REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:8207010073 DOC.DATE: 82/06/25 NOTARIZED: NO DOCKET #
FACIL:50-261 H. B. Robinson Plant, Unit 2, Carolina Power and Ligh 05000261
AUTH.NAME AUTHOR AFFILIATION
ZIMMERMAN,S.R. Carolina Power & Light Co.
RECIP.NAME RECIPIENT AFFILIATION
VARGA,S.A. Operating Reactors Branch 1

SUBJECT: Forwards info in response to NRC request at 820506 meeting re operator training & emergency procedures audit.Info includes pressurized thermal shock (PTS) training schedule, PTS training lesson plans & simulator exercise guides. 586 RPH

DISTRIBUTION CODE: A049S COPIES RECEIVED:LTR 1 ENCL 1 SIZE: 300
TITLE: Thermal Shock to Reactor Vessel

NOTES:

	RECIPIENT ID CODE/NAME		COPIES LTTR	COPIES ENCL	RECIPIENT ID CODE/NAME		COPIES LTTR	COPIES ENCL
	ORB #1 BC	01	3	3				
INTERNAL:	ACRS ABBOTT,E		1		ACRS IGNE,E		1	
	AEOD		1		COM AUSTIN		1	
	COM LIAW,B		1		ELD/HDS1	12	1	
	MURLEY,T		1		NRR CLIFFORD		1	
	NRR DIR		1		NRR GOODWIN,E		1	
	NRR HAZELTON		1		NRR JOHNSON		1	
	NRR KLECKER		1		NRR LOIS,L		1	
	NRR OREILLY,P		1		NRR RANDALL		1	
	NRR THROM,E		1		NRR VISSING,G04		1	
	NRR/DE DIR		1		NRR/DHFS DEPY09		1	
	NRR/DHFS DIR		1		NRR/DHFS/PTRB		1	
	NRR/DL DIR		1		NRR/DL/ADSA		1	
	NRR/DL/ORAB	11	1		NRR/DSI DIR		1	
	NRR/DSI/RAB		1		NRR/DSI/RSB		1	
	NRR/DST DIR		1		NRR/DST/GIB		1	
	REG FILE	05	1	1	RES BASDEKAS		1	
	RES VAGINS,M		1		RES/DET		1	
	RES/DRA		1		RGN2		1	
EXTERNAL:	ACRS	10	1 ~~10~~	~~10~~ 0	LPDR	03	1	1
	NRC PDR	02	1	1	NSIC	06	1	1
	NTIS		1	1				

Limited Dist

TOTAL NUMBER OF COPIES REQUIRED: LTTR ~~43~~ 7 ENCL ~~64~~ 7

CP&L

Carolina Power & Light Company

JUN 25 1982

Office of Nuclear Reactor Regulation
ATTN: Mr. Steven A. Varga, Chief
Operating Reactors Branch No. 1
United States Nuclear Regulatory Commission
Washington, D.C. 20555

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261
LICENSE NO. DPR-23
PRESSURIZED THERMAL SHOCK

Dear Mr. Varga:

During a meeting held on May 6, 1982, regarding the NRC Audit of Operator Training and Emergency Procedures conducted at the H. B. Robinson Steam Electric Plant (HBR) Unit 2, members of the NRC staff requested several items from Carolina Power & Light Company (CP&L). For the benefit of clarification, we have identified each request separately with our response.

NRC Request

Document the Pressurized Thermal Shock (PTS) training schedule.

CP&L Response

The PTS classroom training commenced on May 10, 1982 and was completed on May 18, 1982. The simulator training commenced on May 15, 1982 and was completed on May 25, 1982.

NRC Request

Provide copies of the PTS Training Lesson Plans.

CP&L Response

The PTS Training Lesson Plans are provided as an enclosure to this letter.

A049

Limited Dist

411 Fayetteville Street o P. O. Box 1551 o Raleigh, N. C. 27602

NRC Request

Provide copies of the revised Emergency Procedures.

CP&L Response

Copies of the revised Emergency Procedures were provided to members of the NRC Staff following the May 6, 1982 meeting.

NRC Request

Commit to conducting a walk-through of the new procedures in the HBR Control Room.

CP&L Response

Each new procedure will be walked through the HBR Control Room prior to startup following the refueling which is now underway.

NRC Request

Document the content of the simulator exercises.

CP&L Response

Copies of the Simulator Exercise Guides are provided as an enclosure to this letter.

If you have any questions regarding the material provided, please contact a member of my staff.

Yours very truly,

SR Zimmerman

S. R. Zimmerman
Manager
Licensing & Permits

DCW/mf (125C6T1)
Enclosure

cc: Mr. J. P. O'Reilly (NRC-RII)
Mr. G. Requa (NRR)

PRESSURIZED THERMAL SHOCK

LIST OF ENCLOSURES

1. Pressurized Thermal Shock Introduction
2. Brittle Fracture and the Reactor Vessel (Material Science Session 15)
3. Determination of Heatup and Cooldown Curves (Material Science Session 16)
4. LOCA Transients
5. Loss of Reactor Coolant (Procedure Discussion)
6. Steam Break Transients
7. Loss of Secondary Coolant (Procedure Discussion)
8. Steam Generator Tube Rupture (Procedure Discussion)
9. Inadequate Core Cooling (Mitigating Core Damage Session 8)
10. RCP Seal Failure (Transient and Accident Analysis Session 16)
11. Safety Valve Failure (Transient and Accident Analysis Session 14)
12. S/G PORV Stuck Open (Transient and Accident Analysis Session 15)
13. R.E. Ginna Tube Rupture
14. PTS Concerns with EI-14, AP-19, AP-25, GP-2, and GP-6
15. Student Handouts A, B, & C
16. PTS Final Exam
17. Simulator Exercise Guides

    A. Steam Generator PORV Failure
    B. Small Break LOCA - Pressurizer PORV Fails Open
    C. Main Steam Break (Downstream MSIV)
    D. Pressurizer Safety Leak Without Automatic Turbine Trip

PRESSURIZED THERMAL SHOCK INTRODUCTION

Time: 30 minutes

Session 1 of 1

OBJECTIVES: Upon successful completion of this session, the student will be able to:

Define "pressurized thermal shock" and explain why training on this subject is important — TP-1

MATERIALS:

I. Training Aids

A. Whiteboard or equivalent

B. Overhead projector

II. References

A. WCAP 10019

B. Plant Operating Manual Volume 6 Emergency Instructions

III. Supplies - Pencil and paper

INTRODUCTION:

I. Establish Class Relations

A. State Name

B. Explain procedures (asking questions, volunteering information)

II. Establish Learning Goals

A. State Title

B. State Objectives (from Page 1)

PRESENTATION:

I. Pressurized Thermal Shock

A. Definition - A combination of a rapid temperature reduction and excessive pressure as to risk the vessel integrity. — TP-2

B. Transients with vessel integrity risk from PTS

1. Transients of interest include:

    a. Thermal shock

    b. High or increasing press

2. Reason these transients are potentially limiting

    a. Thermal and pressure tensile stresses are additive on the inside wall

    b. Material toughness is reduced as temperature decreases

3. Transients with a primary or secondary leak that can create a significant thermal shock, Significant events:

    a. Primary leak

    b. Steam break

    c. Rx trip w/o turbine trip

    d. Inadvertent steam dump

    e. Inadvertent SI

4. Transients involving addition of cold water (with no leak) are less severe due to large water inventories (at high temperature)

C. Reason for Study

1. PTS can have serious consequences as regards plant safety. The operator must be able to analyze and identify potential PTS situations

2. Operators must be able to correctly use the plant operating manuals with regard to PTS to protect reactor vessel integrity.

II. List of Sessions to be Taught

SESSION 2: NDT-NORMAL CONDITIONS

A. Brittle fracture and the reactor vessel

1. Brittle fracture considerations

2. Reactor vessel stresses

B. Determination of Heatup and Cooldown Curves

1. Heatup/cooldown determination

2. Heatup/cooldown curves

SESSION 3: TRANSIENTS AND ACCIDENTS WITH PTS CONCERNS AND EI-1 PROCEDURES

A. LOCA

1. LOCA transients

Pressure and temperature relationships

2. LOCA - EI-1 Procedures

B. Steam Break

1. Steam break transients

Pressure and temperature relationships

2. Steam Break - EI-1 Procedures

C. Steam Generator Tube Rupture

EI-1 Procedures

D. Inadequate core cooling section H from EI-1

SESSION 4: CASE HISTORIES WITH PTS CONCERNS

A. HBR RCP seal failure

B. HBR main steam safety valve piping failure

C. HBR stuck open steam generator PORV
D. GINNA Tube Rupture

SESSION 5: PTS CONCERNS IN EI-14, AP-19, AP-25 AND GENERAL PROCEDURES

SESSION 6: EXAMINATION

PRESSURIZED THERMAL SHOCK INTRODUCTION

Objectives

UPON SUCCESSFUL COMPLETION OF THIS SESSION,
THE STUDENT WILL BE ABLE TO:

DEFINE "PRESSURIZED THERMAL SHOCK" AND EXPLAIN WHY TRAINING ON THIS SUBJECT IS IMPORTANT.

PRESSURIZED THERMAL SHOCK
- DEFINITION -

A COMBINATION OF RAPID TEMPERATURE REDUCTION AND EXCESSIVE PRESSURE AS TO RISK THE VESSEL INTEGRITY.

TRANSPARENCY 2

CP&L

HB ROBINSON STEAM ELECTRIC PLANT

NUCLEAR OPERATIONS

lesson plan

MATERIALS SCIENCE

Session 15

H.B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
INSTRUCTOR LESSON PLAN

SUBJECT: Materials Science

SESSION: 15 of 16

SESSION TOPIC: Brittle Fracture and the Reactor Vessel

TIME: 50 minutes

REVISION NO. 0

DATE: 1/5/82

INSTRUCTOR REFERENCES

1. H.B. Robinson Unit No. 2, FSAR, Section 4
2. H.B. Robinson Unit No. 2, Technical Specifications

CLASSROOM EQUIPMENT

1. Chalkboard, Chalk and Eraser
2. Overhead Projector

TRAINING MATERIALS REQUIRED

Transparencies:
1. Lesson Objectives and Reason for Study
2. Effect of Fluence and Copper Content on Shift of RT_{NDT}
3. Pressure Stress on Reactor Vessel
4. Temperature Stress on Reactor Vessel
5. Heatup Stress Profile
6. Cooldown Stress Profile
7. Flence Over Plant Life
8. Charpy V-Notch

STUDENT REFERENCES

1. Student Handout: Materials Science
2. H.B. Robinson Unit No. 2, FSAR, Section 4
3. H.B. Robinson Unit No. 2, Technical Specifications

LESSON PLAN

OUTLINE	KEY AIDS

I. INTRODUCTION

A. Lesson Objectives

Transparency 15-1.

Upon successful completion of this session you will be able to:

1. From memory, state the reactor vessel construction materials.

2. From memory, define RT_{NDT} and describe the procedure and tests used to determine RT_{NDT}.

3. From memory, define ΔRT_{NDT}, describe what effects it, explain how it is measured, and state which vessel materials are more sensitive to it.

4. From memory, state the stresses associated with the reactor vessel for heatup and cooldown of the reactor.

5. From memory, state the limiting stress condition and location associated with the reactor vessel.

B. Reason for Study

Heatup and cooldown effects during plant startup and shutdown cause great stresses on the reactor

LESSON PLAN

OUTLINE	KEY AIDS

vessel. These effects coupled with high pressures and radiation damage provide a potential for brittle fracture of the reactor vessel. This potential catastrophic failure must be guarded against with limitations on the vessel.

II. PRESENTATION

A. Brittle Fracture Considerations

1. Reactor vessel

a. Construction materials

1) Low-alloy carbon steel plates - SA302 grade B

2) Steel plates welded together

3) Typically over 8 inches thick around core and 5 inches thick at bottom

4) Stainless steel cladding

b. Subject to brittle fracture

1) Must be protected against

2. RT_{NDT}

OUTLINE	KEY AIDS

a. Reference temperature for nil-ductility transition

b. Reference to provide protection

c. Change in NDT over material's life is measured from this reference temperature

1. Dropweight referenced to Charpy V-notch test

   a. Temperature no greater than T_{NDT} + 60°F

   b. Specimens

      1) 3 samples

      2) Each 10 mm x 55 mm x 10 mm

      3) 45° V-notch, radius of .25 mm

   c. Test procedure

      1) Pendulums

         a) 120 ft lbs or 220 ft lbs

         b) Energy last determined by measuring resultant energy of pendulum

LESSON PLAN

OUTLINE	KEY AIDS

c) Sample always broken on first impact

2) Requirements

a) 35 mils (0.035 in) expansion

b) 50 ft lbs impact energy

3) Conduct test until requirements are met by increasing or decreasing the specimen temperature

4) Determines T_{CV} or charpy V-notch temperature

2. RT_{NDT}

a. $RT_{NDT} = T_{CV} - 60^{O}F$
(Reference-Temperature for Nil ductility transition Temp charpy V-notch - 60°F.

b. Applies when RT_{NDT} is greater than T_{NDT}

c. Procedure applies to

1) The base material
2) The heat affected zone (welding)
3) Weld material

OUTLINE	KEY AIDS

3. Shift in RT_{NDT}: ΔRT_{NDT}

   a. Due to fluence (neutron flux)

   b. Materials similar to vessel materials placed inside vessel wall

      1) Samples taken out periodically and tested for ΔRT_{NDT} using these tests

      2) Conservative ΔRT_{NDT} because exposed to higher fluence

   c. Weld material more sensitive

      1) Based on copper content of weld material

      2) Low amounts of nickel result in steels and welds which are significantly less susceptible to irradiation damage.

Transparency 15-2

HBR has .34% cu.
1.2% Ni
HBR has benefit of low nickel content.

C. Reactor Vessel Stresses

1. Pressure

   a. From coolant system pressure

   b. Always tensile

Transparency 15-3

      1) Both inner and outer walls
      2) Inside wall greatest

LESSON PLAN

OUTLINE	KEY AIDS
2. Temperature	
a. Gradients across wall	
b. Either tensile or compressive	Transparency 15-4
1) Heatup	
a) Outer wall temperature lags the inner wall	
b) Stress changes from compressive to tensile through vessel wall	
2) Cooldown	
a) Outer wall lags the temperature drop of the inner wall	
b) Stresses change from tensile to compressive through vessel wall	
3. Stresses caused by radiation damage	
a. Called embrittlement stress	
b. Caused by neutron irradiation	
c. Greater to inner wall	

OUTLINE	KEY AIDS

d. Tensile stress

4. Stress profile

a. Heatup stress profile — Transparency 15-5

1) At 1/4 T — T is thickness of vessel wall

a) Pressure and embrittlement stresses tensile

b) Temperature stress compressive

c) Tend to cancel

2) At 3/4 T

a) All stresses are tensile
b) Reinforce each other
c) Limiting during heatup

d. Cooldown stress profile — Transparency 15-6

1) At 3/4 T

a) Pressure and embrittlement stresses tensile

b) Temperature stress compressive

c) Tend to cancel

2) At 1/4 T

a) All stresses are tensile
b) Reinforce each other
c) Limiting during cooldown

5. Limiting condition

a. Fluence

1) Greater at 1/4 T

2) ΔRT_{NDT} will be greater

3) Can be estimated by knowing full service years — Transparency 15-7

b. Total stress

1) Cooldown

a) Total stress compared with total allowable stress

b) Close at 1/4 T

c. 1/4 T value

1) Most conservative

2) Used for both heatup and cooldown rate calculations

III. SUMMARY

A. OBJECTIVE 1: From memory, state the reactor vessel construction materials.

1. Low-alloy carbon steel plates - SA302 grade B

2. Steel plates welded together with stainless cladding

B. OBJECTIVE 2: From memory, define RT_{NDT} and describe the procedure and tests used to determine RT_{NDT}.

1. RT_{NDT} - reference temperature

2. Determination

LESSON PLAN

OUTLINE	KEY AIDS

a. Charpy V-notch test

1) Use temperatures no greater than $T_{NDT} + 60^{o}F$

2) Requirements

a) 35 nils expansion

b) 50 ft lbs impact energy

3) Determines T_{cv}

b. $RT_{NDT} = T_{cv} - 60^{o}F$

C. <u>OBJECTIVE 3</u>: From memory, define ΔRT_{NDT}, describe what effects it, explain how it is measured, and state which vessel materials are more sensitive to it.

1. Shift in RT_{NDT} due to radiation damage

2. Sample materials placed inside vessel wall

a. Materials tested for ΔRT_{NDT}

b. Conservative

3. Weld material more sensitive - copper content.

D. <u>OBJECTIVE 4</u>: From memory, state the stresses associated with the reactor vessel for heatup and cooldown of the reactor.

1. Pressure

2. Temperature

    a. Heatup
    b. Cooldown

3. Embrittlement stress

4. Stress profile

    a. Heatup

        1) 1/4 T
        2) 3/4 T

    b. Cooldown

        1) 1/4 T
        2) 3/4 T

E. OBJECTIVE 5: From memory, state the limiting stress condition and location associated with the reactor vessel.

1. Fluence

a. Greater at 1/4 T
b. ΔRT_{NDT} greater at 1/4 T

2. 1/4 T valve used in limitation calculations (Most restrictive value on cooldown)

IV. EVALUATION

A. OBJECTIVE 1 QUESTIONS

1. State the reactor vessel construction materials.
Answer: The reactor vessel is constructed with low-alloy carbon steel plates (SA302 Grade B). The steel plates are welded together.

B. OBJECTIVE 2 QUESTIONS

1. Name the test used to determine RT_{NDT}.
Answer: Charpy V-notch test.

2. Define RT_{NDT} and describe its use.

Answer: RT_{NDT} is the reference temperature for nil-ductility transition. It is used as a reference temperature when measuring the change in NDT over a material's life.

C. OBJECTIVE 3 QUESTIONS

1. Why is there a shift in RT_{NDT} during a reactor vessel's lifetime? What is this shift called?
Answer: The shift is called ΔRT_{NDT} and is caused by neutron fluence.

D. OBJECTIVE 4 QUESTIONS

1. State three stresses associated with the reactor vessel.
Answer:
a. Pressure
b. Temperature
c. Embrittlement

2. How do temp. induced stresses differ for heatup and cool-down of the reactor?
Answer: The temperature stresses differ for heatup and cooldown of the reactor. During heatup the outer wall temperature lags the inner wall. Stresses on the inner wall are compressive and change to tensile through the

vessel wall. During cooldown the opposite occurs. Stresses on the inner wall are tensile and change to compressive through the vessel wall.

E. OBJECTIVE 5 QUESTIONS

1. Which location in the reactor vessel wall is the value used calculating limiting conditions?
Answer: 1/4 thickness.

V. ASSIGNMENT
Read section III.2.1, III.2.2 and III.2.3 in the student handout.

TRANSPARENCY 15-1

LESSON OBJECTIVES

Upon successful completion of this session you will be able to:

1. From memory, state the reactor vessel construction materials.

2. From memory, define RT_{NDT} and describe the procedure and tests used to determine RT_{NDT}.

3. From memory, define ΔRT_{NDT}, describe what effects it, explain how it is measured, and state which vessel materials are more sensitive to it.

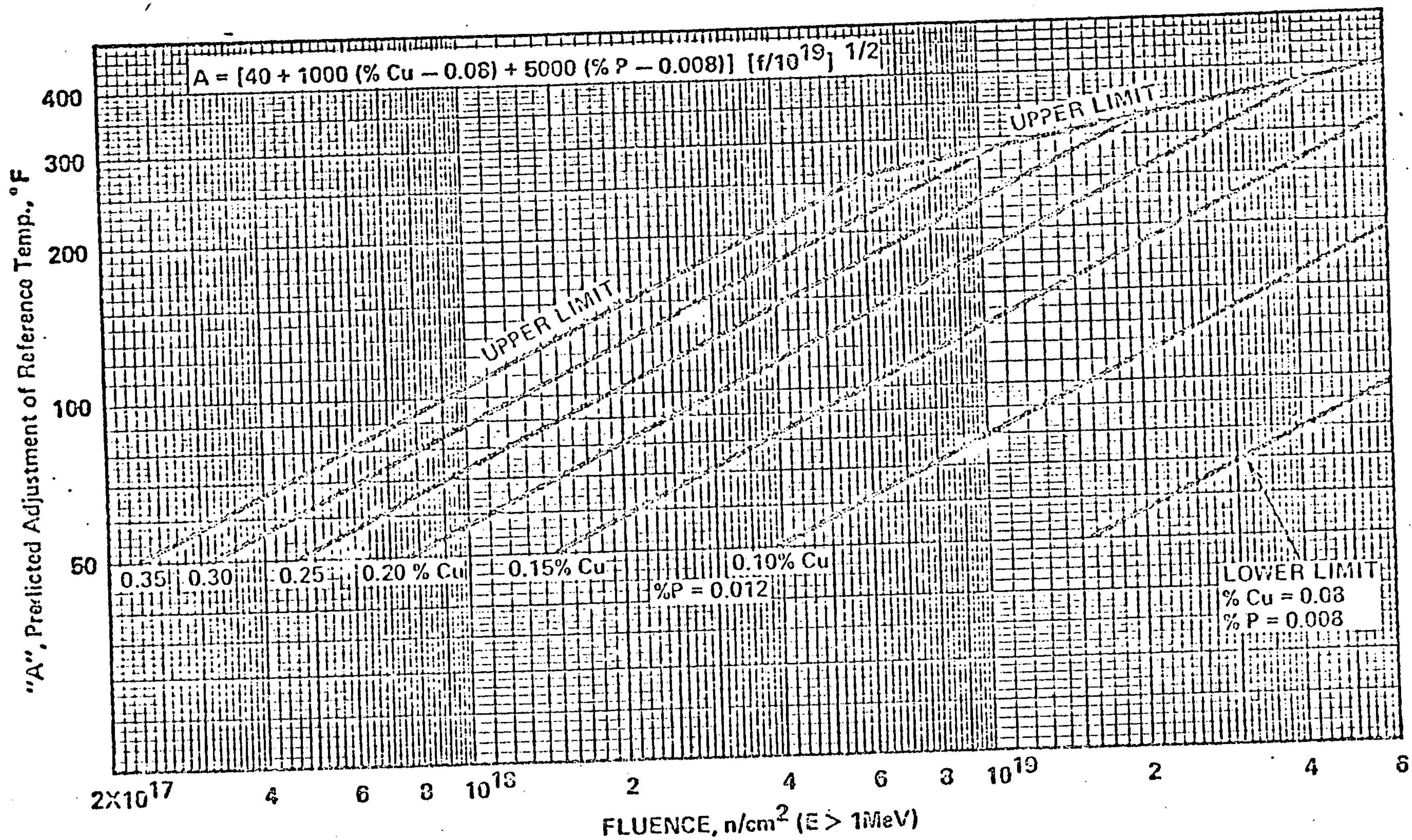
4. From memory, state the stresses associated with the reactor vessel for heatup and cooldown of the reactor.

5. From memory, state the limiting stress condition and location associated with the reactor vessel.

REASON FOR STUDY

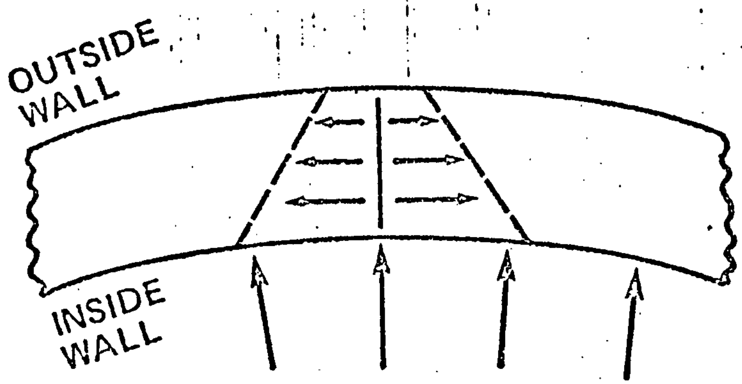
Heatup and cooldown effects during plant startup and shutdown cause great stresses on the reactor vessel. These effects coupled with high pressures and radiation damage provide a potential for brittle fracture of the reactor vessel. This potential catastrophic failure must be guarded against with limitations on the vessel.

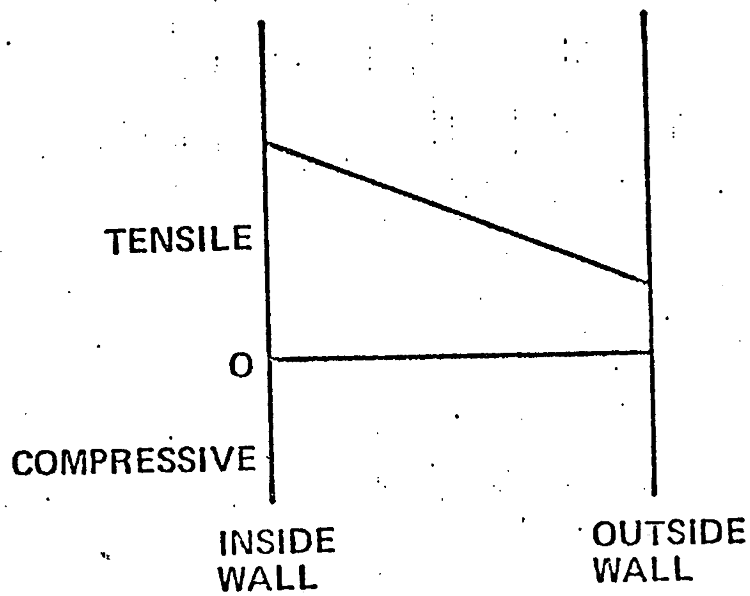
TRANSPARENCY 15-2

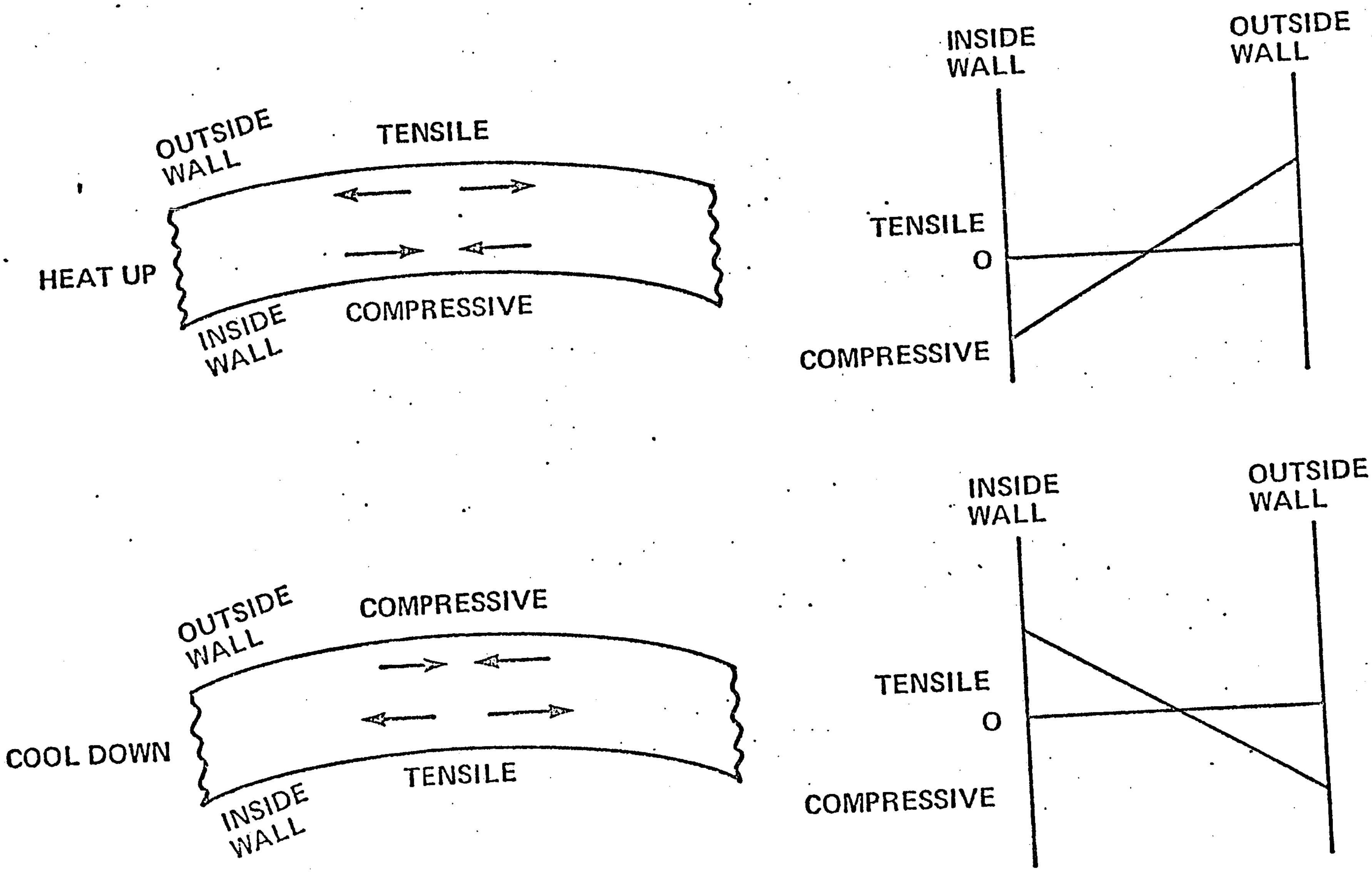


EFFECT OF FLUENCE AND COPPER CONTENT ON
SHIFT OF RT_{NDT}

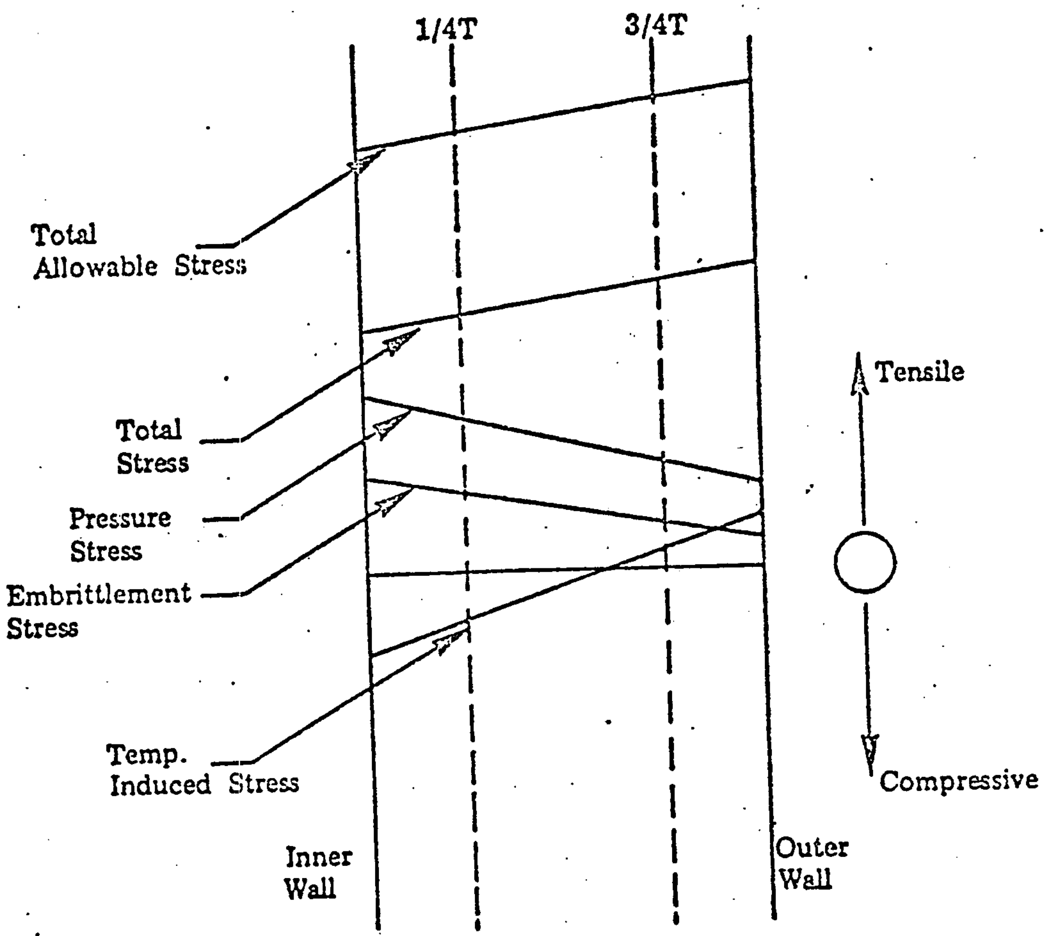
TRANSPARENCY 15-3
PRESSURE STRESS ON REACTOR VESSEL





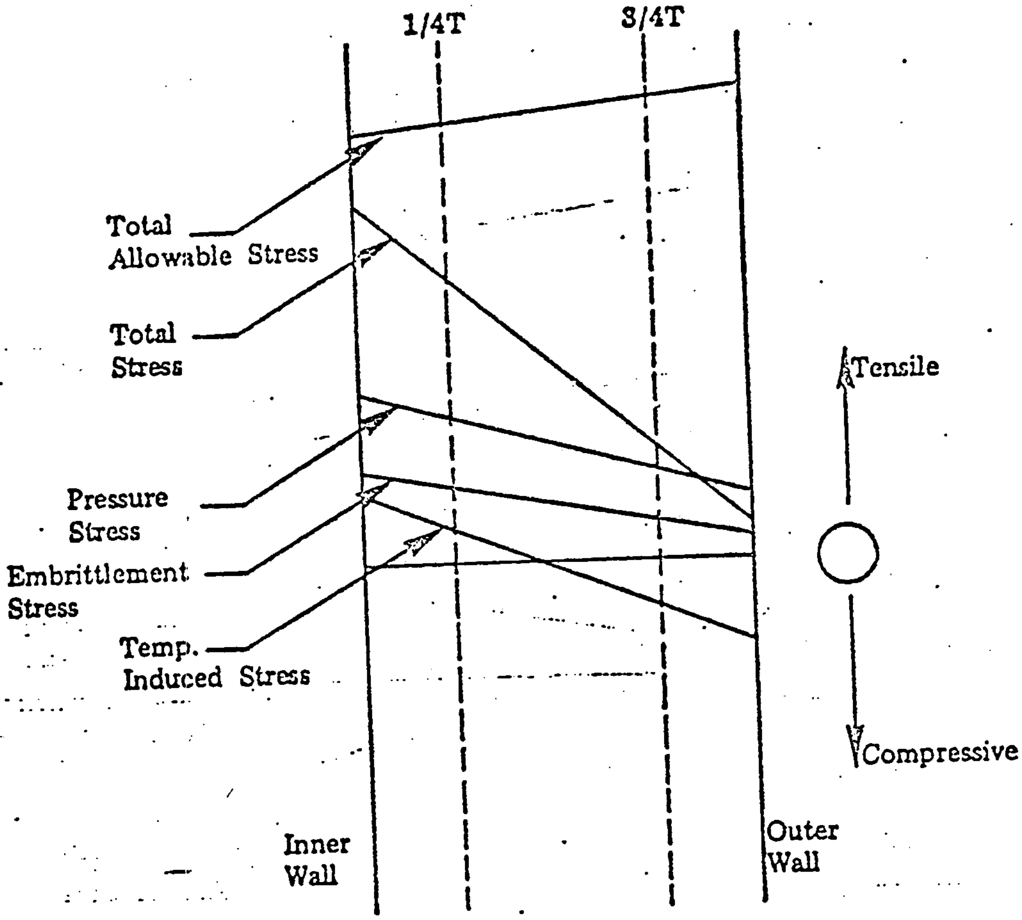


TRANSPARENCY 15-4
TEMPERATURE STRESS ON REACTOR VESSEL



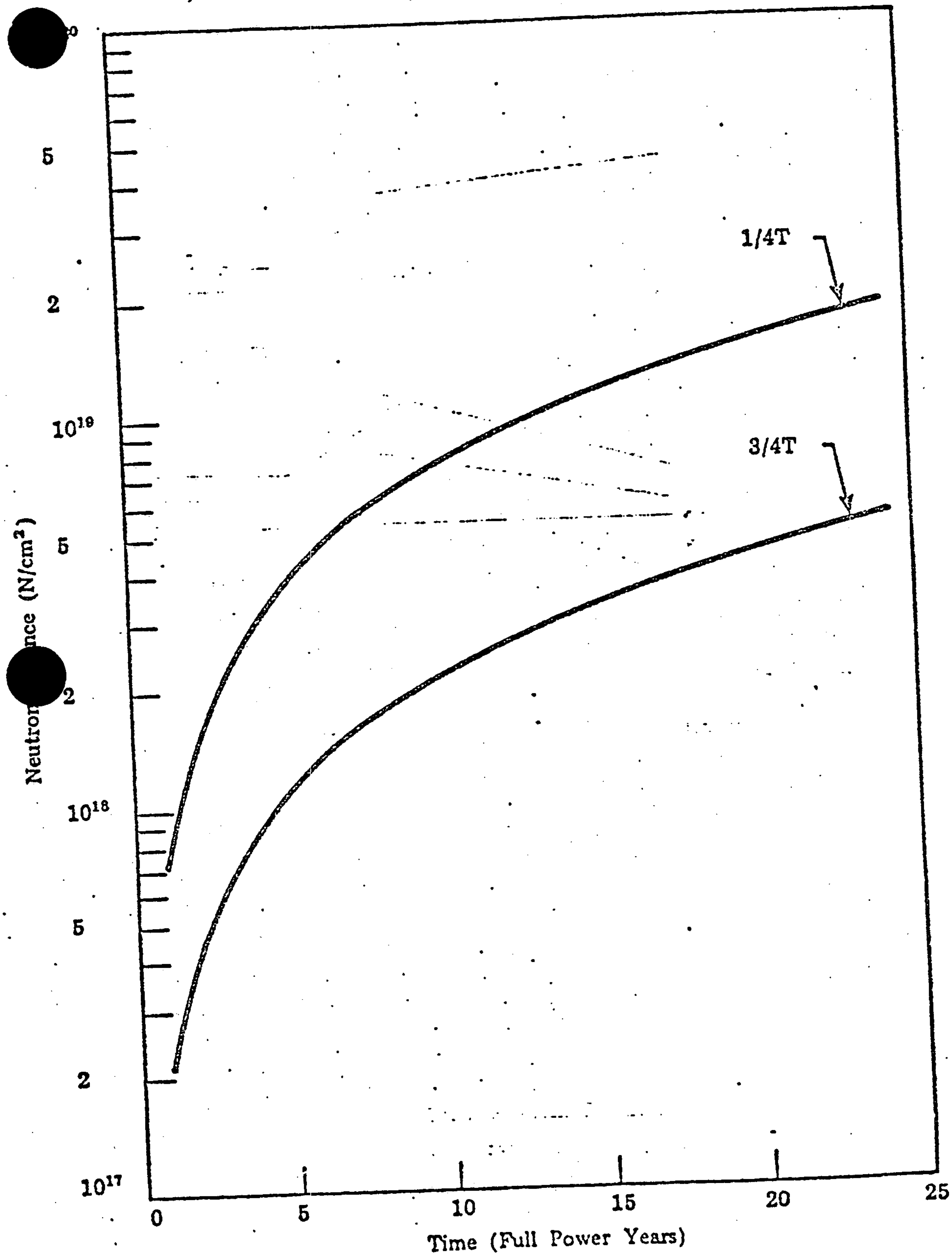
TRANSPARENCY 15-5

Heatup Stress Profile



TRANSPARENCY 15-6
Cooldown Stress Profile

TRANSPARENCY 15-7



FLUENCE OVER PLANT LIFE

Draft

CP&L

HB ROBINSON
STEAM ELECTRIC PLANT

NUCLEAR
OPERATIONS

lesson plan

MATERIALS SCIENCE

See attached curve

Session 16

H.B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
INSTRUCTOR LESSON PLAN

SUBJECT: Materials Science

SESSION: 16 of 16

SESSION TOPIC: Determination of Heatup and Cooldown Curves

TIME: 30 minutes

REVISION NO. 0

DATE: 1/7/82

INSTRUCTOR REFERENCES

1. H.B. Robinson Unit No. 2, Technical Specifications
2. ASME Boiler and Pressure Vessel Code, Section III, Appendix G

CLASSROOM EQUIPMENT

1. Chalkboard, Chalk and Eraser
2. Overhead Projector

TRAINING MATERIALS REQUIRED

Transparencies:
1. Lesson Objectives and Reason for Study
2. Effect of Fluence and Copper Content on Shift of RT_{NDT}
3. Fluence Over Plant Life
4. Heatup Curve
5. Cooldown Curve

STUDENT REFERENCES

1. Student Handout
2. H.B. Robinson Unit No. 2, Technical Specifications

LESSON PLAN

OUTLINE	KEY AIDS

I. INTRODUCTION

A. Lesson Objectives

Upon successful completion of this session you will be able to:.

Transparency 16-1

1. Explain how a change in fluence can result in a change in RT_{NDT} and how this limits heatup and cooldown.
2. From memory, state where the heatup and cooldown limiting curves are found and correctly use these curves.

B. Reason for Study

Heatup and cooldown effects during plant startup and shutdown and accident or transient conditions can cause great stresses on the reactor vessel. These effects coupled with high pressures and radiation damage provide a potential for brittle fracture of the reactor vessel. This potential catastrophic failure must be guarded against with limitations on the vessel.

OUTLINE	KEY AIDS
II. PRESENTATION	
A. Heatup/Cooldown Determination	
1. RT_{NDT} most limiting value	
a. Determine highest RT_{NDT}	
1) For all reactor vessel materials	
2) For H.B. Robinson it is $0^{o}F$	
b. Estimate radiation induced ΔRT_{NDT}	
1) Use Transparency 16-2	Transparency 16-2
a) Must find fluence	
2) Neutron fluence at 1/4 T and 3/4 T	
a) Function of full power service life	
b) Use Transparency 16-3	Transparency 16-3
3) By knowing full service years	

OUTLINE	KEY AIDS
2. Allowable pressure - temperature relationships	
a. Calculated from ASME boiler and pressure vessel code Section IV, Appendix G.	
b. Calculations based on assumption that crack or crack-like defect does exist in the structure.	
c. Stress Analysis Done to Insure	Transparency 16-4
(1) Crack or crack-like defect does not propagate	
(2) Avoid brittle fracture	
B. Heatup/Cooldown Curves	Tech Spec 3.1.2.1
1. Heatup curve	Transparency 16-5
a. From cold shutdown to hot operations	
(1) Heatup rate must be $\leq 60^{\circ}F$/hour	
(2) In any one hour	
b. Applicability of curve	

OUTLINE	KEY AIDS
1) For first 20 effective full power years	
c. Explanation of curve	
1) Heatup limit	
2) Leak test limit	Discuss MPT with respects to curve
3) Criticality limit	
4) Instrument error	
2. Cooldown curve	Transparency 16-6
a. From hot operations to cold shutdown	
1) Cooldown rate must be $\leq 100^{o}F$/hour	
2) In any one hour	
b. Applicability of curve	
1) For first 20 effective full power years	
c. Explanation of curve	
1) Varying cooldown rates	
2) Pressure/temperature combinations	
3) Instrument error	

OUTLINE	KEY AIDS
3. Found in Technical Specification 3.1.2.1	
III. SUMMARY	
A. OBJECTIVE 1:	
. Explain how a change in fluence can result in a change in RT_{NDT} and how this limits heatup and cooldown.	Transparency
1. Find neutron fluence from curves for full power service years	16-3
2. Use the shift of RT_{NDT} curve for the neutron fluence	16-2
B. OBJECTIVE 2: From memory, state where the heatup and cooldown limiting curves are found and correctly use these curves.	
1. Technical Specification 3.1.2.1	
2. Heatup curve	16-5
a. Rate $\leq 60^{\circ}$F/hour	
b. 20 effective full power years	
c. Explanation of curve	
3. Cooldown curve	
a. Rate $\leq 100^{\circ}$F/hour	16-6
b. 20 effective full power years	
c. Explanation of curve	

IV. EVALUATION

A. OBJECTIVE 1 QUESTIONS

1. As plant life increases, how does fluence change?
2. Will the change in (1) result in an increase or decrease in RT_{NDT}?

Answer:

1. Increase
2. Increase

B. OBJECTIVE 2 QUESTIONS

1. Name the limiting heatup and cooldown rates associated with H. B. Robinson Unit 2.
   Answer: From cold shutdown to hot operations, the heatup rate must be $\leq 60^{\circ}$F per hour in any one hour. From hot operations to cold shutdown, the cooldown rate must be $\leq 100^{\circ}$F per hour in any one hour.
2. Where are the heatup and cooldown limiting curves found?
   Answer: Technical Specification 3.1.2.1
3. Using the heatup and cooldown curves, state whether the following temperatures and pressures for the moderator are permissible:
   a. Heatup rate of 20°F/hr with temperature 450°F and the pressure is 2000 psig.
      Answer: Not permissible.

