SHAW, PITTMAN, POTTS & TROWBRIDGE
A PARTNERSHIP INCLUDING PROFESSIONAL CORPORATIONS

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FOIA/PA REQUEST
Case No. 96-351
Date Rec'd 9-3-96
Action Off:
Related Case:

August 30, 1996

Director, Division of Freedom of
Information & Publications Services
Office of Administration
U.S. Nuclear Regulatory Commission
Two White Flint North Building
11545 Rockville Pike
Rockville, MD 20852

Re: Freedom of Information Act Request Regarding the Salem Generating Station, Docket Nos. 50-272 and 50-311

Dear Sir or Madam:

This is a Freedom of Information Act request pursuant to 5 U.S.C. § 552(a)(3) and 10 C.F.R. § 9.23. We request that you make available to Shaw, Pittman, Potts & Trowbridge the documents responsive to the attached Request for Production of Documents. These documents need to be made available as soon as possible to support depositions in an accelerated legal action. In order to expedite production of the documents, we have deliberately tailored this request to be narrow in scope and straightforward in the type of documents requested. We have already obtained copies of relevant documents presently available at the N.R.C. Public Documents Room and they need not be produced again in response to this request. Of course, we agree to bear the cost of this request as per 10 C.F.R. §§ 9.23(b)(4), 9.33, 9.39, and 9.40, and we authorize you to respond to this request piecemeal as documents become available. Please contact me at (202)663-8148, or William Hollaway at (202)663-8294, at your convenience if you have any questions regarding this request.

Please direct your response, pursuant to 10 C.F.R. § 9.27, to:

William R. Hollaway, Ph.D.
Shaw, Pittman, Potts & Trowbridge
2300 N Street, N.W.
Washington, D.C. 20037-1128
(202)663-8294
Fax: (202)663-8007

Thank you for your cooperation in this matter.

Sincerely,

John H. O'Neill, Jr.

Attachment

348107-01 / DOCSDC1

REQUEST FOR PRODUCTION OF DOCUMENTS

I. DIRECTIONS AND INSTRUCTIONS

1. The term "NRC" means the United States Nuclear Regulatory Commission, all offices and/or branches thereof specifically including, but not limited to, headquarters in Rockville, Maryland and the Region I office in King of Prussia, Pennsylvania, and also includes all employees, consultants, agents, and representatives to the maximum extent permitted by 10 C.F.R. § 9.3, unless otherwise indicated by the request.

2. The term "Salem" means one or both units of the Salem Generating Station located in Hancocks Bridge, New Jersey and operated by the Public Service Electric and Gas Company.

3. The term "SAP" means the Salem Assessment Panel that was developed in 1995 specifically to review Salem Generating Station on an ongoing basis, including all members and supervisors thereof.

4. The term "PSE&G" refers the operator of Salem, Public Service Electric and Gas Company.

5. The term "PECO Energy" refers to PECO Energy Company, formerly known as Philadelphia Electric Company.

6. The term "Delmarva" refers to Delmarva Power & Light Company.

7. The term "Atlantic Electric" refers to Atlantic City Electric Company.

8. The term "SALP" means the Strategic Assessment of Licensee Performance, a comprehensive review of plant performance, performed for each plant on an 18-month cycle. The most recent SALP review for Salem was issued on January 3, 1995.

9. The term "Enforcement Action" means a civil penalty levied by the NRC against the licensees of Salem pursuant to single or multiple violations at Salem. The most recent Enforcement Action regarding Salem was issued on October 16, 1995.

10. The term "AIT" means the Augmented Inspection Teams that performed investigations of Salem in 1992, 1993, and 1994, including all members and supervisors thereof.

11. The term "SIT" means the Special Inspection Team that performed an investigation of Salem in 1995, including all members and supervisors thereof.

12. The term "PA" means the comprehensive Performance Assessment evaluation of Salem performed in July-August, 1995 to aid in focusing future NRC inspection resources at Salem.

13. The term "Confirmatory Action Letter" means the letter from the NRC to PSE&G on June 9, 1995 confirming PSE&G commitments to take specific actions prior to the restart of Salem and confirming that failure to take these actions may result in enforcement action.

II. DOCUMENTS REQUESTED

1. All documents concerning the NRC's Salem Assessment Panel ("SAP") established on August 2, 1995, especially including but not limited to:

   a. All internal NRC discussions concerning the formation and purpose of the SAP;

   b. Transcripts, meeting minutes, summaries, and handouts of all meetings of the SAP;

   c. Lists of attendees at all meetings of the SAP;

   d. All materials presented to the SAP;

   e. All notes taken during presentations and meetings of the SAP;

   f. All reports or memoranda of the SAP;

   g. All reports or memoranda written by any members of the SAP concerning Salem.

2. All documents concerning the NRC's Systematic Assessment of Licensee Performance ("SALP") reviews of Salem from 1990 through the present, especially including but not limited to:

   a. Transcripts, meeting minutes, summaries, and handouts of all NRC meetings on the Salem SALP reports;

   b. Lists of attendees at all meetings on the Salem SALP reports;

   c. Variances, differences or changes between consecutive Salem SALP reports;

   d. Internal NRC discussions about interim drafts of the Salem SALP reports;

   e. Internal NRC discussions about final drafts of the Salem SALP reports;

f. Internal NRC discussions about variances, differences or changes between interim reports and the final Salem SALP reports;

g. The basis for each of the findings in the Salem SALP reports;

h. Region I's knowledge of issues raised in the Salem SALP reports;

i. Region I's knowledge of PSE&G's plans to address issues raised in the various Salem SALP reports;

j. Internal Region I discussions concerning the findings and conclusions expressed in the Salem SALP reports;

k. Whether NRC or Region I ever expressed any concerns about poor or declining performance or the like to PSE&G related to the Salem SALP reports;

l. Communications between NRC and Region I personnel concerning consistencies or inconsistencies between the various Salem SALP reports;

m. All documents setting forth or discussing the deliberations and considerations of the SALP boards reviewing Salem performance from 1990 to the present;

n. To the extent not covered by previous requests, all other documents regarding the Salem SALP reports.

3. All documents concerning potential and actual NRC enforcement actions regarding Salem from 1990 to the present, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all Enforcement Conferences concerning Salem between NRC and PSE&G, including but not limited to meetings on February 2, 1992; April 9, 1992; April 6, 1993; February 1, 1994; July 28, 1994; February 10, 1995; June 1, 1995; June 23, 1995; July 13, 1995; and July 28, 1995;

b. Lists of attendees at all Enforcement Conferences concerning Salem between NRC and PSE&G;

c. Transcripts, meeting minutes, summaries, and handouts from all internal NRC meetings concerning enforcement actions regarding Salem;

d. Lists of attendees at all internal NRC meetings concerning enforcement actions regarding Salem;

e. Communications with PSE&G concerning potential and actual NRC enforcement actions regarding Salem;

f. Communications with others concerning potential and actual NRC enforcement actions regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

g. Internal NRC discussions concerning potential NRC enforcement actions regarding Salem;

h. Internal NRC discussions concerning actual NRC enforcement actions regarding Salem, including but not limited to the $50,000 civil penalty issued March 9, 1994; the $500,000 civil penalty issued October 5, 1994; $80,000 civil penalty issued April 11, 1995; and the $600,000 civil penalty issued October 16, 1995;.

i. The basis and rationale for taking each of the enforcement actions regarding Salem;

j. Internal NRC discussions about drafts of the enforcement actions regarding Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the enforc[illegible]t actions regarding Sale[illegible],

l. Internal NRC discussions concerning PSE&G's responses to each of the enforcement actions regarding Salem;

4. All documents concerning meetings between the NRC and PSE&G management or Board of Directors concerning the performance of Salem from 1990 to the present, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all meetings, including but not limited to meetings on June 25, 1992; July 1, 1992; October 10, 1992; July 16, 1993; July 18, 1993; August 6, 1993; May 7, 1994; March 20, 1995; March 21, 1995; April 3, 1995; June 5, 1995; and May 24, 1996;

b. Lists of attendees at all such meetings;

c. Communications with PSE&G concerning such meetings;

d. Communications with others concerning such meetings, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

e. Internal NRC discussions concerning such meetings.

5. All documents concerning the NRC Augmented Inspection Team ("AIT") investigations of incidents at Salem from November 11-December 3, 1991; December 14-23, 1992; June 5-28, 1993; and around April 1994, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all AIT meetings regarding Salem;

b. Lists of attendees at all AIT meetings regarding Salem;

c. Communications with PSE&G concerning the AIT investigations at Salem and AIT meetings regarding Salem;

d. Communications with others concerning the AIT investigations at Salem and AIT meetings regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

e. Internal NRC discussions concerning the AIT meetings regarding Salem;

f. The reasons why the NRC decided to do the AIT investigations at Salem.

g. The basis for each of the findings in the AIT reports of investigations at Salem;

h. Notes taken by inspectors during and after the AIT investigations at Salem;

i. Internal NRC discussions about interim drafts of the AIT reports of investigations at Salem;

j. Internal NRC discussions about final drafts of the AIT reports of investigations at Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the AIT reports of investigations at Salem.

6. All documents concerning the NRC Special Inspection Team ("SIT") review of Salem performance from March 26-May 12, 1995, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all SIT meetings regarding Salem;

b. Lists of attendees at all SIT meetings regarding Salem;

c. Communications with PSE&G concerning the SIT investigation at Salem and SIT meetings regarding Salem;

d. Communications with others concerning the SIT investigation at Salem and SIT meetings regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

e. Internal NRC discussions concerning the SIT meetings regarding Salem;

f. The reasons why the NRC decided to perform the SIT investigation at Salem;

g. The basis for each of the findings in the SIT report regarding Salem;

h. Notes taken by inspectors during the SIT investigation at Salem;

i. Internal NRC discussions about interim drafts of the SIT report regarding Salem;

j. Internal NRC discussions about final drafts of the SIT report regarding Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the SIT report regarding Salem.

7. All documents concerning the NRC's Performance Assessment ("PA") review of Salem from July 11-August 25, 1994, including but not limited to:

a. Transcripts, meeting minutes, summaries, and handouts from all meetings concerning the PA review regarding Salem;

b. Lists of attendees at all meetings concerning the PA review regarding Salem;

c. Communications with PSE&G concerning the PA review and PA review meetings regarding Salem;

d. Communications with others concerning the PA review and PA review meetings regarding Salem, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

e. Internal NRC discussions concerning the PA review meeting regarding Salem;

f. The reasons why the NRC decided to do a PA review regarding Salem;

g. The basis for each of the findings in the report regarding the PA review regarding Salem;

h. Notes taken during the PA review regarding Salem;

i. Internal NRC discussions about interim drafts of the PA review report regarding Salem;

j. Internal NRC discussions about final drafts of the PA review report regarding Salem;

k. Internal NRC discussions concerning the findings and conclusions expressed in the PA review report regarding Salem.

8. All documents concerning the Confirmatory Action Letter of June 9, 1995 (CAL No. 1-95-009), including but not limited to:

   a. Communications with PSE&G concerning the Confirmatory Action Letter;

   b. Communications with others concerning the Confirmatory Action Letter, especially including but not limited to PECO Energy, Delmarva, and Atlantic Electric;

   c. Internal NRC discussions concerning the Confirmatory Action Letter;

   d. Discussions with Region I concerning non-final drafts of the Confirmatory Action Letter;

   e. Discussions with Region I concerning final drafts of the Confirmatory Action Letter;

   f. Region I's knowledge of the issues raised in the Confirmatory Action Letter;

   g. Region I's knowledge of PSE&G's plans to address issues raised in the Confirmatory Action Letter.

348574-01 / DOCSDC1

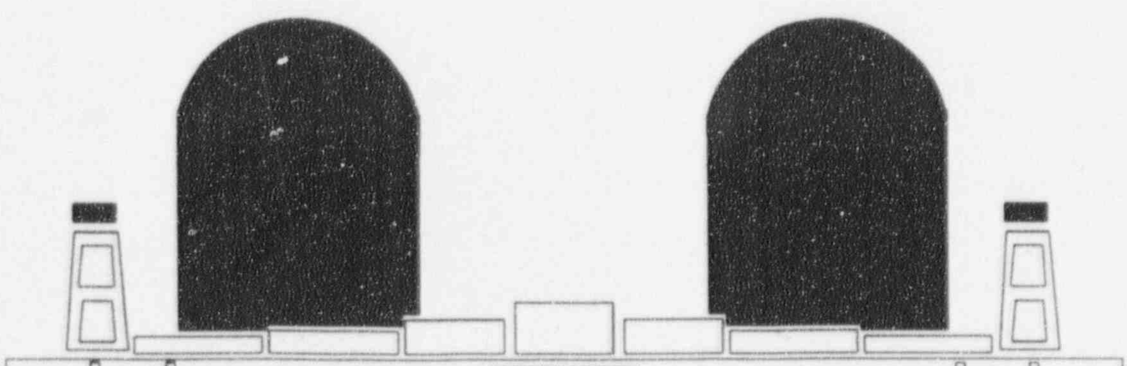
PSE&G Public Service Electric and Gas Company

SALEM UNIT 1

REACTOR TRIP/SAFETY INJECTION

EVENT DATE: APRIL 7, 1994

SALEM
GENERATING STATION



SALEM U1 REACTOR TRIP/SAFETY INJECTION

AGENDA

INTRODUCTION

J. Hagan

CURRENT PLANT STATUS

J. Hagan

SEQUENCE OF EVENTS

L. Catalfomo

PRELIMINARY ASSESSMENT OF EVENT

M. Morroni

ROOT CAUSE DETERMINATION PLAN (TROUBLESHOOTING)

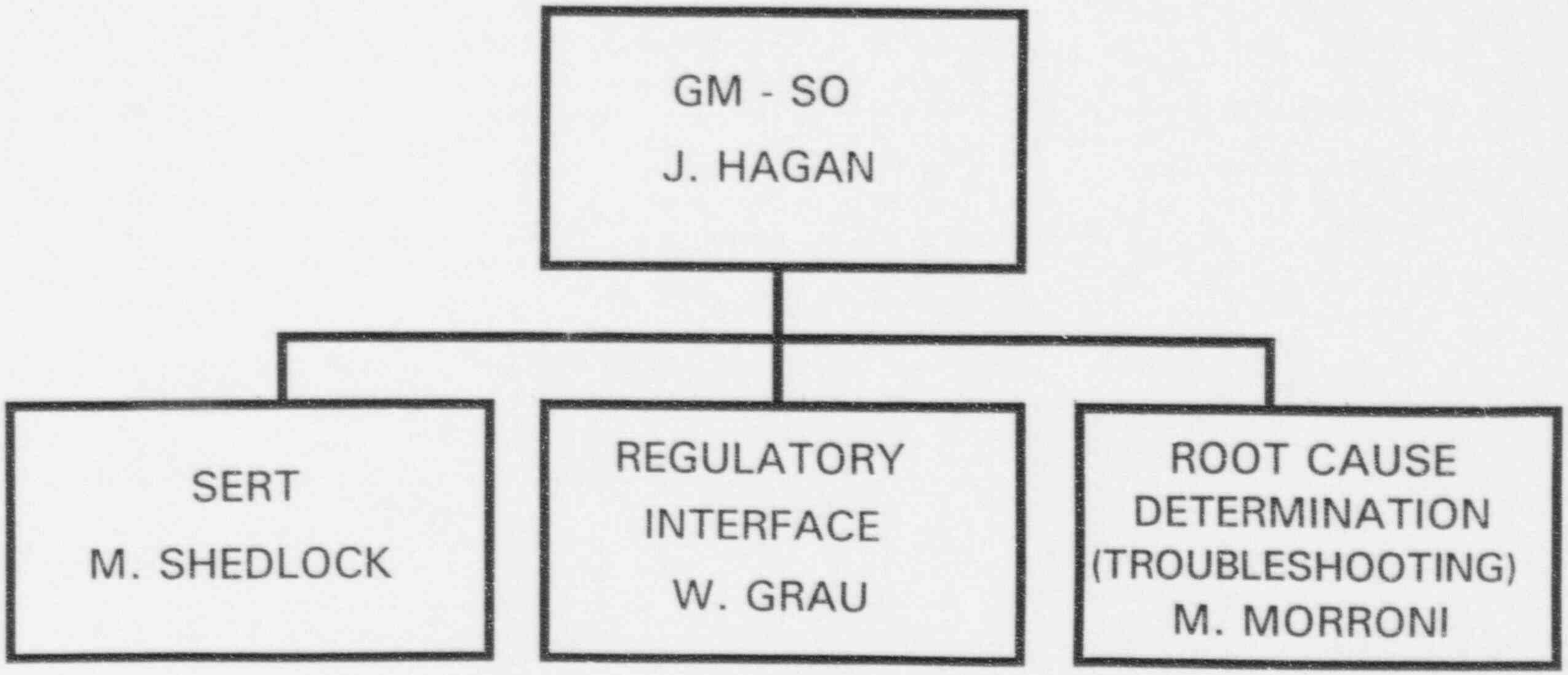
M. Morroni

SIGNIFICANT EVENT RESPONSE TEAM (SERT)

M. Shedlock

REGULATORY INTERFACE

F. Thomson


GM - SO
J. HAGAN
SERT
M. SHEDLOCK
REGULATORY
INTERFACE
W. GRAU
ROOT CAUSE
DETERMINATION
(TROUBLESHOOTING)
M. MORRONI

SALEM U1 REACTOR TRIP/SAFETY INJECTION

CURRENT PLANT STATUS

- Salem Unit 1
  - Cold shutdown Mode 5
  - Temp 187 F
  - Pressure 300 PSIG

- Salem Unit 2
  - Mode 1
  - Reduced Power due to the potential for grass influx at the Circ. Water Intake

94A11-6

SALEM U1 REACTOR TRIP/SAFETY INJECTION

SEQUENCE OF EVENTS

- Plant Status Prior to Event
  - Unit 1 at 75% power
  - Control Rods in manual
- Rapid Power Reduction initiated due to excessive grass build-up on Circ. Water Screens (80 MWe)
- Power Reduced to below P-10 (10% power)
  - Operator inserted rods due to increasing Tavg resulting from load reduction
  - Tavg went low (531 F)
  - Operator withdrew Rods to Raise Tavg
- Reactor Power increased to 25% resulting in Reactor Trip on Power Range Low Setpoint High Flux (25%) (10:49)
- Safety Injection - High Steam Flow with Low Tavg (only Train A of SSPS actuated)
  - A number of SI Related Valves, including 2 MSIVs, did not stroke. All affected valves were manually repositioned in accordance with EOP guidance.
- Unusual Event Declared (18C Manual or Automatic ECCS actuation with discharge to the vessel) 11:00 am
- IAW EOPs, at the SI reset step, operator noticed Train B remained armed. Additionally, 2RP4 SI Block Light was flashing, indicating Train disagreement

SALEM U1 REACTOR TRIP/SAFETY INJECTION

SEQUENCE OF EVENTS

- PR-1 and PR-2 (Pressurize PORVs) Auto Open on Hi PZR Pressure
  - Pressurizer Solid
- During recovery 11 Steam Generator Safety Valve opened for several minutes due to high Tavg (approx. 552 F) causing RCS cooldown
- Safety Injection - Low Pressurizer Pressure (from the armed SSPS - Train B)
  - Manual Safety Injection initiated almost simultaneously at SRO direction
- While resetting Second Safety Injection, Operator noticed 2RP4 light was now solid (Trains agreed)
  - Tech. Spec. Action Statement entered due to 2 blocked Auto Safety Injection Trains (11:41)
- Alert Declared (17B - Precautionary Standby) (13:16)
  - Precautionary measure to insure that the right technical support personnel were in place
  - Recognized that actions required by Tech. Spec. 3.0.3 could not be met
- Pressurizer Bubble restored, Pressurizer Level restored, EOPs exited, IOP-6 entered, cooldown initiated (17:15)
- Terminated Alert (20:20)
- Entered Mode 4, Hot Shutdown (4/8, 01:06)
- Entered Mode 5, Cold Shutdown (4/8, 11:24)

94AI1-2

SALEM U1 REACTOR TRIP/SAFETY INJECTION

PRELIMINARY ASSESSMENT OF EVENT

- Reactor Trip Logic operated as designed
- Appears that Auto Safety Injection Logic operated as designed
- Initial safety injection resulted from a momentary HI Steam Flow signal
- SSPS response relies on mechanical components (relays)
- SSPS Train B did not activate due to the momentary signal and component timing

94AI1 11

SALEM U1 REACTOR TRIP/SAFETY INJECTION

ROOT CAUSE DETERMINATION PLAN (TROUBLESHOOTING)

- Establish cause of initial event (reactor trip)
  - Plant response
  - Hardware and equipment
  - Personnel actions

- Determine if any equipment malfunctioned
  - Identify components requiring further review
  - Conduct appropriate troubleshooting

SALEM U1 REACTOR TRIP/SAFETY INJECTION

SERT CHARTER

- Conduct an independent review and assessment of the circumstances of the reactor scram and the subsequent SI experienced by Salem Unit 1 on April 7, 1994.
- Perform an independent assessment of the root cause determinations performed by plant staff.
- Develop sequence of Events/Causal Factors chart and identify failed barriers.
- Assess the safety significance of the event
- Compare the actual plant response to the anticipated response as per plant design.
- Assess operator response prior to, during and subsequent to the event (to cold shutdown).
- Assess use of operating experience (i.e. any similar events/generic implications).
- Assess response of the organization to the requirements of the Emergency Plan.
- Produce a uniform and comprehensive report, including root cause determination and corrective action recommendations.

94AI1-14

SALEM U1 REACTOR TRIP/SAFETY INJECTION

SIGNIFICANT EVENT RESPONSE TEAM

Members

Mark Shedlock

Nuclear Procurement Mat'l Control, SERT Manager

Bruce Smith

Information Coordinator

Joe Pierson

Operations

Steve Stephens

Maintenance

Warren Evens

Technical

Bob Franks

QA

Bill Meyer

Nuclear Training Center

Virender Solanki

Safety Review

Ken Myers

Reliability & Assessment

Dave Best

Nuclear Engineering

Steve Smith

Safety Review

Bob Kent

Fuels

Alex House

Bill Weckstein

Emergency Planning

Bob Burnham

INPO

94AI1-10

SALEM U 1 REACTOR TRIP/SAFETY INJECTION

REGULATORY INTERFACE

- PSE&G Response Team
- Tracking of Questions/Issues
- Licensing Documentation
- Logistics
- Daily De-Briefs

94AI1-6

PARAMETER AND SETPOINT INFORMATION

REACTOR TRIP	SETPOINT	COINCIDENCE	INTERLOCK	PROTECTION AFFORDED
Source Range High Flux	10E5 cps	1 of 2 channels	P-6 P-10 (High Volts Off)	-Startup Protection
Intermediate Range High Flux Trip	I.R. current equivalent to 25% reactor power	1 of 2 channels	P-10	-Startup Protection
Power Range High Flux Low Setpoint Trip	25%	2 of 4 channels	P-10	-Power excursion from low powers
Power Range High Flux High Setpoint Trip	109%	2 of 4 channels	N/A	-Rapid power excursion
Manual Reactor Trip	Switch to Trip position	1 of 2 switches	N/A	-Operator judgment
Power Range Neutron Flux High Positive Rate	+5% with a 2 second time constant	2 of 4 channels	N/A	-Rod injection protection
Power Range Neutron Flux High Negative Rate	-5% with a 2 second time constant	2 of 4 channels	N/A	-DNB protection for dropped rod(s) accident
OT Delta T	Variable with Tavg, Pzr Press, & AFD	2 of channels	N/A	-DNB protection slow transients
OP Delta T	Variable with Tavg	2 of 4 channels	N/A	-Excessive KW/Ft -B/U to high neutron flux trip
Pressurizer Low Pressure Trip	1865 psia (rate comp.)	2 of 4 channels	P-7	-DNB protection
Pressurizer High Pressure Trip	2385 psig	2 of 4 channels	N/A	-Overpressure protection -RCS integrity
Pressurizer High Level Trip	92%	2 of 3 channels	P-7	-Overpressure protection -Prevent water relief thru safety valves

REACTOR TRIP	SETPOINT	COINCIDENCE	INTERLOCK	PROTECTION AFFORDED
Loss of Flow Trip	<90% of nominal full loop flow	2 of 3 detectors on: - 2 of 4 loops - 1 of 4 loops	 P-7 P-8	-DNB protection
SF/FF Mismatch and Low S/G Lvl	40% of rated steam flow and 25% S/G level	1 of 2 SF/FF mismatches <u>and</u> 1 of 2 S/G Lvls on 1 of 4 S/Gs	N/A	-Redundant to low-low S/G water level
Steam Generator Water Level	16%	2 of 3 channels on 1 of 4 S/Gs	N/A	-Adequate heat sink
RCP Bus Undervoltage	2900 volts	1 of 2 buses taken twice	P-7	-DNB protection -Anticipatory loss of low
RCP Bus Underfrequency	56.5 Hz	1 of 2 buses taken twice	P-7	-DNB protection -Anticipatory loss of flow -Trips all RCPs
RCP Breaker Position Trip	Breaker open	2 or more loops	P-7	-DNB protection -Anticipatory loss of flow
Safety Injection	SI actuation	Any 1 of 5 signals	N/A	-Core protection in the event of LOCA
Turbine Trip	-45 psig trip oil pressure <u>or</u> -4/4 stop valves closed (15% movement in the closed direction)	-2 of 3 channels -4 of 4 valves	P-9	-Provide turbine protection -reduce severity of ensuing transient

PERMISSIVE	SETPOINT	COINCIDENCE	FEATURES
P-2 Low Power Interlock	PT-505 < 15% turbine power	1 of 1 channel	-Blocks automatic rod withdrawal
P-4 Reactor Trip	Trip breakers open (a single RTB and it's associated bypass breaker)	N/A (signal generated from auxiliary contacts on the reactor trip breakers)	-Actuates Turbine Trip -Closes feedwater Vlvs below 554 degrees -Prevents opening feedwater Vlvs closed by SI or Hi-Hi S/G Lvl -Selects no-load setpoint for the Hi Stm flow SI and Stm line Isol. -Swaps steam dumps to plant trip controller -Prevents auto SI reactuation after SI is reset
P-6 Source Range	10-10 amps ------------------------ Reset 7-11 amps (2/2)	1 of 2 Intermediate Range NI channels	-Allows manual block of source range Hi flux trip -Deenergizes source range high voltage
P-7 At Power	P-10 or P-13	1 of 2 inputs	Auto unblocks the following trips: -RCP bus UV -RCP bus UF -Pzr Low Press -Pzr Hi Level -Low Flow in >1 loop -Opening of >1 RCP breaker
P-8 Low Flow	36% power	2 of 4 power range NI channels	Auto unblocks low flow in 1 loop trip
P-9 Turbine Trip	49% power	2 of 4 power range NI channels	Auto unblocks reactor trip on a turbine trip

PARAMETER AND SETPOINT INFORMATION

PERMISSIVE	SETPOINT	COINCIDENCE	FEATURES
P-10 Nuclear at Power	10% power	2 of 4 power range NI channels	-Allows manual block of: 1) IR Hi flux trip and rod stop 2) PR Hi flux low trip -Blocks SR Hi volts (B/U to P-6) -Feeds P-7
P-11 Low Pressure SI Block	1915 psig	2 of 3 Pzr pressure channels	-Allows manual block of low Pzr pressure SI
P-12 Lo-Lo Tavg	543 degrees F	2 of 4 Tavg channels	-Blocks steam dumps -Allows manual block of Hi steam flow SI -Actuates SI and Stm line Isol. on Hi steam flow
P-13 Turbine at Power	10% Power	1 of 2 turbine impulse pressure channels (PT-505 or PT-506)	Inputs to P-7
P-14 Hi-Hi SG Level	67% level	2 of 3 detectors on 1 of 4 S/Gs	-Trips main turbine -Trips main feed pumps -Closes feedwater valves

ROD STOP	SETPOINT	COINCIDENCE	FUNCTION
Overpower Rod Stop	103% power	1 of 4 power range NI channels	-Blocks auto and manual rod withdrawal
High Flux Rod Stop	current equivalent to 20% power	1 of 2 intermediate range NI channel	-Blocks auto and manual rod withdrawal
OT Delta T Rod Stop	OT Delta T setpoint minus 3%	2 of 4 OT Delta T channels	-Blocks auto and manual rod withdrawal -Actuates turbine runback
OP Delta T Rod Stop	OP Delta T setpoint minus 3%	2 of 4 OP Delta T channels	-Blocks auto and manual rod withdrawal -Actuates turbine runback
Control Bank "D" Withdrawn	228 steps on PA converter	N/A	-Blocks auto rod withdrawal

ACTUATION	SETPOINT	COINCIDENCE
1.) Safety Injection		
Manual	N/A	1 of 2 key switches
Containment Pressure Hi	4 psig	2 of 3 detectors
Pressurizer Pressure Low	1765 psig	2 of 3 detectors
Stm Line Differential Pressure	100 psid below two of the three remaining loops	2 per steam line on any steam line
High Stm Flow Coincident with Lo-Lo Tavg or Low Steam line Pressure	-Stm Flow: -40% of full Stm flow from 0% to 20% power. -linearly increasing to 110% of full steam flow from 20% power to 100% power. -Lo-Lo Tavg 543 degrees F. -Low Stm line pressure 600 psig.	-Stm Flow: 1 of 2 detectors per loop on 2 or more loops. -Lo-Lo Tavg: 2 of 4 detectors. -loop? -Stm Line Press: 1 of 1 detectors on 2 of 4 loops.
2.) Containment Spray Actuation:		
Manual	N/A	2 of 2 key switches from 1 of 2 locations
Containment Presure Hi-Hi	15.0 psig	2 of 4 detectors

ACTUATION	SETPOINT	COINCIDENCE
3.) Containment Isolation:		
a.) Phase "A" Isolation:		
Manual	N/A	1 of 2 push buttons
Safety Injection	N/A	Any SI signal
b.) Phase "B" Isolation:		
Manual	N/A	2 of 2 key swtiches in 1 of 2 locations
Containment Pressure Hi-Hi	15.0 psig	2 of 4 detectors
c.) Containment Ventilation Isolation:		
Manual	N/A	-1 of 2 pushbuttons (same ones as for phase "A" isolation). -2 of 2 pushbuttons in 1 of 2 locations (same ones as for phase "B" isolation).
Containment Atmosphere Gaseous Radioactivity (R11A,R12A,R12B,R41A,R41B,R41C)	2 times background	1 of 1 detector
4.) Steam Line Isolation:		
Manual	N/A	1 of 2 pushbuttons on each steam line
Containment Presssure Hi-Hi	15.0 psig	2 of 4 detectors
High Stm Flow Coincident with Lo-Lo Tavg or Low Steam line Pressure	-Stm Flow: -40% of full Stm flow from 0% to 20% power. -linearly increasing to 110% of full steam flow from 20% power to 100% power. -Lo-Lo Tavg 543 degrees F. -Low Stm line pressure 600 psig.	-Stm Flow: 1 of 2 detectors per loop on 2 or more loops. -Lo-Lo Tavg: 2 of 4 detectors. -Stm Line Press: 1 of 1 detectors on 2 of 4 loops.

ACTUATION	SETPOINT	COINCIDENCE
5.) Auxiliary Feedwater Actuation:		
Manual	N/A	Manual start at pump control bezel
Steam Generator Lo-Lo Water Level (starts all AFW pumps)	16% level	-2 of 3 detectors on 1 of 4 S/G for motor driven AFW pumps. -2 of 3 detectors on 2 of 4 S/G for turbine driven AFW pump.
RCP Bus Undervoltage (starts turbine driven only)	2900 volts	1 of 2 buses taken twice
Safety Injection (starts motor driven AFW pumps only)	N/A	Any SI signal
AMSAC Actuation	<5% level when armed (> 40% power)	1 of 2 trains.
Trip of Both Main Feed Pumps (starts motor driven AFW pumps only)	S/G feed pump trip sig. 1	2 of 2 pumps

SAFEGUARDS ACTUATIONS

PARAMETER AND SETPOINT INFORMATION

ACTUATION	SETPOINT	COINCIDENCE
1.) Safety Injection		
Manual	N/A	1 of 2 key switches
Containment Pressure Hi	4 psig	2 of 3 detectors
Pressurizer Pressure Low	1765 psig	2 of 3 detectors
Stm Line Differential Pressure	100 psid below two of the three remaining loops	2 per steam line on any steam line
High Stm Flow Coincident with Lo-Lo Tavg or Low Steam line Pressure	-Stm Flow: -40% of full Stm flow from 0% to 20% power. -linearly increasing to 110% of full steam flow from 20% power to 100% power. -Lo-Lo Tavg 543 degrees F. -Low Stm line pressure 600 psig.	-Stm Flow: 1 of 2 detectors per loop on 2 or more loops. -Lo-Lo Tavg: 2 of 4 detectors. -Stm Line Press: 1 of 1 detectors on 2 of 4 loops.
2.) Containment Spray Actuation:		
Manual	N/A	2 of 2 key switches from 1 of 2 locations
Containment Presure Hi-Hi	15.0 psig	2 of 4 detectors

ACTUATION	SETPOINT	COINCIDENCE
3.) Containment Isolation:		
a.) Phase "A" Isolation:		
Manual	N/A	1 of 2 push buttons
Safety Injection	N/A	Any SI signal
b.) Phase "B" Isolation:		
Manual	N/A	2 of 2 key swtiches in 1 of 2 locations
Containment Pressure Hi-Hi	15.0 psig	2 of 4 detectors
c.) Containment Ventilation Isolation:		
Manual	N/A	-1 of 2 pushbuttons (same ones as for phase "A" isolation). -2 of 2 pushbuttons in 1 of 2 locations (same ones as for phase "B" isolation).
Containment Atmosphere Gaseous Radioactivity (R11A,R12A,R12B,R41A,R41B,R41C)	2 times background	1 of 1 detector
4.) Steam Line Isolation:		
Manual	N/A	1 of 2 pushbuttons on each steam line
Containment Presssure Hi-Hi	15.0 psig	2 of 4 detectors
High Stm Flow Coincident with Lo-Lo Tavg or Low Steam line Pressure	-Stm Flow: -40% of full Stm flow from 0% to 20% power. -linearly increasing to 110% of full steam flow from 20% power to 100% power. -Lo-Lo Tavg 543 degrees F. -Low Stm line pressure 600 psig.	-Stm Flow: 1 of 2 detectors per loop on 2 or more loops. -Lo-Lo Tavg: 2 of 4 detectors. -Stm Line Press: 1 of 1 detectors on 2 of 4 loops.

DRAFT

NRC AUGMENTED INSPECTION TEAM

EXIT MEETING

SALEM UNIT 1 REACTOR TRIP WITH MULTIPLE SAFETY INJECTIONS

ARTIFICIAL ISLAND PROCESSING CENTER

APRIL 22, 1994, 10:30 A.M.

AGENDA

I. INTRODUCTIONS — M. WAYNE HODGES

II. PURPOSE OF INSPECTION

III. SEQUENCE OF EVENTS — ROBERT J. SUMMERS

IV. SAFETY SIGNIFICANCE

V. PRELIMINARY FINDINGS

- A) PLANT EQUIPMENT
- B) PROCEDURE ADEQUACY
- C) PERSONNEL ACTIVITIES
- D) GENERIC IMPLICATIONS

VI. ASSESSMENT OF PSE&G INVESTIGATIONS

VII. CONCLUDING NRC REMARKS — M. WAYNE HODGES

VIII. PSE&G REMARKS — STEVEN E. MILTENBERGER

PURPOSE OF INSPECTION

THE GENERAL OBJECTIVES OF THE AUGMENTED INSPECTION TEAM WERE TO:

1. CONDUCT A THOROUGH REVIEW OF THE CIRCUMSTANCES SURROUNDING THE 4/7/94 SALEM UNIT 1 REACTOR TRIP AND SUBSEQUENT LOSS OF THE PRESSURIZER STEAM BUBBLE.

2. ASSESS OPERATORS' ACTIONS PRIOR AND SUBSEQUENT TO THE REACTOR TRIP; DEVELOP A SEQUENCE OF EVENTS AND CAUSAL FACTOR ANALYSIS FOR THE PLANT AND OPERATORS' RESPONSES ASSOCIATED WITH THE EVENT; COMPARE ACTUAL PLANT RESPONSE TO EXPECTED PLANT RESPONSE.

3. REVIEW THE LICENSEE EVENT CLASSIFICATION AND NOTIFICATIONS.

4. ASSESS SAFETY SIGNIFICANCE OF THE EVENT.

5. EXAMINE EQUIPMENT FAILURES AND IDENTIFY ASSOCIATED ROOT CAUSES.

6. DETERMINE IF ANY DESIGN DEFICIENCIES ASSOCIATED WITH THE EVENT EXISTED THAT WARRANTED PROMPT ACTION.

SEQUENCE OF EVENTS

INITIAL CONDITIONS ON APRIL 7, 1994:

REACTOR POWER AT 75%
CONTROL RODS IN MANUAL
12A CIRCULATING WATER PUMP OUT-OF-SERVICE

10:16 TO 10:43	POWER REDUCTION DUE TO CLOGGING OF CIRCULATING WATER SCREENS BY RIVER GRASS. FIVE OUT OF SIX CIRCULATING WATER PUMPS TRIP OUT OF SERVICE.
10:44 TO 10:47	REACTOR COOLANT SYSTEM TEMPERATURE DECREASES BELOW LOW-LOW SETPOINT, PLANT POWER AT 80 MWE. OPERATOR PULLS RODS TO RESTORE RCS TEMPERATURE. REACTOR POWER INCREASES FROM 7% TO 25%.

10:47	REACTOR TRIPS AT 25% POWER RANGE LOW SETPOINT. AUTOMATIC SAFETY INJECTION ON HIGH STEAM FLOW WITH LOW-LOW TAVG ON "A" TRAIN LOGIC ONLY.
10:49 TO 11:05	EMERGENCY OPERATING PROCEDURES ENTERED. UNUSUAL EVENT DECLARED. OPERATORS RESOLVE SI LOGIC TRAIN DISCREPANCIES.
11:05 TO 11:26	PRESSURIZER PORVS AUTO OPEN ON HIGH PRESSURIZER PRESSURE, INDICATING PRESSURIZER WAS FILLING TO SOLID OR NEAR SOLID CONDITION. A STEAM GENERATOR SAFETY VALVE OPENS CAUSING RCS COOLDOWN AND DEPRESSURIZATION.
11:26	SECOND ACTUAL AUTOMATIC SI DUE TO LOW PRESSURIZER PRESSURE.
11:49	PRESSURIZER RELIEF TANK RUPTURE DISK RUPTURES

13:16	ALERT DECLARED TO ENSURE PROPER TECHNICAL STAFF AVAILABLE
16:30	PRESSURIZER STEAM SPACE RE-ESTABLISHED
17:15	EOPS EXITED, NORMAL SHUTDOWN PROCEDURE IOP-6 ENTERED
20:20	ALERT TERMINATED

APRIL 8, 1994

01:06	MODE 4 (HOT SHUTDOWN) ENTERED
11:24	MODE 5 (COLD SHUTDOWN) ENTERED

BUBBLE?

May add / will probably be asked

SAFETY SIGNIFICANCE

EVENTS OF 4/7/94 DEPICTED AN UNUSUAL TRANSIENT IN WHICH PLANT CONDITIONS CHALLENGED BOTH THE AUTOMATIC PROTECTIVE FEATURES AND THE OPERATORS WHO CONTROL THE PLANT.

SOME EQUIPMENT PERFORMANCE WAS NOT AS EXPECTED AND OPERATOR PERFORMANCE EXHIBITED SOME WEAKNESS

HOWEVER, ALL BARRIERS (FUEL CLADDING, RCS PRESSURE BOUNDARY, CONTAINMENT) TO RELEASE OF FISSION PRODUCTS WERE MAINTAINED

MOST SIGNIFICANT CONCERN IDENTIFIED WAS THAT THE AUTOMATIC SAFETY INJECTION SYSTEM OPERATED IN A WAY THAT REQUIRED EXTENSIVE OPERATOR ACTION

> OPERATOR ACTION EXTENDED THE TIME TO ~~MEET~~ Reach TERMINATION CRITERIA IN THE EOPS
>
> THIS RESULTED IN ECCS INJECTIONS PRODUCING A SOLID (OR NEAR-SOLID) RCS
>
> SOLID PLANT CONFIGURATION LED TO ~~RELIANCE ON~~ PRESSURIZER PORV~~S~~ Cycling TO CONTROL RCS PRESSURE
>
> OPERATION OF THE PORVS COULD HAVE RESULTED IN A CHALLENGE TO THE RCS BOUNDARY

OVERALL CONCLUSION: SEQUENCE OF EVENTS POSED A CHALLENGE TO THE RCS PRESSURE BOUNDARY, BUT PLANT EQUIPMENT OPERATED PROPERLY TO MAINTAIN THAT BOUNDARY. NO EVIDENCE OF DAMAGE TO FISSION PRODUCT BARRIERS WAS IDENTIFIED.

PRELIMINARY FINDINGS

PLANT EQUIPMENT

CONDENSER CIRCULATING WATER

RIVER GRASS POSES CHALLENGE TO SCREENS ON A SEASONAL BASIS - THROUGH PLANT HISTORY, MARCH - MAY ~~TIMEFRAME~~ HAS BEEN MOST SEVERE

IN THE SPRING OF 1993, GRASS AT CIRC WATER HAD CAUSED APPROXIMATELY 16 ~~DIFFERENT~~ PERIODS OF REDUCED POWER OPERATION AT BOTH SALEM UNITS

LICENSEE DEVELOPING CIRC WATER SCREEN MODIFICATIONS (SCHEDULED TO BEGIN FALL 1994) FOR FASTER AND EASIER TO CLEAN SCREENS

SERVICE WATER

DUE TO HYDROLOGIC AND GEOLOGIC REASONS, ULTIMATE HEAT SINK IS NOT AS EXPOSED TO RIVER GRASS CONCERNS AS CIRC WATER

SSPS LOGIC TRAIN DISAGREEMENT

STEAM FLOW SIGNAL PERTURBATIONS PRODUCED BY TURBINE TRIP CAUSED FALSE INDICATIONS OF STEAM LINE BREAK, OF SHORT ENOUGH DURATION TO ONLY BE IDENTIFIED BY ONE TRAIN OF SI LOGIC ~~(ACTUAL SI OCCURRED DUE TO~~ COINCIDENT WITH ABNORMAL LOW TAVE PRODUCED BY OPERATOR ACTIONS)

LICENSEE HAS INSTALLED TIME DELAY IN SI LOGIC TO ~~PREVENT~~ MINIMIZE SPURIOUS SI ACTUATION ~~ON~~ DUE TO FALSE (SHORT DURATION) HIGH STEAM FLOW INDICATIONS

ESF COMPONENTS

VARIOUS ESF COMPONENTS DID NOT ACTUATE DUE TO COMBINATION OF EXTREMELY SHORT-DURATION STEAM FLOW INDICATIONS AND LACK OF SI TRAIN B LOGIC

PORVs

SOLID RCS OPERATION RESULTED IN THE TWO PRESSURIZER PORVs OPERATING A MINIMUM OF 300 TIMES (COMBINED)

LICENSEE'S DISASSEMBLY AND INSPECTION FOUND DAMAGED PORV INTERNALS

ATMOSPHERIC STEAM RELIEFS (MS 10s)

CONTROLLER RESET WINDUP ISSUE: DUE TO PROLONGED OPERATION BELOW MS

10 LIFT SETPOINT, CONTROLLER SATURATION OCCURS, DELAYING VALVE RESPONSE TO STEAM GENERATOR PRESSURE ABOVE SETPOINT

Did they ever have operable ~~PORVs~~ ADV

SLOW MS 10 RESPONSE AND OPERATOR FAILURE TO TAKE MANUAL CONTROL RESULTED IN MAIN STEAM SAFETY RELIEF LIFTING

ROD CONTROL

ROD CONTROL IN MANUAL (VICE AUTO) SINCE FEBRUARY DUE TO OPERATOR CONCERNS WITH Tave-Tref INDICATIONS. ENGINEERING RESOLVED COMPARATOR CIRCUIT PROBLEM IN MARCH, HOWEVER, OPERATORS CHOSE TO MAINTAIN CONTROL IN MANUAL - OPS WAS RIGHT, AUTO D/N WORK

MANUAL CONTROL OF RODS DURING DOWN-POWER TRANSIENT LED TO OVERCOOLING OF RCS

PROCEDURE ADEQUACY

INADEQUATE PROCEDURES FOR OPERATION OF THE ATMOSPHERIC RELIEF VALVES - OPERATORS DID NOT TAKE MANUAL CONTROL OF ATMOSPHERIC RELIEFS, WHICH COULD HAVE ALLEVIATED THE RESET WINDUP PHENOMENON

WEAK GUIDANCE FOR RAPID DOWN-POWER WITH ROD CONTROL IN MANUAL - LED TO OVERCOOLING OF RCS

WEAK GUIDANCE FOR RESPONSE TO CIRCULATING WATER OR LOW CONDENSER VACUUM PROBLEMS. ~~LOW-LOW CONDENSER VACUUM ALARM RESPONSE PROCEDURE HAD INCORRECT TURBINE TRIP SETPOINT INFORMATION~~

EOP-DIRECTED ACTIONS (MANUAL ALIGNMENT OF ECCS COMPONENTS) FOR PARTIAL SI CONTRIBUTED TO SOLID PRESSURIZER (CONSIDER ACTUATING OTHER TRAIN VICE MANUAL ALIGNMENT?)

A YELLOW PATH TO ESTABLISH A PRESSURIZER BUBBLE WAS AVAILABLE, ISSUE WITH OPERATOR TRAINING, FUNCTIONAL RECOVERY PROCEDURE ENTRY CONDITIONS, CLARITY OF SOLID PLANT PRESSUR CONTROL IN EOPS (ESTABLISH BUBBLE OR SOLID PLANT COOLDOWN?)

