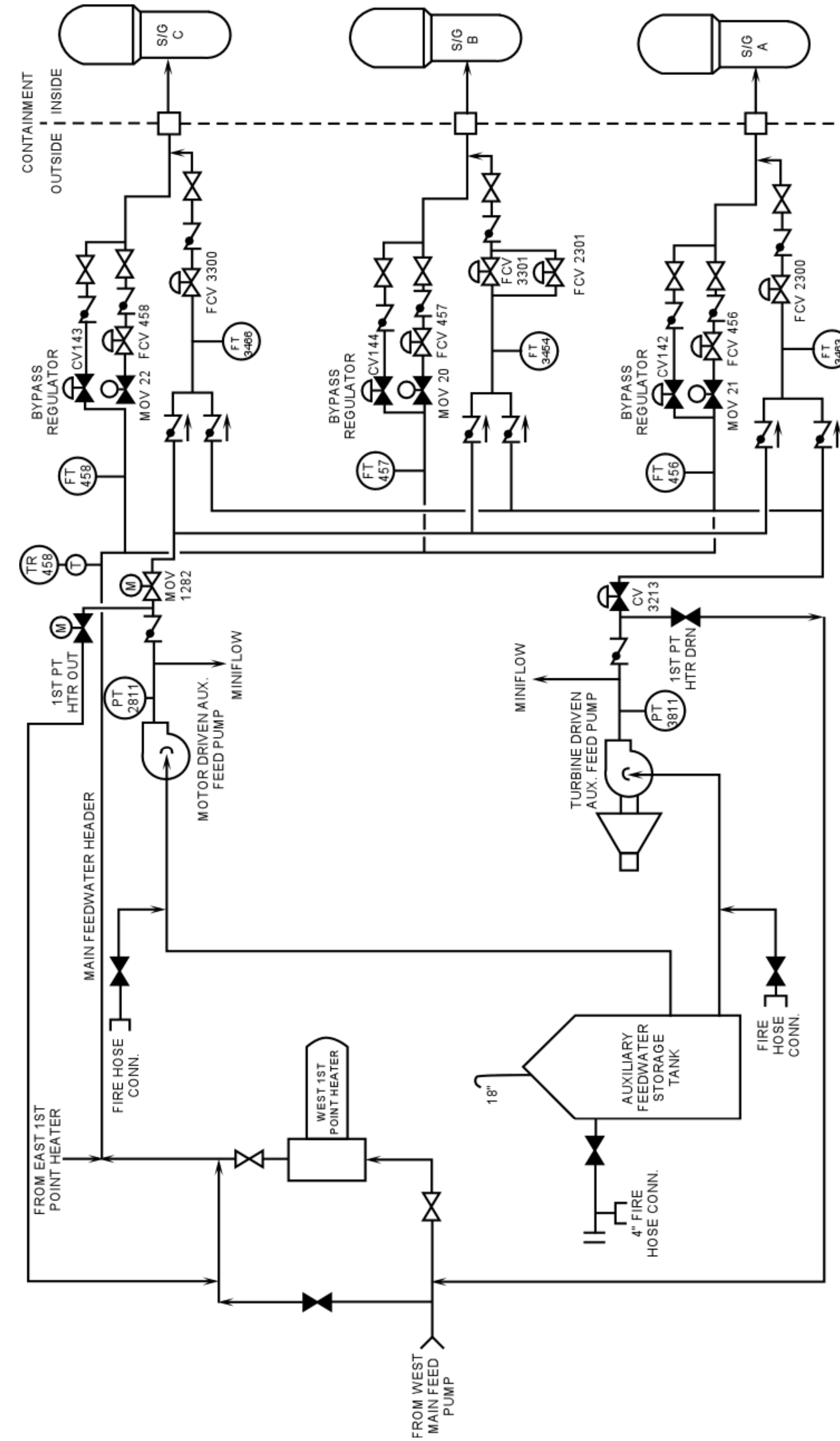


Figure 7.3-5 Auxiliary Feedwater System

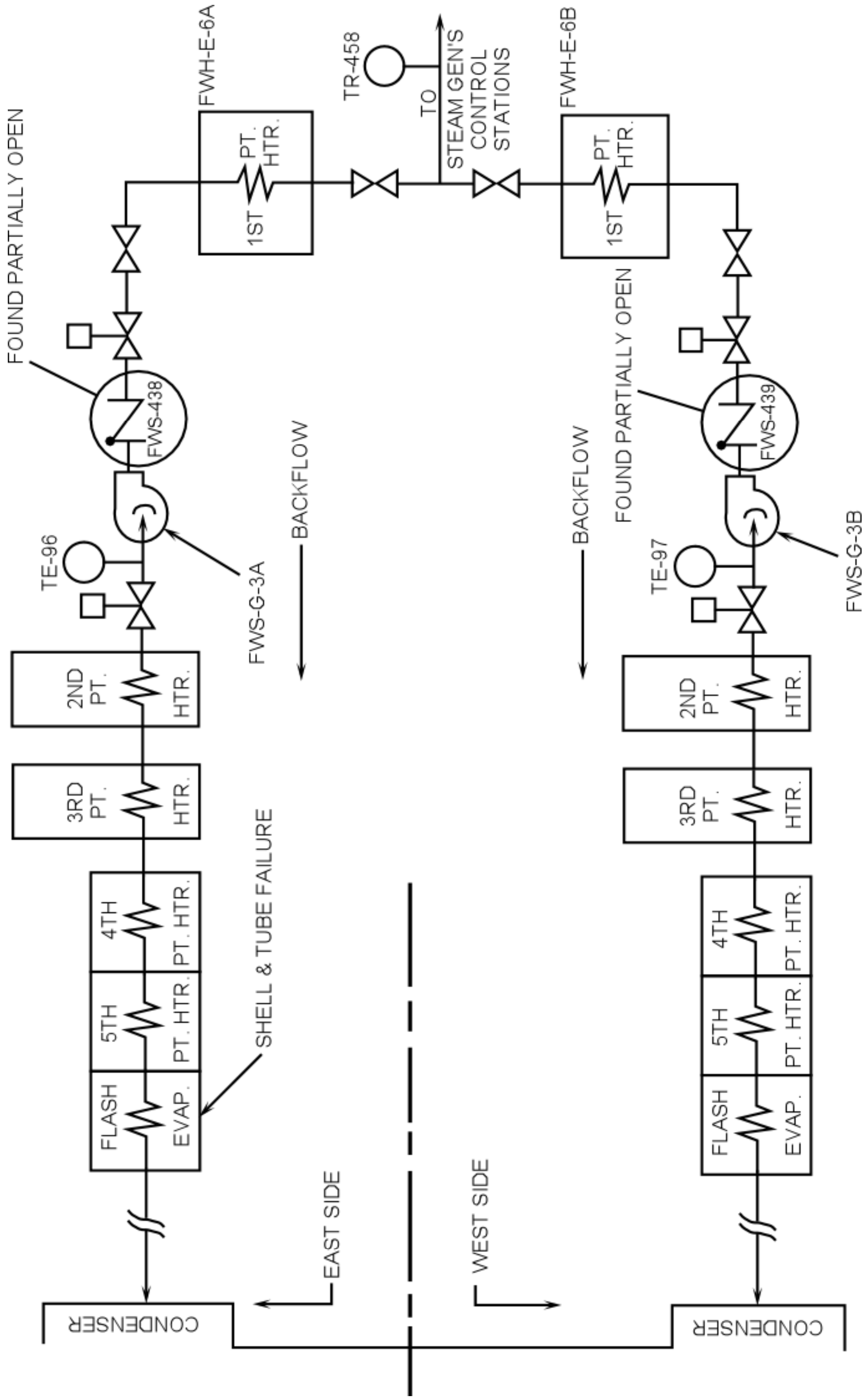


Figure 7.3-6 SONGS-1 Feedwater Flow Diagram

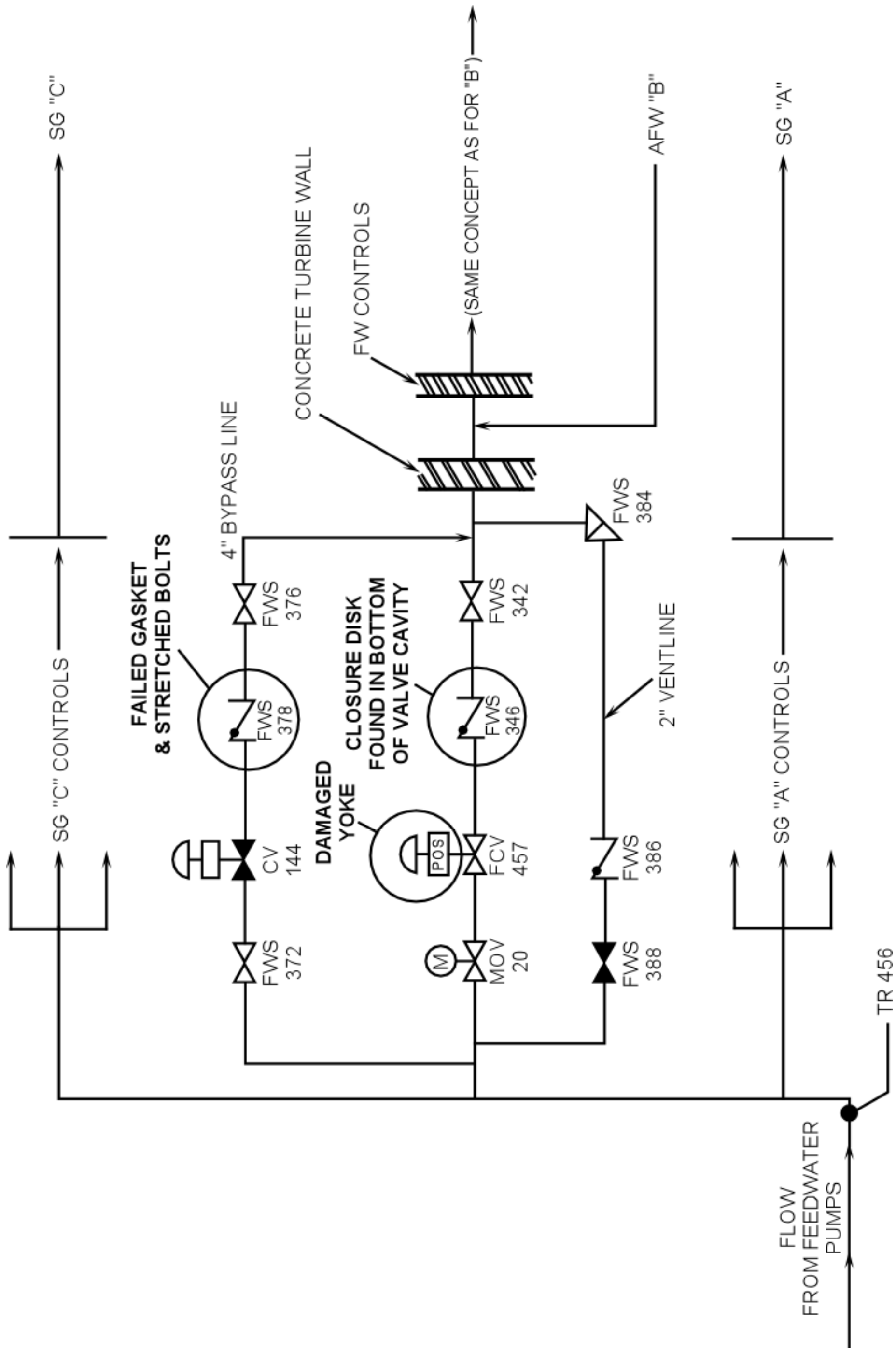