OUTLINE	KEY AIDS

b. Cooldown rate of 30°F/hr with temperature 450°F and the pressure is 800 psig.
Answer: Permissible.

c. Heatup rate of 70°F/hr with the temperature 500°F and the pressure 2200 psig.
Answer: Not permissible.

d. Heatup rate of 20°F/hr with the temperature 520°F and the pressure is 2000 psig.
Answer: Permissible.

V. ASSIGNMENTS

A. The Student Handout

B. Read in H. B. Robinson Unit No. 2, Technical Specifications the bases for 3.1.2.1.

TRANSPARENCY 16-1

LESSON OBJECTIVES

Upon successful completion of this session you will be able to:

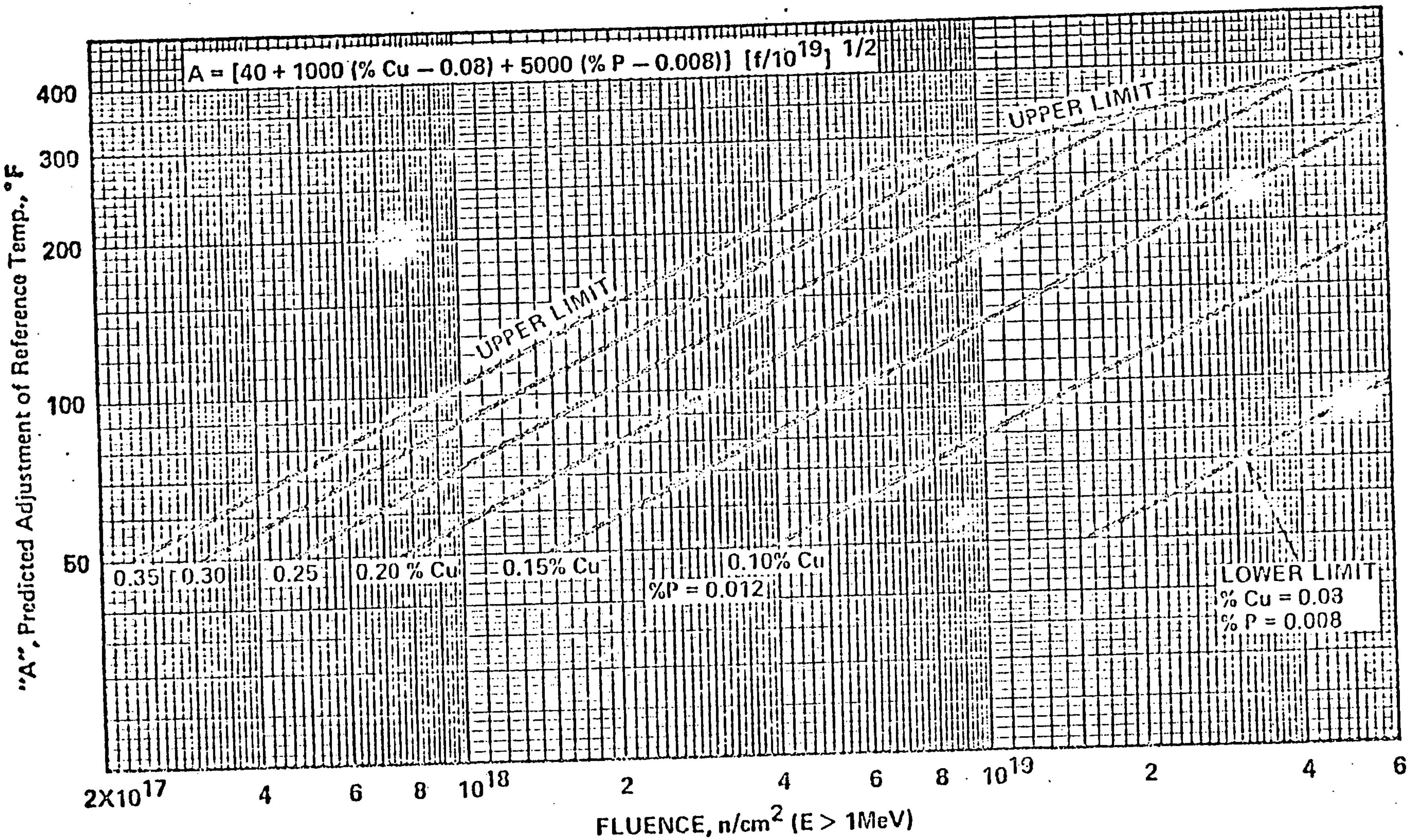
1. Explain how a change in fluence can result in a change in RT_{NDT} and how this limits heatup and cooldown.

2. From memory, state where the heatup and cooldown limiting curves are found and correctly use these curves.

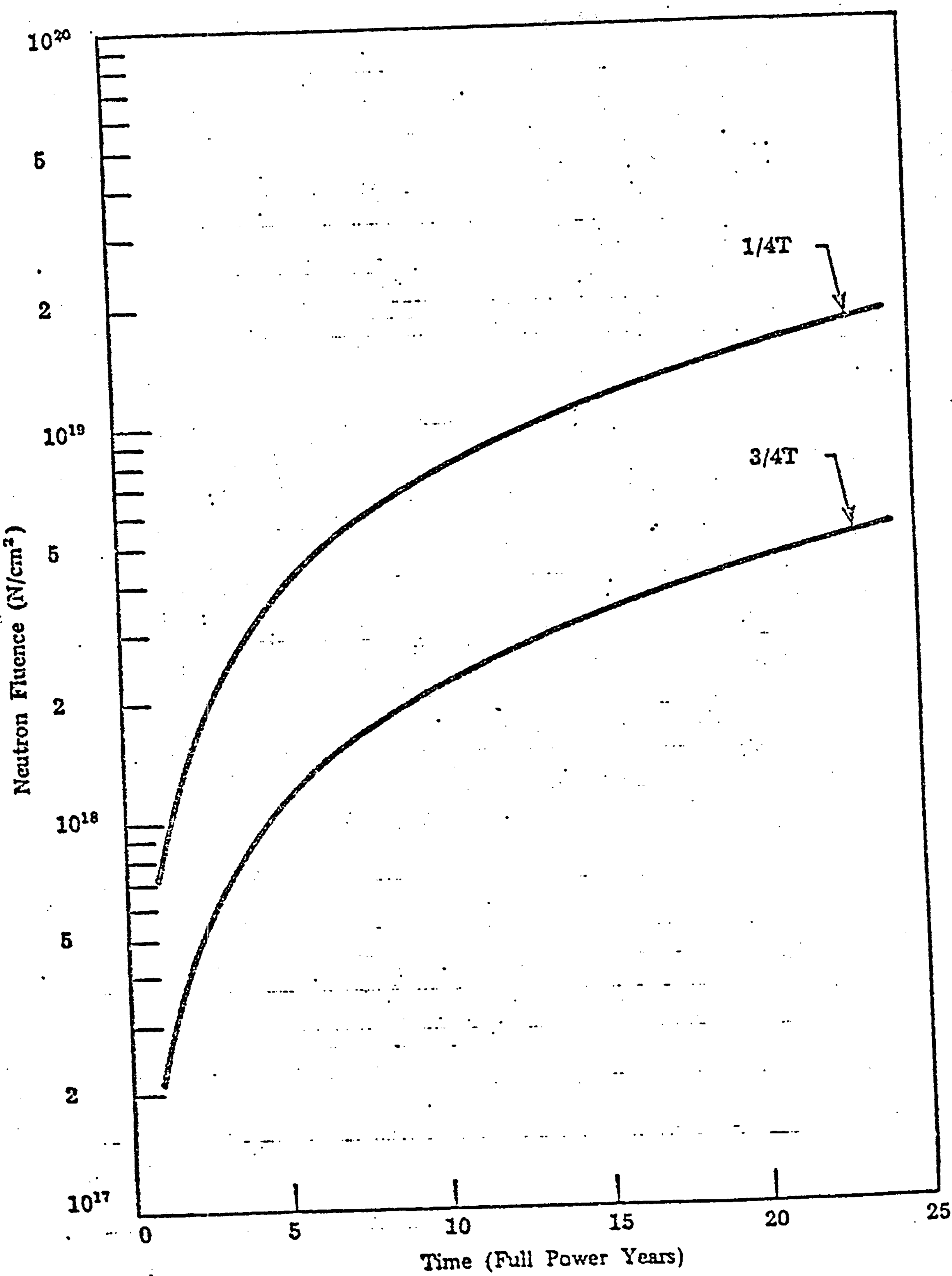
REASON FOR STUDY

Heatup and cooldown effects during plant startup and shutdown and accident or transient conditions can cause great stresses on the reactor vessel. These effects coupled with high pressures and radiation damage provide a potential for brittle fracture of the reactor vessel. This potential catastrophic failure must be guarded against with limitations on the vessel.

TRANSPARENCY 16-2

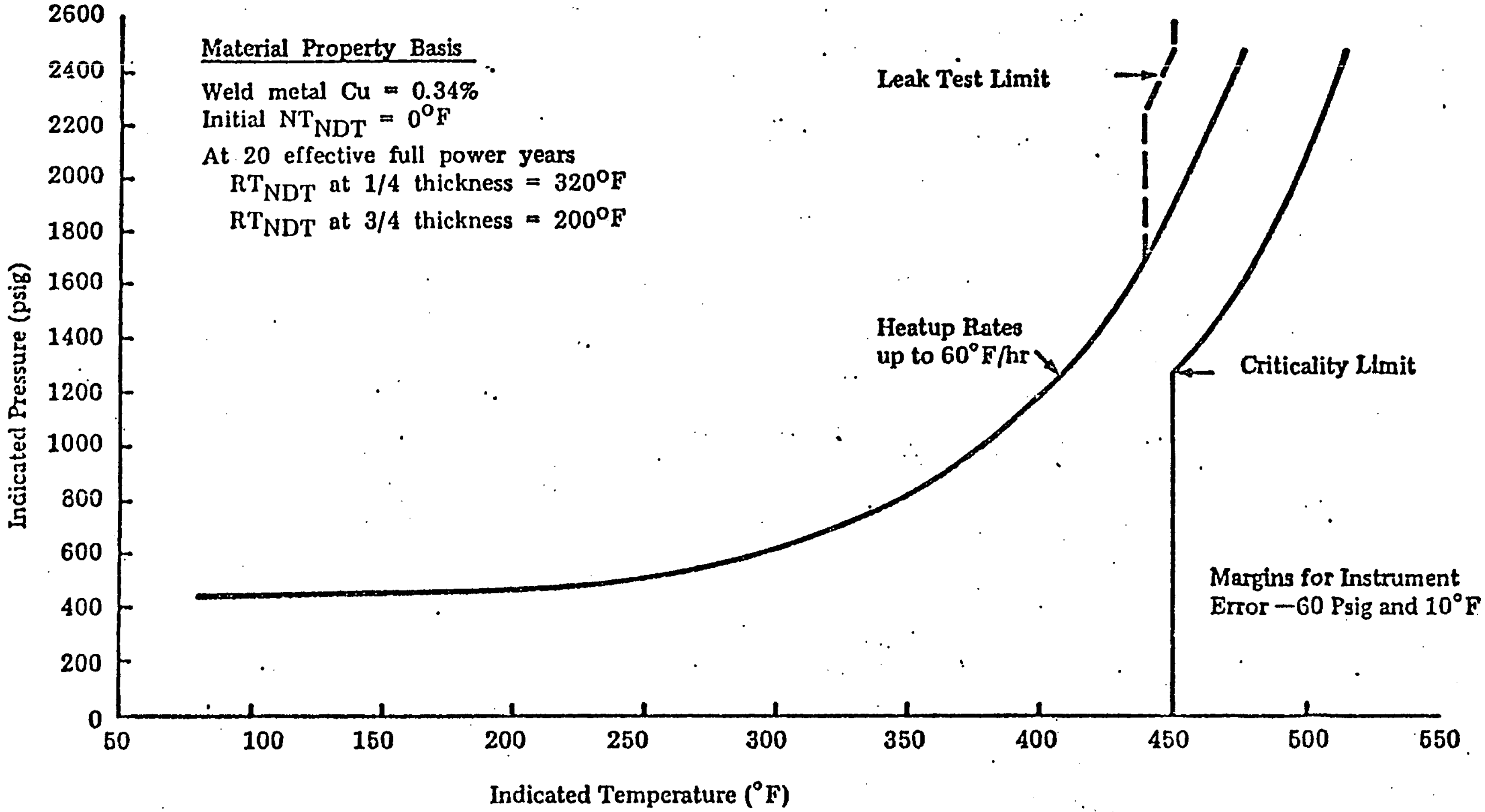


EFFECT OF FLUENCE AND COPPER CONTENT ON
SHIFT OF RT_{NDT}



FLUENCE OVER PLANT LIFE

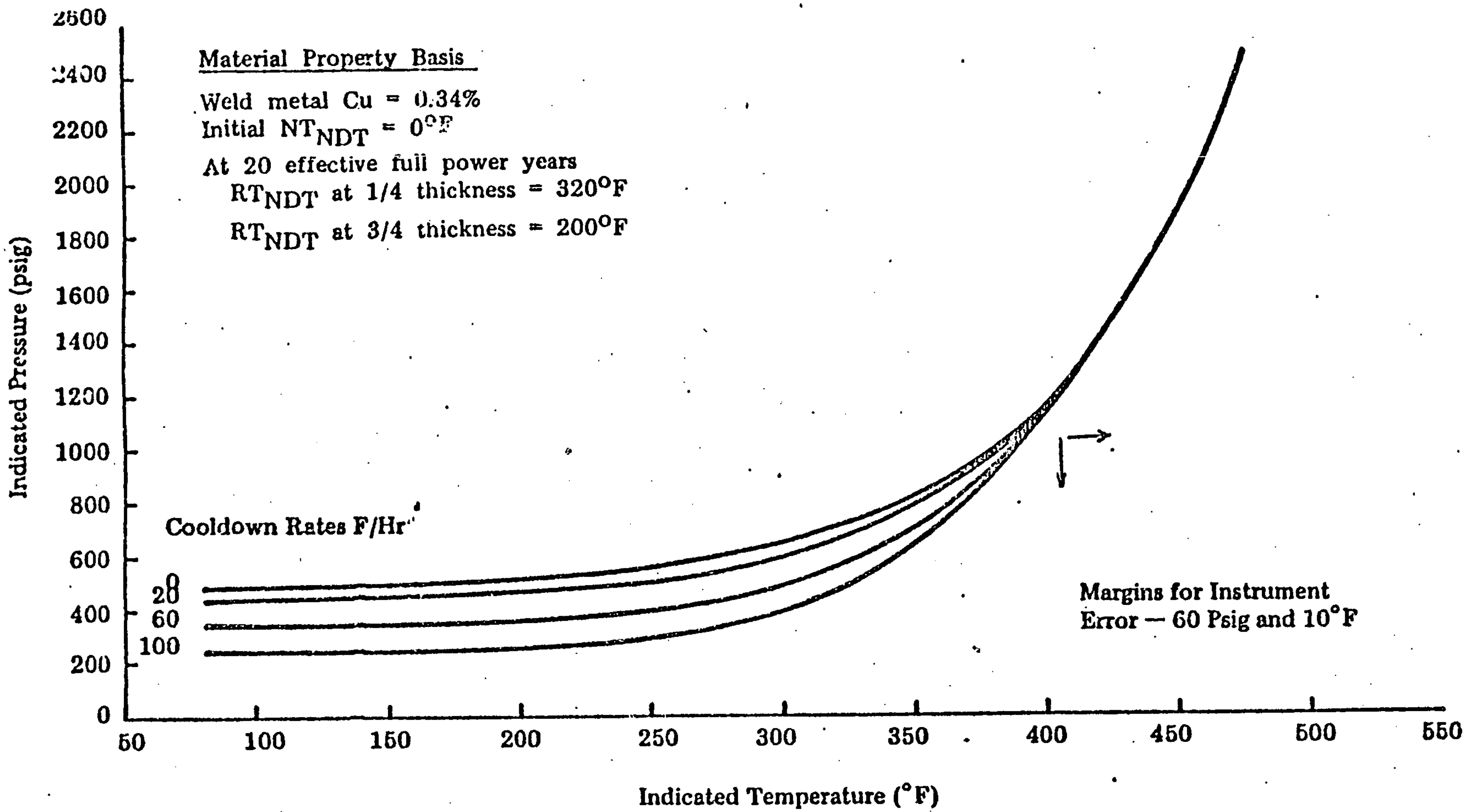
TRANSPARENCY 16-4



H.B. ROBINSON UNIT NO. 2

REACTOR COOLANT SYSTEM HEATUP LIMITATIONS

(APPLICABLE FOR PERIODS UP TO 20 EFFECTIVE FULL POWER YEARS)



H.B. ROBINSON UNIT NO. 2

REACTOR COOLANT SYSTEM COOLDOWN LIMITATIONS

(APPLICABLE FOR PERIODS UP TO 20 EFFECTIVE FULL POWER YEARS)

LOCA TRANSIENTS

Time: 1 hour

Session 1 of 1

OBJECTIVES: Upon successful completion of this session the student will be able to:

1. Describe the progress of the two key parameters during a LOCA transient. TP-1

2. Determine the limiting case for small LOCA's using control room indications.

MATERIALS:

I. Training Aids

A. White board or equivalent

B. Overhead projector

C. Transparencies

1. Objectives

2. 1" break - pressure vs. time

3. 1" break - temperature vs. time

4. 1" break - pressure vs. temperature

5. 2" break - pressure vs. time

6. 2" break - temperature vs. time

7. 2" break - pressure vs. temperature

8. 3" break - pressure vs. time

9. 3" break - temperature vs. time

10. 3" break - pressure vs. temperature

II. References

A. WCAP-10019

B. Plant operating manual - Volume #6 Emergency Instruction

III. Supplies

A. Pencil and paper

B. Graph paper

INTRODUCTION

I. Establish Class Relations

A. State name

B. Explain procedures (asking questions, volunteering information)

II. Establish Learning Goals

A. State title

B. State objectives (from Page 1)

PRESENTATION

LOCA Transient

I. Students sketch

A. Small break LOCA

B. Label the sketches and give typical valves for

1. RCS press vs. time

2. RCS^{Tc} vs. time

II. Large LOCA - greater than 4" break

A. Primary side pressure assumed to equal CV pressure

B. Will produce a thermal shock

1. Will not maintain elevated system pressure

2. Not a pressurized thermal shock concern

C. Core cooled by

1. Full SI actuation

2. Recirculation

III. Small LOCA

A. Will consider breaks greather than 1" but less than 4"

B. These can be subdivided into "smaller break LOCA's" and "larger break LOCA's"

1. Smaller break - distinguished by maintaining S/G tubes full of water

2. Larger breaks - dump water from S/G tubes, stop loop flow

C. Smaller breaks TP-2

1. Continuous flow in loops TP-3

a. Downcomer is maintained

b. NAT circ.

2. Flow caused by density difference TP-4

a. Cold SI water

b. Heat addition in the core

3. As long as SI flow is greater than or equal to break flow

a. Keeps the S/G tubes full

b. Loop flow continues

4. Results in higher downcomer temperature

a. Due to loop flow mixing with SI water

b. This is an asset since pressure will be up

c. Mixing keeps downcomer temperature up

D. Larger breaks (towards 4")

1. Breaks that drain the S/G tubes TP-5

2. Causes loop flow to stop TP-6

3. No SI/loop flow mixing TP-7

4. Cold leg and downcomer temperature drop rapidly TP-8

a. SI water replaces warmer water removed by break TP-9

b. No mixing

E. Limiting case TP-10

1. Smallest break that fails to maintain loop flow (or natural circulation)

2. Most severe combination of pressure/temperature due to:

a. Rapid cold leg/downcomer cooldown because of loop flow interruption

b. Slow depressurization because of relatively small break size

IV. Loss of Coolant

A. EI-1 discussion

1. Initially - max charging flow and seal injection flow cannot maintain pressurizer level

2. Reactor trip and SI due to low pressure

3. SI flow increases with decreasing RCS pressure

4. Analysis has shown small break - worst case LOCA

a. Large mass loss prior to actual injection

b. "Hanging-up" of pressure caused by pressurizer

5. Main responsibilities of operator

a. Ensure all automatic actions have occurred

b. Carry out change over to recirculation phase

c. To check for a leak in the injection line

d. To carry out the relevant isolation procedure

SUMMARY

I. Drawing

II. Large LOCA

III. Small LOCA
with "smaller breaks" and
"larger breaks"

IV. LOCA - EI-1 Discussion

The following curves (figures III. 1-16, 1-13, 1-15 & 1-12) are based on the following initial conditions and assumptions.

1. Small break LOCAs (1-4 inches)
2. Analyzed to obtain minimum fluid temperature in reactor vessel downcomer and maximize pressure in the RCS.

   a. All systems that provide cooling to the RCS are assumed to operate at maximum capability (i.e., all trains of SI, all aux. feedwater pumps, etc.)
   b. All warm sources at conservatively low temperature (40°F)
   c. Core heat generation at a nominal value

3. Hot leg break location selected because

   a. Ensures all SI flow delivered to the downcomer
   b. Reduces primary load flow required for break energy removal
   c. Cold leg remains filled with subcooled liquid
   d. Maximum cooldown rate for a given break size

4. Automatic no-load T_{ave} steam dump & max. AFW flow with condensate storage tank at 40°F, S/G level maintained in narrow range

5. RCP trip is assumed to occur coincident with reactor trip

<u>LOCA TRANSIENTS</u>

OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION, THE STUDENT WILL BE ABLE TO:

1. DESCRIBE THE PROGRESS OF THE TWO KEY PARAMETERS DURING A LOCA TRANSIENT.

2. DETERMINE THE LIMITING CASE FOR SMALL LOCA'S USING CONTROL ROOM INDICATIONS.

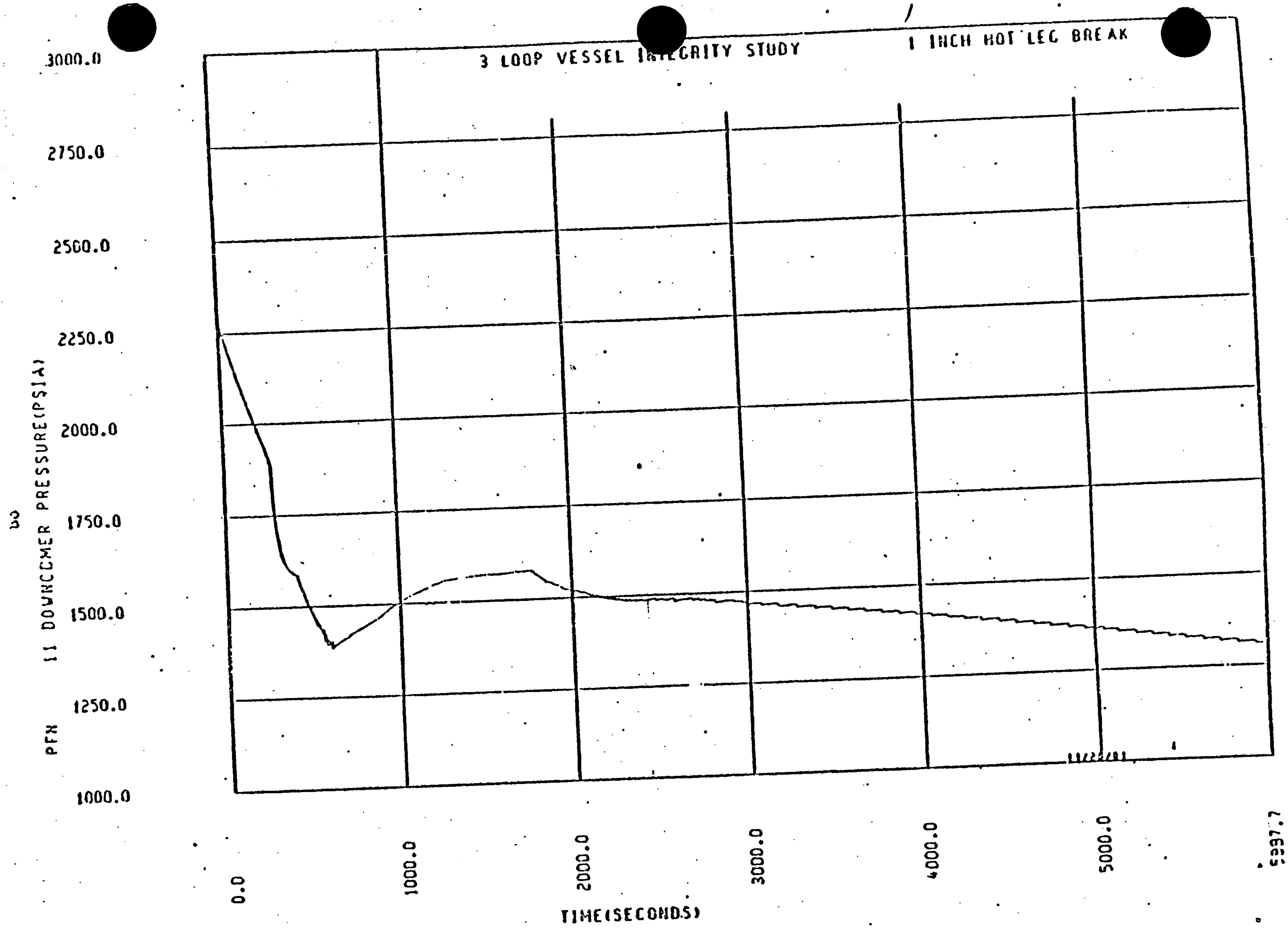


Figure III.1-17 Downcomer Pressure
... 1 Inch Hot Leg Break

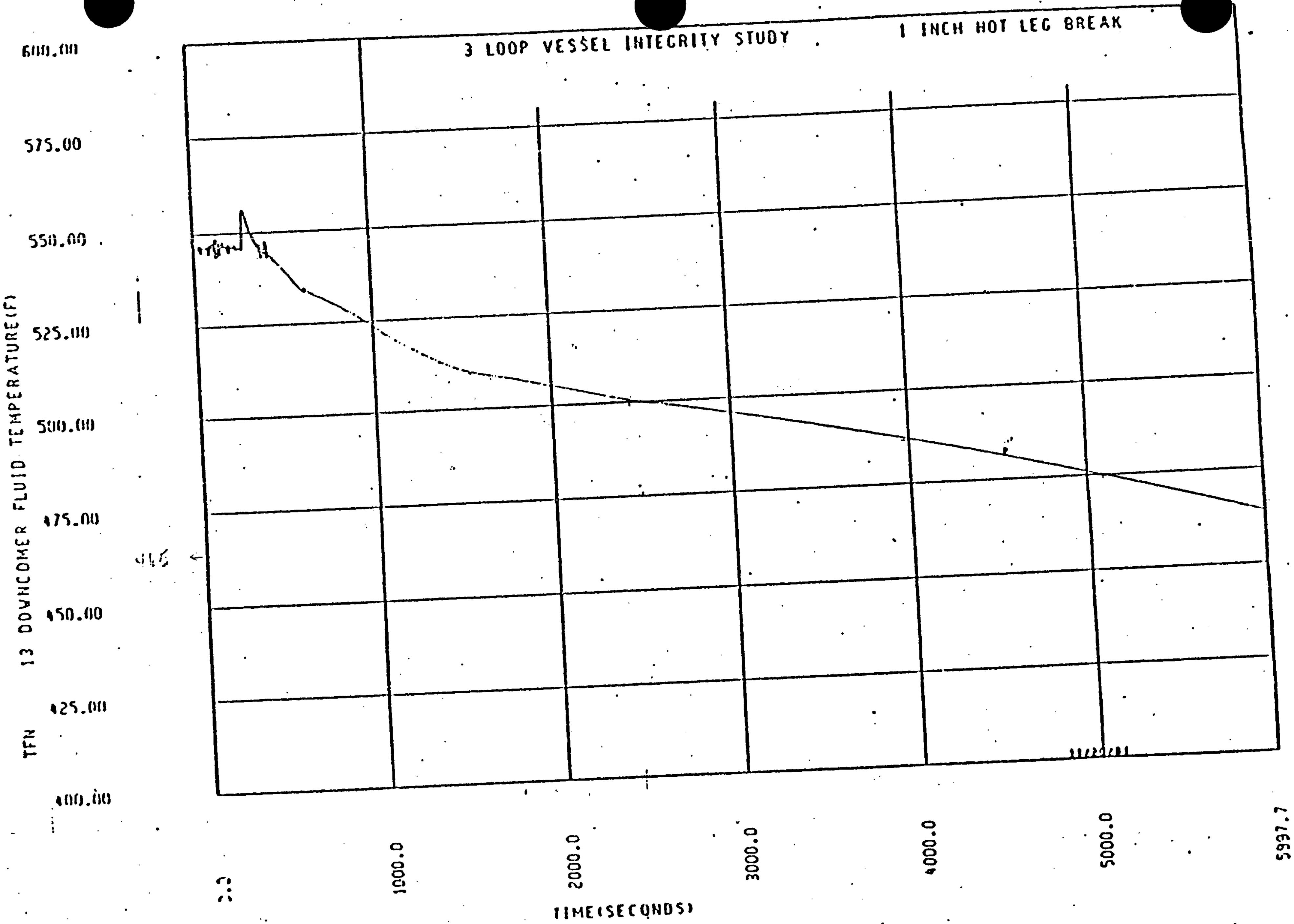
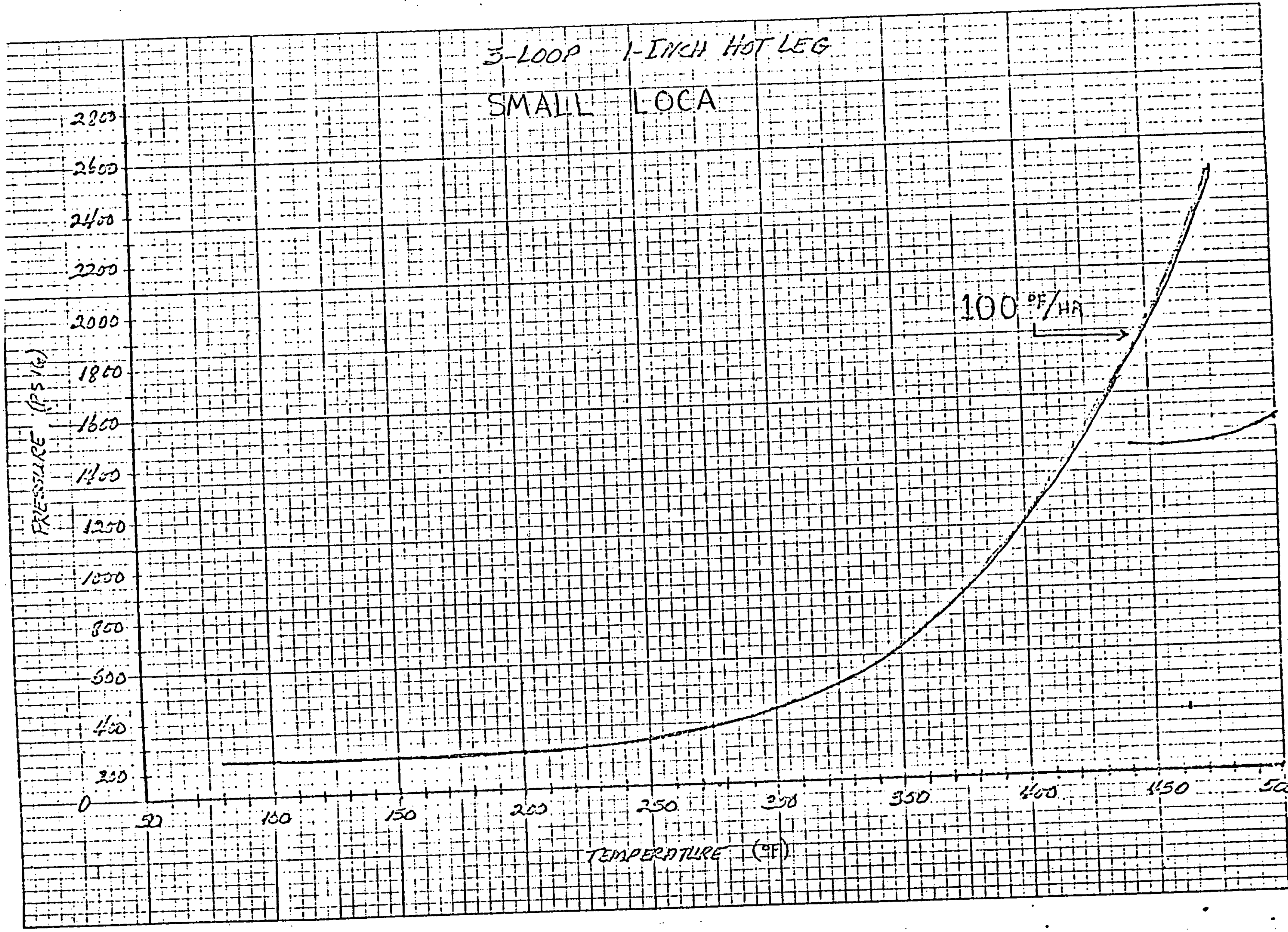


Figure III.1-14 Downcomer Fluid Temperature
3 Loop 1 Inch Hot Leg Break.

NO. 341-10 DIETZGEN GRAPH PAPER
10 X 10 PER INCH



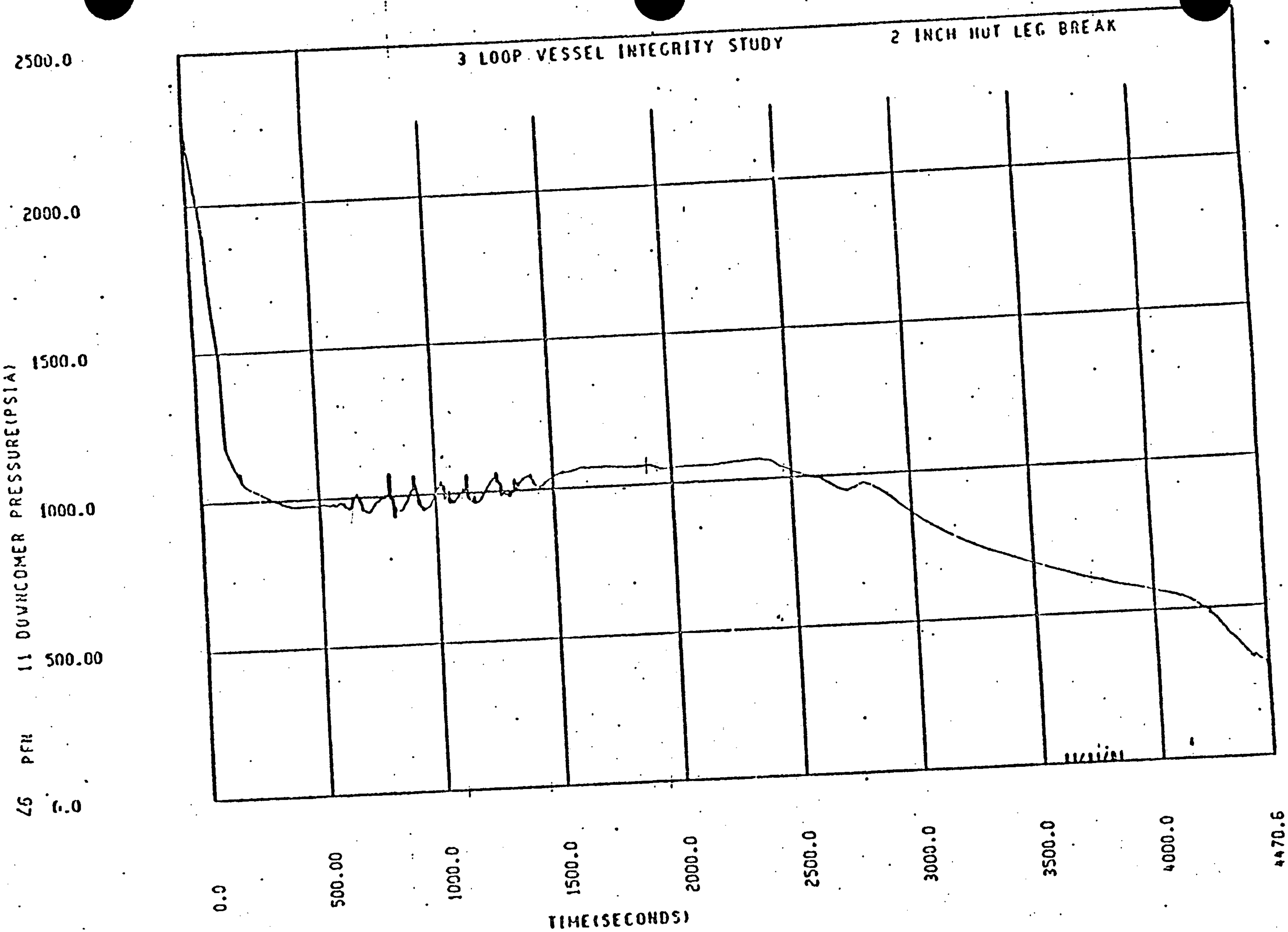


Figure III.1-16 Downcomer Pressure

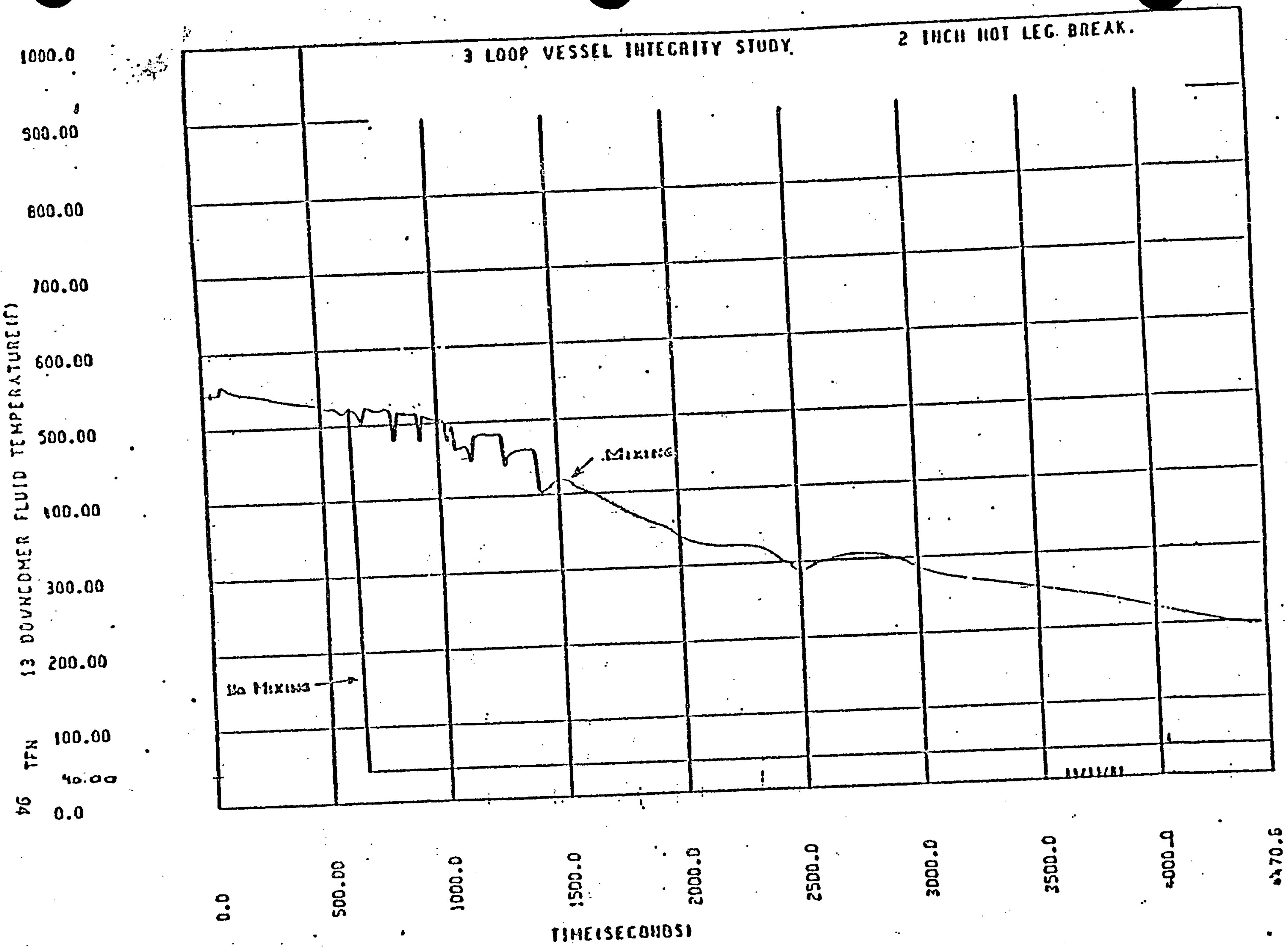
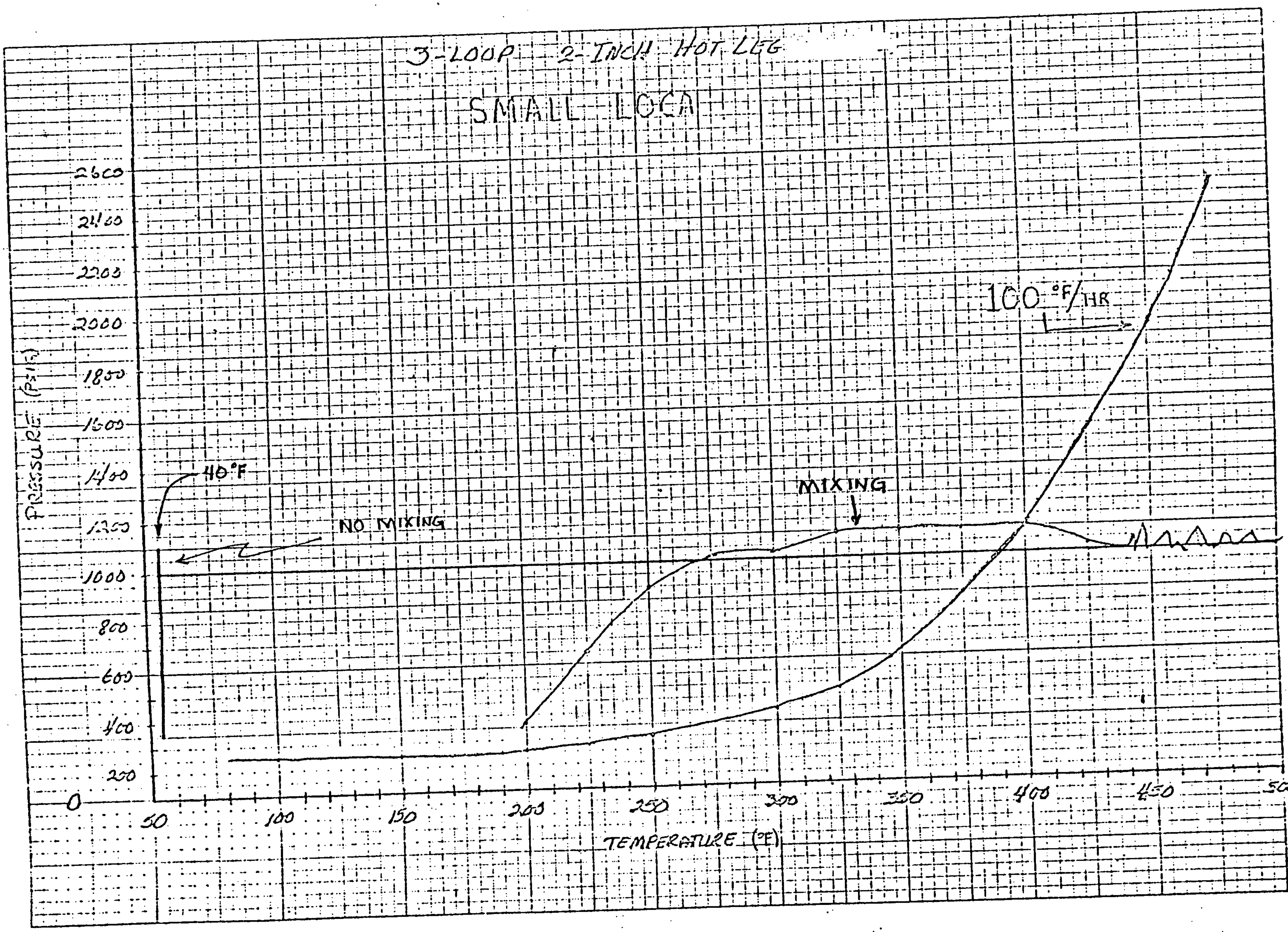


Figure III.1-13 Downcomer Fluid Temperature

NO. 341-10 DIETZGEN GRAPH PAPER
10 X 10 PER INCH

MADE IN U.S.A.