AFTER RESET OF THE FIRST SAFETY INJECTION, OPERATOR GUIDANCE FOR THE SI TRAIN DISAGREEMENT WAS WEAK

PERSONNEL ACTIVITIES

POSITIVE SHORT TERM INITIATIVE, PLANNING, AND TEAMWORK FOR GRASS

- ATTACKS AND RESPONSE AT INTAKE

- PRE-TRIP COMMAND AND CONTROL OF OPERATOR ACTIVITIES WAS WEAK

  - POORLY CONTROLLED RAPID DOWN-POWER WITH MULTIPLE REACTIVITY CHANGES

  - VAGUE DIRECTION TO PULL RODS TO RESTORE Tave LED TO EXCESSIVE ROD PULL AND RCS COOLDOWN

  - CONTROLS OPERATOR DIRECTED TO LEAVE RODS TO MANIPULATE ELECTRICAL LOADS; SHIFT SUPERVISOR OPERATED RODS, VACATING SUPERVISORY ROLE DURING TRANSIENT

  - SENIOR SHIFT SUPERVISOR LEFT CONTROL ROOM AREA IN ORDER TO BYPASS CONDENSER VACUUM PERMISSIVES TO ATTEMPT CIRC WATER PUMP START

  - FOLLOWING SOME REACTOR CONTROL MANIPULATIONS, OPERATORS DID NOT MONITOR REACTOR RESPONSE

- POST-TRIP COMMAND AND CONTROL OF OPERATOR ACTIVITIES WAS FAIR

  - PROBLEM WITH MS-10 CONTROLLER CONTRIBUTED TO STEAM GENERATOR SAFETY RELIEF LIFTING AND SECOND SI

  - USE AND KNOWLEDGE OF YELLOW CSF PATH WAS WEAK, CONTRIBUTING TO SOLID PLANT AND ALERT DECLARATION

  - OPERATORS DID USE AVAILABLE TECHNICAL SUPPORT TO PLACE THE PLANT IN A STABLE CONDITION FOLLOWING THE EVENT

  - OPERATOR AWARENESS OF REACTOR PRESSURE AND WILLINGNESS TO INITIATE A MANUAL SI WAS GOOD

  - OPERATORS IMPLEMENTED AND FOLLOWED EOPS, ALLOWING SI TO RUN UNTIL EOP TERMINATION CRITERIA MET. HOWEVER, ONE VALVE WAS MISSED

- EVENT CLASSIFICATIONS AND NOTIFICATIONS WERE PER PROCEDURE

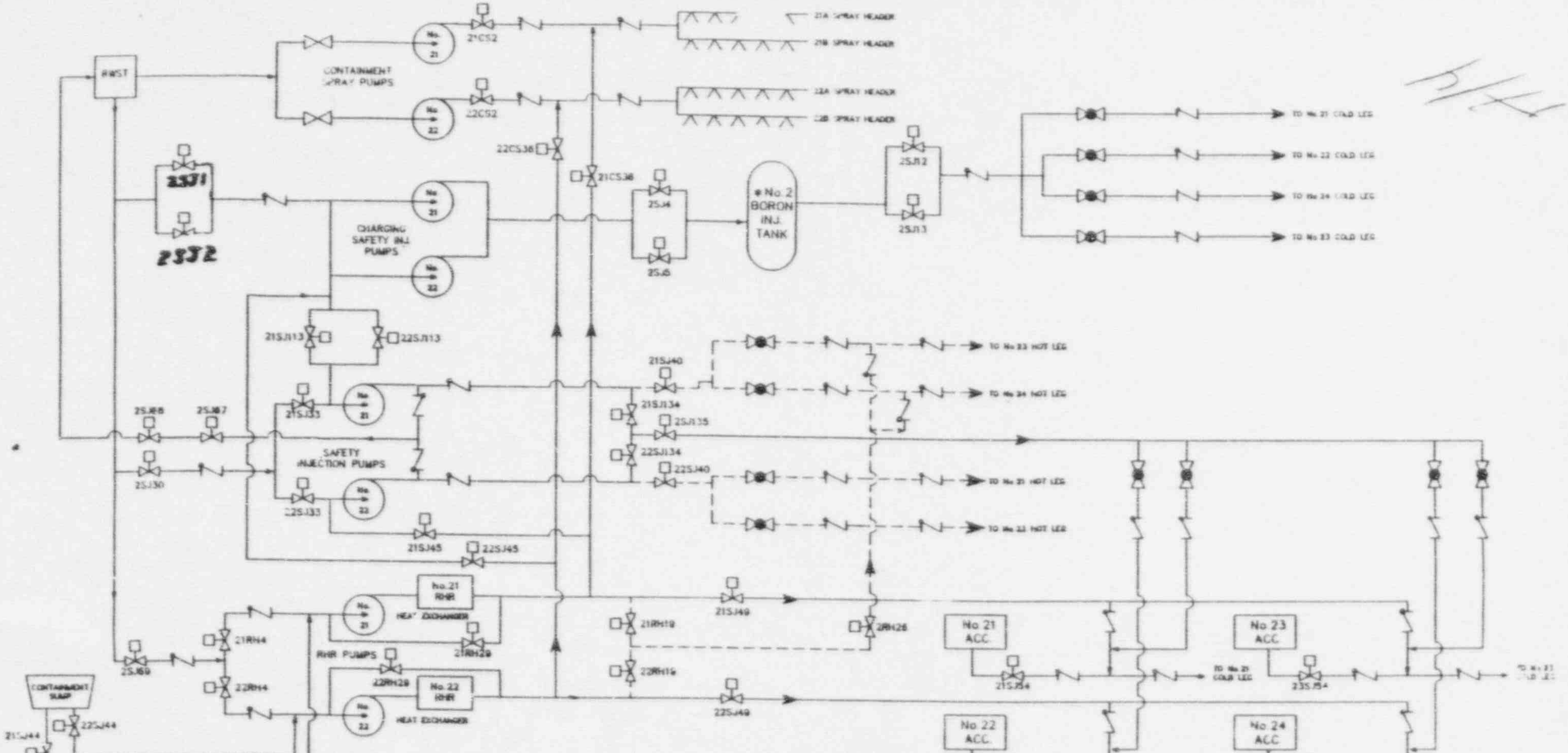
  - WEAKNESS NOTED IN AVAILABILITY OF TECHNICAL INFORMATION IN INITIAL NOTIFICATION DUE TO LOCATION AND EXPERIENCE LEVEL OF COMMUNICATOR

  - LICENSEE DECISION TO DECLARE AN ALERT WAS GOOD, BASED ON OBTAINING PROPER TECHNICAL SUPPORT FOR OPERATORS

GENERIC IMPLICATIONS

IEEE 279 CONCERNS

PORV CONCERNS

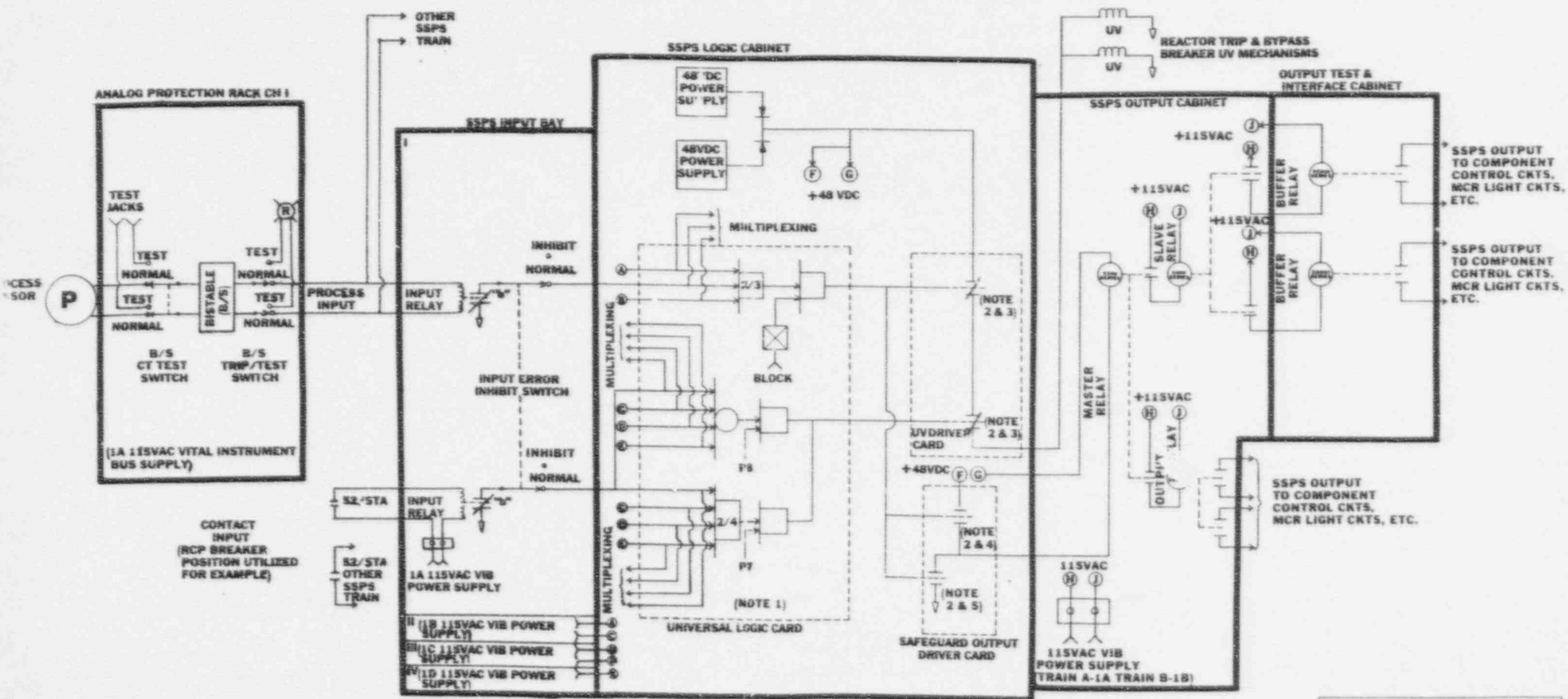


* NOTE: BORON INJECTION TANK NO LONGER CONTAINS 21,000 PPM BORIC ACID. NOT REQUIRED BASED ON NEW ACCIDENT ANALYSIS. VALVES SJ4 AND SJ5 ARE NORMALLY OPEN.

LP NO.	
TITLE ECCS COMPOSITE	
FIG. NO.	REV
AV SERVICES NO. AV1000	

EC-11

INFORMATION ONLY



NOTES:

1. The logic functions shown are achieved on the Universal Logic Card, but not necessarily on the same or a single card.
2. Functional representation only, solid state components are used to achieve the actual function.
3. Contact closed when no trip condition is present.
4. Contact closed when no safeguards condition is present.
5. Contact open when no safeguards condition is present.

TITLE: SALEM SOLID STATE PROTECTION SYSTEM (SSPS) FUNCTIONAL DIAGRAM

NUCLEAR LICENSING WORK STANDARD

NRC INSPECTION MANAGEMENT

ATTACHMENT 1

QUESTION AND ANSWER TRACKING FORM

ITEM NUMBER: AIT-CW-004

SOURCE: NRC/PSE&G (SELECT ONE)

DATE: 4/9/94

NRC CONTACT: John Kauffman

NRC QUESTION: Please provide a copy of night order and Engineering Memo regarding manual rod control on U-1

PSE&G CONTACT:

LICENSING CONTACT: OTT

PSE&G RESPONSE: RITZMAN

Engineering Memo 94-51, Rev 1 provided

Night Order Book Entry From 3/14/94

DATE: 4/9/94

NLR REVIEW: YES / NO (SELECT ONE)

RESPONSE ACCEPTED BY NRC: YES / NO (SELECT ONE)

INSPECTOR'S NAME:

DATE:

ATTACHMENT 1
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LICENSING CONTACT:

RITZMAN

PSE&G RESPONSE:

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Night Order Book Entry From 3/14/94

DATE: 4/9/94

NLR REVIEW: YES / NO (SELECT ONE)

RESPONSE ACCEPTED BY NRC: YES / NO (SELECT ONE)

INSPECTOR'S NAME:

DATE:

Night Order Book
Daily Entry

March 14, 1994

1. The Hope Creek Outage incentive plan has been published. As usual, Salem will earn incentive days based on our continued availability. The FYI is enclosed.

2. All personnel are reminded that if they know of anyone interested in working in Salem Operations Department, forward the resume and employment application to the O.M. or O.E.s. The minimum qualifications to be considered for employment are; previous commercial experience or US Navy nuclear power program experience. We have interviewed a number of people recently in an effort to fill the fifteen open personnel requisitions however, some of these positions might remain unfilled after offers are made and another "job fair" will be held if required.

3. All personnel are reminded that if a "S" (safety) priority work request is written, action should taken immediately to rectify the situation or to ensure the safety of the other personnel in the Station. For instance, an A/R priority "S" was written on FHB lighting being a safety hazard. Action should have been taken to restore the lighting immediately by contacting Maintenence Controls electrical supervision, or the Controls Technician, or the lighting should have been restored by Operations. For other items appropriate action might include roping off the area with safety tape, or taking other action to alert and protect our fellow employees.

4. Chemistry has informed us that S/G Cat Cons on Unit 1 are much better. Place max Blowdown I/S only from 0000 to 0600 as we are currently doing on Unit 2.

5. Control Rods on Unit 1 have stepped again without an apparent demand as indicated on the recorder (taking credit for the 1 degree high error) Please leave Rod Control on Unit 1 in manual until this is completely resolved. Since the investigation seems to indicate that a similar problem may exist on Unit 2, maintain Unit 2 Rod Control in manual also pending the outcome of the investigation and troubleshooting.

6. An incident report presented by system engneering indicates there are approx 16 ckts in Unit 1 relay room (predominantly 125vdc ckts) that do not meet the cable separation criteria. These ckts and the corrective actions are under investigation, but until that time system engineering is telling us that there is no operability concern as long as fire protection is operable and a roving fire watch patrol is maintained. Please ensure that the fire protection systems for the relay room are not impaired for corrective maintenance work, unless absolutely necessary, until this is resolved.

Night Order Book
Daily Entry

March 14, 1994

7. Enclosed is a memo from R. Swartzwelder in response to a question about permit requirements which might prohibit opening both the north and south tide gates for short periods of time. My thought is that during the periods of slack tide we could open both tide gates for the time period required to thoroughly clean the upper trough. This would allow the trough end, away from the "normally" open tide gate, to have better flow.

8. Enclosed is a change of shift for R. Blose's jury duty.

9. As you know, Pete is in Atlanta. If something arises with which the SNSS needs assistance, you can contact Joe Serwan by pager 478-5153 or home phone 769-0786. Tomorrow we will provide Bob Olsen's contact numbers.

10. Mike Cocking, John Robertson, and Joe Serwan toured Circ Water with Frank Becker. Frank had just blown down the screen wash pumps and other persons were actively involved with trough cleaning. We would like to pass along our appreciation for a job well done.
Shift supervision should tour the Circ. Water at least twice a shift in order to ensure the Management's expectations are communicated to the NEO's and in order to ensure the Station is made aware of, and properly prioritized the equipment challenges presented to our personnel.

V-SHIFT SNSS____ NSS____ NSS____ NSSF____ NSSW____
W-SHIFT SNSS____ NSS____ NSS____ NSSF____ NSSW____
X-SHIFT SNSS____ NSS____ NSS____ NSSF____ NSSW____
Y-SHIFT SNSS____ NSS____ NSS____ NSSF____ NSSW____
Z-SHIFT SNSS____ NSS____ NSS____ NSSF____ NSSW____
OPS STAFF____ ____ ____ ____ ____

OPS-MGR____ OE1____ OE2____ SWCC1____ SWCC2____

ENGINEERING MEMO # 94-51, REV 1

TO: Bob Olsen, Senior Shift Nuclear Supervisor - Days (Unit 1)
FROM: John Pehush, System Engineer
SUBJECT: Rod Speed Control, Tave/Terr Recorder Indication
DATE: 03/17/94

The purpose of this memo is to provide an update of the overview of the troubleshooting effort of previously delineated in Engineering Memo # 94-51, Rev 0 ref. W.O. 940224227. The exact reason the recorder indication was indicating low has been traced to a malfunctioning Isolator.

The Terr signal is developed by subtracting the Tref (1st. Stage Turbine) and the Highest Tavg which is patched into the summator. While performing the Tave/Terr recorder calibration check, multiple grounds were identified. When a ground connection from the negative terminal to shield was lifted, both the isolator and recorder responded correctly. Disconnecting the ground de-coupled the noise from the Tref input, unfortunately this masked the source of the of the indication step changes. Additional troubleshooting on 3/14/94 discovered that the Tref input from Isolator 1TM505A had ≈ 196 mVAC noise. By 3/15/94, the noise level had increased to over 300 mV. Subsequently the Isolator was replaced and the recorder indication returned to normal.

Signal Summator 1PC412A receives four inputs and its output determines if rods are required to step. Electrical noise of 40 mVAC was measured on the High Auctioneered Tave input. Isolator 1TM412N, which supplies this signal to 1PC412A was replaced and the noise eliminated. Since the Isolator was replaced it was found to have drifted approx. 25 mV. This is why the Rods started to step in Auto on 3/14/94. The Isolator has been re-calibrated and I&C will monitor it to determine if it has a drift problem.

Engineering still believes that grounds loops can introduce errors. System Engineering has requested I&C to lift the ground and verify that no indication shift occurs. However, based on scaling calculations of 1st Stage Pressure versus High Auctioneered Tavg the Terr indication appears correct.

A Work Request will be initiated to verify the P-250 input is properly scaled.

A review of the Unit 2 Hagan Component History Database shows that 2TM505A Isolator had capacitors replaced on 04/12/93 under W.O. 930705008, therefore its signal should be normal.

c. J. Morrison P. Ott B. O'Grady

Initiator John Pehush 3/18/94 Approved Ken Stey 3/18/94

Peer Review [illegible]

NUCLEAR LICENSING WORK STANDARD
NRC INSPECTION MANAGEMENT

ATTACHMENT 1
QUESTION AND ANSWER TRACKING FORM

ITEM NUMBER: AIT-CW-005

SOURCE: NRC/PSE&G (SELECT ONE)

DATE: 4/9/94

NRC CONTACT: John Kauffman

NRC QUESTION: Please provide a copy of the annunciator response procedures for "Lo" and "Lo Lo" Condenser Vacuum for U-1

PSE&G CONTACT:
OTT

LICENSING CONTACT:
RITZMAN

PSE&G RESPONSE:
Pages 9 and 18 of S1.OP-AR.ZZ-0007 were provided
S1.OP-AB.COND-0001 was also provided

DATE: 4/9/94

NLR REVIEW: YES / NO (SELECT ONE)

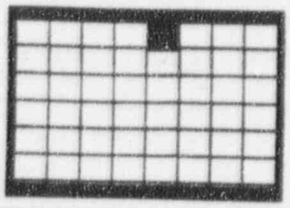
RESPONSE ACCEPTED BY NRC: YES / NO (SELECT ONE)

INSPECTOR'S NAME:

DATE:

A/17

ALARM



5

CNDSR
VAC
LO

DEVICES: 1PD2400

SETPOINT: $\leq$ 25 inches H_g

1.0 CAUSE(S):

1.1 Condenser vacuum is $\leq$ 25 inches H_g.

2.0 AUTOMATIC ACTION:

2.1 None

3.0 OPERATOR ACTIONS:

3.1 **CONFIRM** alarm by indication on Panel 1RP1.

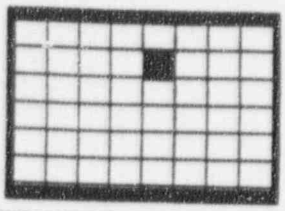
3.2 <u>GO TO</u> S1.OP-AB.COND-0001(Q), Loss of Condenser Vacuum.

Page 1 of 1

G-5

References: Dwg. 212882, 218457

ALARM



13

CNDSR
VAC
LO-LO

DEVICES: 1PD188

SETPOINT: ≤ 23 inches Hg

1.0 CAUSE(S):

1.1 Condenser vacuum is ≤ 23 inches Hg.

2.0 AUTOMATIC ACTION:

2.1 ≥ P-9 (49% power), Turbine Trip, Reactor Trip

2.2 ≤ P-9 (49% power), Turbine Trip

3.0 OPERATOR ACTIONS:

3.1 CONFIRM alarm by indication on Panel 1RP1.

3.2 IF a Turbine Trip occurs, THEN PERFORM the following:

A. IF ≥ P-9 (49% power), THEN GO TO 1-EOP-TRIP-1, Reactor Trip or Safety Injection.

B. IF ≤ P-9 (49% power), THEN GO TO S1.OP-AB.TRB-0001(Q), Turbine Trip Below P-9.

3.3 GO TO S1.OP-AB.COND-0001(Q), Loss of Condenser Vacuum.

Page 1 of 1

G-13

References: Dwg. 212863

LOSS OF CONDENSER VACUUM

USE CATEGORY : **I**

REVISION SUMMARY

- This is a Minor Revision to perform the following changes:
  - Clarify Step 3.1 by removing Substep B, Substep A provides the direction to maintain condenser pressure within established limits.
  - Correct valve nomenclature in Step 3.5.A
  - Change OHA-G2 to OHA-G5 and OHA-H31 to OHA-G36 in the Technical Bases Document. These changes are required by the installation of DCP 1EC-3085 and to correct a typographical error in Rev. 0 that used H31 instead of H32.

IMPLEMENTATION REQUIREMENTS

- None

APPROVED: [signature] Operations Manager - Salem 5/15/96

Date

ABNORMAL OPERATING PROCEDURE
S1.OP-AB.COND-0001(Q)
LOSS OF CONDENSER VACUUM

1.0 **ENTRY CONDITION**

1.1 Unexpected decrease in condenser vacuum with the Main Turbine and Generator in service.

2.0 **IMMEDIATE ACTIONS**

2.1 None

3.0 **SUBSEQUENT ACTIONS**

NOTE

Turbine load reduction ramp rates of 5%/min. or less are desirable to prevent operation of Steam Dumps, which could worsen the low vacuum condition.

CAUTION

Main Turbine trip will occur at 18 to 22 in. hg vacuum (8-12 in. hga)

3.1 INITIATE Main Turbine load reduction until vacuum stabilizes.

A. **IF** required, **THEN** further reduce Turbine load to maintain Condenser pressure:

- Less than 3.5 in. hga (load equal to or less than 30%)
- Less than 5.5 in. hga (load greater than 30%)

3.2 **IF** the cause of vacuum decrease is a Circulating Water System malfunction, **THEN GO TO** S1.OP-AB.CW-0001(Q), Circulating Water System Malfunction.

3.3 START all available Condenser Vacuum Pumps IAW S1.OP-SO.AR-0001(Z), (III-8.3.1), Condenser Air Removal System Normal Operation.

3.4 SEND Operators to perform Attachment 1, Loss of Vacuum Local Checks.

- NOTIFY Operator to monitor Condenser Hotwell and Condensate Pump Suction piping for indications of flashing.

3.5 MONITOR Condensate Pump suction temperature on P-250 to ensure Condensate temperature is maintained less than 130°F until the low vacuum condition is corrected:

- T2504A 11 Condensate Pump Suction Temperature
- T2505A 12 Condensate Pump Suction Temperature
- T2506A 13 Condensate Pump Suction Temperature

A. **IF** Condensate Pump suction temperatures reach or exceed 130°F, **THEN** bypass the Condensate Polishing System as follows:

1. OPEN 11CN108 through 13CN108, Bypass Polisher.

2. CLOSE 1CN109, Polisher Inlet Valve.

B. **IF** Condensate Polishing remains in service, **THEN** notify Chemistry Department to closely monitor Condensate Polishing resin performance until Condenser Vacuum is restored to normal range.

3.6 **IF AT ANYTIME**, flashing is indicated in Condenser Hotwell or Condensate Pump suction piping, reduce Main Turbine load until flashing stops.

3.7 **IF** a Condenser Vacuum Pump malfunction is indicated, **THEN** Go to Step 3.11

3.8 **IF** Condenser air inleakage is indicated, **THEN** Go to Step 3.15

3.9 **IF** Turbine Gland Sealing Steam System malfunction is indicated, **THEN** perform S1.OP-SO.GS-0001(Z), (III-4.3.1), Turbine Gland Sealing Steam System Normal Operation, to restore system to proper operation.

3.10 Continue symptom diagnosis per Steps 3.4 through 3.9 to determine further actions. **IF** cause of decreasing Condenser Vacuum has not been determined, **THEN** return to step 3.1 for symptom rediagnosis or as directed by SNSS/NSS.

3.11 **IF** Condenser Vacuum Pump cannot be returned to normal operation, **THEN** isolate the faulty vacuum pump from the condenser by closing the affected AR25 valve and stopping the affected vacuum pump.

3.11 Can the remaining Condenser Vacuum Pumps maintain stable or increasing Condenser vacuum?

NO YES———> Go to Step 3.14
|
V

3.13 RETURN to Step 3.1 for symptom rediagnosis or as directed by SNSS/NSS.

3.14 This procedure has been completed. When conditions permit, return to normal operation IAW the appropriate procedure.

3.15 Can source of Condenser air inleakage be isolated in present plant conditions?

YES NO———> Go to Step 3.19
|
V

3.16 ISOLATE the source of Condenser air inleakage.

3.17 DETERMINE if Condenser vacuum is returning to normal operating range.

3.18 This procedure has been completed. When conditions permit, return to normal operation IAW the appropriate procedure.

3.19 ESTABLISH plant conditions required, and isolate source of Condenser air inleakage.

3.20 This procedure has been completed. When conditions permit, return to normal operation IAW the appropriate procedure.

END OF PROCEDURE

ATTACHMENT 1
LOSS OF VACUUM LOCAL CHECKS

1. VERIFY proper operation of Condenser Vacuum Pumps:

   - Separating tank water level in normal range on local sight glass
   - Motor, pump, and seal tank operating at proper temperature
   - No abnormal noises indicating loss of seal water, overheating, or mechanical failure
   - Valve alignment correct IAW S1.OP-SO.AR.0001(Z), (III-8.3.1), Condenser Air Removal System Normal Operation

2. VERIFY proper operation of the Turbine Gland Sealing Steam System:

   - Gland Sealing Steam Supply Pressure between 18.7 and 24.7 psia, locally indicated at PL-187
   - Operating Gland Condenser Exhauster Inlet and Outlet Dampers properly positioned as indicated by Gland Exhaust Pressure between 14 and 19.5 in. H_2O, locally indicated at PL-823
   - Idle Gland Condenser Exhauster Inlet and Outlet Dampers fully shut
   - Turbine Auxiliary Cooling supplying the Gland Seal Condenser

3. Locally CHECK systems with Condenser penetrations to determine source of air inleakage:

   - Condenser Vacuum Breakers closed and not leaking
   - Proper level in Condensate Return Tank when in service to Unit 1
   - House Heating System return tank level and alignment
   - Feed Train High Level Divert valves closed or operating properly when required to be open
   - Condenser Penetrations and associated piping - no indications of air-inleakage

4. Locally CHECK Circulating Water System for proper operation.

   - Water Box differential pressure greater than zero but less than 10 psid

S1.OP-AB.COND-0001(Q)
LOSS OF CONDENSER VACUUM
TECHNICAL BASES DOCUMENT

1.0 **REFERENCES**

1.1 Technical Documents

A. Salem Generating Station Updated Final Safety Analysis Report:

1. Section 10.4.1.1, Main Condenser Design Basis

2. Section 10.4.1.2, Main Condenser System Description

3. Section 10.4.2, Main Condenser Evacuation System

4. Section 10.4.3, Turbine Gland Sealing System

B. Westinghouse Technical Manual I.L.1250-3959-A, Section II, Limits, Settings, and Precautions

C. DE-CB.CN-0015(Q), Configuration Baseline Documentation for Steam Generator Feedwater and Condensate System

1.2 Procedures

A. S1.OP-SO.GS-0001(Z), (III-4.3.1 Rev. 3), Turbine Gland Sealing System Normal Operation

B. S1.OP-SO.CW-0001(Z), (III-7.3.1 Rev. 9), Circulating Water System Normal Operation

C. S1.OP-SO.AR-0001(Z), (III-8.3.1 Rev. 7), Condenser Air Removal System Normal Operation

D. S1.OP-SO.CN-0002(Z), (III-9.3.2 Rev. 8), Feed Pump Operation

E. S1.OP-PT.CN-0001(Z), (PI/S-VALVE-1 Rev. 0), Potential Valve Leakage Test

F. SC.OP-DD.ZZ-0D30(Z), Operations Log 10 - 1 Hour Condenser D/T Readings

G. OD-35, Operations Log 15 - Circulating Water/ Service Water Daily Logs

H. ARP-OHA-G5, CNDSR VAC LO

I. ARP-1CC3, TURBINE TROUBLE

1.3 Drawings

A. 205202, No. 1 Unit Steam Generator Feed and Condensate P&ID, Rev. 41

B. 205208, No. 1 Unit Air Removal Condenser P&ID, Rev. 26

C. 205209, No. 1 Unit Circulating Water P&ID, Rev. 44

D. 205632, No. 1 Unit Condensate Polishing System P&ID, Rev. 17

E. 205207, No. 1 Unit Turbine Gland Sealing Steam System and Leakoff P&ID, Rev. 20

1.4 Conformance Documents - NONE

1.5 Industry Concerns

A. INPO O-MR 236, Loss Of Condenser Vacuum Due To Air Inleakage

B. NSO LER 89-003, Rx Trip-#23 S/G SF/FF Mismatch With Low S/G Level Due To Inadequate Procedures

C. NRC Inspection Nos. 50-272/90-80 and 50-311/90-80, concerns local actions versus Control Room actions

2.0 DISCUSSION

2.1 This procedure provides the direction necessary for plant operation with an unexplained decrease in Condenser vacuum. It is the intent of this discussion to provide the reasoning behind the logic and flowpath of the procedure. It is not intended to provide additional direction to the procedure.

2.2 Entry Conditions - Entry conditions are based on the Operator recognizing an unexplained decrease in Condenser Vacuum. The symptoms available to the Operator are as follows:

- Increase in Condenser pressure indication
- OHA-G5, CNDSR VAC LO
- OHA-G36, COND POL BYP ALERT
- 1CC3 Alarm, TURBINE TROUBLE

2.3 Immediate Actions - None

2.4 Subsequent Actions - The Operator is notified to reduce turbine load at less than or equal to 5%/min. until vacuum stabilizes. The intent of this action is to reduce the steam flow into the Condenser sections allowing the Circulating Water System to adequately remove the heat input. This is done immediately to prevent a turbine trip due to low vacuum, resulting in a much more severe transient when the unit is operating at power levels above the Turbine Trip - Reactor Trip setpoint of 49% (P-9). The rate of load reduction is suggested to prevent operation of the Steam Dump System which could worsen the low vacuum condition. The Rod Control System is designed to accommodate ramp load changes of 5%/min. or less. The Operator is cautioned that a Turbine Trip occurs between 18 and 22 in. hg vacuum if stabilizing actions are not taken promptly. Turbine backpressure limits are addressed and the requirements for Turbine load reduction are specified in a conditional statement. The values for Condenser pressure are based on Turbine backpressure limits for minimizing Turbine blade "flutter" as discussed in the Main Turbine Technical Manual. If the Operator cannot maintain the unit within these requirements, Reactor Power is reduced and the Turbine is removed from service.

Step 3.2 directs the Operator to the Circulating Water System Malfunction AOP if the cause of vacuum decrease is due to Circ Water problems.

Step 3.3 starts all available Condenser Vacuum Pumps in an attempt to stop the pressure increase in the condenser. Since air intrusion into a condenser is a very effective insulator on the relatively cold condenser tubes, any effort to remove even small amounts of air is beneficial to restoring vacuum.

Operators are then dispatched to check operation of systems having an effect on Condenser vacuum. Attachment 1, Loss of Vacuum Local Checks, provides guidelines for determining common causes of vacuum problems.

If the Operator is able to stabilize and maintain the unit at power, Condensate temperature is continuously monitored to insure that the Condensate Polishing resin is not damaged due to elevated temperatures or that steam flashing does not occur in the Condenser Hotwell or in the Condensate Pump suction piping. This is necessary to avoid more severe transients which could occur due to a loss of Steam Generator Feed Pumps, which has occurred in the past at Salem (ref. LER 89-003-00). Direction is provided to the Operator should flashing occur or if bypassing Condensate Polishing is required.

Once the cause is determined, the Operator is directed to the appropriate section of the procedure.

If it is determined that a malfunction of the Condenser Vacuum Pumps is the cause of the loss of vacuum, and the pump cannot be rapidly restored to normal operation, the faulty pump is removed from service and isolated from the condenser before plant conditions are reanalyzed. When a vacuum pump is removed from service, it is confirmed that the remaining vacuum pumps can maintain Condenser vacuum or the unit is placed in a condition allowing repair and restoration of the faulty pump.

If the fault is in the Turbine Gland Sealing Steam System, the Operator is directed to the normal operating procedure which provides direction for valve and damper position, Gland Condenser Exhauster operation, Turbine Auxiliary Cooling requirements, and the various system configurations available to the Operator to provide proper gland sealing.

If the loss of vacuum is due to air inleakage, isolation requirements for the source of inleakage are determined. If possible, the source is isolated, restoration of vacuum is confirmed, and the procedure is exited. If the unit configuration will not allow isolation of the source of inleakage, the unit must be placed in a condition allowing repairs of the fault and the procedure is exited.

The limit on Condensate Pump suction temperature (130°F) is below that temperature which is known to cause resin damage or Chemistry transients due to the resin releasing previously captured impurities. This limit also minimizes the possibility of flashing occurring in the low pressure regions of the Condensate System.

END OF DOCUMENT

NUCLEAR LICENSING WORK STANDARD

NRC INSPECTION MANAGEMENT

ATTACHMENT 1

QUESTION AND ANSWER TRACKING FORM

ITEM NUMBER: AIT-CW-037

SOURCE: NRC/PSE&G (SELECT ONE)

DATE: 4/12

NRC CONTACT: Warren Lyon

NRC QUESTION:

~~Please see back~~ provide C.W. time line and S.W. SCREEN STARTS/STOPS FOR EVENT PERIOD

RBS per W. Lyon 4/12/94

PSE&G CONTACT:

Smith; Morrison / Johnson

LICENSING CONTACT:

McTIGUE x 2991

PSE&G RESPONSE:

See attached 4pgs

RBS

DATE: 4/13/94

NLR REVIEW: YES / NO (SELECT ONE)

RESPONSE ACCEPTED BY NRC: YES / NO (SELECT ONE)

INSPECTOR'S NAME:

DATE:

4/18

Would you provide readily available data for circ water and SW pertaining to equipment failures and difficulties during "grass attacks" for the time spanned by the event and for any time SW has been affected? Data of interest include:

- level difference across screens
- level difference (or applicable info.) across trash racks
- system pressure downstream of strainers
- flow rate downstream of strainers
- loss/restoration of pumps
- loss/restoration of screens (shear pin failures, other)
- screen wash failures/inadequacies
- use of fire hoses
- other?
  Strainer Backwash problems

The purpose is to quantitatively establish a correlation (or lack of) between circ water and SW. The secondary purpose is a record of equipment behavior/impacts during the event.

SAME TIME - S.W. SCREEN START/STOP.

SEQUENCE OF EVENTS - CW

RESPONSE TO NRC QUESTION AIT-CW-037

ATTACHED ARE 2 PAGES FROM SERT REPORT 93-07 INVESTIGATION THE JUNE 1993 EVENT INITIATING AT CIRC WATER. THAT REPORT EXAMINED THE EFFECTS AT SERVICE WATER AT THE SAME TIME OF THE EVENT AT CIRC WATER ADN CONCLUDED THAT SERVICE WATER WAS NOT AFFECTED.

ALSO ATTACHED IS A TIME LINE OF CIRC WATER PUMPS IN SERVICE/OUT OF SERVICE DURING THE 04/07/94 EVENT. INCLUDED IN THIS RESPONSE IS A LISTING OF SERVICE WATER OHA WINDOW B21 AND B22 ACTIVATIONS DURING THE TIME PERIOD FROM 0000 HOURS TO 1200 HOURS. EACH WINDOW IS ACTIVATED BY A DIFFERENTIAL OF 4" WATER ACROSS ANY OR ALL OF 3 TRAVELLING SERVICE WATER SCREENS. SCREENS, WHEN STARTED, RUN FOR APPROXIMATELY 22 MINUTES. FURTHER IDENTIFICATION OF INDIVIDUAL SCREEN STARTS IS NOT AVAILABLE.

AITCW37.DOC

CIRCULATING WATER SYSTEM TIME LINE-PUMP OPERATION
04/07/94

TIME	PUMPS I/S	PUMPS O/S
1014	11A, 11B, 12B 13A, 13B	12A
1016	11A/B, 12B, 13A	13B, 12A
10??	11A/B, 12A/B, 13A	13B
1027	11A/B, 12A/B,	13A/B
1034	11A/B, 12B	12A, 13A/B
1038	11A/B, 12B, 13A	12A, 13B
1039	12B, 13A	11A/B, 12A, 13B
1040	12B, 13A/B	11A/B, 12A
1044	12B, 13B	11A/B, 12A, 13A
1046	12B	11A/B, 12A, 13A/B
1047	11A, 12B	11B, 12A, 13A/B

10:47:44 UNIT TRIP

SW SCREENS	PUMP I/S	TIME IN	TIME OUT
14-16	11&14*	0014	0014
14-16	"	0106	0106
11-13	"	0128	0131
14-16 (3 TIMES)	"	0137	0137
14-16 (2 TIMES)	"	0712	0712
14-16 (2 TIMES)	"	0754	0754
14-16 (2 TIMES)	"	1058	1058
14-16	"	1146	1146
24-26	21&24#	0117	0118
24-26		0212	0212
24-26		0333	0333
24-26		0428	0428

NO FURTHER SCREEN ACTIVATIONS UNIT 2 THROUGH 1200
*-11 AND 14 PUMPS MAIN PUMPS, 13, 15, AND 16 RAN FOR SHORT PERIODS DURING THE DAY.
#-21 AND 24 MAIN PUMPS, 26 RAN FOR 4 HOURS.
ESTIMATED HIGH GRASS TIMES AT CIRC WATER INTAKE STRUCTURE
04/07/94 0400-0500 AND 1000-1100

the ice barriers in the spring (approximately April) to aid flow of water to the condensers and to reinstall them in the fall when river temperatures start cooling and flow is not a major issue. Since the ice barriers were being removed later than normal, the timing of the removal/installation cycle should be evaluated.

b. Circulating Water Structure Gratings

Large sections of metal grating are in place near the circulators to provide access to the pump bays for inspections and repairs. Occasionally, when an emergency trip of a circulator occurs, the force of the backflow is sufficient to dislodge these sections, which can fall into the pump bays. When this occurs, large holes are open creating a significant fall and drowning hazard. During this event, one piece of grating for 12A circulator fell into the bay. Actions should be taken to prevent accidental dislodging of the gratings while still allowing easy removal for bay work.

B. REACTOR/TURBINE CONTROLS

The event of circulator loss caused turbine backpressure to increase. Backpressure increased (vacuum decreased) until the turbine protective devices tripped the turbine (as designed) at approximately 20 inches Hg vacuum. Since the reactor was above 49% power (P-9 interlock) an automatic reactor trip occurred as designed. All automatic functions occurred as designed and expected, except for an approximate 30 second delay between a turbine vacuum trip relay actuation and reactor trip. This delay was investigated by Salem Maintenance and Operations and determined to be an alarm relay which actuates at 23 inches vacuum and is independent from the trip feature.

C. CONTROL ROOM INSTRUMENTATION

During the investigation, it was observed that one channel of backpressure PA 5224 has been inoperable for approximately 4 months (on hold, obsolete parts, 4/26/93). Based on all operators recollection, the other channel (PA 5225) never read more than 3.8 inches Hg backpressure versus the approximately 9 inches Hg which would have resulted from a 20 inches Hg vacuum readings on the stripcharts. Operators rely on the backpressure readings to control turbine runback response, in accordance with Abnormal Operating Procedures. Although there is no evidence which indicates that this instrumentation caused improper action during this event, artificially low readings might cause operators to initiate slower power reductions than required. In a slower developing event, quicker response might allow reactor runback to occur faster to get below the P-9 permissive and prevent a reactor trip.

A redundant indicator, the condenser vacuum recorder, appears to have operated correctly.

D. SERVICE WATER SYSTEM

The trash racks, rake, and travelling screens for service water are similar to, but much smaller than those for circulating water. They are classified as non-safety related. Due to the conditions described below, the service water rake and screens are not challenged by debris as are the circulating water systems. As a result, service water screens operates periodically as compared with constantly for circulating water. The service water trash rake is used infrequently while the circulating water trash rack must be cleaned at least daily during heavy grassing periods.

Review of operators' statements and logs, AD-16 report and alarm printouts uncovered no indication that the Service Water System was affected during this event. Even so, the service water trash rake was examined for similarities with circulating water which could cause failure of the system, i.e., improper modification and operation of the trash rake causing accumulation of trash and blockage of the intake. From observation of the hoist cable, it was obvious that the rake had not been run for a period of time. The only observable defect was that one of the rake sled wheels had been removed, by reports, to repair the Circulating Water Rake. No workorder was found to replace this wheel. Two other minor design problems were noted but were deemed not to affect the ability of the rake to operate properly. There was no visible differential across the trash rack.

The Service Water intake has not been subject to the same accumulation of trash and silt as the circulating water intake. For example, while the Corps of Engineers was dredging upriver in 1983, silting caused the shutdown of all circulating water pumps, but the service water intake was not affected. This difference in susceptibility to trash and silting is attributed to the location of the service water intake directly on the river front. The circulating water intake is in a diverging section of the river and the resulting drop in velocity and eddy formation is more conducive to trash and silt accumulation. Nevertheless, the service water intake is scanned for silt accumulation at six-month intervals and cleared when necessary.

4. **PERSONNEL PERFORMANCE**

The event developed so quickly that no actions by control room operators or circulating water operator could have been expected to prevent loss of circulators and the Unit trip. Operator reaction appears to have been prompt and proper throughout the incident. The circulating water operator was in the Unit 2 end of the circulating water structure when 13A and 12A circulators tripped. By the time he got to the Unit 1 end of the structure and assessed the situation, 11A and 11B circulators had already tripped.

Expected operator response would be to place screen controls in manual at high speed. There was inadequate time during this event for him to do so.

5. **PROCEDURES**

No specific procedure or written instructions exist for operation of the trash rake. No operator guidance exists as to what performance criteria is expected during rack cleanings. Written instructions for the divers were limited to the work order description "perform underwater inspection of Unit #2 trash racks 2SCE10, 2SCE11, 2SCE12, 2SCE13, 2SCE14 and 2SCE15".

6. **EVENT CAUSAL FACTOR ANALYSIS AND RESULTS**

A. **The cause of the trip was the inability of the circulating screens to remove excessive amount of debris from the river water prior to loss of the circulators.** The most likely source was the sudden release of debris from the trash rack and/or river bottom caused by the diver cleaning 12B circulator trash rack. Though there is no proof that the cause was not a sudden influx of debris from main river flow, SERT believes the event was diver initiated because of the following:

- o The sequence of circulators trips (see Attachment C) was 13A and 12A (on either side of diver activities) nearly simultaneously followed by sequential tripping of circulators in the direction of tidal flow. 13B circulator, the first circulator which would be affected by intrusion from the river body, did not trip until 12 minutes after 13A.

4/4

RESPONSE TO AIT-CW-051

Date:

4/13/94

NRC Contact:

Steve Barr

NRC Question:

"Prior to the reactor trip, what was the reactivity addition as a result of the decrease in T_{avg} and rod motion in $\Delta k/k$ and pcm."

Upon further discussion with Steve Barr, the NRC is looking for assurance that the local power peaking during the transient was acceptable and, ultimately, that the fuel integrity remained intact.

PSE&G Response:

The PSE&G Nuclear Fuel Section, in conjunction with Westinghouse, has evaluated the effects of this transient on the fuel. Results of this evaluation will be available on 4/15/94 and will be presented by Dave Rothrock (PSE&G Nuclear Fuel) to Warren Lyon (NRC) during the meeting scheduled for 4/15/94 @ 1300.

Prepared By: Lisa Ford - Salem Reactor Engineering Date: 4/14/94

x119

FOR INFO ONLY

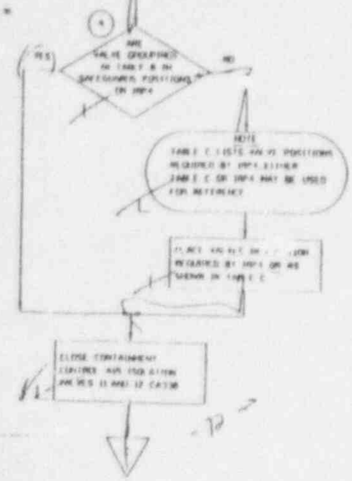


TABLE B

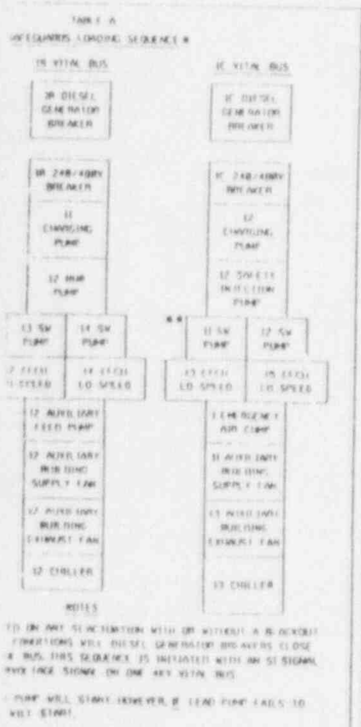
SAFEGUARDS VALVE GROUPING

- SAFETY INJECTION
- FEEDWATER ISOLATION
- PHASE A ISOLATION
- CONTAINMENT VENT ISOLATION

TABLE C

SAFEGUARDS VALVE ALIGNMENT

VALVE	STATUS	VALVE NAME	NOTES
1SJ4	OPEN	BIT INLET	SAFETY INJECTION
1SJ5	OPEN	BIT INLET	
1SJ12 — 0 1057	OPEN	BIT OUTLET	
1SJ13	OPEN	BIT OUTLET	
1CV68 — 1057	CLOSED	CHARGING DISCHARGE	
1CV69	CLOSED	CHARGING DISCHARGE	
11 THRU 14 SJ54	OPEN	ACCUMULATOR OUTLET	
1CV40	CLOSED	DISCHARGE STOP	CV40 AND CV41 WILL NOT
1CV41 — 1057	CLOSED	DISCHARGE STOP	CLOSE UNLESS SJ1 OR SJ2
1SJ1	OPEN	RWST TO CHARGING	FULL OPEN.
1SJ2 — 0 1057	OPEN	RWST TO CHARGING	
11SW20	CLOSED	TURBINE AREA	
12SW20	CLOSED	TURBINE AREA	
1SW26	CLOSED	TURBINE AREA	
11SW127	CLOSED	SW TO 11 CC HX	SW VALVES TO CC CLOSE
12SW376	CLOSED	SW TO 12B CC HX	ONLY ON NEED 3 SEC
12SW368	CLOSED	SW TO 12A CC HX	
11 THRU 14 BF13 (1053)	CLOSED	FW INLET STOP	FEEDWATER ISOLATION
11 THRU 14 BF19	CLOSED	FW CONTROL	
11 THRU 14 BF40	CLOSED	BYPASS	
1WL12	CLOSED	RCDT DISCHARGE	PHASE A ISOLATION
1WL13	CLOSED	RCDT DISCHARGE	
1WL16	CLOSED	CONT SUMP DISCH TO WHUT	
1WL17	CLOSED	CONT SUMP DISCH TO WHUT	
1WL96	CLOSED	RCDT TO GAS ANALYZER	
1WL97	CLOSED	RCDT TO GAS ANALYZER	
1WL98	CLOSED	RCDT PRT TO GAS COMPR	
1WL99	CLOSED	RCDT PRT TO GAS COMPR	
1WL108	CLOSED	NITROGEN TO RCDT	
1SS27	CLOSED	ACCUMULATOR SAMPLING	
1SS33	CLOSED	11 AND 13 HOT LEG SAMPLE	
1SS49	CLOSED	PZR LIQUID SAMPLING	
1SS64	CLOSED	PZR STEAM SAMPLING	
1SS103	CLOSED	ACCUMULATOR SAMPLING	
1SS104	CLOSED	11 AND 13 HOT LEG SAMPLE	
1SS107	CLOSED	PZR LIQUID SAMPLING	
1SS108	CLOSED	PZR STEAM SAMPLING	
11 THRU 14 SS94	CLOSED	SG B/D SAMPLING	
1DR29	CLOSED	CNTMT INLET MAKEUP	
1FP147	CLOSED	CONTAINMENT ISOL	
1CV3	CLOSED	45 GPM ORIFICE	
1CV4	CLOSED	75 GPM ORIFICE	
1CV5	CLOSED	75 GPM ORIFICE	
1CV7	CLOSED	LETDOWN CONTROL	
1CV116	CLOSED	SEAL WATER TO VCT	
1CV284	CLOSED	SEAL WATER TO VCT	
1SJ60	CLOSED	TEST LINE TO CVCS HUT	
1SJ53	CLOSED	11 SI PUMP	
1SJ123	CLOSED	TEST LINE TO CVCS HUT	
1CC113	CLOSED	EXC LINE OUTLET	
1CC215	CLOSED	EXC LINE INLET	
11 THRU 14 GB4	CLOSED	SG OUTLET	
1VC7	CLOSED	CONT RAD MEG ISOL	
1VC8	CLOSED	CONT RAD MEG ISOL	
1VC11	CLOSED	CONT RAD MEG ISOL	
1VC12	CLOSED	CONT RAD MEG ISOL	
1WR80	CLOSED	CONT PRI WATER STOP	
1PR17	CLOSED	GAS ANALYZER	
1PR18	CLOSED	GAS ANALYZER	
1NT25	CLOSED	N2 SUPPLY	
1NT32	CLOSED	N2 SUPPLY	
1VC1	CLOSED	SUPPLY	CONTAINMENT VENT
1VC2	CLOSED	SUPPLY	ISOLATION
1VC3	CLOSED	EXHAUST	
1VC4	CLOSED	EXHAUST	
1VC5	CLOSED	ISOLATION	
1VC6	CLOSED	ISOLATION	



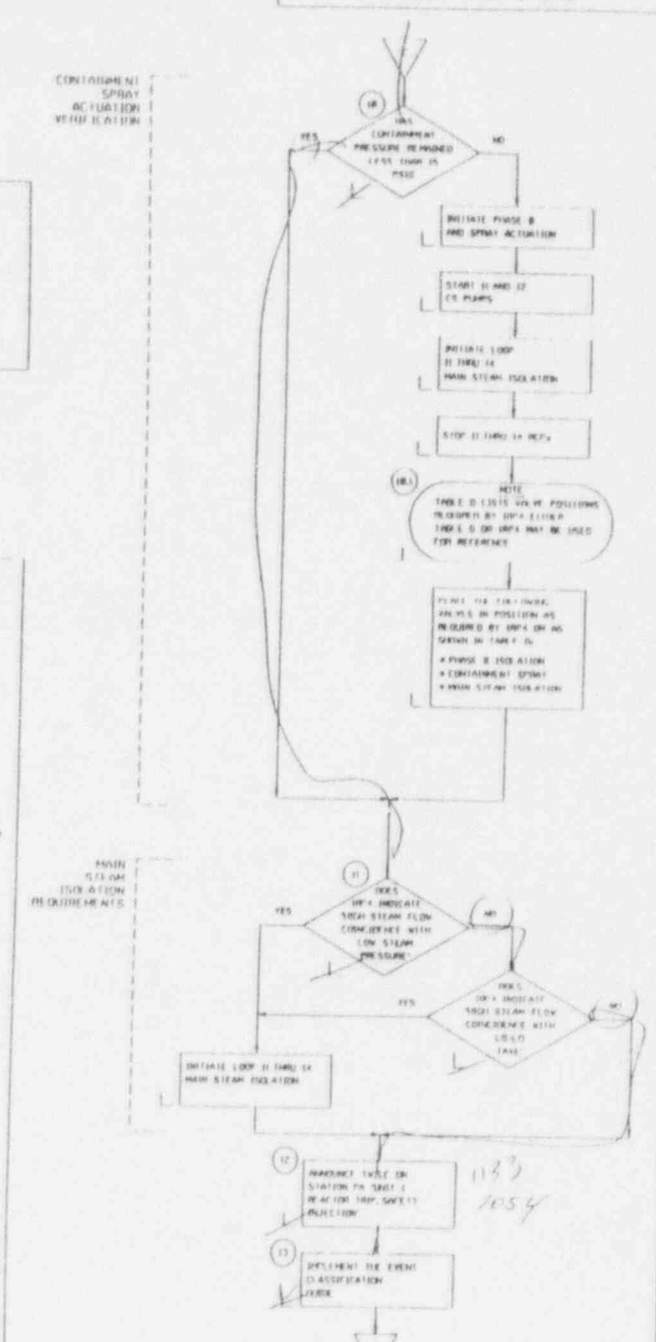


TABLE D

PHASE B ISOLATION ALIGNMENT

VALVE	STATUS	VALVE NAME	NOTES
1CC117	CLOSED	RCP COOLING INLET	PHASE B
1CC118	CLOSED	RCP COOLING INLET	ISOLATION
1CC136	CLOSED	RCP THERMAL BARRIER	
1CC190	CLOSED	RCP THERMAL BARRIER	
1CC136	CLOSED	RCP BEARING OUTLET	
1CC187	CLOSED	RCP BEARING OUTLET	
11CS2	OPEN	CS PUMP DISCH	CONTAINMENT
12CS2	OPEN	CS PUMP DISCH	SPRAY
1CS14	OPEN	TANK DISCH	
1CS16	OPEN	TANK DISCH	
1CS17	OPEN	TANK DISCH	
11 THRU 14 MS167	CLOSED	STOP	MAIN STEAM
11 THRU 14 MS18	CLOSED	WARMUP	ISOLATION
11 THRU 14 MS7	CLOSED	DRAIN	