Figure 7.3-7 SONGS-1 Loop B Steam Generator Flow Control Station

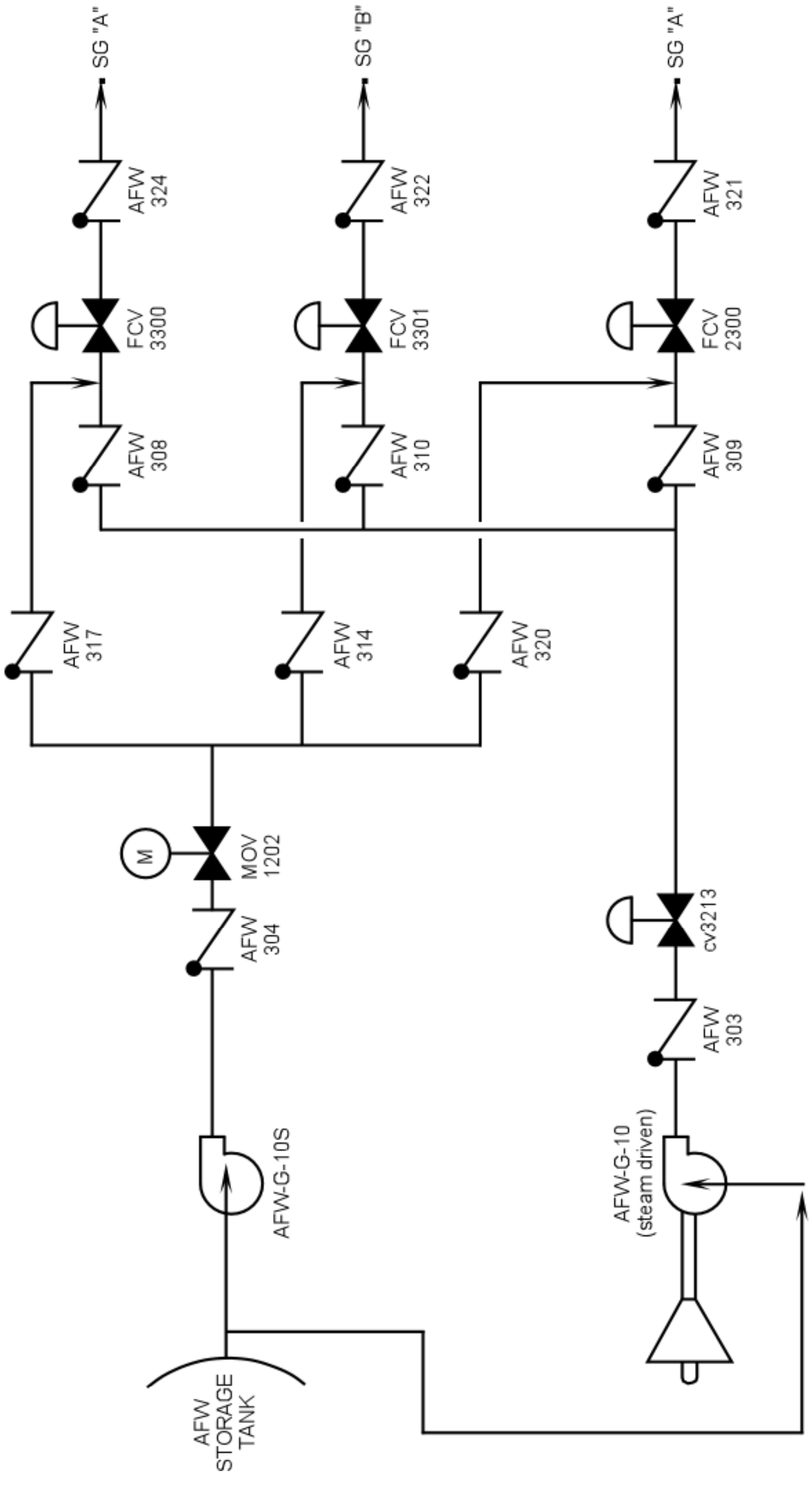


Figure 7.3-8 SONGS-1 Auxiliary Feedwater System

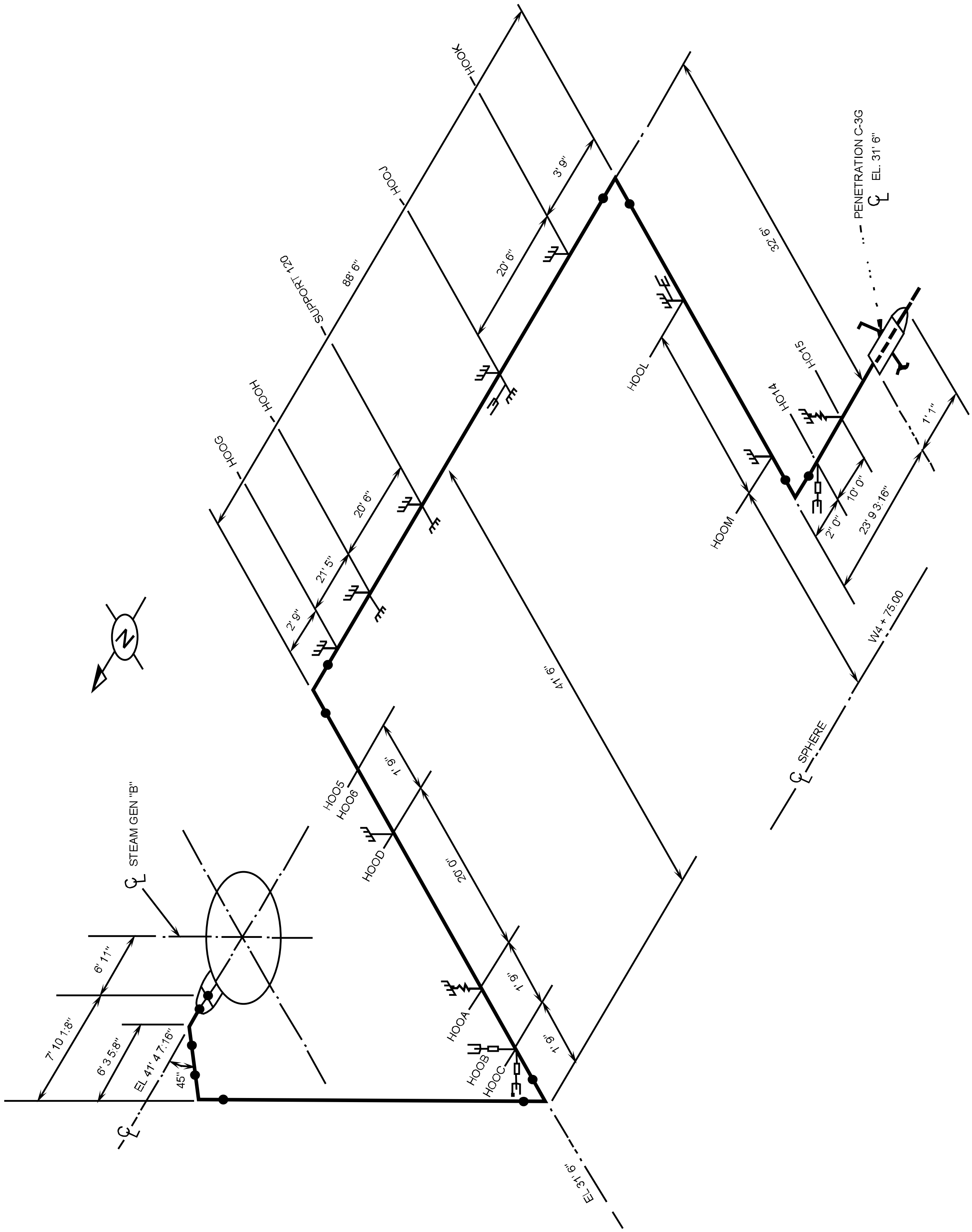


Figure 7.3-9 FW Loop B Piping and Support Layout