TP-7



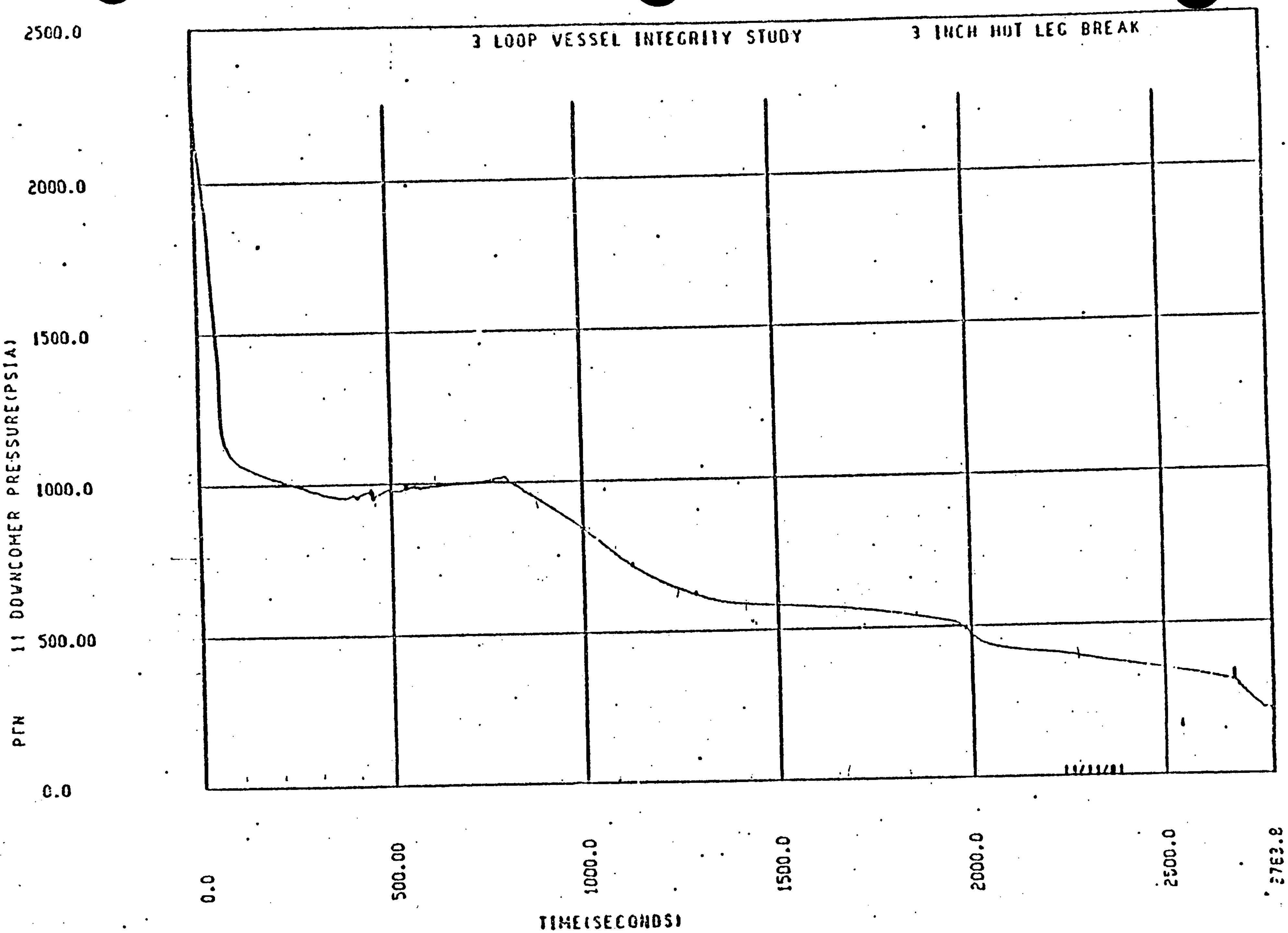


Figure III.1-15 Downcomer

TP-4

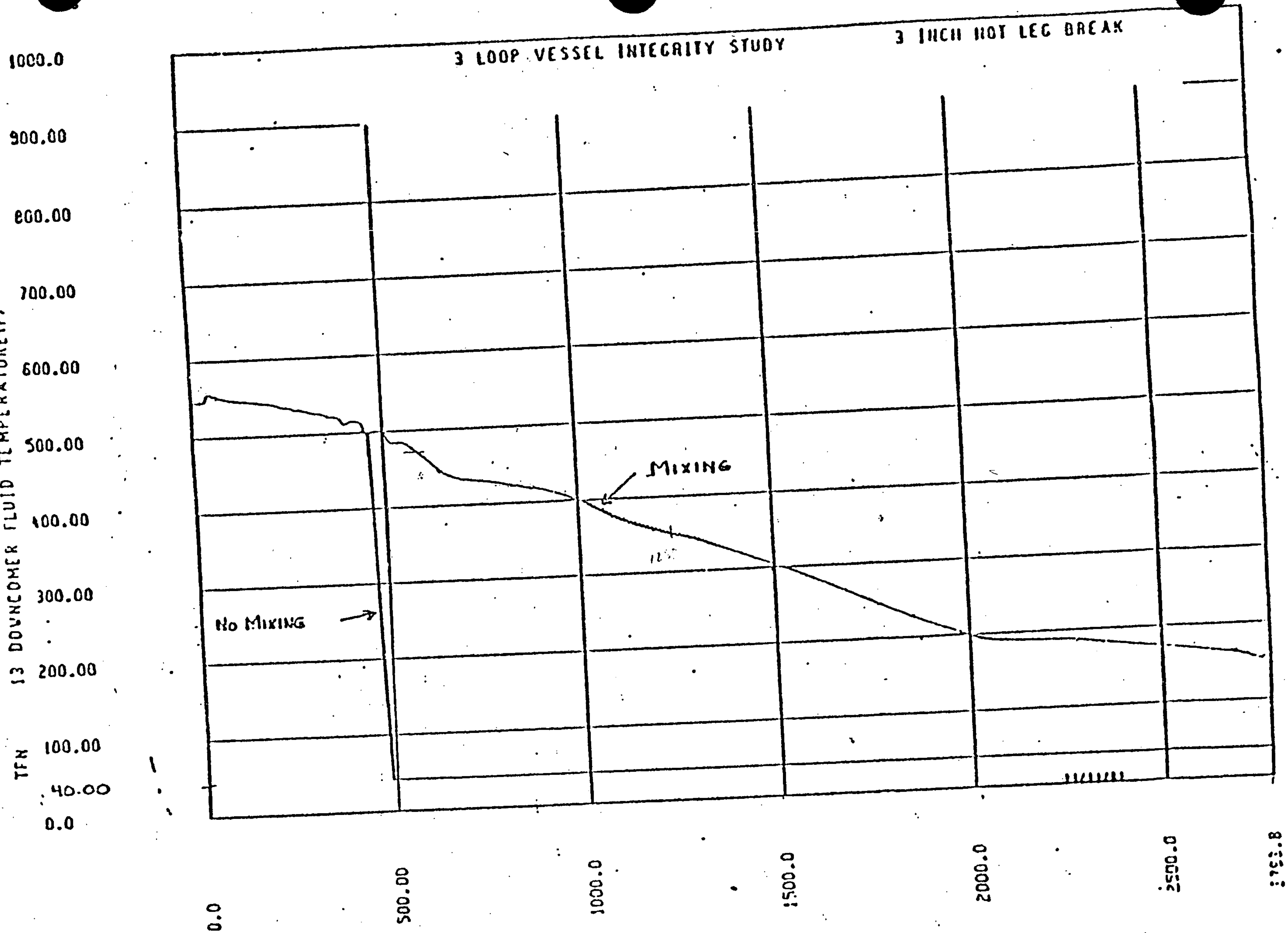
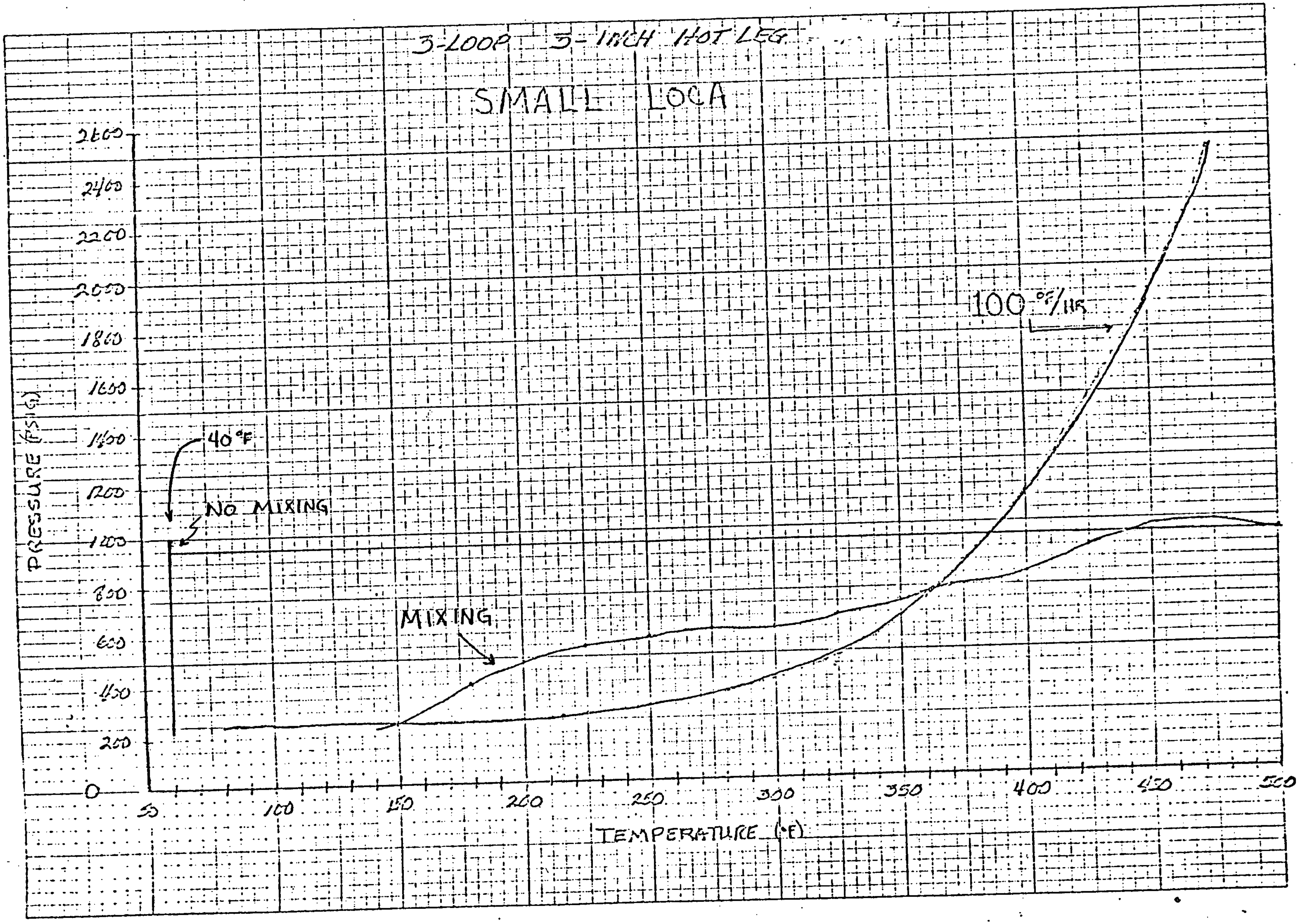


Figure III.1-12 Downcomer Fluid Temperature
3 Loop 3 Inch Hot Leg Break

NO. 341-10 DIETZGEN GRAPH PAPER
10 X 10 PER INCH

DIETZGEN CORPORATION
MADE IN U.S.A.

TP-10



LOSS OF REACTOR COOLANT

Time: 50 minutes

Session 1 of 1

OBJECTIVES:

I. Upon completion of this module the student will be able to: TP 1-1

   A. List the major symptoms of a loss of reactor coolant;

   B. State the two major concerns the operator must be aware of for this transient, from memory, including the major steps he must take to protect the plant;

   C. State, from memory, the safety injection termination criteria for a LOCA.

MATERIALS:

I. Training Aids

   A. Writing board

   B. Overhead projector

   C. Transparencies

II. References

   A. Emergency Instructions Vol. 6

   B. GP-6

SUPPLIES: Pencil and paper

INTRODUCTION

I. Establish Class Relations

A. State name - write on board

B. Ensure student comfort

C. Check on writing implements

D. Explain procedures

1. Ask questions

2. Volunteer information

3. Note taking

4. Test on subject

II. Create General Interest

A. Protection of reactor core and reactor vessel is a major concern of this procedure

B. Procedure is based on Standard DBA

PRESENTATION

I. Symptoms

A. Reduction of RCS pressure and pressurizer level

B. SI flow will be automatically initiated

1. required EI-1

2. maybe AP-25

C. High rad alarms in CV TP 1-2

D. Increase in conatinment pressure TP 1-3

II. Automatic Actions for SI (EI-1)

A. Verify they have occurred

B. Initiate any auto actions that have not occurred

1. from RTGB

2. locally (all possible methods)

III. Instrumentation Needed

A. RCS Pressure

1. Wide range

2. Narrow range

B. RCS Temperature

1. Wide range T_H

2. Wide range T_C

a. PTS parameter

b. Closest temperature to vessel wall

3. Incore thermocouples

4. Reactor vessel head thermocouple

a. Location

b. Purpose

5. Saturation monitor (prime subcooling indicator)

C. Steam Generator

1. Pressure

2. Level

3. Aux. feed flow

D. Pressurizer level

NOTE: Valid except where primary mass loss is through pressurizer steam space

1. Narrow range

2. Wide range

E. CV Pressure

F. RWST level

G. CST level

IV. RECOVERY (EI-1 App. A)

A. Purpose

1. Adequate core cooling

2. Vessel integrity

B. Injection Phase

1. Reactor trip and turbine trip

2. SI actuation

3. Feed isolation

4. CV possible spray actuation - indicates large LOCA

5. Control room ventilation isolation

Note: Inadequate core cooling session

6. Void formation possible

a. 40° subcooling required

1. 20°F errors possible from press-temp.

2. 20°F to assure subcooled

7. In case of blackout

a. Steam AFW pump status

b. Restart battery chargers

1. Trip on UV

2. Manual reclosure

3. At battery chargers

c. Restart inst. air compressors

1. Break trip on UV

2. Reset at MCC 9 and 10

d. CCW

1. Restart if no spray (D/G capacity)

2. Locked out on SI signal

C. Reset SI

1. Shutdown diesels (if not needed)

2. Stop RHR pumps (pump protection)

a. 15 minutes at greater than 130 paig - 1 pump.

b. 30 minutes at greater than 130 psig-2nd pump

3. Trip RCPs at 1300 psig

a. Core blowdown

1) Cold leg break

2) Prior to reflood

b. Cavitation possible

D. Termination of safety injection

1. RCS pressure greater than 1560 psig and increasing

a. Hi Head SI shutoff head (1450 psig)

b. Inst. error (W.R. Press) 110 psig

2. Pressurizer level at no load

a. RCS inventory

b. Core covered

3. (1) S/G water level

a. Narrow range

b. Wide range (u-tubes covered)

c. Ensure heat sink available

4. 40°F subcooled 65° if restart of SI pumps

a. Reduce cycling on SI pumps

b. 25°F addition based on W.O.G.

5. Place SI in standby

a. Plant control regained

b. Shift to normal procedures

E. I. Press. & temp. violate C/D curve

a. Restore to acceptable band

b. Depressurize to achieve

c. Do not heat up if — Transparency of curve 3.4

1) Rapid C/D has occurred

2) Large C/D has occurred

3) Possible flaw propagation

2. Maintain $40^{\circ}F$ subcooling -

F. Sample steam generators

1. Verify tube integraty

2. Minimize potential for radioactive release

3. Isolate MSIVs if necessary

a. At $500^{\circ}F$ RCS temp.

b. 1000 psig RCS press.

G. Check coolant chemistry

1. Boron concentration

2. Fuel integrity

H. Cooldown plant per GP-6

I. Aligh N_2 and sample valves in pipe alley

1. Rad. levels may increase

2. Post accident sample points

J. Terminate spray at CV pressure of 4 psig

1. Steam has been condensed

2. Major energy release if over

K. Prepare for recirculation (if necessary)

SUMMARY

I. Symptoms of a LOCA

A. Press. & level

B. Rad.

C. SI

D. CV press.

II. Verify Auto Actions

III. Major Instruments

A. Press.

B. Temp.

C. Heat sink

D. Subcooling

IV. Recovery

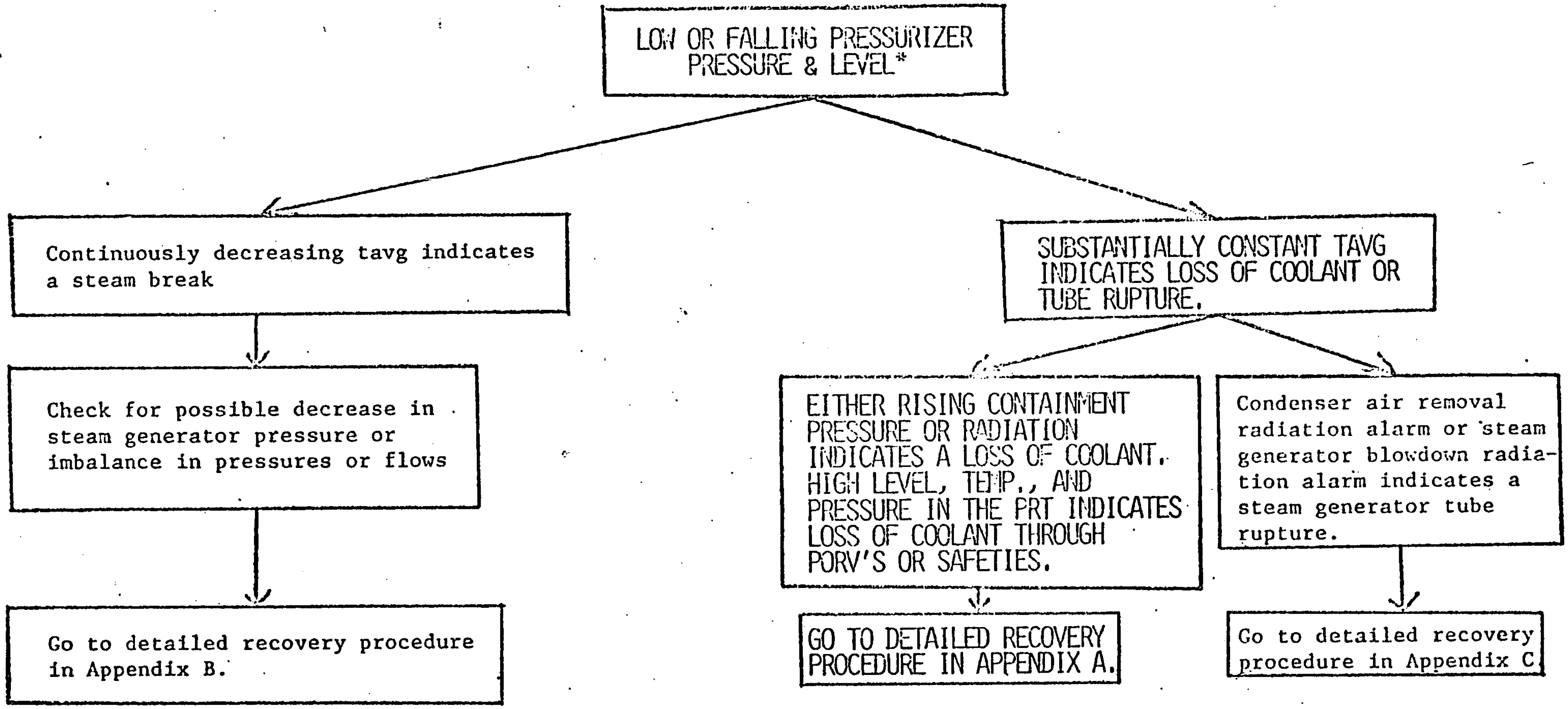
A. Cool core

B. Minimize fuel damage

C. Minimize challanges to R.V. integrity

D. Stabalize plant

BEFORE REACTOR TRIP & "S" SIGNAL



*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

AFTER REACTOR TRIP & "S" SIGNAL

LOW OR FALLING PRESSURIZER PRESSURE & LEVEL*

Abnormally low steam pressure in one or maore steam generators indicates steam break.

Verify by checking for:

1. Lower than normal steam generator levels.
2. A possible first out annunciation of:
   a) Steam/feedwater flow mismatch
   b) Low-low steam generator water level.
   c) High steam line flow.
   d) High steam line differential pressure.

Go to detailed recovery procedure in emergency instruction, Appendix B.

RISING OR NORMAL STEAM PRESSURE IN STEAM GENERATORS INDICATES LOSS OF COOLANT OR TUBE RUPTURE.

EITHER INCREASING CONTAINMENT PRESSURE OR CONTAINMENT HIGH RADIATION ALARM OR RISING SUMP WATER LEVEL INDICATES A LOSS OF COOLANT.

GO TO DETAILED RECOVERY PROCEDURE IN APPENDIX A.

Condenser air removal equipment radiation alarm or steam generator blowdown radiation alarm or possible observed differential rate of rise of steam generator levels.

Go to detailed recovery procedure in Appendix C.

*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

STEAM BREAK TRANSIENTS

Time: 1 hour

Session 1 of 1

OBJECTIVES: Upon successful completion of this session the student will be able to:

1. Describe the progress of key parameters during a steam break transient. TP-1

2. Describe how reactor vessel integrity could be challenged during steam break transients, and how to avoid or if necessary mitigate them.

MATERIALS:

I. Training Aids

A. White board or equivalent

B. Overhead projector

C. Transparencies

1. Objectives
2. Large Steam Break - Pressure vs. Time
3. Large Steam Break - Temperature vs. Time
4. Large Steam Break - Pressure vs. Temperature
5. Large Steam Break - Pressure vs. Time (RCP's tripped)
6. Large Steam Break - Temperature vs. Time (RCP's tripped)
7. Large Steam Break - Pressure vs. Temperature (RCP's tripped)
8. Small Steam Break - Pressure and Temperature vs. Time
9. Small Steam Break - Pressure vs. Temperature

II. References

A. WCAP-10019

B. Plant Operating Manual Volume 6 Emergency Instructions

III. Supplies

A. Pencils and paper

B. Graph paper

INTRODUCTION

I. Establish Class Relations

A. State name

B. Explain procedures (asking questions, volunteering information)

II. Establish Learning Goals

A. State title

B. State objectives (from Page 1)

PRESENTATION

Steam Break Transients

I. Student's Sketch

A. A large steam break on 'A' S/G

B. Label sketches and give typical values for

1. Tc vs. Time

2. RCS Press vs. Time

3. "A" S/G Press vs. Time

II. Large Steam Line Breaks

A. Description

1. Steam generator blows down to atmospheric pressure

2. Rapid decrease in RCS temperature due to:

a. Rapid energy release

b. Cold AFW to steam generators

c. SI flow to the RCS

3. RCS pressure decrease due to temperature decrease (350-400^{o}F; 700-1000 psig)

4. Pressure reaches a minimum when rate of RCS shrinkage = rate of injection (SI & charging)

PRESENTATION (Continued)

5. If the RCS has cooled down to approximately 350°F or less repressurization to SI shut-off head could challenge reactor vessel integrity.

6. RCS pressure tends to increase from pressurizer steam space compression as SI injection fills pressurizer.

7. Then RCS temperatures and pressures tend to increase due to decay heat.

8. Pressure increase is halted (or minimized) when — PTS

   a. Operator secures the SI pumps

   b. Dump steam from good generators

9. Operators also must isolate AFW to faulty steam generator — PTS

   a. Protect steam generator from thermal shock

   b. Prevent (minimize) excessive cooldown

B. Transients

1. With RCP's running — TP-2

   a. Rapid RCS temperature and pressure drop — TP-3, TP-4

   b. $\approx$ 4 minutes temp starts to level off. $\approx$ 10 min. temp. is $\approx$ 200°F

      1. Tc on affected loop

      2. R.V. downcomer thermal shock

   c. Operator assumed to isolate AFW. — PTS

      1. At $\approx$ 4 min. press. is at minimum ($\approx$ 680 psig)

      2. 10 min. press. peaks ($\approx$1000 psig)

      3. Press increases

         (a) SI flow > density increases

         (b) Decay heat

   d. Faulted S/G press.

PRESENTATION (Continued)

2. Without RCP's running TP-5

   a. Loss of power at time of steam break TP-6

   b. Rapid drop in temperature and pressure TP-7

   c. Temp. PTS

      (1) $\approx$ 3 min. temp leveling at 200°F;

      (2) $\approx$10 min. temp increases to $\approx$ 220°F

   d. Press.

      (1) $\approx$ 3 min. press. minimum $\approx$ 900 psig

      (2) Press peaks 10 min. $\approx$ 1300 psig

      (3) Press. increases

         (a) SI flow > density increase

         (b) Decay heat

   e. Faulted S/G Press.

III. Small Steam Break

A. Method of Analyses

1. Small break defined as equivalent to a steam safety valve opening and remaining open

2. Following conservative assumptions made:

   a. Reactor hot, zero power

   b. Immediate Rx trip and SI

   c. No decay heat

   d. SI system operates at design capacity and repressurizes the RCS in short time

   e. No credit for operator action

PRESENTATION (Continued)

B. Transients

1. Press. and Temp. decreases due to TP-8

   a. Energy release through break

   b. Cold injection water (AFW & SI)

2. Temp continues to decrease until 35 to 40 minutes later, then 270°F

3. Press. at min. (1845 psig) 9 minutes, then increases

4. Press reaches PZR PORV setpoint

   a. approximately 35 minutes (after time = 0)

   b. remains there

5. Main concern is to reduce system pressure and maintain subcooling TP-9 PTS

   a. Tc low

   b. Press high

   c. Must reduce press

SUMMARY

I. Drawing

II. Large Steam Break

   A. Description

   B. Transients

III. Small Steam Break

   A. Method of analyses

   B. Transient

STEAM BREAK TRANSIENTS

OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION THE STUDENT WILL BE ABLE TO:

1. DESCRIBE THE PROGRESS OF KEY PARAMETERS DURING A STEAM BREAK TRANSIENT

2. DESCRIBE HOW REACTOR VESSEL INTEGRITY COULD BE CHALLENGED DURING STEAM BREAK TRANSIENTS, AND HOW TO AVOID OR IF NECESSARY MITIGATE THEM.

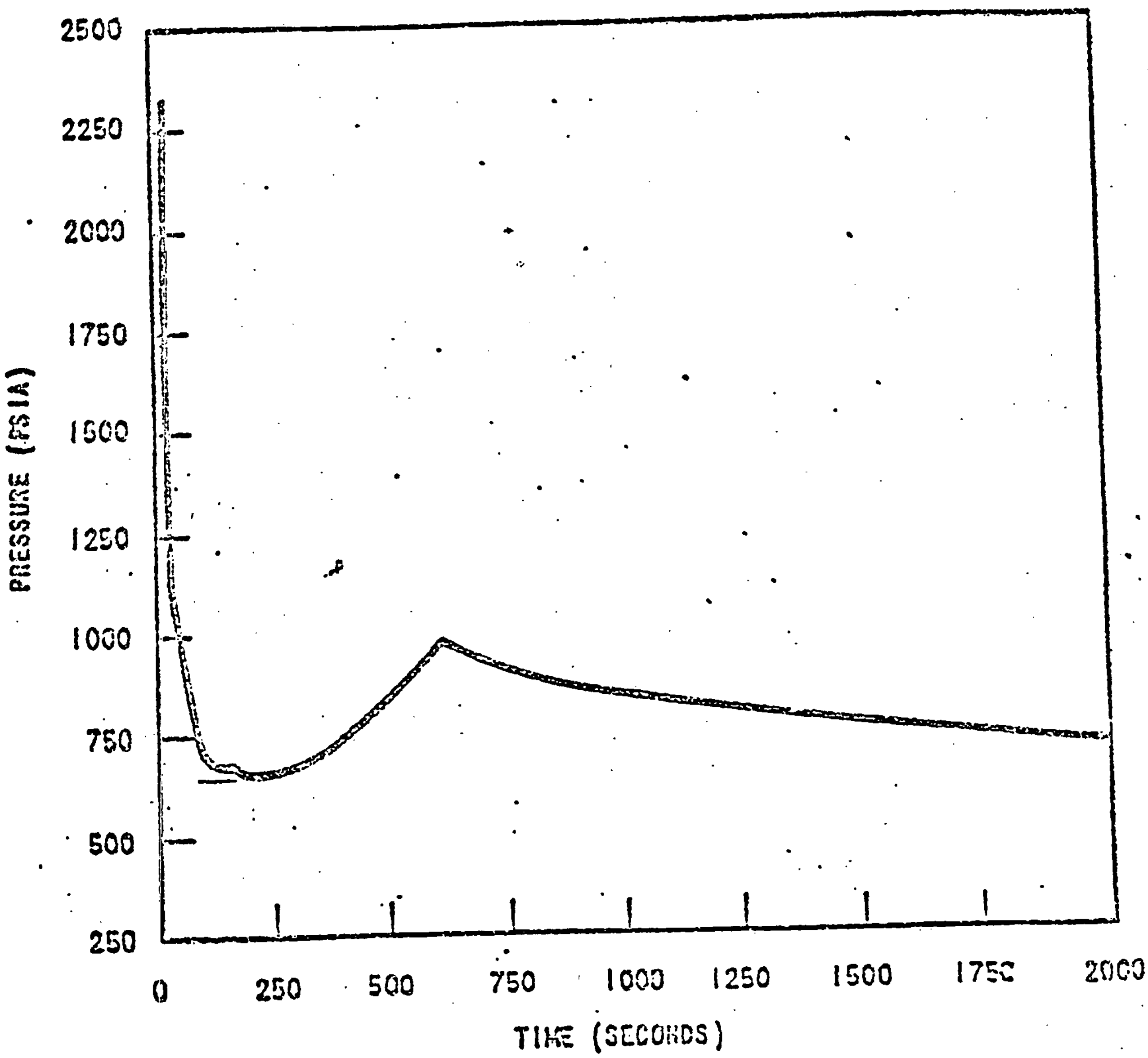


Figure III.1-27 Large Steamline Break With Reactor Coolant Pumps Running. Reactor Coolant Pressure Versus Time

Assumptions and Conditions

12.G03-6

1. Maximum SI and AFW flow rate
2. Minimum injected fluid temperature
3. No decay heat (Maximum Cooldown Case)
4. Initiating event is double-ended guillotine severence
5. SI causes repressurization following initial depressurization
6. SI and AFW flow assumed to start at time of break
7. Operator action terminates AFW flow and SI flow after 10 minutes

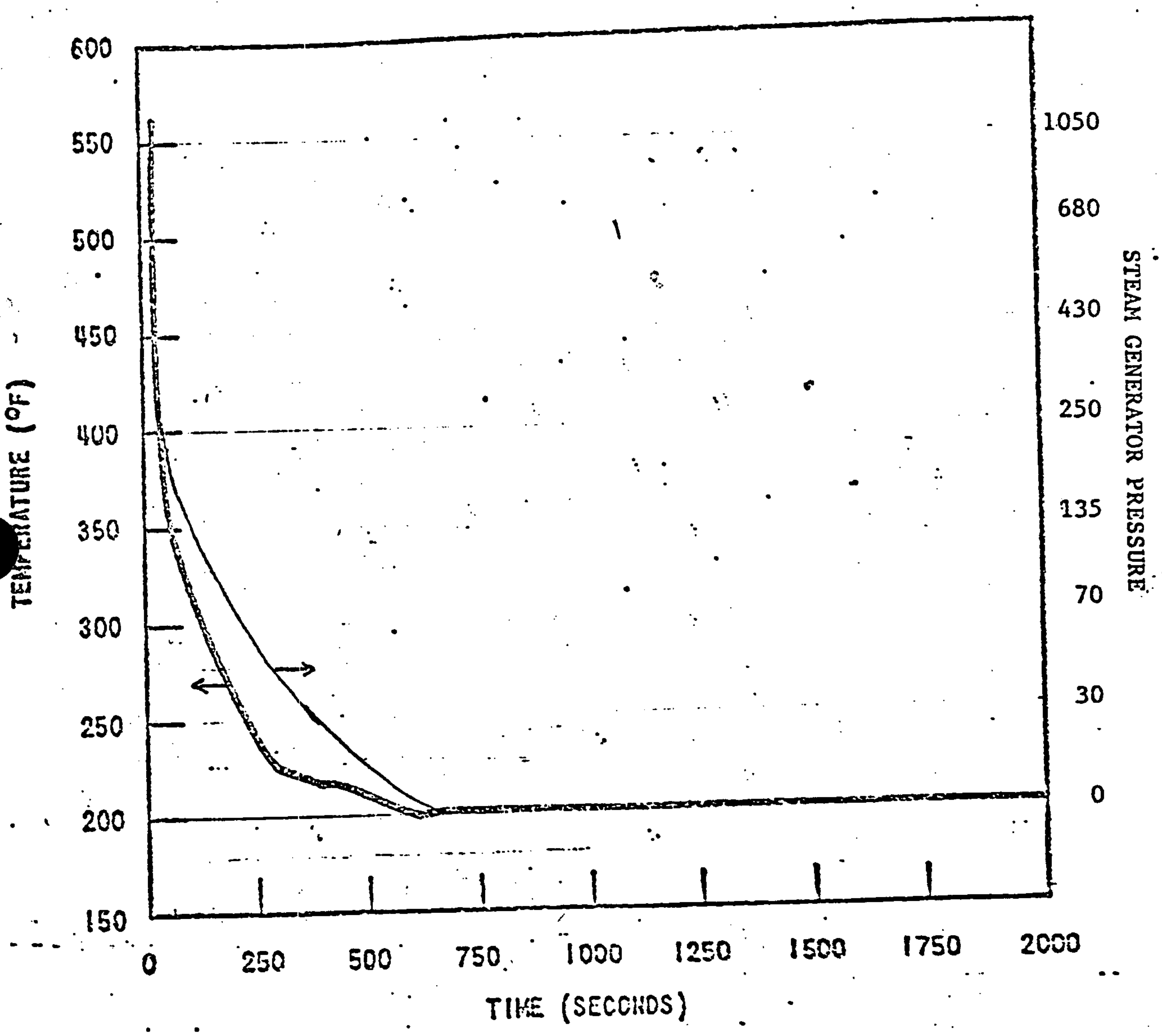
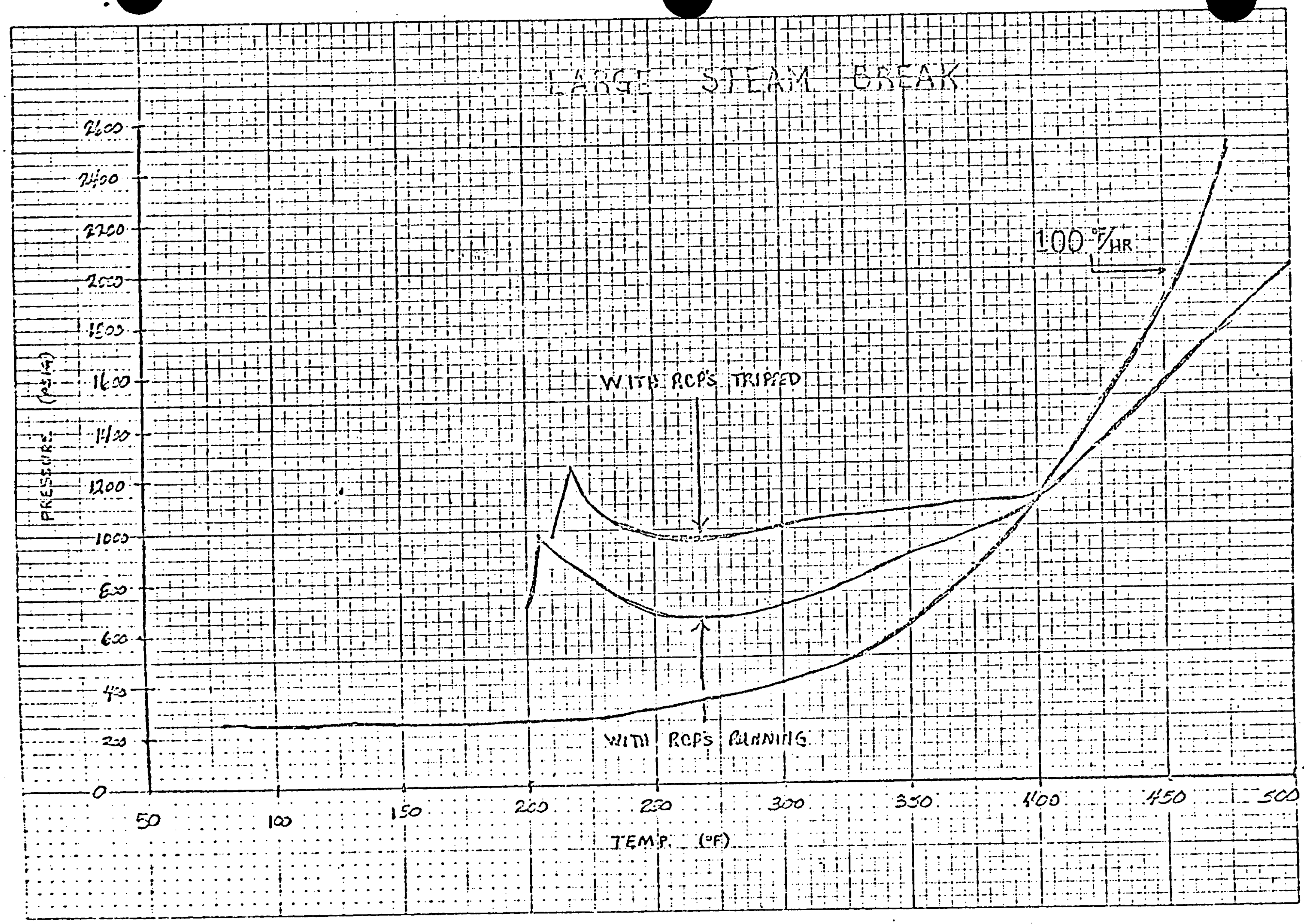


Figure III.1- 28 Large Steamline Break With Reactor Coolant Pumps Running. Cold Leg Temperature Versus Time



LARGE STEAM BREAK
2600
2400
2200
2000
1800
1600
1400
1200
1000
800
600
400
200
0
PRESSURE (psig)
100 °F/HR
WITH RCP'S TRIPPED
WITH RCP'S RUNNING
50
100
150
200
250
300
350
400
450
500
TEMP. (°F)

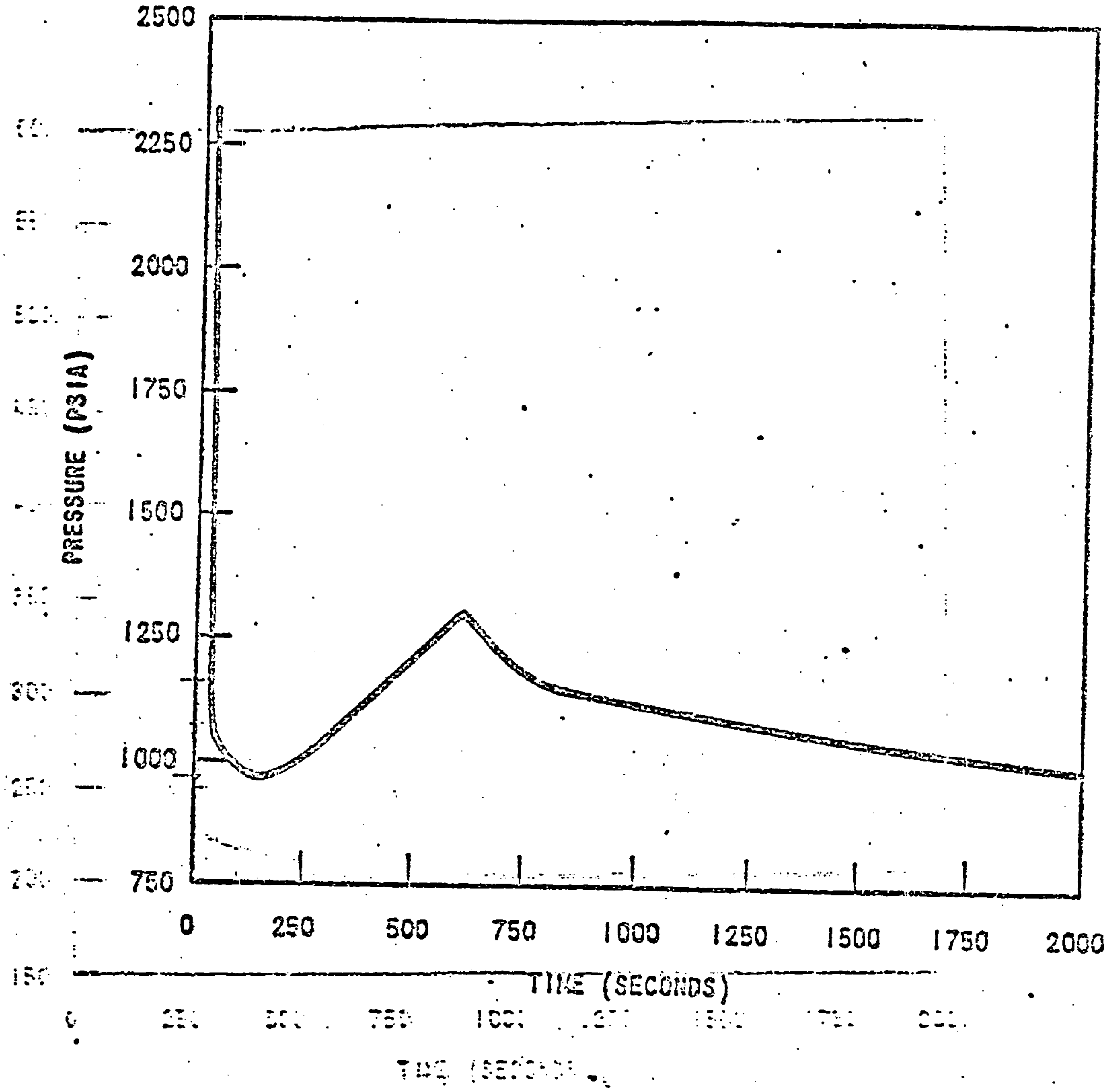


Figure III.1-29 Large Steamline Break With Reactor Coolant Pumps Tripped. Reactor Coolant Pressure Versus Time

Assumptions and Conditions

12.093-7

1. Maximum SI and AFW flow rate
2. Minimum injected fluid temperature
3. No decay heat (Maximum Cooldown Case)
4. Initiating event is double-ended guillotine severence
5. SI causes repressurization following initial depressurization
6. SI and AFW flow assumed to start at time of break
7. Operator action terminates AFW flow and SI flow after 10 minutes
8. RCP's tripped at time of steam break