1-EOP-TRIP-1

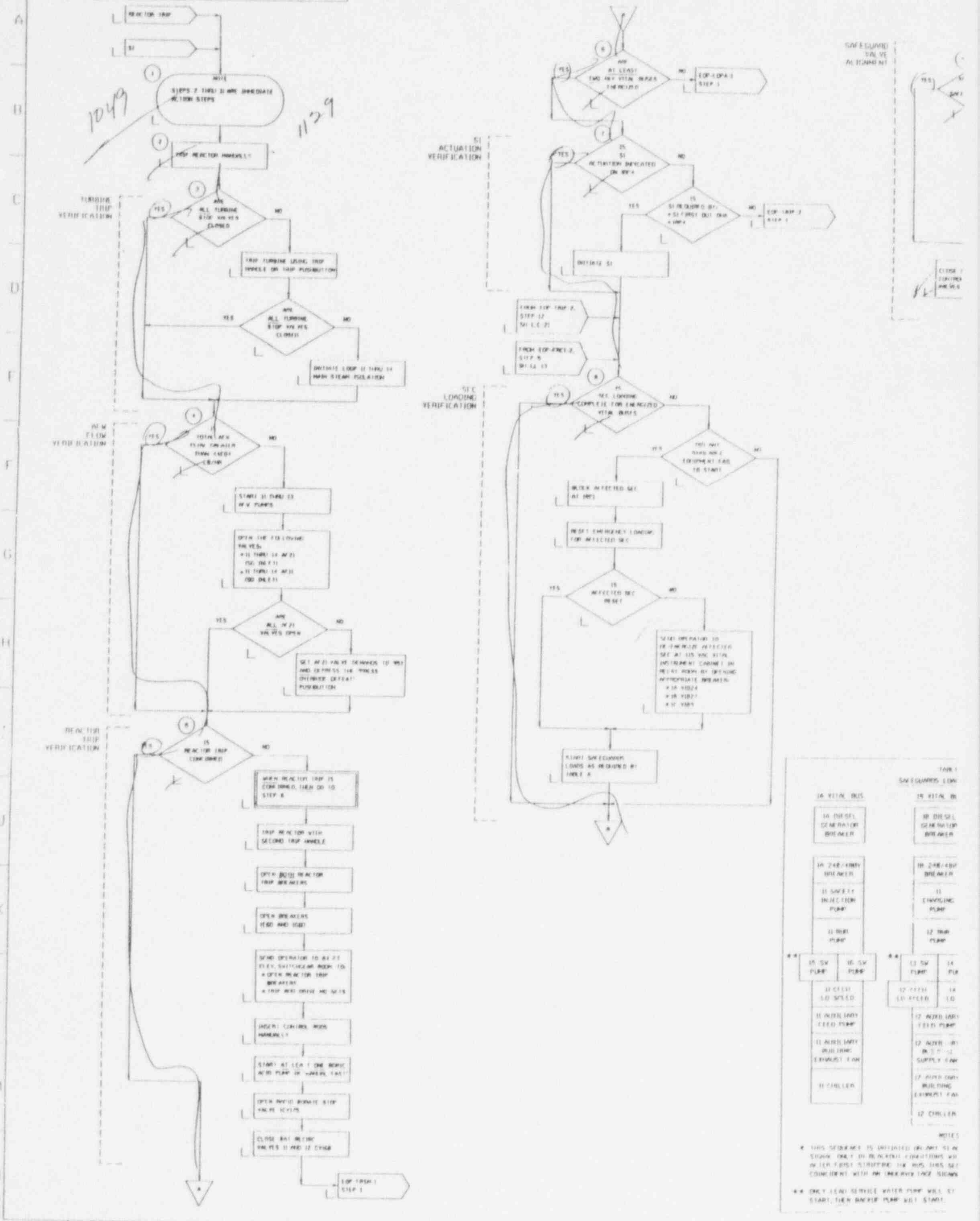
REACTOR TRIP OR SAFETY INJECTION

SHEET 1 OF 4

REV. 4 REV DATE 6/19/92

SALEM GENERATING STATION UNIT 1

1-EOP-TRIP-1 | REACTOR TRIP OR SAFETY INJECTION



1-EOP-TRIP-1	REACTOR TRIP OR SAFETY INJECTION

CONTINUOUS ACTION SUMMARY

CONDITION	ACTION
RCS PRESSURE LESS THAN 1300 PSIG AND SI FLOW ESTABLISHED	STOP RCPs
SINGLE SG FAULTED OR RUPTURED	CLOSE AF11 AND AF21 FOR AFFECTED SG
RCS PRESSURE LESS THAN 1500 PSIG AND BIT FLOW ESTABLISHED	CLOSE CHG PUMP MINIFLOW
RCS PRESSURE GREATER THAN 2000 PSIG	OPEN CHG PUMP MINIFLOW
LESS THAN TWO VITAL BUSES ENERGIZED	GO TO EOP-LOPA-1
RCPs WITHOUT CCW	STOP RCPs
AFST LEVEL LESS THAN 11%	SHIFT AFW PUMP SUCTION
TWO OR MORE POWER RANGES GREATER THAN 5%	GO TO EOP-FRSM-1
5 OR MORE CORE EXIT TCs GREATER THAN 1200°F	GO TO EOP-FRCC-1
5 OR MORE CORE EXIT TCs GREATER THAN 700°F AND RVLIS FULL RANGE LESS THAN 58%	GO TO EOP-FRCC-1
ALL SG NR LEVELS LESS THAN 9% (15% ADVERSE) AND TOTAL FEED FLOW CAPABILITY TO SGs LESS THAN 22E04 LB/HR	GO TO EOP-FRHS-1
RCS COOLDOWN GREATER THAN 100°F IN LAST 60 MIN AND RCS COLD LEG TEMPERATURE LESS THAN 280°F	GO TO EOP-FRTS-1
CONTAINMENT PRESSURE GREATER THAN 47 PSIG	GO TO EOP-FRCE-1

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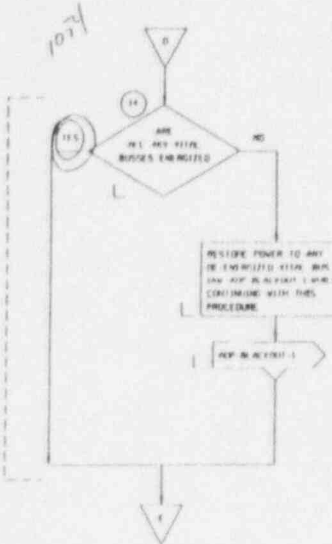
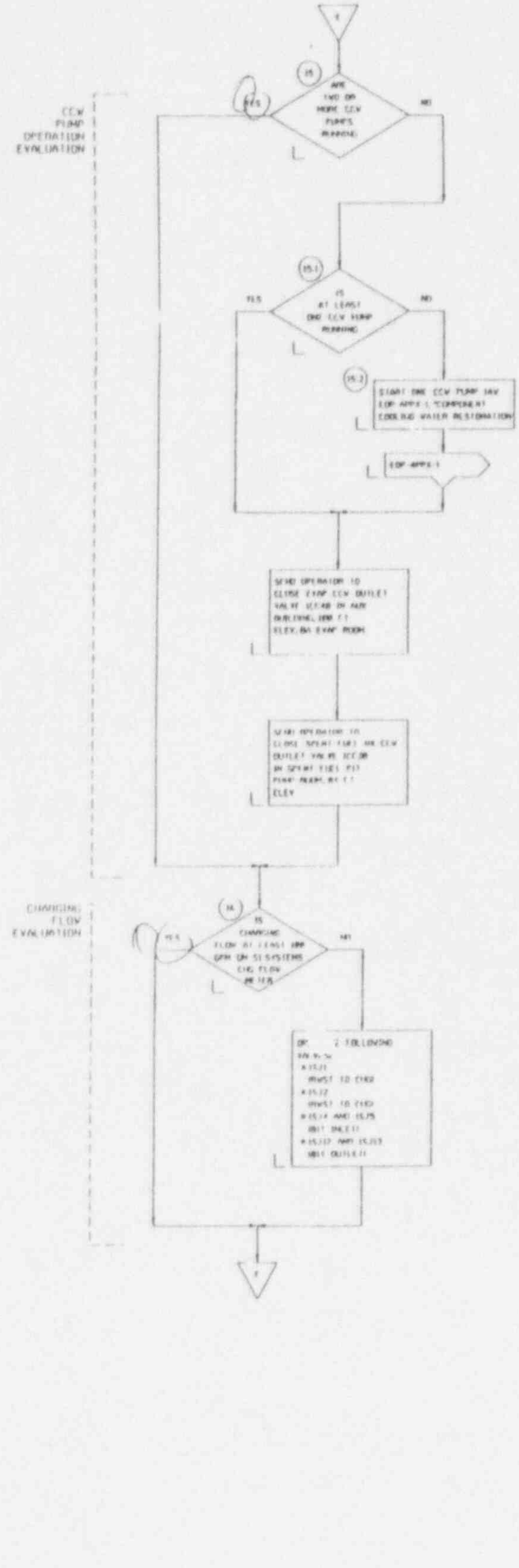
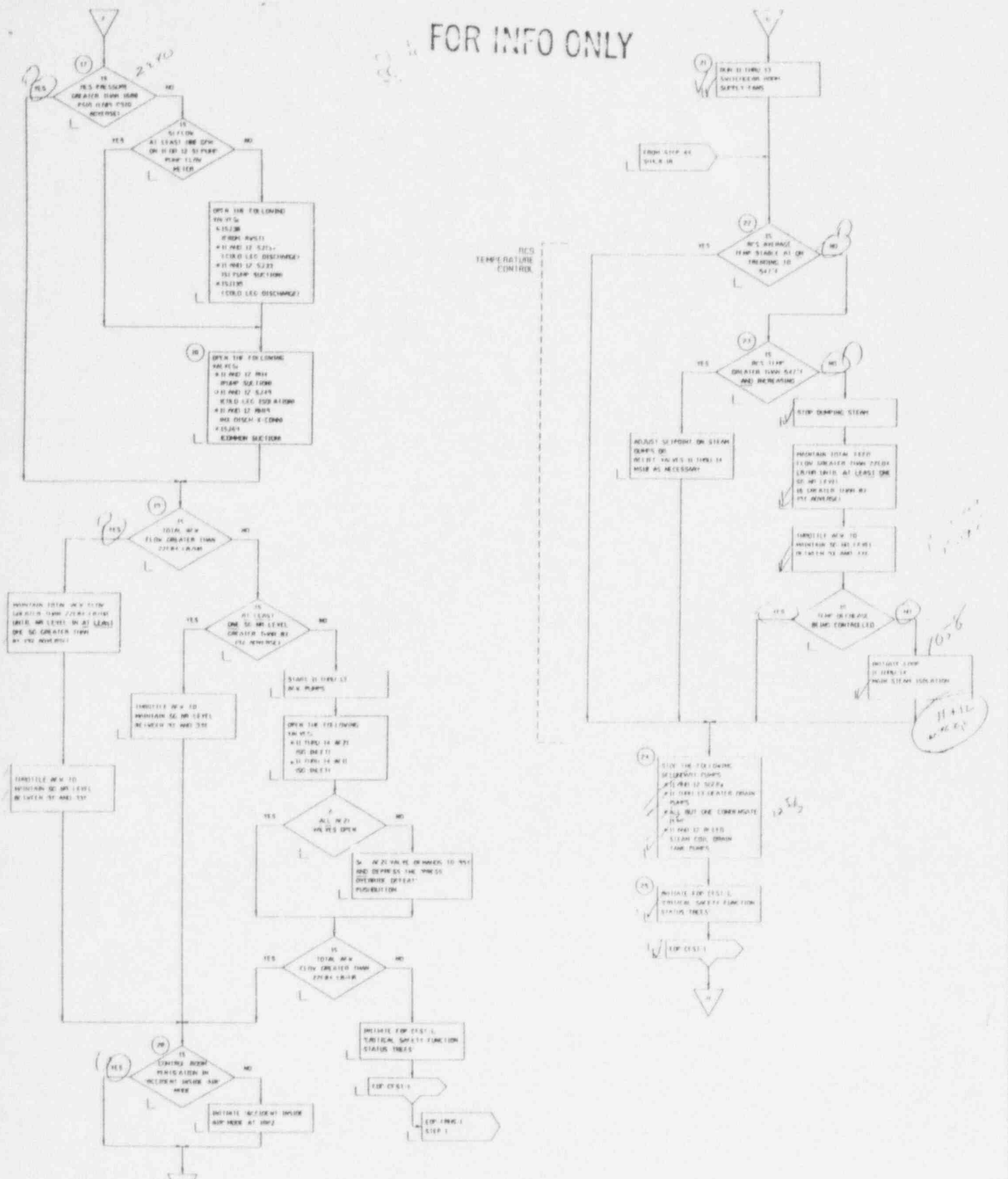




FOR INFO ONLY



1-EOP-TRIP-1

REACTOR TRIP OR
SAFETY INJECTION

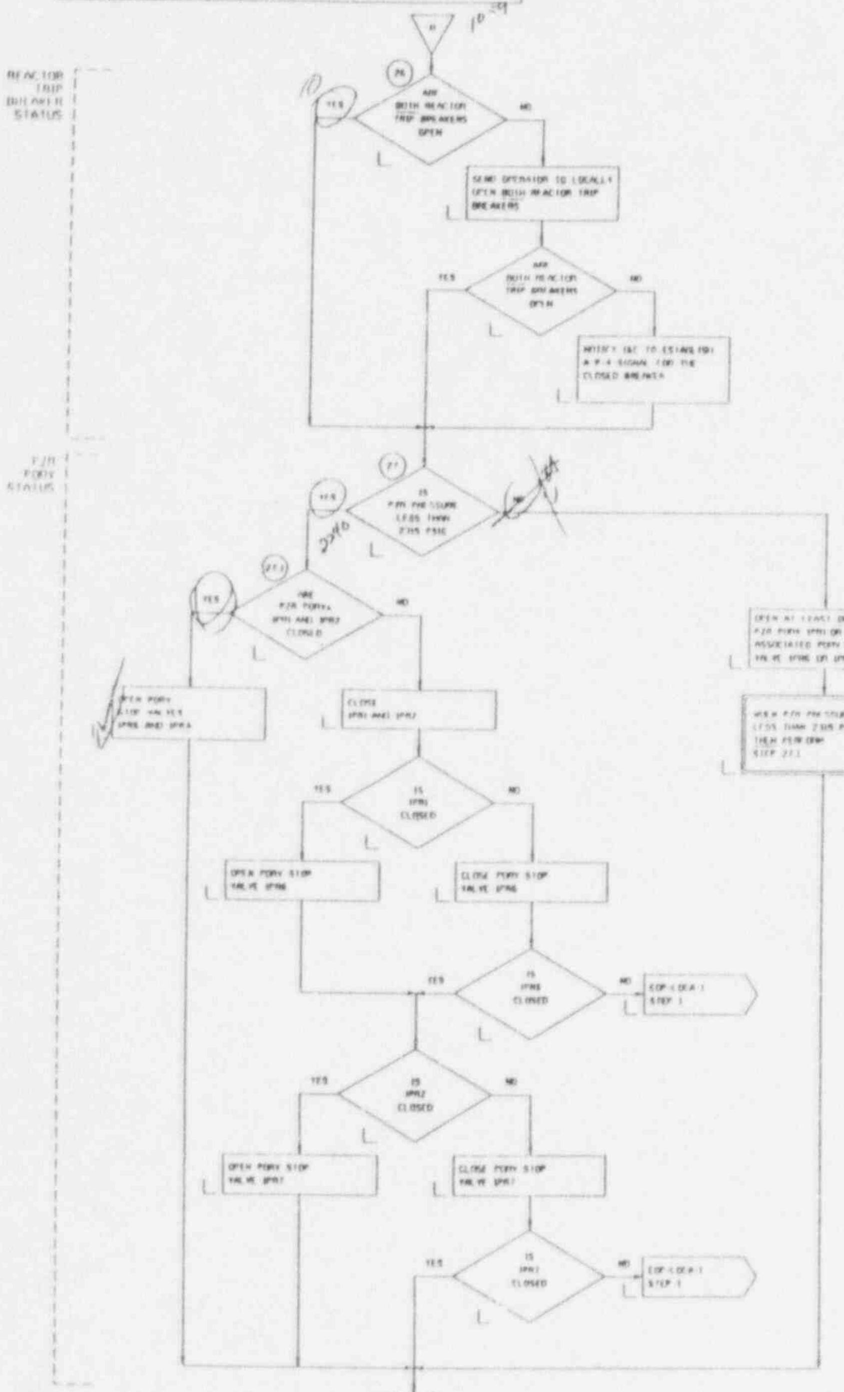
SHEET 2 OF 4

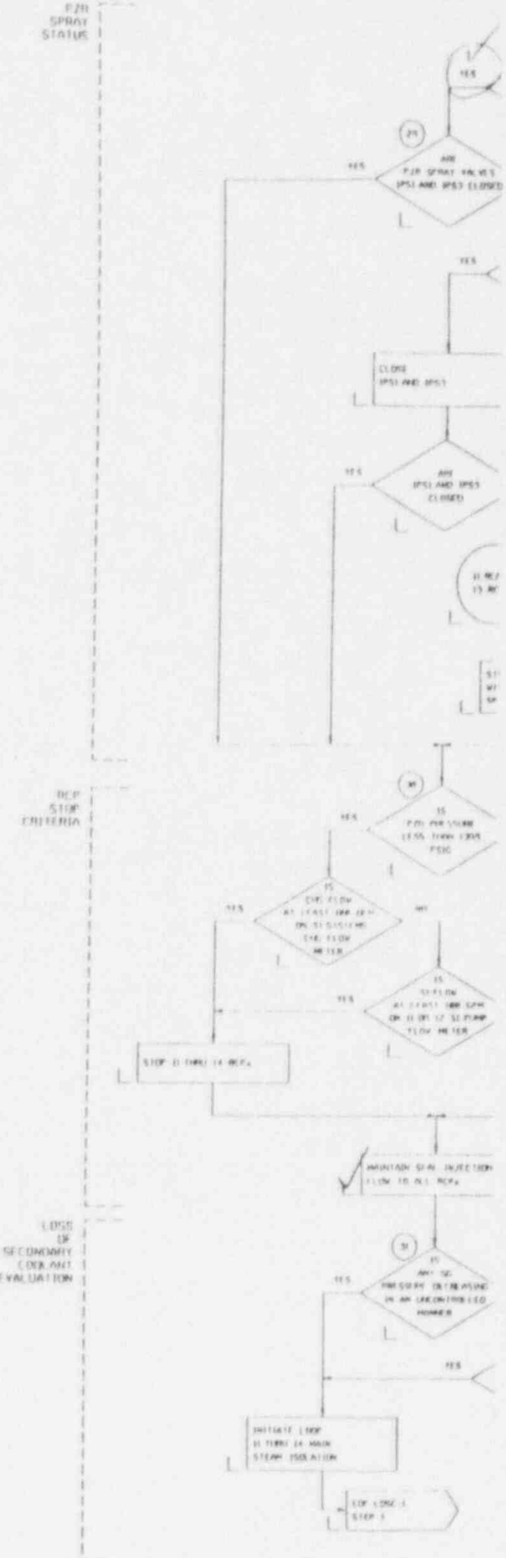
REV 3 REV DATE 5/15/92

SALEM GENERATING STATION | UNIT 1

CONTINUOUS ACTION SUMMARY

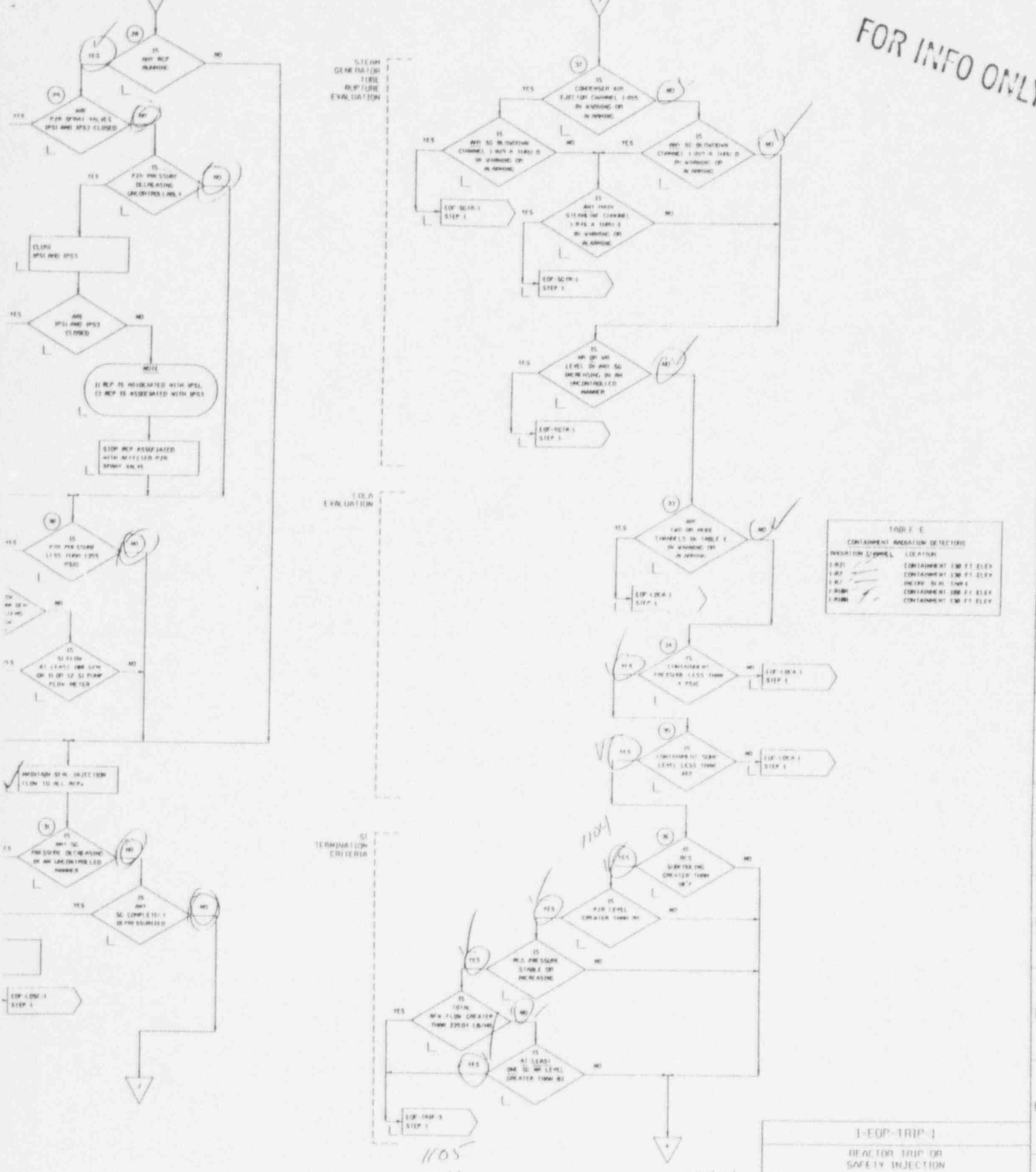
CONDITION	ACTION
RCS PRESSURE LESS THAN 1355 PSIG AND SI FLOW ESTABLISHED	STOP RCPs
SINGLE SG FAULTED OR RUPTURED	CLOSE AF11 AND AF21 FOR AFFECTED SG
RCS PRESSURE LESS THAN 1500 PSIG AND BIT FLOW ESTABLISHED	CLOSE CHG PUMP HDRFLOW
RCS PRESSURE GREATER THAN 2000 PSIG	OPEN CHG PUMP HDRFLOW
LESS THAN TWO VITAL BUSES ENERGIZED	GO TO EOP-LOPA-1
RCPs WITHOUT CCW	STOP RCPs
AFST LEVEL LESS THAN 11%	SHIFT AFW PUMP SUCTION
TWO OR MORE POWER RANGES GREATER THAN 5%	GO TO EOP-FRSM-1
5 OR MORE CORE EXIT TCs GREATER THAN 1200°F	GO TO EOP-FRCC-1
5 OR MORE CORE EXIT TCs GREATER THAN 700°F AND RVLIS FULL RANGE LESS THAN 50%	GO TO EOP-FRCC-1
ALL SG NR LEVELS LESS THAN 8% (15% ADVERSE) AND TOTAL FEED FLOW CAPABILITY TO SGs LESS THAN 22E04 LB/HR	GO TO EOP-FRHS-1
RCS COOLDOWN GREATER THAN 100°F IN LAST 60 MIN AND RCS COLD LEG TEMPERATURE LESS THAN 280°F	GO TO EOP-FRTS-1
CONTAINMENT PRESSURE GREATER THAN 47 PSIG	GO TO EOP-FRCE-1





1-EOP-TRIP-1/SH3

FOR INFO ONLY



1-EOP-TRIP-1

REACTOR TRIP OR SAFETY INJECTION

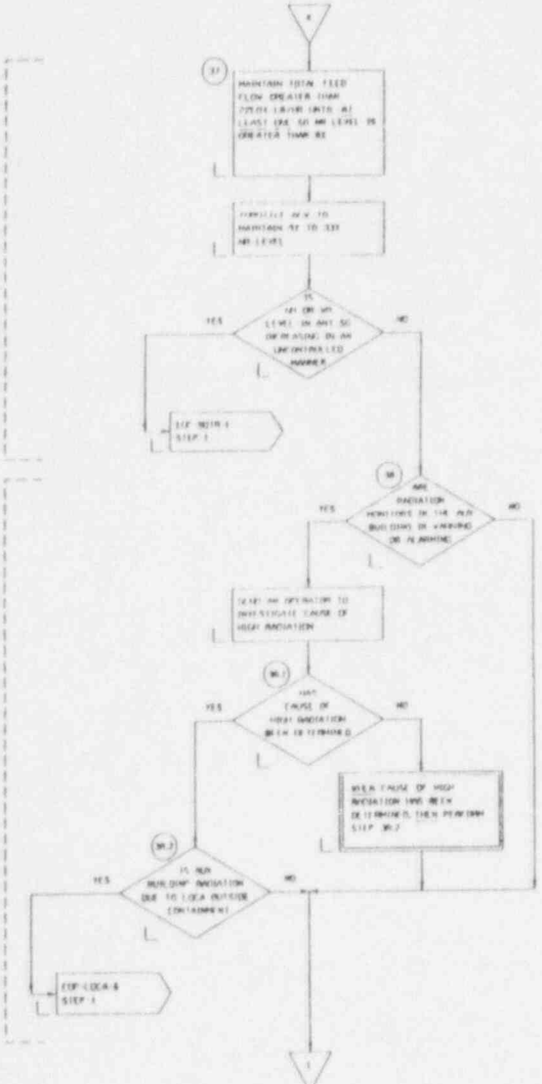
SHEET 3 OF 4

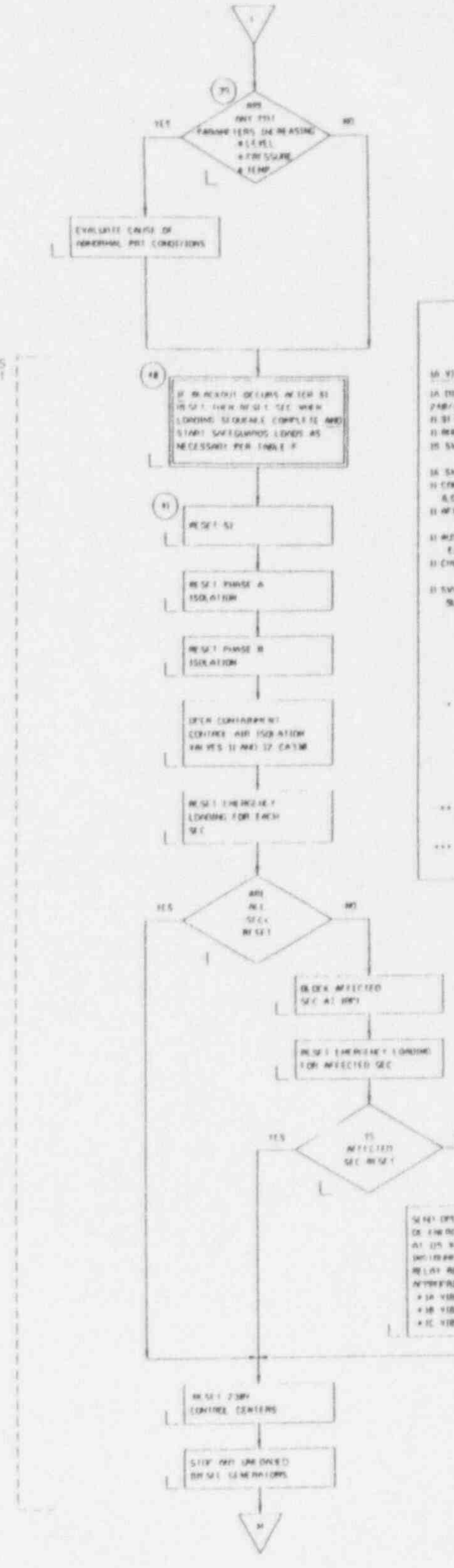
REV 3 REV DATE 5/15/92

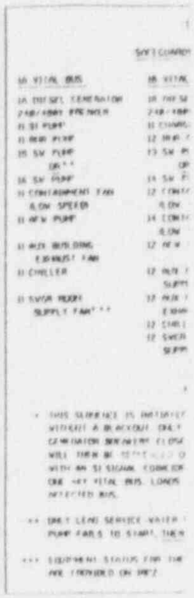
SALEM GENERATING STATION UNIT 1

CONTINUOUS ACTION SUMMARY

CONDITION	ACTION
RCS PRESSURE LESS THAN 1395 PSIG AND SI FLOW ESTABLISHED	STOP RCPs
SINGLE SG FAULTED OR RUPTURED	CLOSE AF11 AND AF21 FOR AFFECTED SG
RCS PRESSURE LESS THAN 1500 PSIG AND BIT FLOW ESTABLISHED	CLOSE CHG PUMP MINIFLOW
RCS PRESSURE GREATER THAN 2000 PSIG	OPEN CHG PUMP MINIFLOW
LESS THAN TWO VITAL BUSES ENERGIZED	GO TO EOP-LOPA-1
RCPs WITHOUT CCW	STOP RCPs
AFST LEVEL LESS THAN [illegible]	SHIFT AFW PUMP SUCTION
TWO OR MORE POWER RANGES GREATER THAN 5%	GO TO EOP-FRSM-1
5 OR MORE CORE EXIT TCs GREATER THAN 1200°F	GO TO EOP-FRCC-1
5 OR MORE CORE EXIT TCs GREATER THAN 700°F AND RVLIS FULL RANGE LESS THAN 50%	GO TO EOP-FRCC-1
ALL SG NR LEVELS LESS THAN 8% (9% ADVERSE) AND TOTAL FEED FLOW CAPABILITY TO SGs LESS THAN 22E04 LB/HR	GO TO EOP-FRHS-1
RCS COOLDOWN GREATER THAN 100°F IN LAST 60 MIN AND RCS COLD LEG TEMPERATURE LESS THAN 280°F	GO TO EOP-FRTS-1
CONTAINMENT PRESSURE GREATER THAN 47 PSIG	GO TO EOP-FRCE-1







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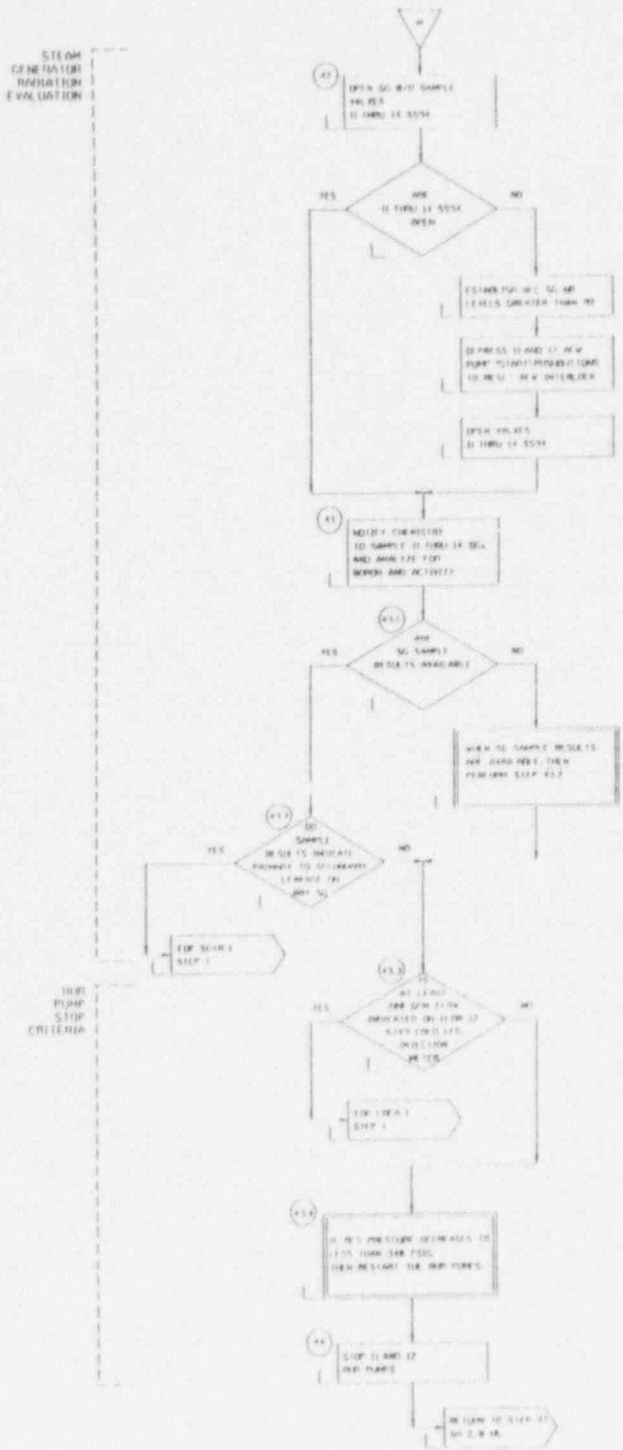


TABLE 7

SAFEGUARDS LOADING SEQUENCE*

1A VITAL BUS	1B VITAL BUS	1C VITAL BUS
1A DIESEL GENERATOR 2A0/1A0 BREAKER	1B DIESEL GENERATOR 2B0/1B0 BREAKER	1C DIESEL GENERATOR 2C0/1C0 BREAKER
11 SI PUMP	11 CHARGING PUMP	12 CHARGING PUMP
11 RHR PUMP	12 RHR PUMP	12 SI PUMP
15 SW PUMP OR** 16 SW PUMP	13 SW PUMP OR** 14 SW PUMP	11 SW PUMP OR** 12 SW PUMP
11 CONTAINMENT FAN (LOW SPEED)	12 CONTAINMENT FAN (LOW SPEED)	13 CONTAINMENT FAN (LOW SPEED)
11 AFW PUMP	14 CONTAINMENT FAN (LOW SPEED)	15 CONTAINMENT FAN (LOW SPEED)
11 AUX BUILDING EXHAUST FAN	12 AFW PUMP	EMERGENCY AIR COMPRESSOR
11 CHILLER	12 AUX BUILDING SUPPLY FAN	12 AUX BUILDING SUPPLY FAN
11 SWGR ROOM SUPPLY FAN***	12 AUX BUILDING EXHAUST FAN	13 AUX BUILDING EXHAUST FAN
	12 CHILLER	13 CHILLER
	12 SWGR ROOM SUPPLY FAN***	13 SWGR ROOM SUPPLY FAN***

NOTES

* THIS SEQUENCE IS INITIATED ON ANY SI ACTUATION WITH OR WITHOUT A BLACKOUT. ONLY IN BLACKOUT CONDITION WILL DIESEL GENERATOR BREAKERS CLOSE AFTER FIRST STRIPPING BUS LOADS. WILL THEN BE SEQUENCED ONTO BUS. THIS SEQUENCE IS INITIATED WITH AN SI SIGNAL COINCIDENT WITH AN UNDERVOLTAGE SIGNAL ON ONE KEY VITAL BUS. LOADS WILL THEN BE SEQUENCED ONTO AFFECTED BUS.

** ONLY LEAD SERVICE WATER PUMP WILL START. HOWEVER, IF LEAD PUMP FAILS TO START, THEN BACKUP PUMP WILL START.

*** EQUIPMENT STATUS FOR THE SWGR ROOM SUPPLY FANS ARE PROVIDED ON RP2.

1-EOP-TRIP-1	
REACTOR TRIP OR SAFETY INJECTION	
SHEET 4 OF 4	
REV 3	REV DATE 5/15/92
SALEM GENERATING STATION	UNIT 1

CONTINUOUS ACTION SUMMARY	
CONDITION	ACTION
RCS SUBCOOLING LESS THAN 18°F OR PZR LEVEL LESS THAN 9% (17% ADVERSE)	OPERATE ECCS EQUIPMENT TO RESTORE SUBCOOLING AND PZR LEVEL
LESS THAN TWO VITAL BUSES ENERGIZED	GO TO EOP-LOPA-1
AFST LEVEL LESS THAN 14%	SHIFT AFW SUPPLY

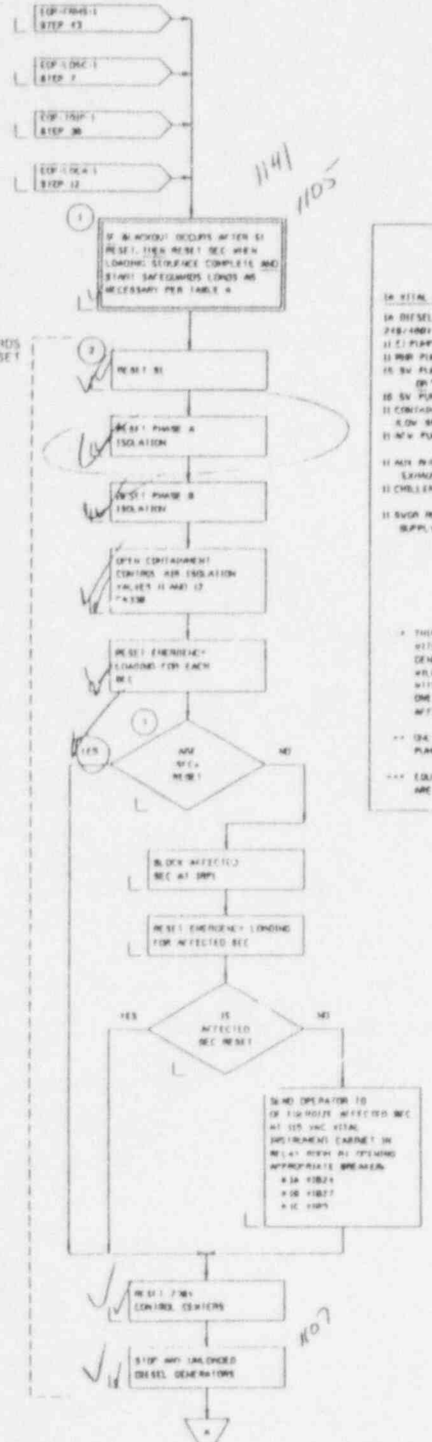


TABLE A

SAFEGUARDS LOADING SEQUENCE*

1A VITAL BUS	1B VITAL BUS	1C VITAL BUS
1A DIESEL GENERATOR	1B DIESEL GENERATOR	1C DIESEL GENERATOR
4KV/480V BREAKER	4KV/480V BREAKER	4KV/480V BREAKER
11 SI PUMP	11 CHARGING PUMP	12 CHARGING PUMP
11 RHR PUMP	12 RHR PUMP	12 SI PUMP
15 SW PUMP OR**	13 SW PUMP OR**	11 SW PUMP OR**
16 SW PUMP	14 SW PUMP	12 SW PUMP
11 CONTAINMENT FAN (LOW SPEED)	12 CONTAINMENT FAN (LOW SPEED)	13 CONTAINMENT FAN (LOW SPEED)
11 AFW PUMP	14 CONTAINMENT FAN (LOW SPEED)	15 CONTAINMENT FAN (LOW SPEED)
11 AUX BUILDING EXHAUST FAN	12 AFW PUMP	EMERGENCY AIR COMPRESSOR
11 CHILLER	12 AUX BUILDING SUPPLY FAN	11 AUX BUILDING SUPPLY FAN
11 SWGR ROOM SUPPLY FAN***	12 AUX BUILDING EXHAUST FAN	13 AUX BUILDING EXHAUST FAN
	12 CHILLER	13 CHILLER
	12 SWGR ROOM SUPPLY FAN***	13 SWGR ROOM SUPPLY FAN***

NOTES

* THIS SEQUENCE IS INITIATED ON ANY SI ACTUATION WITH OR WITHOUT A BLACKOUT. ONLY IN BLACKOUT CONDITION WILL DIESEL GENERATOR BREAKERS CLOSE AFTER FIRST STRIPPING BUS LOADS. LOADS WILL THEN BE SEQUENCED ONTO BUS. THIS SEQUENCE IS INITIATED WITH AN SI SIGNAL COINCIDENT WITH AN UNDERVOLTAGE SIGNAL ON ONE 4KV VITAL BUS. LOADS WILL THEN BE SEQUENCED ONTO AFFECTED BUS.

** ONLY LEAD SERVICE WATER PUMP WILL START. HOWEVER, IF LEAD PUMP FAILS TO START, THEN BACKUP PUMP WILL START.

*** EQUIPMENT STATUS FOR THE SWGR ROOM SUPPLY FANS ARE PROVIDED ON RP2

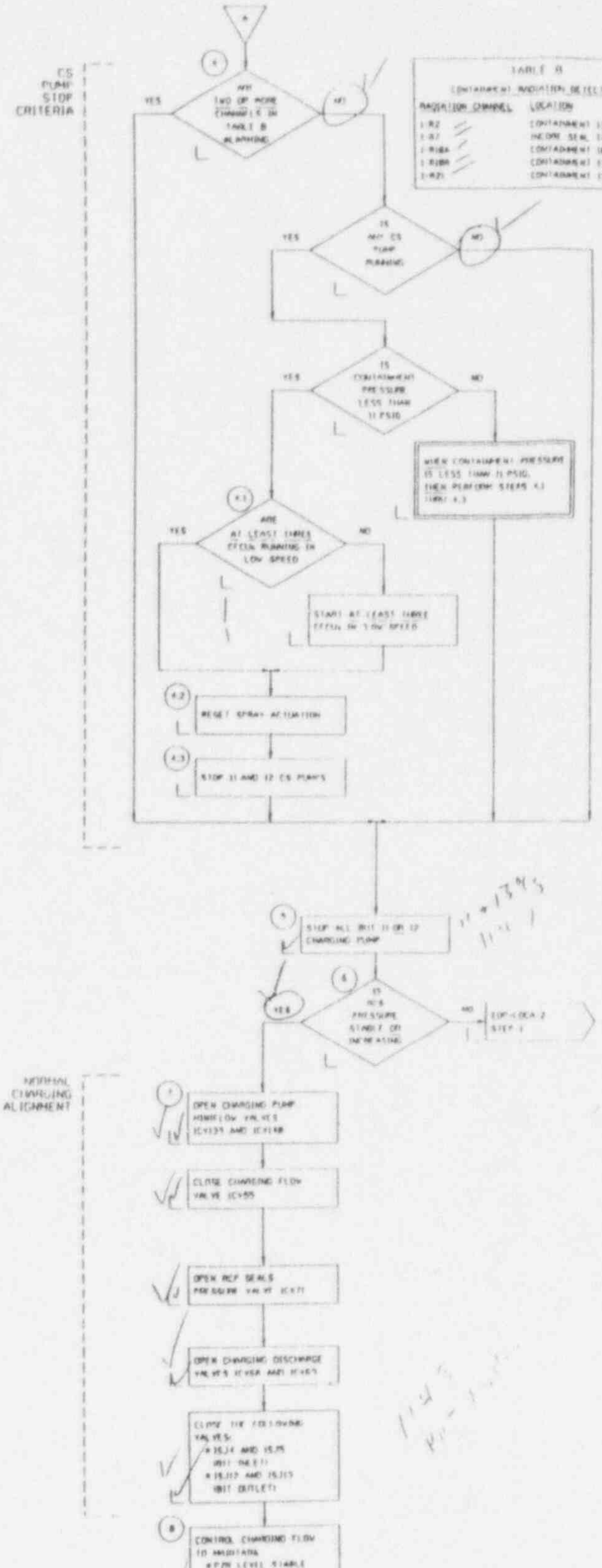
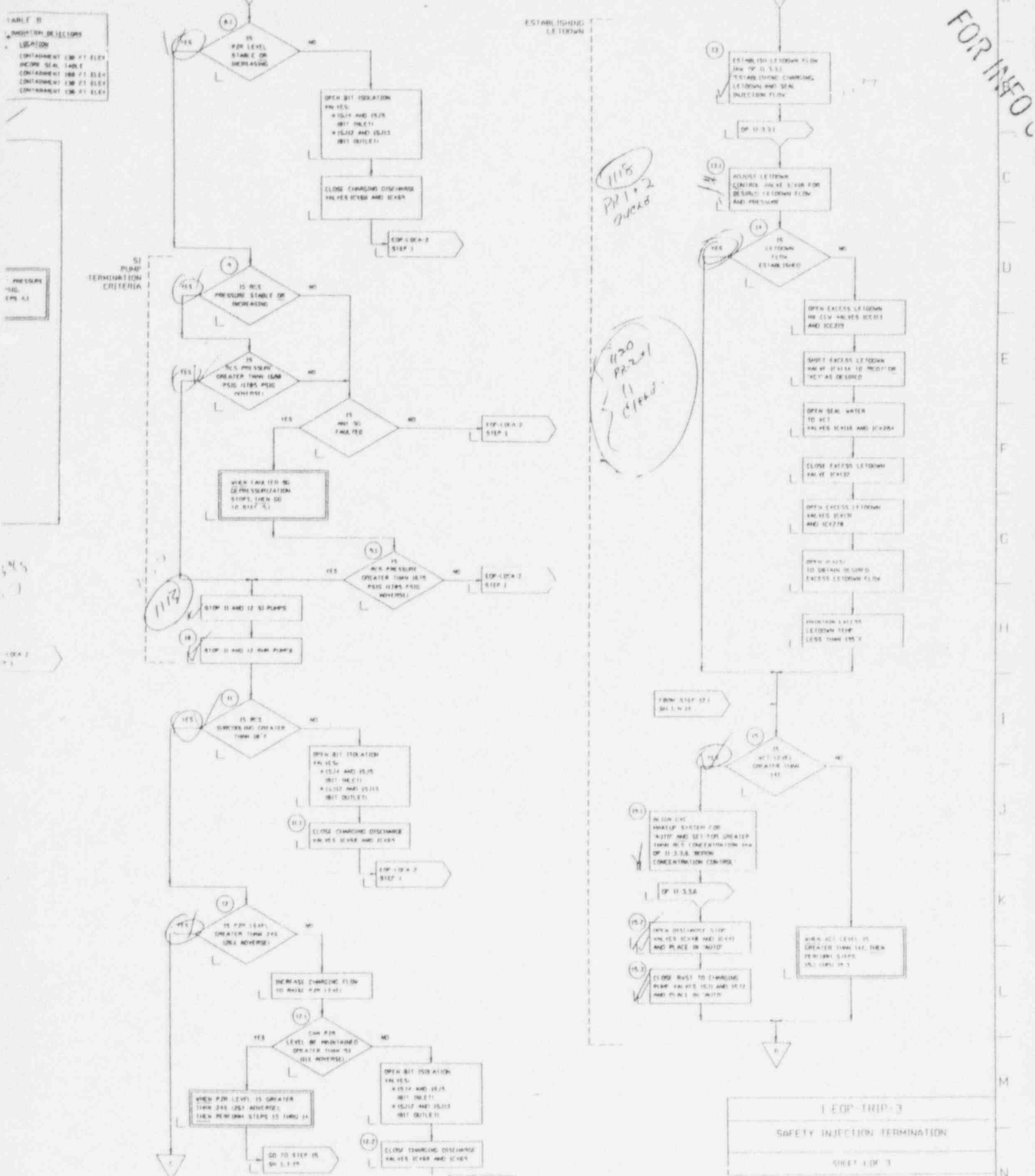


TABLE B

CONTAINMENT RADIATION DETECTOR

RADIATION CHANNEL	LOCATION
1-R2	CONTAINMENT 130
1-R7	INCORE SEAL 148
1-R16A	CONTAINMENT 100
1-R16B	CONTAINMENT 130
1-R21	CONTAINMENT 130