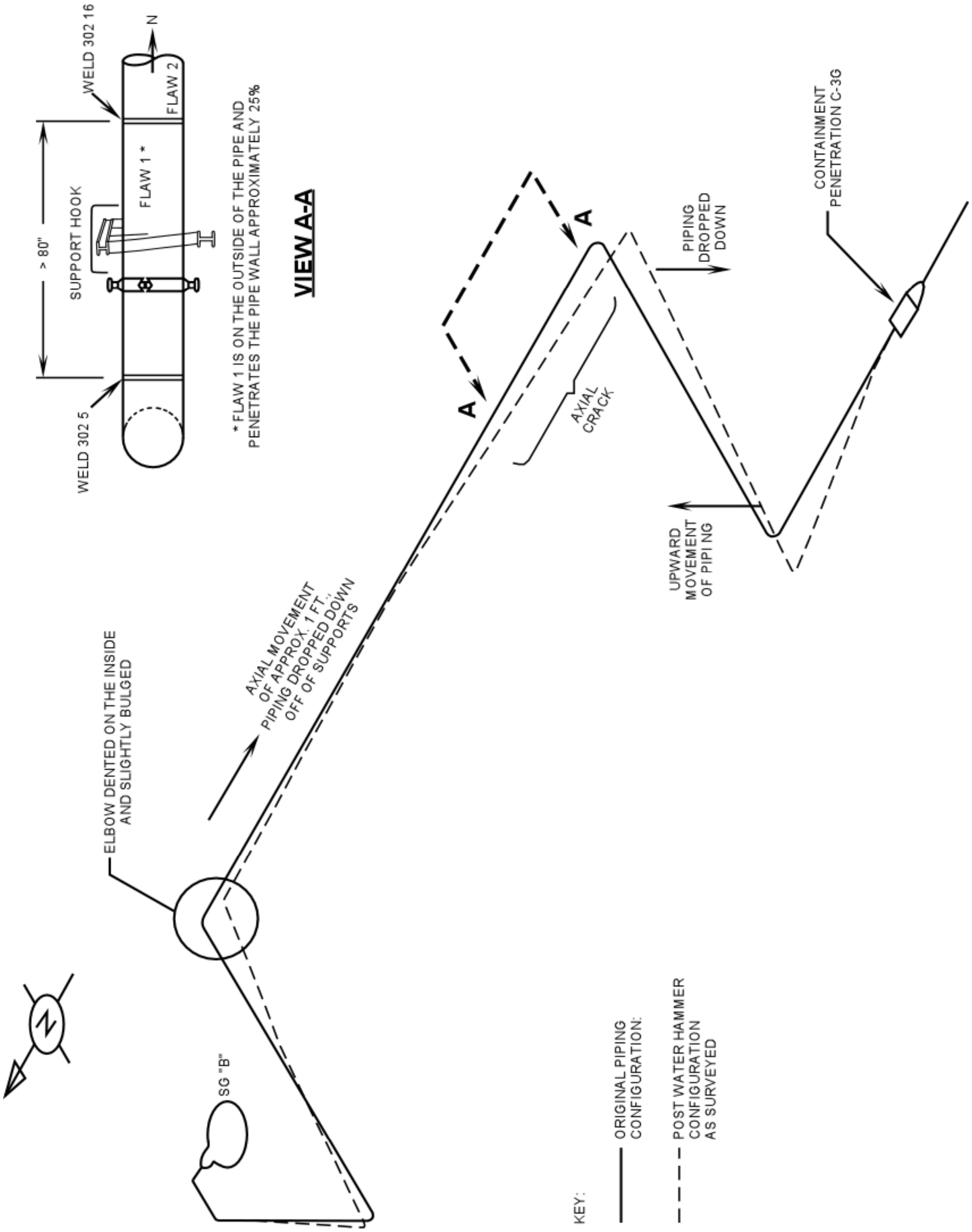


Figure 7.3-10 Overview of Feedwater Piping and Support Damage Due to Water Hammer

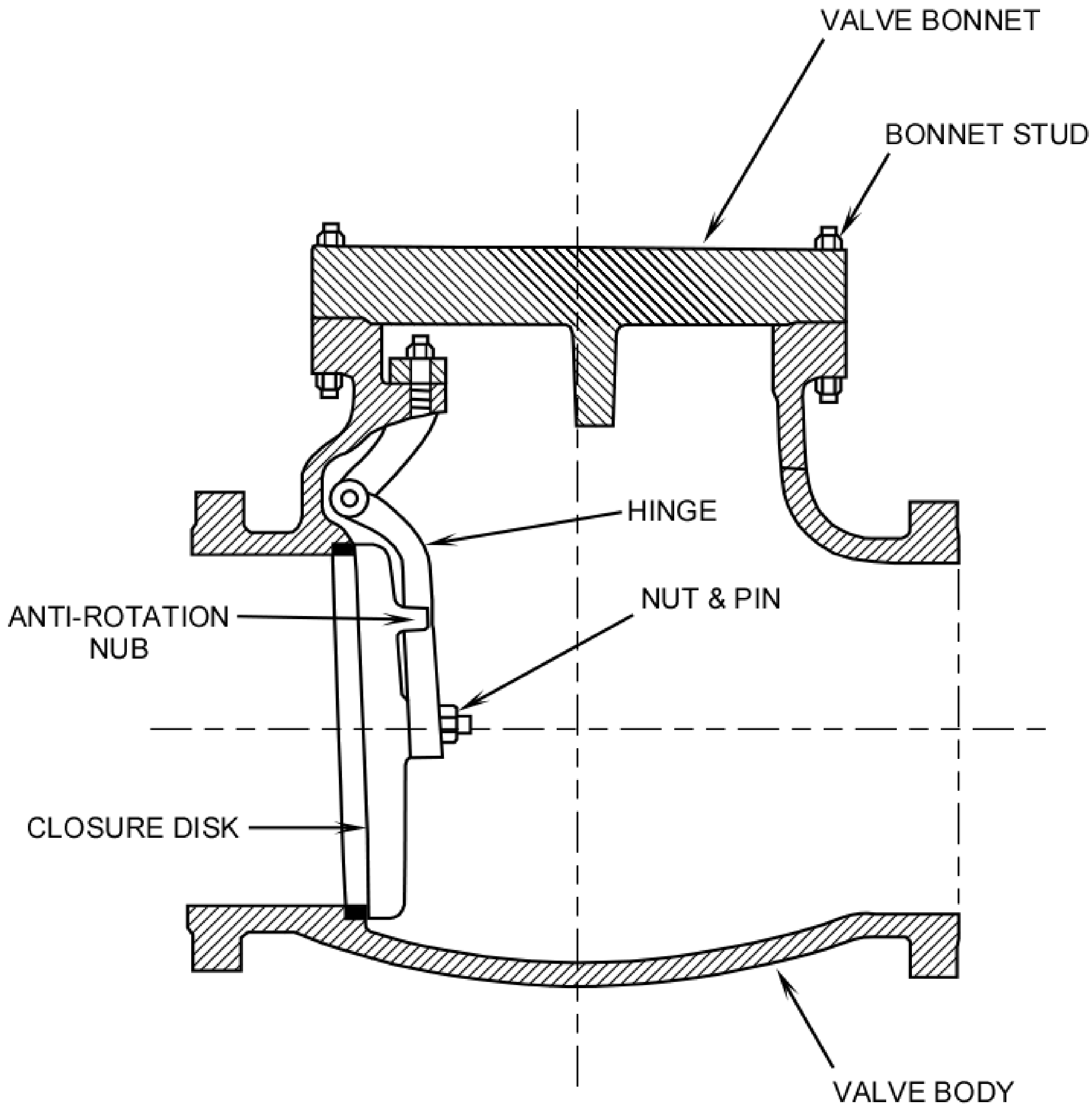
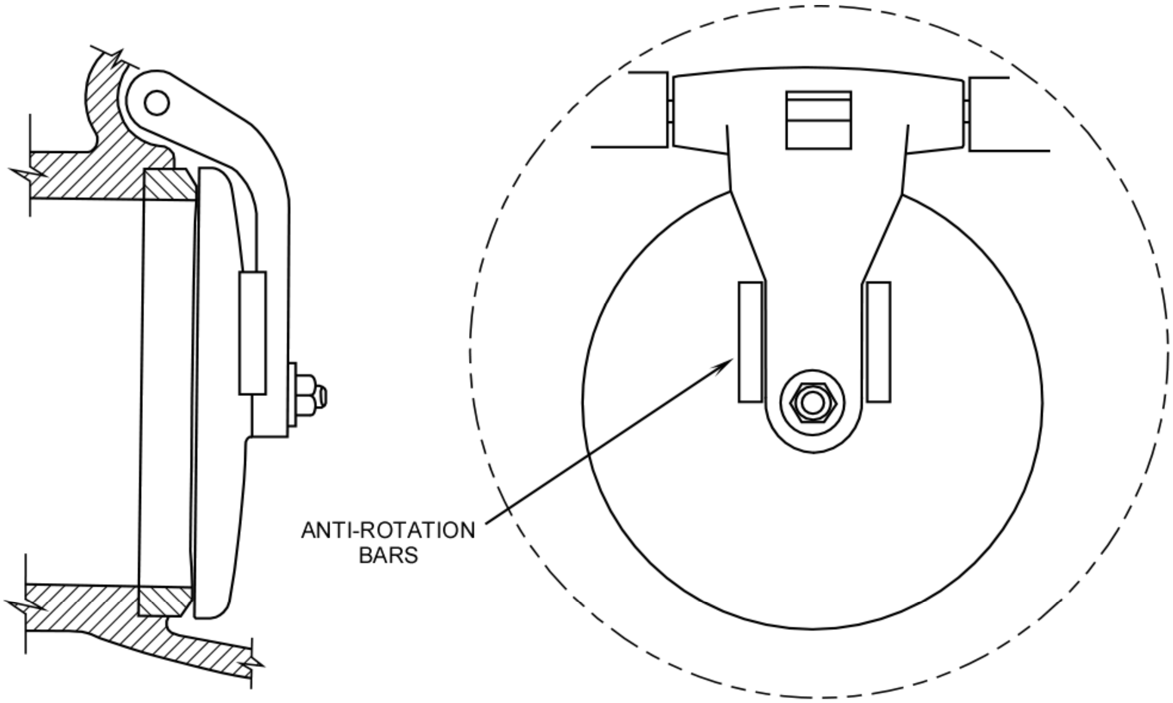
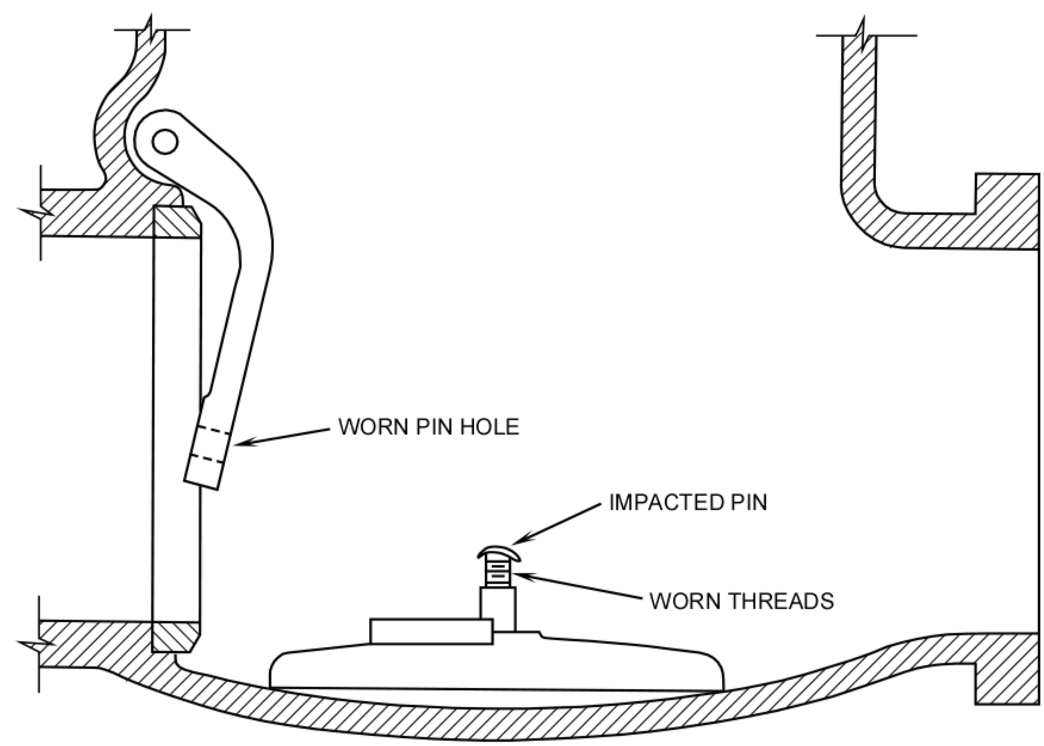