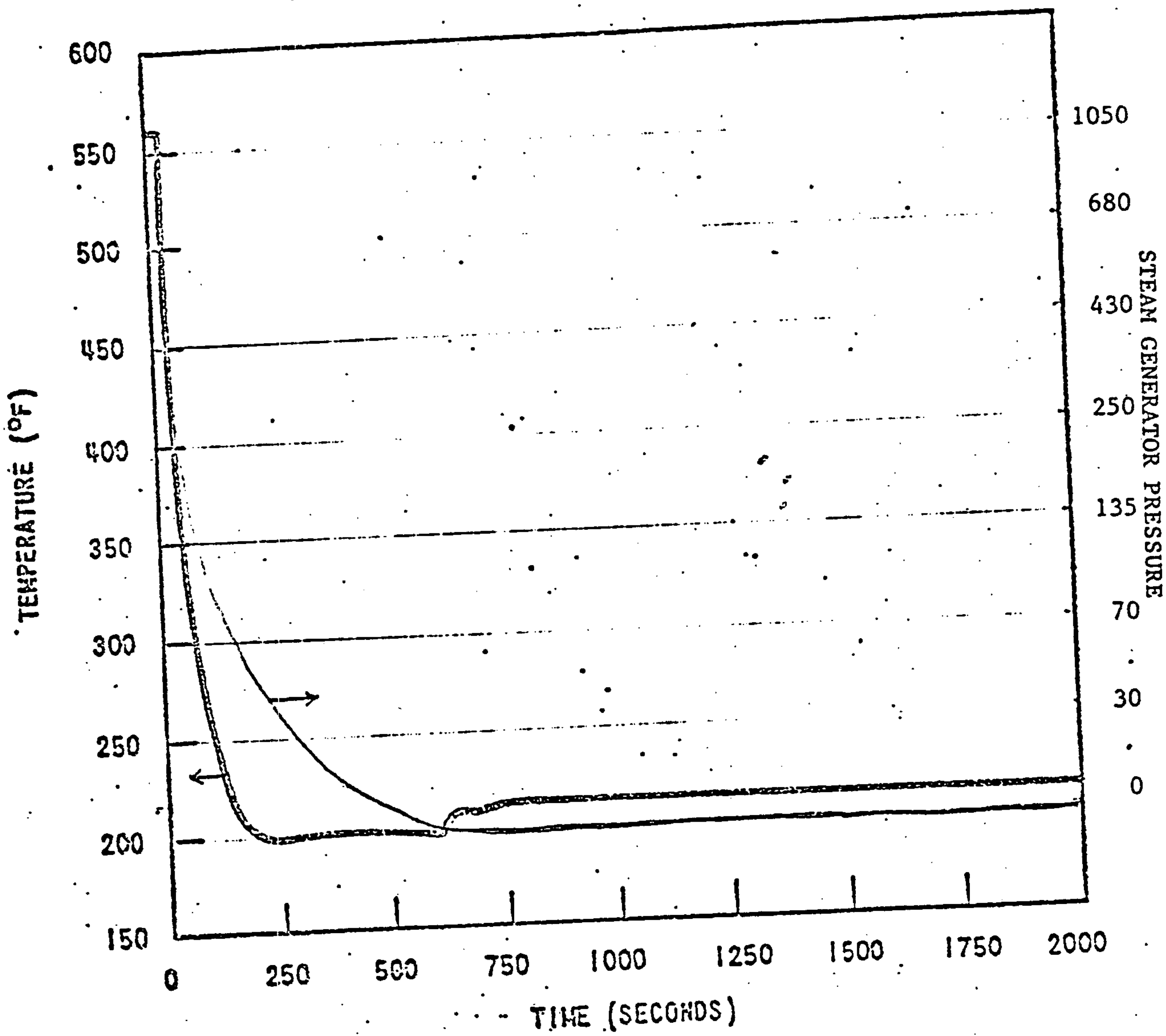
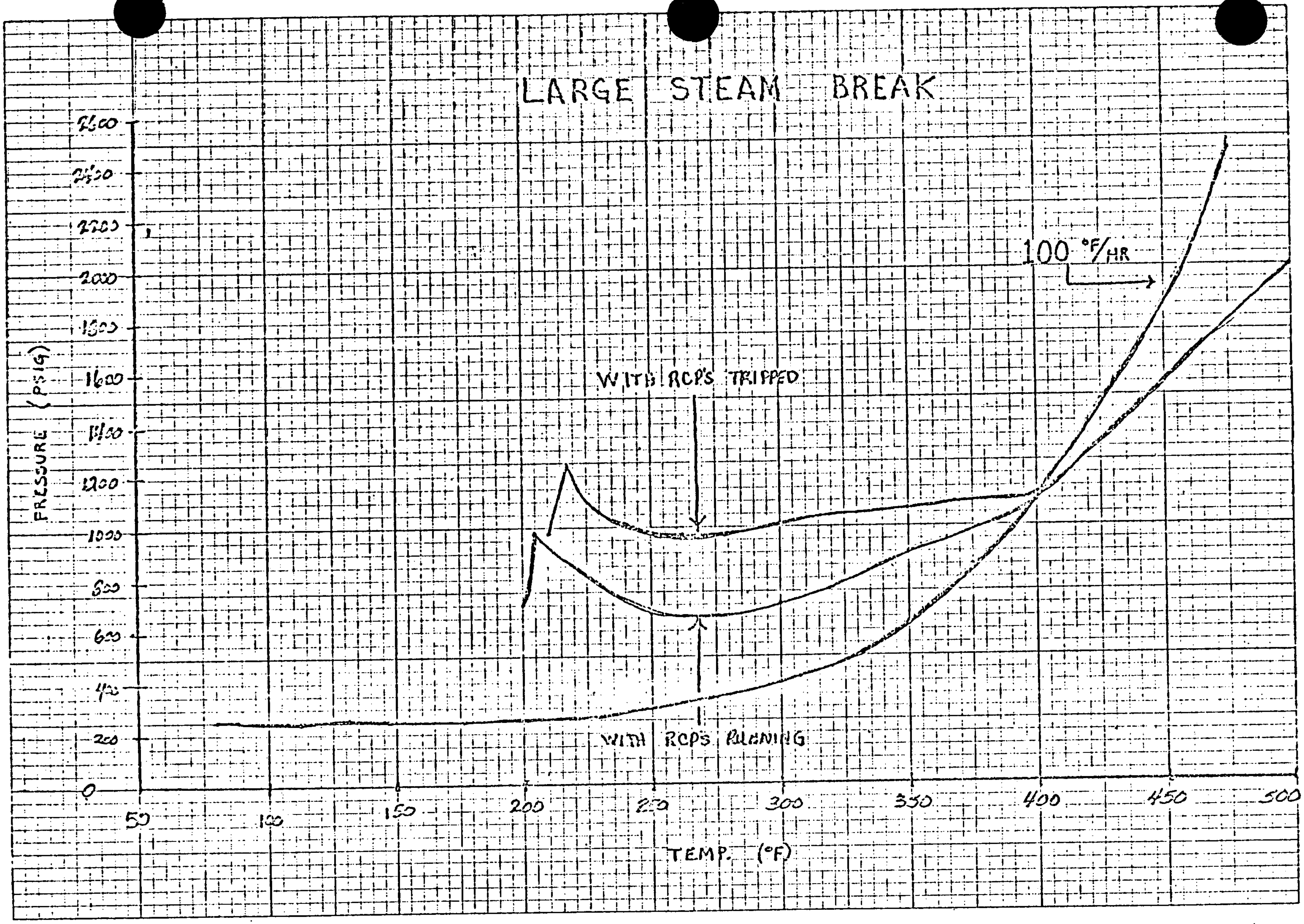


Figure III.1-30 Large Steamline Break With Reactor Coolant Pumps Tripped. Cold Leg Temperature Versus Time


LARGE STEAM BREAK
PRESSURE (PSIG)
TEMP. (°F)
100 °F/HR
WITH RCP'S TRIPPED
WITH RCP'S RUNNING
0
200
400
600
800
1000
1200
1400
1600
1800
2000
2200
2400
2600
50
100
150
200
250
300
350
400
450
500

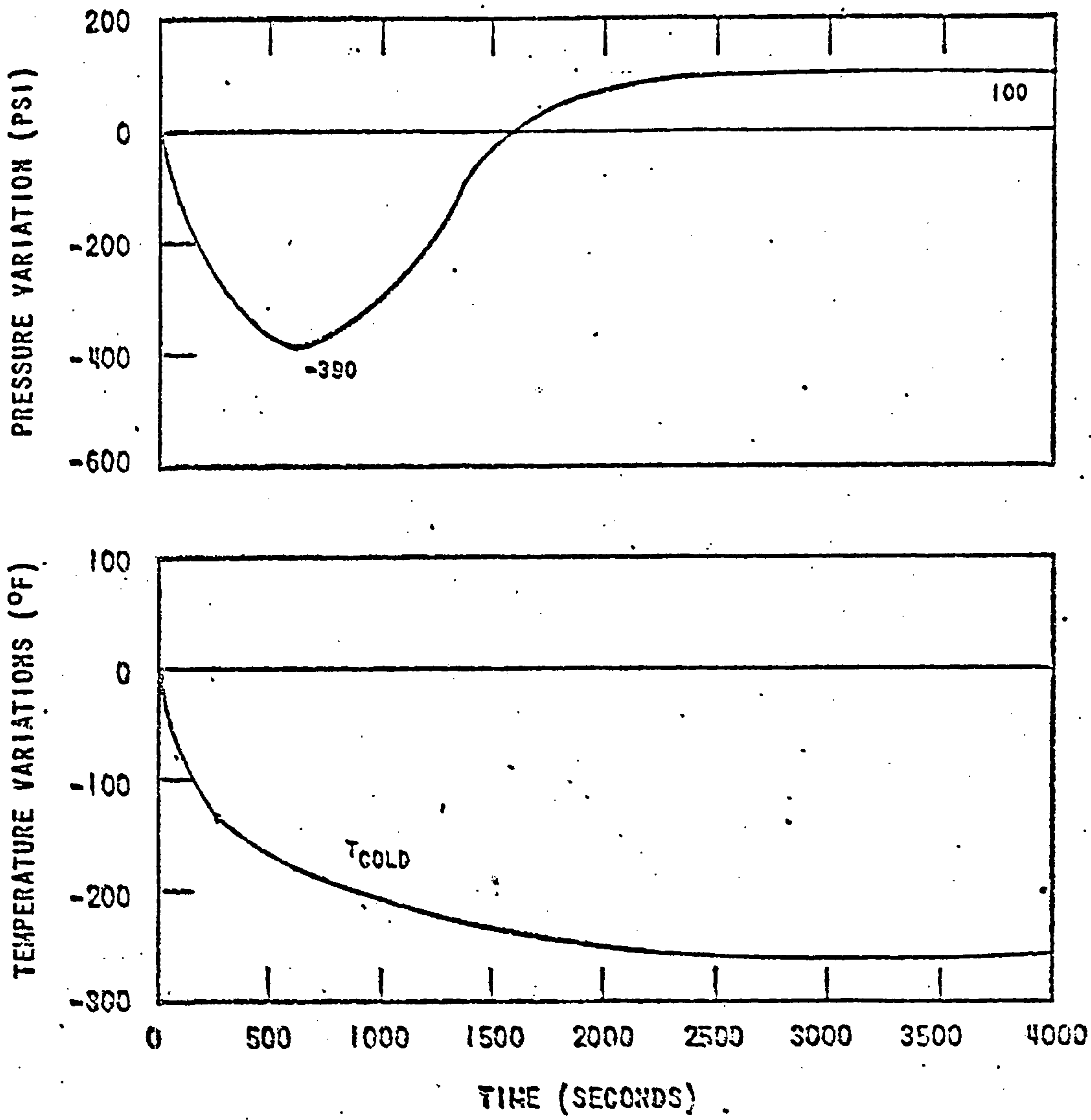
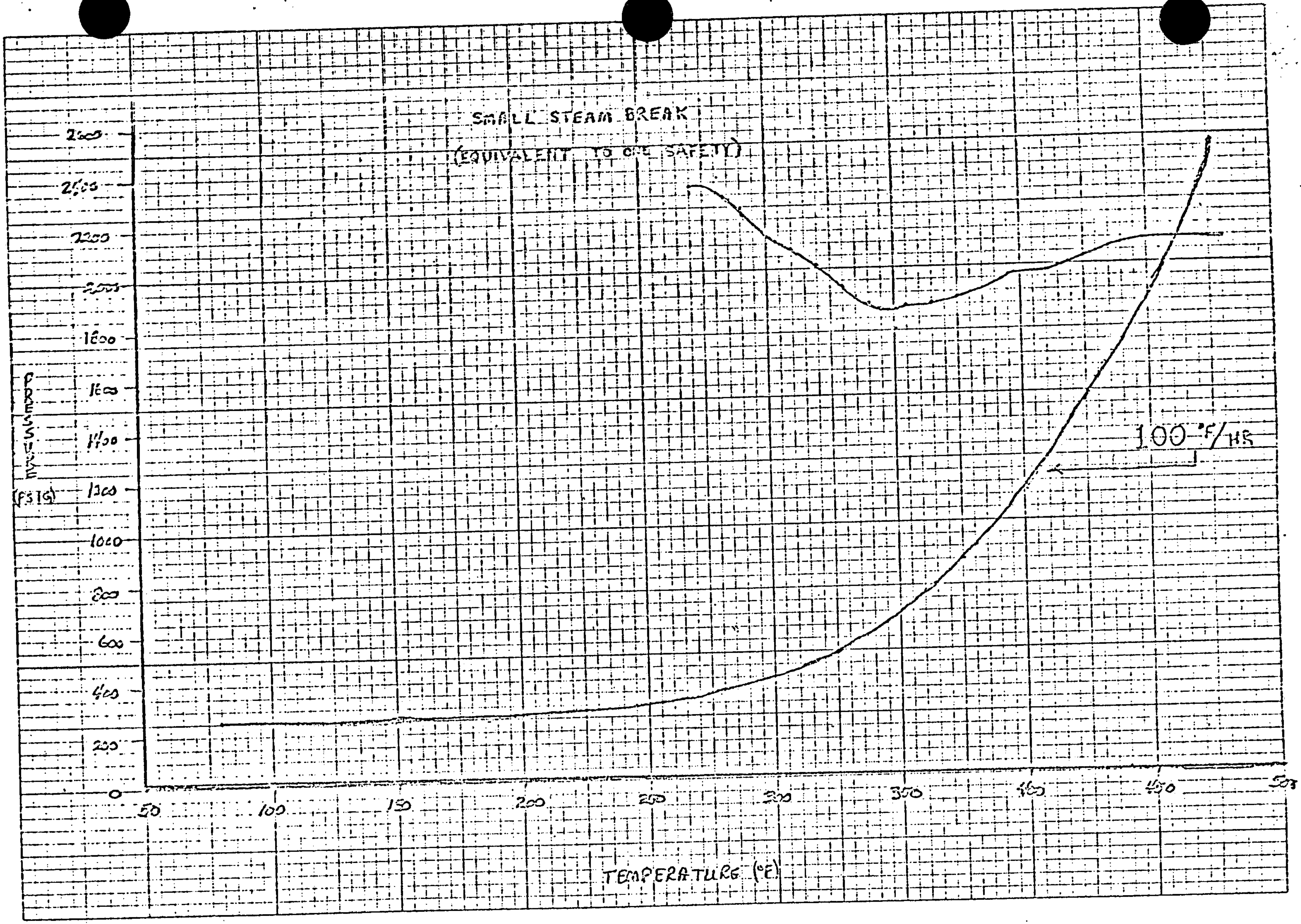


Figure III.1-32 Small Steam Break – Reactor Coolant Pressure and Temperature Variations



SMALL STEAM BREAK
(EQUIVALENT TO ONE SAFETY)
PRESSURE (PSIG)
2200
1800
1000
800
600
400
200
0
50
100
150
200
250
300
350
400
450
500
100 °F/HR
TEMPERATURE (°F)

LOSS OF SECONDARY COOLANT

Time: 50 minutes

Session 1 of 1

Session Time: 50 minutes

OBJECTIVES:

1. Upon completion of this module, the student will be able to list the major symptoms of a loss of secondary coolant.

2. Explain the major concern the operator must consider for this transient, including the major steps he must take to protect the plant.

3. The student will be able to state, from memory, the two safety injection termination criteria for this transient and explain the reason for each.

MATERIALS:

I. Training Aids

   A. Writing board

   B. Overhead projector

   C. Transparencies

II. References

   A. Emergency Instructions Vol. 6

   B. WCAP 10019

   C. General Procedure #6

III. Supplies

   A. Paper and pencils

I. Establish Class Relations

A. State name - write on board

B. Ensure student comfort

C. Check on writing implements

D. Explain procedure

1. Ask questions

2. Volunteer information

3. Note taking

4. Test on subject

II. Objectives

A. Upon completion of this module, the student will be able to list the major symptoms of a loss of secondary coolant. TP 2-1

B. Explain the major concern the operator must consider for this transient, including the major steps he must take to protect the plant.

C. The student will be able to state, from memory, the two safety injection termination criteria for this transient and explain the reason for each.

III. Create General Interest

A. Protection of reactor core and reactor vessel is a major concern of this procedure

B. H. B. Robinson has already had several steam break type events

PRESENTATION

I. Symptoms

A. Reduction of reactor coolant system temperature and pressure - Dependent on break size and location

1. Pumps not tripped (worst case analysis)

Per WCAP 10019

a. Temperature to as low as 200°F

b. Pressure to about 680 psig

2. Pumps tripped (worst case analysis)

    a. Temperature to as low as 225°F

    b. Pressure to about 1100 psig

    c. Steam pressure decrease

    d. Steam flow increase (possible)

    e. SI flow will be automatically initiated

        1) Steam line ΔP

        2) Hi steam flow

II. Determination of Break Location TP 2-2

A. MSIVs closed after initiation TP 2-3

1. All S/G ≈ equal

2. Break downstream of MSIVs

3. Break isolated

B. Pressure lower in 1 steam generator

1. Break before stop valve

    a. Rising containment pressure - break inside CV

    b. Check valve holding

2. Break between CV and stop valve

    a. All stop valves closed or check valve holding

    b. No increase in CV pressure

    c. Noise

3. Two closed MSIVs - no CV pressure

    a. Break between CV and isolated MSIV

        1) Steam pressure in isolated S/G

        2) Noise

    b. Break down stream of CV steam press. in S/G with open MSIV

        1) Uninsulated line

        2) Header

III. Auto Actions for SI (EI-1)

A. Verify they have occurred

B. Initiate any auto actions that have not occurred

1. From RTGB

2. Locally (all possible methods)

IV. Instrumentation Needed

A. RCS pressure

1. Wide range

2. Narrow range

3. Important for

a. Subcooling

b. Cooldown curve

B. RCS temperature

1. Wide range T_h

2. Wide range T_c

a. PTS parameter

b. Closest temp. to vessel downcover

3. Incore thermocouples - subcooling

4. Reactor vessel head thermocouples

a. Location

b. Purpose

5. Saturation monitors - prime subcooling indicator

C. Steam Generator

1. Pressure

2. Level

3. Aux. Feed Flow

4. Used for

a. Break location

b. Break isolation

c. AFW isolation

V. Recovery Procedure from Loss of Secondary Coolant

A. Purpose

1. Stabilize plant

2. Minimize energy release due to break

3. Remove decay heat

a. Prevent lifting of pressure safety valves

b. Reduce possibility of overpressurization

4. Isolate auxiliary feed to faulty steam generator(s)

a. Minimize energy loss

b. Provide feed to good S/G's

5. Maintain shutdown margin

6. Prevent pressurized thermal shock to reactor vessel

a. Stabilize temp.

b. Stabilize press.

c. Keep in bounds of cooldown curve

B. Injection phase

1. Isolate steam lines

a. May stop break

b. Limits energy release

2. Do not reset SI until status is to be changed

a. Auto restart problems

b. May have to rely on manual only

3. Ensure steam dump and PORVs on steam lines closed

a. Potential cause of steam break

b. Not needed uncontrolled C/D

4. Diesel generators to remain in operation until

a. Safeguards loaded

b. Offsite power verified

5. Recognize possibility of void formation in RCS

   a. Temp. - pressure relationships

      1) Vessel head

      2) S/G tube bundle

   b. Pressure control

      1. Spray

      2. Pzr level changes

6. Trip RCPs at 1300 psig

   a. Puts you in natural circulation

   b. Pump protection

   c. Affected loop T_c will drop rapidly - thermal shock

7. Terminate appropriate auxiliary feed pump to limit flow to good steam generators to <400 gpm

   a. Water hammer

   b. Possible damage to feed lines

8. Stop both RHR pumps if pressure >130 psig 15 minutes after accident

   a. Not needed on steam break

   b. Different from cirteria in other procedures

9. Control repressurization of RCS by dumping steam
   <u>NOTE: This is imperative as soon as faulty S/G dries out to prevent pressurized thermal shock to reactor vessel</u>

   a. Decay heat may repressurize

   b. Thermal shock has probably occurred

   c. Keep temp. constant

   c. Drop pressure if necessary

10. Control level in good steam generators

    a. Use AFW

    b. Narrow range

    c. Cold AFW can cause rapid temp. decrease

11. Terminate spray when containment pressure is less than 4 psig

    a. Steam condensed

    b. Major energy release is over

12. <u>SI termination criteria</u>

    a. <u>Caution</u> TP 2-4

    If reactor coolant system could leg temp. is less than <u>360°F</u>, SI <u>MUST BE TERMINATED</u> as soon as SI termination criteria are met to protect reactor vessel integrity. (SI + Chg.)

    1) T_c used

       a) Indicates coldest temp.

       b) Affect on vessel wall

       c) Assumes SI & RCS mix

    2) 360°F cutoff

       a) Only on steam break

       b) Brittle fracture concerns

          1. <350°F

          2. >700 psig

          3. 100°F cooldown curve

    B. 1) <u>One</u> wide range RCS <u>Tc</u> less than 360°F TP 2-5

       a) Brittle fracture

       b) <u>One</u> loop blowdown

    2) RCS pressure >700 psig (stable or increasing)

       a) Press. control regained

       b) Set pt. above accumulator & errors

    3) Pressurizer water level >20% and rising

4) RCS subcooling >40°F

a) Fuel integrity

b) Should not be a problem

5) Water level in one steam generator

a) Narrow range

b) Wide range (u-tubes covered) 70%

c) Provides heat sink

c. 1) <u>All</u> wide range RCS <u>Tc</u> >360°F TP 2-6

2) RCS pressure >1560 psig (stable or increasing)

a) 1450 psig + 110 psig error

b) Outside brittle fracture region

3) Water level in one steam generator

a) Narrow range

b) Wide range (u-tubes covered)

c) Heat sink

4) Pressurizer water level >50%

a) If break inside CV

b) Environmental effects on instruments

c) If break outside CV

1. Pzr level >20%

2. Inst's. not affected

5) RCS subcooling >40°F

a) Press. & temp. instrument errors 20°F (actually 17.5°F)

b) 20°F margin

13. After termination of SI setup in standby

a. An uncontrolled decrease of RCS pressure of 200 psig or pressurizer level by 10% requires reinitiation of SI and return to previous termination pressure

b. Subcooling now changed to 65°F

1) Prevent cycling SI pumps

2) Additional margin

c. If primary system pressure and temperature conditions violate the cooldown and heatup curves, restore conditions to maintain reactor vessel integrity by depressurization, if necessary

1) Thermal shock

2) Don't reheat immediately

3) Soak vessel

14. Reestablish CVCS to RCS

15. Reestablish normal RCS pressure control

16. Borate cold shutdown

17. Restart RCP in loop with spray

a. Dry S/G

b. GP-6

SUMMARY

I. Symptoms

A. RCS temp. & press. decrease

B. Steam pressure decrease

C. Steam flow increase

II. Determine Break Location

III. Auto Actions Occur

IV. Major Instruments

A. Temp.

B. Press.

C. S/G

V. Recovery

A. Stabilize

B. Terminate

C. Press. - temp. concerns

LOSS OF SECONDARY COOLANT

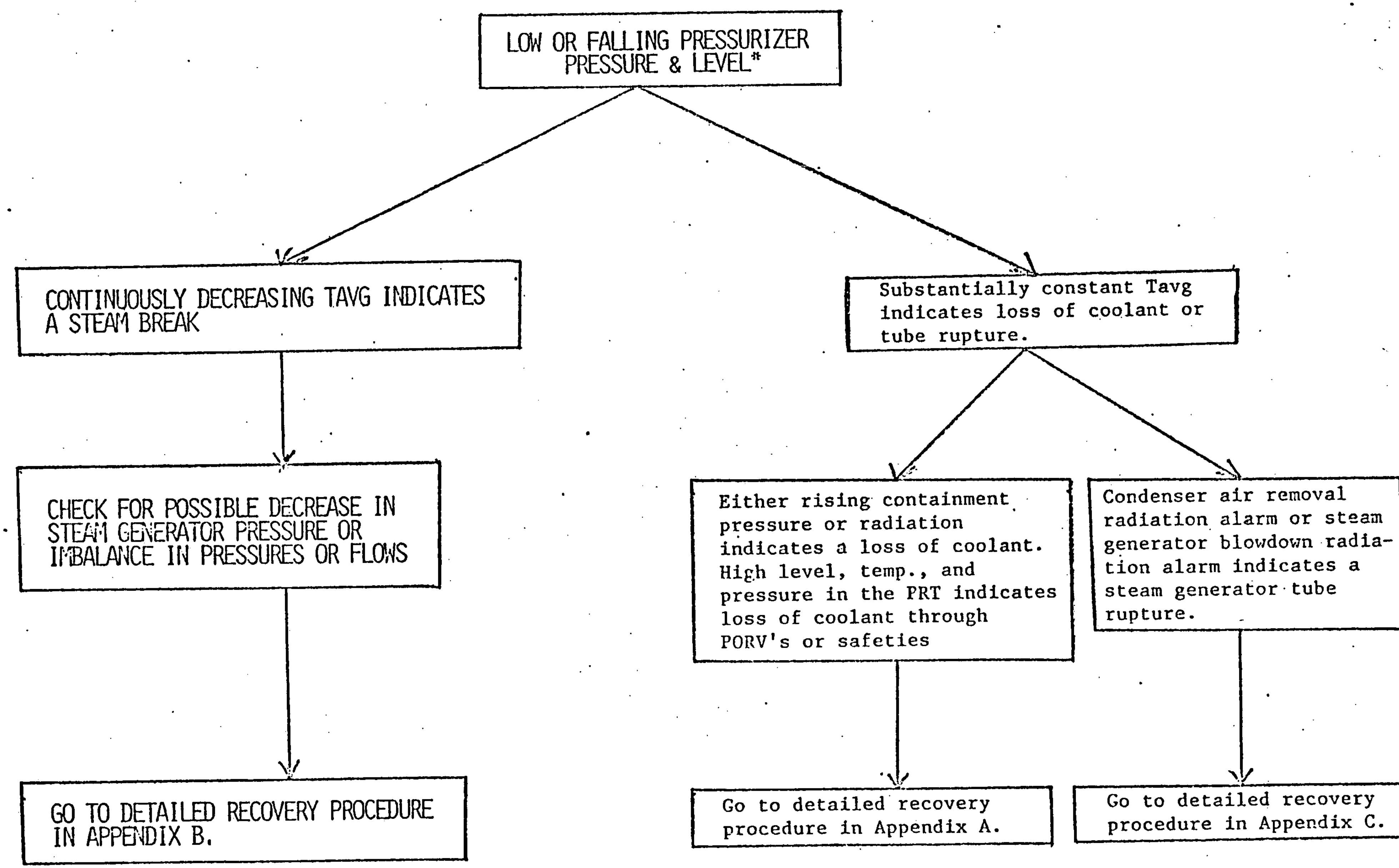
OBJECTIVE

1. UPON COMPLETION OF THIS MODULE, THE STUDENT WILL BE ABLE TO LIST THE MAJOR SYMPTOMS OF A LOSS OF SECONDARY COOLANT.

2. EXPLAIN THE MAJOR CONCERN THE OPERATOR MUST CONSIDER FOR THIS TRANSIENT, INCLUDING THE MAJOR STEPS HE MUST TAKE TO PROTECT THE PLANT.

3. THE STUDENT WILL BE ABLE TO STATE, FROM MEMORY, THE TWO SAFETY INJECTION TERMINATION CRITERIA FOR THIS TRANSIENT AND EXPLAIN THE REASON FOR EACH.

BEFORE REACTOR [illegible] & "S" SIGNAL



*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

AFTER REACTOR TRIP & "S" SIGNAL

LOW OR FALLING PRESSURIZER PRESSURE & LEVEL*

ABNORMALLY LOW STEAM PRESSURE IN ONE OR MORE STEAM GENERATORS INDICATES STEAM BREAK.

VERIFY BY CHECKING FOR:

1. LOWER THAN NORMAL STEAM GENERATOR LEVELS.
2. A POSSIBLE FIRST OUT ANNUNCIATION OF:
   A) STEAM/FEEDWATER FLOW MISMATCH
   B) LOW-LOW STEAM GENERATOR WATER LEVEL.
   C) HIGH STEAM LINE FLOW.
   D) HIGH STEAM LINE DIFFERENTIAL PRESSURE.

GO TO DETAILED RECOVERY PROCEDURE IN EMERGENCY INSTRUCTION, APPENDIX B.

Rising or normal steam pressure in steam generators indicates loss of coolant or tube rupture.

Either increasing containment pressure or containment high radiation alarm or rising sump water level indicates a loss of coolant.

Go to detailed recovery procedure in Appendix A.

Condenser air removal equipment radiation alarm or steam generator blowdown radiation alarm or possible observed differential rate of rise of steam generator levels.

Go to detailed recovery procedure in Appendix C.

*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

CAUTION: If reactor coolant system cold leg temperature is less than 360° F, SI must be terminated as soon as SI termination criteria are met to protect reactor vessel integrity.

LOSS OF SECONDARY COOLANT
S.I. TERMINATION CRITERIA

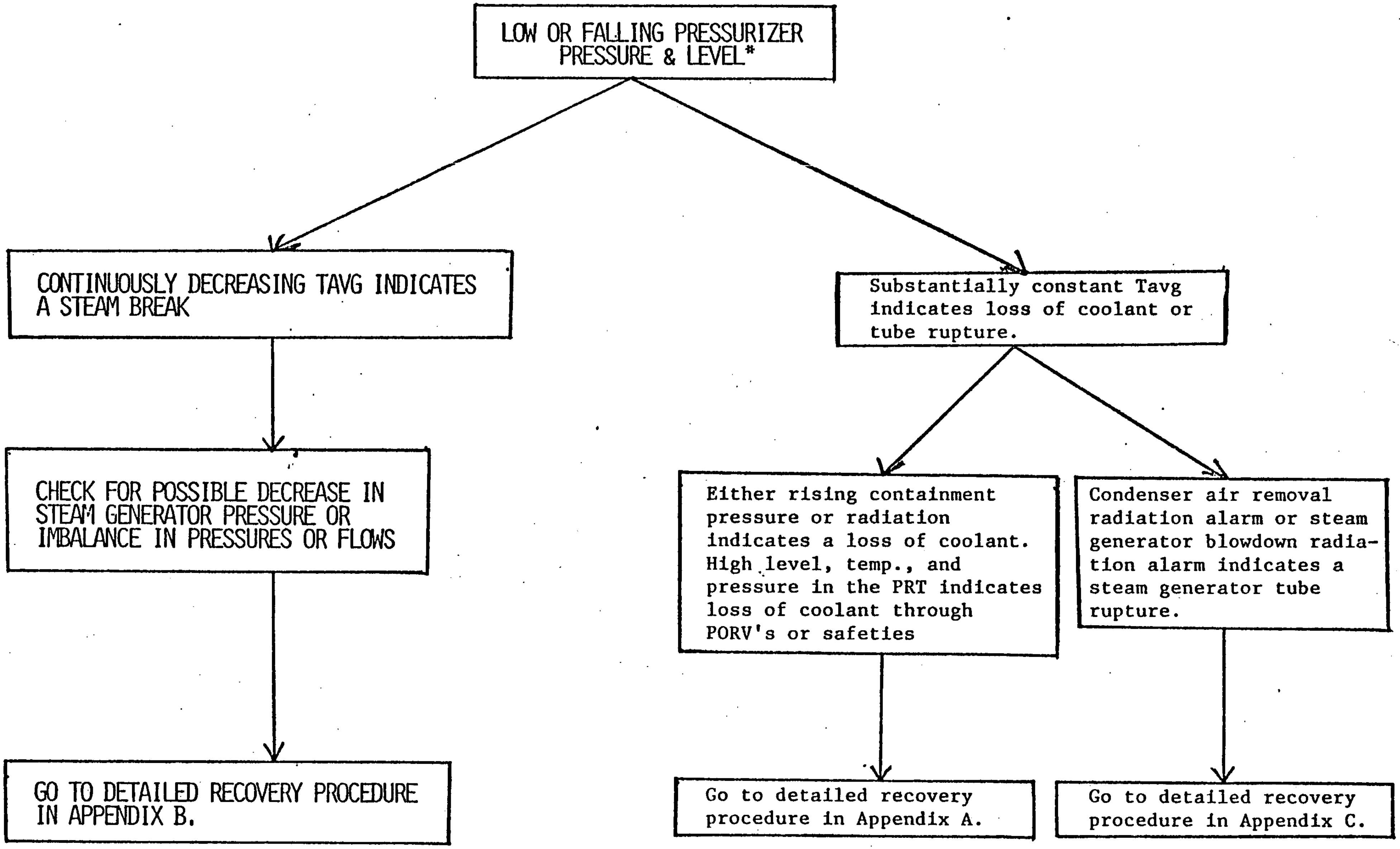
ONE WIDE RANGE RCS Tc IS LESS THAN 350°F, AND
WIDE RANGE RCS PRESSURE IS GREATER THAN 700 PSIG AND
IS STABLE OR INCREASING, AND
PRESSURIZER WATER LEVEL IS GREATER THAN 20% AND RISING
(HEATERS COVERED) AND
RCS SUBCOOLING IS GREATER THAN 40°F, AND
WATER LEVEL IN AT LEAST ONE STEAM GENERATOR IS IN THE
NARROW RANGE SPAN, OR IN THE WIDE RANGE SPAN AT A LEVEL
SUFFICIENT TO ASSURE THAT THE U-TUBES ARE COVERED.

LOSS OF SECONDARY COOLANT
S.I. TERMINATION CRITERIA

ALL WIDE RANGE RCS Tc INDICATORS ARE GREATER THAN 350°F,
AND
RCS PRESSURE IS GREATER THAN 1560 PSIG AND IS STABLE OR INCREASING, AND
WATER LEVEL IN AT LEAST ONE STEAM GENERATOR IS IN THE NARROW RANGE SPAN, OR IN THE WIDE RANGE SPAN AT A LEVEL SUFFICIENT TO ASSURE THAT THE U-TUBES ARE COVERED, AND
PRESSURIZER WATER LEVEL IS GREATER THAN 50% OF SPAN, AND
THE RCS SUBCOOLING IS GREATER THAN 40°F.

Note: If C.V. pressure, radiation level and sump level indications are in the normal (pre-event) range, then a pressurizer level of 20% is acceptable due to the absence of an adverse C.V. atmosphere effect on the pressurizer level transmitters.

BEFORE REACTOR T & "S" SIGNAL



*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

STEAM GENERATOR TUBE RUPTURE

Time: 50 minutes

Session 1 of 1

OBJECTIVES: Upon completion of this module the student will be able to:

1. List the symptoms of a steam generator tube rupture
2. State the two major concerns the operator must be aware of, from memory, for this transient including the major steps he must take to protect the plant and public.
3. State from memory the safety injection termination criteria for a steam generator tube rupture.

MATERIALS:

I. Training Aids
   A. Writing board
   B. Overhead projector

II. References
   A. Emergency Instructions Vol. 6
   B. GP-6
   C. GINNA

SUPPLIES: Paper and pencils

INTRODUCTION:

I. Establish Class Relations

  A. State name - write on board

  B. Ensure student comfort

  C. Check on writing implements

  D. Explain procedures

    1. Ask questions

    2. Volumteer information

    3. Note taking

    4. Test on subject

II. Objectives: Upon completion of this module the student will be able to: TP 3-1

  1. List the symptoms of a steam generator tube rupture

  2. State the two major concerns the operator must be aware of, from memory, for this transient including the major steps he must take to protect plant and public.

  3. State from memory the safety injection termination criteria for a steam generator tube rupture.

III. Create General Interest

  A. Protection of reactor core and reactor vessel is a major concern of this procedure

  B. Tube leaks occur at HBR; therefore, this is a credible event.

  C. Protection of health and safety of the public

PRESENTATION:

I. Symptoms

  A. Reduction of RCS pressure and pressurizer level

  B. Further pressure decrease due to cooldown following reactor trip

  C. SI flow will be automatically initiated

  D. Determination of Accident Type

PRESENTATION (Continued)

1. Steam generator pressure - Rising or normal with low pressurizer pressure TP 3-2
2. R-15 alarm, R-19 alarm TP 3-3
3. One S/G only
   a. TAVG varies very little
   b. ΔT runback may occur

II. Auto Actions for SI (EI-1)
   A. Verify they have occurred
   B. Initiate any auto actions that have not occurred
      1. From RTGB
      2. Locally (all possible methods)

III. Instrumentation Needed
   A. RCS Pressure
      1. Wide range See E-1 Procedure
      2. Narrow range
      3. Important for
         a. subcooling
         b. cooldown curve
   B. RCS Temperature
      1. Wide range T_H
      2. Wide range T_C
         a. PTS parameter
         b. Closest temp to vessel downcomer
      3. Incore thermocouples - subcooling
      4. Reactor vessel head thermocouple
         a. Location
         b. Purpose
      5. Saturation monitor - prime subcooling indicator
   C. Steam Generator
      1. Pressure
      2. Level
      3. Aux. Feed Flow

III. Instrumentation Needed (Continued)

Used for:

1. Locating faulted S/G
2. Cooldown on good S/G's

D. Pressurizer level - one of major indicators

E. CV Pressure

F. RWST Level

G. CST Level

IV. Recovery Procedure Steam Generator Tube Rupture

A. Purpose

1. Maintain core cooling
    a. Keep subcooled
    b. Control cooldown
2. Reduce RCS pressure below S/G safety valve setting - Minimize radioactive material release
    a. reduce possibility of uncontrolled release
    b. may not be monitored
3. Remove residual heat from RCS
    a. Use good S/G's
    b. Keep within cooldown curve
4. Maintain natural circulation
    a. If RCP's unavailable
    b. Use steam dump or S/G PORV's
5. Prevent overflooding of steam generators
    a. From primary to secondary
    b. Solid S/G
        (1) challenge safety valves
        (2) Water slug steam lines

B. Injection phase

1. Do not reset SI until safeguards equipment status to be changed

IV. Recovery Procedure Steam Generator Tube Rupture (Continued)

a. no auto reinitiation until signal clears

b. must rely on manual

2. Reduce auxiliary feed flow

   a. Maintain minimum narrow range S/G level

      (1) Helps locate faulted S/G

      (2) Provides adequate heat sink

   b. Terminate to S/G where level is rising

      (1) Prevent solid S/G

      (2) Assist feeding good S/G's

3. Dump steam to maintain no load TAVG

   a. Prefer condenser

   b. S/G PORV if needed

4. Maintain diesel generators at sync. speed

   a. safeguards started.

   b. outside power available

[illegible]ssion on inadequate core cooling

5. Void formation possible

   a. Excessive use of depressurization while on natural circulation

   b. Maintain 40^{o}F subcooling

   c. Follow pressure temperature curve 3.5 of Vol. 15

6. Trip RCP's if pressure decreases below 1300 psig

   a. After SI pumps running

   b. Pump protection

   c. Natural circulation

7. Stop RHR pumps if pressure >130 psig 15 minutes after accident

   a. Not needed

   b. Pump burnup

IV. Recovery Procedure Steam Generator Tube Rupture (Continued)

8. Identify S/G with ruptured tube
    a. R-19 - A.O. must do
    b. LAB samples
        1. small leak
        2. RCS activity low
    C. Increasing level without feed flow
9. Stop auxiliary feed flow to faulted steam generator
    a. reduce possibility of solid S/G
    b. not steaming
10. Isolate all steam from affected steam generator
    a. Eliminate release path
    b. Start cooldown immediately (GP-6)
    c. Setpoint on faulted S/G PORV to remain at 1000 psig
        1. Prevent lifting safety
        2. Minimize release
11. Reduce system temperature and pressure using steam dump
    a. Reduce RCS pressure to maintain 40° subcooling
        1. Reduce leak flow
        2. More time to cooldown
        3. Maintain Press - Temp on cooldown curve
    c. PORV - blackout operation
    d. Bring temperature of RCS to 480°F(S/G sat., pres. 550 psig)
    e. Isolated steam generator temp. and pressure will be 530°F and 820 psig.
        1. Residual heat
        2. Pressure tries to match RCS
        3. S/G may become second pressurizer

IV. Recovery Procedure Steam Generator Tube Rupture (Continued)

12. Reduce RCS pressure to 870 psig
    a. Stop leak to S/G
    b. Pressurizer spray
    c. Aux. spray
    d. PORV on pressurizer
    e. Keep temp/pressure within cooldown limits
    f. Stop when
        (1) Pressurizer water level >50% or
        (2) RCS pressure equal to faulted steam generator pressure
13. Monitor pressure and pressurizer water level - use in determination of leak rate
    a. Steady or increasing - leak stopped
    b. Decreasing - possibly other problems

C. Termination of safety injection
1. RCS pressure increase of >200 psig after closure of spray valve and or PORV
2. Water level in pressurizer
3. No auto SI reinitiation all signals not reset.
4. RCS and S/G pressure equalize
5. Place SIS in standby

D. Return to normal
1. Return CVCS to normal
2. Return RCS pressure control to normal
    a. Sprays
    b. Heaters
    c. Manually maintain pressure
3. Start RCP in non-faulted loop with spray valve or stop all but one in non-faulted loop with spray
    a. Aid cooldown
    b. Pressure control

IV. Recovery Procedure Steam Generator Tube Rupture (Continued)

c. Chemistry control

d. Stop faulted loop RCP

(1) mixing S/G with RCS

(2) plant chemistry

4. Isolate warm-up line to steam feed pump from faulted S/G

5. Cooldown I.A.W. G.P. and cooldown curve

6. Check coolant chemistry

7. Depressurize S/G to condenser or PORV while doing cooldown

(1) monitor R-14

(2) If cannot dump back to RCS

8. Drain faulted S/G

SUMMARY:

1. S/G tube rupture symptoms

   Major - R15, R19 alarm

2. Two major concerns of operator and major steps to mitigate

   a. Protect plant - cooldown and depressurize RCS

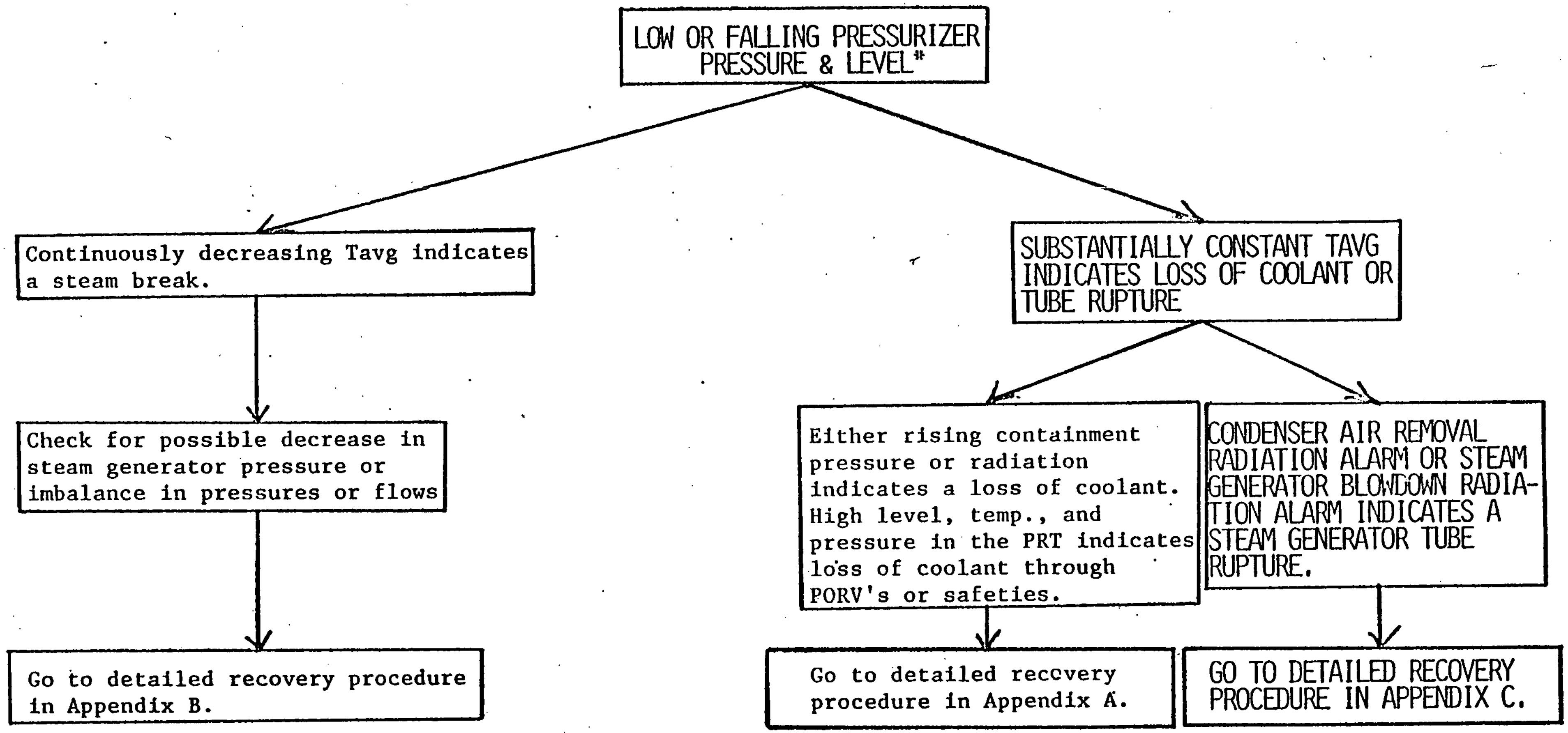
   b. Protect public - isolate leak

3. SI termination

   a. Core covered - pressurizer level

   b. RCS pressure increasing due to SI flow greater than break flow

BEFORE REACTOR TRIP & "S" SIGNAL



*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

AFTER REACTOR TRIP & "S" SIGNAL

LOW OR FALLING PRESSURIZER PRESSURE & LEVEL*

Abnormally low steam pressure in one or more steam generators indicates steam break.