FOR INFO
TABLE B
RADIATION DETECTORS
LOCATION
CONTAINMENT 130 FT ELEV
INCORE SEAL TABLE
CONTAINMENT 100 FT ELEV
CONTAINMENT 130 FT ELEV
CONTAINMENT 130 FT ELEV
B
IS PZR LEVEL STABLE OR INCREASING
YES
NO
OPEN BIT ISOLATION VALVES:
1SJ4 AND 1SJ5 (BIT INLET)
1SJ12 AND 1SJ13 (BIT OUTLET)
CLOSE CHARGING DISCHARGE VALVES 1CV68 AND 1CV69
EOP-LOCA-2 STEP 1
SI PUMP TERMINATION CRITERIA
IS RCS PRESSURE STABLE OR INCREASING
IS RCS PRESSURE GREATER THAN 1500 PSIG (1785 PSIG ADVERSE)
IS ANY SG FAULTED
EOP-LOCA-2 STEP 1
WHEN FAULTED SG DEPRESSURIZATION STOPS, THEN GO TO STEP 9.1
IS RCS PRESSURE GREATER THAN 1675 PSIG (1785 PSIG ADVERSE)
EOP-LOCA-2 STEP 1
STOP 11 AND 12 SI PUMPS
STOP 11 AND 12 RHR PUMPS
IS RCS SUBCOOLING GREATER THAN 30 F
OPEN BIT ISOLATION VALVES:
1SJ4 AND 1SJ5 (BIT INLET)
1SJ12 AND 1SJ13 (BIT OUTLET)
CLOSE CHARGING DISCHARGE VALVES 1CV68 AND 1CV69
EOP-LOCA-2 STEP 1
IS PZR LEVEL GREATER THAN 24% (26% ADVERSE)
INCREASE CHARGING FLOW TO RAISE PZR LEVEL
CAN PZR LEVEL BE MAINTAINED GREATER THAN 5% (11% ADVERSE)
WHEN PZR LEVEL IS GREATER THAN 24% (26% ADVERSE) THEN PERFORM STEPS 13 THRU 14
GO TO STEP 15 SH 1.3.15
OPEN BIT ISOLATION VALVES:
1SJ4 AND 1SJ5 (BIT INLET)
1SJ12 AND 1SJ13 (BIT OUTLET)
CLOSE CHARGING DISCHARGE VALVES 1CV68 AND 1CV69
EOP-LOCA-2 STEP 1
ESTABLISHING LETDOWN
C
ESTABLISH LETDOWN FLOW IAW OP II-3.3.1 "ESTABLISHING CHARGING, LETDOWN AND SEAL INJECTION FLOW"
OP II-3.3.1
ADJUST LETDOWN CONTROL VALVE 1CV18 FOR DESIRED LETDOWN FLOW AND PRESSURE
IS LETDOWN FLOW ESTABLISHED
OPEN EXCESS LETDOWN HX CIV VALVES 1CC113 AND 1CC215
SHIFT EXCESS LETDOWN VALVE 1CV134 TO "RCDT" OR "VCT" AS DESIRED
OPEN SEAL WATER TO VCT VALVES 1CV116 AND 1CV284
CLOSE EXCESS LETDOWN VALVE 1CV132
OPEN EXCESS LETDOWN VALVES 1CV131 AND 1CV278
OPEN 1CV132 TO OBTAIN DESIRED EXCESS LETDOWN FLOW
MAINTAIN EXCESS LETDOWN TEMP LESS THAN 195 F
FROM STEP 17.1 SH 1.3.17
IS VCT LEVEL GREATER THAN 14%
ALIGN CVC MAKEUP SYSTEM FOR "AUTO" AND SET FOR GREATER THAN RCS CONCENTRATION IAW OP II-3.3.6, BORON CONCENTRATION CONTROL
OP II-3.3.6
OPEN DISCHARGE STOP VALVES 1CV40 AND 1CV41 AND PLACE IN "AUTO"
CLOSE RWST TO CHARGING PUMP VALVES 1SJ1 AND 1SJ2 AND PLACE IN "AUTO"
WHEN VCT LEVEL IS GREATER THAN 14%, THEN PERFORM STEPS 15.1 THRU 15.3
D
1115 PR 1+2 1VC18
1120 PR 2+1 11 C1460
1117
1-EOP-TRIP-3
SAFETY INJECTION TERMINATION
SHEET 1 OF 3
REV. 3
REV DATE 5/15/92
SALEM GENERATING STATION
12
13
14
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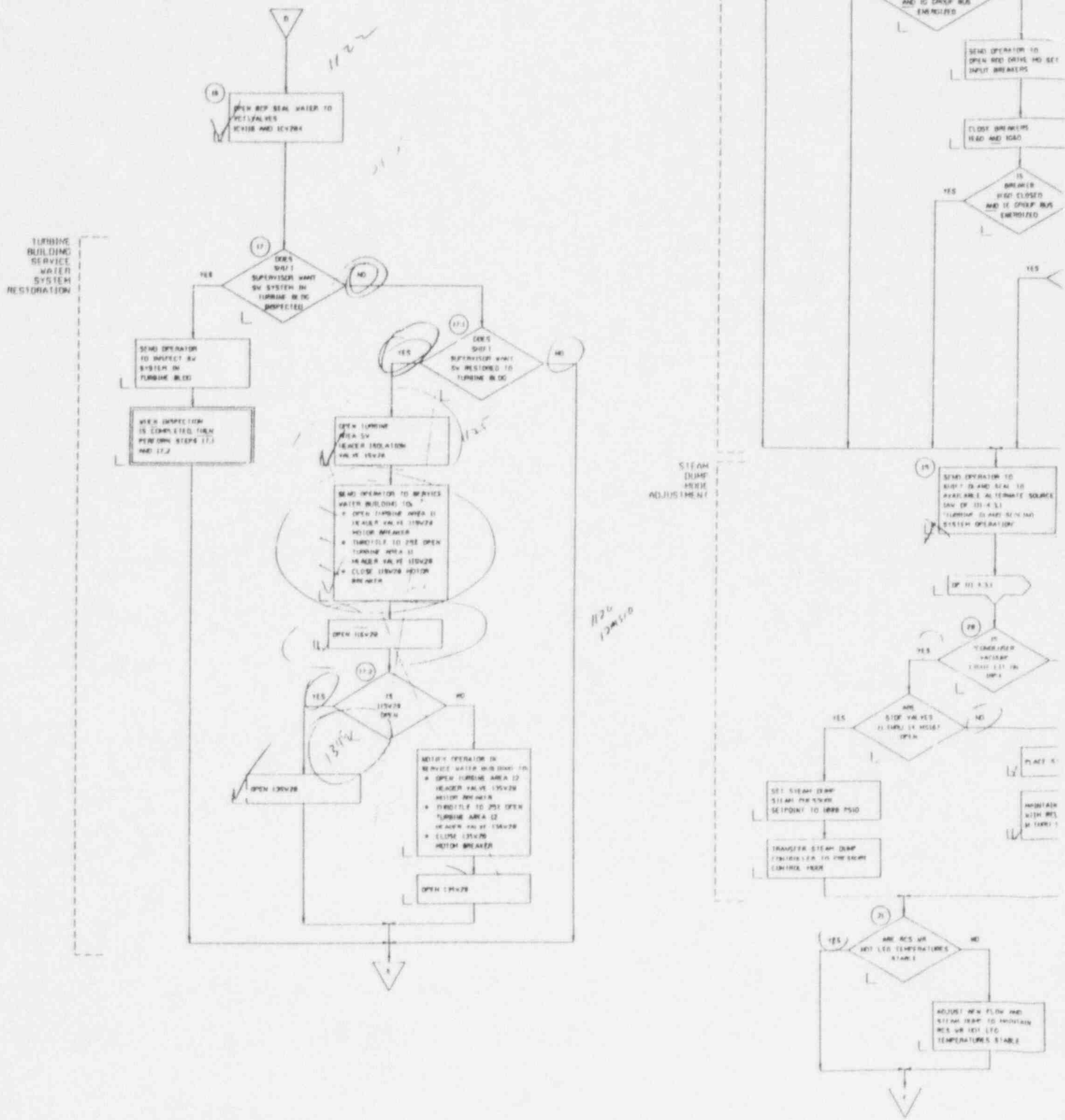
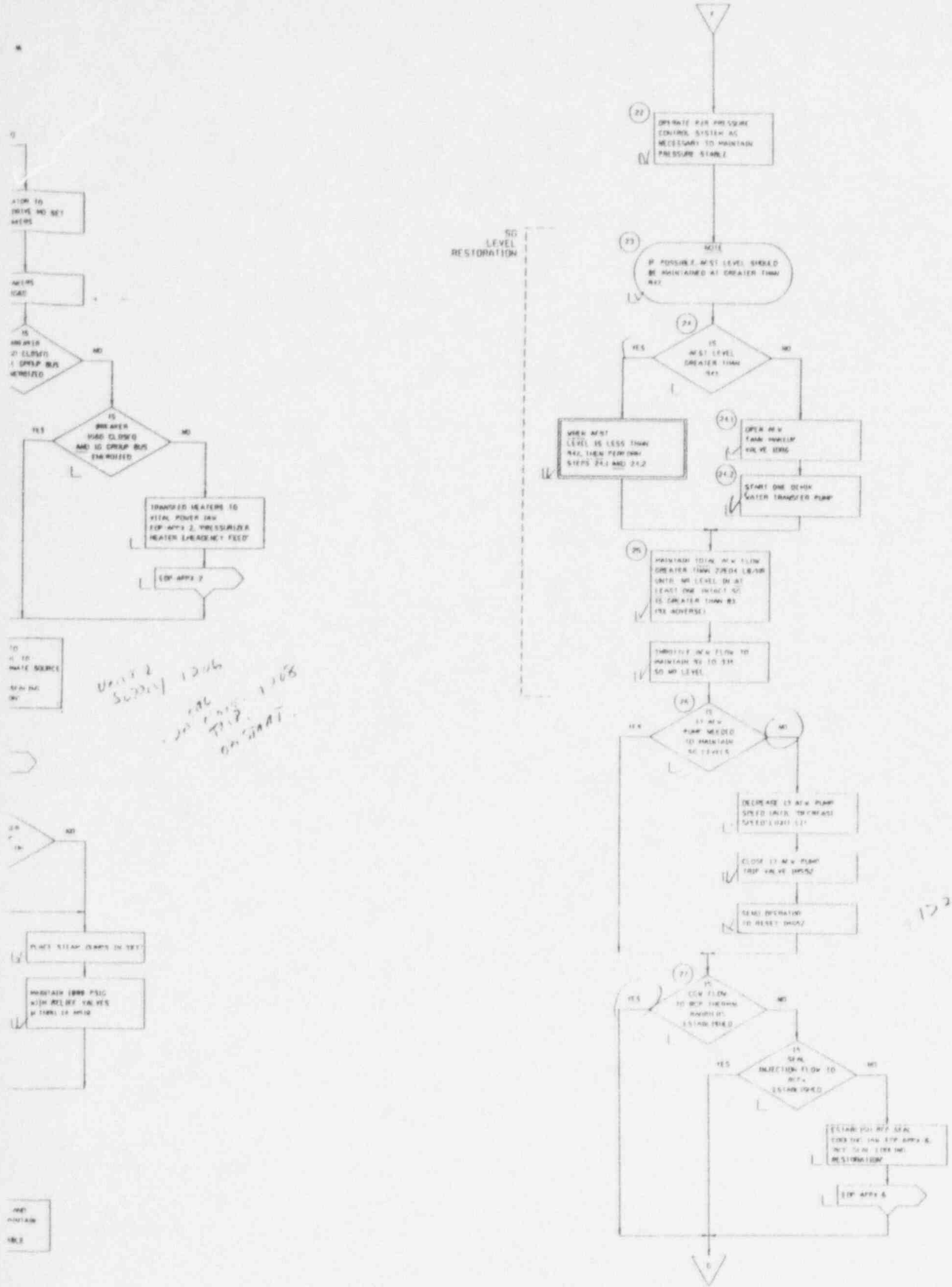
20
21
22

1-EOP-TRIP-3 | SAFETY INJECTION TERMINATION

CONTINUOUS ACTION SUMMARY	
CONDITION	ACTION
RCS SUBCOOLING LESS THAN 30°F OR PZR LEVEL LESS THAN 10 (53 ADVERSE)	OPERATE ECCS EQUIPMENT TO RESTORE SUBCOOLING AND PZR LEVEL
LESS THAN TWO VITAL BUSES ENERGIZED	GO TO EOP-LOPA-1
AFST LEVEL LESS THAN 1??	SHIFT AFW SUPPLY

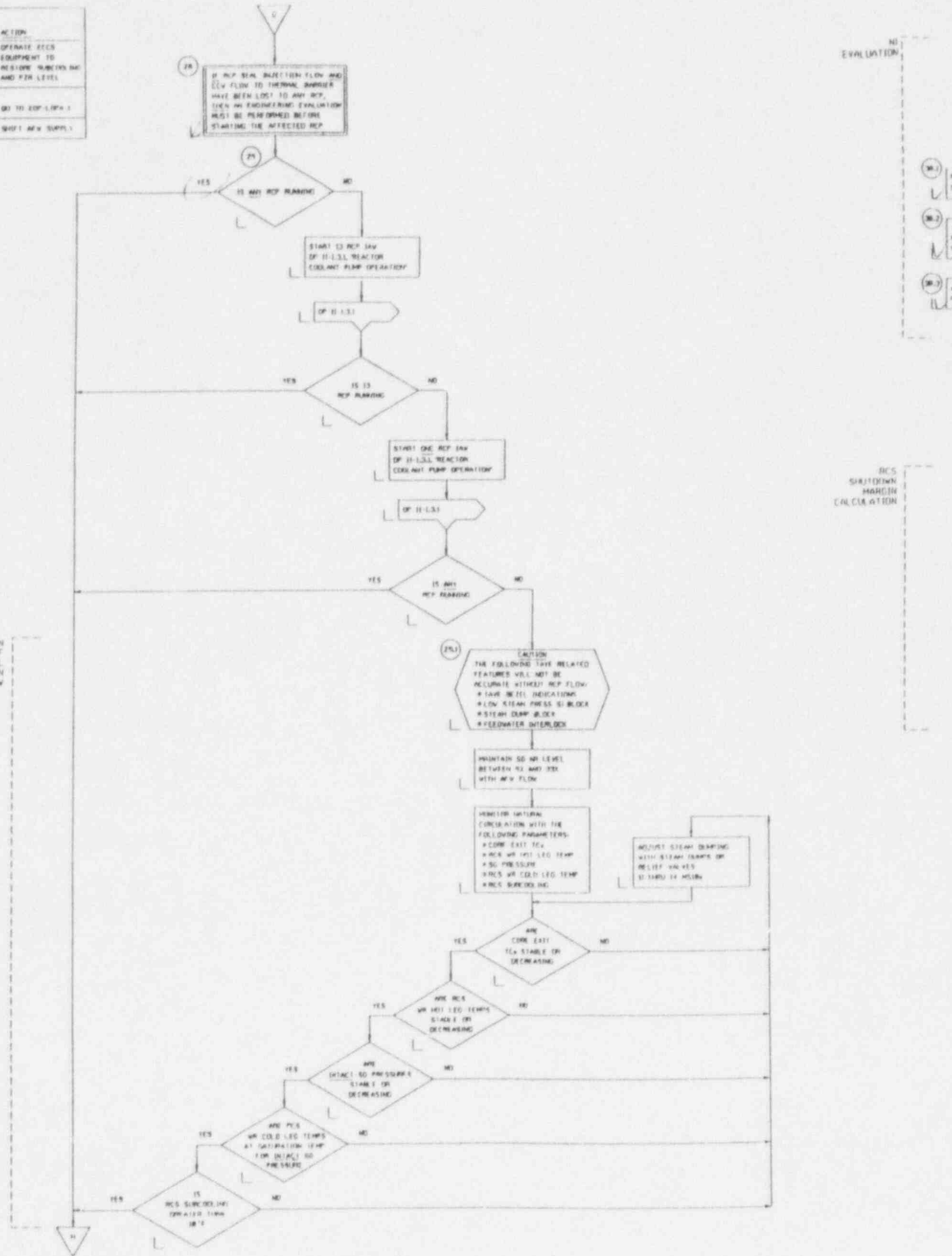




1-EOP-TRIP-3
SAFETY INJECTION TERMINATION
SHEET 2 OF 3
REV 3 — REV DATE 5/15/92
SALEM GENERATING STATION — UNIT 1

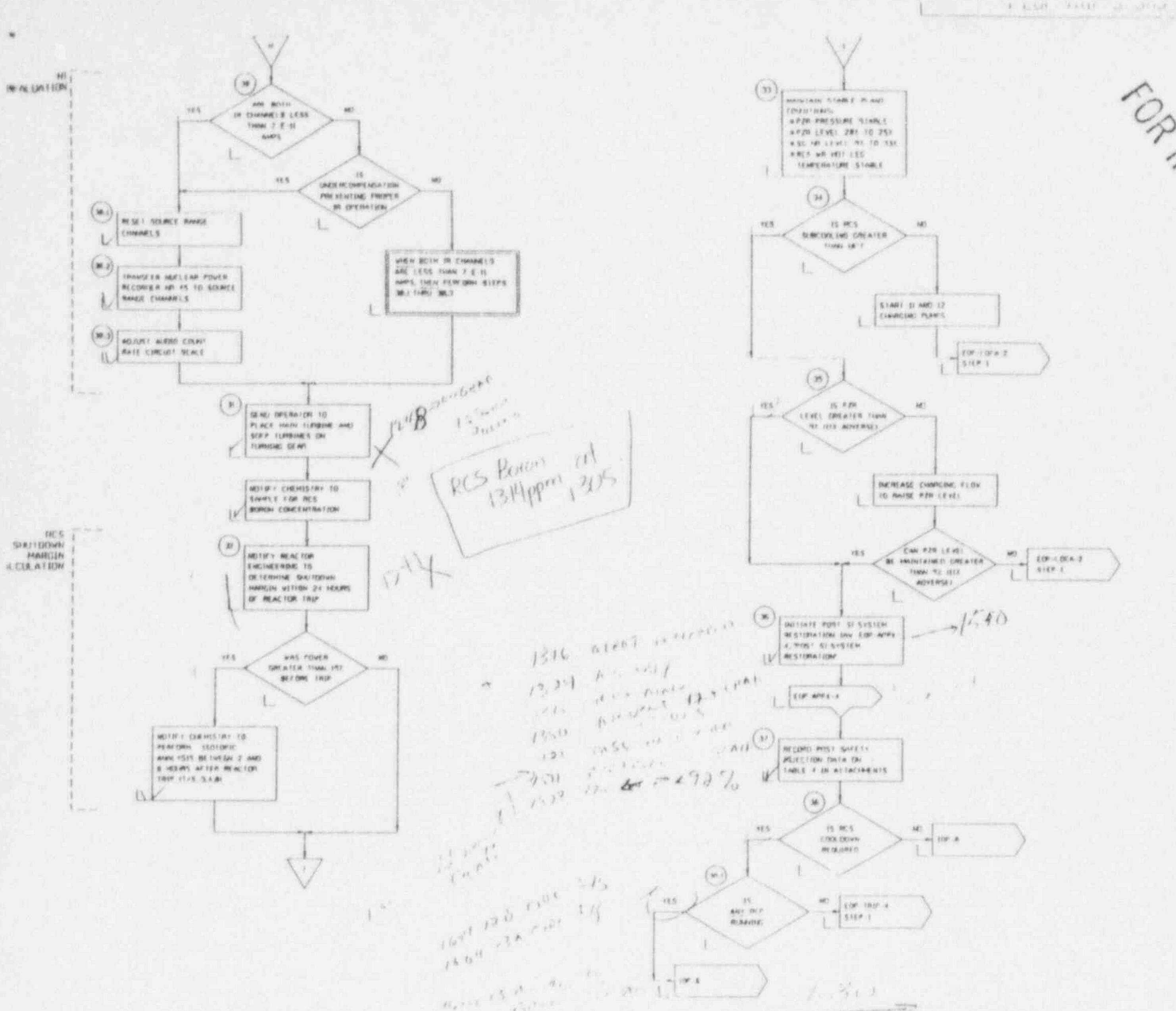
CONTINUOUS ACTION SUMMARY

CONDITION	ACTION
RCS SUBCOOLING LESS THAN 30°F OR PZR LEVEL LESS THAN 3% (11% ADVERSE)	OPERATE ECCS EQUIPMENT TO RESTORE SUBCOOLING AND PZR LEVEL
LESS THAN TWO 4 KV BUSES ENERGIZED	GO TO EOP-LOPA-1
AFST LEVEL LESS THAN 14%	SHIFT AFW SUPPLY



1254
11MS10 open in manual by [illegible]
11MS10 - closed

FOR INFO ONLY



1-EOP-TRIP-3	
SAFETY INJECTION TERMINATION	
SHEET 3 OF 3	
REV. 4	REV DATE 5/15/92
SALEM GENERATING STATION	UNIT 1

John V. Kauffman

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

HISTORY FILE NO. ___-___

Date of Event 4/7/94 Time of Event 10:47 Affected Unit One

Mode 1 Reactor Power ~~25~~ 73 % Generator Output 800 MWe

1) Personnel Assignments

- SNSS M. Gwirtz
- Pri. NEO K. McKune
- NSS W. Holmes
- Sec. NEO J. Stevens
- STA S. Simpson
- Shift Elec. Day Shift
- NSSW S. Simpson
- Shift Tech. Day shift
- Board NCO R. Romanowski
- Contr. Supv. Day shift
- Desk NEO D. Lyons
- Mech. Supv. Day shift

2) Evolutions in progress at the onset of the event:

a. Surveillance Testing	* Yes___	No ✓
b. Troubleshooting	* Yes___	No ✓
c. Maintenance	* Yes___	No ✓
e. Unit Startup	* Yes___	No ✓
f. Unit Shutdown	* Yes___	No ✓
g. Turbine Run Back	* Yes___	No ✓
h. Load change	* Yes ✓	No___

- Increase ___
- Decrease ✓ AB-CW-1 / Grass causing circulator trips

3) Were any of the following inoperable at the onset of the event:

a. Major Equipment	* Yes ✓	No___
b. Protection Systems	* Yes___	No ✓
c. Control Systems	* Yes___	No ✓

* Any question answered YES explain in detail on the following page.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

PERSONNEL AND ACTIVITY STATUS

Explain in detail the circumstances for any question answered yes on the preceeding page. Indicate if the evolution(s) and/or out of service components were significant to the event and/or impeded placing the plant in a stable condition. Include the observations and actions of specific individuals and the adequacy of procedures used. Use additional sheets as necessary.

Unit Load decrease in progress due to heavy grass at Circ Water intake - AB.CW-1 in use at time.

12A Circulator Release in progress due to cleaning

12 CC Pump Cleared / Tagged

NSS (Wolk) assigned to oversee activities at Circulating Water Structure

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

COMPONENT STATUS

1) Reactor Coolant Pumps	11/21	12/22	13/23	14/24
a) In Service	Y	Y	Y	Y

2) Steam Generator Feed Pumps	11/21	12/22
a) In Service	Y	Y
b) Control		
♦ Man.	N	N
♦ Auto.	Y	Y
c) Master Controller Mode		
♦ Man	Y	
♦ Auto.	N	

12 SGFP Oscillating Speed due to low flow condition. Control operator put 12 SGFP at idle speed to steady out Steam Gen Level Control

3) BF19s	11/21	12/22	13/23	14/24
a) In Service	Y	Y	Y	Y
b) Control Mode				
♦ Man.	N	N	N	N
♦ Auto.	Y	Y	Y	Y

4) BF40s	11/21	12/22	13/23	14/24
a) In Service	N	N	N	N
b) Control				
♦ Man.	Y	Y	Y	Y
♦ Auto.	N	N	N	N

5) Auxiliary Feed Pumps	11/21	12/22	13/23
a) Available	Y	Y	Y
b) In Service	N	N	N

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

COMPONENT STATUS

6) AF21s	11/21	12/22	13/23	14/24	
a) Demand *	98	98	98	98	
7) AF11s	11/21	12/22	13/23	14/24	
a) Open	Y	Y	Y	Y	
8) Atmos. Steam Dump (MS10's)	11/21	12/22	13/23	14/24	
a) Auto	Y	Y	Y	Y	
b) Manual					
c) Isolated	N	N	N	N	[illegible]
9) Steam Dump, Condenser	11/21	12/22	13/23		
a) Available	Y	~~N~~Y	N	Circs O/S - Trip caused by Grass	
b) Mode					
♦ Pressure, Setpoint		1005 (psig)			
♦ Auto/Tavg	Y				
♦ Manual	—				
♦ Off	—				
♦ Isolated valve(s)	None	→			
10) Turbine EHC Control Mode					
a) Man.	N				
b) Auto.	Y				
11) Rod Control Control Mode					
a) Man.	Y				
b) Auto.	N				

* Demand set IAW S1(2)OP.SO.AF-0001(Q)

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

COMPONENT STATUS

(12) ELECTRICAL SYSTEMS

a) Vital Buses

	Energized		from 13/21 SPT	14/22 SPT
♦ "A" Vital Bus	Yes ✓	No ___	✓	___
♦ "B" Vital Bus	Yes ✓	No ___	___	✓
♦ "C" Vital Bus	Yes ✓	No ___	___	✓

b) Group Buses

Transferred from APT to SPT at 1047hr

	Energized		from AUX.PWR	STA.PWR
♦ "E" Group	Yes ✓	No ___	___	✓
♦ "F" Group	Yes ✓	No ___	___	✓
♦ "G" Group	Yes ✓	No ___	___	✓
♦ "H" Group	Yes ✓	No ___	___	✓

c) Vital Instrument Buses

	Energized		from INV.	B-U
♦ "A" Instrument Bus	Yes ✓	No ___	✓	___
♦ "B" Instrument Bus	Yes ✓	No ___	✓	___
♦ "C" Instrument Bus	Yes ✓	No ___	✓	___
♦ "D" Instrument Bus	Yes ✓	No ___	✓	___

d) DC Buses

	Energized	
♦ 28 VDC		
■ "A" Bus	Yes ✓	No ___
■ "B" Bus	Yes ✓	No ___
♦ 125 VDC		
■ "A" Bus	Yes ✓	No ___
■ "B" Bus	Yes ✓	No ___
■ "C" Bus	Yes ✓	No ___
♦ 250 VDC	Yes ✓	No ___

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

COMPONENT STATUS
ELECTRICAL SYSTEMS

Explain in detail the circumstances for any question answered Yes on the preceeding page. Indicate if the electrical distribution problems or out of service electrical components were significant to the event and/or impeded placing the plant in a stable condition. Include the observations and actions of individuals and the adequacy of procedures. Use additional sheets as necessary.

Group Buses were transferred from Auxiliary Power Transformer to Station Power Transformer in preparation of removing the turbine from service.

COMPONENT STATUS

13) PRESSURIZER CONTROL STATUS

a) Block Valves

- 1/2 PR6 Open ✓ Closed ____
- 1/2 PR7 Open ✓ Closed ____

b) Controllers

- Master Auto ✓ Man ____
- Level Auto ✓ Man ____
- Spray Valves
  - 1/2 PS 1 Auto ✓ Man ___, Open ✓ Closed ___
  - 1/2 PS 3 Auto ✓ Man ___, Open ✓ Closed ___
- Heaters Auto ✓ Man ___
  - Bk. Up Grp. 11/21 I/S ✓ O/S ____
  - Bk. Up Grp. 12/22 I/S ✓ O/S ____

14) Plant Chemistry (Use the Chemistry Trend book or contact Chemistry for data)

a) Primary Chemistry Conditions Normal ?

- Yes ✓
- No ____

b) Secondary Chemistry Conditions Normal ?

- Yes ✓
- No ____

c) Explain the circumstances for any question answered "NO"

____

____

____

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

SYSTEM TRENDS

(15) REACTOR COOLANT SYSTEM LOOP TEMPERATURE TRENDS

Check box that best describes the rate & direction	REACTOR COOLANT SYSTEM LOOP TEMPERATURE TREND							
	11/21		12/22		13/23		14/24	
AVERAGE (Tavg)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								
HOT LEG (Th)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								
COLD LEG (Tc)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE	✓		✓		✓		✓	
SLOW								
VERY SLOW								

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

SYSTEM TRENDS

(16) PRIMARY SYSTEMS PRESSURE TRENDS

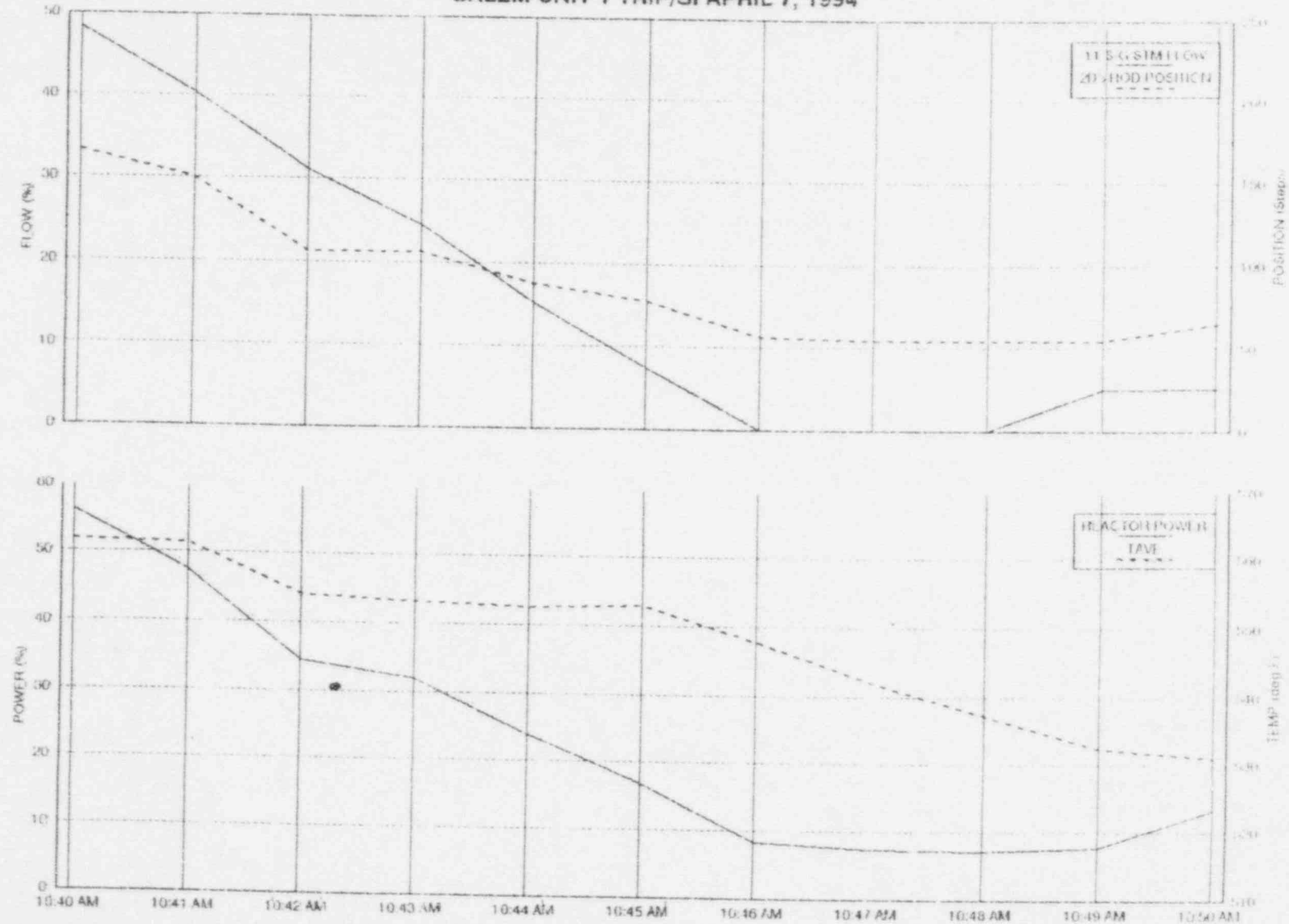
Check box that best describes the rate and direction	PRESSURIZER TRENDS					
	LEVEL		PRESS		SPRAY	
	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE						
VERY FAST						
FAST				✓		
STABLE				Power Reduction		
SLOW		✓			Spray valves = X *	
VERY SLOW						

* Przr Press below spray setpoint

Check box that best describes the rate and direction	REACTOR COOLANT SYSTEM PRESSURE TREND LOOP HOT LEG PRESSURE			
	WIDE RANGE		NARROW RANGE	
	UP	DOWN	UP	DOWN
STEP CHANGE				
VERY FAST				
FAST		✓		✓
STABLE				
SLOW				
VERY SLOW				

Comments RCS Tave was stable initially during the load reduction, but dropped rapidly prior to the trip.
RCS Pressure was decreasing initially during the load decrease and increased following the trip due to charging flow.

SALEM UNIT 1 TRIP/SI APRIL 7, 1994



REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

SYSTEM TRENDS

(17) STEAM GENERATOR LEVEL & PRESSURE TRENDS

Check box that best describes the rate and direction

S/G NARROW RANGE % of span	11/21 UP	DWN	12/22 UP	DWN	13/23 UP	DWN	14/24 UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW		✓		✓		✓		✓
VERY SLOW								

S/G WIDE RANGE	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW		✓		✓		✓		✓
VERY SLOW								

S/G PRESSURE PSIG	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW		✓		✓		✓		✓
VERY SLOW								

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 1, PRE TRIP CONDITIONS

SYSTEM TRENDS

(18) STEAM GENERATOR FEED WATER & STEAM FLOW TRENDS

Check box that best describes the rate and direction

FEED WATER FLOW %	11/21		12/22		13/23		14/24	
	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW		✓		✓		✓		✓
VERY SLOW								

STEAM FLOW %	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW		✓		✓		✓		✓
VERY SLOW								

COMMENTS:

HIGH STEAM FLOW S.I. COINC. W L.L. TAVE

First Safety Injection

POST REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 2, SEQUENCE OF EVENTS CHECKLIST
INSTRUCTIONS

The Sequence of Events Checklist is the transfer of data from the P-250 Sequence of Events print out. For each of the alarms on the checklist the absolute start and differential time is calulated and entered in the space provided. These times are compared to the (maximum allowable) Technical Specification response times to ensure the protection system response(s) were within acceptable limits.

The P-250 computer header "SEQ OF EVENTS" is in absolute time hours:minutes:seconds and a cycle count. The time is for specific group of alarms associated with that header. The header cycle count must be applied to each alarm's cycle count to obtain the absolute time for each alarm. It should be noted that hours may not exceed 24 and minutes seconds & cycles may not exceed 60.

Attachment C of this procedure contains examples of calulating the absolute and differential times.

To perform this, use the following guidelines

I. Convert the alarm into a hours/minutes/seconds/cycle format.

A. Add the subsequent alarm cycles to the "SEQ OF EVENTS" header cycle count.

1. If the sum of the cycles is < 60 cycles then add the number of cycles to the "SEQ OF EVENTS" header time to obtain the absolute time for the alarm. Subtract the Initiating Events absolute time from the alarm's absolute time to obtain the delta (differential) time. Record these times on the Checklist.

2. If the sum is > 60 convert the cycles to seconds & cycles by:

a. Divide the cycles by 60, drop any digits after the decimal point. This is the number of the cycles in seconds.

b. Multiply the seconds (from a.) by 60 then subtract the result from the total cycle count. This is the remaining cycles.

c. Add the seconds & cycles to the "SEQ OF EVENTS" header time. This is the "absolute" time for the alarm and is recorded on the Checklist.

e. Subtract the Initiating Event absolute time from the alarm's absolute time. This is the delta (differential) time to be recorded on the Checklist.

f. Compare the values recorded to the Standards. Record any Feed Pump data on page 3. Document discrepancies on page 4 under comments.

REACTOR TRIP / SAFETY INJECTION REVIEW REPORT
REACTOR TRIP SEQUENCE OF EVENTS CHECKLIST

Reactor Trip ✓ Safety Injection ✓, Did the ECCS actually inject into the RCS, yes ✓ no ___ ?
Initiation Auto ✓, OHA First Out NI Power Range Flux Hi - Lo Setpoint * Manual ___
Event Initiated @ 10 : 47 : 44 cycle count 3 Rx.Trip/SI initiated @ 10 : 47 : 44 : 0005

Sequence of Events Subsequent Alarms	Alarm Signals Initiated into sequence hrs.	min.	sec.	cyc.	Event / Alarm signal difference min	sec	cyc	max. allowable TECH SPEC response time
REACTOR MAIN TRIP BKR A TRIP	10	47	44	0011	0	0	6	< 10 cycles
REACTOR MAIN TRIP BKR B TRIP	10	47	44	0011	0	0	6	< 10 cycles
REACTOR TRIP AUX1 BKR A TRIP	N/A							< 10 cycles
REACTOR TRIP AUX1 BKR B TRIP	N/A							< 10 cycles
SHUNT RELAY A TRIP TRIP	10	47	44	0008	0	0	3	#< 10 cycles
SHUNT RELAY B TRIP TRIP	10	47	44	0008	0	0	3	#< 10 cycles
REACTOR MAN TRP 1 TRIP	N/A							< 30.0 seconds
REACTOR MAN TRP 2 TRIP	10	47	46	0190	0	6	5	< 30.0 seconds
TURBINE STOP VA 11(21) CLOSED	10	47	44	0025	0	0	20	< 1 sec:30 cyc
TURBINE STOP VA 12(22) CLOSED	10	47	44	0035	0	0	30	< 1 sec:30 cyc
TURBINE STOP VA 13(23) CLOSED	10	47	44	0025	0	0	20	< 1 sec:30 cyc
TURBINE STOP VA 14(24) CLOSED	10	47	44	0026	0	0	21	< 1 sec:30 cyc
TURBINE TRIP TRIP	10	47	44	0011	0	0	6	< 10 cycles
TURBINE REMOTE EMERG TRIP TRIP	10	47	44	0012	0	0	7	< 60 cycles

* The P-250 Sequence of Events print out should agree with the OHA, explain any discrepancies in Post Trip portion of this procedure. If the ECCS (Unit 2 ONLY) did inject see T/S 4.4.7.2(d)
\# If >6 cycles, document in Section 3 step 22 and notify the System Engineer.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SAFETY INJECTION SEQUENCE OF EVENTS CHECKLIST

FEED PUMP DATA

MOTOR DRIVEN AUX FEED PUMPS

Direct start signal on a SI or on any single S/G Lo-Lo level trip signal

Subsequent Alarm	Alarm Signal Initiated into sequence				Event / Alarm signal difference			Alarm Standard Expected time difference
	hrs	min	sec	cyc	min	sec	cyc	
11(21) AUX FW PUMP START	10	47	46	0000	0	0	12	< 10 cycles
12(22) AUX FW PUMP START	10	47	45	0057	0	0	9	< 10 cycles

STEAM DRIVEN AUX. FEED PUMPS

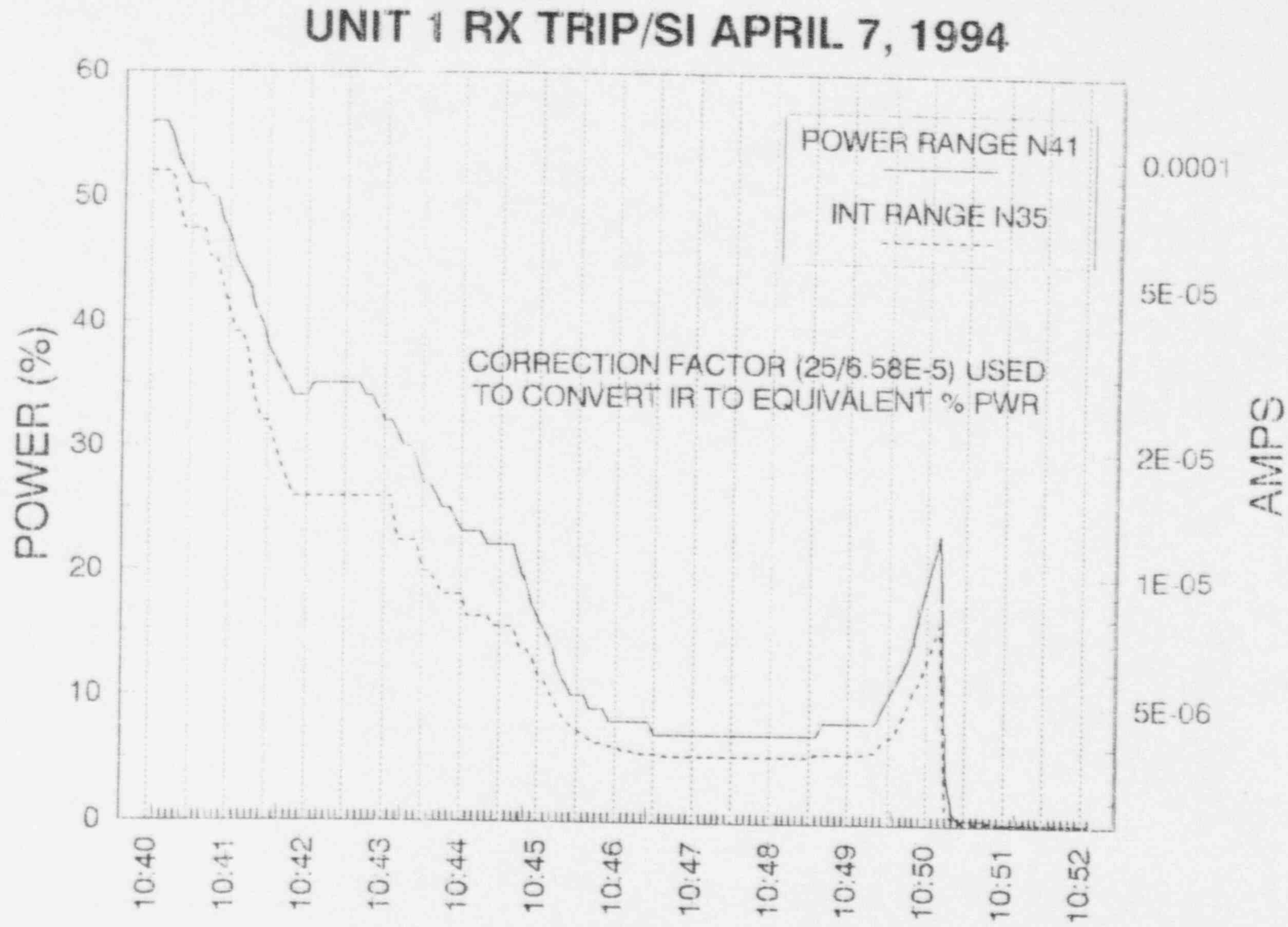
Only on 2 S/G Lo-Lo Levels Trip Signals

Subsequent Alarm	hrs	min	sec	cyc	min	sec	cyc	Alarm Standard
13(23) AUX FW PUMP TURB STOP VA NT CL	Did not receive 2 lo-lo levels-							< 30.0 seconds

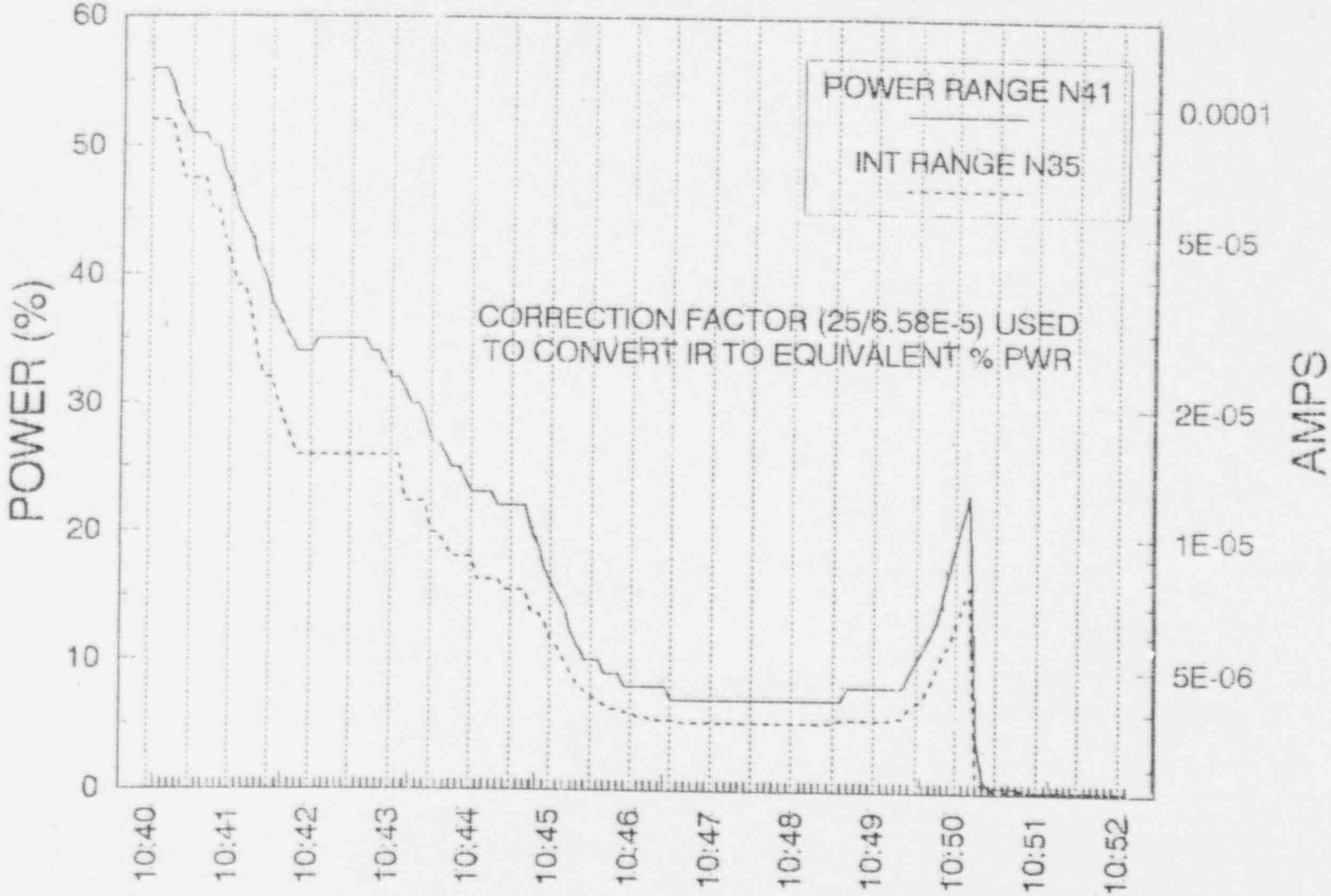
MAIN FEED PUMPS

Trip Manual ___ Auto ___, if "auto" record the "First Out Alarm" ___
(Main Feed Pumps receive a direct Trip from a SI initiation or from any S/G Hi-Hi evel.)

Subsequent Alarms	hrs	min	sec	cyc	min	sec	cyc	Alarm Standard
11/21 SGFP TURB LP CONT VA CL					SGFP's did not			< 5.0 seconds
11/21 SGFP TURB HP CONT VA CL					trip			< 5.0 seconds
12/22 SGFP TURB LP CONT VA CL								< 5.0 seconds
12/22 SGFP TURB HP CONT VA CL								< 5.0 seconds


UNIT 1 RX TRIP/SI APRIL 7, 1994
POWER RANGE N41
INT RANGE N35
CORRECTION FACTOR (25/6.58E-5) USED TO CONVERT IR TO EQUIVALENT % PWR
POWER (%)
AMPS
0
10
20
30
40
50
60
0.0001
5E-05
2E-05
1E-05
5E-06
10:40
10:41
10:42
10:43
10:44
10:45
10:46
10:47
10:48
10:49
10:50
10:51
10:52

UNIT 1 RX TRIP/SI APRIL 7, 1994



REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

PLANT STATUS

SAFETY SYSTEM ACTUATION	TIME	ACTUATION SIGNAL	TRAINS
Reactor Trip	10:47:44 0005	POWER RANGE LO FLUX	
Turbine Trip	10:47:44 0011	REACTOR TRIP	
Safety Injection	10:47:45 0048	HI STM FLOW / LO TAVE	TRAIN A Only
Phase A Isolation	10:47:45 0048	SI	TRAIN A Only
Containment Spray	N/A		
Phase B Isolation	N/A		
Main Steamline Isolation	10:47:45 0048	SI: HI STM FLOW / LO TAVE 11+12 MS167 Did not Close	
Main Feedwater Isolation		11-14 BF13 Did not close Auto 11+12 SGFP Did not Trip.	

Unit 1 + Unit 2 Control Area Ventilation did not swap to Accident inside Air on Train B Dampers

1) RCCA's Inserted

a. Control Yes ✓ No___

b. Shutdown Yes ✓ No___

c. RCCA Not fully inserted _____ _____ _____ _____

2) Reactor Coolant Pumps 11/21 12/22 13/23 14/24

a. In Service Y Y Y Y

3) CVC Charging Pumps 11/21 12/22 13/23

a. In Service Y Y Y

4) Safety Injection Pumps 11/21 12/22

b. In Service Y Y

5) RHR Pumps 11/21 12/22

b. In Service Y Y

6) Auxiliary Feed Pumps 11/21 12/22 13/23

b. In Service Y Y N

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

PLANT STATUS

7) **Containment F.C.U,s** 11/21 12/22 13/23 14/24 15/25

	11/21	12/22	13/23	14/24	15/25
a. High Speed					
b. low speed	✓	✓	✓	✓	✓

8) **Service Water Pumps**

	11/21	12/22	13/23	14/24	15/25	16/26
a. In Service	Y	N	N	Y	Y	N

9) **MS167s**

	11/21	12/22	13/23	14/24
a. Open	✓	✓		
b. Closed			✓	✓

10) **Circulator Pumps** 11/21 12/22 13/23

a. In Service A Y B N A N B Y A N B N

11) **Condenser Steam Dump I/S** Yes___ No ✓ Below P-12 RCS <543°F

12) **Atmospheric Steam Dump**

	11/21	12/22	13/23	14/24
a. In Service				
• Auto	✓	✓	✓	✓
• Man				
• Isolated				

13) **Main Steam Safeties Lifted?** Yes ✓ No___ See Second Safety Injection

a. Loop 11/21 ___ c. Loop 13/23 ___

b. Loop 12/22 ___ d. Loop 14/24 ___

14) **EHC system Runback** Yes___ No ✓

a. Power: from ______% to ______%

b. Time: from ______ to ______

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

PLANT STATUS

15) **RCS Pressure Control Response**

a. Pressurizer heater response Normal? Yes ✓ No ___

c. Pressurizer spray response Normal? Yes ✓ No ___

d. Pressurizer level control Normal? Yes ✓ No ___

e. Pzr PORV Actuated? Yes ✓ No ___

- 1/2 PR 1 Y
- 1/2 PR 2 Y

f. Pzr Safety Lifted? Yes___ No ✓ ? If Yes, attempt to identify the specific valve(s) N/A

- 1/2 PR 3 ___
- 1/2 PR 4 ___
- 1/2 PR 5 ___

1PR4 tailpipe temp was elevated. Loop seal and valve temps. were verified sat. Tailpipe temp. returned to normal after transient with RCS ~ 2235.
Valves removed by DCP during 1R11

16) **Pressurizer Control Status**

a) Block Valves

- 1/2 PR6 Open ✓ Closed ___
- 1/2 PR7 Open ✓ Closed ___

b) Controllers

- Master Auto ✓ Man ___
- Level Auto ✓ Man ___
- Spray Valves
  - 1/2 PS 1 Auto ✓ Man ___, Open___ Closed ✓
  - 1/2 PS 3 Auto ✓ Man ___, Open___ Closed ✓
- Heaters Auto ✓ Man ___ Letdown Isolation before ~~following~~ trip.
  - Bk. Up Grp. 11/21 I/S ___ O/S ✓
  - Bk. Up Grp. 12/22 I/S ___ O/S ✓

PLANT STATUS

17) ELECTRICAL SYSTEMS

a) Vital Buses

	Energized		from 13 SPT	14 SPT	EM.D/G
♦ "A" Vital Bus	Yes ✓	No ___	✓	___	___
♦ "B" Vital Bus	Yes ✓	No ___	___	✓	___
♦ "C" Vital Bus	Yes ✓	No ___	___	✓	___

b) Group Buses

	Energized	
♦ "E" Group	Yes ✓	No ___
♦ "F" Group	Yes ✓	No ___
♦ "G" Group	Yes ✓	No ___
♦ "H" Group	Yes ✓	No ___

c) Vital Instrument Buses

	Energized		from INV.	B-U
♦ "A" Instrument Bus	Yes ✓	No ___	✓	___
♦ "B" Instrument Bus	Yes ✓	No ___	✓	___
♦ "C" Instrument Bus	Yes ✓	No ___	✓	___
♦ "D" Instrument Bus	Yes ✓	No ___	✓	___

d) DC Buses

	Energized		From Charger	Battery
♦ 28 VDC				
▪ "A" Bus	Yes ✓	No ___	✓	___
▪ "B" Bus	Yes ✓	No ___	✓	___
♦ 125 VDC				
▪ "A" Bus	Yes ✓	No ___	✓	___
▪ "B" Bus	Yes ✓	No ___	✓	___
▪ "C" Bus	Yes ✓	No ___	✓	___
♦ 250 VDC Bus	Yes ✓	No ___	✓	___

Any electrical problems significant to the event, or de-energized buss explain in detail the circumstances on following page.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

PLANT STATUS

ELECTRICAL SYSTEMS

xplain in detail the circumstances for any question answered Yes n the preceeding page. Indicate if the electrical distribution roblems or out of service electrical components were significant o the event and/or impeded placing the plant in a stable condition. nclude the observations and actions of individuals and the adequacy f procedures. Use additional sheets as necessary.