Figure 7.3-11 Typical Swing Check Valve

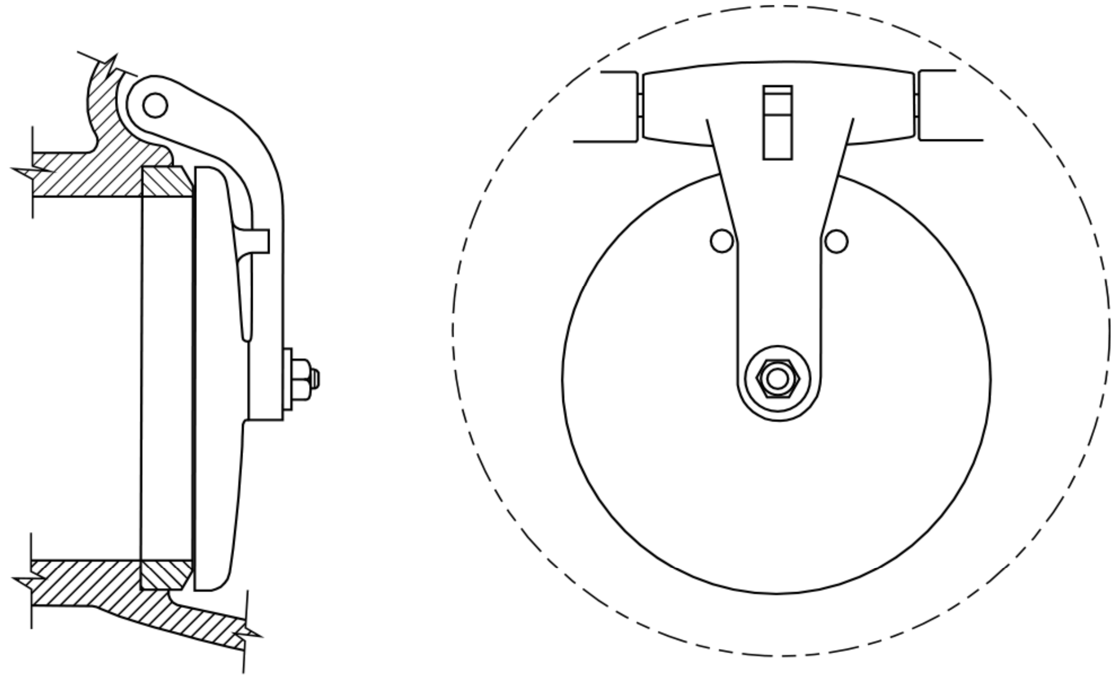


VALVE FWS-346 AS ASSEMBLED

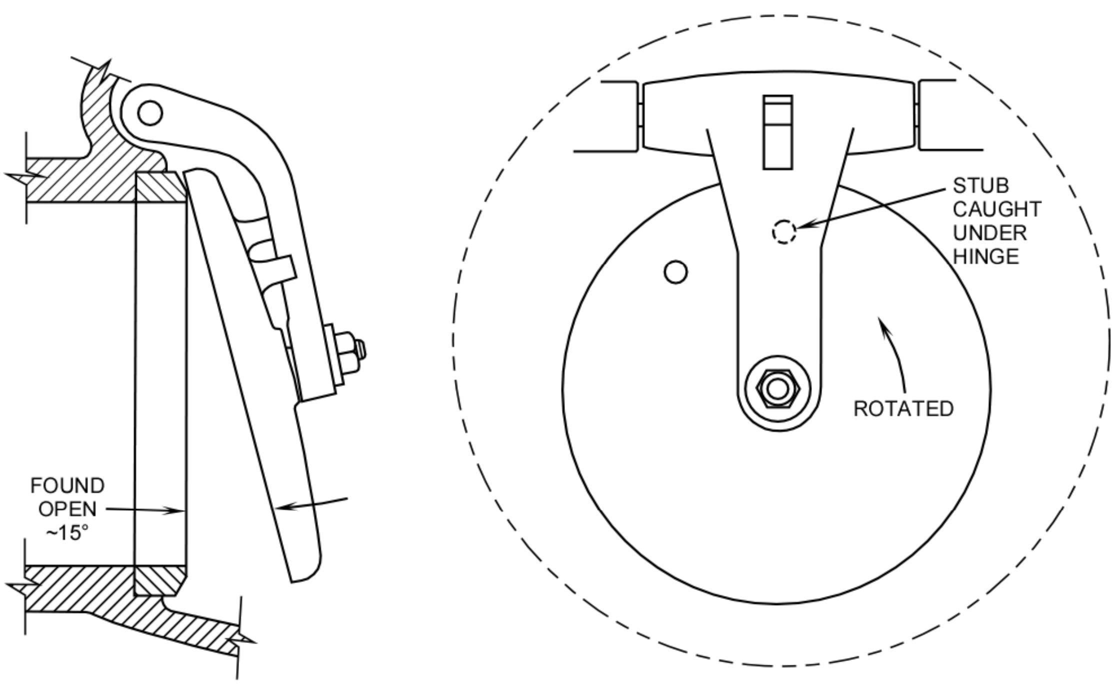


VALVE FWS-346 AS FOUND

Figure 7.3-12 Check Valve FWS-346

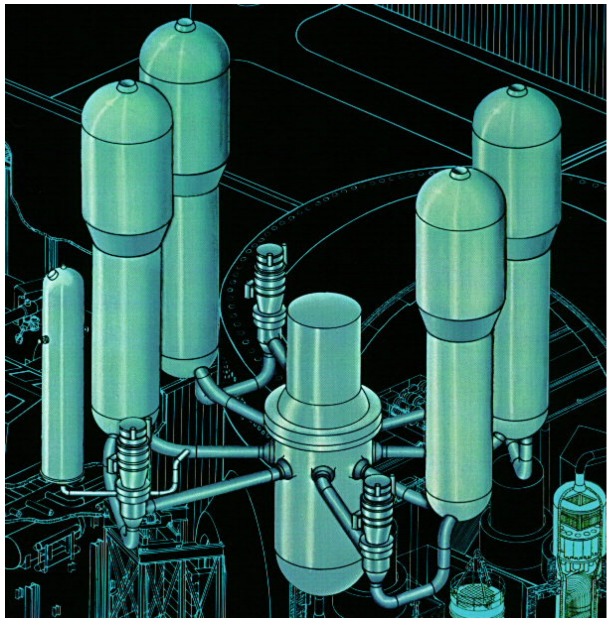


VALVE FWS-438 AS ASSEMBLED



VALVE FWS-438 AS FOUND

Figure 7.3-13 Check Valve FWS-348



Westinghouse Advanced Technology Manual

Chapter 7.4 – Core Damaging Events

2020

HRTD Human Resources Training & Development
U.S.NRC UNITED STATES NUCLEAR REGULATORY COMMISSION Protecting People and the Environment