Verify by checking for:

1. Lower than normal steam generator levels.
2. A possible first out annunciation of:
   a) Steam/feedwater flow mismatch
   b) Low-low steam generator water level.
   c) High steam line flow.
   d) High steam line differential pressure.

Go to detailed recovery procedure in emergency instruction, Appendix B.

RISING OR NORMAL STEAM PRESSURE IN STEAM GENERATORS INDICATES LOSS OF COOLANT OR TUBE RUPTURE.

Either increasing containment pressure or containment high radiation alarm or rising sump water level indicates a loss of coolant.

Go to detailed recovery procedure in Appendix A.

CONDENSER AIR REMOVAL EQUIPMENT RADIATION ALARM OR STEAM GENERATOR BLOWDOWN RADIATION ALARM OR POSSIBLE OBSERVED DIFFERENTIAL RATE OF RISE OF STEAM GENERATOR LEVELS.

GO TO DETAILED RECOVERY PROCEDURE IN APPENDIX C.

*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

CP & L

HB ROBINSON
STEAM ELECTRIC PLANT

NUCLEAR
OPERATIONS

lesson plan

MITIGATING CORE DAMAGE

Session 8

H.B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
INSTRUCTOR LESSON PLAN

SUBJECT: Mitigating Core Damage SESSION: 8 of 35

SESSION TOPIC: Inadequate Core Cooling TIME: 50 minutes

REVISION NO. 0 DATE: 3/23/82

INSTRUCTOR REFERENCES

1. H.B. Robinson Emergency Instruction: Incident Involving Reactor Coolant System Depressurization EI-1
2. H.B. Robinson Technical Specifications Section 3.3

CLASSROOM EQUIPMENT

1. Chalkboard, Chalk and Eraser
2. Overhead Projector

TRAINING MATERIALS REQUIRED

Transparencies:
Lesson Objectives and Reason for Study

STUDENT REFERENCES

1. Student Handout: Mitigating Core Damage
2. H.B. Robinson Emergency Instruction: Incident Involving Reactor Coolant System Depressurization EI-1
3. H.B. Robinson Technical Specifications Section 3.3

LESSON PLAN

OUTLINE	KEY AIDS

I. INTRODUCTION

A. Lesson Objectives

Upon successful completion of this session you will be able to:

Transparency 8-1 and Student Handout

1. From memory, explain the causes of Inadequate Core Cooling.

2. From memory, list the major indications of Inadequate Core Cooling.

3. List and explain two alternative actions to restore cooling to a core which is not adequately cooled.

4. Explain the effects of core boiling on boron concentration and what action is taken.

B. Reason for Study

Transparency 8-1

In an accident situation, particularly if natural circulation is being used for core cooling, the operator must be able to recognize indications that cooling is not effective. Based on his indications and what he believes to be the cause of the problem, the operator must take action to restore

core cooling and monitor the effects of his efforts. The boiling situation can change system behavior in ways that he may not expect.

II. PRESENTATION

A. Causes of Inadequate Core Cooling

1. Improper emergency systems lineup or loss of system operation

o Valves shut or power lost to prevent supply of cooling water to RCS or feed to steam generators.

2. Void formation

a. Saturation conditions reached either at core exit or next to the vessel head which is at high temperature

1) Contains large amount of heat by virtue of mass of metal

2) Decay heat rises

3) Has relatively poor circulation even with RCP's running.

4. Indications
    a. Rapid increase in pzr level
    b. Increase in pzr level exceeds mass injected
    c. Bubble exists somewhere else
        1. Rx vessel head
        2. S/G

b. Non-condensible gas accumulation under head
    1. Dissolved gases normally in RCS
        a. Insufficient to form a large bubble
        b. Will not interrupt natural circulation flow
    2. If core temperatures reach high levels
        a. Zr-H_2O reaction
        b. Large quantities of gas are evolved
        c. Could interrupt flow
    3. Failure in accumulator system
        a. Injection of alrge quantity of nitrogen
        b. Design features are provided to prevent this
        c. High press. limit on accum.

1. Five incore thermocouples reading off scale, greater than 700°F.
    a. This one indication is sufficient to identify ICC (also most rapid response).
        1. All five did not fail
        2. Trust your indication
    b. Choice of TC's to monitor
        1. One close to geometric center of core
        2. One in each quadrant

c. Hot leg RTD's cannot be depended on in ICC

1. React too slowly

2. Steam formed at core exit mixes with reflux flow

a. Before passing into hot leg

b. Lower temperature than above core

3. Steam flowing in hot legs can interfere with RTD measurement

a. RTD in well

b. Response poor in steam environment

4. RTD's are indicative only of hot leg conditions

5. TD's show local core exit temperature

d. Monitor TC's when in natural circ.

2. Saturation conditions reached in RCS as determined by:

a. Incore TC's

b. Wide range temperature instrumentation

c. Saturation monitor

3. Loss of natural circulation as effective heat removal

OUTLINE	KEY AIDS

a. Rapidly increasing or excessively high ΔT

1. above full load ΔT

2. $T_H \uparrow$ with Tc $\rightarrow$ or $\downarrow$

b. Steam generator pressure dropping rapidly while steaming with elevated primary temperatures present.

1. Several hundred PSI

2. Do not expect normal S/G press.

4. Sudden rise or erratic response in nuclear instrumentation.

a. Extensive voiding in core and downcomer

b. Loss of moderator

c. Increase in leakage neutrons reaching detectors.

C. Actions

1. Preferred and most effective: recover high head safety injection

a. Align charging pumps to RCS

b. Addition of water to cold legs

1. flows to downcomer

2. quenches and recovers core

3. May cause thermal shock to vessel

c. TC response:

1. Slight increase as steam swept from core

2. Two phase mixture reaches TC's: drop rapidly

d. Also possible for high head SI to cause enough condensation of steam to cause depressurization enough to cause accumulator injection.

2. Depressurization of steam generators

a. Increase condensation of steam on primary side of tubes.

b. Increased rate of condensation
   1. Local pressure drop within tubes
   2. More steam drawn from loops and core core.

c. Pressure in upper plenum of core drops.
   1. Fluid mixture in lower plenum and downcomer pulled up into core
   2. Quenches core

d. Possible injection
   1. Due to pressure drop
   2. Provides cooling
   3. Start feeding with low head SI

OUTLINE	KEY AIDS

e. Incore TC's: rapid drop.

f. Steam generator depressurization

1) Steaming through PORV

2) Dumps

3) Feeding cold water to steam generator.

3. Starting RCP's

a. Effects of RCP operation in a voided RCS

1) Pumping two phase mixture-void-accumulation-

a) Downcomer

b) Upper core regions

2) Restart of RCP's with partially uncovered core causes sudden quenching of fuel rods

a) Thermal shock

b) Possible geometry change

4. Controlled depressurization of RCS to increase rate of injection with gas bubble in upper head.

a. Natural circ.

1) Allow bubble to expand

2) Uncover top of hot leg

3) Establish escape path to PZR surge line

4) Vent pressurizer - PORV

5) Core remains covered

OUTLINE	KEY AIDS

6) Use SI to cool core

b. With RCP in operation and steam bubble in pressurizer:

1) PORV used to slowly depressurize

2) Additional refined control if spray hand heaters can be used.

3) As bubble grows to hot leg, small bubbles are carried by flow into system.

4) Degass RCS by: CVCS or pressurizer PORV

c. Non-condensible gas bubble binding steam generator precluding heat transfer

1) Loss of natural circulation -

a) Higher than full load ΔT

b) S/G pressure low - increasing RCS temp.

c) Abnormal increase in NIS indication

d) Incore or wide range indicates saturation

e) 5 incore Tc greater than 700°F

2) Establish SI flow from SI system and out pressurizer PORV. If previously terminated

a) PORV will provide 3" break

b) Enough for cooling

c) Break size

1) PORV = 3"

2) Other break greater than 1"

D. Long term effects

1. With significant core boiling, boron will be driven out of solution and accumulate in hottest regions.

a. Decreases heat transfer by reducing thermal conductivity at clad edge.

b. May accumulate in sufficient quantities to interfere with flow.

2. 18 hours into the accident approximately 600 gpm SI flow is directed to hot legs.

a. Injection of cool water into upper plenum suppresses residual boiling and helps collaps steam bubbles.

b. Reversal of flow will help re-dissolve plated boron.

III. SUMMARY

A. <u>OBJECTIVE 1</u>: From memory, explain the causes of Inadequate Core Cooling.

OUTLINE	KEY AIDS

Two main conditions can degrade core cooling:

1. Improper or loss of emergency system operation:

2. Void formation

B. OBJECTIVE 2: From memory, list the major indications of Inadequate Core Cooling.

1. 5 or more incore TC's above 700°F

2. Saturation conditions reached in RCS

3. Sudden or erratic response in nuclear instrumentation

C. OBJECTIVE 3: From memory, list and explain two alternative actions to restore cooling to a core which is not adequately cooled.

1. Preferred and most effective is restoration of high head safety injection.

2. Dump steam and feed S/G's

3. Controlled depressurization of the RCS may be used to increase the rate of injection.

D. OBJECTIVE 4: Explain the effects of core boiling on boron concentration and what action is taken.

LESSON PLAN

OUTLINE	KEY AIDS

Boiling in core will cause plating out of dissolved boron onto core surfaces.

1. Decreases the thermal conductivity

2. Causes flow blockages.

MITIGATING CORE DAMAGES

OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION YOU WILL BE ABLE TO:

1. FROM MEMORY, EXPLAIN THE CAUSES OF INADEQUATE CORE COOLING.

2. FROM MEMORY, LIST THE MAJOR INDICATIONS OF INADEQUATE CORE COOLING.

3. LIST AND EXPLAIN TWO ALTERNATIVE ACTIONS TO RESTORE COOLING TO A CORE WHICH IS NOT ADEQUATELY COOLED.

4. EXPLAIN THE EFFECTS OF CORE BOILING ON BORON CONCENTRATION AND WHAT ACTION IS TAKEN.

REASON FOR STUDY

IN AN ACCIDENT SITUATION, PARTICULARLY IF NATURAL CIRCULATION IS BEING USED FOR CORE COOLING, THE OPERATOR MUST BE ABLE TO RECOGNIZE INDICATIONS THAT COOLING IS NOT EFFECTIVE. BASED ON HIS INDICATIONS AND WHAT HE BELIEVES TO BE THE CAUSE OF THE PROBLEM, THE OPERATOR MUST TAKE ACTION TO RESTORE CORE COOLING AND MONITOR THE EFFECTS OF HIS EFFORTS. THE BOILING SITUATION CAN CHANGE SYSTEM BEHAVIOR IN WAYS THAT HE MAY NOT EXPECT.

CP&L

HB ROBINSON STEAM ELECTRIC PLANT

NUCLEAR
OPERATIONS

lesson plan

Transient and Accident Analysis

Session 16

H.B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
INSTRUCTOR LESSON PLAN

SUBJECT: Transient and Accident Analysis — SESSION: 16 of 16

SESSION TOPIC: Loss of Coolant Event of May 1, 1975 — TIME: 50 minutes

REVISION NO. 0 — DATE: 4/27/82

INSTRUCTOR REFERENCE

1. H.B. Robinson Abnormal Occurrence Report 50-261/75-9
2. H.B. Robinson Abnormal Procedures: Reactor Coolant Pump Abnormal Conditions AP-18
3. H.B. Robinson File Number 2-0-1-a
4. Shift Supervisor Logs of 1-2 May 1975

CLASSROOM EQUIPMENT

1. Chalkboard, Chalk and Eraser
2. Overhead Projector

TRAINING MATERIALS REQUIRED

Transparencies:
1. Lesson Objectives and Reason for Study
2. RCPs Seal Water Flow
3. Initial Accident S/G Level, Steam Flow, PZR Level, and Pressure
4. PZR Level and Pressure During Subsequent Running of RCP "C"
5. RHR and PZR Pressure

STUDENT REFERENCES

1. H.B. Robinson Abnormal Occurrence Report 50-261/75-9
2. H.B. Robinson Abnormal Procedures: Reactor Coolant Pump Abnormal Conditions AP-18
3. H.B. Robinson File Number 2-0-1-a
4. Shift Supervisor Logs of 1-2 May 1975

LESSON PLAN

OUTLINE	KEY AIDS

I. INTRODUCTION

A. Lesson Objectives

Upon successful completion of this session you will be able to:

Key aids: Transparency 16-1 and Student Handbook

1. From memory, state how RTGB and local indications were used by the operators in analyzing and mitigating the effects of this loss of coolant event.

2. State the conclusions and lessons learned from this event including depressurization and pressurized thermal shock.

B. Reason for Study

Key aids: Transparency 16-1

The purpose of this lesson is to familiarize you with the events which occurred on May 1, 1975 concerning the failure of RCP "C" seal, resulting in the discharge of reactor coolant fluid to the containment floor. The familiarization with this and other events will enable you to be better prepared to handle plant emergencies of this nature which should arise while you are on shift.

OUTLINE	KEY AIDS

II. PRESENTATION

A. Conditions Prior to Event

1. Reactor operating at full power

2. All systems operating normally

a.	T_{avg}	$573^{o}F$
b.	PZR level	53%
c.	Plant pressure	2245 psig
d.	RCP "C" seal flow	3.7 gpm
e.	RCP "C" labyrinth	64 inches H_2O

3. Deborating to compensate for xenon buildup

B. Description of the Event

1. During boron dilution RCP "C" seals were very sensitive to all additions

   a. Sensitivity had existed since its replacement a week earlier

OUTLINE	KEY AIDS
b. Leakoff was within prescribed limits	
c. Variations were gradual rather than spiking	
d. It was considered safe to operate with this seal	
2. 1750 - RCP "C" seal leakoff spiked several times	Transparency 16-2 and Handout
a. Monitored for vibration and found normal	
b. No other alarms noted	
3. 1811 - RCP "C" seal leakoff oscillated full range then stabilized off scale high	
4. 1811 - Commenced a load reduction at a rate of 10% per minute	Transparency 16-3 and Handout
a. Procedure required idling RCP "C"	
b. Can operate at ≈ 40% power on two loops	
5. 1817 - component cooling water valve CCW-626 closed due to high flow	

OUTLINE	KEY AIDS

a. Combined return isolation valve for component cooling water to all three RCP thermal barriers

b. Initially thought to be caused by the failure of the cooling coils in the thermal barrier of RCP "C"

6. Coincident with the closure of CCW-626 the following alarms were received

a. Seal water injection filter Hi ΔP

b. RCPs labyrinth seal Lo ΔP

c. RCP shaft #1 seal leak Hi temperature

d. RCP seal leakoff Hi flow

e. RCP shaft seal water Lo ΔP

f. RCP thermal barrier cooling water Hi temperature

g. RCP 3 bearing Hi temperature

h. RCP thermal barrier cooling water Lo flow

OUTLINE	KEY AIDS

i. No 3 RCP stand pipe Lo level

j. No 1 RCP stand pipe Hi level

7. 1818 - Load reduction was stopped at 36% and RCP "C" was de-energized

8. 1819 - Reactor trip — Transparency 16-3

   a. Caused by turbine trip due to high level in "B" steam generator

   b. High steam generator level due to steam flow spike during load reduction

      o Steam spike apparently from lifting of PORV

9. 1832 - Stopped RCPs "A" and "B"

   a. Flashing in seal water return lines threatened to cause loss of seal flow due to pressure surges

OUTLINE	KEY AIDS
b. Flashing was caused by high temperature coolant flowing past RCP "C" thermal barrier and failed number 1 seal, and entering the relatively low pressure of the seal water return lines	
10. 1841 - Received automatic letdown isolation due to low level in the pressurizer	Transparency 16-3
a. Low pressurizer level resulted from rapid cooling caused by a sudden spike in steam flow	
b. Shifted charging supply from volume control tank to the refueling water storage tank	
11. 1854 - Pressurizer level above letdown isolation setpoint, returned charging supply to volume control tank	
12. 1915 - Seal water flow lost to RCP "A"	
o Valve 303C closed to reduce pressure surges in letdown line	
13. 1928 - Seal water flow lost to RCP "B"	

a. Water from RCP "C" seals had filled and overpressurized the reactor coolant drain tank and vent header

b. The RCDT vent was shut

c. WD-1708 opened to drain RCDT to the containment sump

14. Entered the containment to inspect RCP "C" and to close valve CCW-728C, thermal barrier outlet manual isolation valve

a. Valve CVC-303C had not fully isolated the leakoff which was still causing steam formation in the thermal seal

b. It was not possible to enter RCP "C" bay due to steam leaking from number three seal

c. As previously stated it was initially thought that the cooling coils in the thermal barrier had failed, closing CCW-626

d. Based on the following information the cooling coils were determined to be intact

OUTLINE	KEY AIDS
1) No increase on radiation monitor R-17	
2) No increase in component cooling water expansion tank level	
3) The high flow rates were not continuous	
e. The high flow rates were determined to be caused by boiling in the component cooling water coils, accelerating fluid past the flow detector	Boiling determined later. Boiling could occur in any system. Need to be aware
15. 1945 - Blocked open CCW-626	
a. This reduced temperatures below boiling in the thermal barriers	
b. CCW-626 was unblocked and returned to normal operation	
16. 2000 - Breakers were pulled on the containment sump pumps	
a. This was to prevent the overfilling of the waste holdup tanks	

OUTLINE	KEY AIDS

b. The water was originating from the reactor coolant drain tank and the sump in RCP "C" bay.

17. After opening CCW-626 seal water flow in RCP "C" had returned to normal; RCP "A" and "B" seal water flow had not returned

18. Inspection of RCP "C" revealed no steam or leakage from the seals; this indicated that the number 2 seal was holding

19. The objective now was to cooldown the plant; this would require running a RCP to

    a. Equalize temperatures throughout the reactor coolant system

    b. Equalize boron concentration throughout the reactor coolant system

20. Attempts to restore seal water to RCP "A" and "B" were unsuccessful

    a. Running bearing lift pump to lower the shaft and provide more bearing clearance

OUTLINE	KEY AIDS

b. Attempting to rotate the pumps by hand

- It is postulated that the pressure on the reactor coolant system prevented the pumps from rotating — ≈1700 PSIG

c. Making adjustments to

1) Seal injection flow
2) Bearing lift oil lineup
3) Seal leakoff
4) Seal bypass

21. Consideration given to running RCP "C"

a. Seal water flow was present

b. The number two seal was apparently holding pressure

c. RCP technical manual states the pump can be run for 24 hours with a failed number 1 seal and number 2 seal holding full pressure

d. Telephone conversations with the Westinghouse pump representative indicated that pump with failed number 1 seals had successful run

1) Recommended starting pump with seal leakoff open

2) Monitor standpipe levels and temperatures to insure integrity of number 2 seal

3) Then shut the seal leakoff to number 1 seal to cause the number 2 seal to become a film riding seal

22. 2242 - Started RCP "C" with RCS Pressure of 1700 PSIG and temperature of 480°F

a. Shut number 1 seal leakoff

b. Seal leakoff pegged high at 300°F

c. Stator temperature and bearing temperatures remained normal

d. Pump seemed to be operating satisfactorily

23. 2257 - Prepared for cooldown using the main condenser

a. Opened the MSIV bypasses

b. Commenced drawing a vacuum

OUTLINE	KEY AIDS
24. Problems developed in maintaining pressurizer level	
a. Increased seal water to RCP "C" by a factor of 5	
b. No standpipe alarm but suspected number 2 seal failing	
c. Using first 2 then 3 charging pumps	
d. Received indication of 0.5 ft of water in containment sump	
25. Boron concentration analyzed to be at approximately shutdown levels	
26. 0015 - Pressurizer level began falling rapidly due to failure of number 2 seal	Transparency 16-4 and Handout
a. Received high standpipe level alarm	
b. Secured RCP "C"	
c. This terminated any cooldown in progress	
27. 0016 - Started safety injection pumps to hot leg safety injection to loops "B" and "C". Source of water was RWST which was at approximately 65^{o}F.	Transparency 16-4

OUTLINE	KEY AIDS
a. Strip chart recorder level indicated zero	
b. Level indicator LI-462 indicated 6%	
c. Pressurizer level decrease stopped	
d. Level maintained between 20 and 80% by cycling SI pumps.	
28. 0036 - Diverted charging flow from loop "B" cold leg to auxiliary pressurizer spray to reduce system pressure. At this point pressure was 1150 PSIG and temp. approximately 310°F. Pressure rapidly reduced to 500 PSIG with spray.	Transparency 16-4 Maintain subcooling and monitor for PT 5
29. Started the fourth containment recirculation fan and cooler to reduce containment pressure and temperature	HVH-4
30. The SI accumulators partially discharged into the reactor coolant system; accumulator isolation valves were shut	
31. Reactor coolant system boron concentration 1521 ppm	
32. Containment pressure reached its maximum of 3 psig	

OUTLINE	KEY AIDS
a. Started "D" service water pump	
b. Started "B" service water booster pump	
33. 0215 - Shut main steam isolation valves and secured cooldown through the main condensers	
34. Heatup of the RHR system was delayed due to the air line to LCV-460B being broken	
a. This prevented the pressurization of the RHR system	
b. The air line was subsequently repaired and the RHR system warmed	
35. 0341 - RHR system placed in service	Transparency 16-5 and Handout
36. Reduced reactor coolant system pressure from 400 psi to 100 psi	
a. This was accomplished by charging through auxiliary pressurizer spray	
b. When spray was initiated the following occurred	

LESSON PLAN

OUTLINE	KEY AIDS
1) Pressurizer pressure did not significantly decrease	
2) There was a rapid rise in pressurizer level	
3) Upon shutting valve 311, pressurizer level dropped rapidly	
4) Thermocouple temperatures indicated reactor temperature to be stable	Check for sub-cooling
c. It was determined that a steam bubble had formed in one or more steam generators	Steam bubble could also be in reactor head area
1) Due to loss of circulation and limited steam being drawn the steam generators were relatively hot	
2) The pressure reduction allowed the bubble to form	
37. 0517 - Reduced reactor coolant system pressure from 100 psig to 0 psig	
38. Secured charging and allowed water to drain until leak stopped	

C. Final Conditions

1. Approximately 12-inches of water on the containment floor

2. Primary temperature approximately 100°F at 0 psig

3. Boron concentration 1694

4. RCS level was 39-inches below the reactor vessel flange

D. Technical Specification consideration

1. Primary leakage from the seal of RCP "C" exceeded 10 GPM

2. Containment pressure exceed the Tech. Spec. setpoint of 2 PSID

3. As a result of the forced cooldown, excessive cooldown rates were experienced.

   a. Cooldown was from 450°F to approximately 310°F in ½ hour. Cooldown rate was approximately 280°F/Hr.

   b. Prior to auxiliary spray, pressure transient was 1700 to 1150 PSIG.

OUTLINE	KEY AIDS

E. Analysis

1. It was determined to be acceptable to operate on a seal which had shown unusual and highly irregular traces since its replacement a week earlier

2. IF CVC-303C would have been shut initially

   a. The flow through the thermal barrier may have been reduced

   b. The steam formation in the thermal barrier cooling coils might have been prevented and cooling would not have been lost to RCPs "A" and "B"

   c. The pressure surges in the seal water return lines would have been prevented

   d. It would not have been necessary to secure RCPs "A" and "B" — *Key aids: AP-18 - Seal failure Immediately shut 303 valve*

3. If the reason for the closure of CCW-626 could have been determined not to be caused by failed thermal barrier earlier

OUTLINE	KEY AIDS

a. CCW-626 could have been blocked open maintaining flow to the thermal barriers.

1. Safety function override

2. Must station a watch

3. Immediate closure of 303 valve

a) May have avoided CCW-626 problem

b) Procedure revised

b. The amount of water/steam leaking from RCP "C" would have been greatly reduced

c. RCPs "A" and "B" would not have had to be secured. They could have been utilized for normal cooldown

4. The maintaining of either seal injection or component cooling to RCP "A" and "B" would have allowed them to remain running

a. This would have prevented having to run the damaged pump for cooldown

b. It should be noted that when valve 303C was shut and component cooling was restored to the thermal barriers, the number 2 seal stopped leakage from the primary

c. The subsequent running of RCP "C" caused the failure of number 2 seal and it was after this seal failure that the majority of the liquid loss occurred.

d. The large liquid loss resulted in SI which resulted in very rapid cooldown and pressure maintained at >1150 PSIG

5. Some indirect results of not being able to run RCPs "A" and "B"

a. The loss of normal spray which necessitated auxiliary spray from the CVC system

b. The overpressurization of the containment due to the loss of additional fluid after the failure of number 2 seal

OUTLINE	KEY AIDS
c. Due to poor thermal balance in the RCS the steam generators remained considerably hotter than other parts of the system; this resulted in the formation of a steam bubble in the steam generators on a pressure reduction	Steam Generators secured before RHR placed in service and RCPs in service

F. Lessons Learned

1. The closure of CVC-303 would have prevented the loss of RCPs "A" and "B"

2. Do not run RCP in which the number one seal has failed. (Procedures now prohibit this)

3. Once SI is actuated the operator must consider

   a. Uncontrolled cooldown.

   b. Depressurize to minimize pressure thermal shock yet maintain sub-cooled status

   c. Can anything be done to limit cooldown to minimize PTs. (i.e., limit pressurizer level band to low end to minimize amount of cold water added to system)

OUTLINE | KEY AIDS

III. SUMMARY

A. OBJECTIVE 1: From memory, state how RTGB local indications were used by the operators in analyzing and mitigating the effects of this event

1. Immediately commenced load reduction on indication that seal was failing

2. When flashing and the resulting pressure surges threatened to cause the loss of all seal water, RCPs "A" and "B" were secured to prevent their damage

3. Based on radiation, expansion tank level, and flow surges, closure of CCW-626 was determined not to have been caused by a leaking cooling coil and component cooling was restored to the thermal barriers

4. Sudden high standpipe level alarm and rapidly decreasing pressure level indicated the loss of number 2 seal and resulted in stopping RCP "C"

B. OBJECTIVE 2: From memory, state the conclusions and lessons learned from this event

1. The closure of CVC-303 would have prevented the loss of RCPs "A" and "B"

2. Do not run a RCP in which the number one seal has failed

3. The automatic safety features work satisfactorily to protect the reactor

4. The operator must be aware of rapid uncontrolled cooldown and take actions such as depressurization to minimize pressurized thermal shock

IV. EVALUATION

A. OBJECTIVE 1 QUESTIONS

1. During the loss of coolant accident of May 1, 1975 at H. B. Robinson, what indications were used to determine that the isolation valve for component cooling water return from the RCP thermal barriers could be reopened?

   Answer:

   a. The high flow rates through the return line were not consistent but were surging.

   b. No increase in the readings on radiation monitor R-17.

c. No increase in component cooling water expansion tank level.

2. During the loss of coolant accident at H. B. Robinson on May 1, 1975 while pressure was being reduced from 400 psi to 100 psi it was determined that a bubble had been drawn in the steam generator. What indications/events were used to make this determination?
Answer:
Upon the initiation of auxiliary spray pressure did not decrease significantly. There was a rapid rise in pressurizer level. Upon securing the auxiliary spray, pressure still remained relatively constant and pressurizer level dropped rapidly.

B. <u>OBJECTIVE 2 QUESTIONS</u>

1. What procedural modifications were made as a result of the loss of coolant accident which occurred at H. B. Robinson on May 1, 1975 which would prevent the loss of the undamaged RCPs?
Answer:
The closure of valve CVC-303. This will prevent the buildup of high pressures in the seal water return lines due to steam formation and prevent the loss of seal water to the remaining RCPs.

OUTLINE	KEY AIDS

2. During the loss of coolant accident at H. B. Robinson on May 1, 1975, the major portion of the coolant was lost after the failure of the No. 2 seal on RCP "C". What procedural changes have been incorporated which would minimize the likelihood of this seal failing during a similar accident?

   Answer:

   The data indicates that the No. 2 seal was intact until the RCP "C" was restarted to commence the RCS cooldown. At that point the seal failed resulting in the loss of a significant amount of reactor coolant. The AP has now been modified such that once the damaged pump has been secured, it cannot be restarted.

3. Besides maintaining the reactor in a sub-cooled condition, what other temperature pressure condition should the operator consider?

   Answer:

   Limiting the effects of pressurizer thermal shock by limiting cooldown or controlled depressurization.

V. ASSIGNMENTS

A. Read H. B. Robinson Abnormal Occurrence Report 50-261/75-9

B. Read H. B. Robinson Abnormal Procedure: Reactor Coolant Pump Abnormal Conditions (AP-18).

TRANSIENTS AND ACCIDENT ANALYSIS

OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION, YOU WILL BE ABLE TO:

1. FROM MEMORY, STATE HOW RTGB AND LOCAL INDICATIONS WERE USED BY THE OPERATORS IN ANALYZING AND MITIGATING THE EFFECTS OF THIS LOSS OF COOLANT EVENT.

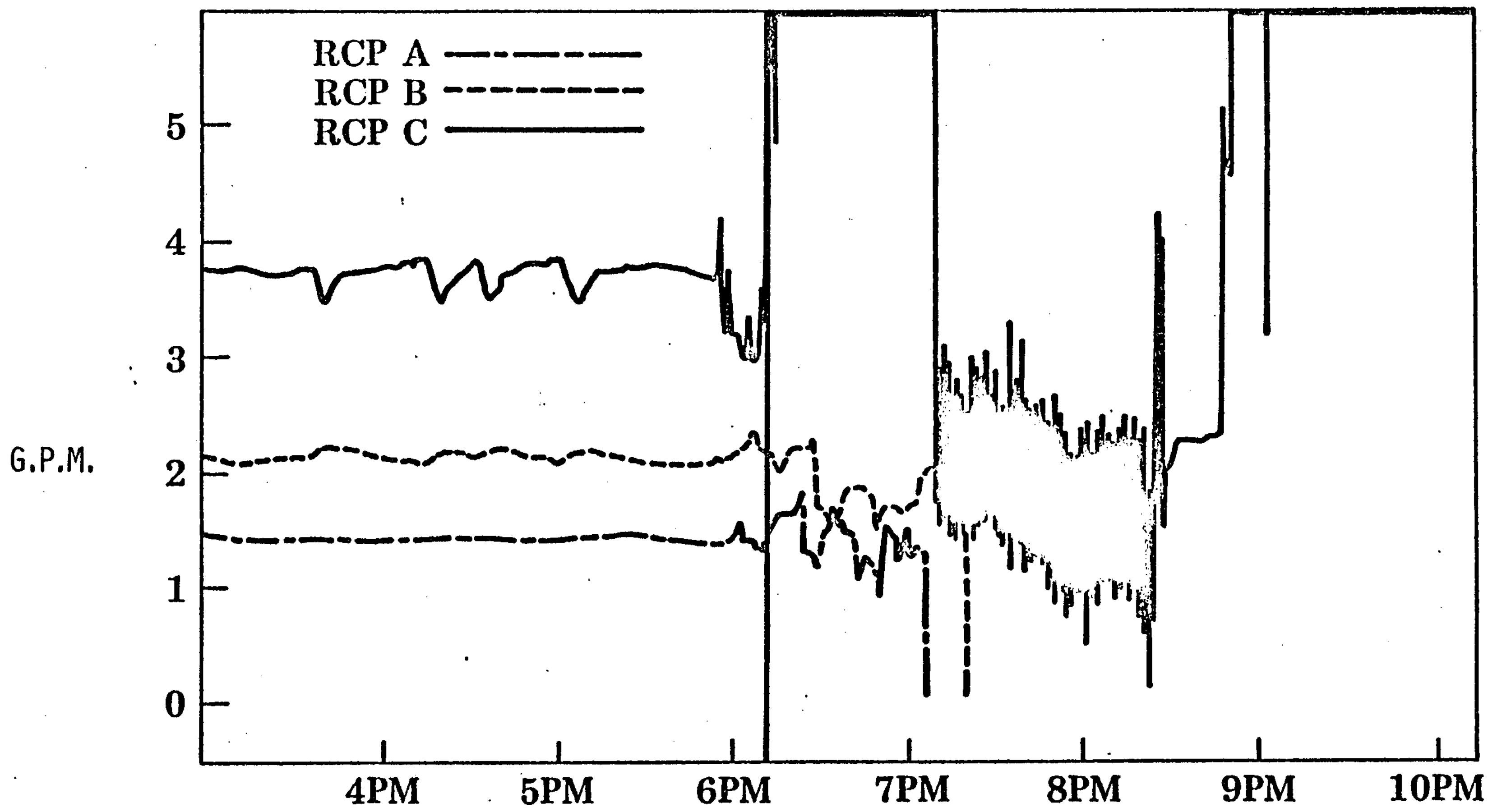
2. STATE THE CONCLUSIONS AND LESSONS LEARNED FROM THIS EVENT INCLUDING DEPRESSURIZATION AND PRESSURIZED THERMAL SHOCK.

REASON FOR STUDY

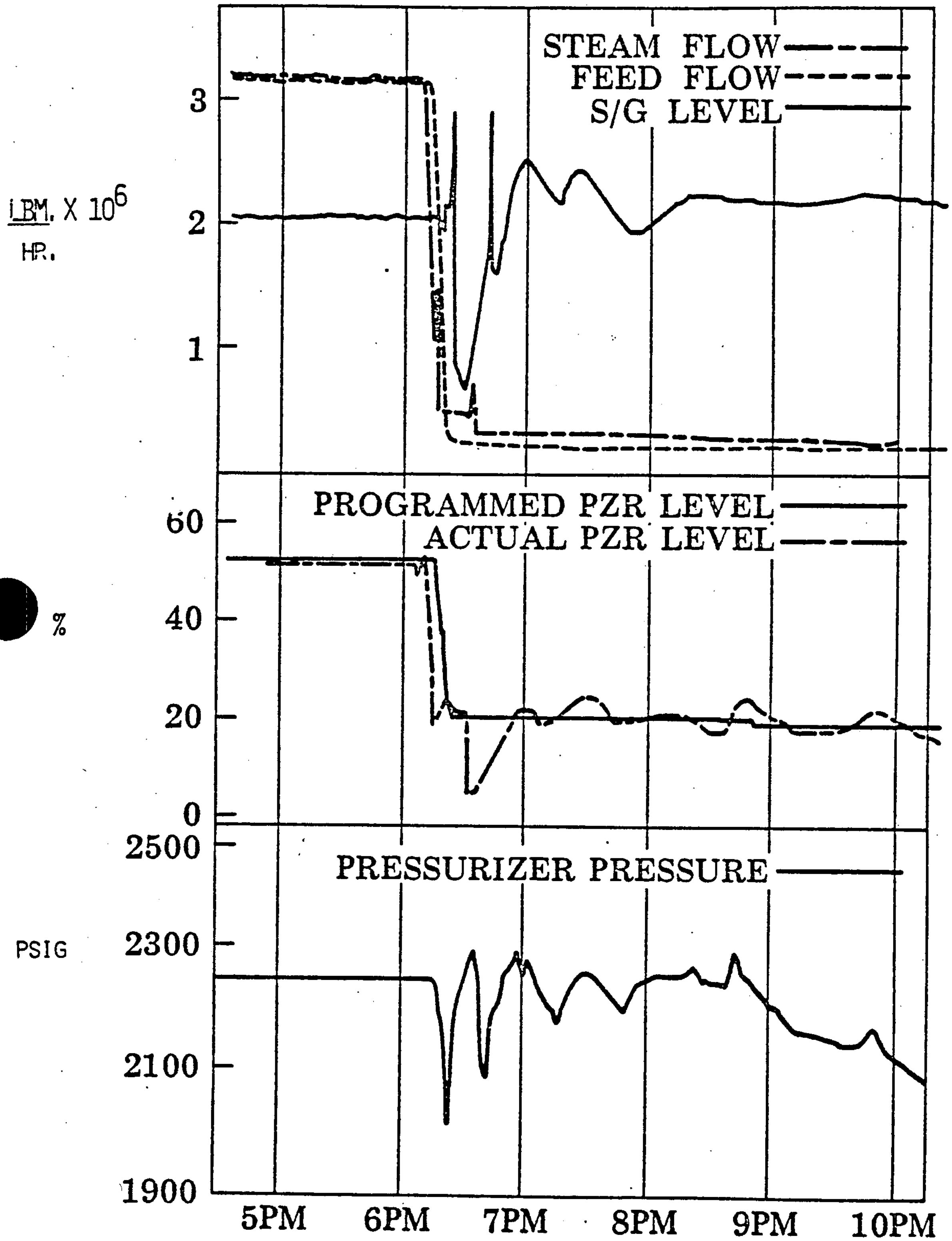
THE PURPOSE OF THIS LESSON IS TO FAMILIARIZE YOU WITH THE EVENTS WHICH OCCURRED ON MAY 1, 1975, CONCERNING THE FAIL-URE OF RCP "C" SEAL, RESULTING IN THE DISCHARGE OF REACTOR COOLANT FLUID TO THE CONTAINMENT FLOOR. THE FAMILIARIZATION WITH THIS AND OTHER EVENTS WILL ENABLE YOU TO BE BETTER PREPARED TO HANDLE PLANT EMERGENCIES OF THIS MATURE WHICH SHOULD ARISE WHILE YOU ARE ON SHIFT.

TRANSPARENCY 16-2

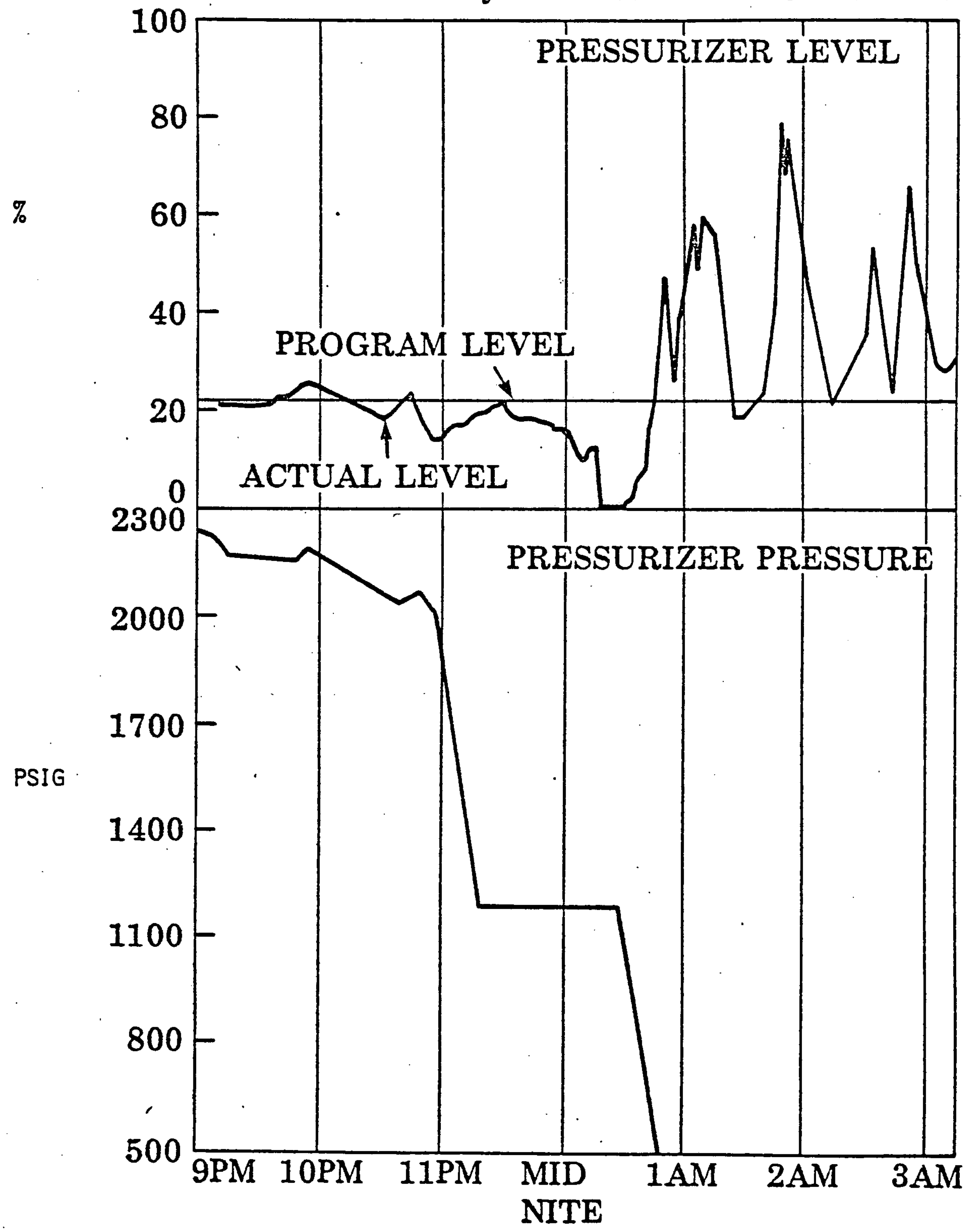
RCPs SEAL WATER FLOW



TRANSPARENCY 16-3
INITIAL ACCIDENT S/G LEVEL,
STEAM FLOW, PRESSURIZER LEVEL, AND PRESSURE

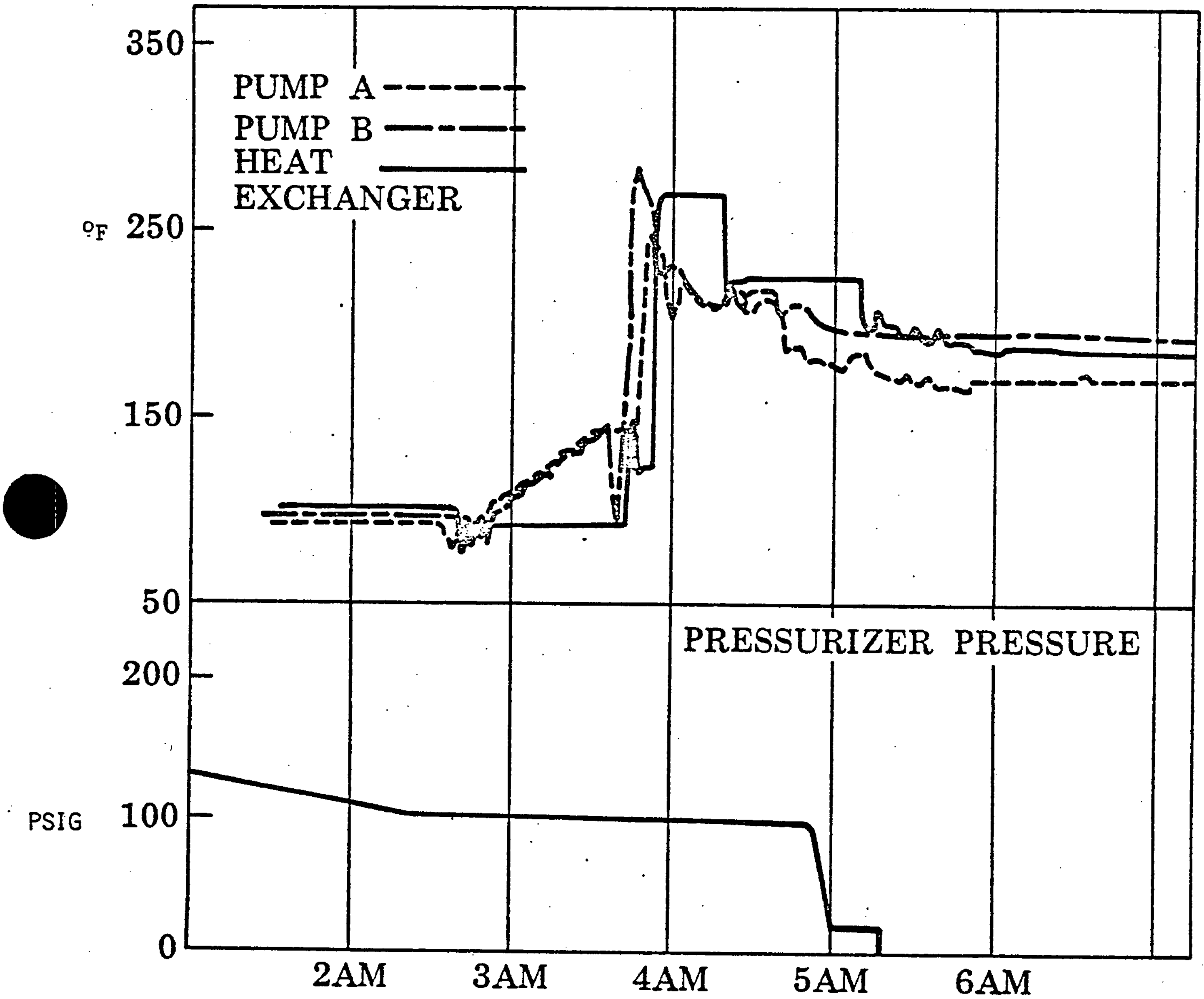


TRANSPARENCY 16-4
PZR LEVEL AND PRESSURE
DURING SUBSEQUENT RUNNING OF RCP "C"



TRANSPARENCY 16-5

RHR TEMP. AND PRESSURIZER PRESSURE



B

CP&L

HB ROBINSON
STEAM ELECTRIC PLANT

NUCLEAR
OPERATIONS

lesson plan

Transient and Accident Analysis
Session 14

H.B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
INSTRUCTOR LESSON PLAN

SUBJECT: Transient and Accident Analysis SESSION: 14 of 16

SESSION TOPIC: H.B. Robinson Event of April 28, 1970 (Steam line break) TIME: 50 minutes

REVISION NO. 0 DATE: 04/26/82

INSTRUCTOR REFERENCES

1. H.B. Robinson Incident Report No. 4
2. H.B. Robinson Emergency Instructions: EI-1, Appendix "B"

CLASSROOM EQUIPMENT

1. Chalkboard, Chalk and Eraser
2. Overhead Projector

TRAINING MATERIALS REQUIRED

Transparencies:
1. Lesson Objectives and Reason For Study

STUDENT REFERENCES

1. Student Handout:
2. H.B. Robinson Incident Report No. 4
3. H.B. Robinson Emergency Instructions: EI-1, Appendix "B"

LESSON PLAN

OUTLINE	KEY AIDS

I. INTRODUCTION

A. Lesson Objectives
Upon successful completion of this session you will be able to: — Transparency 14-1 and Student Handout

1. From memory, correctly evaluate the event.

2. From memory, correctly state the conclusions and lessons learned from this event.

B. Reason for Study
The reasons for studying this session are: — Transparency 14-1

1. To familiarize you with the effects an uncontrolled steam generator blowdown and the resultant uncontrolled cooldown have on the plant,

2. To familiarize you with the procedures for mitigating the effects of an uncontrolled steam generator blowdown.

LESSON PLAN

OUTLINE	KEY AIDS

II. PRESENTATION

A. Plant Conditions Prior to Event

1. Date - April 28, 1970

2. No fuel loaded - No decay heat

3. During hot functional testing

4. Three RCPs in operation

5. RCS pressure 2225 psig

6. RCS temperature 533°F

7. Steam generator steam pressure controlled at 880 to 900 psig by controlling RCS temperature

8. All three steam generator isolation and isolation bypass valves closed

9. Motor driven auxiliary feedwater pumps feeding the steam generators as needed to maintain level

10. Steam generator blowdown valves open

11. Steam generator levels maintained at about 70% on wide range

B. Event Description

1. Secondary safety valve lift pressures were being checked

2. Safety valves on S/G 1 and 2 checked satisfactory

3. Test rig moved to S/G 3 safety valve nearest the turbine deck (set to lift at 1140 psig)

4. At 3:20 pm an exceptionally loud steam release was heard

5. Subsequent investigation revealed the pipe stub to S/G 3 safety valve (1140 psig) had severed (360° Circumferential Break)

6. This left a 6-inch diameter hole open to atmosphere with no isolation valve between it and S/G 3

7. A sharp decrease was observed in:

OUTLINE	KEY AIDS

a. Pressurizer pressure (Decreased to 1862 psig)

b. Pressurizer level

c. No. 3 steam generator level

d. RCS temperature (cooled to 320°F in 1 hour)

8. All RCPs were immediately tripped

9. Two additional charging pumps were put in service. No SI occurred. Source of water was probably at 65°F.

10. Charging pumps set at maximum flow

11. All pressurizer heaters manually tripped

12. Letdown secured

13. Blowdown valves for S/G 1 and 2 closed and S/G 3 blowdown valve opened full

14. Restriction orifice bypass for S/G 3 blowdown line fully opened

15. Two boric acid pumps started, taking suction from boric acid tanks (which contained primary grade water) and discharging to charging pump suction

16. Demineralized water system put in service

OUTLINE	KEY AIDS

17. Transients observed were:

    a. Pressurizer pressure decreased to a low of 1862 psig in about ten minutes and then stabilized.

    b. Pressurizer level immediately dropped from 23% to 0%

    c. RCS temperature dropped from 533°F to 320°F in about 55 minutes before stabilizing

    d. S/G 3 level dropped from 68% to 0% (wide range) in about 50 minutes

    e. S/G 1 and 2 levels remained relatively constant

18. As pressurizer pressure began to increase again (after ten minutes), one charging pump was stopped to provide better control of the pressure increase. Pressure was increased to 2050 psig.