Electrical Distribution was unchanged by the event. Diesel Generators started, but did not load during the SEC Actuation. 1B Urgent Trouble Alarm was actuated and the NEO was dispatched to investigate the problem.
Alarm was Starting air pressure low on 1B Diesel Generator

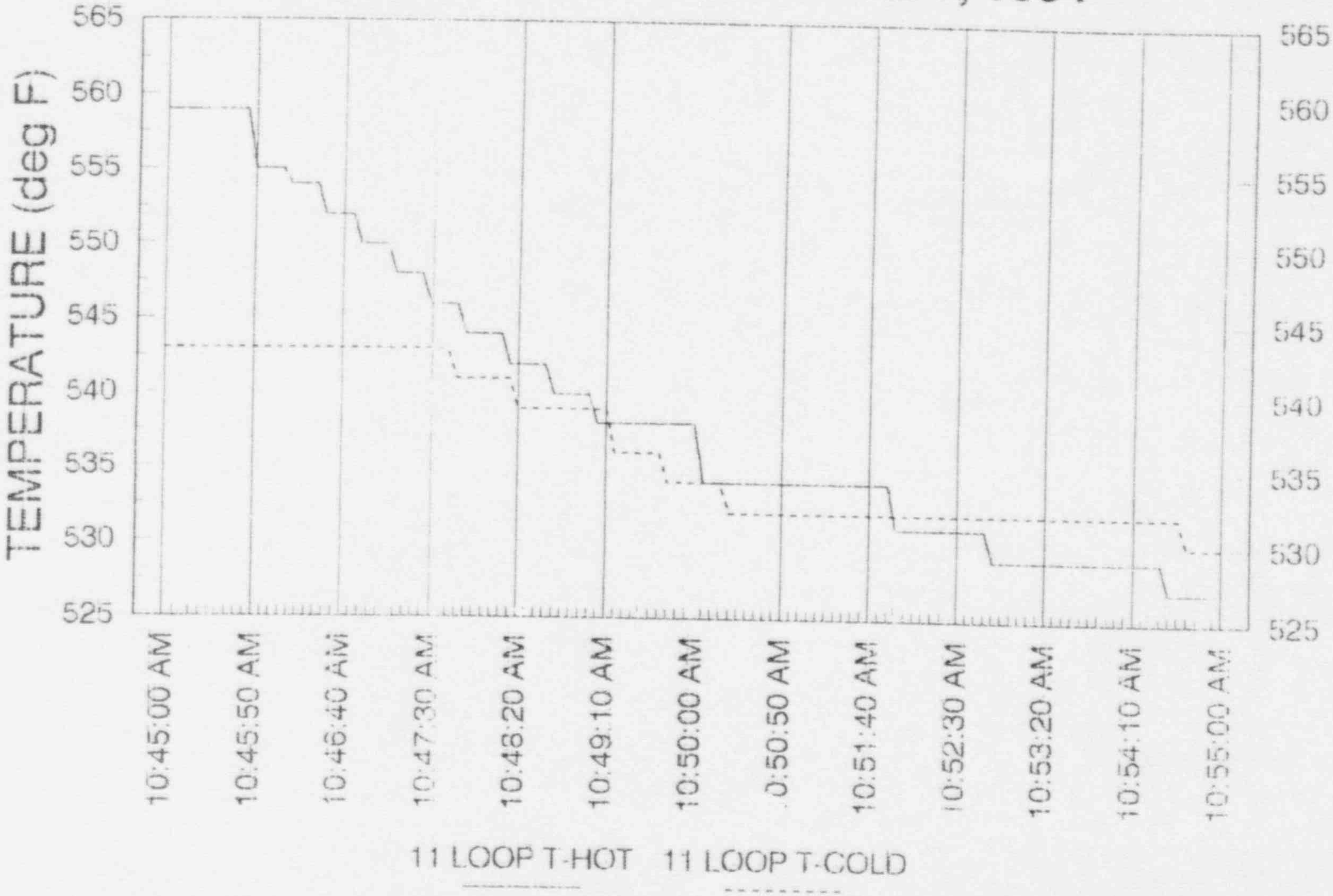
REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

SYSTEM TRENDS

(18) REACTOR COOLANT SYSTEM LOOP TEMPERATURE TRENDS

Check box that best describes the rate & direction	REACTOR COOLANT SYSTEM **LOOP TEMPERATURE** TREND							
	11/21		12/22		13/23		14/24	
AVERAGE (Tavg)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW		✓		✓		✓		✓
VERY SLOW								
HOT LEG (Th)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW	✓		✓		✓		✓	
VERY SLOW								
COLD LEG (Tc)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW	✓		✓		✓		✓	
VERY SLOW								

SALEM UNIT 1 TRIP/SI APRIL 7, 1994



REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

SYSTEM TRENDS

(19) PRIMARY SYSTEMS PRESSURE TRENDS

Check box that best describes the rate and direction	PRESSURIZER TRENDS					
	LEVEL		PRESS		SPRAY	
	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE						
VERY FAST		✓				
FAST				✓		
STABLE					Closed initially	
SLOW					✓	
VERY SLOW						

Check box that best describes the rate and direction	REACTOR COOLANT SYSTEM PRESSURE TREND LOOP HOT LEG PRESSURE			
	WIDE RANGE		NARROW RANGE	
	UP	DOWN	UP	DOWN
STEP CHANGE				
VERY FAST				
FAST				
STABLE				
SLOW	✓		✓	
VERY SLOW				

Comments Immediately following the trip, Tave decreased from 538°F to 527°F. RCS Tave increased from 527°F to 555F over ~30 minutes after MSIV closure. Pressurizer Level initially dropped rapidly on the trip, but increased quickly due to the safety injection flow. Similarly Pressurizer Pressure dropped rapidly during the trip and increased quickly due to the safety injection flow, until it reached 2250 psig, then Sprays maintained pressure for apparoximately 15 minutes

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

SYSTEM TRENDS

20) STEAM GENERATOR LEVEL & PRESSURE TRENDS

Check box that best describes the rate and direction

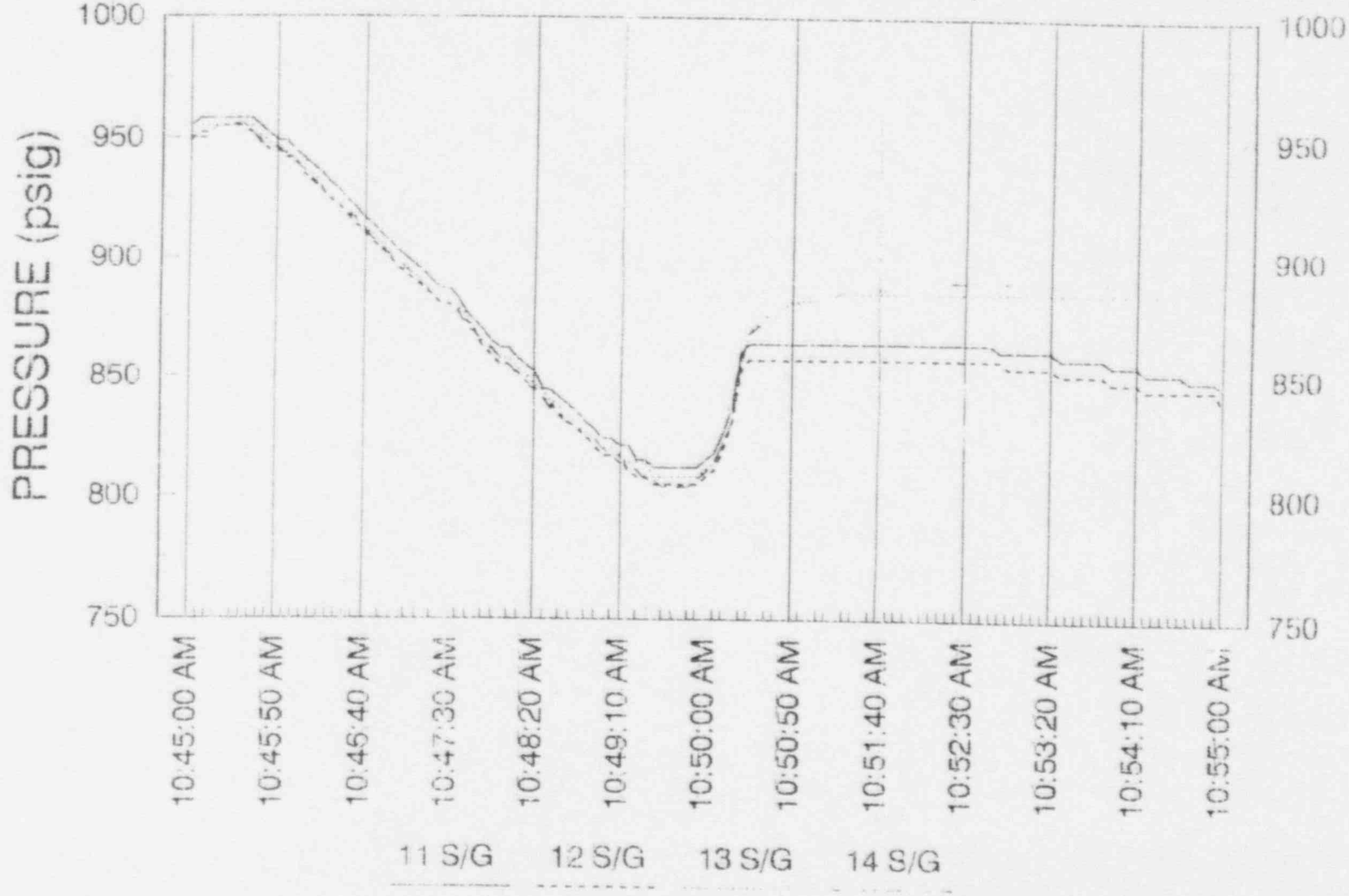
S/G NARROW RANGE % of span	11/21 UP	11/21 DWN	12/22 UP	12/22 DWN	13/23 UP	13/23 DWN	14/24 UP	14/24 DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								

S/G WIDE RANGE	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW	✓		✓		✓		✓	
VERY SLOW								

S/G PRESSURE PSIG	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW		✓		✓	✓		✓	
VERY SLOW								

★ 11+12 MS167s Open

SALEM UNIT 1 TRIP/SI APRIL 7, 1994



REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

SYSTEM TRENDS

(21) STEAM GENERATOR FEED WATER & STEAM FLOW TRENDS

Check box that best describes the rate and direction

FEED WATER FLOW %	11/21		12/22		13/23		14/24	
	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								

STEAM FLOW %	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								

COMMENTS: All Steam Generator Levels dropped rapidly during the trip and recovered slowly with Auxiliary Feedwater flow.
Steam Generator Pressures dropped slowly until the MSIVs were all closed, and then increased slowly with increasing Tave. Initially Steam Gen Pressures had increased due to the plant trip.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

(22) REACTOR TRIP INITIATION

✓ a. Automatic ✓ First Out Alarm F-9 POWER RANGE LOW SETPOINT TRIP

- Does the first out alarm agree with the P-250 Pre/Post Trip Review print out obtained in section 2, If No explain in detail. Yes ✓ No___

- Document any discrepancies found between the P-250 Pre/Post Trip Review print out and the "Standards"

N/A

N/A b. Manual ___ Explain reason for manual actuation

First Safety Injection.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

(23) SAFETY INJECTION INITIATION

✓ a. Automatic, First Out Alarm None

- Does the first out alarm agree with the P-250 Pre/Post Trip Review print out obtained in section 2, Yes___ No ✓ If No explain in detail.

- Document any discrepancies found between the P-250 Pre/Post Trip Review print out and the "Standards"

Safety Injection OHA F-21 High Steam Flow with Low-Low Tave did not alarm on BETA
Several Train B valves (12CA330, 1CV68, 1CV41, 1SJ2 1SJ12, 11-14BF13, 1CV284)
did not actuate automatically and required manual positioning during
the appropriate EOP-TRIP-1 step in the procedure.
11 and 12 MS167 did not close as required on the Main Steam Isolation
11 and 12 SGFP did not trip as required on the Safety Injection Signal.
Red light for 'SI and FW Isol' was blinking on 1RP4 Status Panel prior to reset.
Blue light for 'Auto SI Block' was blinking on 1RP4 Status Panel after SI reset.
Train B did not require resetting on ESFAS Panel.

N/A b. Manual, explain reason for manual actuation

✓ c. If water was actually injected into the RCS:

- Attach a copy of Table ~~4~~ 2, EOP-TRIP-3.

- UNIT 2 ONLY comply with T/S 4.4.7.2(d) Check Valve Leak Rate Test.

(24) Were there any annuniciated alarms which were unusual for the event? Yes ____ No ✓ If Yes, explain in detail.

(25) Were there any alarms which should have annuniciated but did Not? Yes ✓ No ____ . If Yes, explain in detail.

See 23 Above.

Cond. ~~ldo~~ lo-lo alarm (OHA) came in but cond lo did not.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

(26) Review recorder charts, record and explain any discrepancies, unusual or Not understood trends in the space provided below.

Discrepancies Noted Yes ✓ No ____

WR temp - Tc went > TH when safetyes lifted. All but 11 loop.

(27) Is there any equipment out of service which would prevent the unit from being returned to service Yes ✓ No ____ ? If Yes, explain in detail.

SSPS train B Δ (see attached sheet)

Low P_{PZR} S.I.

POST REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 2, SEQUENCE OF EVENTS CHECKLIST
INSTRUCTIONS

The Sequence of Events Checklist is the transfer of data from the P-250 Sequence of Events print out. For each of the alarms on the checklist the absolute start and differential time is calulated and entered in the space provided. These times are compared to the (maximum allowable) Technical Specification response times to ensure the protection system response(s) were within acceptable limits.

The P-250 computer header "SEQ OF EVENTS" is in absolute time hours:minutes:seconds and a cycle count. The time is for specific group of alarms associated with that header. The header cycle count must be applied to each alarm's cycle count to obtain the absolute time for each alarm. It should be noted that hours may not exceed 24 and minutes seconds & cycles may not exceed 60.

Attachment C of this procedure contains examples of calulating the absolute and differential times.

To perform this, use the following guidelines

I. Convert the alarm into a hours/minutes/seconds/cycle format.

A. Add the subsequent alarm cycles to the "SEQ OF EVENTS" header cycle count.

1. If the sum of the cycles is < 60 cycles then add the number of cycles to the "SEQ OF EVENTS" header time to obtain the absolute time for the alarm. Subtract the Initiating Events absolute time from the alarm's absolute time to obtain the delta (differential) time. Record these times on the Checklist.

2. If the sum is > 60 convert the cycles to seconds & cycles by:

a. Divide the cycles by 60, drop any digits after the decimal point. This is the number of the cycles in seconds.

b. Multiply the seconds (from a.) by 60 then subtract the result from the total cycle count. This is the remaining cycles.

c. Add the seconds & cycles to the "SEQ OF EVENTS" header time. This is the "absolute" time for the alarm and is recorded on the Checklist.

e. Subtract the Initiating Event absolute time from the alarm's absolute time. This is the delta (differential) time to be recorded on the Checklist.

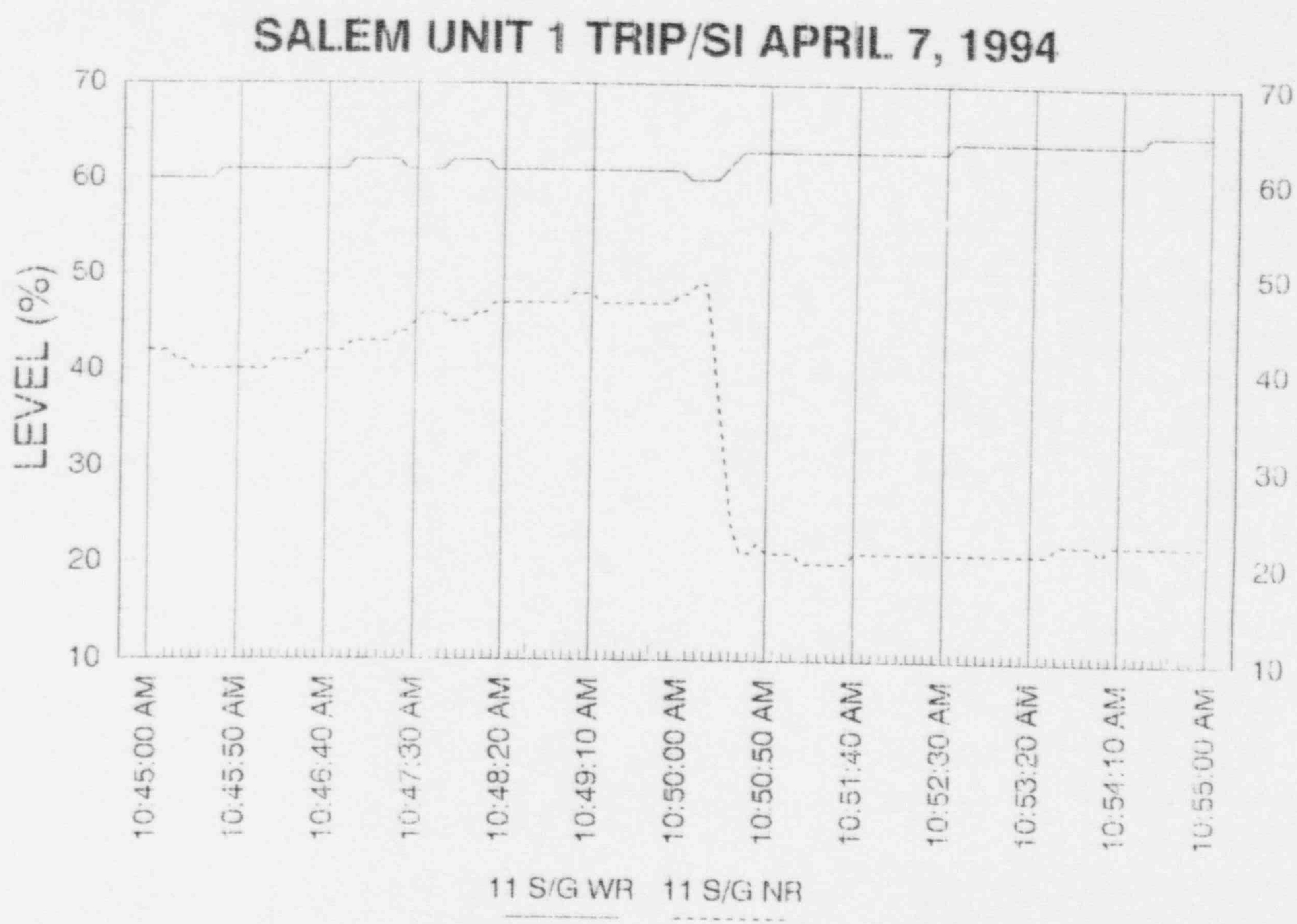
f. Compare the values recorded to the Standards. Record any Feed Pump data on page 3. Document discrepancies on page 4 under comments.

REACTOR TRIP / SAFETY INJECTION REVIEW REPORT
REACTOR TRIP SEQUENCE OF EVENTS CHECKLIST

Reactor Trip ___ Safety Injection X . Did the ECCS actually inject into the RCS, yes X no ?
Initiation Auto X . OHA First Out E5 Pressurizer Pressure Low * Manual X
Event Initiated @ 11 : 26 : 09 cycle count 1039 Rx.Trip/SI initiated @ 11 : 26 : 26 : 19

Sequence of Events Subsequent Alarms	Alarm Signals initiated into sequence hrs.	min.	sec.	cyc.	Event / Alarm signal difference min	sec	cyc	max. allowable TECH SPEC response time
REACTOR MAIN TRIP BKR A TRIP	:	:	:		:	:		
REACTOR MAIN TRIP BKR B TRIP	:	:	:		:	:		< 10 cycles
REACTOR TRIP AUX1 BKR A TRIP	:	:	:		:	:		< 10 cycles
REACTOR TRIP AUX1 BKR B TRIP	:	:	:		:	:		< 10 cycles
SHUNT RELAY A TRIP TRIP	:	:	:		:	:		< 10 cycles
SHUNT RELAY B TRIP TRIP	:	:	:		:	:		#< 10 cycles
REACTOR MAN TRP 1 TRIP	11	27	25	30	00	59	11	#< 10 cycles
SI REACTOR MAN TRP 2 TRIP	11	26	41	04	00	14	45	< 30.0 seconds
TURBINE STOP VA 11(21) CLOSED	:	:	:		:	:		< 30.0 seconds
TURBINE STOP VA 12(22) CLOSED	:	:	:		:	:		< 1 sec:30 cyc
TURBINE STOP VA 13(23) CLOSED	:	:	:		:	:		< 1 sec:30 cyc
TURBINE STOP VA 14(24) CLOSED	:	:	:		:	:		< 1 sec:30 cyc
TURBINE TRIP TRIP	:	:	:		:	:		< 1 sec:30 cyc
TURBINE REMOTE EMERG TRIP TRIP	:	:	:		:	:		< 10 cycles
								< 60 cycles

* The P-250 Sequence of Events print out should agree with the OHA, explain any discrepancies in Post Trip portion of this procedure. If the ECCS (Unit 2 ONLY) did inject see T/S 4.4.7.2(d)
\# If >6 cycles, document in Section 3 step 22 and notify the System Engineer.


SALEM UNIT 1 TRIP/SI APRIL 7, 1994
LEVEL (%)
70
60
50
40
30
20
10
10:45:00 AM
10:45:50 AM
10:46:40 AM
10:47:30 AM
10:48:20 AM
10:49:10 AM
10:50:00 AM
10:50:50 AM
10:51:40 AM
10:52:30 AM
10:53:20 AM
10:54:10 AM
10:55:00 AM
11 S/G WR
11 S/G NR

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SAFETY INJECTION SEQUENCE OF EVENTS CHECKLIST

FEED PUMP DATA

MOTOR DRIVEN AUX FEED PUMPS

Direct start signal on a SI or on any single S/G Lo-Lo level trip signal

Subsequent Alarm	Alarm Signal Initiated into sequence				Event / Alarm signal difference			Alarm Standard Expected time difference
	hrs	min	sec	cyc	min	sec	cyc	
11(21) AUX FW PUMP START	:	:	:	N	:	:		< 10 cycles
12(22) AUX FW PUMP START	:	:	:		A :	:		< 10 cycles

STEAM DRIVEN AUX. FEED PUMPS

Only on 2 S/G Lo-Lo Levels Trip Signals

Subsequent Alarm	hrs	min	sec	cyc	min	sec	cyc	Alarm Standard
13(23) AUX FW PUMP TURB STOP VA NT CL	:	:	:	N	A :	:		< 30.0 seconds

MAIN FEED PUMPS

Trip Manual ___ Auto ___, if "auto" record the "First Out Alarm"
(Main Feed Pumps receive a direct Trip from a SI initiation or from any S/G Hi-Hi evel.)

Subsequent Alarms	hrs	min	sec	cyc	min	sec	cyc	Alarm Standard
11/21 SGFP TURB LP CONT VA CL	:	:	:		:	:		< 5.0 seconds
11/21 SGFP TURB HP CONT VA CL	:	:	:	N	:	:		< 5.0 seconds
12/22 SGFP TURB LP CONT VA CL	:	:	:		A :	:		< 5.0 seconds
12/22 SGFP TURB HP CONT VA CL	:	:	:		:	:		< 5.0 seconds

2ND S.I. Low P_{PZR} S.I.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3. POST TRIP CONDITIONS

PLANT STATUS

SAFETY SYSTEM ACTUATION	TIME	ACTUATION SIGNAL	TRAINS
Reactor Trip	10:47:44 0005	POWER RANGE Hi FLUX LOW SETPOINT	
Turbine Trip	10:47:44 0011	Rx TRIP	
Safety Injection #2	11:26:25 0025	Low PPZR PRESS	B ONLY*
Phase A Isolation	11:26:25 00025	SI	B ONLY
Containment Spray	N/A	N/A	N/A
Phase B Isolation	N/A	N/A	N/A
Main Steamline Isolation	N/A	N/A	N/A
Main Feedwater Isolation	N/A	N/A	N/A

*Manual Initiation from Train B after Auto Initiation, which actuated Train A.

1) **RCCA's Inserted**

a. Control Yes ✓ No___

b. Shutdown Yes ✓ No___

c. RCCA Not fully inserted N/A ___ ___ ___

2) **Reactor Coolant Pumps**

	11/21	12/22	13/23	14/24
a. In Service	✓	✓	✓	✓

3) **CVC Charging Pumps**

	11/21	12/22	13/23
a. In Service	✓	✓	No

4) **Safety Injection Pumps**

	11/21	12/22
b. In Service	✓	✓

5) **RHR Pumps**

	11/21	12/22
b. In Service	✓	✓

6) **Auxiliary Feed Pumps**

	11/21	12/22	13/23
b. In Service	✓	✓	No

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3. POST TRIP CONDITIONS

PLANT STATUS

7) **Containment F.C.U,s**

	11/21	12/22	13/23	14/24	15/25
a. High Speed					
b. low speed	✓	✓	✓	✓	✓

8) **Service Water Pumps**

	11/21	12/22	13/23	14/24	15/25	16/26
a. In Service	✓	No	No	✓	✓	No

9) **MS167s**

	11/21	12/22	13/23	14/24
a. Open				
b. Closed	✓	✓	✓	✓

10) **Circulator Pumps**

	11/21	12/22	13/23
a. In Service	A ✓ B No	A No B ✓	A No B No

11) **Condenser Steam Dump I/S** Yes___ No ✓ (MAIN STEAM LINE ISOLATED)

12) **Atmospheric Steam Dump**

a. In Service	11/21	12/22	13/23	14/24
• Auto	✓	✓	✓	✓
• Man				
• Isolated				

13) **Main Steam Safeties Lifted?** Yes ✓ No___ (INITIATING EVENT)

a. Loop 11/21 ✓ c. Loop 13/23 ✓

b. Loop 12/22 ___ d. Loop 14/24 ✓

14) **EHC system Runback** Yes___ No ✓

a. Power: from ______% to ______%

b. Time: from ______ to ______

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

PLANT STATUS

15) **RCS Pressure Control Response**

a. Pressurizer heater response Normal? Yes ✓ No ___

c. Pressurizer spray response Normal? Yes ✓ No ___

d. Pressurizer level control Normal? Yes ___ No ✓ PZR SOLID

e. Pzr PORV Actuated? Yes ✓ No ___

- 1/2 PR 1 ✓
- 1/2 PR 2 ✓

f. Pzr Safety Lifted? Yes___ No ✓ ? If Yes, attempt to identify the specific valve(s)

- 1/2 PR 3 ___
- 1/2 PR 4 ___ * Tailpipe temperature 220°F
- 1/2 PR 5 ___

16) **Pressurizer Control Status**

a) Block Valves

- 1/2 PR6 Open ✓ Closed ___
- 1/2 PR7 Open ✓ Closed ___

b) Controllers

- Master Auto ✓ Man ___
- Level Auto ✓ Man ___
- Spray Valves
  - 1/2 PS 1 Auto ✓ Man ___, Open___ Closed ✓
  - 1/2 PS 3 Auto ✓ Man ___, Open___ Closed ✓
- Heaters Auto ✓ Man ___
  - Bk. Up Grp. 11/21 I/S ___ O/S ✓
  - Bk. Up Grp. 12/22 I/S ___ O/S ✓ ~~B~~ A DUE TO LETDOWN ISOLATION

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

PLANT STATUS

17) ELECTRICAL SYSTEMS

a) Vital Buses

Vital Buses	Energized		from 13 SPT	14 SPT	EM.D/G
♦ "A" Vital Bus	Yes ✓	No	✓		
♦ "B" Vital Bus	Yes ✓	No		✓	
♦ "C" Vital Bus	Yes ✓	No		✓	

b) Group Buses

Group Buses	Energized	
♦ "E" Group	Yes ✓	No
♦ "F" Group	Yes ✓	No
♦ "G" Group	Yes ✓	No
♦ "H" Group	Yes ✓	No

c) Vital Instrument Buses

Vital Instrument Buses	Energized		from INV.	B-U
♦ "A" Instrument Bus	Yes ✓	No	✓	
♦ "B" Instrument Bus	Yes ✓	No	✓	
♦ "C" Instrument Bus	Yes ✓	No	✓	
♦ "D" Instrument Bus	Yes ✓	No	✓	

d) DC Buses

DC Buses	Energized		From Charger	Battery
♦ 28 VDC				
▪ "A" Bus	Yes ✓	No	✓	
▪ "B" Bus	Yes ✓	No	✓	
♦ 125 VDC				
▪ "A" Bus	Yes ✓	No	✓	
▪ "B" Bus	Yes ✓	No	✓	
▪ "C" Bus	Yes ✓	No	✓	
♦ 250 VDC Bus	Yes ✓	No	✓	

Any electrical problems significant to the event, or de-energized buss explain in detail the circumstances on following page.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

PLANT STATUS

ELECTRICAL SYSTEMS

Explain in detail the circumstances for any question answered Yes on the preceeding page. Indicate if the electrical distribution problems or out of service electrical components were significant to the event and/or impeded placing the plant in a stable condition. Include the observations and actions of individuals and the adequacy of procedures. Use additional sheets as necessary.

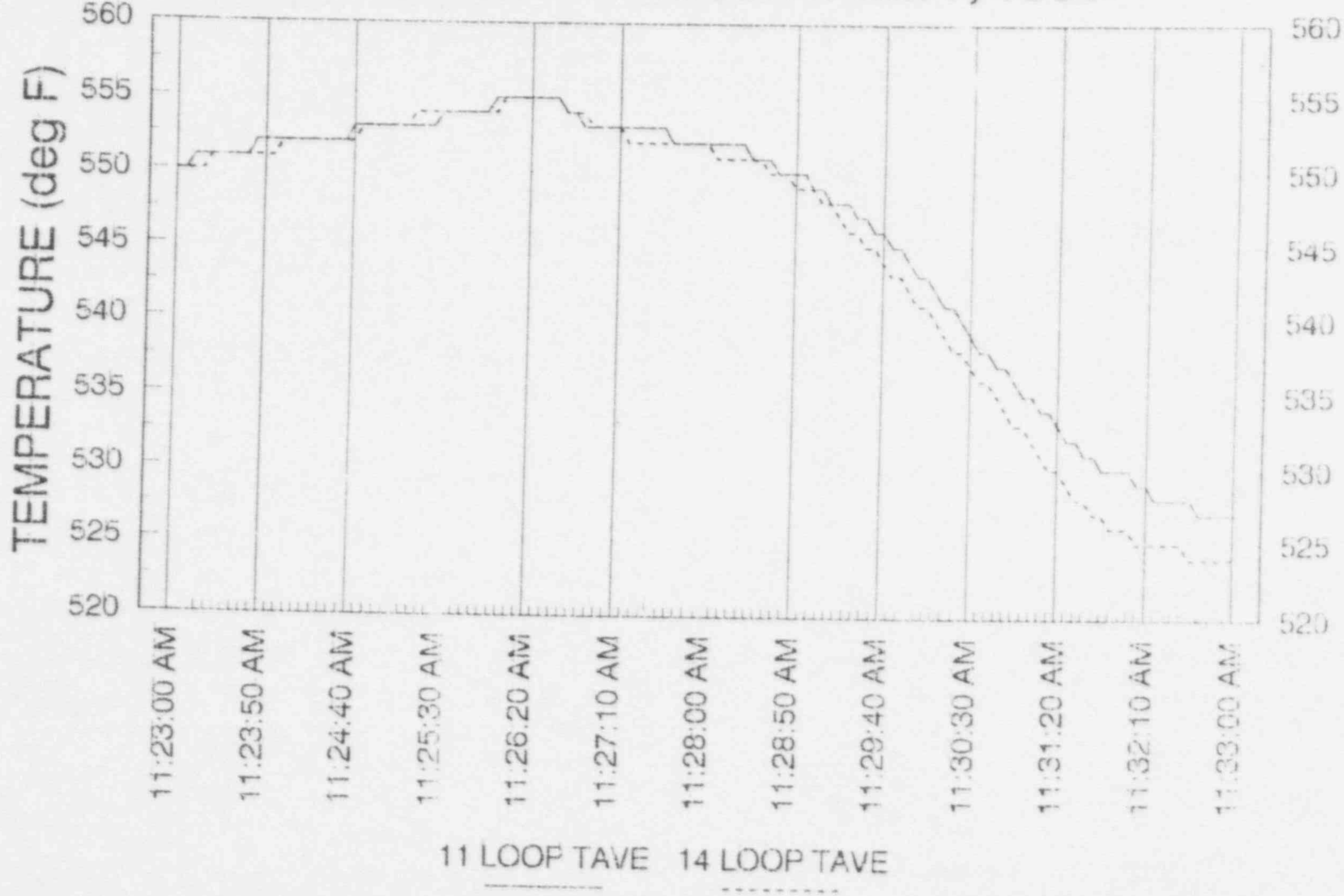
SEE pg. 16 of INITIAL S.I. (4. SF COINC w/ LL T_{ave})

SYSTEM TRENDS

18) REACTOR COOLANT SYSTEM LOOP TEMPERATURE TRENDS

Check box that best describes the rate & direction	REACTOR COOLANT SYSTEM LOOP TEMPERATURE TREND							
	11/21		12/22		13/23		14/24	
AVERAGE (Tavg)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								
HOT LEG (Th)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								
COLD LEG (Tc)	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								

SALEM UNIT 1 TRIP/SI APRIL 7, 1994



REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3. POST TRIP CONDITIONS

SYSTEM TRENDS

19) PRIMARY SYSTEMS PRESSURE TRENDS

Check box that best describes the rate and direction	PRESSURIZER TRENDS					
	LEVEL		PRESS		SPRAY	
	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE						
VERY FAST						
FAST			✓			
STABLE	actual level ↓ but indicated level remained >100%					
SLOW					Closed initially then opened as Pzr ↑	
VERY SLOW						

Check box that best describes the rate and direction	REACTOR COOLANT SYSTEM PRESSURE TREND LOOP HOT LEG PRESSURE			
	WIDE RANGE		NARROW RANGE	
	UP	DOWN	UP	DOWN
STEP CHANGE				
VERY FAST	✓			
FAST				
STABLE				
SLOW			off scale - High	
VERY SLOW				

Comments RCS temps ↓ rapidly when 11 SG safety valve opened causing RCS press to ↓ rapidly (RCS was water solid). Following the low Pzr SI + the closure of the open safety valve (SG), RCS temps trended slowly upward to ~ 540°F and the PZR went water solid again causing a rapid ↑ in RCS press. Pressurizer Level remained greater than 100% indicated since the level taps are some distance below the top of the pressurizer.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

SYSTEM TRENDS

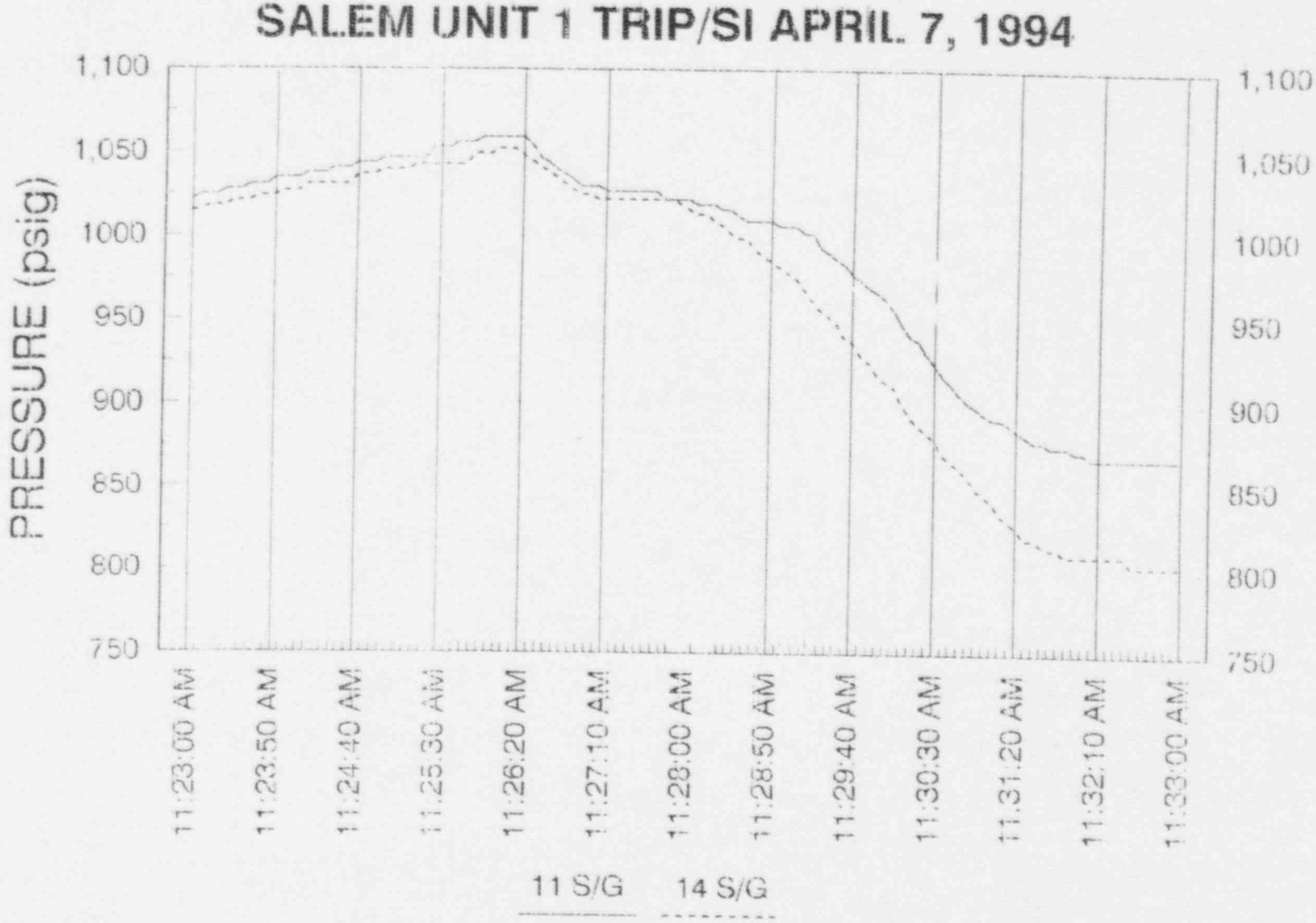
(20) STEAM GENERATOR LEVEL & PRESSURE TRENDS

Check box that best describes the rate and direction

S/G NARROW RANGE % of span	11/21 UP	11/21 DWN	12/22 UP	12/22 DWN	13/23 UP	13/23 DWN	14/24 UP	14/24 DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW	✓		✓		✓		✓	
VERY SLOW								

S/G WIDE RANGE	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW	✓		✓		✓		✓	
VERY SLOW								

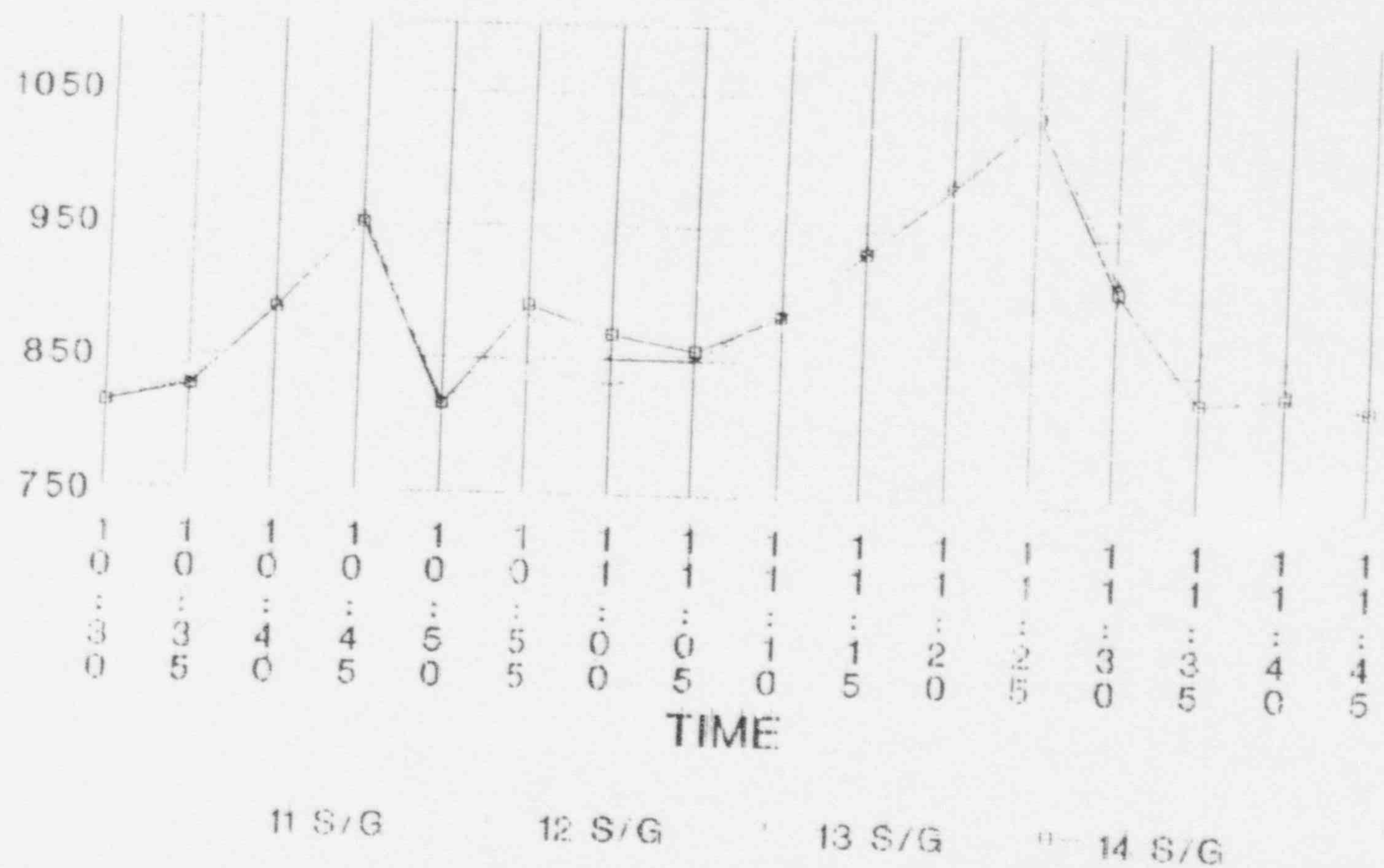
S/G PRESSURE PSIG	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST								
FAST		✓		✓		✓		✓
STABLE								
SLOW								
VERY SLOW								



SALEM UNIT 1 TRIP/SI APRIL 7, 1994
PRESSURE (psig)
1,100
1,050
1000
950
900
850
800
750
11:23:00 AM
11:23:50 AM
11:24:40 AM
11:25:30 AM
11:26:20 AM
11:27:10 AM
11:28:00 AM
11:28:50 AM
11:29:40 AM
11:30:30 AM
11:31:20 AM
11:32:10 AM
11:33:00 AM
11 S/G
14 S/G

UNIT 1 TRANSIENT APRIL 7, 1994

Steam Pressures



REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

SYSTEM TRENDS

(1) STEAM GENERATOR FEED WATER & STEAM FLOW TRENDS

Check box that best describes the rate and direction

FEED WATER FLOW %	11/21 UP	11/21 DWN	12/22 UP	12/22 DWN	13/23 UP	13/23 DWN	14/24 UP	14/24 DWN
STEP CHANGE								
VERY FAST								
FAST								
STABLE								
SLOW	off scale		off scale		off scale		off scale	
VERY SLOW								

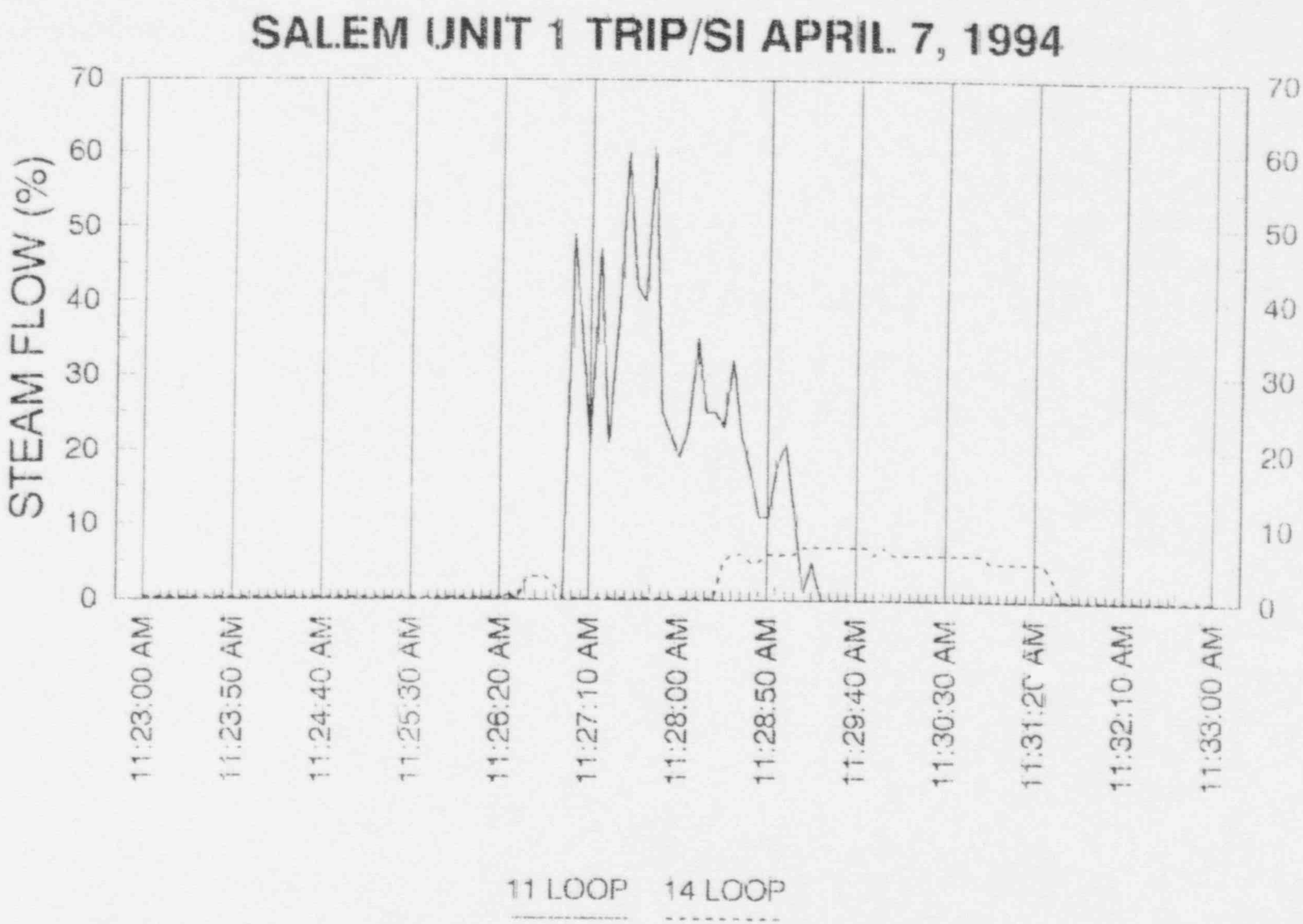
STEAM FLOW %	UP	DWN	UP	DWN	UP	DWN	UP	DWN
STEP CHANGE								
VERY FAST							*	*
FAST								
STABLE	✓		✓		✓		✓	
SLOW								
VERY SLOW								

COMMENTS: * 14 SG steam flow spiked ~ 15-20 min after SI indicating MS-10 relieving press.