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7.4.0 Core Damaging Events

Learning Objectives:

1. State how the following parameters respond to a stuck-open pilot-operated relief valve (PORV) following a reactor trip from 100% power:
   a. PORV tail-pipe temperature
   b. Reactor coolant system pressure
   c. Pressurizer level
   d. Reactor vessel level
2. State the significance of superheated conditions in the reactor coolant system.
3. State the key operator errors that contributed to core damage during the Three Mile Island (TMI) accident.
4. Describe the event that initiated the core damage sequence at TMI.
5. Discuss industry and regulatory changes that resulted from the accident at TMI.
6. Describe the differences in technology that make U.S. commercial reactors not susceptible to an event similar to the Chernobyl accident.
7. Recognize the sequence of events that led to fuel damage at Fukushima Dai-ichi.
8. Recognize the NRC regulatory response to the accident at Fukushima Dai-ichi.

7.4.1 Introduction

There have been several core damaging events in the history of nuclear power, but three of these have been particularly formative in public perception and public policy; Three Mile Island, Chernobyl, and Fukushima Dai-ichi.

7.4.2 Three Mile Island Accident

In March of 1979, Three Mile Island (TMI) Unit 2 experienced a loss of normal feedwater, resulting in a reactor trip on high reactor coolant system (RCS) pressure. Over the next several hours a combination of poor design, equipment failure, and operator error resulted in core uncovery and the melting of approximately 60% of the fuel.

7.4.2.1 Sequence of Events

Just prior to the reactor trip, the Pilot-Operated Relief Valve (PORV) on the pressurizer opened as designed in response to the increasing RCS pressure, but failed to close when system pressure subsequently decreased. Figure 7.4-1 illustrates the system flowpaths. The operating crew allowed this loss of coolant to continue for more than two hours.

A few minutes after the trip, the operating crew noticed a rapid rise in pressurizer level. Pressurizer level was actually rising due to the formation of steam in the RCS, which was forcing water into the pressurizer, but the crew believed the reactor coolant system was approaching a water-solid condition. The operators responded to the rising pressurizer level by reducing makeup (high pressure injection) flow and by establishing maximum letdown flow. For 2 hours and 19 minutes RCS inventory was continuously depleted through the open PORV and via letdown with essentially no makeup flow.

Forty-six minutes into the event, the letdown radiation monitor indicated that core damage had begun. One hour and 40 minutes into the event, the crew tripped all Reactor Coolant Pumps (RCPs) in response to indications of cavitation. RCP operation had maintained a frothy steam/water flow through the fuel, which was effectively removing some heat. When the operators tripped the RCPs, the steam and water separated, the fuel was partially uncovered, and significant clad oxidation began to occur, followed by fuel melting. RCS hot leg temperature began to indicate superheated conditions. Superheated steam in the hot leg indicated that the core was uncovered, but the crew was not trained to recognize this development. Crew members continued to believe that the core was covered because of the high pressurizer level.

Two hours and 19 minutes into the event, the operators isolated the open PORV, but continued letdown flow. Three hours and 20 minutes into the event, the operators initiated makeup flow to the RCS. This inventory addition quenched the core, but also probably caused considerable shattering of fuel pins. About 60% of the core had melted by this time. In the next several hours the crew struggled to establish natural circulation flow, but a large hydrogen bubble in the RCS restricted flow. Sixteen hours into the event, the crew established a stable cooldown rate.

7.4.2.2 Accident Contributors

Equipment failure, poor design, and personnel error all contributed to this accident.

The only equipment failure directly involved in core damage was the failure of the PORV to close when RCS pressure dropped below the PORV open setpoint.

Ambiguous PORV position indication, poor human factors in control room design, and lack of reactor vessel level indication were design deficiencies that contributed to the accident. The position indication for the PORV did not provide a direct reading of actual valve position, but only indicated the status of the actuating solenoid. The indications for the tank that received the PORV discharge were on a back panel, not readily visible from the areas containing frequently operated equipment. These factors made it more difficult to diagnose the stuck-open PORV. There was no indication of actual water level in the reactor vessel. This deficiency made determination of RCS inventory more difficult.

The crew failed to isolate the open PORV and incorrectly reduced makeup flow in response to the rising pressurizer level. Either isolating the PORV or allowing automatic emergency core cooling injection would have prevented core damage. These errors revealed basic inadequacies in the operator training program. The crew had been trained to avoid filling the pressurizer, but was not trained to recognize symptoms of an open PORV or inadequate core cooling.

The crew errors were, for them, applications of what seemed to be common sense. The first supposed common-sense conclusion concerns the significance of pressurizer level. The pressurizer is higher than the reactor vessel, and these vessels are connected by a large-diameter pipe which contains no valves. It seems “reasonable” that if the higher tank contains water, then the lower tank must be full. Abetting this conclusion was the lack of direct level indication for the lower tank (the reactor vessel). In reality, pressurizer level is a reliable indication of RCS inventory only when the core-exit coolant is subcooled. During this accident, the pressurizer remained full while the coolant in the reactor vessel slowly boiled away. The reasons for this are discussed in section 7.4.2.3. The second supposed common-sense conclusion concerns PORV tail-pipe temperature. It seems “reasonable” that if the pressurizer steam space temperature is 650°F, then the tail-pipe temperature of an open PORV will approach 650°F. This is also a false conclusion which is further discussed in section 7.4.2.3.

7.4.2.3 PWR response to an open PORV

Figure 7.4-3 illustrates how a Westinghouse plant responds to events similar to those experienced at the outset of the TMI accident. When a PORV remains open after a reactor trip, RCS pressure drops as the steam space of the pressurizer is vented to the Pressurizer Relief Tank (PRT). When RCS pressure drops to the saturation pressure associated with the core-exit temperature, steam formation in the core causes pressure to stabilize.

The initial tail-pipe temperature of the open PORV is a function of the saturation temperature for downstream pressure. Throttling the vented steam via the PORV is a constant-enthalpy process, as illustrated by the “initial throttling” arrow in Figure 7.4-2. The properties of the vented steam vary along the constant-enthalpy line from pressurizer conditions to tail-pipe conditions. When steam is vented at 650°F, the process remains under the vapor dome, so the tail-pipe temperature is dictated by the downstream pressure. (Lines of constant pressure and temperature are concurrent under the vapor dome.) Even though the pressurizer steam space is at 650°F, the tail-pipe temperature initially rises to only 250°F (saturation temperature for tail-pipe pressure). The tail-pipe pressure is a function of PRT pressure and backpressure in the line due to the large steam flow. The temperature continues to rise as PRT pressure increases, then drops when the PRT rupture disk vents the PRT to the containment atmosphere. Eventually, as illustrated by the second arrow in Figure 7.4-2, steam is vented from different pressurizer conditions at a different specific enthalpy to a depressurized PRT. The end state of this process is outside the vapor dome, resulting in superheated conditions in the PORV tail-pipe.

Because of steam formation in the core, water is forced into the pressurizer. Pressurizer level rises to 100%. As RCS inventory depletes, pressurizer level remains high. The steam formed at the core exit is vented out the open PORV. The pressurizer remains largely full as steam flows up the pressurizer surge line, even as the coolant in the core boils away. For these conditions (core-exit coolant saturated or superheated), the only reliable indication of RCS inventory is the Reactor Vessel Level Indication System (RVLIS). Pressurizer level is a useful measure of RCS inventory only when the coolant is subcooled at the core exit.

7.4.2.4 Industry And Regulatory Response

The accident led to sweeping reforms implemented by the industry and the NRC.

The Three Mile Island accident demonstrated to US industry leaders that the industry must do a better job of policing itself to ensure that an event of this magnitude should never happen again. The Institute of Nuclear Power Operations (INPO) was formed by nuclear utilities and staffed by utility personnel. INPO has established standards against which plants are measured. An inspection of each member plant by INPO representatives is typically performed every 18 - 24 months. The Institute's programs include information sharing, events analysis, human performance improvement, training program accreditation, and plant evaluations.

Operator training was extensively revised. The NRC raised the standards for operator examinations. Exams are now more focused on knowledge of plant operations, and the passing grade has been increased to 80%. Licensees are now required to have a simulator facility and to provide comprehensive training in the diagnosis of and recovery from possible plant malfunctions and potential accident conditions.

Nuclear plant emergency operating procedures are now symptom based, with a focus on safety functions. The procedures prior to the TMI accident were based on the premise that the operators would properly diagnose an event and then implement the proper procedure. Current procedures do not rely on the operator’s ability to diagnose.