19. Pressurizer level indication returned after about 30 minutes and increased to normal operation level (no load, 22%) 30 minutes later

LESSON PLAN

OUTLINE	KEY AIDS
20. At 20% pressurizer level, the second charging pump was stopped and the control group of heaters was energized	
21. At 22% pressurizer level the control group of heaters was placed in automatic control. Pressure being maintained at no load conditions.	
22. Boric acid pumps were stopped and VCT makeup system returned to normal operating condition	
23. Twenty minutes after pressurizer level reached 22%, feedwater was added to S/G 1 and 2 and their blowdown valves were opened 3 turns	
24. S/G 3 blowdown valve was closed	
25. At 5:30 pm S/G 1 and 2 isolation valve bypass valves were opened and reheater purge lines opened to atmosphere to lower pressure and temperature in S/G's (830 psig)	
26. At 200 psig in S/G 1 and 2, "C" RCP was started (RCS temperature 320°F, pressure 1260 psig)	PTS
27. RCS pressure increased slowly to 1300 psig	
28. RCS temperature increased rapidly to 360°F	

OUTLINE	KEY AIDS
29. RCS cooled to 345°F and 425 psig	Back within cooldown curve
30. RHR system placed in service	
31. RCS pressure maintained at 425 psig and RCS temperature decreased to 180°F with RCPs running (to complete required run time on reactor internals with 3 RCP's running)	
C. Event Evaluation	
1. Operator actions	
a. RCPs tripped to eliminate source of heat to RCS	No fuel loading
b. All charging pumps running at maximum flow to makeup water volume lost by rapid cooling of RCS	
c. Pressurizer heaters were tripped to prevent overheating them due to loss of pressurizer level	
d. Letdown was secured to reduce loss of RCS volume	

e. Blowdown valves to S/G 1 and 2 closed to prevent S/G 1 and 2 from acting as heat sinks

o This reduces the RCS cooldown

f. Blowdown valve and bypass around restriction orifice to S/G 3 opened to reduce the water level in the S/G as quickly as possible

o This reduces the RCS cooldown

g. Uncontrolled plant cooldown occurred due to S/G blowing dry and addition of cooler RWST water for makeup

2. Equipment failures

a. Blowdown was caused by the severing of one of the S/G 3 safety valves

b. All other equipment performed as expected

D. Conclusions and Lesson Learned

1. If RCPs had not been tripped, the RCS pressure and temperature transients would have been less severe. Procedure now prevents this.

2. This was potentially serious pressurized thermal shock situation in that plant experienced 213°F/hr. cooldown rate with pressure maintained greater than 1862 psig. Pressure was then increased to 2050 psig which added to potential severity. — TAVE 320°

LESSON PLAN

OUTLINE	KEY AIDS
A. <u>OBJECTIVE 1</u>: From memory, correctly evaluate the event:	
1. S/G blowdown was caused by severing of the 1140 psig safety valve to S/G 3	
2. RCP tripped - elimates heat source	
3. Charging pumps running at maximum flow - makeup volume lost by rapid cooldown of RCS	
4. Pressurizer heaters tripped - prevents overheating	
5. Letdown secured - reduce RCS volume loss	
6. S/G 1 and 2 blowdown secured - prevents S/G 1 and 2 from acting as heat sinks (MSIV's already closed)	To minimize cooldown
7. S/G 3 blowdown valve and restriction orifice bypass valve opened - reduce water level in S/G as quickly as possible	To minimize cooldown
8. Uncontrolled plant cooldown occurred due to S/G blowing dry and addition of cooler RWST water for makeup	
B. <u>OBJECTIVE 2</u>: From memory, correctly state the conclusions and lessons learned from this event	
1. If RCPs had not been tripped, RCS pressure and	

temperature transients would have been less severe. (Procedures now prevent this)

2. This was potentially serious pressurized thermal shock situation in that plant experience 213°F/hr cooldown rate with pressure maintained greater than 1862°F. Pressure was than increased to 2050 psig which added to potential severity.

A. OBJECTIVE 1 QUESTION

1. Why were all three charging pumps running at maximum flow at the beginning of this accident?
   Answer: To makeup RCS water volume lost by the rapid cooldown

2. How was RCS temperature being maintained prior to the event on April 28, 1970 at H.B. Robinson Unit 2?
   Answer: No fuel was loaded and all 3 RCPs were used to maintain temperature.

B. OBJECTIVE 2 QUESTIONS

1. How could the RCs pressure and temperature transient have been reduced in this accident involving an uncontrolled steam generator blowdown?
   Answer: By not tripping the RCPs which were the only means of supplying heat to the RCS.

2. Once the operator recognized that the cooldown rate was in excess of 200°F/hr should he have increased pressure? Explain.
   Answer: No. Should be concerned with pressurized thermal shock and operator should have decreased pressure.

V. ASSIGNMENTS

A. Read H.B. Robinson Emergency Instructions EI-1, Appendix "B"

TRANSPARENCY 14-1

LESSON OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION YOU WILL BE ABLE TO:

1. FROM MEMORY, CORRECTLY EVALUATE THE EVENT.
2. FROM MEMORY, CORRECTLY STATE THE CONCLUSIONS AND LESSONS LEARNED FROM THIS EVENT.

REASON FOR STUDY

THE REASONS FOR STUDYING THIS SESSION ARE:

1. TO FAMILIARIZE YOU WITH THE EFFECTS AN UNCONTROLLED STEAM GENERATOR BLOWDOWN AND RESULTANT UNCONTROLLED COOLDOWN HAVE ON THE PLANT.
2. TO FAMILIARIZE YOU WITH THE PROCEDURES FOR MITIGATING THE EFFECTS OF AN UNCONTROLLED STEAM GENERATOR BLOWDOWN.

c

CP&L

HB ROBINSON
STEAM ELECTRIC PLANT

NUCLEAR
OPERATIONS

lesson plan

Transient and Accident Analysis
Session 15

H.B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2
INSTRUCTOR LESSON PLAN

SUBJECT: Transient and Accident Analysis SESSION: 15 of 16

SESSION TOPIC: Event of November 5, 1972 (S/G PORV Malfunction) TIME: 50 minutes

REVISION NO. 0 DATE: 4/28/82

INSTRUCTOR REFERENCE

H.B. Robinson Incident Report No. 50

CLASSROOM EQUIPMENT

1. Chalkboard, Chalk and Eraser
2. Overhead Projector

TRAINING MATERIALS REQUIRED

Transparencies:
1. Lesson Objectives and Reason for study

STUDENT REFERENCE

Student Handout:

LESSON PLAN

OUTLINE	KEY AIDS
I. INTRODUCTION	
A. Lesson Objectives Upon successful completion of this session, you will be able to: 1. From memory, correctly evaluate the event. 2. From memory, correctly state the conclusions and lessons learned from this event.	Transparency 15-1 and Student Handout
B. Reason for Study To familiarize you with the consequences of a steam generator power operated relief valve sticking open and the resultant uncontrolled cooldown.	Transparency 15-1
II. PRESENTATION	
A. Plant Conditions Prior to the Event 1. Date - November 5, 1972	

OUTLINE	KEY AIDS

2. Reactor power level - 70%
3. Generator load - 520 MW
4. Turbine valve test in progress

B. Event Description

1. Right stop valve push button was depressed
2. Load decreased from 520 MW to 150 MW
3. Reactor manually tripped at 0103
4. Reactor trip tripped the turbine and steam dump was commenced
5. When no load T_{avg} was reached, PORV RV-1 remained open for 5 minutes
6. RCS cooled down to 509°F
7. Emergency boration was commenced and secured after two minutes
8. Startup requirements were insured and at 0156, shutdown banks were pulled
9. At 0326 reactor startup was commenced

LESSON PLAN

OUTLINE	KEY AIDS
10. RCS temperature being maintained at 546°F by steam dump valves and PORVs	PORVs used to trim S/G levels
11. At 0333, with reactor subcritical, PORV RV-2 opened and failed to close (causing RCS cool-down)	
12. RV-2 is a fail closed valve but control air isolation and pulling of electrical fuses did not close the valve	
13. Control and shutdown rod banks were inserted	
14. Emergency boration began at 0345	
15. Safety injection actuation occurred at 0349 due to low pressurizer pressure and low level. RWST water added that was at approximately 55°F	S/G blowing dry & cold SI flow result in uncontrolled cooldown
16. MSIV V1-3B was closed at 0402 to allow S/G 2 to blowdown and minimize the RCS temperature and pressure transient	
17. Emergency boration secured at 0440	
18. Safety injection pumps secured at 0506	
19. At 0508 PRT level noted at 98%, up from 70% prior to the incident	Later determined to be caused by letdown relief valve opening

OUTLINE	KEY AIDS
20. PRT drain and vent valves were opened to reduce the level	
21. At 0509 containment sump high level light indicating 0.5 feet level was received	
22. Valve WD-1708 was opened to dump PRT to containment sump	
23. At 0515, R-11 alarmed at 130,000 cpm	
24. At 0520 received condensate collection system high level (1.5 feet and increasing) and dew point recorder increased to 170°F from 160°F	From Aux. Operator
25. At 0540 component cooling water surge tank level had dropped from 49% to about 4%	Later determined to be caused by the excess letdown relief valve opening
26. Containment vessel inspection at 0607 noted:	
a. Water on floor	
b. No visible damage was apparent	
27. A second containment vessel inspection at 0705 noted:	
a. Ruptured disk on west end of PRT	

b. Other disc was deformed and possibly ruptured

c. About four feet of water was found in reactor vessel sump

28. At 0900, RHR was placed in service

29. By 1500 RCS temperature was about 200°F

30. Activity releases

a. Gross beta and gamma - 0.217 mCi
b. Particulate - 0.217 mCi
c. Tritium - 1.561 mCi
d. Values are within release rates permitted

C. Event Evaluation

1. Operator actions - were appropriate and timely

2. Equipment failures

a. PORV RV-2

1) Jammed open because the valve's inner valve and inner valve guide bushing were scored

OUTLINE	KEY AIDS

2) RV-1, 2, and 3 were disassembled and repaired

b. Turbine stop valves

1) Disassembled and cleaned

2) Problem caused by phosphate buildup between valve shaft and valve bushing

c. Relief valve CS-715 - CV isolation caused to lift

1) Dumping CCW to CV sump

2) Additional cause - excessive CCW press.

d. Relief valve CV-203

1) To re-establish letdown flow, upstream isolation valve was opened before downstream isolation valve

2) CV-203 jammed open due to valve bellows having unscrewed

3) Relieves to PRT (which dumped to containment sump)

OUTLINE	KEY AIDS
4) Made it difficult to establish let-down flow	
e. Boron injection tank boron concentration	
1) Changed from 21, 424 ppm to 10,785 ppm	
2) SI pumps were dead headed because RCS pressure remained above pump discharge head	Indicates pressure greater than 1450 psig
3. System responses - except for the failures that caused the accident, the plant responded as expected	
a. Uncontrolled cooldown in this transient	
1) 157°F in 2 hours - TAVE-389°F	
2) Less severe than LOCA or MSLB that occurred at HBR	
b. Closing of affected S/G MSIV sooner may have further limited cooldown. (Check valve leakage)	
D. Conclusions and Lessons Learned	
1. This is an example of an uncontrolled blowdown of a steam generator	

2. The effects are the same as if a small main steam line break has occurred upstream of the MSIVs

3. The blowdown plus SI actuation results in uncontrolled cooldown.

III. SUMMARY

A. OBJECTIVE 1: From memory, correctly evaluate the event.

1. Operator actions appropriate and timely

2. Equipment failures

a. PORV RV-2

b. Turbine stop valves

c. Relief valve CS-715

d. Relief valve CV-203

e. High head SI to BIT isolation valve SI-867A

f. Boron injection tank boron concentration

3. System responses were as expected

a. Cooldown of approximately 80°F/hr was experienced

B. OBJECTIVE 2: From memory, correctly state the conclusions and lessons learned from this event.

1. Example of uncontrolled blowdown of a steam generator

2. Effects same as small main steam line break

3. The blowdown plus SI actuation resulted in uncontrolled coolant cooldown.

IV. EVALUATION

A. OBJECTIVE 1 QUESTIONS

1. What was the primary cause of the event on November 5, 1972 at H.B. Robinson Unit 2?
Answer: The failing open of power operated relief valve RV-2

B. OBJECTIVE 2 QUESTIONS

1. The event on November 5, 1972 at H.B. Robinson Unit 2 is an example of what type of accident?
Answer: An uncontrolled blowdown of a steam generator. The effects are the same as a small main steam line break upstream of the MSIVs.

2. What factors contributed to the resultant uncontrolled coolant cooldown.

a. SI actuation with colder makeup water

OUTLINE	KEY AIDS
b. S/G blowdown	

V. ASSIGNMENTS

Read Student Handout

TRANSPARENCY 15-1

LESSON OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION, YOU WILL BE ABLE TO:

1. FROM MEMORY, CORRECTLY EVALUATE THE EVENT.

2. FROM MEMORY, CORRECTLY STATE THE CONCLUSIONS AND LESSONS LEARNED FROM THIS EVENT.

REASON FOR STUDY

TO FAMILIARIZE YOU WITH THE CONSEQUENCES OF A STEAM GENERATOR POWER OPERATED RELIEF VALVE STICKING OPEN AND THE RESULTANT UNCONTROLLED COOLDOWN.

H.B. ROBINSON STEAM ELECTRIC UNIT NO. 2

INSTRUCTOR LESSON PLAN

SUBJECT: Mitigating Core Damage

Session:

SESSION TOPIC: R.E. Ginna: Steam Generator Tube Rupture

Time: 50 minutes

REVISION NO. 0

DATE: 5-6-82

INSTRUCTOR REFERENCES

1. NRC report on the January 25, 1982 steam generator tube rupture at R.E. Ginna Nuclear Power Plant NUREG-0909 April, 1982

CLASSROOM EQUIPMENT

1. Chalkboard, chalk and eraser
2. Overhead projector

TRAINING MATERIALS REQUIRED

Transparencies:

1. Lesson objectives and reason for study
2. Figure 3.3 reactor cold loop temperatures from Ginna report
3. Figure 3.1 reactor coolant system pressure from Ginna report

STUDENT REFERENCES

Student Handout

LESSON PLAN

OUTLINE	KEY AIDS

I. INTRODUCTION

A. Lesson Objectives

Upon successful completion of this session, you will be able to: TP-1

1. Briefly describe the initial symptoms and alarms which alerted the operator to this event.

2. List of the operator steps taken to mitigate this event

3. Correctly state the conclusions and lessons learned from this event.

B. Reason for Study

The Nuclear Power Industry has experienced many steam generator tube problems. The event at the R.E. Ginna Power Plant was a catastropic failure which could occur at HBR. It is important that the operator know the sequence of events, actions taken (both automatic and manual), and concerns for core cooling, PTS and release of radionuclides to the environs.

Note: (This particular event has not been evaluated as it may pertain to HBR. This lesson is presented for information)

II. PRESENTATION

A. Initial Conditions

1. Date - January 25, 1982

2. Power - 100%

3. RCS pressure 2197 Psig

4. RCS temperature 572°F

5. No indicated primary to secondary leakage

B. Event Description

1. 9:25 a.m. the following alarms and indications were received

   a. Charging pump speed alarm

   b. B S/G level deviation alarm

   c. B S/G steam-flow/feed-flow mismatch alarm

   d. Pressurizer level and pressure deviation alarms

   e. Air ejector radiation monitor (R-15) alarm

   f. Pressurizer low pressure alarm (2185 psig)

2. 9:26 power reduction commenced; steam dumps armed

   Pressure 2064 Temp. increasing due to load reduction

3. 9:37 third charging pump started

4. 9:28 steam dumps modulating shut, auto reactor trip (Lo-pressure 1873 psig) auto safety injection (1723 psig) feedwater isolation - auto start motor driven AFW pumps

LESSON PLAN

OUTLINE	KEY AIDS
5. 9:29 RCP's tripped manually, pressurizer indicated empty. Turbine driven AFW pump started (Lo-Lo level in S/G)	Procedure requires at 1715 psig
6. 9:30 Initial RCS depressurization stopped at 1200 psig (Note: Later concluded that steam bubble probably formed in vessel head. This coupled with SI/flow terminated pressure drop)	
7. 9:32 'B' steam supply to turbine driven AFW pump secured	Concerned about release of radioactivity
8. 9:38 operator used steam dumps in manual to cooldown plant	
9. 9:40 isolated 'B' S/G Tc 'B' loop commenced dropping to approximately 340°F	TP-2
10. 9:48 secured AFW pumps to control level in 'A' S/G	
11. 9:53 shut manual isolation valve to 'B' S/G PORV (This made PORV unavailable and resulted in 5 challenges to an unisolable S/G safety valve)	HBR does not have manual violation valve on S/G PORV's
12. 9:55 'B' S/G level off-scale high on narrow range indication	
13. 9:57 SI and containment isolation reset	
14. 10:07 pressurizer PORV cycled twice (charging pumps were secured prior to this step but indicates SI pumps still running)	

LESSON PLAN

OUTLINE	KEY AIDS
15. 10:09 cycled pressurizer PORV again. This time valve stuck open RCS pressure dropped to 900 psig & pressurizer level increased rapidly (first clear indication to control room operators that bubble had formed in upper head. Actually was second time a steam bubble had formed in head)	'B' loop Tc dropped to 240°F and then returned to 340°F TP-2 & 3 Pressure cycles 800-1350 psig
16. 10:11 PORV block valve fully closed; pressurizer level off-scale high SI/flow now increasing RCS pressure	
17. 10:19 one 'B' S/G safety valve lifted and closed (Note: SI & charging flow maintained RCS pressure high resulting in continued RCS inleakage into faulted S/G) The safety valve lifted 4 more times during event	
18. 10:38 SI flow was terminated but charging flow maintained	
19. 10:42 energized pressurizer heaters to re-establish pressurizer steam bubble	
20. 11:21 started 'A' RCP (Note: Any steam bubble in head would now have condensed due to cooler water in loops)	
21. Approximately 2:00 p.m. plant cooldown and controlled depressurization in progress. Cooldown via 'A' S/G PORV with 'A' RCP providing flow through 'A' loop and backflow through 'B' loop; operators maintained RCS pressure 25 psi below 'B' S/G pressure. 'B' S/G was being cooled by intermittently feeding it with AFW while bleeding it via the ruptured tube to the RCS	

OUTLINE	KEY AIDS

C. Event Evaluation

1. Upon analysis of tube rupture in 'B' S/G based on initial alarms and indications, operators commence turbine unload. Continued RCS pressure drop resulted in automatic reactor trip and safety injection actuation.

2. The pressurizer emptied and initial depressurization reached 1200 psig. Later analysis showed probable steam bubble formation in vessel head. Later SI flow would have collapsed this bubble.

3. Affected S/G was used to dump steam for 15 minutes after initial indication.

4. Affected S/G PORV was manually blocked rather than placing controller in manual and shutting down on signal. This resulted in total reliance on S/G safeties to relieve any high pressure situation in affected S/G

5. Pressure PORV was operated in attempts to equalize the pressure differential between RCS and 'B' S/G. When valve stuck open on fourth attempt steam bubbles forced in upper head region and in top of tubes in 'B' S/G

6. Affected S/G safety valve lifted 5 times. This resulted in release of radioactively to environs. Operators showed concern about radioactivity releases by securing steam from affected S/G to turbine driven AFW pump early in event.

LESSON PLAN

OUTLINE	KEY AIDS

D. Conclusions and Lessons Learned

1. Affected S/G PORV should not have been manually blocked. It could have been used to control pressure in affected S/G rather than rely on safety valves.

2. Operators showed appropriate concern for the following:

   a. Radioactive releases

   b. Cooldown & depressurize to minimize extent of leak and to aviod high pressure situation in affected S/G

   c. Maintain subcooling and recollapse bubbles that may form in other locations than pressurizer.

3. Although later ayalysis has shown that a significant thermal shock did not occur, the potential existed for one. Operators must be aware of cold loop temperatures and potential affects with RCS pressure still high.

III. SUMMARY

A. Objective 1: Briefly describe the initial symptoms and alarms which alerted the operator to this event.

1. The operators had initial indication of the event and its magnitude

2. The following initial alarms were received:

a. Charging pump speed alarm - indicated high speed - potential leak

b. B S/G level deviation alarm indicated high level - results of primary to secondary leakage

c. B S/G steam - flow/feed-flow mismatch alarm - high steam flow

d. Pressurizer level and pressure deviation alarm

e. Pressurizer low pressure alarm - D and E indicated potential primary leak

f. Air ejector radiation monitor - key indicator of primary to secondary leak

B. Objective 2: List the operator steps taken to mitigate this event

1. Operated charging and SI pumps to makeup for leakage & initial cooldown shrinkage

2. Attempted to keep RCS pressure low and still maintain sub-cooling

3. When conditions warranted, operators draw bubble (in pressurizer and started a RCP to collapse any bubbles that may still have existed in vessel head or steam generator tubes.

4. Took steps, such as securing steam from affected S/G to turbine driven AFW pump, to minimize radioactive releases

C. Objective 3: Correctly state the conclusions and lessons learned from this event

1. Affected S/G PORV should not have been manually blocked. It could have been used to control pressure in affected S/G rather than rely on safety valves

2. Operators showed appropriate concern for the following:

   a. Radioactive releases

   b. Cooldown and depressurize to minimize extent of leak and avoid high pressure situation in affected S/G

   c. Maintain subcooling and recollapse bubbles that may form in other locations than pressurizer.

3. Although later analysis has shown that a significant thermal shock did not occur, the potential existed for one, operators must be aware of cold leg temperatures and potential affects with RCS pressure still high

IV. EVALUATION

A. Objective 1 Questions

1. List the alarms that the control room operators initially received to indicate the source and magnitude of the casualty.

   a. Charging pump speed alarm

   b. 'B' S/G level deviation alarm

LESSON PLAN

OUTLINE	KEY AIDS

c. 'B' S/G steam-flow/feed flow mismatch

d. Pressurizer level and pressure deviation alarm

e. Pressurizer low pressure alarm

f. Air ejector radiation monitor

B. Objective 2 Questions

1. What actions did the operators take when they became aware that a bubble had formed in other than the pressurizer?

   a. Maintained SI & Charging flow

   b. Monitored temperatures

   c. When conditions warranted drew bubble in pressurizer and started RCP

2. What actions did operators take to minimize radioactive release?

   a. Secured affected S/G as soon as possible

   b. S/G to steam supply from affected S/G to steam driven AFW pump

   c. Attempted to keep RCS pressure low to minimize chances of affected S/G safeties from lifting

LESSON PLAN

OUTLINE	KEY AIDS

C. Objective 3 Questions

1. List the conclusions and lessons learned

   a. Affected S/G PORV should not have been manually blocked. It could have been used to control pressure in affected S/G rather than rely on safety valves.

   b. Operators showed appropriate concern for the following

      1. Radioactive releases

      2. Cooldown & depressurization

      3. Maintain subcooling

   c. Later analysis showed no significant thermal shock yet operator should be aware that potential existed.

TRANSPARENCY 1

LESSON OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION YOU WILL BE ABLE TO:

1. BRIEFLY DECRIBE THE INITIAL SYMPTOMS AND ALARMS WHICH ALERTED THE OPERATOR TO THE EVENT.

2. LIST THE OPERATOR STEPS TAKEN TO MITIGATE THIS EVENT.

3. CORRECTLY STATE THE CONCLUSIONS AND LESSONS LEARNED FROM THIS EVENT.

REASON FOR STUDY

THE NUCLEAR POWER INDUSTRY HAS EXPERIENCED MANY STEAM GENERATOR TUBE PROBLEMS. THE EVENT AT THE R.E. GINNA POWER PLANT WAS A CATOSTROPIC FAILURE WHICH COULD OCCUR AT HBR. IT IS IMPORTANT THAT THE OPERATOR KNOW THE SEQUENCE OF EVENTS, ACTIONS TAKEN (BOTH AUTOMATIC AND MANUAL), AND CONCERNS FOR CORE COOLING, PTS AND RELEASE OF RADIONUCLIDS TO THE ENVIRONS.

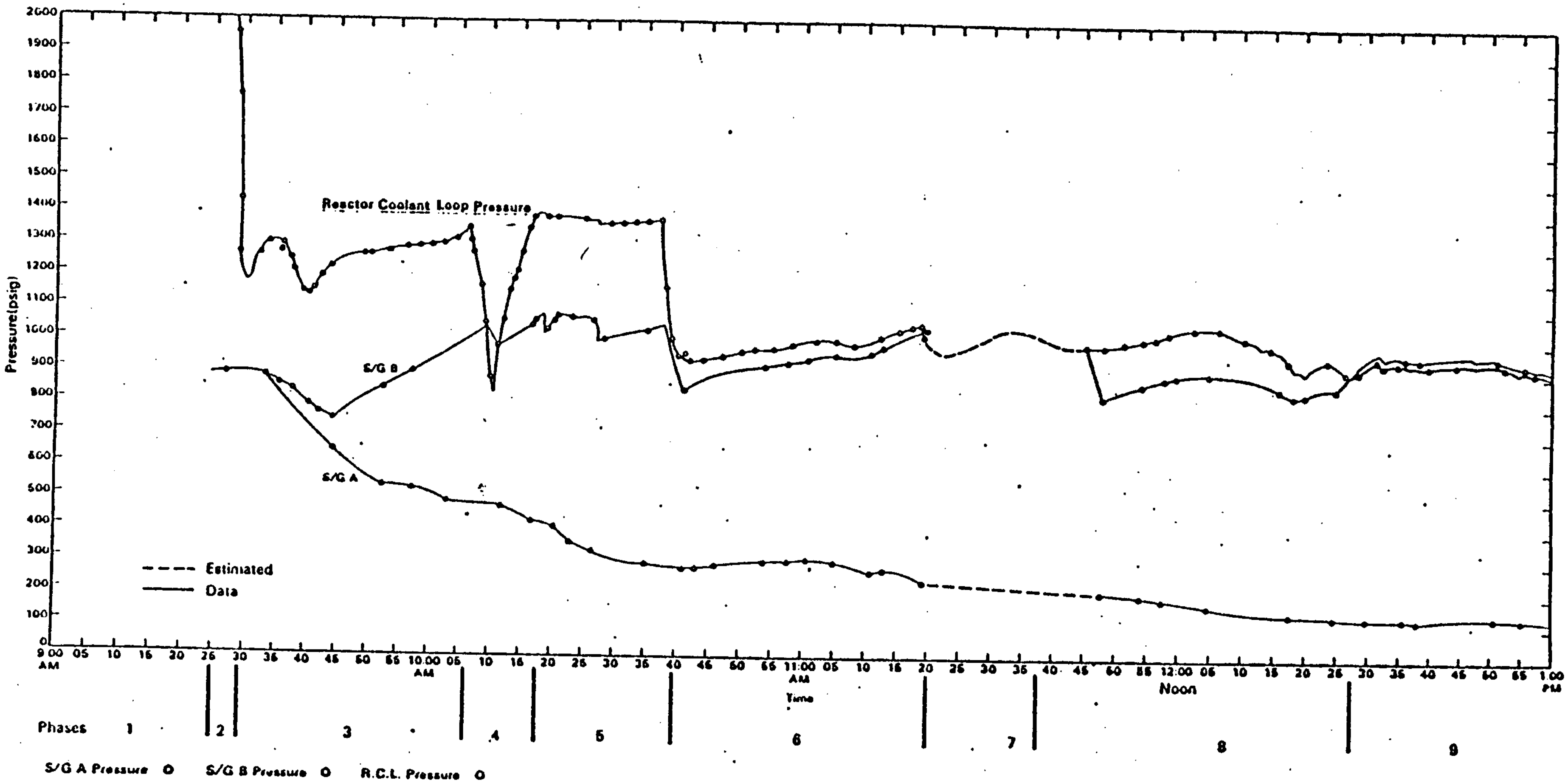
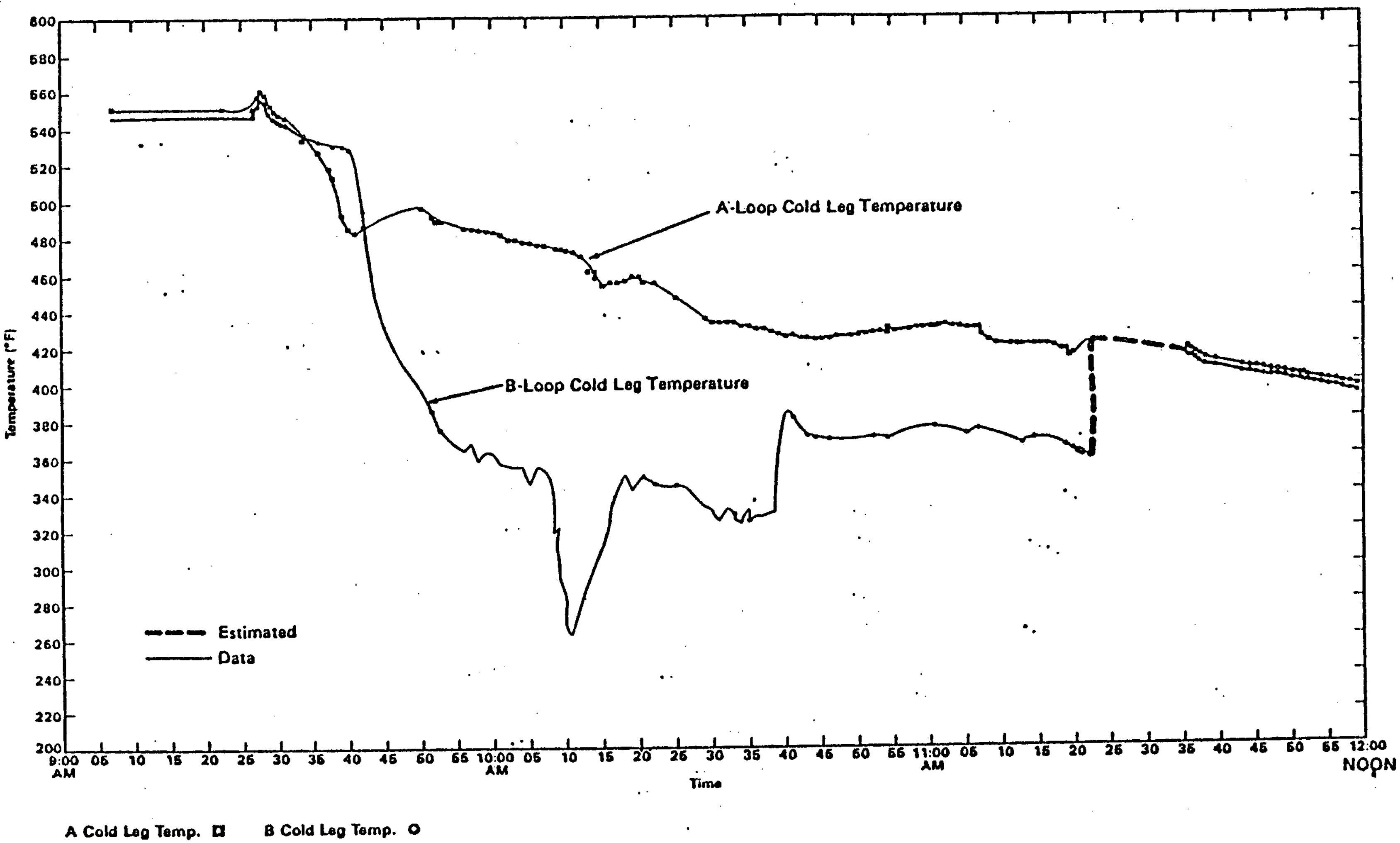


Figure 3.1 Reactor coolant system and steam generator pressure response as a function of time, January 25, 1982

TRANSPARENCY 3



TRANSPARENCY 2

Figure 3.3 Reactor coolant loop cold-leg temperature as a function of time, January 25, 1982

PTS CONCERNS WITH EI-14, AP-19, AP-25, GP-2, GP-6

Time: 50 minutes

Session 1 of 1

OBJECTIVES: Upon successful completion of this session the student will be able to:

1. Recognize condition or statements with PTS implications in the following procedures

   a. EI-14
   b. AP-19
   c. AP-25
   d. GP-2
   e. GP-6

2. Describe the actions that can be taken to reduce the likelihood of a thermal transient (PTS event) occuring, given the initial plant conditions and initiating problem.

MATERIALS:

I. Training Aids

   A. Chalkboard, chalk and erasers

   B. Overhead projector

   C. Transparencies

II. References

   A. Abnormal Procedures AP-19, 25

   B. General Procedures GP-2, 6

   C. Emergency Instructions EI-14

III. Supplies - pencil and paper
   - student handout

INTRODUCTION

I. Establish Class Relations

A. State Name

B. Explain procedures (asking questions, volunteering information)

II. Establish Learning Goals

A. State title

B. State objectives

PRESENTATION

I. Procedures That Have A PTS Concern

A. EI-14 Reactor Trip (Part A)

B. AP-19 Malfunction of Pressure Control

C. AP-25 Spurious SI Safeguards Actuation

D. GP-2 Plant heatup from cold conditions

E. GP-6 Plant cooldown from hot shutdown conditions

II. Concerns

A. EI-14

1. Part A - Reactor Trip

a. Section C.2.c

"Check that turbine stop valves, governor valves, intercept and reheat stop valves are closed"

b. Section D.2

"Avoid allowing the transient to bring Tave below 530°F."

2. Concern - possible excessive cooldown of the reactor vessel due to:

a. Turbine not tripped (valves not closed)

b. Steam dump

1. Control malfunction

2. Steam dump stuck open

c. Stuck open PORV

3. Operator actions

    a. Manual trip turbine

    b. Shut MSIVs

    c. Isolate air to PORVs if stuck open

B. AP-19

1. High RCS pressure - "high pressure must be avoided due to the possiblity of over-pressurizing the system."

2. Concern

    a. During solid plant operation, heatup or cooldown possibility exists to exceed the pressure/temperature limits

    b. Possible causes of excessive pressure are:

        1. Solid Plant

            a. Excessive charging flow

                1. Controller malfunctions

                2. Operator error

                3. Loss of instrument air

            b. Letdown flow reduction caused by PCV-145 or HCV-142 malfunction

                1. Loss of instrument air

                2. Operator error

            c. PORV's blocked

3. Operator actions

    a. Solid

        1. Correct charging/letdown flow imbalance

            a. Use of HCV-142

            b. PCV - 145

            c. Charge pump speed

2. Increase heat removal

   a. Increase flow through RHR heat exchangers

   b. Start other RHR pump

b. Bubble

   1. (1.4.1) De-energize pressurizer heaters it they failed to cut off automatically

   2. (1.4.2) If pressurizer spray control is in automatic and spray has not initiated, shift spray control to manual and adjust spray to decrease pressure

   3. (1.4.3) Use auxiliary spray, if necessary, and the ΔT between the pressurizer and TE 123 (CVC charging line temp) is below 320°F

C. AP-25

1. Spurious safeguards actuation

   a. Inadvertently actuated due to human or logic error, etc.

   b. Necessary to terminate and return the plant to normal condition

   c. If safe operations dictates, actions required may be performed simultaneously or out of sequence

   d. If initiation is at other than normal temperature and pressure (during heatup/cooldown) the conditions for SI termination in EI-1 should not be established <u>if</u> the heatup/cooldown curve would be violated

      1. RCS pressure 1560 psig

      2. Pressurizer level at no load

      3. Water level in narrow range of one S/G or U tubes covered wide range

      4. 40°F subcooled

2. Concern

   a. SI pump shutoff head - 1450 psig + 110 psig instrument error

b. SI pump BKRs not racked out/in until 350°

c. Between 350° and 435°, curve may be violated due to SI pumps

3. Operator action

Terminate SI in this region as soon as possible by stopping all operating safety injection pumps

D. GP-2

1. Plant heatup- Instruction 4.0
Overpressurization Caution - "If all three RCPs were stopped prior to heatup do not start a RCP when the RCS is solid, stagnant and S/G temperature is greater than the RCS. Measure S/G temperature 4 ft. above the tube sheet. Area shall be covered with insulation prior to measuring. This temperature must be less than or equal to loop surface temperature of RHR-750.

a. Steam generator will act as heat source

b. Uneven RCS heat distribution

2. Concern

a. Rapid heatup of RCS

b. Subsequent uncontrolled pressure increase

3. Operator action if S/G temperature is greater than RCS

a. Allow plant to heatup

b. Cooldown S/G by feed and bleed

Note: Low temperature overpressure protection system should prevent this, however the possibility still exists.

4. Turkey Point Event

A. Conditions

1. Temperature - 106°F

2. Pressure - 310 psig

3. RHR in service - solid plant

B. Event

1. RCP - start

2. High pressure signal isolates RHR loop - pressure greater than 465 psig.

3. Seal injection continued - pressure to 1100 psig - Seal injection can be terminated at low temp.

4. Operator opens PZR. PORV - failure of automatic low pres. protection system.

5. RHR isolates 2nd time - pressure 355 psig transmitter failure.

6. Pressure increase to 750 psig - seal injection continued.

C. Corrective Actions

1. Terminate seal injection - at low temperature no problem.

2. Place excess letdown in service

3. Trip charging pump on pumps

Notes: See attached Turkey Point Event

E. GP-6

1. Plant cooldown - precaution 3.8 "complete PT 2.7, 2.8 prior to going solid if it is suspected they will become due during the outage. These should not be run when water solid due to potential for overpressurization of the RCS.

   a. Concern - even though SI & RHR pumps operate on recirc., system isolation valves may leak by causing an overpressure condition while water solid.

   b. Action - follow procedure

2. Precaution 3.9 (applicable to heatup/cooldown) "SI pump breakers must be racked out when RCS temperature is less than 350°F and system not vented to C.V."

   a. Concern - above 350 but below 435°F, should the SI pumps start, unless terminated the potential exists for violation of P,T curve due to shutoff head of SI pump.

   b. Action - terminate SI as soon as possible to preclude an overpressure condition.

3. Instruction 4.9
"With the steam dump via the condenser or PORV on manual control, slowly increase the rate of steam dump by adjusting the pressure control setpoint"

a. Wide range RCS temp.

b. Wide or narrow range pressure

c. S/G level

1. Concern - that using a PORV particularly, is that it or a steam dump valve may become stuck open yeilding an excessive cooldown and exceeding P,T curve - overpressure reactor vessel.

2. Action

a. Exercise extreme caution

b. Shut MSIV's if necessary - above 200°F

c. Isolate air to PRVs if necessary

III. SUMMARY

A. Objective one is to recognize in procedures EI-14, AP-19 & 25, GP-2 & 6 places or statements that are of concern with PTS.