11 S/G steam flow was oscillating at ≈ 60% - 70% during the time safeties were lifting.

Steam Generator Levels (NR) rapidly increased, then decreased during the lifting of the safety valves

Steam Generator Levels (WR) rapidly decreased, then slowly increased during the safety valve lifting



SALEM UNIT 1 TRIP/SI APRIL 7, 1994
STEAM FLOW (%)
0
10
20
30
40
50
60
70
11:23:00 AM
11:23:50 AM
11:24:40 AM
11:25:30 AM
11:26:20 AM
11:27:10 AM
11:28:00 AM
11:28:50 AM
11:29:40 AM
11:30:30 AM
11:31:20 AM
11:32:10 AM
11:33:00 AM
11 LOOP
14 LOOP

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

(22) REACTOR TRIP INITIATION - N/A - Rx tripped as initial conditions

___ a. Automatic ___ First Out Alarm___

- Does the first out alarm agree with the P-250 Pre/Post Trip Review print out obtained in section 2, Yes___ No___ If No explain in detail.

- Document any discrepancies found between the P-250 Pre/Post Trip Review print out and the "Standards"

N/A

___ b. Manual ___ Explain reason for manual actuation

N/A

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

23) SAFETY INJECTION INITIATION

✓ a. Automatic, First Out Alarm F-5 PZR PRESSURE LOW

- Does the first out alarm agree with the P-250 Pre/Post Trip Review print out obtained in section 2, Yes ✓ No___ If No explain in detail.

- Document any discrepancies found between the P-250 Pre/Post Trip Review print out and the "Standards"

✓ b. Manual, explain reason for manual actuation

Manual SI directed by NSS at approx 1800 psig with press rapidly ↓; NCO initiated SI manually on Train B.

✓ c. If water was actually injected into the RCS:

- Attach a copy of Table ~~1~~ 2, EOP-TRIP-3.

- UNIT 2 ONLY comply with T/S 4.4.7.2(d) Check Valve Leak Rate Test.

TABLE 2 EOP-TRIP-3

POST SAFETY INJECTION DATA

Initial Pressurizer Level	On program	%
Final Pressurizer Level	> 100	%
Initial Pressurizer Pressure	~1800 ↓	PSIG
Final Pressurizer Pressure	2100	PSIG
Initial Tavg	524	F
Final Tavg	540	F
RWST Temperature (T0650A)	97°	F
Duration of Safety Injection	18 (first)	Min.
	15 (second)	min

Total Gallons Injected - 8500 Gallons
RWST (Δ Level) - 1.0 ft.

Recorded by S.D. Simpson Date 04-07-94

Reviewed by [signature] Date 4-7-94
Senior Shift Supervisor/Shift Supervisor

(24) Were there any annuniciated alarms which were unusual for the event? Yes ____ No ✓ If Yes, explain in detail.

(25) Were there any alarms which should have annuniciated but did Not? Yes____ No✓ . If Yes, explain in detail.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

(26) Review recorder charts, record and explain any discrepancies, unusual or Not understood trends in the space provided below.

Discrepancies Noted Yes____ No ✓

(27) Is there any equipment out of service which would prevent the unit from being returned to service Yes ✓ No____ ? If Yes, explain in detail.

- DRT Rupture Disk
- Circulators / Screens

See Attached sheet

(28) EVENT DISCRIPTION

Describe the sequence of events which led to the initiation of the event and the actions performed to place the plant in a stable condition. Include the observations and actions of specific individuals and the adequacy of the procedures used. The individuals involved in the event should meet together to have a critique of the event to help reconstruct the event as it occurred. This description should be a result of that critique.

See Attached Sheets.

Section IV Analysis of Incident

Sequence of Events

I. Load Reduction due to grass problems at Circulating Water Structure

Initial Conditions - 73% Reactor Power, 800 MWe, T_{ave} at 562 ^{o}F, Bank D at 195 steps, rods in Manual

[All times normalized to BETA times]

Salem Unit 1 reduced electric power output (750 MWe) at 0913 hours due to the 12 Heater Drain Pump being taken out of service and 12CN27 going closed. This valve was subsequently opened manually by the secondary NEO. At approximately 10:14 hours, the control operator noticed a high differential pressure on the 13B Circulator as indicated on 1RP5 status panel. 13B Circulator emergency tripped two minutes later on high differential pressure before the circulator had stopped in the normal method. Load was reduced from 750 MWe to 80 MWe over the next thirty minutes at increasing rates from 1% per minute to 8% per minute. 12A Circulator was in the process of being returned to service from cleaning and was being primed at the time of the event. During this time, circulators were cycled in and out of service as follows:

1. 13B Circulator tripped at 10:16:19 hours
2. 13A Circulator tripped at 10:26:55 hours
3. 12A started and tripped at 10:34 hours
4. 13A restarted at 10:35:46 hours
5. 13B restarted at 10:38:49 hours
6. 11B and 11A tripped at 10:39:08 hours
7. 13A tripped at 10:43:48 hours
8. 13B tripped at 10:46:11 hours
9. 11A restarted at 10:46:26 hours

11A X —
B X
12A X
B
13A X — X
B X — X

The lowest condenser vacuum appears to have been 21.67 in Hg at approximately 10:42 hours. Prior to the reactor trip, 11A and 12B Circulators were in service. The crew was preparing to take the turbine off-line due to the low condenser vacuum (24.55 in Hg) and unavailability of circulators.

At 10:42:26 hours, the P-8 permissive on Reactor Coolant loop flows automatically reset to its two-of-four loop trip logic. Following shortly thereafter, the P-10 permissive reset at 10:45:04 hours due to the reduction of reactor power as seen by the Power Range channels less than 10% reactor power. This permissive reinstates the low setpoints (25%) for the Power Range and Intermediate Range High Neutron Flux trips, as well as the control rod withdrawal stop at 20% on the Intermediate Range. The reactor power was stabilized at 7% power and 80 MWe following the rapid load decrease.

II. Low Power Operations

In preparation for taking the turbine off-line, the NSS directed the control operator on the rods to swap the Auxiliary Power Transformer to the 11 and 12 Station Power Transformers. At this time, the RCS average temperature was still high as indicated on the T_{error} recorder (563 ^{o}F), so a 100-gallon boration was in progress. RCS average temperature started decreasing at approximately 10:40 hours and decreased less than 554 ^{o}F at 10:41:38 hours. RCS temperature was less than 547 ^{o}F at 10:45:38 hours. A minimum RCS temperature of 530 ^{o}F was reached at 10:48:50 hours, when the control operator started pulling control rods.

After the transformers had been transferred to the station power transformers, the desk control operator returned to the rod control. At some time after his return to the control rods, the desk operator initiated another 100-gallon boration to restore T_{ave} (553 ^{o}F at 10:44:30 hours) to normal temperature (550 ^{o}F) for approximately 8% power.

At 10:48:52 hours, the desk operator started to withdraw control rods to restore T_{ave} to normal. T_{ave} had decreased to approximately 530 ^{o}F. As the control operator withdrew the rods from 50 steps to 95 steps, reactor power increased from 8% to more than 23.6% at 10:48:52 hours to 10:49:43 hours. T_{ave} increased from 531 ^{o}F to 537 ^{o}F from 10:49:16 hours to 10:49:43 hours. X

III. Reactor Trip - First Safety Injection

The reactor tripped at 10:49:45 hours due to N42 and N44 Power Range channels seeing greater than 25% power. Since the P-10 permissive had cleared when three of four channels had been reduced below 10% power, the low range trip setpoints had been reinstated for the Power Range and Intermediate Range channels. Within one second following the trip, a safety injection occurred due to the high steam flow bistables actuating on all four steam lines at 10:49:46 hours for two cycles. It is postulated at this time that this may be caused by a pressure pulse returning along the steam lines across the steam flow transmitters due to the rapid closure of the turbine stop valves. Due to the short duration of this signal, Train A of SSPS actuated but not Train B.

The 1B Diesel "Urgent Trouble" alarm illuminated on the overhead annunciator at 10:49:57 hours and the STA requested the NSSF to investigate the cause of the alarm. The NSSF found that the low Starting Air Pressure was illuminated on the local 1B Diesel Panel and reported this information back to the shift supervisor. This alarm was acknowledged and reset, since the starting air compressor had restored pressure to normal.

The fact that Train B did not pick up the Safety Injection signal was confirmed by several associated motor-operated valves that did not stroke and the flashing red light on the 1RP4 status panel for the "SI & FW ISOL" bezel. The valves (1CV68, 1CV41, 1SJ12, 1CV284, 1SJ2, 12CA330 and 11-14BF13) were placed in their safeguards position in accordance with EOP-TRIP-1 step 9. With the initiation of the safety injection on Train A, the Control Room ventilation transferred to "Accident inside Air" mode as indicated on 1RP2 status panel. However, the redundant components from Train B did not actuate on Unit 1 or Unit 2.

Following the reactor trip and safety injection, RCS temperature decreased to approximately 527 ^{O}F due to the injection of cold ECCS water and the subsequent cooldown from the secondary side. When the procedure step for the control of RCS temperature was reached, two of the Main Steam Isolation valves were already closed due to the signal from the safety injection (High Steam flow with Low-Low T_{ave}). In accordance with the procedure, the control operators initiated Main Steam Isolation from the CC1 panel, which closed the 11 and 12 MS167s to stop any further cooldown. Also, both Steam Generator Feedwater pumps were tripped manually by the control operator during the appropriate procedure step.

An Unusual Event was declared at 1100 hours in accordance with Section 18C of the Emergency Classification Guide due to the injection of ECCS water into the reactor vessel. The appropriate notifications were made within the proper time frames to the outside agencies.

After closure of the Main Steam Isolation valves at 10:58 hours, RCS temperature started increasing slowly. Pressurizer level and pressure were also increasing due to the Charging pumps injecting. Safety injection was reset at 11:05 hours and the Charging flow was reduced to one pump at 11:08:53.

At 11:05 hours, the operators entered EOP-TRIP-3, Safety Injection Termination, in order to reset the Safety Injection. As they worked through the procedure, the control operator noticed that the Train B Safety Injection was not actuated, but pushed the "Reset" button in accordance with the procedure. This caused the flashing red light (SI & FW ISOL) to extinguish and the flashing blue light (AUTO SI BLOCK) to illuminate. All the ECCS pumps were secured by 11:14:17 hours and normal charging was in service. While the control operators were in the process of restoring letdown in accordance with the procedure the Pressurizer level and pressure were increasing. At 11:07:51 hours, Pressurizer level increased above the 92% high-high level setpoint.

The Pressurizer pressure increased above 2335 psig and both PORVs lifted for the first time at 11:18:38 hours. The PORVs lifted numerous times over the next forty minutes until 11:56:19 hours.

IV. Second Safety Injection

RCS temperature was stable at 527 °F until 11:02:37 hours which correlates roughly to the closure of the Main Steam Isolation valves at 10:58 hours. RCS temperature continued to increase above 547 °F at 11:20:07 hours. As RCS temperature increased, the Steam Generator pressures increased until they reached the lift setpoint for the first safety valve on 11 Steam Generator. The 11MS15 initially lifted at 11:25:56 hours. Over the next two and one-half minutes, at least one safety valve was lifting on 11 Main Steam loop. When the NSSF went to the roof to inspect which safety valves were lifting, he noticed that 13MS15 and two plumes of steam on 11 Steam Generator loop were blowing. In less than a minute, the 13MS15 had reseated, and he returned to the Unit 1 control room to report his findings. The highest RCS temperature observed was 555.7 °F on 12 Main Steam loop. Following the lifting of the safety valve(s), RCS temperature and pressure dropped rapidly.

As the shift crew observed the sharp drop in RCS temperature and pressure, they were aware that they could still get the automatic safety injection from Train B. Since they could not get the safety valve(s) closed, they were making preparations to manually initiate the safety injection. However, the automatic safety injection occurred on low Pressurizer pressure, and was picked up on the overhead annunciator F-5 at 11:28:26 hours. The control operator did initiate the manual safety injection on Train B approximately fifteen seconds after the automatic signal. This signal also picked up Train A safety injection equipment. In accordance with procedures, the crew returned to EOP-TRIP-1 and performed the immediate actions and safety injection verification. Two of the valves, 1CV68 and 12CA330, which had been repositioned after the first safety injection did move to their safeguards position during this second actuation. The control operator initiated the manual reactor trip approximately forty-five seconds after the manual safety injection initiation.

The reason for the rapid drop in RCS pressure can be attributed to the cooling of the RCS due to the safety valve lifting. Since the RCS was essentially solid prior to this second safety injection, a small change in RCS temperature caused a large change in RCS pressure. During the time frame of the safety valve lifting, the control operator attempted several times to get the MS10s to respond in the "Automatic" mode, but eventually manually opened the valves, until the safety valve(s) reseated.

The 1B Diesel "Urgent Trouble" alarm illuminated again on the overhead annunciator at 11:28:38 hours and the STA requested the NSSF to investigate the cause of the alarm. The equipment operator found that the low Starting Air Pressure was illuminated on the local 1B Diesel Panel and reported this information back to the shift supervisor. This alarm was acknowledged and reset, since the starting air compressor had restored pressure to normal. The console "Diesel Trouble" alarms had illuminated on all the diesels and is currently under investigation.

The shift crew completed the EOP-TRIP-1 procedure for the second time at 11:41 hours and entered EOP-TRIP-3 for the second resetting of safety injection. The control operator noticed that, at this time, both trains of safety injection required resetting and the blue light on the 1RP4 status panel was now solid. Both trains of SSPS had their automatic safety injection outputs blocked due to the automatic actuations on both trains. However, the manual actuation signal was still operable from either train. Therefore the shift entered the appropriate action statement at 11:41 hours for the SSPS inoperability.

V. Short Term Recovery Phase

The shift crew recognized that the Pressurizer was solid and that a bubble would need to be drawn in the Pressurizer prior to cooldown. At 11:49 hours, the Pressurizer Relief Tank (PRT) rupture disk blew out due to the pressure in the tank exceeding 90 psig, while level in the PRT was 82%. Without the steam bubble in the Pressurizer, the Technical Specification requires that the unit be placed in Hot Shutdown in six hours. Also with both trains of automatic safety injection blocked, the limiting condition for the SSPS operability was exceeded. The Technical Specification 3.0.3 was entered which also required the plant to be placed in Hot Shutdown within six hours.

In order to restore the operability of the Pressurizer, the steam bubble had to be reestablished which would take several hours. Without initiating the cooldown immediately, the unit would end up being cooled down at 100 ^{O}F per hour in order to meet the applicable action statement times. This transient was deemed undesirable by station management because it would unduly challenge the plant and personnel with no net safety gain. Therefore, station management decided to request discretionary enforcement from the NRC in order to allow an orderly cooldown. This additional twelve-hour timeframe allowed the degas and cooldown of the RCS at the same time, as well as the completion of the normal surveillance requirements for entry into Hot Shutdown (Mode 4).

VI. Longer Term Recovery Phase

The Emergency Duty Officer (EDO) relieved the SNSS of Emergency Coordinator duties at 12:08 hours. Since the Pressurizer was water solid at the time and no procedures were directly applicable with the Reactor Coolant Pumps in service, the EDO and General Manager decided to call a precautionary Alert. The purpose of this Alert was to assemble the appropriate engineering expertise in the Technical Support Center to deal with any unexpected perturbations during the cooldown. Although the Emergency Action Levels did not require the escalation to an Alert level, there was no other mechanism within the Emergency Plan procedures to assemble the required engineering people. The Alert was declared at 13:16 hours in accordance with ECG Section 17B and the appropriate notifications to the outside agencies were made in the proper time frames.

At 1630 hours, EOP-TRIP-3 was exited with three open items on the 12 SGFP turning gear, the RWST level, and the BAST level and IOP-6 was entered for the cooldown. In order to get the steam bubble drawn in the Pressurizer, the heaters were energized and the temperature of the Pressurizer fluid was raised from 560 ^{O}F to 650 ^{O}F. The reestablishment of the steam bubble lasted from 13:00 hours to 15:00 hours. After the Pressurizer steam space reached saturation, the shift initiated the draining of the Pressurizer. The Pressurizer level returned on scale at 15:11 hours and reached 50% level at 16:23 hours. While the crew was establishing the steam bubble, the boration for the Cold Shutdown condition was established.

The RCS boron concentration of 1469 ppm was established at 16:20 hours and the transition was made from EOP-TRIP-3 to IOP-6 for the cooldown. Preparations for the cooldown were completed at 17:15 hours and RCS cooldown proceeded at approximately 25 ^{O}F per hour. During the initial stages of the cooldown, the 12 Steam Generator was being used as the primary method for the cooldown. Due to the unreliable operation of the 11MS10 during the event, the valve was left in "Manual" and "Closed". At 18:00 hours, the STA noticed that one of the bistables on the steamline differential pressure was illuminated on the RP4 status panel indicating that 12 Steam Generator was 100 psi less than 11 Steam Generator. The STA immediately drew the NCO's attention to this fact and the steaming rate on 12 Steam Generator was reduced to 20 ^{O}F per hour. Subsequently, the NSS for the unit was notified of this problem.

The shift turnover for the shift crew was monitored by the Operations management for completeness in the transfer of information on the plant status. Some of the specific items were the status of various equipment and the time frames to comply with the license requirements as a result of the discretionary enforcement. At 20:20 hours, the Alert was terminated and the various facilities were demobilized. shortly thereafter.

The cooldown to Mode 4 proceeded without incident in accordance with IOP-6. The POPS functionals were completed at 22:07 hours and the RCS degasification was being performed concurrently. Salem Unit 1 entered Hot Shutdown (Mode 4) at 01:06 hours. The RHR system was placed in service 06:00 hours and the cooldown to Cold Shutdown (Mode 5) was reached at 11:24 hours on 8 April 1994.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 3, POST TRIP CONDITIONS

(29) PERSONNEL STATMENT (continued)

Name ______________________ Badge # _____ - _____

PAGE ___ of ___

POST REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 4, ROOT CAUSE DETERMINATION

This section is a guideline used to identify the events Root Cause and other contributing factors. Only those Categories that are specific or contributory to the event need to be completed.

ROOT CAUSE CATEGORIES.

A. Human Performance Problems
  1. Personnel involved
  2. Activity being performed
  3. Procedure Compliance
  4. Response and/or actions taken
  5. Communication Deficiencies
  6. Work Place Deficiencies
  7. Planning & Scheduling Deficiencies
  8. Policy Implementation

B. Component Failure
  1. Components involved
  2. Component failure mode

C. Design Deficiencies
  1. Configuration
  2. Analysis

D. Manufacture/Construction Deficiencies
  1. Material
  2. Fabrication
  3. Assembly
  4. Components

E. Assembly/Installation Deficiencies
  1. Material
  2. Fabrication
  3. Assembly
  4. Components

F. External Causes
  1. Natural Causes
  2. Man-made Causes

G. Documentation Problems
  1. Type of Document
  2. Document Deficiency

H. Other/Undetermined
  1. Undetermined
  2. Other

POST REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 4, ROOT CAUSE DETERMINATION

A. **HUMAN PERFORMANCE**

1. Personnel Involved

✓ a. Employment Status

✓ ♦ Permanent Employee

___ ♦ Temporary Employee

___ ♦ Contract Personnel

✓ b. Operations Personnel

___ ♦ Operations Management

___ ♦ Work Control Center Staff

___ ♦ Operations Staff

✓ ♦ Shift Supervision

✓ ♦ Licensed Operator

___ ♦ Non-licensed Operator

N/A c. Maintenance Personnel

___ ♦ Supervision

___ Mechanical

___ Controls/Electrical

___ ♦ Technician

___ Mechanical

___ Controls/Electrical

N/A d. Miscellaneous Personnel

___ ♦ Technical

___ ♦ Security

___ ♦ Training

___ ♦ Site Services

___ ♦ Engineering

___ ♦ Relay Dept.

___ ♦ Other ______________________

POST REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 4, ROOT CAUSE DETERMINATION

✓ 2. Supervision

___ a. Lack of Supervision

___ b. Improper Supervision

✓ c. Other Resource Management

✓ 3. Lack of Knowledge / Training

___ a. Training not Effective

___ b. Training not Received

___ c. Training Incorrect

✓ d. Other Reactivity Manipulations and Low Power Operations

✓ 4. Type of Activity Being Performed

___ a. Start-up

___ b. Load Escalation

___ c. Routine Operation

___ d. Maintenance

___ e. Shutdown

✓ f. Load Reduction

___ g. Testing

___ Corrective ___ Emergent ___ Preplanned

___ Preventive ___ Unauthorized ___ Unplanned

5. Diagnosis, nature of the problem and the specific portion of the Activity during which problem occurred.

___ b. Preparation ____________________

✓ c. Performance Rapid Load Reduction, Low Power Operations

✓ d. Termination Recovery from First Safety Injection, Initial Cooldown from NOP/NOT

✓ 6. Surveillance & Monitoring

N/A a. Surveillance

___♦ Condition subject to discovery by surveillance

___♦ Surveillance performed properly

___♦ Surveillance performed improperly

___ out of sequence ___ improper line up

___ wrong component ___ wrong unit

✓ b. Monitoring

✓ ♦ Monitoring not performed

___♦ Monitoring performed properly

___♦ Adverse action on discovery by monitoring

___♦ Monitoring performed improperly

___ wrong component ___ wrong unit

___ wrong indication ___ misread indication

N/A c. Adverse action/condition not subject to discovery by surveillance testing and/or monitoring.

Describe ____

____

___ d. Other ____

N/A 7. Activity Verification Requirements

___ a. Verification not required

___ b. Verification required

___♦ Independent ___♦ Non independent

___ c. Verification performance

___♦ Improperly performed ___♦ Not performed

POST REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 4. ROOT CAUSE DETERMINATION

N/A 8. Procedure Use & Compliance

a. Type of Procedure in effect

___• Normal Operating ___• Maintenance

___• Abnormal Operating ___• Test/Calibration

___• Emergency Operating ___• Surveillance

___• Administrative ___• Trouble shooting

___• Permanent ___• Temporary

___• Other ______________________________

___b. Type of Deficiency:

___• Lack of a specific procedure for existing conditions

___• Failure to follow procedure when one existed

___• Correct procedure was used

___ Incorrect Revision ___ Erroneous Information

___ Poor Format ___ Incomplete Information

___• Improperly followed the correct procedure

___• Used the wrong procedure

___• Used unapproved procedure

___• Other ______________________________

Specific step, verbiage and deficiency ______________________________

____

____

____

____

____

✓ 9. Improper or Inadvertent Actions

✓ a. No response or action was provided when one was required because:

- ✓ ♦ A need to provide a response/action was not recognized
  Rod Withdrawal without monitoring Tave, Power
- ___ ♦ A need to respond was recognized but the proper response was not determined.
- ✓ ♦ Proper response was identified but not in a timely manner.
  NCO was familiar with MS10 problem, but did not monitor Tave increase
- ✓ ♦ Other SRO should not have moved rods himself due to loss of command/control

✓ b. The response/action chosen was improper because:

- ___ ♦ Plant data was misinterpreted.
- ___ ♦ The action chosen was directed toward satisfying the wrong operational goal.
- ✓ ♦ Better alternatives existed than the plan of action chosen. Transfer of Group Buses from APT to SPT was not required at the time
  Reassignment of NCO from Control Rods to Electrical System Alignment.
- ___ ♦ Failure to obtain feedback about the results of the implemented action was demonstrated.
- ___ ♦ Other, ______________________________

N/A c. The proper response/action was chosen but was not properly executed because:

- ___ ♦ Required response/action was omitted.
- ___ ♦ Performed out of sequence.
- ___ ♦ Performed with insufficient precision.
- ___ ♦ Control board deficiency exists such that the response/action was not adequately supported.
- ___ ♦ Other ______________________________

✓ ~~N/A~~ 10. Communication

N/A a. Written Communication

___♦ Standing Orders ___ ♦ Letter/Memo

___♦ Night Orders ___ ♦ Instructions

___♦ Tagging ___ ♦ Line-up

___ Request ___ Mechanical

___ Release ___ Electrical

___♦ Other ______________________________

✓ b. Oral Communication

___♦ Message not received

___♦ Message Received was:

___ Misinterpreted ___ Not Understood

___ Not Performed ___ Performed Incorrectly

___ Incorrect ___ Not timely

N/A c. Message Communication Medium

___♦ Direct, Eye Contact ___♦ Indirect, due to Barrier

___♦ Phone ___♦ Page ___♦ Sound Powered Head Set

___♦ Portable Radio ___♦ Other ______________

Specific verbiage and/or deficiency, explain ______________

Periodic communication of Tave and Power were not shared by the crew through the load reduction and the recovery after the first safety injection.
NCO did not inform NSS of problem with Tave
STA and NSS had communication problems.

N/A 11. Work Place Deficiencies

N/A a. Environment

___♦ Noise ___♦ Heat

___♦ Space ___♦ Fumes

___♦ Personnel ______________________________

___♦ Equipment ______________________________

___♦ Other ______________________________

Describe ______________________________

____

N/A b. Man/Machine Interface

___♦ Design ___♦ Installation

___♦ Labeling ___♦ Nomenclature

___♦ Position ___♦ Location

___♦ Other ______________________________

Describe ______________________________

____

N/A c. Tools or Equipment

___♦ Availability

___♦ Adequacy

___♦ Other ______________________________

Describe ______________________________

____

POST REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 4, ROOT CAUSE DETERMINATION

N/A 12. Planning and Scheduling Deficiencies

Describe ______________________________

____

✓ 13. Policy Problems

✓ a. Lack of policy Expectations concerning operation at less than 541 °F RCS Tav

___ b. Policy not implemented

___ c. Policy improperly implemented

___ d. Policy implemented, but not followed

___ e. Policy not effective

N/A B **COMPONENT FAILURE**

___ 1. Component involved in Root Cause

___ a. Mechanical

___ ♦ Tanks, Pressure Vessels

___ ♦ Valves, valve actuators

___ ♦ Pumps/Compressors

___ ♦ Fasteners/Welds

___ ♦ Diesels

___ ♦ Turbine

___ ♦ Piping, pipe supports, snubbers

___ b. Electrical Components

___ ♦ Motor

___ ♦ Circuit Breakers

___ ♦ Transformers

___ ♦ Bus Work

___ ♦ Cable/Wire

___ ♦ Fuses

___ ♦ Generator

___ ♦ Other ______________________________

___c. Electronic Components

___♦ Switch ___♦ Solenoid

___♦ Relay ___♦ Diode

___♦ Instrumentation ___♦ Circuit Board

___♦ Other____

N/A 2. Component Failure Mode

___a. Corrosion ___ c. Erosion

___b. Fatigue ___ d. Other ______________

___♦ Vibration ___♦ Friction

___c. Overheating

___♦ Insufficient cooling ___♦ Insufficient Lubrication

___d. Electrical/Electronic component degradation

___e. Undetermined

___f. Other____

Specific Component and failure mode________________________

✓ C. **DESIGN DEFICIENCY**

N/A 1. Configuration Design Deficiency

___a. Mechanical ___c. Hydraulic

___b. Electrical ___d. Electronic

✓ 2. Design Analysis/Specification Deficiency

___a. Stress

___♦ Mechanical ✓ ♦ Hydraulic

___♦ Thermal ___♦ Chemical

___b. Electrical ✓ c. Electronic Steam Flow Transmitter Respons

___d. Improper Selection of Materials or Parts

✓ e. Logic or Control Design Deficiency MS10 Reset Wind up

✓ f. Unanticipated Interaction of Systems or Components SSPS Single Tra Actuation

✓ g. Other Capability of CW Screens to cope with annual grass influx

N/A D. **MANUFACTURE/CONSTRUCTION**

N/A 1. Material Deficiencies

___2. Fabrication Deficiencies

___3. Assembly Deficiencies

___4. Improper Components/Parts

___5. Other ______

N/A E. **ASSEMBLY/INSTALLATION**

N/A 1. Improper Materials

___2. Fabrication Deficiencies

___3. Alignment Deficiencies

___4. Improper components/parts

___5. Other ______

✓ F. **EXTERNAL CAUSES**

✓ 1. Environmental Conditions

✓ a. Natural Causes

___ ♦ Lighting ___ ♦ High winds

___ ♦ Flooding ✓ ♦ Other River Grass

Describe Large influx of grass at high and low tides has challenged the reliability of the Circulating Water System during the spring and fall.

N/A b. Man-made Causes

Describe

N/A G. **DOCUMENTATION**

1. Type of Document

N/A a. Drawings, P&IDs or Diagrams

___ b. Departmental Procedures/Directives

___ c. Night Orders/Standing Orders

___ d. Vendor Manual/Instructions

___ e. Engineering Letters/Memos

___ f. Training Manuals/Lesson Plans

___ g. System Description Manuals

___ h. Other ______________________________

2. Documentation Deficiency

N/A a. Lack of Documentation

___ b. Incomplete Documentation

___ c. Erroneous Documentation

___ d. Unrevised Documentation

___ e. Other ______________________________

N/A H. **OTHER/UNDETERMINED**

N/A 1. Cannot be determined

___ 2. Other ______________________________

Describe ______________________________

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 5, ROOT CAUSE DETERMINATION
SUMMARY

Explain in detail root cause determination and contributing factors that led to the initiation of the event. Use additional sheets as necessary

See Attached Sheet.

Section IV Root Cause

A number of root cause(s) can be categorized within the three phases of this incident. The first phase of this incident is the time frame from the initial load reduction due to the grass problems at the Circulating Water Structure and the low power operations until the time of the reactor trip. A second phase involves the time of the reactor trip until the lifting of the first safety valve. The final phase includes the period of the high steam flow on 11 Steam Generator until the recovery from the entire event.

In addressing the first phase of the incident, there are several components to the root cause. The reduction of challenges to the operation of the Salem units is an important piece to improving the reliability and safe operation of the units. Over the past six weeks, the operating shift crews were being challenged two or three times daily by the river grass buildup on the Circulating Water Screens. During the time frame, there were extended periods of load reductions and numerous transients. Although the shift was aware of the tide changes and had stationed personnel at key areas, the exact magnitude of the grass influx is usually not known until after the fact. Load was reduced from 73% power to 8% power in a period of thirty minutes. Circulators were tripping and restarting over this perkiod, so the availability of the steam dumps was limited as was the RCS temperature control.

The situation with the circulators appeared to be improving at approximately 10:45 hours and load had been reduced to 8% power. As the plant started to stabilize, the shift supervisor was making preparations to take the turbine off-line due to the condenser vacuum and circulator situation. In preparation for this evolution, he instructed the NCO monitoring the primary plant to transfer the Group Buses from the Auxiliary Power Transformer to the Station Power Transformer. The other control operator was attending to the Steam Generator level control, because of the oscillations on 12 SGFP at the low load and the master control was in "Manual". The extra NCO on the shift was under the Condenser Hotwells throttling the outlet valves to prevent cavitation on the Condensate Pumps and the primary equipment operator had been sent to help with the circulators. A Night Order Book entry was made on 9 April 1994 concerning the usage of the extra NCO and duty personnel such as, the primary operator and shift technical advisor.

In reviewing the actions of the crew, the supervisor assigned the inappropriate priority of actions to the NCOs. This conclusion is based on the fact that the Group Buses would have transferred automatically after tripping the turbine and RCS temperature was decreasing at the time. There was no recollection of communication that the P-10 permissive had cleared during the load reduction. When the crew recognized that primary temperature was below the Technical Specification limit, the NCO withdrew the control rods too quickly without monitoring power and temperature closely. The power increase combined with the RCS temperature increase caused the Power Range channels to increase to the low power trip setpoint of 25%. The root cause of this phase of the event is poor crew performance and inadequate communication between the crew members.

The second phase of this event was exacerbated by a design problem with the steam flow transmitters. After the reactor trip, the safety injection signal was generated by a pressure pulse returning along the steam lines due to the rapid closure of the Turbine Stop valves. Because the time response on the steam flow transmitters is so quick (20 msec) and the scaling on the transmitter is relatively small (0 to 130 in H_2O), this phenomenon which is often seen at high power trips was also seen during low power trips. Since RCS temperature was below 543 ^{o}F, the high steam flow bistable was actuated and the safety injection occurred on Train A only. The duration of the pressure pulse was less than 30 msec. Based on subsequent testing of the SSPS input relays, the duration of these pulses could activate one SSPS train and not the other.

Since the partial actuation required more time to verify the proper safety injection alignment, the Pressurizer reached a higher level than a normal safety injection. The reset point of the safety injection was still within the UFSAR time requirements of twenty minutes, however, there is a recent letter from Westinghouse on the necessity to reset the safety injection in ten minutes. After closure of all the MS167s, the RCS temperature started to increase. The crew did not recognize the temperature increase in time to stop the safety valves from lifting. Therefore, the root cause of this phase of the event are related to a design problem with the steam flow transmitters. A contributing factor to this part of the event is the lack of operator action to mitigate the primary temperature and secondary pressure increase.

The third part of the event could have been avoided if the MS10s had worked properly to relieve the pressure on the Steam Generator at its setpoint of 1035 psig. The design of the control circuit is subject to a phenomenon known as "reset windup", which causes the circuit to take longer to respond. When the operator failed to take "Manual" control of the MS10s, the pressure increased above the lift setpoint for the Steam Generator safety valves. With the Pressurizer going solid following the first safety injection, RCS pressure control was strictly a balance of the mass input and output. The safety valve(s) lifting caused a rapid cooldown of the primary system. This temperature decrease caused the rapid pressure decrease and actuated the second safety injection. The control operator attempted to open the MS10s during the safety valves lifting, but had difficulty in getting the valves to respond properly. 11MS10 has been found to have a problem with a binding servo-setpoint station. Therefore, the root cause of this phase of the event is an equipment problem with a contribution from the control operator inaction to take "Manual" control in time. *

The shift turnover for the shift crew was monitored by the Operations management for completeness in the transfer of information on the plant status. Some of the specific items were the status of various equipment and the time frames to comply with the license requirements as a result of the discretionary enforcement. At 20:20 hours, the Alert was terminated and the various facilities were demobilized. shortly thereafter.

The cooldown to Mode 4 proceeded without incident in accordance with IOP-6. The POPS functionals were completed at 22:07 hours and the RCS degasification was being performed concurrently. Salem Unit 1 entered Hot Shutdown (Mode 4) at 01:06 hours. The RHR system was placed in service 06:00 hours and the cooldown to Cold Shutdown (Mode 5) was reached at 11:24 hours on 8 April 1994.

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 5, PRE START UP CORRECTIVE ACTIONS

Corrective Actions required prior to startup. Use additional sheets as necessary.

See Attached Sheet

Section IV Corrective Actions

Mode Change Contraints

1. 12 CFCU SW Flow (12SW76)	940411117	Mode 3
2. PRT Rupture Disk Replacement		Mode 4
3. Rod Control Speed Troubleshooting	940410151	Mode 2
4. Bank C Step Counter	940407162	Mode 2
5. SSPS Train B Analysis	Engineering Evaluation	Mode 4
6. Pressurizer Pressure Bistables	940414141 940414148 940414151 940414161	Mode 3
7. Lift Testing on Safety Valves 11-14MS15, 11MS14		Mode 2

Short Term

8. 11MS10 Troubleshooting/Repair 13MS10 Troubleshooting/Repair 14MS10 Troubleshooting/Repair	940408204 940408235 940408236	
9. 13TB10 Repair	940407136	
10.1PR1/1PR2 Evaluation	Complete	13 APR 94
11.Tailpipe Evaluation	WIP	13 APR 94
12.Condenser Vacuum	940411128 940413247	
13.1RP4 Status Lights dim (BF13s,CV284)	940415116	Mode 2
14.High Steam Flow Bistables on PT505 High Steam Flow Bistables on PT506	940408259 940408262	Mode 3 Mode 3
15.1PS1 No closed limit in EOP-TRIP-1 1PS3 No closed limit in EOP-TRIP-1	940411199 940416063	
16.MS10 Reset Windup Design Change		Mode 2
17.Steam Flow Transmitter Dampening		
18.1B Diesel Urgent Trouble Alarm		

19.Training on the incident for all operating shifts at the simulator. (See attached outline)

Attachment

SALEM UNIT 1 EVENT OF APRIL 7, 1994

DEMONSTRATION AND LESSONS LEARNED

1. Temperature Control During a Rapid Load Reduction

    a. Be careful not to over-borate; it takes a while for the boron to reach the reactor

    b. Be aware of the current power defect and how that relates to total boration and/or rod movement

        1) For example, Unit 2 is currently at about 50% power and 840 ppm boron

        2) Power Defect = 925 pcm

        3) This equals about 170 steps on the rods (about 6 pcm/step)

        4) This equals about 400 gallons of boric acid (about 1200 gallons on Unit 1)

        5) Think ahead!!

2. Communications - Make sure you communicate problems, concerns, status to the other members of your crew; if you need help or input, ask for it

3. Resource Management

    a. Bring in the third NCO as soon as problems arise; maybe he won't be necessary, but maybe he will play a crucial role

    b. Prioritization - During any situation, control of the reactor has to be the top priority; during the transient, the RO was directed to swap the group buses

    c. More to follow from operations management on this issue

4. Minimum Temperature For Criticality

   a. Due to the excessive use of rods/boron, the following conditions were established

      * Tavg=532 deg.F * Reactor Power=8% * Load=80 MWe

   b. The continuous withdrawal of rods will result in a rapid power increase; the following reinstated at P10

      1) IRNI Rod Stop at I=20%

      2) PRNI Hi Flux Low Setpoint Trip at 25%

      3) IRNI Hi Flux Trip at I=25%

   c. The Block pushbuttons were not, **and should not,** be used under these conditions; these pushbuttons are used in a deliberate, controlled manner IAW IOP-3

   d. IOP and AB revisions will address the condition of being critical below 541 deg. F; the goal is to raise Tavg and reduce power by reducing steam demand; any rod motion will be **slow** rod motion

5. Single Train Safety Injection

   a. Several valves are train dependent

A Train Only	B Train Only
SJ13	SJ12
SJ1	SJ2
CV69	CV68
CV40	CV41
CV116	CV284
11CA330	12CA330

   b. Only the A Train saw the Hi Stm Flow ICW Lo-Lo Tavg SI/MSLI that came in after the trip

      1) In addition, SR621 in the A Train failed (BF13s and SGFPs)

      2) In addition, 11 and 12MS167s did not close

   c. Since the B Train had not actuated, it could not be reset <u>and</u> <u>blocked;</u> when a subsequent SI demand was generated, the B Train actuated

   d. If you should receive and recognize a single train SI, you could place the six valves in the safeguards position by manually initiating an SI ? should they?

6. SNSS Involvement in EOP Operations

   a. There is next to none.

   b. During future simulator training, the SNSS will no longer be allowed to routinely assist the crew with the EOPs. During scenarios that are not required for reactivity manipulations, the SNSS will be in another room.

7. MS10 Reset Windup

   a. MS10 saturation contributed to the lifting of a Code Safety, which resulted in a second SI. Twenty minutes later, the PRT rupture disc blew.

   b. The NCO should take the MS10s out of saturation if the MS10s are required to be open. The new EOP revision will include a step to address this issue.

   c. If an automatic action has failed to occur, the NCO should take manual action to accomplish the function, IAW AD-02.

8. Bubble Formation in EOP-TRIP-3

   a. Completion of TRIP-3 was delayed due to a perceived lack of procedural guidance on how to draw a bubble in the Pressurizer. A Yellow Path existed as soon as Pzr Level increased above 92%. FRCI-1, Response to High Pzr Level, gives specific direction on drawing a bubble.

   b. The Pzr Vapor Space Temperature was about 550 deg. F after two SIs. It took four hours to establish a bubble.

   c. The ERG Basis Document addresses the issue of Tech Spec/EOP interface. See attached.

   d. IOP-6 and IOP-8 contain steps that direct the operator to evaluate safety related systems for operability after EOP usage.

2. DESCRIPTION

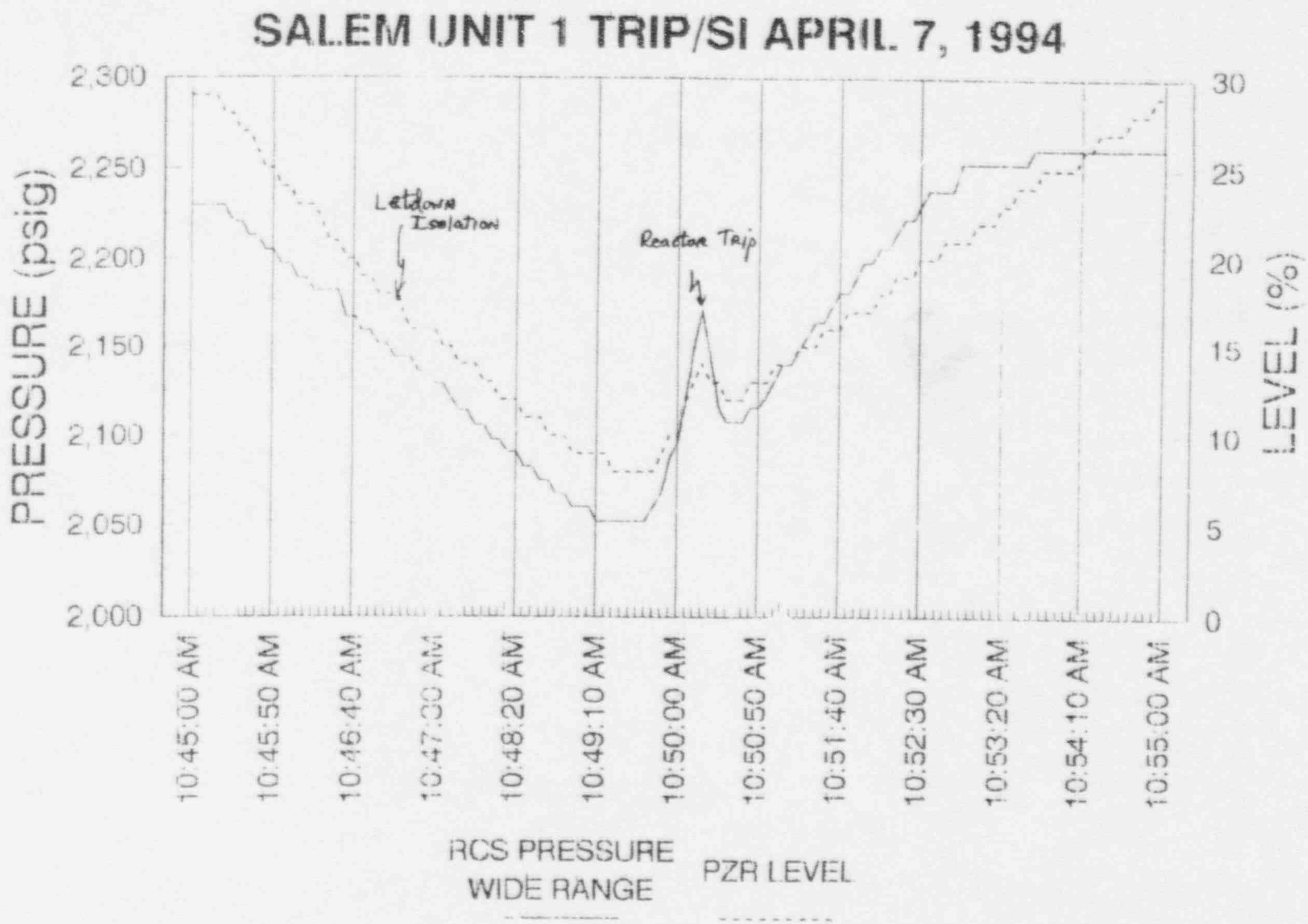
The plant Technical Specifications contain the limiting conditions for plant normal operation in the applicable modes. By abiding by these conditions, the plant's operation would be conducted in a safe manner and the design safety features would be ready to respond if a design basis accident were to occur. One could consider that the Technical Specifications play a preventative and preparative role in ensuring plant safety. If an accident does occur, the Emergency Response Guidelines play a responsive role in dealing with the accidents. The Emergency Response Guidelines provide the actions to be performed and parameters to be monitored to maintain plant safety and to achieve optimal recovery.

When the safety systems are actuated and performing their role during an accident, many of the preparative Technical Specifications will be violated due to the action of the safety systems (e.g., after the RWST is injected into the RCS, its level will be below its Technical Specification limit). The accident itself could be a violation of the preventative Technical Specifications (e.g., a LOCA will exceed RCS leak limits).

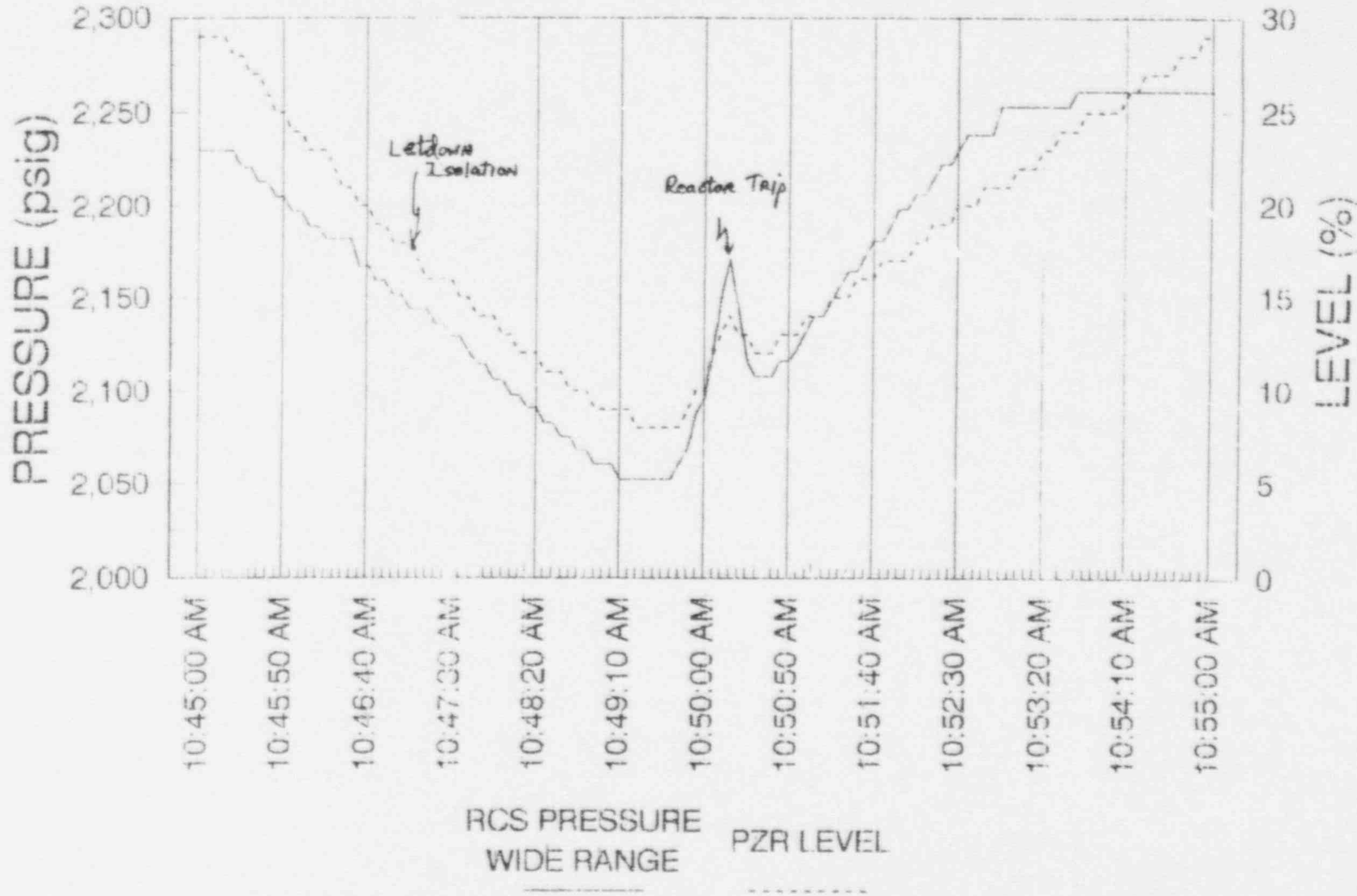
The Emergency Response Guidelines were developed to respond to accident conditions and are supported by extensive analytical background, in most cases best estimate. The actions delineated in the ERGs are those actions necessary to deal with the accident in order to maintain or restore the plant in a safe condition. In general, the Technical Specification limitations are considered in developing the emergency response actions in the ERGs. However, the ERGs contain actions which will lead to Technical Specification violations in order to maintain plant safety (e.g., opening pressurizer PORVs during a complete loss of secondary heat sink will violate RCS leak limitations, but is necessary to provide for core cooling and prevent more severe consequences).