Also, current procedures identify critical safety functions that, if met, ensure that the integrity of barriers to radioactive release is maintained, regardless of the initiating event.

The NRC was extensively reorganized to better focus on safe operation of the plants. Resident inspectors were placed at each site.

NUREG-0737, “Clarification of TMI Action Plan Requirements,” summarizes the changes in regulations in response to the accident. The changes include the areas of shift manning, operator training, control room design, accident monitoring instrumentation systems, operating procedures, and operating experience review. Reactor vessel level monitoring systems were added to PWR plants after the TMI accident.

The NRC revised emergency planning rules and guidance to provide for improved capability for a wide range of accidents.

In summary, the changes that resulted from the TMI accident changed virtually every area of plant operation and regulation.

7.4.3 Chernobyl Accident

Chernobyl 4 was a Soviet RBMK-l000 type reactor rated at 3200 MW thermal power and 1000 MW electric output. The RBMK-l000 is a graphite-moderated boiling water reactor that contains 1661 parallel, vertical pressure tubes loaded with fuel assemblies.

This type of reactor exhibits a positive void coefficient of reactivity, because the moderator is graphite instead of water. In the RBMK design, the coolant does not provide neutron moderation. As a result, the coolant is a poison. Coolant voiding adds positive reactivity. The fuel temperature coefficient of reactivity (Doppler) is negative. In normal operation, the overall core power coefficient is negative at and near full power but becomes positive at lower power levels.

The Chernobyl Unit 4 operators were performing a turbine generator coastdown test as part of a plant shutdown. Due to delays in conducting the test, reactor power level dropped lower than the test requirements, with a resultant positive power coefficient at the lower power. When reactor power level became unstable, the crew responded by disabling much of the reactor protection system. The test was then initiated by tripping a turbine generator, which caused four of eight reactor coolant pumps to coast down without a trip. With a decrease in coolant flow but no decrease in power, a significant amount of voiding developed rapidly in the core. The positive void coefficient caused the reactor to become prompt critical. Even though the operators manually tripped the reactor, the trip was too late to be effective. Two power peaks occurred about one second apart. The power levels of these two peaks were estimated to be 11,000% reactor power and 47,000% reactor power, respectively. The first power peak destroyed the core of reactor number 4. The second peak, which was much more powerful, shot very hot lumps of graphite and reactor fuel into the air. These lumps landed in various places and caused many fires. In all, the explosion created a crater with burning graphite and about 30 fires in other places around the plant. The main reactor fire continued to burn for nine days, releasing a large amount of radioactive material into the environment.

The sequence of events that occurred at Chernobyl is not possible at reactor plants in the United States. The reactor designs used in the U.S. always have negative overall power coefficients. The RCS voiding that drove Chernobyl prompt critical would cause a U.S. reactor to be subcritical. Also, there are no credible accidents at U.S. reactors that will instantly breach all fission product barriers. The moderator in U.S. reactors (water) will not burn.

Many on-site fatalities resulted from the Chernobyl disaster. An international study concluded that in the general population, nine child fatalities from thyroid cancer can be linked to the accident. Additional deaths are possible, but not documented. In contrast, the TMI accident has not led to any documented health problems either in the work force or in the general population to date.

The only significant impact of the Chernobyl accident on the United States was in the public perception of nuclear power. Some nations responded to this event by choosing to phase out all nuclear power.

Since there are few design similarities, this accident did not lead to significant changes in plant design, operation, or regulation in the United States.

7.4.4 Fukushima Dai-ichi Accident

As was the case of the Three Mile Island Accident in March 1979, details of causes, effects and damages at the Fukushima Dai-ichi units will be unveiled over the next many years. This information is based on the incomplete information available at the current time.

7.4.4.1 Natural Event Description

On March 11 2011 at 1446 Japan Standard Time (JST), an earthquake occurred off the coast of Japan approximately 112 miles NE of the Fukushima Dai-ichi nuclear power station. Seismic monitors at Fukushima Dai-ichi measured the event at .56g. This is in excess of plant design.

This earthquake triggered a tsunami estimated to be traveling in excess of 500 miles per hour. Latest data indicates that over 250 miles of the Japan Pacific coast was inundated up to six miles inland by the tsunami estimated to be up to 125 feet high. The tsunami washed away entire towns and cities as well as devastated much of the area's infrastructure such as roads, railways, power lines, communications, etc. In October 2016 the death toll was nearly 20,000 with 2,500 missing.

7.4.4.2 Fukushima Dai-ichi Site Description

The Fukushima Dai-ichi site is a six unit General Electric based Boiling Water Reactor Generating Station.

Units 1-3 were operating at full power. Units 4-6 were in refueling outages. Unit 4 had a full core off-load to the spent fuel pool. Units 5 and 6 had partial core off-loads to the spent fuel pool.

7.4.4.3 Tsunami Event and Site Effects

Flooding of the EDG and Emergency Switchgear Rooms resulted in a loss of all AC and DC power for units 1, 2 and 4 and a loss of all AC power (Station Blackout) for unit 3. Unit 6 retained DC power and one EDG and was able to use the EDG to support fuel pool cooling for both units 5 and 6.

Over the next few days all fission product barriers failed on units 1, 2, and 3. Multiple hydrogen explosions damaged structures. The status of the fuel in the Unit 4 spent fuel pool is unknown.

7.4.4.4 United States Nuclear Regulatory Commission Responses

Several orders and a 50.54(f) letter were issued March 12, 2012. Orders which apply to pressurized water reactors were:

- Implement strategies that will allow them to cope without their permanent electrical power sources for an indefinite amount of time.
- Install water level instrumentation in their spent fuel pools. The instrumentation must remotely report at least three distinct water levels: 1) normal level; 2) low level but still enough to shield workers above the pools from radiation; and 3) a level near the top of the spent fuel rods where more water should be added without delay.

At the same time, NRC issued several requests for information:

- Use present-day information to reevaluate the earthquake effects or hazards that could impact their site. Analyze the reevaluated hazards to determine if existing plant structures, systems, and/or components need to be undated.
- Inspect existing plant protection features against seismic and flooding events, and correct any degraded conditions.
- Assess the required staffing and communications equipment necessary to respond to a large accident that may affect multiple reactors at their site, and make changes as necessary.

Rulemaking activities were begun concerning:

- The rulemaking effort will permanently write into the agency's rules the requirements already imposed by the beyond design basis external events order.
- Create a new rule requiring the integration of the emergency procedures, extensive damage mitigating guidelines, and severe accident mitigation guidelines.

The staff of the U.S. Nuclear Regulatory Commission (NRC) has prepared a draft final rule *Federal Register* (FR) notice (FRN) (Enclosure 1) that would establish MBDBE requirements. This rule (1) makes generically applicable requirements previously imposed by order for the mitigation of beyond-design-basis external events and for remotely monitoring the spent fuel pool wide-range level, (2) includes provisions to have an integrated response capability, and (3) addresses six petitions for rulemaking (PRMs). The staff also considered two nonconcurrences in the finalization of the draft final rule and its supporting guidance:

NCP-2016-018 related to loss of all alternating current (ac) and direct current (dc) electrical power and NCP-2016-014 related to use of risk information to address reevaluated seismic hazard information.

As discussed in Section I of the draft FRN, the NRC has undertaken numerous regulatory actions following the 2011 Fukushima Dai-ichi event in Japan. These actions began with the work of the Near-Term Task Force (NTTF) and the development of the associated NTTF recommendations. The NRC's response to the NTTF Report, which was an enclosure to SECY-11-0093, "Near-Term Report and Recommendations for Agency Actions Following the Events in Japan," dated July 12, 2011 (Agency wide Documents Access and Management System (ADAMS) Accession No. ML11186A950), was provided in SECY-11-0124, "Recommended Actions To Be Taken without Delay from the Near-Term Task Force Report," and SECY-11-0137 "Prioritization of Recommended Actions To Be Taken in Response to Fukushima Lessons Learned." These two papers identified actions to be taken in the near term and prioritized the NTTF recommendations. The near-term actions ultimately culminated in the issuance of three orders; a request for information, under Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.54(f), that addressed several regulatory issues; and two Advance Notices of Proposed Rulemaking (ANPR). The regulatory efforts to address lessons learned from Fukushima have evolved over time, and the two rulemaking activities discussed in the ANPRs were consolidated into the MBDBE rulemaking.

The NRC staff (staff) developed and provided to the Commission a proposed rule in SECY-15-0065, "Proposed Rulemaking: Mitigation of Beyond-Design-Basis Events (RIN 3150-AJ49)," on April 30, 2015 (ADAMS Accession No. ML15049A201). The Commission issued its direction on the proposed rule on August 27, 2015, in Staff Requirements Memorandum (SRM)-SECY-15-0065 (ADAMS Accession No. ML15239A767). In accordance with the Commission's direction, the staff revised the proposed rule and issued it for a 90-day public comment period on November 13, 2015 (80 FR 70609). In addition to seeking comment on the proposed rule and supporting draft guidance, the FRN also requested feedback on a number of specific topics related to the proposed rule and on the potential cumulative effects of regulation (CER). The agency also published three draft regulatory guides for comment with the proposed rule.

The comment period closed on February 11, 2016. The NRC received 20 comment submissions that the staff reviewed and considered in the development of the final MBDBE rule, as described in Enclosure 2. During development of the final rule, the staff held a public meeting to discuss CER and used the feedback obtained at that meeting to inform implementation requirements in the final MBDBE rule.