B. Problems Encountered

1. EI-14, excessive cooldown - following reactor trip; use of steam dump

2. AP-19, overpressurization - failure of pressure control - Turkey Point event

3. AP-25, violation of P,T curve particularly in the region of 350° - 435° during heatup or cooldown - ensure termination of SI if not needed

4. GP-2, uncontrolled temperature and pressure increase resulting in violation of PT curve - S/G can be a heat source

5. GP-6

a. Overpressurization of solid plant

b. Same as AP-25

c. Excessive cooldown

d. Malfunction of HCV142, PCV145

Subject: Cold Pressurization of Reactor Coolant System

Reference: INPO/NSAC Significant Event Report 2-82
Turkey Point 4 Event in November 1981

Description: While in cold shutdown with the system solid at 106°F and 310 psig and on the residual heat removal (RHR) system, an RHR system inlet isolation valve closed due to a high pressure signal generated after starting a reactor coolant pump. This isolated the letdown path which connects directly to the RHR system. Since reactor coolant pump seal injection continued, system pressure increased to 1100 psig before the operator opened a relief valve. The overpressure mitigating system (OMS) did not automatically open a relief valve because a signal summator (Hagan Model #111, Part 411-084-004) had failed high, increasing the opening setpoint. Once the RHR system inlet isolation valve closed, an interlock prevented opening the isolation valve while the pressure exceeded 465 psig.

After restoring the system and plant parameters, a second RHR system inlet isolation valve closed two hours later at 355 psig due to a transmitter failure. Reactor coolant pump seal injection continued, and system pressure increased to 750 psig before the operator opened a relief valve. The transmitter failure was caused earlier by unintentionally hydrotesting the transmitter's sensor line with a leaking isolation valve to the transmitter.

Suggested Action:

Include this event in plant training as an example of the potential for overpressurizing the reactor vessel while cold and below the vessel's reference temperature for nil-ductility transition. In this case the overpressure protection system <u>did not</u> fuction because of an equipment failure. When in cold solid conditions, operators <u>should not</u> depend totally on the overpressurization protection system, but should also monitor RCS pressure and temperature conditons closely and be prepared to take necessary actions. A similar event at H. B. Robinson could entail considerable investigation and justification for a subsequent start-up because of the particular vessel chemistry and irradiation time. No action other than training emphasis appears necessary as it would require at least two failures to produce such an event.

PTS CONCERNS WITH EI-14, AP-19, AP-25, GP-2, GP-6

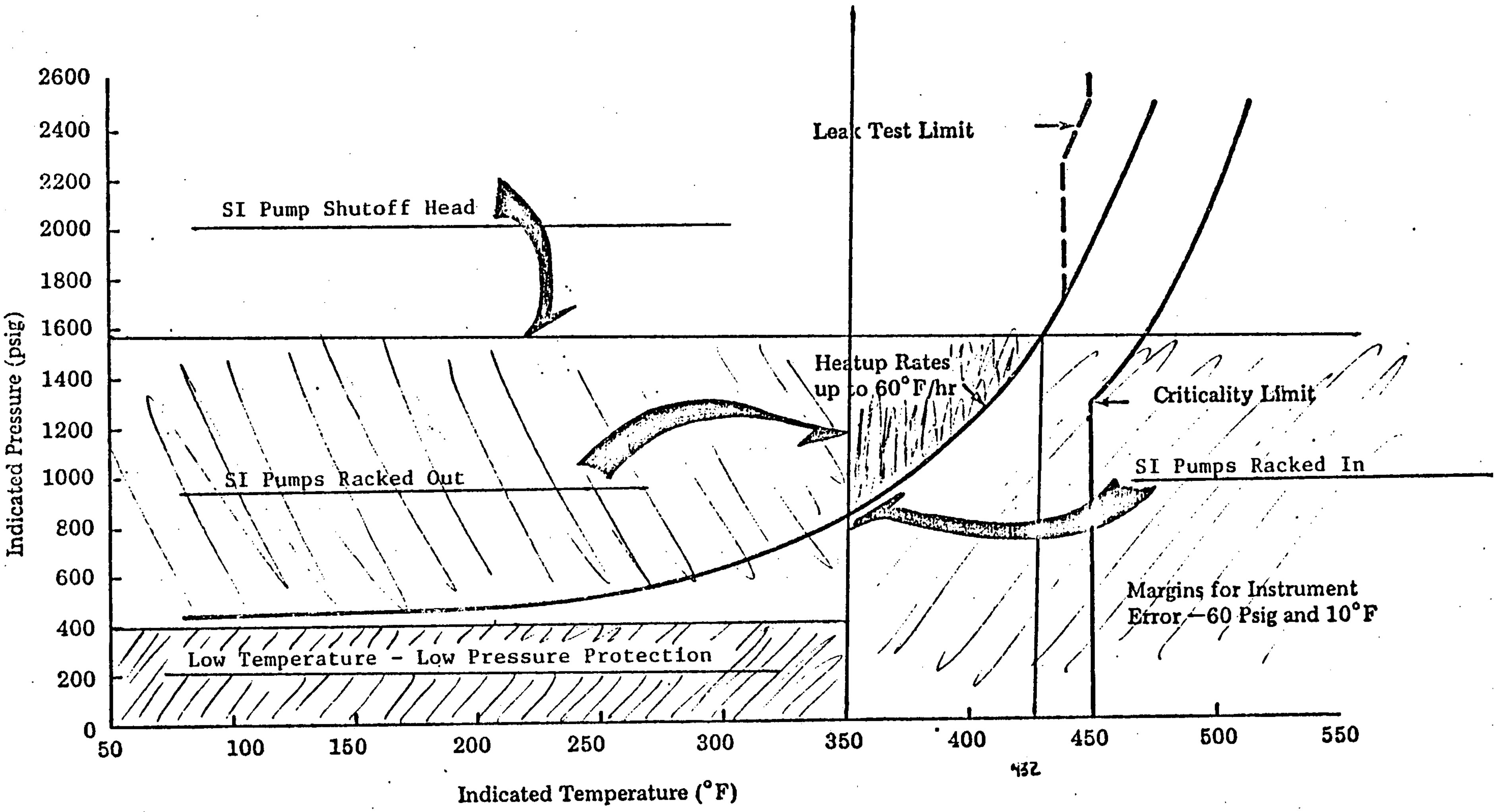
OBJECTIVES

UPON SUCCESSFUL COMPLETION OF THIS SESSION, THE STUDENT WILL BE ABLE TO:

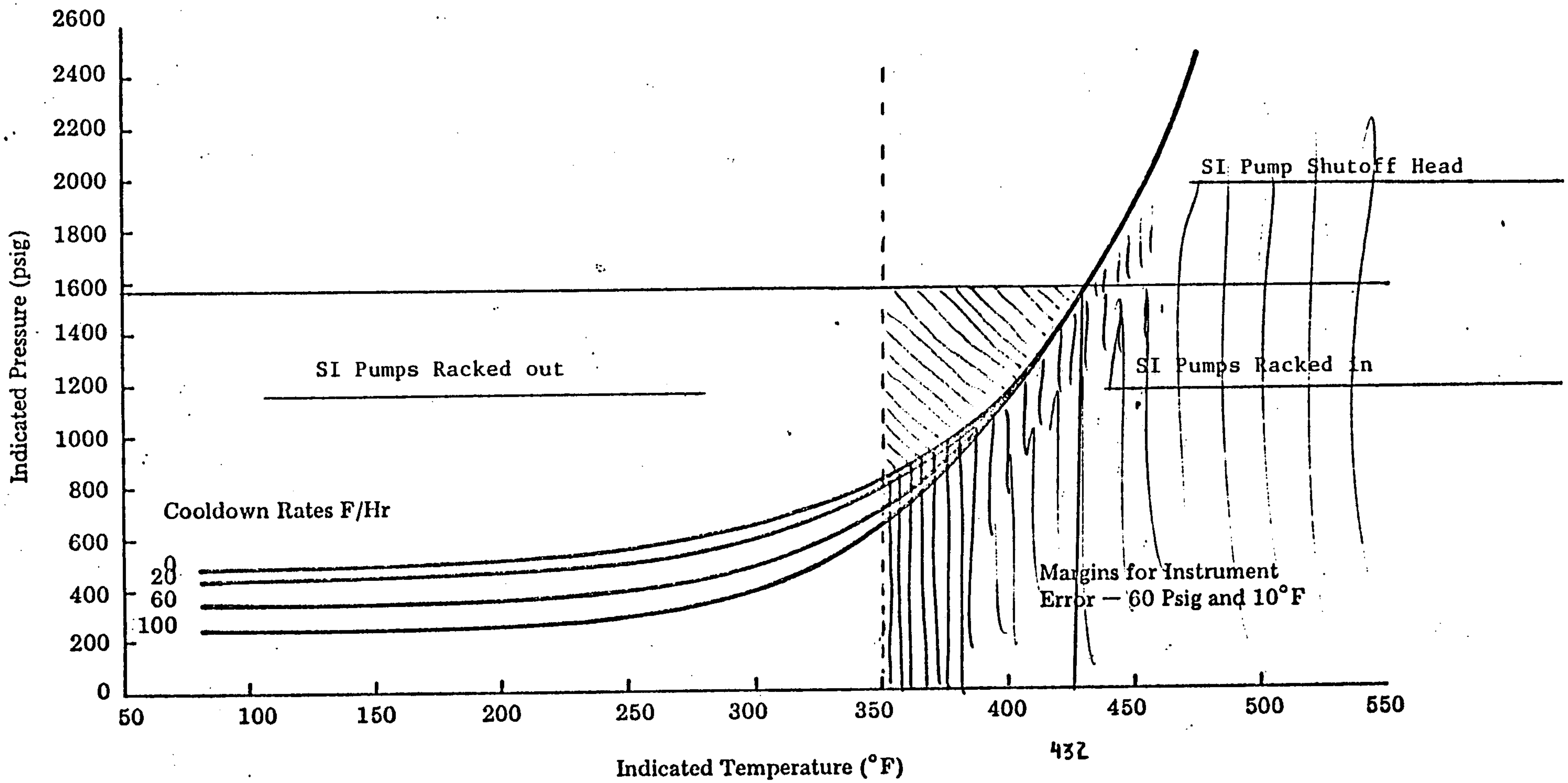
1. RECOGNIZE CONDITIONS OR STATEMENTS WITH PTS IMPLICATIONS IN THE FOLLOWING PROCEDURES:

   A. EI-14
   B. AP-19
   C. AP-25
   D. GP-2
   E. GP-6

2. DESCRIBE THE ACTIONS THAT CAN BE TAKEN TO REDUCE THE LIKELIHOOD OF A THERMAL TRANSIENT (PTS EVENT) OCCURRING, GIVEN THE INITIAL PLANT CONDITIONS AND INITIATING PROBLEM.



Typical Reactor Coolant System Heatup Limitations



Typical Reactor Coolant System Cooldown Limitations

CAUTION

IF THE SI PUMPS ARE STOPPED WITHIN THE FIRST TWO MINUTES OF A SAFEGUARDS ACTUATION, THE FUSES MUST BE PULLED AND REINSERTED AT BREAKERS TO ALLOW THEM TO BE RESTARTED!

PRESSURIZED THERMAL SHOCK

STUDENT HANDOUT

"A"

(EI-1)

Whenever you enter EI-1, there are three primary concerns that should be at the front of your mind.

1. Protect the health and safety of the general public
2. Keep the core cool
3. Maintain RCS and reactor vessel integrity

By following EI-1 which requires you to verify that all automatic actions have occurred (and initiate any that have not occurred) you are showing concern for the public. This is reinforced by taking the appropriate actions to stabilize the plant.

When you take the correct actions to establish core cooling (forced or natural circulation) and 40°F subcooling you have addressed the second major concern.

Finally, by monitoring reactor coolant system temperature and pressure and cooldown rate, you are prepared to address the third concern. Keeping the temperature and pressure within the bands of the cooldown curve and taking actions to avoid repressurization following a thermal transient (due to cooldown) will reduce the possibility of compromising reactor vessel integrity.

Understanding the reasons for each step in EI-1 will help you to correctly respond to reactor coolant system depressurization events. Make every effort to understand <u>why</u> you take an action <u>when</u> you are required to take that action by procedure.

CP&L

H. B. ROBINSON
SEG PLANT

TITLE

H. B. ROBINSON STEAM ELECTRIC PLANT

UNIT NO. 2

EMERGENCY INSTRUCTION - 1

INCIDENT INVOLVING REACTOR COOLANT SYSTEM DEPRESSURIZATION

REVISION 19

REV.	APPROVED BY	DATE	REV.	APPROVED BY	DATE	REV.	APPROVED BY	DATE
20	RBS/[illegible]	3-13-80	27	RBS/ms	4-30-81			
21	RBS/ms	4-8-80	28	RBS/ms	6-02-81			
22	RBS/ms	6-20-80	29	RBS/ms	11-13-81			
23	RBS/ms	9-27-80	30	RBS/ms	4-27-82			
24	RBS/ms	3-17-81						
25	RBS/ms	3-26-81						
26	RBS/ms	4-16-81						

Recommend By: [illegible signature] 12-31-79
Operating Supervisor - Unit No. 2 DATE

Approved By: [illegible signature] 12/31/79
General Manager DATE

Table Of Contents - E. I. - 1

A. DISCUSSION

The behavior of many nuclear plant parameters, which the operator can observe in the Control Room, will be similar in many respects following either a loss of reactor coolant, steam line rupture or steam generator tube rupture. For instance, the symptoms of all three accidents which should immediately become apparent to the operator are falling pressurizer pressure and level, and in the case of slower accidents, increased charging pump speed and turbine runback on ΔT protection prior to trip. The operator must accurately determine the accident type as soon as possible so that he can carry out the required checks and initiate the relevant recovery procedure. A brief description of the accidents and objects of the recovery procedure are given below.

1. Loss of Coolant

This emergency results in a breach of the primary pressure boundary such that maximum charging flow and reactor coolant pump seal injection flow can no longer maintain pressurizer level. A safety injection and a reactor trip will be initiated by the falling pressurizer pressure on a time scale which is dependent upon the magnitude of the break. Injection flow will increase with decreasing reactor coolant system pressure. The accumulators will automatically discharge their fluid inventory when the reactor coolant system pressure drops below the accumulator pressure. In the case of rapid depressurization leading to very low reactor coolant system pressure, the residual heat removal pumps will commence injection and refill the reactor vessel.

pb

A. DISCUSSION (Continued)

Analysis has shown that a small break is the worse case break for this design. This is primarily due to the very large mass loss prior to actual injection of replacement fluid. The "hanging-up" of pressure is caused by the pressurizer, similar to its normal control mode. Reactor coolant pumps are tripped at 1300 psig to prevent long term core uncovery during a "worse-case" small break. Long term control and cooldown of the reactor coolant system is achieved through recirculation of spilled reactor coolant from the containment sump. This is carried out by the residual heat removal pumps and the Safety Injection Pump taking suction from the outlet of the residual heat exchangers. Containment pressure increases due to the release of energy from the reactor coolant system to the containment. Containment isolation, phase A, and containment ventilation isolation will result from the safety injection signal at 4 psig. Spray actuation and containment isolation, phase B, will occur at approximately 50% containment design pressure (20 psig).

The main functions of the operator in this type of accident is (1) to insure all automatic actions have occurred, (2) to carry out the change-over from the injection phase to the recirculation phase, (3) to check for possible existence of a leak in an injection line and (4) to carry out the relevant isolation procedure.

The volume of water in containment may be determined by referring to Curve No. 7.2 in P.O.M. Volume 15 based on the containment water level readings. Also, the equipment possibly affected by the water level may be determined by referring to the In-Containment Equipment Elevation List in Appendix A of S.D.-35.

A. DISCUSSION (Continued)

2. Loss of Secondary Coolant

This emergency is the result of a break in a main steam, feedwater or blowdown line and will result in a reduction in reactor coolant temperature and pressure at a rate which is dependent upon the size and location of the break. The reactor automatic protection system is designed to shut the plant down safely. The action of the safety injection system in pumping boric acid to the reactor coolant system will ensure continued shutdown.

In the case of a full blowdown of one steam generator (this results from either a break upstream of a main steam isolation valve or a break downstream of the main steam isolation valves coupled with one failed main steam isolation valve), reactor coolant temperatures and pressures will have fallen to the region of 400°F and 700-1000 psig in two or three minutes and safety injection flow will be underway. Some voids will form but will not interfere with cooling. The continued action of safety injection will tend to re-pressurize the reactor coolant system to the shut-off head of the safety injection pumps with little change in reactor coolant temperature. At this stage, water level will have returned in the pressurizer and in fact the pressurizer may be full of subcooled fluid and noncondensible gases. The subsequent course of the accident would be for the reactor coolant system temperatures and pressure to increase under the influence of residual heat. → DELETE

A. DISCUSSION (Continued)

If no action is taken to reduce the temperature of the good steam generator by steam dump, the reactor coolant system will be re-pressurized to the pressurizer safety valve setting (2485 psi) with discharge of reactor coolant to the pressurizer relief tank with subsequent release to the containment. If the reactor coolant system has cooled down significantly during the accident (to 350°F or less), repressurization all the way to the shut off head of the S.I. pumps could challenge reactor vessel integrity. Operator action should therefore aim to eliminate, or at least minimize, these effects by dumping steam from the good steam generators to maintain temperature. At an early stage in the accident, the operator must also isolate auxiliary feedwater flow to the faulty steam generator to protect it from thermal shock, to prevent excessive cooldown of the reactor coolant system, and prevent excessive auxiliary feedwater spillage to the defective loop.

3. Steam Generator Tube Rupture

This accident results in leakage of reactor coolant into the plant steam system and as a result, pressurizer pressure and level will decrease leading to a low pressure reactor trip. The cooldown following plant trip will further decrease pressurizer pressure and actuate safety injection. Pressurizer level indication may be lost and require use of spray or the PORV's to return on scale. If the reactor coolant pumps are operating, the spray will collapse the bubble and safety injection will refill the pressurizer. Use of the pressurizer PORV's is necessary if normal spray is not possible. The relief tank will collapse the bubble in much the same manner as spray. Auxiliary spray should never be used when letdown is isolated due to increased stress on piping and the pressurizer vessel as cold water enters. After passing through a minimum pressure, dependent upon the size of the leak, the reactor pressure will increase to a stable value of about 1400 psi by the continued action of safety injection. In the absence of action by the operator, continued leakage into the steam generator together with auxiliary feedwater flow would result in the steam generator water level rising into the steam lines of the faulty steam generator as it becomes water solid.

A. DISCUSSION (Continued)

Operator action should aim to minimize the contamination of the steam system and water carryover by prompt isolation of the faulty steam generator. To achieve this, steam dump must be carried out using all steam generators initially and auxiliary feedwater flow to the faulty steam generator should be cut-off when it has been identified.

The reactor automatic protection equipment is designed to shut the plant down safely in the event of any of the above emergencies. The safety injection system is designed to provide emergency core cooling and to maintain the reactor shutdown.

The plant safeguards systems operate from offsite power or from on-site emergency diesel power if offsite power is not available.

4. Recovery

Due to the inability to develop an emergency procedure that would totally apply to every possible sequence of events during a plant transient or event, specific plant recovery methods may have to be developed on a case by case basis. For example, it may become desirable to terminate safety injection under conditions other than those described in this procedure, or restart one or more reactor coolant pumps if they were secured during the initial transient. (Forced circulation is the preferred method of plant cooldown. It may be desirable to restart a RCP. If plant pressure and temperature control have stabilized, subcooled conditions exist, and pump operating requirements can be met.) Deviations from the plant emergency procedures must be reviewed and approved by the appropriate members of plant management. Consultation with the applicable vendors and/or the NRC may be desirable and prudent.

pb

B. SYMPTOMS

The following symptoms may arise in a plant which has undergone or is undergoing one of the above accidents.

1. Pressurizer Low Pressure Alarm and Indication.
2. Pressurizer Low Level Alarm and Indication.
3. Low Tavg Alarm and Indication.
4. High Containment Pressure Alarm and Indication.
5. Containment High Radiation Monitor Alarm, R-2, R-7, R-11 & R-12.
6. Condenser Air Removal Equipment Radiation Monitor Alarm, R-15.
7. Steam Generator Blowdown High Radiation Alarm, R-19.
8. Containment High Sump Level Indication.
9. Rapidly Decreasing Reactor Coolant Average Temperature.
10. Steamline Low Pressure Alarm and Indication.
11. Steamline High Flow Alarm and Indication.
12. Low Steam Generator Water Level Alarm and Indication.
13. Steam Flow/Feedwater Flow Mismatch Alarm and Indication.
14. High Steam Line Differential Pressure Alarm and Indication.
15. Increased Charging Pump Speed.
16. Pressurizer PORV Line High Temperature Alarm and Indication.
17. Pressurizer PORV Position Indication and Annunciator Alarm.
18. Safety Valve Line High Temperature Alarm and Indication.
19. Pressurizer Relief Tank High Temperature Alarm and Indication.
20. Pressurizer Relief Tank High Level Alarm and Indication.
21. Pressurizer Relief Tank High Pressure Alarm and Indication.
22. Pressurizer Safety Relief Valve Open and Annunciator Alarm.
23. Auxiliary Feedwater Flow Indication.
24. Increasing Containment Hydrogen Concentration.

B. SYMPTOMS (Continued)

NOTE: Many of the process variables noted above are typically monitored by more than one channel. Always verify indication on redundant channels.

NOTE: There are situations when the pressurizer water level indication is not a valid indication of primary system inventory such as a stuck open pressurizer PORV or when a steam bubble exists in the reactor vessel head or steam generator U-tubes. Therefore, this level indication should always be used in conjunction with other system indications to verify primary coolant inventory.

C. IDENTIFICATION OF ACCIDENT TYPE

The manual actions and precautions in Section E & F are those which require the operator's immediate attention in the event of a large loss of reactor coolant or secondary fluid leading to rapid reactor trip and actuation of safety injection. The operator will determine the accident type subsequently. However, in the event of a slow transient in which reactor trip is delayed for a few minutes, the operator may be able to decide which type of fault has occurred prior to reactor trip and initiation of safety injection.

1. After Reactor Trip and S.I. Actuation: (Refer to Figure 1).
   a. Observe the steam pressure in the steam generators.
   b. If the pressure is rising or normal in the steam generators together with low pressurizer pressure, the accident is either a loss of coolant accident or a steam generator tube rupture. These can be distinguished as follows:
      1. If there is an increase in containment pressure, a containment high radiation alarm, rising sump water level or any combination of these symptoms, the situation is uniquely defined as a loss of coolant accident
      2. If there is a condenser air removal equipment radiation alarm or a steam generator blowdown radiation alarm, the accident is uniquely defined as a steam generator tube rupture.

pb

C. IDENTIFICATION OF ACCIDENT TYPE (Continued)

c. If the pressure is abnormally low in one or more steam generators, coincident with low pressurizer pressure and level, the accident is a main steam line break.

In the case of a steam break, the approximate break location may be determined as follows:

1. All main steam isolation valves closed and similar behavior in each steam generator indicates that the break is downstream of these stop valves.
2. Pressure in one steam generator substantially lower than the others together with rising containment pressure indicates that the break is in the lower pressure steam line and inside the containment.
3. As in (2) above but with no increase in containment pressure, containment sump level, and with all main steam isolation valves closed indicates a break in the lower pressure steam line outside the containment and upstream of the main steam isolation valves.
4. As in (3) above with only two main steam isolation valves closed invokes two possibilities. (1) If the lower pressure steam line is one with a closed main steam isolation valve, the break is outside the containment and upstream of the closed main steam isolation valve, (2) If the higher pressure steam lines contain the closed valves, the break is outside the containment but not upstream of the closed main steam isolation valves.

NOTE: An operator can be dispatched to verify Items 3 & 4.

C. IDENTIFICATION OF ACCIDENT TYPE (Continued)

2. Before Reactor Trip and S.I. Actuation

In a slow loss of coolant accident or a steam generator tube rupture, Tavg will vary very little and a ΔT protective runback may occur before reactor trip whereas a definite and continuous decrease in Tavg will be observed in the steam break accident. The loss of coolant accident and the tube rupture accident can then be differentiated as described in Figure 2.

pb

FIGURE 1

AFTER REACTOR TRIP & "S" SIGNAL

Low or falling pressurizer pressure & level*

Abnormally low steam pressure in one or more steam generators indicates steam break.

Verify by checking for:

1. Lower than normal steam generator levels.
2. A possible first out annunciation of:
   a) steam/feedwater flow mismatch
   b) low-low steam generator water level.
   c) high steam line flow.
   d) high steam line differential pressure.

Go to detailed recovery procedure in Emergency Instruction, Appendix B.

Rising or normal steam pressure in steam generators indicates loss of coolant or tube rupture.

Either increasing containment pressure or containment high radiation alarm or rising sump water level indicates a loss of coolant.

Go to detailed recovery procedure in Appendix A.

Condenser air removal equipment radiation alarm or steam generator blowdown radiation alarm or possible observed differential rate of rise of steam generator levels.

Go to detailed recovery procedure in Appendix C.

*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

BEFORE REACTOR TRIP & "S" SIGNAL

Low or falling pressurizer pressure & level*

Continuously decreasing Tavg indicates a steam break.

Check for possible decrease in steam generator pressure or imbalance in pressures or flows

Go to detailed recovery procedure in Appendix B.

Substantially constant Tavg indicates loss of coolant or tube rupture.

Either rising containment pressure or radiation indicates a loss of coolant. High level, temp., and pressure in the PRT indicates loss of coolant through PORV's or safeties.

Go to detailed recovery procedure in Appendix A.

Condenser air removal radiation alarm or steam generator blowdown radiation alarm indicates a steam generator tube rupture.

Go to detailed recovery procedure in Appendix C.

*Pressurizer level may not fall if the loss is in the steam space of the pressurizer.

D.1 AUTOMATIC ACTIONS FOLLOWING THE GENERATION OF THE SAFETY INJECTION SIGNAL

a. Reactor trip, resultant turbine trip.

b. Normal feedwater isolation to the steam generators results in:

1. Steam generator main feedwater pumps trip out of service.

2. Steam generator main block, feed regulator, and bypass feedwater valves close.

c. Both diesel generators start and come up to speed.

d. The non-essential breakers will trip to prepare 480V Bus E1 and 480V Bus E2 for the subsequent safeguards starting sequence.

NOTE: If a site blackout should occur during the interval between SI initiation and reset, the equipment start sequence may not reactivate. It will then be necessary to manually reinitiate the SI sequence as conditions dictate.

e. The following valves are actuated to the position indicated below at the initiation of the safeguards components starting sequence.

1. The boron injection inlet and discharge valves SI-867A, SI-867B, 870A, and 870B are opened.

2. Core deluge valves from the residual heat removal pumps RHR-744A and RHR-744B are opened.

3. The boron injection tank recirculation return valves SI-841A and SI-841B are closed.

f. Safeguards equipment for the injection phase will receive a signal to start sequentially in the following order:

pb

TRAIN A (Safeguards Bus E-1 Energized)

1. Safety Injection Pump A
2. Safety Injection Pump B
3. Residual Heat Removal Pump A
4. Service Water Pump A and Service Water Booster Pump A
5. Service Water Pump B
6. Containment Fan HVH-1
7. Containment Fan HVH-2
8. Auxiliary Feedwater Pump A

TRAIN B (Safeguards Bus E-2 Energized)

1. Safety Injection Pump C
2. (If Bus E-1 is not energized safety injection pump B is running with Train B)
3. Residual Heat Removal Pump B
4. Service Water Pump C and Service Water Booster Pump B.
5. Service Water Pump D
6. Containment Fan HVH-3
7. Containment Fan HVH-4
8. Auxiliary Feedwater Pump B

g. The containment isolation, phase A, signal will be generated and close the following isolation valves:

CVC-200A	Letdown orifice isolation
CVC-200B	Letdown orifice isolation
CVC-200C	Letdown orifice isolation
CVC-204A	Letdown line isolation
CVC-204B	Letdown line isolation
PS-956A	Sample line isolation (pressurizer steam)
PS-956B	Sample line isolation (pressurizer steam)
PS-956C	Sample line isolation (pressurizer liquid)
PS-956D	Sample line isolation (pressurizer liquid)
PS-956E	Sample line isolation (hot leg)

pb

D.1 g. Continued

PS-956F	Sample line isolation (hot leg)
PS-956G	Sample line isolation (accumulator)
PS-956H	Sample line isolation (accumulator)
RC-HC-516	Pressurizer relief tank to gas analyzer
RC-HC-519A	Primary water to pressurizer relief tank
RC-HC-519B	Primary water to pressurizer relief tank
RC-HC-553	Pressurizer relief tank to gas analyzer
CC-HC-739	Component cooling from excess letdown heat exchanger
SI-855	Nitrogen supply for the accumulators
FP-248	Fire Protection Containment Isolation
FP-249	Fire Protection Containment Isolation
FP-256	Fire Protection Containment Isolation
FP-258	Fire Protection Containment Isolation
WD-1721	Reactor coolant drain tank pump discharge
WD-1722	Reactor coolant drain tank pump discharge
WD-1723	Containment sump to waste holdup tank
WD-1728	Containment sump to waste holdup tank
WD-1786	Vent header from reactor coolant drain tank
WD-1787	Vent header from reactor coolant drain tank
WD-1789	Gas analyzer from reactor coolant drain tank
WD-1794	Gas analyzer from reactor coolant drain tank
SGB-FCV-1930A	Steam generator A blowdown line
SGB-FCV-1930B	Steam generator A blowdown line
SGB-FCV-1931A	Steam generator B blowdown line
SGB-FCV-1931B	Steam generator B blowdown line
SGB-FCV-1932A	Steam generator C blowdown line
SGB-FCV-1932B	Steam generator C blowdown line
SGB-FCV-1933A	Steam generator A sample line

pb

D.1 g. Continued

SGB-FCV-1933B	Steam generator A sample line
SGB-FCV-1934A	Steam generator B sample line
SGB-FCV-1934B	Steam generator B sample line
SGB-FCV-1935A	Steam generator C sample line
SGB-FCV-1935B	Steam generator C sample line
RC-550	N_2 supply to Pressurizer Relief Tank
RM-1	Radiation Monitoring Pump outlet
RM-2	Radiation Monitoring Pump inlet
RM-3	Containment Outlet
RM-4	Containment Inlet

h. The containment isolation phase A signal, initiates Isolation Valve Seal Water System (IVSWS) by opening valves IVSW-PCV-1922A and IVSW-PCV-1922B.

i. The containment ventilation isolation signal will be generated and the following isolation valves will close.

HVAC-V12-6	HVAC-V 12-13
HVAC-V12-7	HVAC-V 12-10
HVAC-V12-8	HVAC-V 12-11
HVAC-V12-9	HVAC-V 12-12

j. The steam driven auxiliary feedwater pump will start automatically on loss of voltage on 4160 V busses 1 and 4 or Lo-Lo level in two steam generators.

k. Each accumulator will begin discharging its contents to its respective loop when the RCS pressure drops below the gas pressure in the accumulator.

D.1 l. The control room ventilation isolation signal will be generated, tripping HVE-16, starting HVE-19; closing the intake damper to HVA-1 and opening the bypass damper for HVE-19.

m. Verify that heat is being removed from the RCS through the steam generator by noting automatic steam dump to the condenser or to atmosphere and that the average coolant temperature decreases towards no-load (530°F).

n. Instrument air isolation to the containment (IA-1716) will close (may be overridden for operation of various pneumatic valves in the containment; if safety injection is reset then IA-1716 must be independently reset before it will reopen).

D.2 <u>AUTOMATIC ACTIONS FOLLOWING THE GENERATION OF THE HIGH-HIGH CONTAINMENT PRESSURE SIGNAL</u>

a. The spray pumps start and their discharge valves to the Containment, SI-880A, SI-880B, SI-880C and SI-880D open.

Spray additive tank discharge valves SI-845A and SI-845B will open.

b. Main steam isolation valves close.

c. The containment isolation phase B signal will be generated and close the following isolation valves:

CVC-381	Reactor coolant pumps seal water return line
CC-FCV-626	Reactor coolant pumps thermal barrier cooling water return line
CC-735	Reactor coolant pumps thermal barrier cooling water return line
CC-716A	Reactor coolant pumps cooling water inlet line
CC-716B	Reactor coolant pumps cooling water inlet line
CC-730	Reactor coolant pumps bearing oil cooler cooling water return line

pb

E. IMMEDIATE OPERATOR ACTIONS

If a safety injection signal has been generated or if indications suggest that a signal should have generated, but automatic initiation of safety injection has not occurred, manually initiate the safety injection signal, then;

1. Verify that reactor trip, turbine trip and safety injection have all taken place following the "S" signal.
2. Verify that containment spray has taken place following the Phase B "P" signal.
3. Verify that the safety injection system is pumping in boric acid from boron injection tank and from the refueling water storage tank.
4. Verify with the monitor lights that the valves associated with safety injection, Phase "A" and/or "B", are in the proper position after safety injection initiation. (Light indicates when valve is in safeguard position.)
5. Verify that the main feedwater pumps have tripped and that the auxiliary feedwater pumps and the respective automatic valves are actuated. Check the auxiliary feedwater flow indicators on the RTGB to verify auxiliary feedwater flow.
6. Check for proper operation of both diesel generators & emergency busses.
7. In the event that the safeguards equipment has not been properly actuated, the operator will place the equipment in operation manually.

pb

F. PRECAUTIONS AFTER A SAFETY INJECTION SIGNAL

1. Do not reset Safety Injection until the status of the safeguards equipment is to be changed, (i.e. stopping equipment or changing valve lineup).

2. If two residual heat removal pumps are operating, stop one for pump protection if the reactor coolant system pressure is still above 130 psig 15 minutes after the accident.

3. Do not terminate high head safety injection until:

   a. The reactor coolant pressure is greater than 1560 psig and increasing, and

   b. Pressurizer level is at no-load level and responding, and

   c. The water level in at least one steam generator is on narrow range span or in the wide range span at a level sufficient to assure that the U-tubes are covered, and

   d. At least 40°F of subcooling exists in the primary system.

      NOTE 1: If 40°F subcooling can not be maintained after termination of safety injection, manually re-initiate safety injection.

      NOTE 2: Stopping and starting of the SI pumps can cause pump motor overheating or reduced motor life. If the SI pumps are restarted once after termination, ensure the RCS is at least 65°F subcooled prior to the second SI termination.

F. PRECAUTIONS AFTER A SAFETY INJECTION SIGNAL (Continued)

4. As a minimum, operational decisions should be based on the following indications:

   a. Narrow range pressurizer pressure if available.

   b. RCS wide range temperature and pressure.

   c. Steam pressure.

   d. Steam generator water level and/or auxiliary feedwater flow.

   e. Containment pressure.

   f. RWST level.

   g. Condensate storage tank level.

   h. Pressurizer level.

5. The Diesel Generators are to remain in operation at synchronous speed until all safeguards equipment has loaded onto the emergency buses and the incoming power sources are verified to be properly aligned.

6. Insure that RCS depressurization is not due to the opening of one or both pressurizer PORV'S. If so, close the associated block valve.

7. If the reactor coolant pressure drops below 1300 psig, trip all coolant pumps to prevent long term core uncovery during a "worse case" small break. If the pressure remains above 1300 psig, at least two reactor pumps should continue to run to force flow through the core unless pump seal or motor destruction is imminent as noted by;

   a. RCS loop flow is extremely erratic and RCP vibration is beyond operating limits indicating excessive pump cavitation, or;

pb

F. PRECAUTIONS AFTER A SAFETY INJECTION SIGNAL (Continued)

b. Component cooling to the RCP is lost resulting in motor bearings approaching 200°F or windings approaching 248°F, or;

c. The No. 1 seal leakoff is not within the range of installed indication, or;

d. Seal injection flow or component cooling water lost to the thermal barrier causing pump bearing temperature to approach 200°F.

NOTE: The reactor coolant pumps can be restarted if the pressure transient is stabilized and subcooled conditions exist.

8. The operator should recognize that, while unlikely, the possibility of reference leg boiling exists in a depressurized pressurizer or steam generator. If reference leg boiling is suspected in a depressurized steam generator, the operator should use several other plant parameters such as auxiliary feedwater pressure, steam generator pressure, and RCS wide range temperature to verify the existance of water in one or more steam generators. For absolute determination of level after a high energy rupture, refer to Section G. Abnormal containment environments (high temperature, condensing steam) may cause level and/or pressure indicating instruments to fail.

9. Should a blackout occur during the injection phase prior to resetting the SI signal, manual action will be required to reload the safeguards equipment onto the emergency bus. A manual SI initiation can accomplish this action.

pb

F. PRECAUTIONS AFTER A SAFETY INJECTION SIGNAL (Continued)

10. During a LOCA, monitor the in core thermocouples frequently. If five incore thermocouples go off scale high (greater than 700°F) an inadequate core cooling situation exists. See Section H for recovery from an inadequate core cooling after a LOCA situation.

11. During a LOCA and the subsequent recovery, the reactor coolant system saturation monitor should be used as a rapid method of determining the pressure margin to saturated conditions (the monitor will give a direct indication of the difference between saturation pressure for the RCS temperature and actual RCS pressure), amount of subcooling in °F, and the effectiveness of the core cooling method (natural circulation, forced circulation, S.I., etc.). Always verify the indications of this monitor using other available plant instrumentation.

12. If it has been determined that the safeguards actuation is the result of equipment malfunction or human error and that operation of safety injection or containment spray is not necessary, refer to AP-25.

13. Initiate Emergency Plan, Volume 13, if necessary by definitions given in the plan.

14. Establish an open line of communication with the NRC within <u>one hour</u> after it has been determined that the reactor is not in a controlled or expected mode of operation.

15. If at least one reactor coolant pump cannot be restarted, refer to GP-5A for plant temperature and pressure control on natural circulation.

pb

G. STEAM GENERATOR AND PRESSURIZER INDICATED LEVEL CORRECTION PROCEDURE

The various level indicating instruments for the steam generators and pressurizer are calibrated for either normal operating conditions or cold shutdown conditions. Following a high energy line break in the containment, (steam line rupture, or LOCA) system pressures and containment temperature can vary significantly from the calibration reference values. This variation causes three separate but significant sources of error in indicated levels depending on the severity of the incident (reference leg heating, transmitter heating, and transmitter depressurization). The procedure outlined below will allow the operator to determine actual water inventories from indicated narrow range steam generator levels and the three normal operating (hot calibration) channels of pressurizer level. The effects on indicated level of abnormal containment temperature and abnormal component pressure are additive.

Methodology

1. Determine containment temperature, indicated narrow range steam generator levels and/or indicated pressurizer level.
2. If containment temperature is normal, (approximately 90°F) go to Step 5.
3. From Volume 15 (Curve Book), Curve 7.10, determine the correction factor (in % of level span) due to abnormal containment temperature. Note that there is one curve for the steam generators and a separate curve for the pressurizer.

pb

G. STEAM GENERATOR & PRESSURIZER INDICATED LEVEL CORRECTION PROCEDURE (Continued)

4. Subtract the correction factor from indicated level. Divide the result by 1.02 to account for an approximately 2% error due to transmitter heating. The result is component water level corrected for abnormal containment temperature only. If component pressure is at its normal operating pressure, omit Step 5.

5. From Volume 15 (Curve Book), Curve 7.11 (for the steam generators) or Curve 7.12 (for the pressurizer) determine true component water level. Use the level determined in Step 4 above as indicated level (horizontal axis) when entering the curve. If containment temperature is normal, enter the curve with instrument indicated level directly. (Steps 3 and 4 need not be performed). Interpolate the component pressure curves provided if necessary.

pb

H. INADEQUATE CORE COOLING AFTER A LOCA

The following indications can be used to verify and/or determine a loss of core cooling capability.

- Rapidly increasing or excessively high ΔT due to the loss of natural circulation.
- Decreasing steam generator pressure at elevated primary temperature while steaming the generators. This is a result of a loss of energy transfer between the primary and secondary plant.
- Abnormal increase in source and intermediate nuclear instrumentation due to void formation in the core causing a loss of shielding.
- Incore thermocouples or wide range temperature instrumentation indicating saturation temperature or greater.
- Five incore thermocouples indicating off scale (greater than 700°F).
- Available indications on the Reactor Coolant System saturation monitor.

To recover from this condition, the following general steps should be taken:

1. Continue to provide constant safety injection and/or charging flow to the RCS, and maintain the water inventory in all operable steam generators.
2. Monitor primary temperatures to determine the effectiveness of subsequent actions.
3. Depressurize the RCS by:
   a. Dumping steam to the condenser or atmosphere, or;
   b. Open a pressurizer PORV with safety injection and/or charging flow available.

   NOTE: Use the pressurizer PORV as a last choice to depressurize.

pb

H. INADEQUATE CORE COOLING AFTER A LOCA (Continued)

4. If no means for RCS depressurization are available or effective, then start a reactor coolant pump, if possible.

The most likely source of inadequate cooling is void formation due to saturation conditions or non-condensible gas formation in the coolant system. With a gas bubble located in the upper reactor vessel head, several methods of core cooling are unaffected.

1. The steam generators can be used to remove decay heat using reactor coolant pumps forced flow or natural circulation.
2. The safety injection system can be used to cool the core while venting through the pressurizer power operated relief valve. Core cooling by any of these methods can proceed indefinitely if the primary coolant pressure is held constant.
3. If a lower system pressure is desired, a controlled depressurization will allow the bubble to grow slowly until it uncovers the top of the hot legs.

   This controlled depressurization can be performed in two ways:

   a. If the reactor coolant pumps can be operated, depressurization can be performed with a steam bubble in the pressurizer. Depressurization would be through the pressurizer power operated relief valve. Extra control is achieved with the pressurizer heaters and sprays if available. As the bubble grows to the top of the hot leg, small bubbles are carried through the system. Degassing is done with the spray line and/or the Chemical and Volume Control System. The steam generators will carry away decay heat.

pb

H. INADEQUATE CORE COOLING AFTER A LOCA (Continued)

b. If the reactor coolant pumps cannot be operated or their operation is undesirable, the pressurizer can be made water solid with the safety injection pumps running and the power operated relief valve. Depressurization is controlled by judicious use of the various valves, lines and pumps available in the safety injection system and the pressurizer relief valve. As the bubble grows to the top of the hot leg, it slides across the hot leg and up into the steam generators. As depressurization continues, the gas bubbles grow in the steam generators and the upper head but the core remains covered and cooled by safety injection water. If there is enough gas, the pressurizer surge line would eventually be "uncovered". Some of the gas would burp into the pressurizer and out the valve. This burping process would continue until the system was at the desired pressure. At that time, the current cooling mode could be continued or the system could be placed in an RHR mode (special care is needed for operation).

Note that a gas bubble cannot be located in the steam generator with the reactor coolant pumps running. If a gas bubble forms in the steam generator during natural circulation, the reactor coolant pumps could be restarted for degassing or safety injection flow could be initiated with the power operated relief valve open. ΔT will become excessively large as natural circulation is lost. The steam generators will lose their ability to transfer heat, and will lose pressure rapidly under steaming conditions while primary temperature increases.

pb

Completed By________________

Approved By________________

Date________________

H. B. ROBINSON STEAM ELECTRIC PLANT
UNIT NO. 2
APPENDIX "A" CHECKOFF SHEET

DETAILED RECOVERY PROCEDURE - LOSS OF REACTOR COOLANT

1.0 PURPOSE

This procedure is to be used to insure that proper cooling is provided to the core and the integrity of the reactor vessel is maintained after a safety injection occurs due to a loss of primary coolant. It is divided into the following sections:

(2) Injection Phase

(3) Initial Recirculation Phase

(4) Long Term Recirculating Phase

(5) Alternate Recirculation Flow Paths (Long Term Only)

(6) Cooling With Non-Condensible Gas Voids in the Reactor Coolant System

All precautions noted in Section F of E.I.-1 apply to this appendix. The magnitude of the coolant loss will be deciding factor in the use of the injection and cooling equipment.

2.0 INJECTION PHASE

2.1 Ensure the following has occurred:

2.1.1 Reactor and turbine trip. ________

2.1.2 SI equipment has started. ________

2.1.3 Feedwater has isolated. ________

2.0 INJECTION PHASE (Continued)

2.2 All SI valve status lights are energized. NOTE: De-energized valves will not have monitor lights energized. FCV-1436A and B do not necessarily energize. R-15 provides their actuation. ________

2.3 Verify that the following valves are in the position noted to insure injection flow reaches the core, log any discrepancies:

2.3 2.3.1	C.V. Sump to RHR Suction	SI-860 A	Closed	________
2.3.2	C.V. Sump to RHR Suction	SI-860 B	Closed	________
2.3.3	C.V. Sump to RHR Suction	SI-861 A	Closed	________
2.3.4	C.V. Sump to RHR Suction	SI-861 B	Closed	________
2.3.5	SI Pump Miniflow Recirc.	SI-856 A	Open	________
2.3.6	SI Pump Miniflow Recirc.	SI-856 B	Open	________
2.3.7	"A" RHR Pump Suction	SI-862A	Open	________
2.3.8	"B" RHR Pump Suction	SI-862B	Open	________
2.3.9	"A" RHR Pump Discharge to SI/Spray Suction	SI-863A	Closed	________
2.3.10	"B" RHR Pump Discharge to SI/Spray Suction	SI-863B	Closed	________
2.3.11	RWST to SI/Spray Suction	SI-864A	Open	________
2.3.12	RWST to SI/Spray Suction	SI-864B	Open	________
2.3.13	Hot Leg Injection	SI-866A	Closed	________
2.3.14	Hog Leg Injection	SI-866B	Closed	________
2.3.15	Hot Leg Injection Header	SI-869	Open	________

2.3.16 Safety Injection Flow Verified.

NOTE: The following valves are de-energized and have no status indication on the safe guards status panel; SI-865A, B, & C.