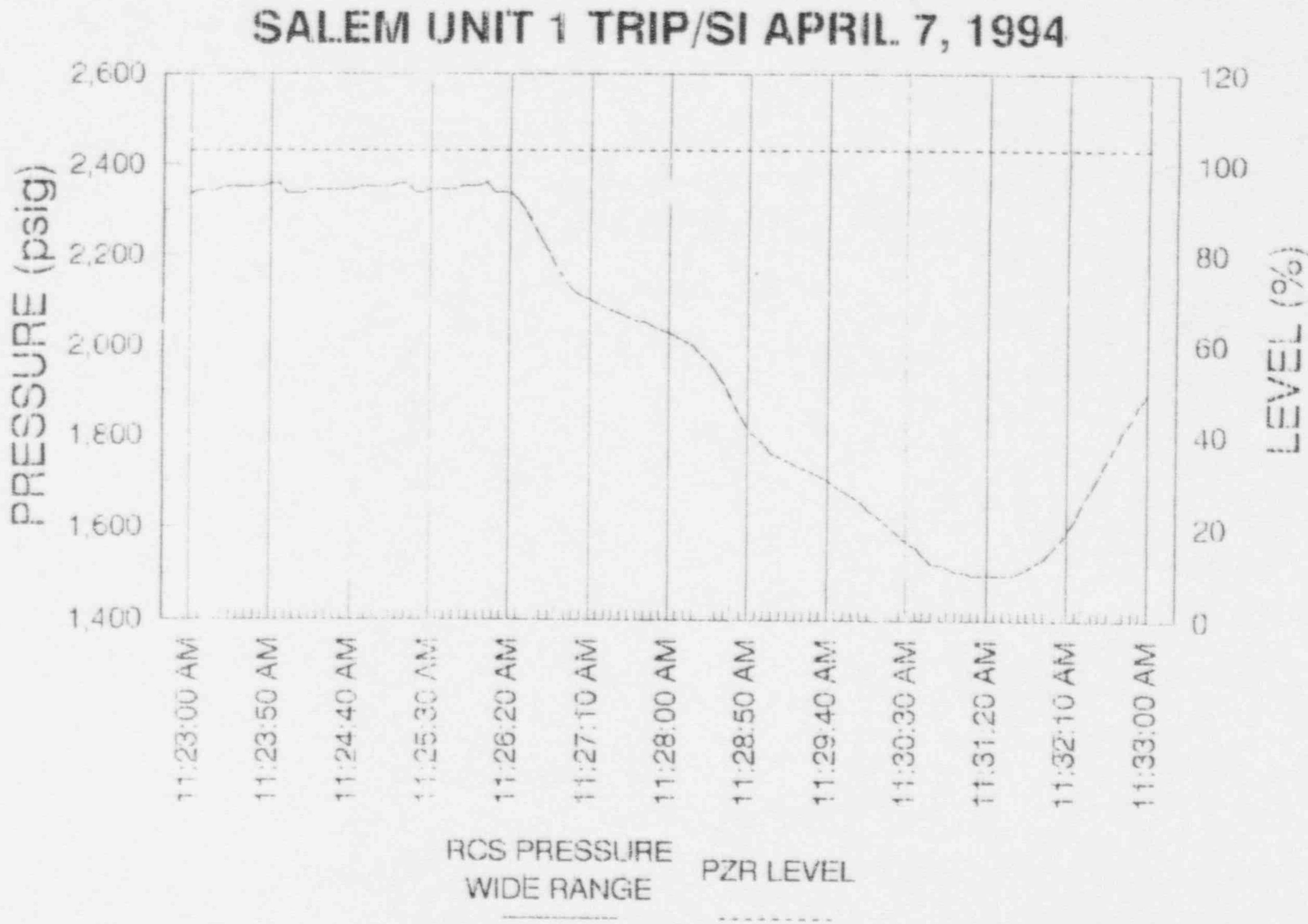
Although it is desirable to remain within Technical Specification limits at all times, one must keep in mind that the overall objective is to protect the health and safety of the public. This may require violating a particular Technical Specification in response to an accident.

The fact that the ERGs provide guidance that may result in Technical Specification violations was identified to the United States Nuclear Regulatory Commission (NRC) at a meeting on February 9, 1982, to update the NRC on the status of the ERG program. At this meeting and in their internal meeting summary (Reference 1), the NRC "acknowledged that it may be necessary in some emergency situations to take actions which are, or can lead to, violation of Technical Specifications."


SALEM UNIT 1 TRIP/SI APRIL 7, 1994
PRESSURE (psig)
2,300
2,250
2,200
2,150
2,100
2,050
2,000
LEVEL (%)
30
25
20
15
10
5
0
Letdown Isolation
Reactor Trip
10:45:00 AM
10:45:50 AM
10:46:40 AM
10:47:30 AM
10:48:20 AM
10:49:10 AM
10:50:00 AM
10:50:50 AM
10:51:40 AM
10:52:30 AM
10:53:20 AM
10:54:10 AM
10:55:00 AM
RCS PRESSURE WIDE RANGE
PZR LEVEL

SALEM UNIT 1 TRIP/SI APRIL 7, 1994




SALEM UNIT 1 TRIP/SI APRIL 7, 1994
PRESSURE (psig)
2,600
2,400
2,200
2,000
1,800
1,600
1,400
LEVEL (%)
120
100
80
60
40
20
0
11:23:00 AM
11:23:50 AM
11:24:40 AM
11:25:30 AM
11:26:20 AM
11:27:10 AM
11:28:00 AM
11:28:50 AM
11:29:40 AM
11:30:30 AM
11:31:20 AM
11:32:10 AM
11:33:00 AM
RCS PRESSURE WIDE RANGE
PZR LEVEL

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 5, POST START UP CORRECTIVE ACTIONS

Long Term Corrective Actions not required prior to startup. Use additional sheets as necessary.

See Attached Sheet

Long Term

1. Resolution of the issue with the crossover of Wide Range T_h and T_c on SPDS and Wide Range recorders. (Technical)

2. Resolution of Safety Injection reset time of ten minutes versus Salem UFSAR time of twenty minutes. (Nuclear Fuels)

3. Evaluation of alternatives to cycling the Reactor Trip breakers versus entering Technical Specification 3.0.3 after a safety injection. (Operations/Technical)

4. Establish appropriate procedural guidance on low temperature operations. (Operations)

5. Revise ECP-CFST procedures to allow establishing a steam bubble at NOP/NOT within the EOP network. (Operations)

6. Training Issues (Operations/Training)

   a. Reactivity manipulations at low powers with different boron concentrations. This will include the communications that should take place between the NCOs and NSS during power transients.

   b. Resource management. Assignment of personnel to the highest priority tasks. Including a discussion of the transfer of electrical buses during rapid load reductions.

   c. Actions taken in EOP-TRIP-1 step 9, Safeguards Valve Alignment Verification, to reposition numerous valves not actuated by a single train.

   d. Proper sequence and actions to be taken to deal with the MS10 reset windup problem.

   e. The proper actions to take, if T_{ave} falls below the minimum temperature for criticality.

   f. The usage of yellow path Functional Recovery procedures within the EOP network.

   g. Reactivity manipulations on the simulator using different boron concentrations.

7. Resolution of Circulating Water grass problems. (E&PB)

REACTOR TRIP/SAFETY INJECTION REVIEW REPORT
SECTION 5, SIGNATURE SHEET

HISTORY FILE NO. _____ - _____

Root Cause Summary and Corrective Action Recommendations completed.

Pete Orth
OPERATING ENGINEER Date 4/16/94

Reactor Trip/Safety Injection Review Report package review completed.

OPERATIONS MANAGER Date 4-16-94

SORC review of Reactor Trip/Safety Injection Review Report package completed. Report is satisfactory to recommend startup .

94-030
SORC CHAIRMAN Date 4/18/94

SORC Open Item initiated for tracking any long term corrective action that cannot be accomplished via issuance of a priority '31' Work Order

SORC SECRETARY Date ________

GM-SO review of Reactor Trip/Safety Injection Review Report package is satisfactory and unit startup may proceed. — with the short term action items as listed

GENERAL MANAGER-SALEM OPERATIONS Date 4/18/94

SALEM GENERATING STATION UNIT ONE

OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE 4-7-94

TIME	SYSTEM	REMARKS
0001	Z-SHIFT	
	SNSS	KAFANTARIS
	NSS	ROBERDSON
	STA	GALLAGHER
	NSSW	GALLAGHER
	NSSF	BIRNEY
	NCO	BOOS, SHARKEY
	NEO	SWOPE, SCHULTZ
	CM	SOBEL, DAVIS
	PLANT STATUS	MODE 1, 74% POWER, 750 MWE, TAVE ≈ 563°F
		CONTROL RODS MAN, BANK D @ 195 STEPS
		15 & 16 SW PUMPS I/S 11A, 11B, 12A, 12B, & 13A
		CIRC I/S 13B EMERG. TRIPPED @ 2355 ON
		4-6-94
0004	CW	13 B CIRC I/S
0023	GB	MAX GENERATOR BLOWDOWN
0035	I&C	START S1. IC-CC. RCP-0039(Q) 12SG STM FLOW II
0113	SW	14 SW PUMP I/S, 15 SW PUMP O/S
0114	SW	11 SW PUMP I/S, 16 SW PUMP O/S
0116	CW	13A CIRC O/S - CLEANING
0155	I&C	S1. IC-CC. RCP-0039(Q)

The NCO need only sign the log once immediately following his last entry at Shift Relief.

SALEM GENERATING STATION UNIT ONE

OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE 4-7-94

TIME	SYSTEM	REMARKS
0225	CHEM ~~0225~~	RCS BORON 1065 PPM
0227	CW	13A CIRC I/S
0343	CW	13B CIRC O/S - CLEANING
0423	I&C	START S1.IC-CC.RCP-0021(Q) PZR LVL CH II
0508	I&C	S1.IC-CC.RCP-0021(Q) COMPLETE
0514	I&C	START S1.IC-CC.RCP-0051(Q) 13 SG STM PRESS
		CH II.
0603	GB	GB BACK TO 40K ON ALL S.G^S
0619	CW	13B CIRC I/S
0625	I&C ~~CW~~	S1.IC-CC.RCP-0051(Q) COMPLETE
0645	VC	CONT. PRESS RELIEF I/S VC 5 & 6 - OPEN

The NCO need only sign the log once immediately following his last entry at Shift Relief.

SALEM GENERATING STATION UNIT 1

OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE 4/7/94

TIME	SYSTEM	REMARKS
0700	X SHIFT	SNSS - GWIRTZ
		NSS - HOLMES STA - SIMPSON
		NCO - LYONS, KOMANSKY
		NEO - PRI - McKUNE, SEC - STEVENS, CW/SW - RHOADS
		CM1 - HEADMAN, CM2 - MYERS
	STATUS	MODE 1, 73% RX POWER, 800 MWe, TAVE 562°F, RODS MAN.
		BANK D @ 195, 11+14 SW PUMP - I/S, ALL CIRCS - I/S.
0727	CW	INITIATE STOP 12A FOR CLEANING.
0817	VC	CONTAINMENT PRESSURE RELIEF - O/S.
0913	HD	12 HEATER DRAIN PP - O/S TO BE C/T.
0913	SW	13 SW PP - I/S LOW HEADER PRESS DUE TO 12CC HX TESTING.
0918	CN	12CN27-X NEO DISPATCHED TO LOCAL CONTROL PANEL.
0919	CN	12CN27 TAKEN TO MAN - OPEN BY NEO
0920	SW	13 SW PP - O/S 12CC HX TESTING COMPLETE
0921	VC	15 CFCU - I/S
0921	CN	12CN27 - O
0932	TC	13 TAC PP - I/S MAINTENANCE INVESTIGATING OIL LEAK.
0951	TC	11 TAC PP - O/S
0945	TS/CHEM	12 GDTK O_2 - 1.6%
0958	FHV	1 FH BLDG SUPPLY FAN I/S TEST AFTER MAINTENANCE ON DAMPER
1000	FHV	1 FH BLDG SUPPLY FAN O/S

The NCO need only sign the log once immediately following his last entry at Shift Relief.

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SALEM GENERATING STATION UNIT 1

OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE 4/7/94

TIME	SYSTEM	REMARKS
1014	CW	INITIATE STOP 13B CIRC HIGH SCREEN ΔP
1016	CW	13B CIRC EMERG. TRIP
1027	CW	13 A CIRC EMERG. TRIP
1032	Rx/TURB.	COMMENCE LOAD REDUCTION @ 1%/MIN FROM ≈ 650 MWe
		TURBINE BACK PRESSURE ≈ 4.9".
1033	Rx/TURB.	INCREASE LOAD REDUCTION RATE TO 3%/MIN.
1034	CW	12A CIRC START + IMMEDIATE EMERGENCY TRIP.
1038	Rx/TURB.	INCREASE LOAD REDUCTION RATE TO 5%/MIN.
1039	CW	11B CIRC. EMERG. TRIP 11A CIRC. EMERG TRIP
		BOTH ON HIGH SCREEN ΔP.
1040	Rx/TURB	INCREASE LOAD REDUCTION RATE TO 6%/MIN.
1040	Rx/TURB	INCREASE LOAD REDUCTION RATE TO 8%/MIN.
1042	CW	12A CIRC START + IMMEDIATE EMERG. TRIP
1043	CW	12B CIRC EMERG TRIP.
1047	4KV	SWAPPED 1E, 1F, 1G, 1H GROUP BUSSES TO STATION
		POWER TRANSFORMERS
1049	Rx.	REACTOR TRIP / SAFETY INJECTION TRANSITION TO EOP
		NETWORK (1 EOP-TRIP-1)
1630	EOP/IOP	EXIT 1-EOP-TRIP-3 WITH EXCEPTIONS: FROM 1-EOP TRIP-3-12 SGFP
		NOT ON TURNING GEAR. FROM APPENDIX 4 - FILL RWST + FILL BASTs.
		ENTER 1-IOP-6

The NCO need only sign the log once immediately following his last entry at Shift Relief.

MB

SALEM GENERATING STATION UNIT 1

OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE 4/7/94

TIME	SYSTEM	REMARKS
1631	CHEM	RCS BORON 1469ppm (TAKEN @ 1620)
1637	CW	12B CIRC - I/S
1640	SF/SJ	COMMENCE FILL OF SPENT FUEL POOL FOR TRANSFER TO RWST.
1645	TS	CONTAINMENT SUMP INLEAKAGE 1.8 GPM (0.5GPM FROM PASS
		IDENTIFIED, 1.3 GPM UNIDENTIFIED) ENTER TS 3.4.6.2.b and b.
		FOR RCS LEAKAGE.
1659	CHEM	PZR. BORON 1506 ppm (TAKEN @ 1645) - PZR WITHIN 50ppm
		OF RCS. SAT TO COMMENCE COOLDOWN.
1701	NI	SOURCE HIGH FLUX AT SHUTDOWN BLOCK - REMOVED.
1710	PZR	PRESSURIZER HEATERS - OFF
1715	IOP-6	COMMENCE COOLDOWN PER 1-IOP-6.
1717	CB	COMMENCE BORATION - 2000 GAL @ 25GPM
1730	TS.	NRC GRANTS DISCRETIONARY ENFORCEMENT ALLOWING
		SALEM 1 TO BE IN MODE 4 BY 0641 ON 4/8/94
1740	CHEM	START CHEMICAL ADDITION (HYDRAZINE) TO 12, 13 + 14
		STEAM GENERATORS.
1745	TS/CHEM	DEI RESULTS: 2.73×10^{-2} µCi/ml @ 1415
		2.77×10^{-2} µCi/ml @ 1620
1747	VC	11 + 13 CFCU PLACED IN SLOW SPEED (4 CFCU IN SLOW)
1750	Rx. PROT.	LOW PRESSURIZER PRESSURE SAFETY INJECTION BLOCKED.
1820	VC	12 CFCU INOPERABLE - LOW FLOW

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SALEM GENERATING STATION UNIT 1

OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE 4/7/94

TIME	SYSTEM	REMARKS
1821	VC	12 CFCU - O/S, 15 CFCU - I/S SLOW SPEED.
1824	CHEM	NOTIFIED CHEM TO ADD HYDRAZINE TO 11 STEAM GEN.
1838	RCS	COMPLETE 2000 GAL BORIC ACID ADDITION.
		R. R[illegible]

The NCO need only sign the log once immediately following his last entry at Shift Relief.

SALEM GENERATING STATION UNIT 1

OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE APR 07 1994

TIME	SYSTEM	REMARKS
1900	2 SHIFT	
	SNSS	KAFANTARIS
	NSS	ROBERTSON
	STA	GALLAGHER
	NSSF	BIRNEY
	NSSOW	HUNTELMAN
	NCO	CON: BOOS DESK: SHARKEY AND ORRIS
	NEO	PRI: SHULTZ SEC: SWOPE
	CM	PRI: SOREL SEC: DAVIS
	STATUS	MODE III: 200CPS 500° 1540# COOLDOWN TO MODE V IN PROG.
		ALL RCPS - I/S 11&12 AF Pp's - I/S, 12 CC Pp - O/S
		SW: 11,14,15 Pp's - I/S CW: 11A, 12B, 13B Pp's - I/S
1954	CHEM	RCS BORON SAMPLE AT 1915: 1614PPM PZR BORON AT 1910: ~1544PPM
1955	CN	COND POLISHER PLACED BACK - I/S
1959	CVC	STARTED 900 GAL BORATION
2020	STATUS	TERMINATED ALERT
2030	CVC	COMPLETED 950 GAL BORATION
2031	RWST	RWST LVL 40.7 EXITED T.S.A.S
2045	RCS	GREATER THAN 4HRS WITH UNIDENTIFIED LEAKAGE >1GPM
		RCS COOLDOWN IN PROG.
2052	CHEM RCS	RCS SAMPLE AT 2020 - 1622PPM PZR AT 2010 - 1601 PPM

The NCO need only sign the log once immediately following his last entry at Shift Relief.

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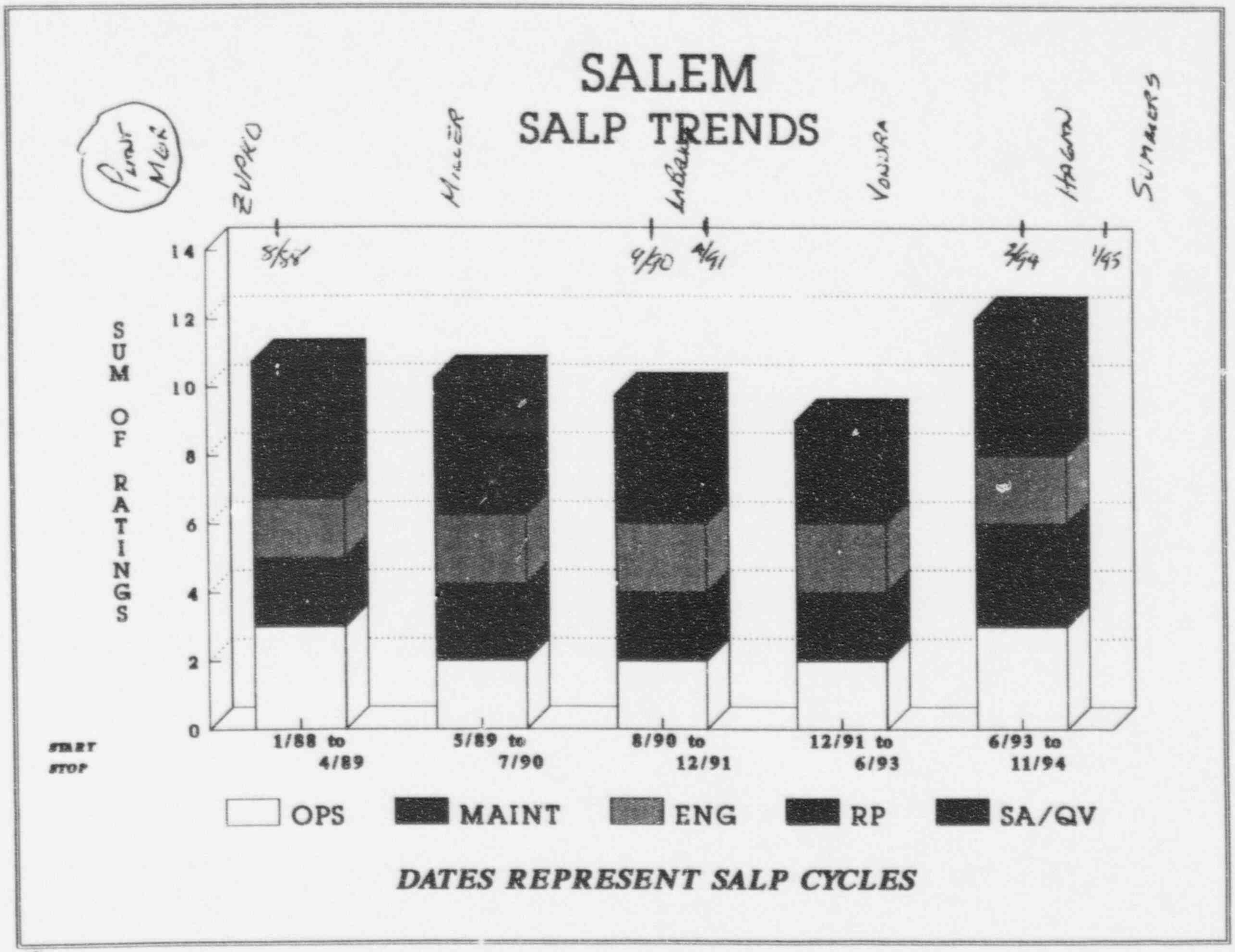
MC

SALEM GENERATING STATION UNIT 1

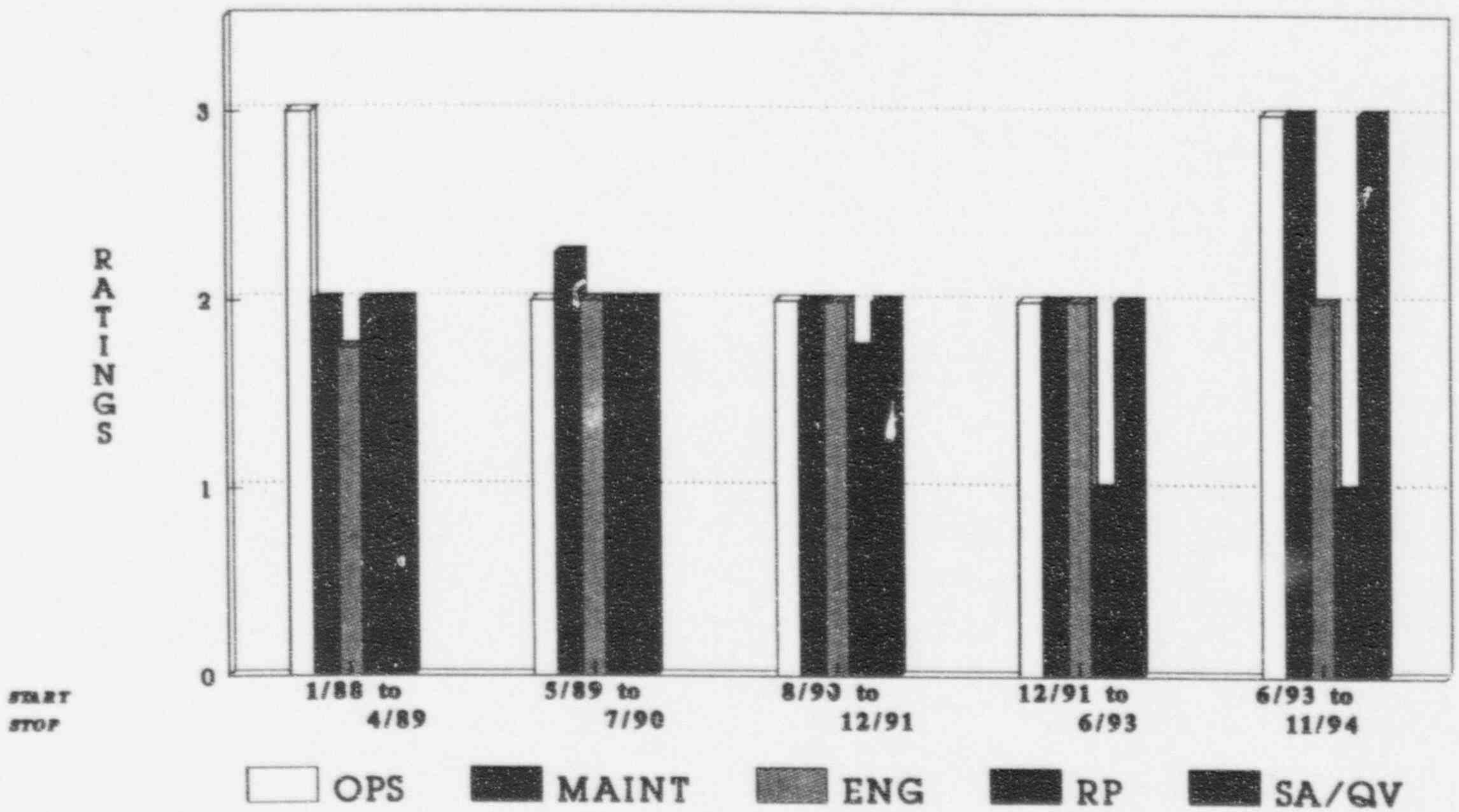
OPERATIONS LOG 1 CONTROL ROOM NARRATIVE LOG DATE APR 07 1994

TIME	SYSTEM	REMARKS
2108	I&C	START S1.IC-FT.RCP-0070 1PT-403 RCS HOT LEG PRESS CHAN II
2135	I&C	COMPLETED 1PT403 FUNCTIONAL.
2136	I&C	START S1.IC-FT.RCP-0071 1PT405 RCS HOT LEG PRESS CH I
2146	RCS	EXITED T.S.A.S FOR RCS UNIDENTIFIED LEAKAGE BASED
		ON NO CONT. SUMP RUN FOR GREATER THAN 350 MIN IAW
		S1.OP-SO.RC-0004.
2207	I&C	COMPLETED 1PT-405 FUNCTIONAL
2213 ~~2208~~	CHEM	RCS BORON - 1685 PPM PZR BORON - 1641 PPM
2222	SGBD	SGBD FLOW IND ON 12+14 - F/± T.S.A.S. 3.3.3.8 Act b29
2358	CVC	STARTED S1.OP.SO.CVC-0011 RCS DEGASIFICATION.
		Matt [illegible]

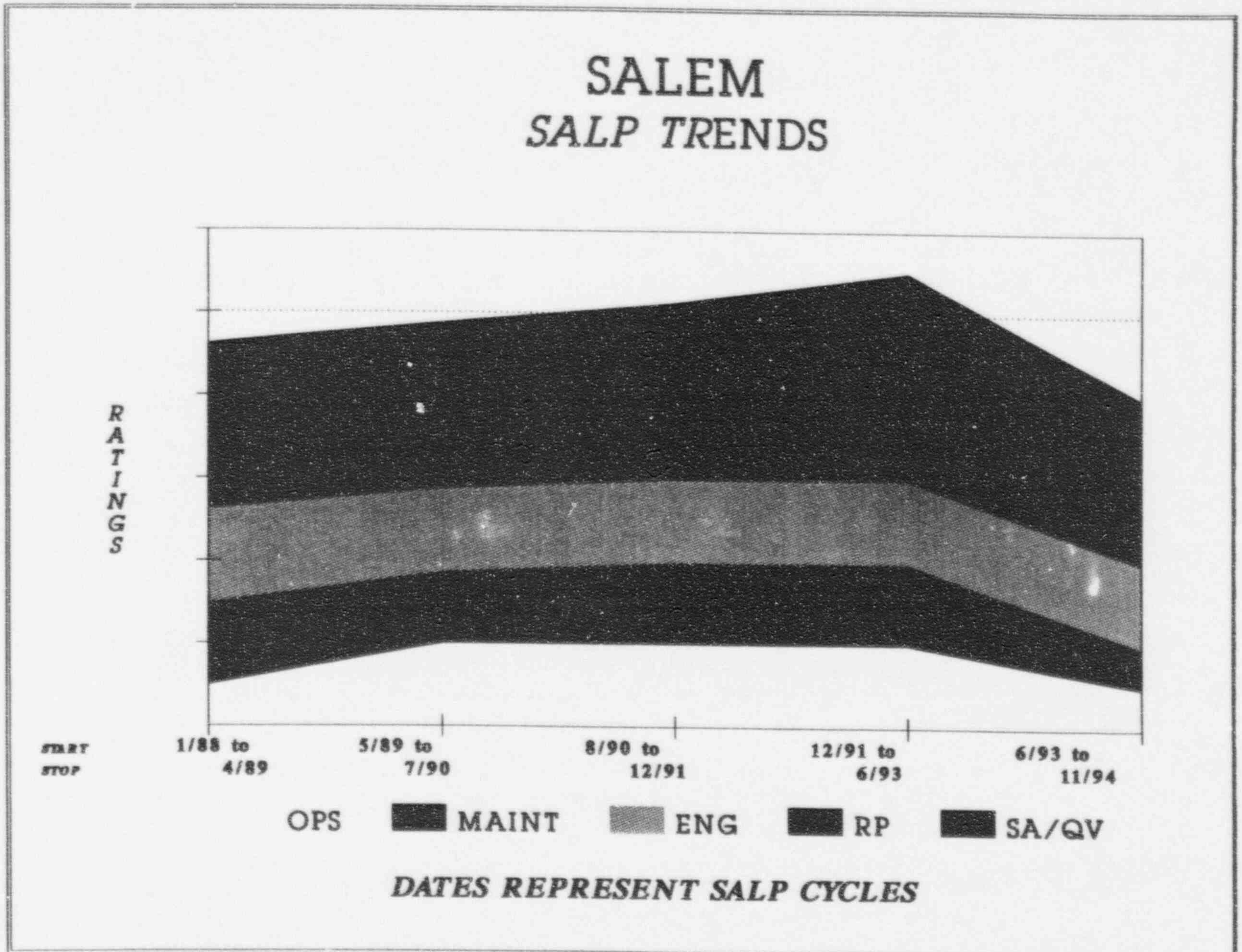
The NCO need only sign the log once immediately following his last entry at Shift Relief.


SALEM
SALP TRENDS
Plant Mgr
ZUPKO
MILLER
LABAW
VONDRA
HAGAN
SUMMERS
8/88
9/90
4/91
2/94
1/95
SUM OF RATINGS
0
2
4
6
8
10
12
14
START
STOP
1/88 to 4/89
5/89 to 7/90
8/90 to 12/91
12/91 to 6/93
6/93 to 11/94
OPS
MAINT
ENG
RP
SA/QV
DATES REPRESENT SALP CYCLES
F/13

SALEM
SALP TRENDS

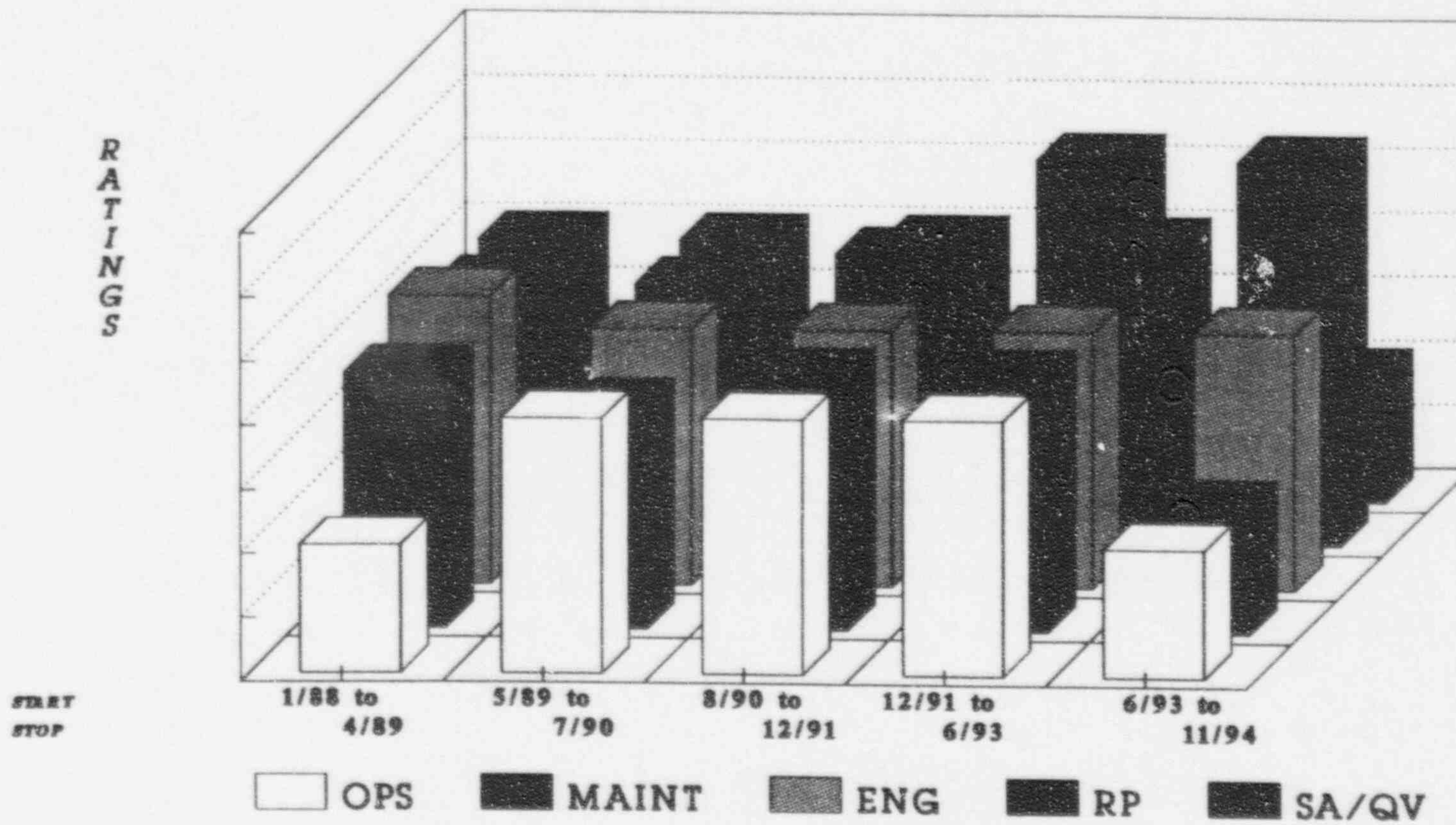


DATES REPRESENT SALP CYCLES


SALEM
SALP TRENDS
RATINGS
START
STOP
1/88 to 4/89
5/89 to 7/90
8/90 to 12/91
12/91 to 6/93
6/93 to 11/94
OPS
MAINT
ENG
RP
SA/QV
DATES REPRESENT SALP CYCLES

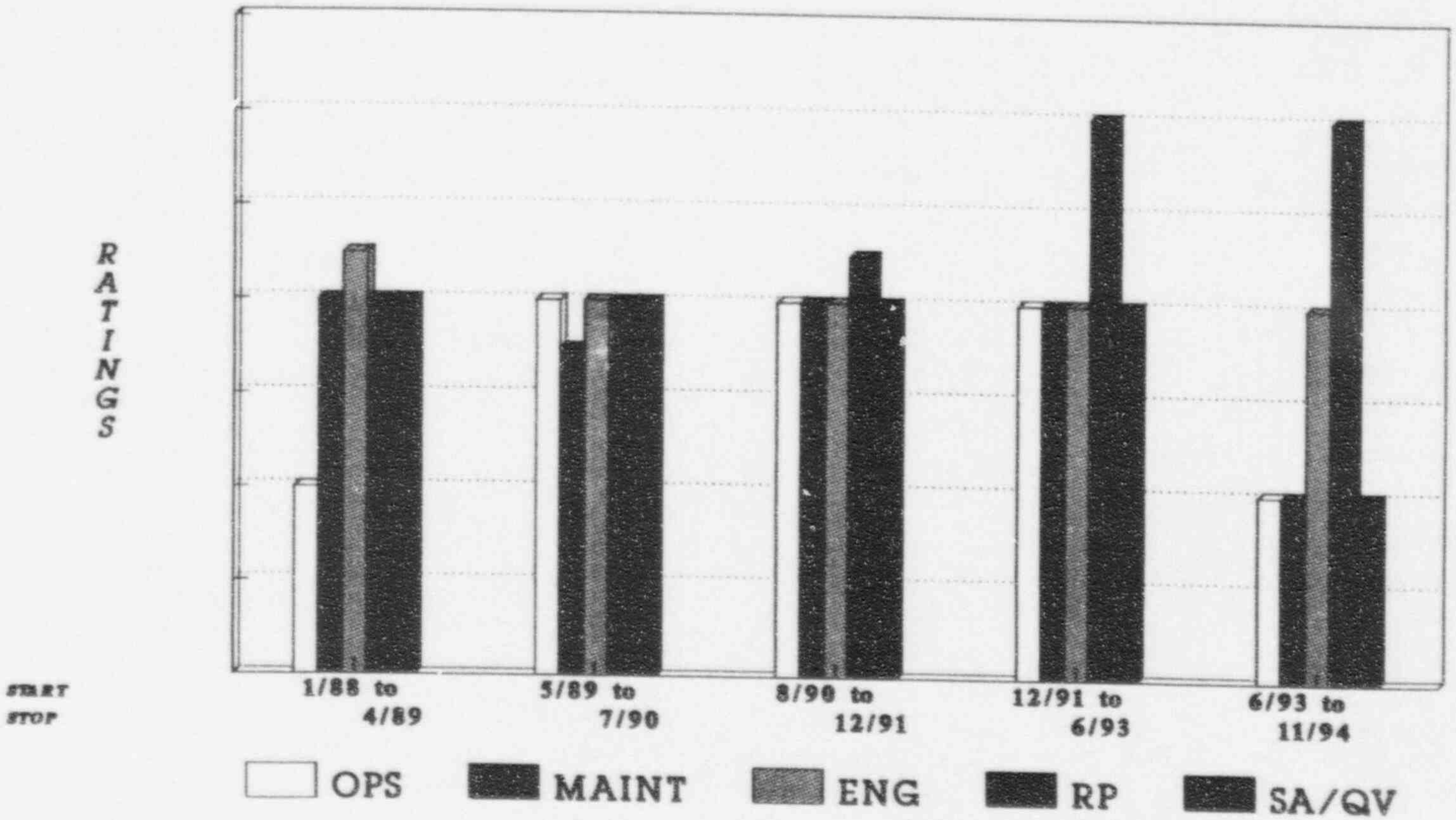
SALEM

SALP TRENDS



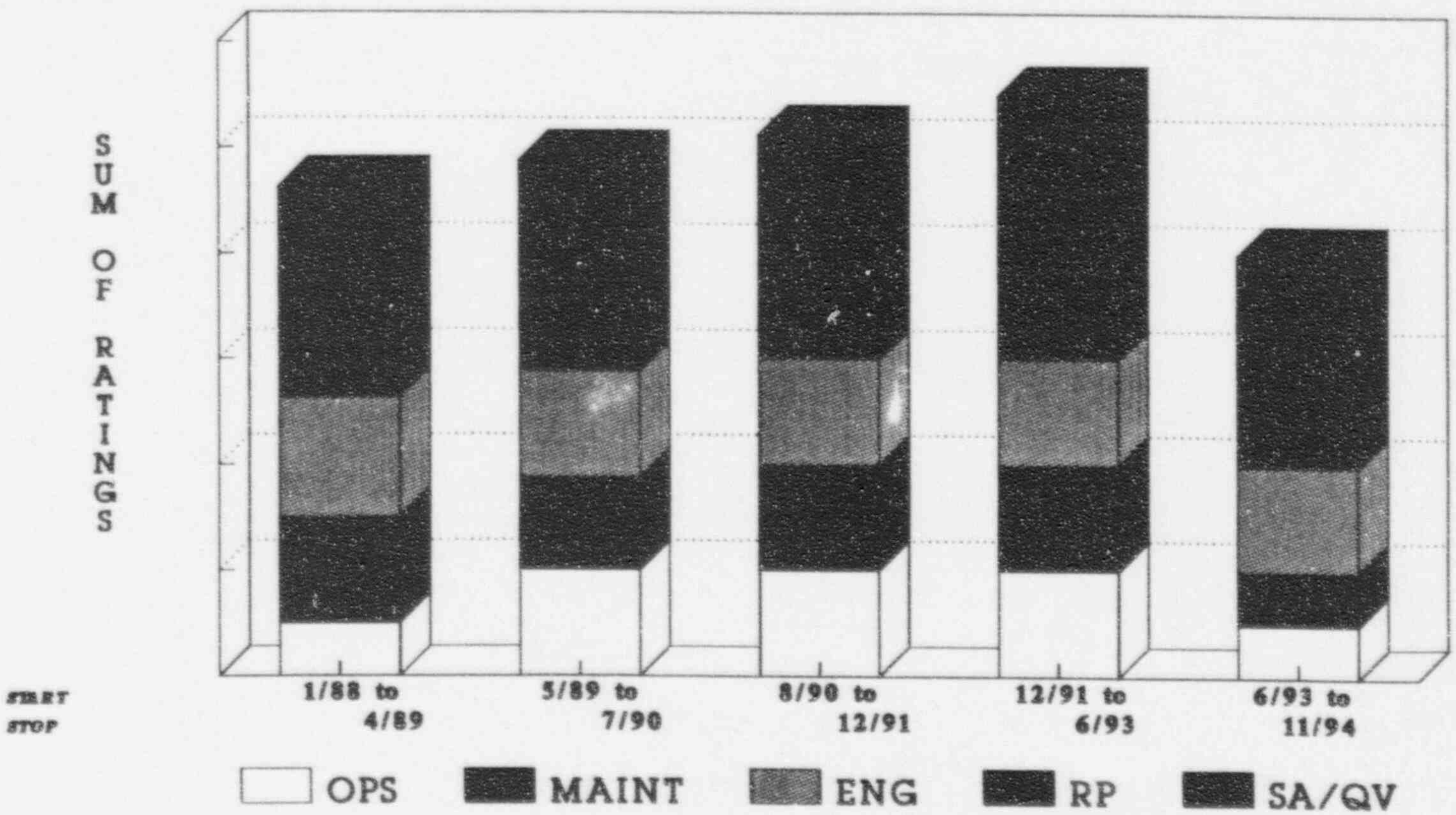
DATES REPRESENT SALP CYCLES

SALEM
SALP TRENDS

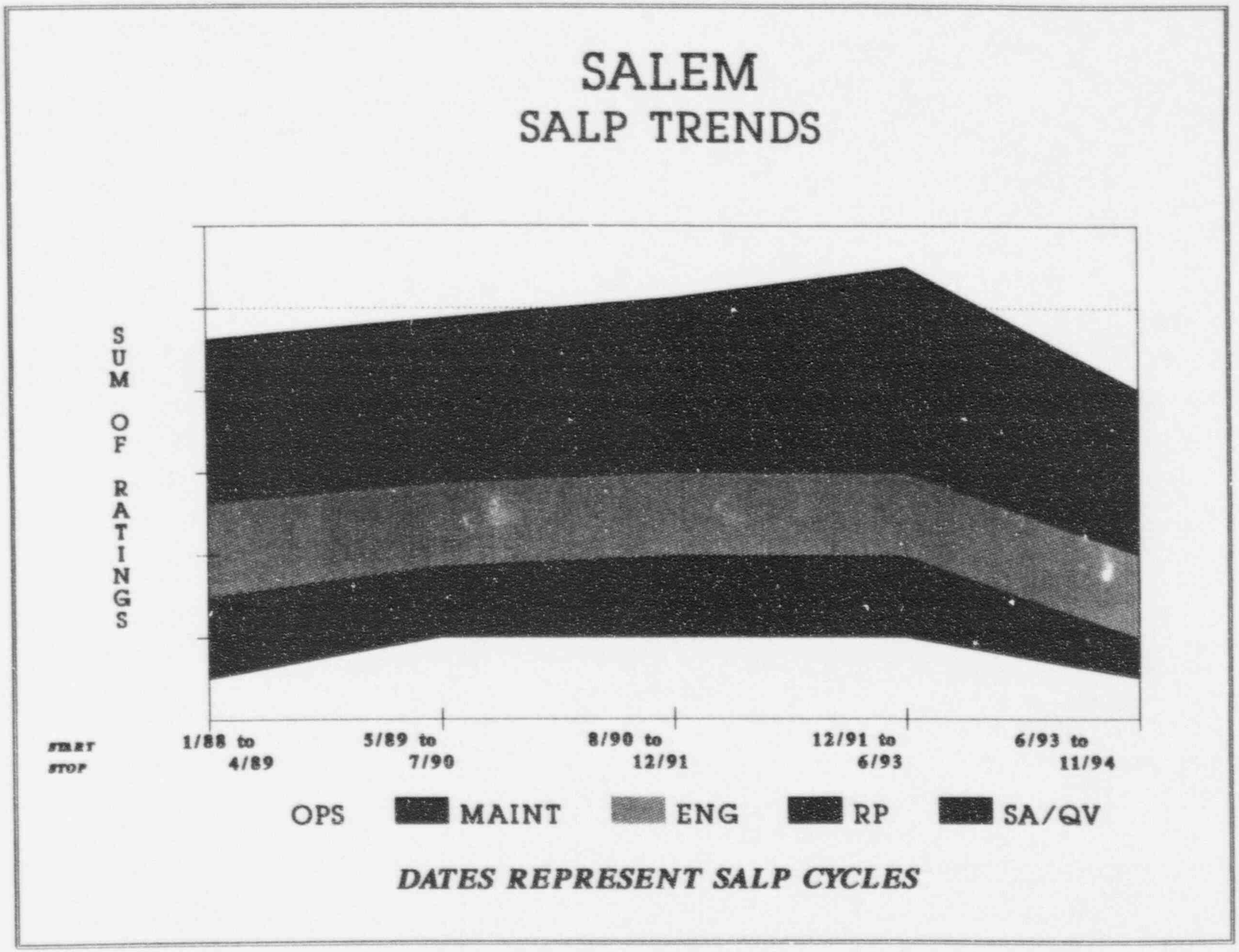


DATES REPRESENT SALP CYCLES

SALEM
SALP TRENDS



DATES REPRESENT SALP CYCLES



SALEM
SALP TRENDS
SUM OF RATINGS
START
STOP
1/88 to 4/89
5/89 to 7/90
8/90 to 12/91
12/91 to 6/93
6/93 to 11/94
OPS
MAINT
ENG
RP
SA/QV
DATES REPRESENT SALP CYCLES

The performance of the Salem Nuclear Generating Station was critically reviewed during the June 1995 Senior Management Meeting. On March 21, 1995, the NRC's Executive Director for Operations, Director, Office of Nuclear Reactor Regulation and the Regional Administrator, Region I, met with the license's Board of Directors to assure their understanding of NRC's concerns and confirm their commitment to improved performance. Since the latter meeting, the licensee has revised their corrective action plans, continued efforts to improve their management team, and established higher standards of performance for their staff, particularly licensed operators. On May 17, 1995, the licensee voluntarily shutdown Unit 1 to resolve concerns with switchgear room supply fans, committed to a comprehensive multi-discipline evaluation of all outstanding maintenance issues, revised and refocused the engineering support organization, and initiated a high level review of the problems which led to the Unit 1 shutdown.

Clearly, it will take time and significant effort to resolve the performance concerns at Salem. However, NRC senior managers concluded that facility performance at this time was neither declining nor at a point that justified placement on the NRC's problem plant list.

ENCLOSURE

EVALUATION OF AIT GENERIC CONCERNS

1. Technical Specification (TS) 3/4.3.4, Turbine Overspeed Protection.

   Technical Specification 4.3.4.2 requires that the turbine overspeed protection system be demonstrated operable at specified intervals by direct observation of the movement of each of the noted valves through at least one complete cycle from the running position. The action requirement specifies that with one inoperable valve per high and low pressure turbine, the inoperable valve(s) be restored to operable status within 72 hours. Thus, while the LCO does not specify that redundant overspeed protection systems are to be operable, the action and surveillance requirements address requirements for the redundant valves used to trip the turbine on overspeed. Because the overspeed protection system closes redundant valves (two valves in series), the allowable outage time of 72 hours is consistent with other technical specification action requirements.

   However, Technical Specification 4.3.4.3 also requires that the turbine overspeed protection systems be demonstrated operable at least once per 18 months by performance of a channel calibration. This technical specification requires the disassembly and visual inspection every 40 months of at least one of each type of the trip valves. In addition to the noted action requirements for inoperable valves, the actions specify that with the turbine overspeed protection system otherwise inoperable, it be restored to operable status within 6 hours or the turbine must be isolated from the steam supply. Hence, the surveillance and action requirements address requirements for both the overspeed protection system and the valves that close to trip the turbine.

   As for the STS not specifically requiring surveillance testing of the overspeed protection circuit (OPC), the OPC is considered to be a control rather than a protection system. The staff does not consider that an operable OPC would satisfy the limiting condition for operation for an operable overspeed protection system for any plant nor that the OPC is subject to the technical specification requirements for overspeed protection systems.

   The latest edition of the Westinghouse STS includes requirements in Technical Specification 3/4.3.2, "Engineered Safety Features Actuation System Instrumentation", that address turbine trip, the associated automatic initiation logic, and the instrument channels that initiate turbine trip and feedwater isolation on high steam generator water level. Also, the P-4 interlocks, consisting of two trains of reactor trip and bypass breaker position sensors that initiate turbine trip, are also

H15

addressed under the limiting conditions for operation and surveillance requirements. The technical specifications for some plants, including Salem, do not contain the requirements for automatic actuation logic or the P-4 interlock. The staff feels this is an oversight and should be corrected in those technical specifications. However, this would be a backfit and would have to be justified to require licensees to propose changes in their plant technical specifications. Consideration will be given to the need for further action on this matter.

The staff agrees that the STS requirements for turbine overspeed protection system, Technical Specification 3/4.3.4, could be more clearly written. The staff also believes that any misunderstanding on their applicability can be clarified by a generic communication without the necessity to change the current STS. The sufficiency of the STS for turbine overspeed protection and the need for any changes will be included as part of the reevaluation of the safety aspects of turbine missiles based upon the Salem event. In addition, action is being taken as part of the technical specification improvement program to improve the construction, clarity, and intent of technical specifications and their bases in the development of the new STS. This effort includes the relocation of many existing requirements from the STS based upon criteria that was included in the Commission Policy Statement on Technical Specification Improvements. The turbine overspeed protection specification is one of those requirements that is to be relocated and will not be included in the new STS.

Technical Contact:
Tom Dunning, OTSB, FTS 964-1189

2. Solenoid Valve Failures

As a short term response the NRR staff issued Information Notice 91-83, "Solenoid-Operated Valve Failures Resulted in Turbine Overspeed." We believe that this notice, Generic Letter 91-15, and ongoing staff discussions with industry on SOV reliability have sufficiently alerted licensees on the potential problems and consequences of SOV failures in turbine protection applications. The Salem event also demonstrated the strong economic incentive to improve turbine control system reliability.

Additionally, the EDO has asked AEOD to perform a study of turbine-related operating experience to identify generic turbine related safety concerns.

In the long term we will continue to monitor the SOV failure issue. We consider the current guidance to be adequate. We do not consider further generic communications on SOVs to be warranted at this time.

Technical Contact:
Jerry Carter, OEAB, FTS 964-1153

3. Turbine Generator Fires.

   In response to the Vandellos Nuclear Power Plant (Spain) turbine rotor failure and the secondary fire event, NRR developed an action plan to examine the event scenario and performed an assessment of the potential vulnerabilities an event of this magnitude may have on U.S. facilities. The staff, as a part of this assessment, conducted an on-site review of the turbine generator, and turbine building fire protection features available to mitigate the consequences of a hydrogen and/or lube oil fire resulting from a catastrophic failure of the turbine (e.g., overspeed, rotor failure). This on-site assessment of turbine generator and turbine building fire protection features was performed at six U.S. facilities (Brunswick, V.C. Summer, Point Beach, Prairie Island, Calvert Cliffs, and Susquehanna).