DISCUSSION:

The draft final rule applied to power reactor applicants and licensees and includes the following provisions:

- Provisions that make generically applicable requirements previously imposed by Order EA-12-049, “Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events,” dated March 12, 2012 (ADAMS Accession No. ML12054A735), for the mitigation of beyond-design-basis external events. These requirements constitute the majority of the requirements in this rule and are located mainly in 10 CFR 50.155(b)(1), with portions in paragraphs (c), (d), (e), and (g) as described further below.
- Requirements for licensees to consider the effects of the reevaluated seismic and flooding hazards information within the mitigation strategies and guidelines, in accordance with the Commission direction provided in SRM-COMSECY-14-0037 (ADAMS Accession No. ML15089A236), “Staff Requirements - COMSECY-14-0037 - Integration of Mitigating Strategies for Beyond-Design-Basis External Events and the Reevaluation of Flooding Hazards,” dated March 30, 2015. These requirements appear in 10 CFR 50.155(b)(2).
- Requirements previously in 10 CFR 50.54(hh)(2) for mitigation of the effects of a loss of a large area of the plant due to explosions or fire. These requirements appear in 10 CFR 50.155(b)(3).
- Requirements to integrate the above capabilities with the emergency operating procedures. These requirements appear in 10 CFR 50.155(b)(4).
- Reasonable protection requirements that enable the proper degree of regulatory assurance to be applied to the equipment and structures, systems, and components (SSCs) that perform a beyond-design-basis function for the purposes of the MBDBE rule. These requirements appear in 10 CFR 50.155(c)(2) and (c)(3).
- Supporting requirements for the integrated response capability that include staffing, communications, training, drills or exercises, and documentation of changes. These requirements are found in 10 CFR 50.155(b), (c), (d), (e) and (g).
- Provisions that make generically applicable requirements previously imposed by Order EA-12-051, “Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Effective Immediately),” dated March 12, 2012 (ADAMS Accession No. ML12056A044), for remotely monitoring the spent fuel pool wide-range level. These requirements appear in 10 CFR 50.155(f).
- Requirements that facilitate the decommissioning of reactors that are subject to this rule. These requirements appear in 10 CFR 50.155(a)(2).
- Provisions that rescind orders, including Orders EA-12-049 and EA-12-051, for which the MBDBE rule will now provide the governing substantive requirements. These requirements appear in 10 CFR 50.155(i).
- Provisions that facilitate the removal of a variety of license conditions for which the MBDBE rule will now provide the governing substantive requirements. These requirements appear in 10 CFR 50.155(i).

10CFR50.155(b) *Strategies and guidelines.* Each applicant or licensee shall develop, implement, and maintain:

- (1) Mitigation strategies for beyond-design basis external events—Strategies and guidelines to mitigate beyond-design-basis external events from natural phenomena that are developed assuming a loss of all ac power concurrent with either a loss of normal access to the ultimate heat sink or, for passive reactor designs, a loss of normal access to the normal heat sink. These strategies and guidelines must be capable of being implemented site-wide and must include the following:
- (i) Maintaining or restoring core cooling, containment, and spent fuel pool cooling capabilities; and
- (ii) The acquisition and use of offsite assistance and resources to support the functions required by paragraph (b)(1)(i) of this section indefinitely, or until sufficient site functional capabilities can be maintained without the need for the mitigation strategies.
- (2) Extensive damage mitigation guidelines—Strategies and guidelines to maintain or restore core cooling, containment, and spent fuel pool cooling capabilities under the circumstances associated with loss of large areas of the plant impacted by the event, due to explosions or fire, to include strategies and guidelines in the following areas:
- (i) Firefighting;
- (ii) Operations to mitigate fuel damage; and
- (iii) Actions to minimize radiological release.

10CFR50.155(c) *Equipment*.

- The equipment relied on for the mitigation strategies and guidelines required by paragraph (b)(1) of this section must have sufficient capacity and capability to perform the functions required by paragraph (b)(1) of this section.
- (2) The equipment relied on for the mitigation strategies and guidelines required by paragraph (b)(1) of this section must be reasonably protected from the effects of natural phenomena that are equivalent in magnitude to the phenomena assumed for developing the design basis of the facility.

10CFR50.155(d) *Training requirements*.

Each licensee shall provide for the training of personnel that perform activities in accordance with the capabilities required by paragraphs (b)(1) and (2) of this section.

10CFR50.155(e) *Spent fuel pool monitoring*.

In order to support effective prioritization of event mitigation and recovery actions, each licensee shall provide reliable means to remotely monitor wide-range water level for each spent fuel pool at its site until 5 years have elapsed since all of the fuel within that spent fuel pool was last used in a reactor vessel for power generation. This provision does not apply to General Electric Mark III upper containment pools.

10CFR50.155 (f) *Documentation of changes*.

- (1) A licensee may make changes in the implementation of the requirements in this section without NRC approval, provided that before implementing each such change, the licensee demonstrates that the provisions of this section continue to be met and maintains documentation of changes until the requirements of this section no longer apply.

- (2) Changes in the implementation of requirements in this section subject to change control processes in addition to paragraph (f) of this section must be processed via their respective change control processes, unless the changes being evaluated impact only the implementation of the requirements of this section.
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10CFR50.155 (g) *Implementation*.

Each holder of an operating license for a nuclear power reactor under this part on September 9, 2019, and each holder of a combined license under part 52 of this chapter for which the Commission made the finding specified in 10 CFR 52.103(g) as of September 9, 2019, shall continue to comply with the provisions of paragraph (b)(2) of this section, and shall comply with all other provisions of this section no later than September 9, 2022, for licensees that received NRC Order EA–13–109 or September 9, 2021, for all other applicable licensees.

10CFR50.155 (h) *Withdrawal of orders and removal of license conditions*.

(1) On September 9, 2022, Order EA–12–049, "Order Modifying Licenses With Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," and Order EA–12–051, "Order Modifying Licenses With Regard to Reliable Spent Fuel Pool Instrumentation," are withdrawn for each licensee or construction permit holder that was issued those Orders.

7.4.5 Summary

The most significant United States commercial reactor accident occurred at Three Mile Island Unit 2 in 1979. Due to a combination of equipment failures, design deficiencies, and operator errors, about 60% of the core melted, and the plant was permanently shut down. No member of the general public received a significant radiation dose, and no plant worker suffered any documented adverse health effects from the accident. It is possible to re-create this accident sequence at any U.S. pressurized water reactor. The event led to sweeping changes in the industry.

An international commercial reactor accident occurred at Chernobyl Unit 4 in 1986. The reactor was blown apart by a steam explosion induced by a reactivity transient, followed by a graphite fire. The sequence of events at Chernobyl cannot occur in the types of commercial reactors operating in the U.S.

An earthquake and resulting tsunami led to the failure of all fission product barriers at three Japanese boiling water reactors. This led to significant changes in rulemaking regarding station blackout, natural phenomena, and multiple unit site response. Some of these changes are still in progress and have resulted in 10 CFR 50.155.