   As a result of these assessments, residual fire risk vulnerabilities were identified in the area of fire protection and the mitigation of the secondary fire events resulting from a turbine failure. These residual vulnerabilities are currently being evaluated by NRR. Upon completion of this evaluation, it is anticipated that, as a minimum, a summary of residual turbine generator fire risk vulnerabilities will be presented to the industry in a future NRC Information Notice.

   Technical Contact:
   Pat Madden, SPLB, FTS 964-2854

4. Balance of Plant Systems.

   In Item 4, you suggested that an NRC program review and evaluation was warranted to determine if sufficient regulatory attention is directed to Balance of Plant (BOP) systems that have the potential to adversely affect or challenge the operation of safety-related systems, structures, and components. An example was given that current NRC inspection program requirements direct little attention to such systems as the turbine control system even though the turbine control system affects (and is affected by) the reactor protection system.

   Such a review and evaluation has basically already been conducted. The NRR staff believes that the major concerns identified above have been addressed by the final maintenance rule, issued July 10, 1991, (56 FR 31306) under 10 CFR 50.65. The final rule specifically addresses nonsafety-related structures, systems and components (SSC): (1) That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures; or (2) Whose failure could prevent safety-related SSC from fulfilling their safety-related function; or (3) Whose failure could cause a reactor scram or actuation of a safety-related system.

The NRR staff has also provided inspection guidance for BOP systems. This guidance was issued September 30, 1988, as Inspection Procedure (IP) No. 71500, "Balance of Plant Inspection" and is included in the Inspection Manual.

Over the years, the staff has been concerned about the level of attention given to the BOP systems by the licensees. The most recent studies such as NUREG/CR-5622, "Analysis of Reactor Trips Originating in the Balance of Plant Systems," issued in September, 1990, and the AEOD Annual Reports (NUREG-1272) show that licensee performance in the BOP areas has continued to improve since 1984.

With the issuance of the final maintenance rule, and the continued improvement of most licensees, we do not believe further regulatory requirements are required at this time. However, we continue to evaluate regulatory requirements for nonsafety-related systems as part of our review of the passive advanced light water reactor (ALWR) designs which rely on nonsafety-related systems as their first line of defense against design basis accidents. Any insights gained from the ALWR reviews could be considered for applicability to present reactor designs if such insights were considered to be of sufficient safety significance.

Technical Contact:
Bill Lafave, SPLB, FTS 964-3285

5. Turbine Missile Generation Analysis.

The staff believes that the immediate safety concern is the failure of the turbine overspeed protection system (i.e., solenoid valve failure) rather than the generation of turbine missiles. The regulatory emphasis should be placed on maintenance and inspection of the turbine overspeed protection system to prevent turbine overspeed.

However, we agree with your assessment that the SRP needs to be re-evaluated. The following actions are being taken:

1. SRP 3.5.1.2, "Turbine Missiles," will be revised to include the current review procedures on the turbine missile probability calculation and to address the probability of blade failure and the probability of the failed blades penetrating the turbine casing.

2. SRP 10.2.3, "Turbine Disk Integrity," will be revised to include procedures for reviewing blade integrity and for reviewing the latest turbine design such as one-piece rotor construction.

We will incorporate our SRP revision activity into the upcoming Standard Review Plan Update and Development Program which is being coordinated by the Policy Development and Technical Support Branch; Program Management, Policy Development, and Analysis Staff of NRR.

Technical Contact:
John Tsao, EMCB, FTS 964-2702

DISCUSSION OF INDIVIDUAL VIOLATIONS

INDIVIDUAL ENFORCEMENT ISSUES

CRITERION XVI/V:

- Reactor Head Vent Valve Limit Switches -- Safety Classification
  - IR 95-02 (B.1)
- Power Operated Relief Valve -- TS Action Statement
  - IR 95-02 (B.2)
- Reactor Head Vent Valve 2RC40 -- Test Failure
  - IR 95-02 (B.3)
- Oil Issues -- Degraded Conditions
  - IR 95-07 (1-3)
- Battery Charger -- Internal Inspection Work Order
  - IR 95-07 (4)
- Pressurizer Code Safety Valves -- Set Point Tolerances
  - LER 95-05; IR 95-07 (5)
- RHR Pump Minimum Recirculation Flow Valves -- Failure to Open
  - IR 95-10 (A)
- Switchgear Ventilation Supply Fan -- Evaluation of Operability
  - IR 95-10 (B)
- Containment Personnel Airlock -- Gasket Condition
  - IR 95-10 (C)

INDIVIDUAL ENFORCEMENT ISSUES

CRITERION XVI/V
(continued)

- EDG Jacket Water Cooling System -- Instrument Line Failures
  - IR 95-10 (D)
- Residual Heat Removal Discharge Valve RH10 -- Impact Noises
  - IR 95-10 (E)
- Pressurizer Code Safety Valve 2PR66 -- Mispositioned Following Modification
  - IR 95-02 (A)

PRESSURIZER OVERPRESSURE PROTECTION SYSTEM (POPS) ISSUES

- IR 94-32

- Failure to Report Condition Outside Design Basis (50.72 and 50.73)
- Reliance on Unapproved Code Case (50.60)
- Failure to Perform Safety Evaluation (50.59)
- Failure to Timely Correct (Criterion XVI)

10 C.F.R. PART 50, APPENDIX B, CRITERION V

Pressurizer Code Safety Valve 2PR66

Issue:

During a modification to install a drain system for the Unit 2 Pressurizer Code Safety Valve Loop Seals, NBU did not adequately ensure that the drain valves were properly positioned prior to plant startup following installation. Specifically, valve 2PR66 was left closed throughout the operating cycle between May 1993 and October 1994. As a result, Unit 2 operated with the loop seals filled with water.

NBU Position:

NBU agrees with the finding.

Root Causes:

- Tagging Request Inquiry System (TRIS) Database backlog (6000 changes) was accepted; not timely addressed.

- Less than adequate turnover acceptance of the Design Change Package (DCP) by Operations. In particular:

  - The Operations DCP Coordinator only verified that the component was added to the TRIS Database and did not confirm that the component was added to the appropriate lineups.

  - The TRIS Coordinator did not create an auxiliary lineup according to procedure.

  - 2PR66 was not added to RC-MECH-001 lineup in a timely manner.

10 C.F.R. PART 50, APPENDIX B, CRITERION V

Pressurizer Code Safety Valve 2PR66

Significant Corrective Actions:

- TRIS backlog reduced to zero and being maintained at zero.
- Design Change Packages from most recent Unit 1 and Unit 2 Refueling Outages were reviewed.
- Design Change Process to be revised to include final component position.
- Enhancements to be made to "Change Package Turnover" requirements.

Potential Consequences:

- Engineering evaluation determined that no unacceptable restriction of pressure relief flow or pipe whip effects would have resulted from valve mispositioning.
    - Thermal hydraulic analysis performed to determine hydrodynamic effect of Power Operated Relief Valve (PORV) and safety valve actuation.
    - Hydrodynamic loads combined with other load conditions (i.e., deadweight, thermal, seismic) determined to be acceptable.
    - Piping and supports operable above elevation 131' 4"; functional below.

PRESSURIZER OVERPRESSURE PROTECTION SYSTEM (POPS) ISSUES

POPS protects RCS from exceeding TS pressure/temperature (P/T) limits by opening two Power Operated Relief Valves (PORVs) during low temperature overpressure (LTOP) transients. POPS designed to meet single failure criterion -- either PORV would have sufficient relief capacity to limit peak pressure below P/T limit.

March 1993	Westinghouse Nuclear Safety Advisory Letter (NSAL) re. nonconservatisms in setpoint methodology for POPS.
September 1993	Westinghouse provided Salem-specific bounding calculation results (Delta-P).
December 1993	PSE&G completed re-evaluation to address NSAL; peak transients could exceed P/T limits.
December 1993	Issue dispositioned by administratively limiting maximum number of Reactor Coolant Pumps (RCPs) in service and increasing P/T limit by 10% based on unapproved Code Case N-514.
January 1994	System Engineer questions use of unapproved Code Case; indicates Westinghouse analyses acknowledges exceedance of Appendix G P/T curves.
April 1994	Discrepancy Evaluation Form (DEF) initiated to address NSAL issue without reliance on Code Case N514; no operability concern identified.
May 1994	Second resolution of NSAL issue: Unit 1 TS P/T curve limit of 450 psig exceeded by 0.7; noted that RH3 and GOTHIC computer code would provide necessary margin.
September 1994	Problem Report (PR) by Mechanical Engineering; identified problem with relying on pressure "bubble".
October 1994	PR resolution, based on crediting existing administrative controls, revised POPS design basis transient.
November 1994	Incident Report by Nuclear Licensing and Regulation addressing error in revised POPS transient assumption; exceeds TS P/T limits. Neither Westinghouse or industry had identified this aspect of the issue.
December 1994	LER 94-017-00 for Unit 1.

POPS ISSUES

1. 10 CFR 50.72 AND 50.73 (Reportability)

Issue:

Personnel became aware -- in December 1993 -- that the margins to TS P/T limits were reduced/lost; both Units were in an unanalyzed condition outside the Design Bases. Failure to report the condition is an apparent violation of 10 CFR 50.72 and 50.73.

NBU Position:
NBU agrees with the finding. The issue should have been recognized as reportable in December 1993.

Root Causes:

- Lack of understanding of the regulatory significance (i.e. reportability implications) of the Westinghouse analysis results.
- Failure to utilize formal processes.
- Insufficient management monitoring of the process.
- Inadequate organizational interface.

POPS ISSUES

2. 10 CFR 50.60 (USE OF AN UNAPPROVED CODE CASE)

Issue:

Reliance on an unapproved ASME Code Case N-514, without the required exemption, is an apparent violation of 10 CFR 50.60. The Code Case was used in the December 1993 disposition; an exemption request was not submitted until December 1994.

NBU Position:

NBU agrees that reliance was inappropriately placed on the unapproved Code case in December 1993.

Root Causes:

Prior to January 25, 1994

- Personnel performing the activity were inadequately trained for the task.
- Organizational interface was inadequate when Code Case was initially applied.

After January 25, 1994

- Inadequate supervisor/management sensitivity to implement existing corrective action procedures and/or processes.

POPS ISSUES

3. 10 CFR 50.59 (Safety Evaluations)

Issues:

Failure to perform a safety evaluation -- between October 1994 and December 1994 -- to determine if the change in the POPS design-basis transient had created an "unreviewed safety question" is an apparent violation of 10 CFR 50.59.

NBU Position:

NBU agrees with the finding.

Root Causes:

- The need for a safety evaluation was not recognized.
  - Personnel involved lacked objectivity -- they believed there was little safety significance to the issue and were focused on resolving the issue without consideration of associated regulatory requirements (i.e., 50.59).

POPS ISSUES

4. 10 CFR 50, APPENDIX B, CRITERION XVI (TIMELY RESOLUTION)

Issue:

Failure to initiate timely or effective corrective actions to address the POPS setpoint issue is an apparent violation of Criterion XVI. PSE&G attempted to resolve the issue for over one year without entering the issue into either of the two existing quality systems for engineering discrepancies (the Incident Report system and the DEF process). The final resolution was not complete as of December 1994.

NBU Position:

NBU agrees with this finding. A DEF should have been initiated as early as March 1993. There were also many opportunities missed to initiate an Incident Report.

Root Cause:

A lack of supervisor/management sensitivity to the need to implement existing programs, procedures, and processes, resulted in a failure to enter this issue into the Corrective Action Programs.

POPS ISSUES

SAFETY SIGNIFICANCE

- Potential Consequences ultimately determined to be minimal, based on:

  - RH3 valve was available to limit peak pressure below Appendix G limit when POPS required to be in service.

  - Code Case N514 was ultimately accepted.

  - Westinghouse NSAL safety significance evaluation (stress analysis) indicated that periods of operation outside Appendix G would create no problem in regards to vessel integrity.

- Regulatory Significance derives from the broader implications: the failure to demonstrate rigorous adherence to established processes, to make prompt and conservative determinations on reportability and operability, and to efficiently deal with an engineering issue in a timely fashion.

POPS ISSUES

CORRECTIVE ACTIONS

- The Corrective Action Program has been significantly improved.

- Management has re-emphasized supervision's primary role to assess emerging issues objectively as opposed to helping develop a solution.

- Guidance has been provided to appropriate Engineering personnel on ASME Code application.

- Procedure and program commitment and compliance has been re-emphasized, especially in the area of "Corrective Action".

- Personnel involved have received appropriate reinforcement on procedure compliance, responsibility for compliance with licensing commitments, and problem reporting.

- Management has re-emphasized that 10 CFR50.59 is applicable if revisions to calculations/evolutions alter either the design basis, basis of analysis, or conclusions in the FSAR.

- Lessons learned from these events will be disseminated to appropriate personnel.

POPS ISSUES

ENGINEERING PERSPECTIVES

- Personnel and organizational assessments.
- Regulatory process training.
- Close licensing/engineering interface.
- Sensitive issues awareness.

CLOSING REMARKS

- Corrective actions address:
  - Broad implications of issues -- Management and Corrective Action Program.
  - Numerous Criterion XVI examples.
    - PR66 issue consistent with Criterion XVI.
- Additional examples likely as result of ongoing efforts.
- Extensive corrective actions ongoing.
- Culture and performance will change.

APPENDIX - INDIVIDUAL CRITERION XVI ISSUES

10 C.F.R. 50, APPENDIX B, CRITERION XVI

Reactor Head Vent Valve Limit Switches

Significant Corrective Actions:

- Outstanding DEFs are being reviewed for impact on operability prior to restart.
- Previously resolved DEFs with follow-up actions are being reviewed for completion of committed actions.
- Tracking process established for DEFs which require follow-up action.
- DEF process has been incorporated into the NBU Corrective Action Program.
- Corrective Action Program has been significantly improved.
    - NAP-6 training and IMPACT Plan initiatives will address expectations re: regulatory implications.
- Non-safety related limit switches will be replaced prior to restart of Unit 1.
- Non-safety related parts utilized in safety related applications are being evaluated for proper classification.

Potential Consequences:

- Impact on RHVV --

  Failure of limit switches in a manner that will impact the safety functions of the RHVV is not credible.

    - Non-safety related switches are identical to safety-related switches.
    - Control power is ungrounded (requiring two faults to disable power].
    - Switches (reed type) are encapsulated in glass.

- Impact on indication --

  Common mode failure is not credible. Single failure will be indicated by having both open and close indication or not at all for a single valve.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Power Operated Relief Valve - TS Action

Issue:

On February 24, 1995, Unit 1 operators placed control of a PORV in manual mode (rendering it inoperable), and failed to adhere to the Technical Specification (TS) 3.4.3 action statement. This performance error is similar to a violation of the same Technical Specification requirement involving Unit 2 on March 24, 1994. NBU's corrective actions for the earlier event do not appear to have been effective in preventing recurrence of the recent performance deficiency.

NBU Position:

NBU agrees this was a performance deficiency.

Root Cause:

- Failure of operations crews to satisfy expectations.
- Narrow focus of previous corrective actions.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Power Operated Relief Valve - TS Action

Significant Corrective Actions:

- Operating shift, as well as oncoming shift, counseled regarding expected level of performance.
- Modifications to Corrective Action Program will improve scope of corrective action efforts.
- Modifications to Technical Specification Action Tracking procedure.

Potential Consequences:

- Failure to implement TS action statement in a timely manner did not have an adverse impact on the unit because:
  - Block valve did not have leakage at the time.
  - A stuck open PORV is a low probability event.
  - Stuck open PORV is addressed in Emergency Operating Procedures (EOPs).
  - No impact of manually open PORV and open block valve on operator response if an event requiring the PORV had occurred.
  - Steam generator tube rupture is worst case applicable event and would not have been adversely affected by the as-found configuration.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Reactor Head Vent Valve 2RC40 -- Test Failure

Issue:

On July 6, 1994, safety related reactor head vent valve 2RC40 failed to separate (stoke open) during testing while Unit No. 2 was in cold shutdown. This failure was never documented and formally assessed relative to preventive maintenance, operability, actions to prevent recurrence, or generic implications.

NBU Position:

NBU agrees with the finding.

Root Cause:

- Unacceptably high reporting threshold.
  - Inadequate management expectations.
  - Inadequate culture regarding evaluation, resolution, and documentation of events.

Significant Corrective Actions:

- Corrective Action Program modifications will result in lower threshold, clearer management expectations, and documentation of events.
- Expectations to be communicated and reinforced by management on a continual basis.
- Assessment performed to ensure that similar component failures have been properly documented and assessed for extent of condition.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Reactor Head Vent Valve 2RC40 -- Test Failure

Potential Consequences:

- Failure occurred in Mode 5 when valves are not required; valve did not stroke open at higher temperature and pressure while still in Mode 5.

- The Reactor Head Vent System is required in Modes 1-4 to vent off non-condensible gases subsequent to a LOCA during natural recirculation.

    - Failure to open would preclude venting.

    - Failure to close would result in additional inventory lost from the Reactor Coolant System (RCS) [to the Pressurizer Relief Tank (PRT) and eventually to the containment Emergency Core Cooling System (ECCS) sump].

- NBU Probabilistic Risk Assessment (PRA) for loss of Head Vent System while in Mode 1:

    - Failure to open - risk significance not readily calculated but judged to be low (valves are not credited in Chapter 15 analyses or in PRA).

    - Failure to close - risk significance considered negligible.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Oil Issues

Issues:

- An oil sample laboratory report, dated August 4, 1994, recommended resampling and changing the oil on the No. 21 high-head safety injection pump based upon a ten-fold increase in wear concentration.

- An oil analysis, dated November 28, 1994, identified high wear particle concentration in the No. 22 high-head safety injection pump speed increaser oil.

- A lab report, dated October 6, 1994, recommended resampling the No. 23 Auxiliary Feed Auxiliary Feedwater (AFW) turbine lube oil due to a trace amount of water found and a marked increase in wear concentration particles.

NBU Position:

NBU agrees that these issues could have been more timely addressed.

Root Causes:

- Expectations regarding individuals' responsibilities in the performance monitoring program were not enforced.

- Turnaround time for lab analyses challenged the ability of the system engineer to make timely decisions.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Oil Issues

Significant Corrective Actions:

- Management's expectations have been clarified regarding system manager responsibilities in the performance monitoring program.
- The system manager concept has been implemented through reorganization, dedication, refocusing personnel, and individual reinforcement of individual system manager ownership, responsibility, and accountability.
- NBU management is assessing options for improving the turnaround time for sample results.

Potential Consequences:

- The underlying, specific technical issues had low potential for safety consequences because at no time was the equipment seriously degraded.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Battery Charger – Internal Inspection

Issue:

In May 1994, a System Engineer initiated a work request to inspect the 2A1 28 VDC battery charger Ground Detection Circuit wiring. The request was initiated following a system walkdown that revealed that the Unit 1 chargers were configured differently than Unit 2 chargers. The work order to conduct the charger internal inspection was not performed until late 1995, and when conducted discovered that an incorrect configuration did exist.

NBU Position:

NBU agrees with the finding.

Root Cause:

- Personnel Failure.
  - Failure to properly prioritize the corrective maintenance work order.
  - Inadequate individual follow-through to ensure timely implementation of process.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Battery Charger – Internal Inspection

Significant Corrective Actions:

- Assessments of whether similar ground detection circuitry wiring discrepancies exist will be completed by 8/15/95.
- The method for prioritization of maintenance work orders will be improved by 8/31/95.
- Appropriate disciplinary action was taken for failure to prioritize.
- Modifications to Corrective Action Program will better ensure adequacy of prioritization of similar work orders.

Potential Consequences:

- The internal ground detection circuit (improperly installed in 2A1 VDC charger) did not affect the ability of the 28 VDC system to perform its safety function.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Pressurizer Code Safety Valves

Issue:

Salem personnel, when informed by the vendor of out-of-tolerance Pressurizer Code Safety Valves, failed to initiate an Incident Report (IR), and therefore, the NBU did not initiate timely root cause or reportability evaluations.

NBU Position:

NBU agrees with the finding.

Root Cause:

- Management expectations regarding when an IR was required (i.e., reportability) were unclear/inadequately communicated.
  - System engineers did not recognize reportability implications.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Pressurizer Code Safety Valves

Significant Corrective Actions:

- Personnel involved in failure to initiate IRs were counseled.
- The IMPACT Plan being implemented as part of the restart effort contains actions to improve the definitions of roles, responsibilities, and results expected which will be used to hold individuals accountable.
- Training was conducted on new NAP-6; NAP-6 addresses operability and reportability reviews, as well as initiation of ARs.
- Lessons learned will be incorporated into quarterly operating experience feedback (OEF) for Engineering support personnel (includes system managers and others).

Potential Consequences:

- Analyses which rely on PSV relief capability for mitigation meet all safety analysis criteria with/an assumed 3% setpoint tolerance.
  - These analyses were performed by Westinghouse for future UFSAR Chapter 15 changes.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

RHR Pump Minimum Flow Recirculation Valves

Issue:

- From February 9, 1995 through June 7, 1995, plant staff did not timely and adequately determine (and failed to correct) cause of failure of vales to open on low Residual Heat Removal (RHR) flow.

- RHR was inoperable until June 7, 1995.

NBU Position:

NBU agrees with the finding.

- Operating crews did not recognize the safety significance of valves' automatic open feature on January 26 and February 9, 1995.

- Operability was not assessed in a timely manner from June 3, 1995 until the June 7 shutdown decision.

Root Causes:

- Less than adequate management oversight and implementation of Generic Letter 91-18 associated with:

    - Recognizing the need for an Operability Determination program and procedure

    - Less than adequate training on Operability Determinations.

    - Less than timely review of maintenance backlog related to Operability Determinations.

- The implementation of Operability Flow Charts was less than effective in improving Operability Determinations.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

RHR Pump Minimum Flow Recirculation Valves

Significant Corrective Actions:

- Operability Determination expectations reinforced by management and supervision
- Issuance of Operations Directive - 2. "Operability Determinations."
- Training of Operations and Engineering personnel to reinforce expectations regarding application of Generic Letter 91-18.
- Ongoing reinforcement of operator awareness of Generic Letter 91-18 through requalification training.
- Review of the entire maintenance backlog for additional "Operability Determination" issues.
- Appropriate disciplinary actions.

Potential Consequences:

- EOPs adequately address valve failure to both open or close. In particular:
  - Closed: Westinghouse analysis concluded that no RHR pump damage would be expected to occur for approximately 45 minutes in a deadheaded condition
    - EOPs address securing RHR pumps -- 45 minutes provides adequate time for this action
  - Open: minimum required ECCS flow met with valves open (WCAP 10325).

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Switchgear Ventilation Supply Fan

Issue:

From December 12, 1994, until May 16, 1995, plant staff failed to correct or determine the cause of the failure of the #12 safety-related switchgear supply fan. As a result, during this time, Unit 1 operated with a safety-related power system incapable of withstanding a single failure.

NBU Position:

NBU agrees with the finding.

Root Causes:

- Operations personnel did not recognize that an operability assessment was required after the failure of the first fan (to address lack of standby fan).
- Neither Operations nor Technical Department took a leadership role in ensuring that the first fan was repaired in a timely manner.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Switchgear Ventilation Supply Fan

Significant Corrective Actions:

- Operations Directive, OD-02, was created to provide guidance to the SNSS/NSS for conducting Operability Determinations of Structures, Systems, and Components and for documenting review results.

- The IMPACT Plan being implemented as part of the restart effort contains actions to initiate a cultural change within the Operations Department (i.e., personnel must actively take a leadership role in pursuing needed repairs).

- The system manager concept has been implemented through reorganization, dedication and refocusing of personnel, and reinforcement of individual system manager ownership, responsibility, and accountability.

- Lessons learned will be incorporated into quarterly operating experience feedback (OEF) by engineering personnel.

Potential Consequences:

- With certain actions and controls, the system was capable of maintaining required temperatures. Even with an active failure of the last operating SPAV supply fan, coincident with a LOCA, Unit 1 could have been safely shutdown (assuming specified ambient outside temperatures, observed room temperatures, and using additional ventilation paths).

- PRA analysis also established acceptable risk for operation with both #12 and #13 fans inoperable for 5 days.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Containment Personnel Airlock Gasket

Issue:

On three separate occasions, Unit 1 staff failed to correct, determine cause, or prevent recurrence of the 100' elevation personnel airlock to pass its local leak rate test. From March 6, 1995, until May 8, 1995, the containment boundary was incapable of withstanding a single failure.

NBU Position:

NBU agrees with the Criterion XVI finding relative to timely corrective action. However, subsequent analysis shows the containment boundary was capable of withstanding a single failure and performing its intended function.

Root Causes:

- Practical root cause experience in the organization is limited.
- Corrective action evaluations were not given appropriate priority by Maintenance organization.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

Containment Personnel Airlock Gasket

Significant Corrective Actions:

- Increased department management oversight of Corrective Action Program; better prioritization brought about by the significance levels established in NAP 6.
- Established a core group of personnel to focus on root cause techniques to obtain experience on root cause evaluations.
  - As an interim step, added a utility loanee with root cause evaluation experience to the department staff.
- Assessed proper lubrication requirement with vendor.
- Reviewed other hatch openings that use this type gasket and determined that same conditions do not apply.

Potential Consequences:

- Four seals on each door -- 2 inner, 2 outer.
  - Each door has two seals.
- Airlock successfully passed 21 surveillance tests between March 6 and May 3 failures.
- Total containment leakage remained below TS limit.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

EDG Jacket Water Cooling – Instrument Lines

Issue:

From February 29, 1992, until June 7, 1995, Unit 1 staff failed to correctly determine the cause or take action to preclude recurrence of failures of instrument lines connected to the jacket water cooling system for the 1B and 1C Emergency Diesel Generators (EDGs).

NBU Position:

NBU agrees with the finding.

Root Causes:

- The root cause of the piping nipple failure was an inadequate vibration tolerant design.
  - Failure mode was vibration induced fatigue cracking.
  - Contributing cause was a lack of specification of dimensions potentially critical to vibration tolerance on manufacturer documentation.
- The root cause associated with inadequate design modification implemented in 1986 was:
  - Failure to perform adequate post-modification testing to validate the effectiveness of the modification.
  - Lacking validation of the modification, failure to establish a conservative "qualified life" for the piping nipples.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

EDG Jacket Water Cooling – Instrument Lines

Root Causes (cont'd):

- The root causes associated with the inadequate corrective action following the 1992 1C failure were:
    - Lack of required knowledge associated with prior failures.
    - Failure to perform any failure analysis.
    - Inappropriate corrective action process root cause determination threshold.
- The root causes associated with the inadequate corrective action following the 1993 1B failure were:
    - Personnel did not know or seek out all available information associated with prior failures.
    - Wrong assumptions were utilized in defining corrective actions.
    - Corrective action to re-position the tubing supports was not identified in a timely manner and was not completed.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

EDG Jacket Water Cooling -- Instrument Lines

Significant Corrective Actions:

- Upon discovery, compensatory actions were taken by Operations to assure make up water was available.
- Interim adjustment of 1B and 1C EDG piping was implemented to reduce the potential for resonance.
- Design changes have been identified and will be implemented for all EDGs prior to restart.
- A vibration tolerance design review will be performed for all EDGs and peripheral equipment.
- Lessons learned from this event are in the process of being communicated to all appropriate Engineering personnel.
- Appropriate material will be incorporated into the maintenance and planning department training programs.
- Component Failure Analysis training has been conducted for approximately 67 individuals (design and system engineering personnel).
- The Corrective Action Program has been significantly improved.

Potential Consequences:

- The plant is designed to safely shutdown with two out of three EDGs. It is considered unlikely that failure of two EDG jacket water lines would occur within the period required to perform emergency repair for a first failure. Based on the failure mechanism, it is expected that sufficient time would be available for operators to detect the first jacket water leak to perform emergency repairs. Event recovery success is dependent upon the success of operator intervention to restore jacket water cooling to the failed EDG.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

RHR Discharge Valve RH10 – Impact Noise

Issue:

From July 1, 1992 until June 10, 1995, Salem staff failed to determine the cause of, correct, or prevent recurrence of impact noise from the interior of the No. 21 RHR discharge manual isolation valve.

NBU Position:

NBU agrees with the finding.

Root Causes:

- Inadequate Management/Supervisory Oversight
    - Lack of engineering analysis of the physical condition of the valve.
    - Lack of discipline by system engineer regarding tracking, trending, and record keeping.

10 C.F.R. PART 50, APPENDIX B, CRITERION XVI

RHR Discharge Valve RH10 – Impact Noise

Significant Corrective Actions:

- Valve will be disassembled and an engineering analysis will be written to document and validate the suspected cause of the impact noises.

- System manager concept has been implemented through reorganization, dedication, refocusing of personnel and reinforcement of individual system manager ownership, responsibility and accountability.

Potential Consequences:

- Issue does not appear to impact operability.

- Failure modes and effects for 21 RH10 were considered: in no case is the plant left with a loss of RHR.

SALEM PRELIMINARY ASSESSMENT NOTES

ROBERT GALLO - TEAM MANAGER

JEFFREY JACOBSON - TEAM LEADER

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Customized Inspection Planning Process

Phases of Assessment

* Review of Performance Insights
* Site Visit
* Final Analysis & Develop Inspection Recommendations

Customized Inspection Planning Process

Types of Information Reviewed

* Inspection reports(last 2 years)
* Plant performance review results
* Last SALP report
* Enforcement history
* Senior management meeting licensee performance input & results
* LERS (last 2 years)
* LER analysis
* Performance indicators(last 2 years)
* Licensee self-assessment

Operations / Customized Inspection Planning Process

Operations Areas

Safety Focus & Management Involvement
- 11 sub-areas

Problem Identification & Resolution
- 12 sub-areas

Quality of Operations
- 7 sub-areas

Programs & Procedures
- 5 sub-areas

LICENSEE CONTROL SYSTEMS

EXCESSIVE CHALLENGES TO THE PLANT CAUSED BY THE FAILURE TO RESOLVE KNOWN EQUIPMENT AND OPERATIONAL DEFICIENCIES.

- o ROD CONTROL SYSTEM ANOMALIES
- o RADIATION MONITOR SPURIOUS ACTUATIONS
- o CIRCULATING WATER SYSTEM SCREEN CLOGGING

LICENSEE CONTROL SYSTEMS

INSPECTION FOCUS AREAS

ARE PROBLEMS BEING IDENTIFIED AND RAISED TO PROPER LEVELS OF MANAGEMENT?

IS MANAGEMENT ASSIGNING THE PROPER PRIORITY TO RESOLVING THE ISSUES?

ARE ALL PERTINENT ASPECTS OF THE ISSUES PROPERLY UNDERSTOOD BY THE RESPONSIBLE ORGANIZATIONS?

DO THE PERFORMANCE INDICATORS, BEING UTILIZED BY MANAGEMENT, APPROPRIATELY IDENTIFY PERFORMANCE WEAKNESSES? WHAT OTHER METHODS ARE BEING UTILIZED TO ASSESS PERFORMANCE?

OPERATIONS

SPORADIC SAFETY FOCUS EXHIBITED DURING CONTROL ROOM OPERATIONS.

- NO PROGRAMMATIC OPERABILITY GUIDANCE HAS BEEN DEVELOPED

  DEFICIENCY REPORTING SYSTEM DOES NOT INCLUDE OPERABILITY ASSESSMENT

- WEAK STATUS AND CONTROL OF OUT-OF-SERVICE EQUIPMENT

- RESTART DECISIONS NOT ALWAYS CONSERVATIVE

OPERATIONS

INSPECTION FOCUS AREAS

REVIEW EQUIPMENT CLEARANCE ORDER PROCESS AND OPERATIONS CONTROL OF OUT-OF-SERVICE EQUIPMENT.

REVIEW OPERABILITY POLICIES/ DECISIONS/JCO'S.

REVIEW TECHNICAL SPECIFICATIONS INTERPRETATIONS.

ASSESS CONTROL ROOM COMMAND AND CONTROL.

ENGINEERING

ENGINEERING HAS NOT DEMONSTRATED THE ABILITY TO RESOLVE EQUIPMENT DEFICIENCIES.

- o CIRCULATING WATER SCREEN CLOGGING EVENTS
- o ROD CONTROL SYSTEM ANOMALIES
- o DIGITAL UPGRADES TO PLANT ANNUNCIATOR SYSTEM NOT FULLY UNDERSTOOD

ENGINEERING

INSPECTION FOCUS AREAS

DOES LARGE AMOUNT OF CONTRACT DESIGN WORK PREVENT THE LICENSEE FROM OBTAINING THE NECESSARY SYSTEM/EQUIPMENT KNOWLEDGE AND EXPERTISE TO RESOLVE EQUIPMENT DESIGN AND PERFORMANCE WEAKNESSES?

ARE RIGHT PROJECTS BEING APPROPRIATELY FUNDED/SCHEDULED FOR COMPLETION?

* IS ENGINEERING APPROPRIATELY INVOLVED IN EQUIPMENT TROUBLESHOOTING ACTIVITIES?

MAINTENANCE

NUMEROUS EQUIPMENT FAILURES AND MAINTENANCE PERSONNEL ERRORS CONTINUE TO CHALLENGE OPERATIONS.

- RADIATION MONITOR FAILURES
- FEEDWATER CONTROLLERS
- TRANSIENTS CAUSED BY PERSONNEL ERRORS
- CIRCULATING WATER SCREEN CLOGGING

MAINTENANCE

INSPECTION FOCUS AREAS

REVIEW ADEQUACY OF POST-MAINTENANCE TESTING PROGRAM.

ASSESS MANAGEMENT OVERSIGHT OF WORK ACTIVITIES.

ARE REPETITIVE EQUIPMENT FAILURES DUE TO MAINTENANCE OR ENGINEERING DEFICIENCIES?

IS MANAGEMENT PROVIDING APPROPRIATE ATTENTION TO BALANCE OF PLANT EQUIPMENT CONDITION AND OPERABILITY?

TECHNICAL SUPPORT

(EP, FIRE PROTECTION, SECURITY, HEALTH PHYSICS)

NO MAJOR WEAKNESS IDENTIFIED.

Entrance

Introductions

Purpose and Scope - Develop customized inspection plan based upon an objective
next SALP cycle

Schedule - 7:45 - 5:15 4:00 team meeting
Daily licensee briefing

Preliminary Exit - Thursday August 25 10:00 AM
Will Discuss Issues/and Perceived Weak Areas

Final Public Exit Sept. 8 or 9 Time Will Be Issued At That Time
Final Report By Oct 5 94-201

Inspection Logistics - Performance Based
Team Member Contacts

My role - ~~how still you understand~~ evaluate managements understanding of performance weaknesses and ~~what~~ re-actions have been taken to address them.

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Su	M	T	W	Th	Fri	Sat
		3:00 Meet with Hagen 4:00 TM	~~[illegible]~~ meeting Admin CR 9:00 Plant Eng Interface meeting Admin CR 12:30 CPAT Review [illegible] ~~[illegible]~~ 4:00 TM	8:00 [illegible] ~~Management~~ ~~Meeting~~ Admin CR 10:00 Management meeting with Hagen 3:30 Management Oversight Group (Mob Trailer) 4:00 TM	8:00 Management Meeting 9:00 Quality Council Meeting Lobby C/R 9:00 Management meeting with Hagen 4:00 TM	
	12:00 Quarterly Project Review 1:00 Briefing on circ water 2:00 Meet with Miltenberger 4:00 TM	9:30-12 ? (9:30) VP & CNO Staff meeting 4:00 TM	4:00 TM	10:00 Preliminary Exit		

Tues 8/16

Meeting with Joe Hagan

Operator Work Arounds operability John Morrison – summation of individual issues creating a safety concern.

Use of IPE ?

Validation (Reliance on Performance Indicators) ?

Motor Vehicle in protected area

Engineering involvement in Plant Activities

Unplanned Scrams Unit 1 vs Unit 2

Performance indicators for uneventful days of operation

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* SRO Work Control Center – Poor knowledge of Shutdown risk

~~Opers~~ Engineering involvement in day to day activities

BOP – walkdown material condition BOP good

service water screens – poor

MS-10 atmospheric reliefs – 4 of 8 leaking

RCA – very good, except for RHR rooms

Post Maintenance Testing ?

Operator work Arounds ? how are they documented

Labeling on Valves – Poor

Team meeting Wed

Performance Indicators

JCO's, Operability Determinations

Use of risk information

Breaker Testing 125 VDC Unit 1

Go over work plan

<u>Thur. meeting with Joe Hagan</u>

Good identification of deficiencies ~~with~~ using EMIS tags and tracking of items

Weekly operating experience meeting. (Good Interdept Participation)

* Large number of Operations requests to change procedures. (~1000)

Procedure quality is O.K. Backlog is increasing. No performance indicator?

* Fire Brigade: Leader & two members = no plant system training per App R

Design Engineering Program Looks Good

1. Good prioritization process
2. 43 design basis documents

Too many program enhancements at one time? specifically in operations.

<u>Thur Team meeting</u>

[illegible] in expectations plus increase in overnight work. Need examples of operations program changes (JD)

Are we evaluating Independent Assessments

Work tracking and fragmentation [illegible] [illegible] reporting System. Walk thru assessment tree

[illegible] Bulletin for Gallo.

* LFP140 fire protection foam for diesel fuel oil. Removed collar with danger tag.

* SERT procedure doesn't specify team member qualifications. Recent SERT was ineffective in

[illegible]

Material deficiencies. What happens when wrong parts make it to the field.

Root cause analysis on Screen wash pump failures.

Fri meeting with Joe Hagan

* 2FP140 Fire protection Foam For disel fuel oil. Removed collar with danger tag.

* SGRT Procedure doesn't specify team member qualifications, Not getting at root issues.

* Weak trending and Fragmentation in Deficiency Reporting Systems.

* operators stressed due to execution change on large amount of emergent work.

* operations procedure quality is O.K. Still a large backlog of procedure changes

* Planning support on backshifts is weak.

* planners not using IPE, PRA

Fri Team Meeting

Engineering Critical Issues List. Is it a true reflection of plant needs.
Good root cause and oversight of incident report program.
Maintenance not properly using procedures. (Breaker, damper support)
No acceptance criteria in breaker procedure. Inadequate detail.
~~PMT~~ Planners don't understand responsibility for PMT.
New troubleshooting procedures looked real good.
Shutdown risk use in control room. O.K.
Backshifts

Sat

Identify instances where engineers have pro-actively improved performance before problems [illegible] [illegible]
Look at Post Modification Testing.

Follow-up Items
Maint

4.1 Safety Focus
* pre activity briefings

Management [illegible]

4.4 Quality of Maint Work
* training of personnel

4.5 [illegible]

4.2 Problem Ident and Resolution
* Feedback mechanism for work [illegible]
* Review Maintenance Self Assessments

4.3 Material Condition
* Monitor failure rates

Licensee Control

1.1 Problem Ident

* Review DR samples/lack of evaluations
* Review QA surveillance effectiveness

1.2 Root Cause Analysis

* Check screen wash pump failures

1.3 Trending + Evaluation

* Evaluate programs/availability of trending data

1.4. Corrective Action Tracking Systems

* Check to make sure all 17 problem identification systems are tracked.

Engineering

3.1 Safety Focus

Management Involvement

* Staffing [illegible]

3.2 Problem [illegible] + Resolution

* plant [illegible]
* responsiveness to [illegible]
* backlog of operating experience feedback

3.3 [illegible] Design

Calculation availability

3.4 Quality of Eng

* Review mod packages

[illegible]

* [illegible]

2.0 Operations

2.1 Safety Focus & Management Involvement

* Focus review of overtime

* ~~Review shutdown risk training~~

2.2. Problem Ident & Resolutions

* ~~Identify use of established programs for identifying work schedule~~

2.3 Quality of Operations

Mon Team Meeting

Talk about writeups. Need for relevant information. Write-ups for exit meeting.

Tues Hogan Meeting Need answers to JCO's, overtime.

Installing cables in energized 125VDC panel. Operations released job and did not understand full extent of work. Job shouldn't been working.

TPB putting
, work.
, not required
, release job.

EOF looked good. HVAC room used for cleaning

EMIS tag found in garbage.

Breaker tagging ~~[illegible]~~ wording discrepancies

TSC had old EOP's.

Introductions

Purpose of inspection

This meeting will cover only the On-site portion of the assessment. Team will finalize results next week

Public exit meeting Sept 9 at 10:00. where we will present the final assessment results.

Team Member Presentation

Thank team. Well balanced assessment. Encourage evaluation of findings

Thank Rich, Dave, and Joe. Good interface in management meetings.

License control

more ~~operators~~ probing assessments both in audits and surveillances. Common problem but is needed to achieve your goals of world class performance.

Operations

management oversight on integration of performance assessments. Effect on operating crews.

Resolve operator work arounds

Positive operator performance.

Engineering

Critical issues list

communications to operations

Maintenance backshift support - inexperienced personnel

procedural adherence / procedural acceptability

[illegible]

EXIT MEETING

GOOD MORNING. MY NAME IS ROBERT GALLO, I AM FROM THE SPECIAL INSPECTION BRANCH FROM NRC HEADQUARTERS AND I WAS THE TEAM MANAGER FOR THIS ASSESSMENT.

THIS IS THE EXIT MEETING FOR THE NRC COMPREHENSIVE ASSESSMENT OF PERFORMANCE CONDUCTED DURING THE PERIOD OF JULY 11 THROUGH AUGUST 25, 1994. THIS MEETING IS OPEN FOR PUBLIC OBSERVATION. QUESTIONS WILL BE TAKEN FROM THE PUBLIC AND THE PRESS FOLLOWING THE CONCLUSION OF THE MEETING. I'D LIKE TO START THE MEETING BY HAVING THE NRC REPRESENTATIVES IN ATTENDANCE INTRODUCE THEMSELVES FOLLOWED BY THE PSE&G REPRESENTATIVES. I'LL THEN DISCUSS THE PURPOSE OF THIS ASSESSMENT. JEFFREY JACOBSON THE NRC TEAM LEADER FOR THIS ASSESSMENT WILL THEN PRESENT THE TEAM'S FINDINGS. UPON CONCLUSION OF THE NRC PRESENTATION PSE&G WILL BE GIVEN THE OPPORTUNITY TO MAKE ANY CLOSING REMARKS.

INTRODUCTIONS

The purpose of the assessment was to develop a comprehensive evaluation of performance at the Salem site. This evaluation of performance will then be used to better focus future NRC inspection resources at the Salem site. The assessment was based on an in-office, integrated review of documentation, followed by a broad scope on-site performance based review.

The in-office portion of the assessment consisted of a three week review of NRC inspection reports, licensee event reports, performance indicators, event investigations, licensee self assessments and other documentation. The documentation review covered the period from January 1, 1992 to July 31, 1994. Upon completion of the in-office assessment a preliminary assessment report was issued by letter dated August 4, 1994 which detailed the teams's findings. A two week on-site assessment was then conducted from August 15 through August 25, 1994. The on-site assessment focused on programmatic areas determined to be weak during the in-office review, as well as those areas that were indeterminate.

The assessment team consisted of six NRC inspectors, a team leader, and a team manager all whom were independent of the normal oversight of the Salem site.

After the conclusion of the on-site assessment, the team performed a comprehensive evaluation using the results of both the in-Office review and the on-site assessment. The results of this evaluation are presented on a Performance Assessment/Inspection Planning Tree which is shown on the overhead. As you can see, the tree is divided into five individual performance areas: licensee control systems, operations, engineering, maintenance, and plant support. These individual performance areas have been sub-divided into

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individual elements. Each performance area, as well as each individual element has been assigned a rating based upon the assessment results. Areas and elements where reduced, normal, and increased NRC inspection appear to be warranted have been assigned green, yellow, and red ratings respectively. The details concerning the team's findings will be presented in the assessment report which should be issued within about 30 days.

Mr. Jacobson will now present the team's findings:

As you can see from the tree, the team found that increased NRC inspection is warranted in the areas of Licensee Control Systems and Maintenance, normal NRC inspection is warranted in the areas of Operations and Engineering, and reduced NRC inspection is warranted in the area of Plant Support.

In the area of Licensee Control Systems the team determined that although the framework for effective control systems has been established, management and implementation of control systems have been ineffective. Management oversight of corrective action program activities has been weak, appropriate root cause evaluations have not been consistently performed, and effective corrective action performance indicators do not currently exist. In addition, key positions within the quality oversight organization remain unfilled, and key personnel in other organizations involved with corrective actions system implementation are new to their positions. Failure to appropriately identify root causes, specifically those involving programmatic issues have resulted in repetitive problems which have often challenged operators and plant safety systems. A good example of this is with SERT 94-01 which ~~[illegible]~~ [illegible] to identify programmatic weaknesses associated with numerous failures of the steam generator level control circuitry.

The team identified that significant recent improvements have been made in the area of Operations, specifically in the conduct of operations in the unit control rooms. Control room demeanor, sensitivity to equipment anomalies, and communications all seem to have improved significantly from the period covered by the team's in-office documentation review. Weaknesses were however identified with management oversight of operational enhancements and resolution of operational work-arounds and bypasses. The team noted that the large number of operational enhancements recently instituted to improve performance, combined with a recent surge in emergent work activities presented a challenge to some operations personnel. Operational work-arounds which require operators to take non-routine actions to compensate for degraded equipment conditions have only recently begun receiving appropriate attention.

Overall, current engineering work, programs, and procedures appear to be acceptable, but engineering has not demonstrated the ability to pro-actively seek out and correct system and component

deficiencies before they lead to increasingly challenging plant events. For example, long standing problems associated with the circulating water system, rod position indication, and excessive reactor cooldown transients are only recently coming to closure. In addition, engineering work priorities do not seem to be driven by the needs of the plant, and errors made during the original plant design and during recent vendor engineered design modifications continue to surface.

In the area of maintenance, significant weaknesses were identified with both maintenance programs and with program implementation. These weaknesses included an over-reliance on the use of generic troubleshooting procedures, ineffective use of the procedure feedback process, inadequate post-maintenance testing training, the inexperience of backshift personnel, and procedural adequacy and adherence. The team also expressed some concern regarding the control and oversight of the numerous organizations that perform maintenance and modification type work on-site. The maintenance organization demonstrated good performance with regard to work prioritization, dissemination of operating experience feedback information, equipment problem identification, and general plant housekeeping.

The plant support areas of emergency preparedness, fire protection, security, and health physics continue to show strong performance. During the team's in-office review few concerns were identified in the plant support area and as a result only limited time was spent on-site evaluating these activities. The team identified that management and communications within the various plant support organizations appeared to be effective. Problem identification appeared to be pro-active and effective, and programs and procedures appeared to be good. Performance indicators in the health physics area continue to show good ALARA results and good contamination control. Security, although not without some minor incidents has shown aggressive pursuit of identified issues. A team review of the emergency preparedness facilities provided favorable results. Response to Appendix R fire protection issues appears to have also been acceptable.

I'd like to close my remarks by saying that I encourage PSE&G to look at the team's findings as a way of identifying opportunities for improvement and as an aid in assessing overall plant performance. I'll now turn the floor over to PSE&G for any closing remarks.

SALEM FINAL PERFORMANCE ASSESSMENT RESULTS

INSPECTION TEAM: ROBERT GALLO, TEAM MANAGER
JEFFREY JACOBSON, TEAM LEADER

FORREST RANDALL HUEY, LICENSEE CONTROL SYSTEMS
THOMAS STETKA & JAKE ZIMMERMAN, MAINTENANCE
JOHN D. WILCOX, JR. & GREG GALLETTI, OPERATIONS
ROLF WESTBERG, ENGINEERING

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SALEM FINAL PERFORMANCE ASSESSMENT RESULTS

LICENSEE CONTROL SYSTEMS

STRENGTHS

*GOOD FRAMEWORK OF PROBLEM IDENTIFICATION SYSTEMS

*GOOD ROOT CAUSE TRAINING

WEAKNESSES

*INEFFECTIVE MANAGEMENT AND OVERSIGHT OF CORRECTIVE ACTION SYSTEMS

*INCONSISTENT QUALITY OF ROOT CAUSE EVALUATIONS

*INEFFECTIVE CORRECTIVE ACTION PERFORMANCE INDICATORS

*KEY MANAGEMENT POSITIONS IN QA ORGANIZATION ARE UNFILLED

OPERATIONS

STRENGTHS

*CONDUCT OF OPERATIONS INCLUDING CONTROL ROOM DEMEANOR, SENSITIVITY TO EQUIPMENT ANOMALIES, AND COMMUNICATIONS

WEAKNESSES

*MANAGEMENT OVERSIGHT OF OPERATIONAL ENHANCEMENTS

*RESOLUTION OF OPERATIONAL WORK AROUNDS

ENGINEERING

STRENGTHS

*GOOD PROGRAMS AND PROCEDURES

*CURRENT DESIGN WORK LOOKS GOOD

WEAKNESSES

*INABILITY TO PRO-ACTIVELY CORRECT SYSTEM AND COMPONENT DEFICIENCIES BEFORE THEY LEAD TO SIGNIFICANT EVENTS

*ENGINEERING WORK PRIORITIES DO NOT ALWAYS REFLECT PLANT NEEDS

*ENGINEERING ERRORS MADE DURING ORIGINAL PLANT DESIGN AND DURING VENDOR ENGINEERED DESIGN MODIFICATIONS

MAINTENANCE

STRENGTHS

*WORK PRIORITIZATION

*PROBLEM IDENTIFICATION

*GENERAL PLANT HOUSEKEEPING

*DISSEMINATION OF OPERATING EXPERIENCE FEEDBACK

WEAKNESSES

*PROCEDURAL ADHERENCE AND ADEQUACY

*OVER-RELIANCE ON GENERIC TROUBLESHOOTING PROCEDURES

*INEFFECTIVE USE OF PROCEDURE FEEDBACK PROCESS

*SPECIFICATION OF POST MAINTENANCE TESTING REQUIREMENTS

*INEXPERIENCE OF BACKSHIFT PERSONNEL

PLANT SUPPORT

STRENGTHS

*PROBLEM IDENTIFICATION

*ALARA AND CONTAMINATION CONTROL

*EMERGENCY PREPAREDNESS FACILITIES

WEAKNESSES

NONE IDENTIFIED