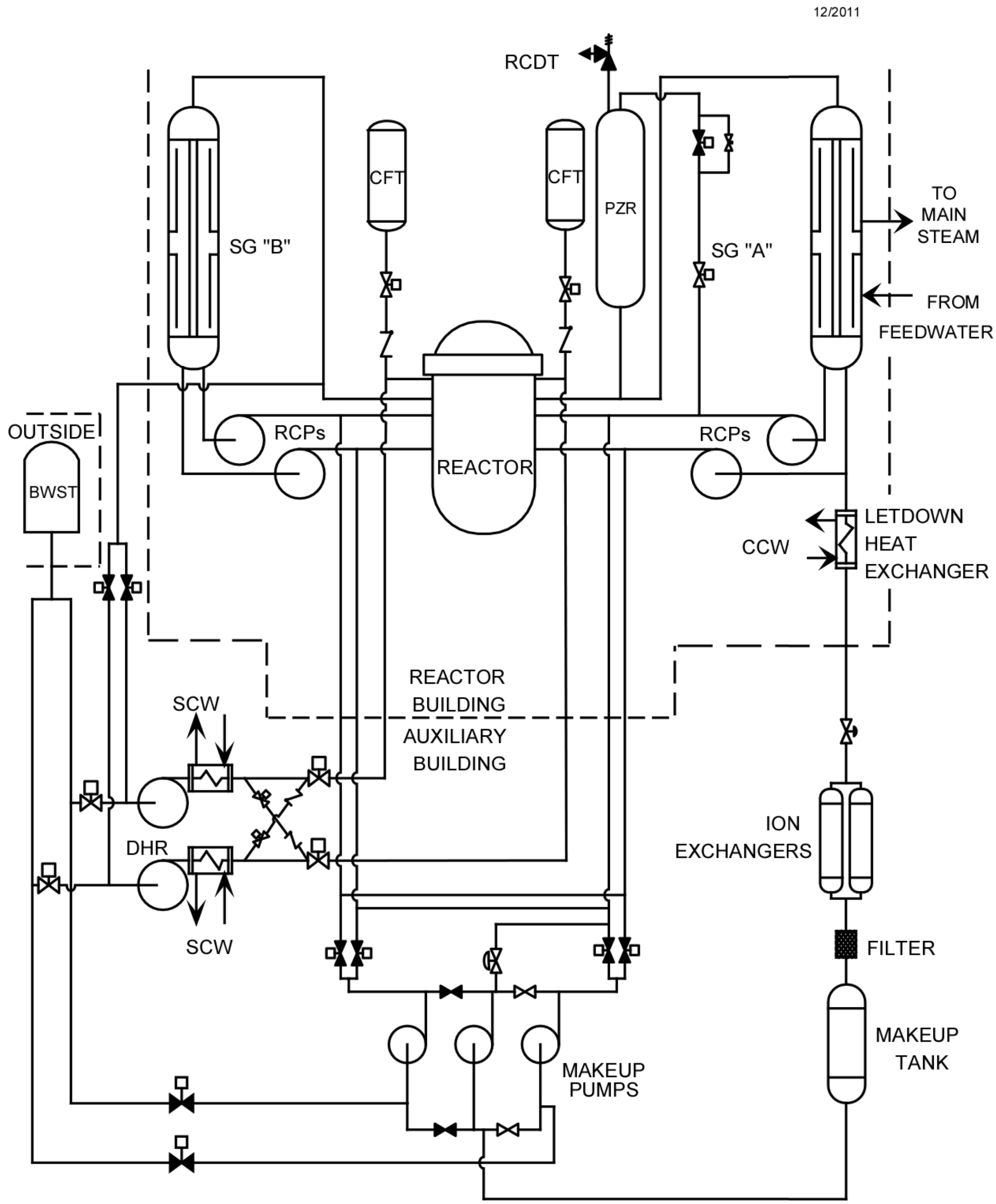


Figure 7.4-1 Basic Babcock & Wilcox Plant Systems

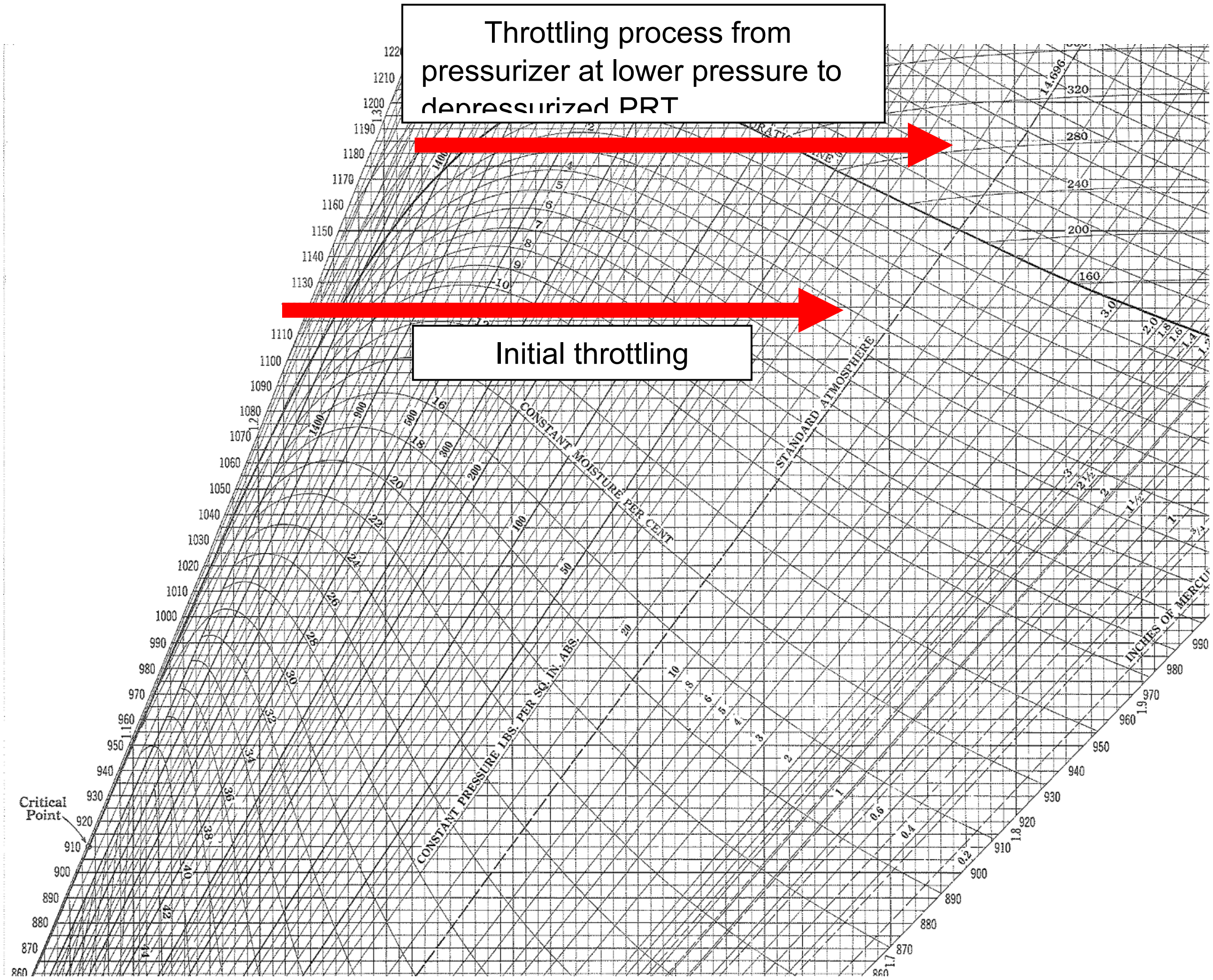
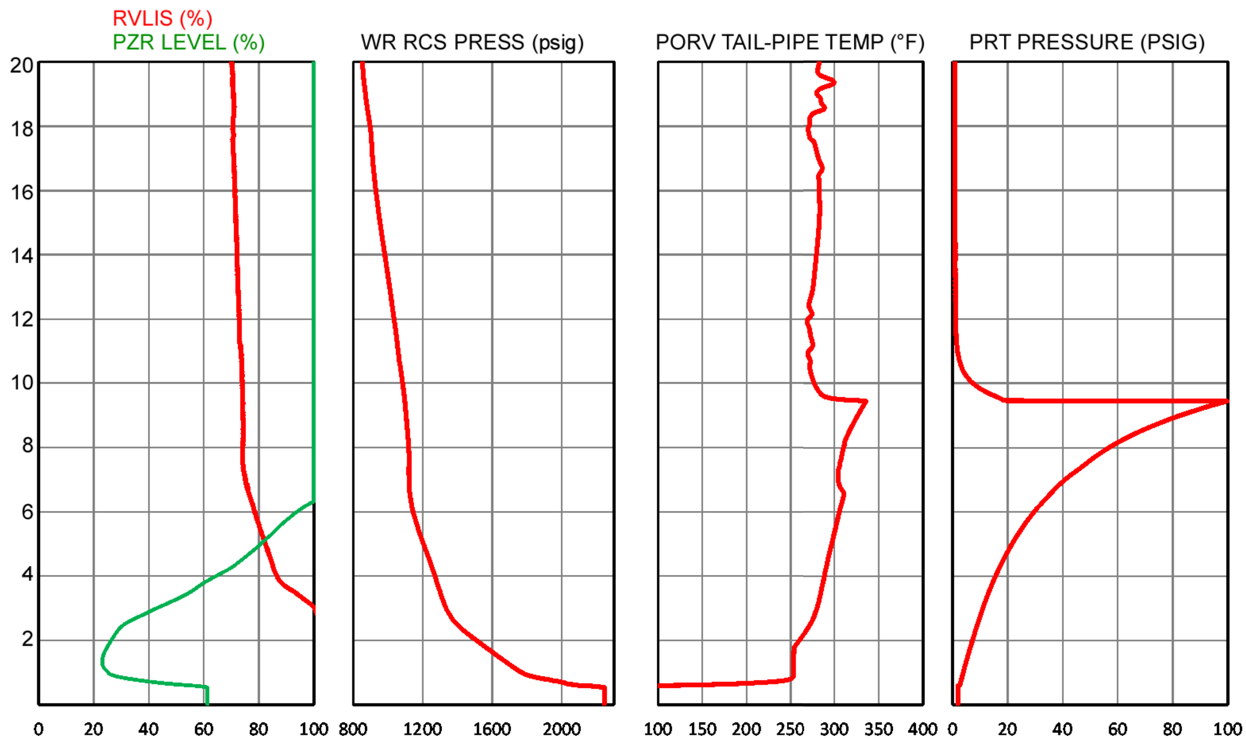


Figure 7.4-2 Mollier Diagram



For these trends, the reactor tripped from 100%, one PORV was opened, ECCS flow was disabled, and all reactor coolant pumps were tripped. These conditions existed during the TMI accident.

Figure 7.4- 3 Plant Response to Open PORV

NRC EOC Update 5 May, 2011 1200 EDT
100 R/hr debris outside Unit 3 Reactor Building

UNIT	CORE DAMAGE ESTIMATE	CORE COOLING	PRIMARY CONTAINMENT	SECONDARY CONTAINMENT	DRYWELL RADIATION LEVELS	TORUS RADIATION LEVELS
UNIT 1	55% and uncovered	26 gpm fresh water via feedwater line	Damaged Leak rate est. at 3 cubic meters per hour	Severely damaged by hydrogen explosion	Unknown	114 R/hr 4 mR/hr at west gate
UNIT 2	35% and uncovered	30gpm fresh water	Damage suspected	Damaged	2070 R/hr	40 R/hr 4 mR/hr at west gate
UNIT 3	30% and uncovered	31 gpm fresh water	Damage suspected	Damaged	1260 R/hr	50 R/hr
UNIT 4	In spent fuel pool	N/A	Relaxed for outage	Severely damaged by hydrogen explosion	N/A	N/A
UNIT 5	None	N/A	N/A	N/A	N/A	N/A
UNIT 6	None	N/A	N/A	N/A	N/A	N/A

Figure 7.4- 4 NRC Update 5-May-2011