The following valves are de-energized and have no position indication; SI-878A & B.

2.0 INJECTION PHASE (Continued)

2.4 If containment spray has been initiated, verify the following equipment status:

	Containment Spray Status Lights Energized.		______
2.4.1	SI-844A A Spray Pump Suction Valve	Open	______
2.4.2	SI-844B B Spray Pump Suction Valve	Open	______
2.4.3	SI-845A Spray Additive Tank Outlet	Open	______
2.4.4	SI-845B Spray Additive Tank Outlet	Open	______
2.4.5	A Containment Spray Pump	Running	______
2.4.6	B Containment Spray Pump	Running	______
2.4.7	SI-845C Spray Additive Throttle Valve Adjusted to Deliver 12 GPM on FI-949.		______
2.4.8	Spray Flow verified.		______

2.0 INJECTION PHASE (Continued)

NOTE: Close valves SI-845A, B, & C when the level in the spray additive tank reaches 0%.

2.5 Verify that Control Room intake duct isolation has occurred and that emergency recirculation ventilation has been initiated. ______

2.6 The operator must recognize the possibility of forming voids in the primary coolant system large enough to compromise the core cooling capability, especially if natural circulation is used. Void formation can be minimized by maintaining RCS pressure with the safeguards equipment. Temperatures should be controlled at least 40°F below the saturation temperature for the RCS pressure. Refer to pressure/temperature curve 3.5 in Volume 15 (Curve Book).

2.7 For a coincident station blackout, the following additional actions are required:

2.7.1 Verify automatic start of the steam driven auxiliary feedwater pump and the opening of its automatic discharge valves. ______

2.7.2 Restart both battery charges. ______

2.7.3 Restart B & C component cooling pumps if no containment spray pumps are being powered by the diesels. ______

2.7.4 Restart A & B Instrument Air Compressors. ______

pb

2.0 INJECTION PHASE (Continued)

2.8 The following steps are to be performed on an as necessary basis depending on the severity of the coolant loss. Conditions for altering equipment status are stated in precautions, Section F of E.I.-1.

2.8.1 Reset safety injection signal if equipment is to be stopped.

2.8.2 If all safeguards equipment has completed loading on emergency buses, the power sources are verified to be properly aligned, starting air receivers have repressurized, and a blackout did not occur, shut down the diesel generators.

2.8.3 If two (2) residual heat removal pumps are operating and reactor coolant system pressure is greater than 130 psig 15 minutes after the accident, stop one RHR Pump. (The second pump may be stopped at 30 minutes provided it is not expected to provide cooling flow in the immediate future.)

2.8.4 If the reactor coolant pressure drops below 1300 psig, trip all coolant pumps to prevent long term core uncovery during a "worse case" small break. If the pressure remains above 1300 psig, at least two reactor coolant pumps should continue to run to force flow through the core unless pump seal or motor destruction is imminent as noted by:

pb

2.0 INJECTION PHASE (Continued)

a. RCP flow is erratic and pump vibration is excessive indicating pump cavitation, or;

b. Component cooling to the pumps is lost, resulting in motor bearing approaching 200°F, or winding approaching 248°F, or pump leakoff approaching 200°F, or;

c. The No. 1 seal leakoff is not within the range of installed indication.

d. Seal injection is lost and component cooling water is not available to thermal barrier.

2.8.5 Do not terminate high head safety injection unless:

a. The reactor coolant pressure is greater than 1560 psig and increasing, and

b. Pressurizer level is at no-load level and responding, and

c. Water level in at least one steam generator is on narrow range or in the wide range span at a level sufficient to assure that the U-tubes are covered, and

d. At least 40°F of subcooling exists in the primary system.

NOTE 1: If 40°F subcooling cannot be maintained after termination of safety injection, manually reinitiate safety injection.

NOTE 2: Stopping and starting of the SI pumps can cause pump motor overheating or reduced motor life. If the SI pumps are restarted once after termination, ensure the RCS is at least 65°F subcooled prior to the second SI termination.

2.0 INJECTION PHASE (Continued)

NOTE 3: If the loss of coolant appears to be large and the RHR system will be used for injection, go directly to Step 2.11.

2.9 If safety injection is terminated, place all safety injection pumps in standby mode and maintain operable safety injection flowpaths. If subcooled conditions can be maintained and plant pressure & temperature control can be returned to normal, continue plant operations in accordance with applicable G.P.'s or A.P.'s.

2.10 If pressure is decreasing slowly or has stabilized above the dead head pressure of the SI pumps and cannot be returned to normal range, use steam dump (pressure mode or atmospheric steam relief) and pressurizer pressure control (normal spray, auxiliary spray if available, or manual cycling of the pressurizer PORV). (Use of the PORV should only be used if both normal and auxiliary sprays are not available.) to decrease reactor coolant temperature and pressure. Do not use auxiliary spray as long as letdown is isolated to prevent thermal shock to the pressurizer. Maintain 40°F subcooling condition per Curve 3.5 of the Curve Book. If primary system temperature and pressure conditions violate the heatup and cooldown curves, restore conditions to maintain reactor vessel integrity by depressurization, if necessary.

NOTE: If RCP's are still operating their steam generator pressure is roughly the same as the RCS saturation pressure. If no RCP's are operating, good natural circulation can be assumed if the ΔT will vary proportionately with the amount of steam dump applied and the steam pressure does not rapidly decrease in an unexplainable manner in the steam generators.

NOTE: Natural circulation on 3 steam generators will develop a 50°F ΔT at 9% reactor power.)

he

2.0 INJECTION PHASE (Continued)

2.10.1 Sample S/G's as soon as possible. Log all results. Record any jumpers installed in the Jumper Log.

2.10.1.a To sample "A" S/G, run a jumper between terminal points 1 and 67 on Auxiliary Panel "MC".

2.10.1.b To sample "B" S/G, run a jumper between terminal points 1 and 69 on Auxiliary Panel "MC".

2.10.1.c To sample "C" S/G, run a jumper between terminal points 1 and 71 on Auxiliary Panel "MC".

2.10.1.d The switches on the steam generator blowdown and sampling panel in the Auxiliary Building across from the Sampling Room can now be used to obtain the samples.

NOTE: If there is no alarm condition existing on Radiation Monitor R-19, the S/G sampling valves will open as soon as the jumpers are installed.

2.10.2 If a leak exists that could endanger the site or general public, reduce RCS temperature to less than 500°F before closing MSIV's. ______

2.10.3 If the safety injection pumps have not already borated the reactor coolant system to cold shutdown, use the charging pumps to borate the system. ______

2.0 INJECTION PHASE (Continued)

2.10.4 Cooldown using applicable sections of GP-6 if the pressure and temperature can be controlled. Ensure that all steam generators are cooled to prevent their acting as pressurizers once the primary system pressure is reduced.

NOTE: Tripping of the RCP's is not required if the cooldown and depressurization can be controlled to maintain subcooled conditions.

pb

2.0 INJECTION PHASE (Continued)

2.11 Dispatch an operator to the pipe alley to isolate nitrogen to the reactor coolant drain tank, and open CV atmosphere post accident sample valves.

2.11.1	WDS-1793 Nitrogen supply to RCDT	Closed ______
2.11.2	VCT-18 Hi Point CV Sample Line Isol.	Open ______
2.11.3	VCT-19 Mid Point CV Sample Line Isol.	Open ______
2.11.4	VCT-20 Lo Point CV Sample Line Isol.	Open ______

2.12 If containment spray has been actuated, and if the containment pressure is reduced to less than 4 psi internal pressure, reset containment spray. Shut down the spray pumps and close the SI-880 valves. The spray should remain in standby mode.

2.13 If it appears that the loss of coolant cannot be terminated or stabilized without consuming the available contents of the RWST, proceed with alignment for recirculation. Initiate the alignment procedure no later than the point at which the refueling water storage tank reaches the low level alarm (27%). One of three safety injection pumps and one of two spray pumps have to be stopped at 27% on the RWST level.

NOTE: See Curve No. 7.2 in P.O.M. Volume 15 to determine the volume of water in containment based on the extended range water level indicators on the core cooling and containment panel. Also see the in-containment equipment elevation list in Appendix A of S.D.-35 to determine what equipment may be affected by the level of water in containment.

3.0 INITIAL RECIRCULATION PHASE

3.1 The maximum time between termination of the RHR flow during the injection phase and reinitiation of RHR flow on the recirculation phase should be less than ten (10) minutes to avoid damage to the fuel. Therefore, as much as possible of the alignment should be completed prior to stopping the injection phase.

3.2 On the "Safety Injection Valve Control Power Defeat Panel", located in the back of the RTGB, energize control power for the following valves:

3.2.1 SI-862 A & B Energized____________

3.2.2 SI-863 A & B Energized____________

3.2.3 SI-864 A & B Energized____________

3.2.4 SI-866 A & B Energized____________

NOTE: If operation of the following valves is required, the breakers on MCC-5 and MCC-6 must first be closed.

MCC-5	MCC-6
SI-865 A & C.	SI-865B
SI-878 A	SI-878 B

3.3 The operator on the control panel verifies that the controllers for RHR-605 and RHR-758 are in the closed position. ____________

3.4 Dispatch an available operator to enter the RHR heat exchanger room and align the following:

3.4.1 RHR-760 RHR Letdown to Purification Open ____________

3.4.2 CVC-205B RHR Letdown to Purification Open ____________

3.4.3 IA-291 Air Supply to RHR 605 Open ____________

3.4.4 IA-292 Air Supply to RHR 758 Open ____________

3.0 INITIAL RECIRCULATION PHASE (Continued)

3.5 When the low level alarm point (27%) is reached in the RWST, stop one of three safety, and stop one of two containment spray pumps to conserve the injection supply. ______

3.6 Align hot leg high head injection by first closing SI-869, then open both SI-866A and SI-866B.

3.6.1	SI-869 Hot Leg Injection	Closed	______
3.6.2	SI-866A Hot Leg Injection	Open	______
3.6.3	SI-866B Hot Leg Injection	Open	______

3.7 When the RWST reaches the low-low level alarm at 9%, stop the remaining safety injection pump, RHR pumps, and spray pumps. Complete the valve realignment for recirculation within 10 minutes.

3.7.1	Stop the operating safety injection pumps.			______
3.7.2	Stop the operating residual heat removal pumps.			______
3.7.3	Stop the operating containment spray pumps.			______
3.7.4	SI-856A	SI Miniflow Recirc.	Closed	______
3.7.5	SI-856B	SI Miniflow Recirc.	Closed	______
3.7.6	SI-864A	RWST to SIS	Closed	______
3.7.7	SI-864B	RWST to SIS	Closed	______
3.7.8	SI-862A	RHR Suction from RWST	Closed	______
3.7.9	SI-862B	RHR Suction from RWST	Closed	______
3.7.10	SI-863A	RHR to SI/RWST	Open	______
3.7.11	SI-863B	RHR to SI/RWST	Open	______
3.7.12	SI-860A	CV Sump to RHR Suction	Open	______
3.7.13	SI-860B	CV Sump to RHR Suction	Open	______
3.7.14	SI-861A	CV Sump to RHR Suction	Open	______

3.0 INITIAL RECIRCULATION PHASE (Continued)

3.7.15 SI-861B CV Sump to RHR Suction Open ________

3.7.16 RHR-759A RHR Outlet 'A' RHR Heat Exchanger Closed________

3.7.17 RHR-759B RHR Outlet 'B' RHR Heat Exchanger Closed________

3.7.18 CCW-749A Cooling Water for RHR Hx Open ________

3.7.19 CCW-749B Cooling Water for RHR Hx Open ________

3.7.20 RHR-FCV-605 RHR HEX Bypass Closed________

3.8 Verify that two (2) component cooling water pumps are operating. ________

3.9 Ensure that no low flow alarms are present on the component cooling to the following pumps:

Safety Injection Pumps ________

Residual Heat Removal Pumps ________

Spray Pumps ________

3.10 Start one (1) residual heat removal pump and two (2) S.I. Pumps. ________

CAUTION: The S.I. Pumps must be started as soon as possible after starting the RHR pump to prevent possible RHR pump damage. With valves RHR-759 A & B and FCV-605 shut, the RHR pump will run deadheaded until the S.I. pumps are started.

3.11 Verify the flow to the cold legs. FI-943________________GPM. ________

3.12 If containment spray is desired, start one (1) spray pump. Throttle flow to 1160 gpm as read on FI-958A or FI-958B by opening the discharge valve breaker at the desired flow. ________

3.0 INITIAL RECIRCULATION PHASE (Continued)

3.13 If it appears that the loss of coolant cannot be terminated or stabilized within 18 hours after the accident, continue the procedure for long term recirculation.

4.0 LONG TERM RECIRCULATION

4.1 Eighteen hours after the accident, the mode of recirculation must be changed to reduce the boron concentration in the reactor vessel. It has been estimated that the boron concentration would be approximately 23% at eighteen hours after a break on one of the cold legs. The flow path changes from cold leg injection to a split flow between hot and cold leg injection.

4.2 At eighteen hours after the accident, stop the operating safety injection pumps and the operating RHR pump. ________

4.3 Align for hot leg injection as follows:

4.3.1	SI-870A	BIT Outlet	Closed________
4.3.2	SI-870B	BIT Outlet	Closed________
4.3.3	SI-869	Hot Leg Injection	Open ________
4.3.4	Start an RHR Pump (See Caution Under Step 3.12)		________

4.4 Start two (2) safety injection pumps and verify flow on FI-940____________gpm. ________

4.5 Start the second RHR pump. ________

4.6 Align for cold leg injection using the residual heat removal system as follows:

4.6.1 Throttle RHR-759A by opening its breaker when the flow reaches 1100 gpm. ________

4.6.2 Throttle RHR-759B by opening its breaker when the flow increases to 2250 gpm. ________

4.7 The plant is now aligned for long term cooling.

pb

5.0 ALTERNATE RECIRCULATION FLOW PATH (LONG TERM ONLY)

5.1 In the event of a failure of a pump or flow path, this section provides alternate equipment or paths that may be substituted for the normal equipment.

5.2 "Failure of One of Two Residual Heat Removal Pumps".

5.2.1 Remove the affected pump from service. ________

5.2.2 Do not use the 744 valves as a flow path. Use only the high head injection lines. ________

5.2.3 Alternate every twelve (12) hours between hot and cold leg injection using the SI-870's for cold leg and SI-869 for hot leg. ________

5.2.4 Repair the affected pump and return to service using long term recirculation in section 4 of appendix A. ________

5.3 "Loss of High Head Hot Leg Recirculation".

5.3.1 Isolate the failed section of piping using SI-869 or other valves upstream. ________

5.3.2 Continue cooling through the RHR-744's and cold leg high head injection 870's. ________

5.3.3 The alternate flow path will be through letdown-purification from RHR and return through the hot leg charging line.

5.3.4 Align the CVCS letdown to receive the RHR flow, bypassing purification, reactor coolant pump seal injection, and the charging pumps as follows:

pb

5.0 ALTERNATE RECIRCULATION FLOW PATH (LONG TERM ONLY)

5.3.4.1 Isolate cover gas to the VCT. ________

5.3.4.2 Bypass and isolate the reactor coolant filter.
CVC-250 Open ________
CVC-249 Closed ________
CVC-253 Closed ________

5.3.4.3 Open "A" Charging Pump recirculation line.
CVC-277C Open ________

5.3.4.4 Isolate reactor coolant pump seal injection filters.
CVC-293B Closed ________
CVC-293D Closed ________

5.3.4.5 HCV-121 Charging flow control. Open ________

5.3.4.6 CVC-TCV-143 VCT/Demin. Diversion. VCT ________

5.3.4.7 Re-establish instrument air to containment.
IA-1716 Open ________

5.3.4.8 CVC-310A Hot Let charging. Open ________

5.3.4.9 CVC-310B Cold Leg charging. Closed ________

5.3.4.10 PCV-145 Letdown pressure control. Full Open ________

5.3.4.11 LCV-115A VCT/CVC HUT Diversion. VCT ________

5.3.5 Open RHR-HCV-142 letdown to purification to initiate flow. ________

5.3.6 Adjust RHR-HCV-758 and/or 744A and B to provide sufficient backpressure to force a flow of 50 to 100 gpm through the charging line. ________

pb

5.0 ALTERNATE RECIRCULATION FLOW PATH (LONG TERM ONLY) (Continued)

5.3.7 Repair, if possible, the normal hot leg injection line and return to service using long term recirculation in Section 4 of Appendix "A".

5.3.8 For informational purposes, a third option is available using the RHR pump recirculation line and backflow through RHR-750 and 751. However, radiation levels may be prohibitive in the pipe alley and RHR pit for valve alignment.

5.4 "Loss of High Head Recirculation".

5.4.1 Secure all safety injection pumps. ________

5.4.2 Continue cold leg recirculation with the residual heat removal pumps through RHR-744A and B. ________

5.4.3 Align the letdown purification system as in previous Section 5.3. ________

5.4.4 Continue recirculation in this manner until the high head pumps can be returned to service. ________

pb

Completed By:________________________

Approved By:________________________

Date:______________________________

H. B. ROBINSON STEAM ELECTRIC PLANT
UNIT NO. 2
APPENDIX "B" CHECKOFF SHEET
DETAILED RECOVERY PROCEDURE - STEAM LINE OR FEED LINE RUPTURE
(LOSS OF SECONDARY COOLANT)

1.0 PURPOSE

The objective of this checkoff is to protect the reactor core by:

1.1 Establish stabilized temperature and pressure conditions prior to plant cooldown.

1.2 Minimize the energy release due to the break.

1.3 Prevent the pressurizer safety valves from lifting by dumping steam from the good steam generators.

1.4 Isolate the auxiliary feedwater flow to the faulty steam generator to protect it from thermal shock and limit auxiliary feedwater flow to $\leq$400 gpm to the undamaged steam generators.

1.5 To borate the reactor coolant system and maintain reactor shutdown margin.

1.6 Maintain reactor vessel integrity by preventing pressurized thermal shock conditions.

2.0 INJECTION PHASE

2.1 Verify that steamline isolation has occurred. If not, manually initiate steamline isolation. ________

2.2 Do not reset Safety Injection until the status of the safeguards equipment is to be changed. ________

2.3 Verify that the steam dump valves and the atmosphere relief valves are closed to insure that the emergency has not resulted from an inadvertent opening of these valves. ________

2.4 The diesel generators are to remain in operation at synchronous speed until all safeguards equipment has loaded onto the emergency buses and the incoming power sources are verified to be properly aligned. ________

2.0 INJECTION PHASE (Continued)

2.5 It is important to recognize the possibility of forming voids in the reactor coolant system large enough to compromise the core cooling capability, especially if natural circulation is used. Void formation can be minimized by maintaining RCS hot and cold leg temperature at least 40°F below the saturation temperature for the existing RCS pressure. Refer to Pressure/Temperature Curve 3.5 in Vol. 15 (Curve Book).

2.6 If the reactor coolant pressure drops below 1300 psig, trip all reactor coolant pumps after safety injection pump operation has been verified. If the pressure remains above 1300 psig, at least two reactor coolant pumps should continue to run to force flow through the core unless pump seal or motor destruction is imminent as noted by:

a. RCS loop flow is extremely erratic and RCP vibration is beyond operating limits indicating excessive pump cavitation, or;

b. Component cooling to the RCP is lost resulting in motor bearings approaching 200°F or windings approaching 248°F, or;

c. The No. 1 seal leakoff is not within the range of installed indication, or;

d. Seal injection flow and component cooling water to the thermal barrier causing bearing temperature to approach 200°F.

2.7 Due to the arrangement of main steam isolation valves and check valves, it is impossible for more than one steam generator to blowdown to ambient pressure even in the event of failure of one main steam isolation valve. Therefore, determine if one steam generator has blowdown by observation of steam pressure and isolate the auxiliary feedwater flow to that steam generator.

CAUTION: To prevent the possibility of severe water hammer in the feedwater lines, prior to isolating auxiliary feedwater flow to the damaged S/G, secure <u>either</u> the steam driven AFW pump or <u>both</u> motor driven AFW pumps. This will limit flow to <u>each</u> of the good S/G's to $\leq$400 gpm.

pb

2.0 INJECTION PHASE (Continued)

2.8 Stop both residual heat removal pumps if RCS pressure is above 130 psig 15 minutes after the accident.

2.9 The drop in reactor coolant temperature reaches a minimum as the affected steam generator starts to "dry out". Temperature and pressure will tend to increase rapidly as the process progresses, therefore, it is imperative to establish steam dump from the "good" generators to stabilize temperatures and control repressurization of the primary system to ensure reactor vessel integrity. This can be done by using one of the following methods:

2.9.1 Use the atmospheric dump valves, or;

2.9.2 If the break is upstream of an MSIV and off-site power is available, reset the safety injection signal and steam line isolation. Open the MSIV's from the "good" steam generators and establish condenser vacuum and use the condenser dumps.

NOTE: Do not allow the RCS pressure to decrease to the steam pressure in the undamaged steam generators.

Subsequent actions to restore primary system pressure and temperature conditions in accordance with the heatup and cooldown curves (curves 3.3 or 3.4, Vol. 15, Curve Book) should be taken by reducing primary system pressure while avoiding further primary system cooldown.

2.10 Control level in the good generators using the auxiliary feedwater system.

2.11 Terminate sodium hydroxide addition if spray has been initiated. When containment pressure has been reduced to less than 4 psi internal pressure, reset spray, stop the spray pumps and close the SI-880 valves.

2.0 INJECTION PHASE (Continued)

2.12 Do not terminate high head safety injection until the precautions listed below have been reviewed and the necessary conditions met:

CAUTION: IF REACTOR COOLANT SYSTEM COLD LEG TEMPERATURE IS LESS THAN 360°F, SI MUST BE TERMINATED AS SOON AS SI TERMINATION CRITERIA ARE MET TO PROTECT REACTOR VESSEL INTEGRITY.

a.
- One wide range RCS Tc is less than 360°F, and
- Wide range RCS pressure is greater than 700 psig and is stable or increasing, and
- Pressurizer water level is greater than 20% and rising (heaters covered) and
- RCS subcooling is greater than 40°F, and
- Water level in at least one steam generator is in the narrow range span, or in the wide range span at a level sufficient to assure that the U-tubes are covered.

or

b.
- All wide range RCS Tc indicators are greater than 360°F, and
- RCS pressure is greater than 1560 psig and is stable or increasing, and
- Water level in at least one steam generator is in the narrow range span, or in the wide range span at a level sufficient to assure that the U-tubes are covered, and
- Pressurizer water level is greater than 50% of span, and

  NOTE: If C.V. pressure, radiation level and sump level indications are in the normal (pre-event) range, then a pressurizer level of 20% is acceptable due to the absence of an adverse C.V. atmosphere effect on the pressurizer level transmitters.
- The RCS subcooling is greater than 40°F.

2.0 INJECTION PHASE (Continued)

2.13 When SI termination conditions have been met, stop all SI pumps and close the SI-870's and SI-867's. Leave the injection system in standby.

CAUTION: Unless a controlled evolution is in progress, if RCS pressure decreases by greater than 200 psig from the value established in 2.12 a or b above, or pressurizer level decreases by 10% or more from the level established in 2.12 a or b above, manually reinitiate safety injection and/or restart any charging pumps that were secured to return RCS pressure to the value which existed when SI was reset (case 2.12a) or to 1560 psig (case 2.12b).

NOTE: Stopping and starting of the SI pumps can cause pump motor overheating or reduced motor life. If the SI pumps are restarted once after termination, ensure the RCS is at least 65°F subcooled prior to the second SI termination.

2.14 Re-establish normal makeup and letdown to maintain pressurizer level within the normal operating range.

2.15 Re-establish operation of pressurizer heaters after verification of sufficient level. Refer to Section G if elevated temperatures exist in containment.

2.0 INJECTION PHASE (Continued)

2.16 Verify that RCS boron concentration meets cold shutdown requirements.

2.17 If the RCP's were secured during earlier stages of the transient, restart at least one RCP in an intact loop (a loop with a spray line if possible) when RCS pressure and temperature have been stabilized, subcooled conditions exist, and RCP operating prerequisites are met.

2.18 After stabilizing the reactor coolant system temperature and pressure, proceed with plant cooldown using forced flow from the reactor coolant pumps or if a RCP can not be restarted, natural circulation. Refer to the applicable GP's.

pb

Completed By:____________________

Approved By:____________________

Date:____________________

H. B. ROBINSON STEAM ELECTRIC PLANT
UNIT NO. 2
APPENDIX "C" CHECKOFF SHEET
DETAILED RECOVERY PROCEDURE - STEAM GENERATOR TUBE RUPTURE

1.0 PURPOSE

This checkoff has been developed to achieve the following objectives:

1.1 To maintain core cooling by replacing excessive coolant loss and preventing the primary system from reaching saturation.

1.2 To reduce the reactor coolant system pressure below the steam generator atmospheric safety valve setting and minimize the discharge of radioactive material to the outside atmosphere.

1.3 To maintain the ability to remove the necessary residual heat from the reactor coolant system.

1.4 To maintain the system natural circulation by assuring sufficient overpressure over localized coolant fluid temperatures.

1.5 To prevent overflooding of the faulty steam generator and water-slugging the steam lines.

2.0 INJECTION PHASE

2.1 Do not reset Safety Injection until the status of the safeguards equipment is to be changed.

pb

2.0 INJECTION PHASE (Continued)

2.2 Reduce auxiliary feedwater flow as necessary to the steam generators to maintain minimum narrow range water level, or wide range level sufficient to assure that the U-tubes are covered, as no-load temperature and pressure are established.

NOTE: If the water level increases in one steam generator, completely isolate auxiliary feedwater flow to that steam generator.

2.3 If outside power is available, verify that condenser steam dump maintains the no-load Tavg. (or that the steam dump valves are closed if Tavg. is less than 547°F), and transfer steam dump to steam header pressure control. If off site power or the condenser is not available, use the steam generator PORV's to stabilize the RCS at approximately no-load temperature.

2.4 The diesel generators are to remain in operation at synchronous speed until all safeguard loads have been assumed by the emergency buses and incoming power supplies have been verified to be aligned properly.

2.5 It is important to recognize the possibility of forming voids in the reactor coolant system large enough to compromise core cooling capability through excessive use of RCS depressurization methods, especially if natural circulation is used. Void formation can be minimized by maintaining RCS hot and cold leg temperatures at least 40°F below the saturation temperature for the existing RCS pressure. Refer to Pressure/Temperature Curve 3.5 in Vol. 15 (Curve Book). Section 11 discusses the cooling of the reactor coolant system with voids present.

2.0 INJECTION PHASE (Continued)

2.6 Maintain RCS pressure and temperature within the limits shown on Curve 3.5.

2.7 If the reactor coolant pressure drops below 1300 psig, trip all reactor coolant pumps after safety injection pump operation has been verified. If the pressure remains above 1300 psig, at least two reactor coolant pumps should continue to force flow through the core unless pump seal or motor destruction is imminent as noted by:

a. RCS loop flow is extremely erratic and RCP vibration is beyond operating limits indicating excessive pump cavitation, or;

b. Component cooling to the RCP is lost resulting in motor bearings approaching 200°F or windings approaching 248°F, or;

c. The No. 1 seal leakoff is not within the range of installed indication, or;

d. Seal injection flow and component cooling water to the thermal barrier causing bearing temperature to approach 200°F.

2.8 Both residual heat removal pumps can be stopped if RCS pressure is above 130 psig 15 minutes after the accident.

pb

3.0 RECOVERY PHASE

3.1 Identify the steam generator with the ruptured tube by one or more of the following methods:

3.1.1 Steam generator samples or blowdown monitor R-19. To obtain either:

3.1.1.1 Reset containment isolation. ________

3.1.1.2 Alternately open the blowdown sample isolation to receive sample to R-19 or sample sink. ________

3.1.1.3 Identify the generator with high activity, ________ steam generator. ________

3.1.1.4 Manually isolate the blowdown and sample lines from the affecced steam generator. ________

3.1.2 An unexpected rise in one steam generator water level with AFW flow reduced or stopped. ________

3.2 Stop auxiliary feedwater to the faulty steam generator to prevent flooding. ________

3.3 Isolate main feedwater to the faulty steam generator. ________

3.4 Isolate the affected steam generator by closing its main steam isolation valve, its bypass valve, and its steam admission valve to the steam driven AFW pump. ________

NOTE 1: Cooldown must immediately follow step 3.4.

NOTE 2: The setpoint of the affected steam generator PORV should not be raised above 1000 psig. While a release to atmosphere would occur at a slightly lower pressure should the steam generator become overpressurized, the PORV is much more likely to reseat than a steam generator safety. Thus, any release that might occur is more likely to be terminated quickly.

3.0 RECOVERY PHASE (Continued)

3.5 Reduce system temperature and pressure using steam dump.

3.5.1 If off-site power is available, dump steam to the condenser. Ensure that the vacuum pump exhaust has been diverted to the plant vent. Maintain pressurizer level on scale through the use of normal spray or the PORV's, the SI pumps should continue to run throughout this phase to maintain pressure. ________

3.5.2 If blackout conditions exist:

3.5.2.1 Use atmospheric dumps on the two good steam generators. ________

3.5.2.2 Reestablish charging pump operation. ________

3.5.2.3 Reestablish power to station service bus 1, 2A, or 2B from offsite sources or the emergency diesels and energize pressurizer heaters per E.I.-7, Appendix "A". ________

3.5.2.4 Ensure that at least one component cooling water pump is in operation. ________

3.5.3 Continue steam dump until the reactor coolant average temperature is less than 480°F, (This corresponds to a steam generator pressure of 550 psig.). ________

NOTE: By cooling down with the steam generator isolated at approximately 530°F, its pressure will remain near 870 psig.

bs

3.0 RECOVERY PHASE (Continued)

3.6 Reduce reactor system pressure to approximately 870 psig as follows:

3.6.1 Manually initiate charging flow to the RCS from all available charging pumps. Do not reinitiate letdown.

NOTE: During controlled reactor coolant system depressurization, the 1300 psig reactor coolant system pressure criteria for tripping the reactor coolant pumps DOES NOT APPLY.

3.6.2 If the RCP's are in service, use the pressurizer spray to reduce the pressure.

3.6.3 If offsite power is not available, or the RCP's are not in service, open one pressurizer PORV to decrease pressure.

NOTE: If the pressurizer PORV is opened, an increase in pressurizer level is expected as liquid replaces the escaping steam.

3.6.4 Stop the depressurization operation if:

3.6.4.1 If the indicated water level in the pressurizer rises above 50% of span OR,

3.6.4.2 As soon as the reactor coolant system pressure decreases to a value equal to the faulted steam generator steam pressure.

3.0 RECOVERY PHASE (Continued)

3.6.5 After the depressurization operation has been terminated, monitor the system pressure and the pressurizer water level for the following:

3.6.5.1 If the pressurizer water level continues to rise or remains nearly constant concurrent with a reactor coolant system pressure decrease, suspect additional RCS leakage other than a steam generator tube rupture and investigate and correct as necessary.

3.6.5.2 If the pressurizer water level continues to increase concurrent with a reactor coolant system pressure increase, the safety injection flow is greater than the leak.

3.6.6 When reactor coolant system pressure has increased by at least 200 psi (after shutting the spray valve or verified closure of the pressurizer PORV) and an indicated water level has returned in the pressurizer, stop all operating safety injection pumps and charging pumps not needed for normal charging and reactor coolant pump seal injection flow.

CAUTION: Automatic reinitiation of safety injection will not occur since all actuating signals are not reset.

NOTE: Following termination of safety injection, pressurizer pressure should decrease to a value equal to the faulted steam generator steam pressure.

pb

3.0 RECOVERY PHASE (Continued)

3.6.7 Place all safety injection pumps in a standby mode and maintain operable safety injection flow paths.

CAUTION: If, during subsequent recovery actions, pressurizer water level can not be maintained above 20 percent indicated level, manually initiate safety injection flow to re-establish pressurizer water level in the operating range.

3.7 Re-establish letdown and normal charging to facilitate control and maintain pressurizer level in the operating range. Re-establish use of pressurizer heaters.

3.7.1 If the reactor coolant pumps are secured, establish the required conditions for operation of a reactor coolant pump and start the pump in a non-faulted loop (preferably in the loop connected to the pressurizer, or if this is the faulted loop, in the other loop to which a spray line is connected). If all reactor coolant pumps are running, trip all but one reactor pump so as to maintain one pump operating in the loop connected to the pressurizer, or if this is in the faulted loop, in the other loop to which a spray line is connected.

3.8 Isolate the supply and warmup steam to the steam driven auxiliary feedwater pump from the affected steam generator.

3.0 RECOVERY PHASE (Continued)

3.9 Proceed with plant cooldown using steam dump and the appropriate GP's. The primary pressure should not be allowed to exceed the pressure of the isolated steam generator while maintaining sub-cooled conditions.

NOTE: Throughout the cooldown (even after the plant is on RHR and the RCP's have been secured) maintain a steam bubble in the pressurizer. Solid water pressure control may not be effective.

3.10 Periodically sample the RCS boron to ensure that the affected steam generator is not diluting the coolant.

3.11 Simultaneous with the cooldown, slowly reduce the faulted steam generator's pressure by venting it through its bypass valve to the condenser. Monitor R-14 to ensure release limits are not exceeded (vacuum pump exhaust diverted to plant vent). This method can continue after vacuum is lost by operating the vacuum pumps and manually opening one steam dump valve. If the condenser is not available, use the affected steam generator's PORV to reduce its pressure as RCS pressure is lowered. (This will minimize leakage flow.)

3.12 An alternate method of disposing of the water in the affected steam generator so as to minimize the releases, is to allow it to drain into the RCS as it is cooled down and depressurized. Sufficient CVCS HUT capacity must exist to accept the additional water.

pb

3.0 RECOVERY PHASE (Continued)

Care must be taken to ensure the steam generator water does not dilute the RCS boron below the required concentration. Due to the lack of flow in the affected steam generator, the steam temperature in the affected generator will be higher than the remaining generators. Thus, level in the affected generator must be kept above the top of the U-tubes to prevent a rapid, unplanned steam generator depressurization caused by the hot steam coming into contact with the relatively cold U-tubes. If this method of disposing of the affected steam generator water is used, maintain level above the top of the U-tubes in the affected steam generator until the steam pressure is reduced to near atmospheric pressure.

pb

BASES FOR PTS-RELATED CHANGES TO EI-1 PROCEDURE

1. Tc will be used instead of Th as a dual criteria with RCS pressure for operator termination of SI following a loss of secondary cooling event.

   Basis - Tc is a more direct indication of the most severe temperature experienced by the reactor vessel inner wall during this event under the assumption that good mixing exists between SI flow and reactor coolant.

2. SI termination criteria for minimum RCS pressure will change based on value of Tc with respect to 360°F and for loss of secondary cooling events only.

   Basis - Fracture mechanics studies performed by Westinghouse indicate that for reactor vessel material temperatures below 350°F, brittle fracture is a concern for RCS pressures above 700 psig. In order to establish a conservative reference point for reactor vessel integrity, CP&L selected a temperature of 360°F which corresponds to an RCS pressure of 700 psig on the 100°F/hr cooldown curve. Purdent operation would dictate that operator action mitigate prolonged exposure of the reactor vessel to pressures in excess of 700 psig when Tc is less than 360°F. (700 psig equivalent to accumulator setpoint plus uncertainty.)

3. SI termination on RCS pressure is 700 psig for Tc less than 360°F and 1560 psig for Tc greater than 360°F for loss of secondary coolant.

   Basis - See item 2 for explanation of criteria for Tc less than 360°F. For Tc greater than 360°F the allowable pressure conditions for assuring reactor vessel integrity are not as stringent and 2000 psig was used previously in assessing SI termination. The 2000 psig criteria has been reduced to 1560 psig since this conforms more closely to the actual HBR SI pumps shutoff head plus uncertainty characteristics. The earlier 2000 psig criterion constituted a carryover from the small break LOCA event and the need to maintain subcooled core cooling and minimization of core voids. Specialnote should be taken that the dual SI termination criteria

is only applicable to EI-1, Appendix B. The operator also has gained additional margin to exceeding PTS conditions during a transient.

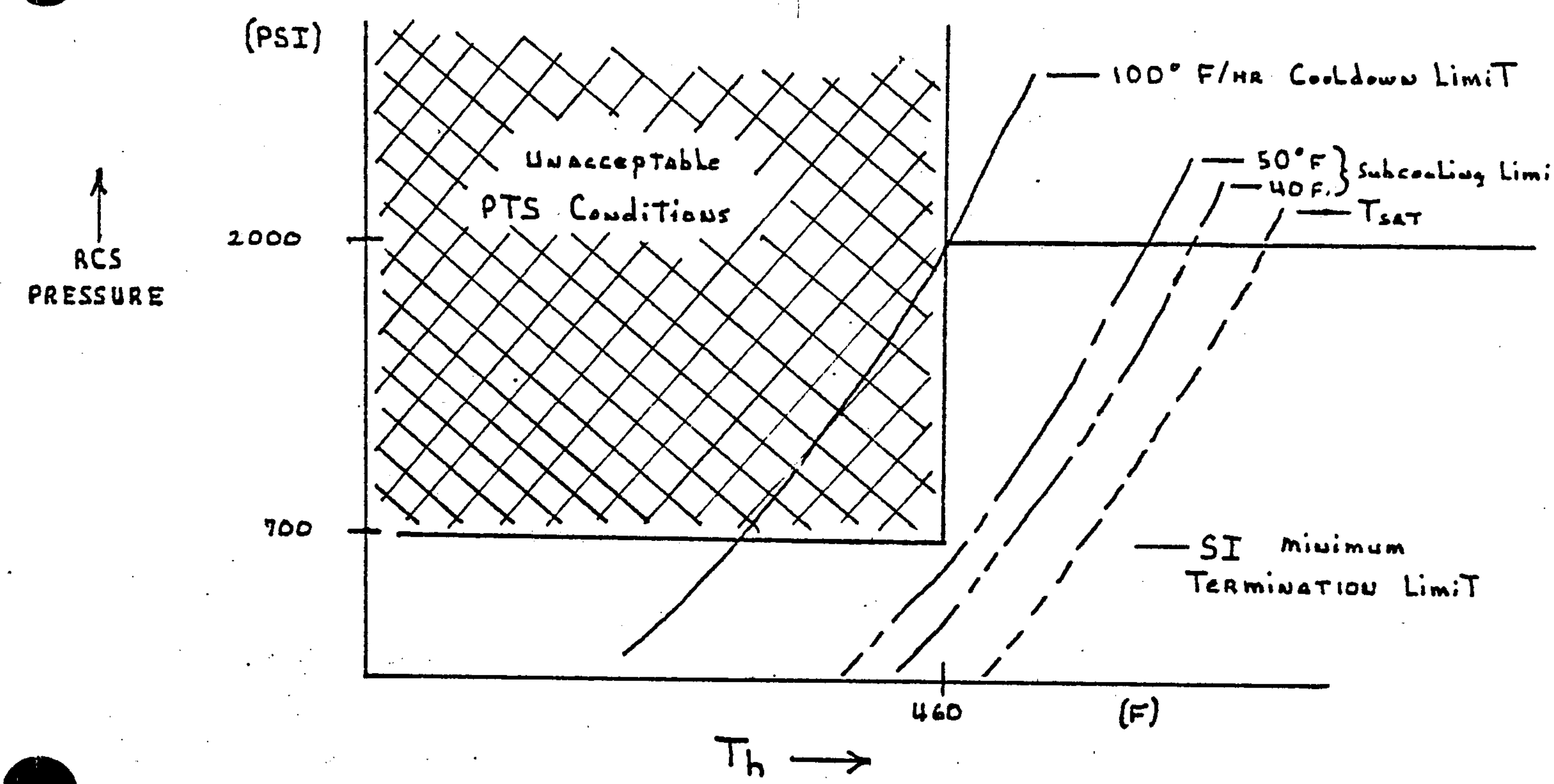
4. SI termination for LOCA events on RCS pressure has been reduced from 2000 psig to 1560 psig minimum pressure.

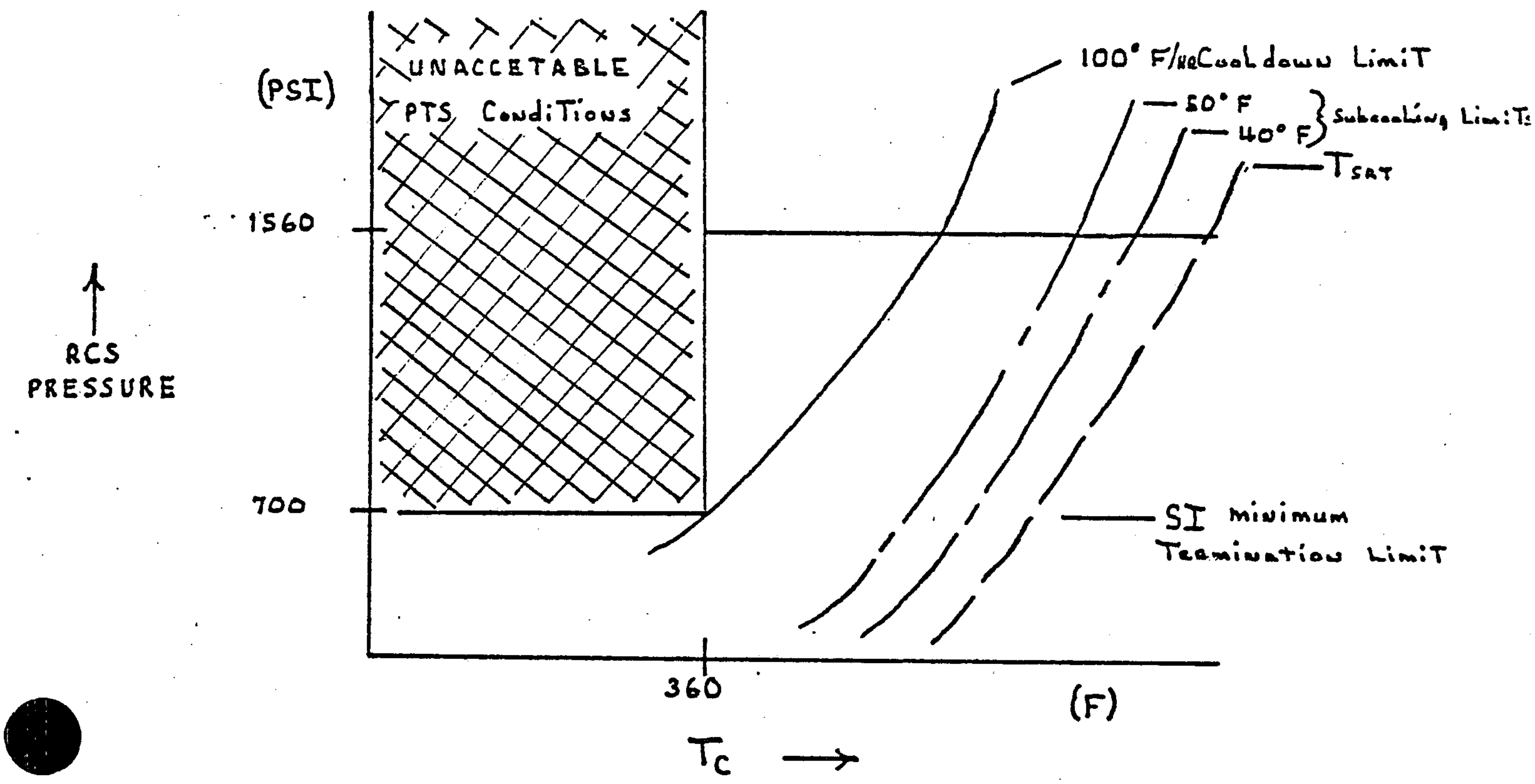
   Basis - This change is consistent with HBR SI pumps shutoff head plus uncertainty. Westinghouse has concurred with this change for plants with low head SI pumps. This change is more significant to the LOCA then other depressurization events since it addresses reactor vessel integrity through a significant reduction in SI termination pressure criteria and since no dual criteria exists as yet for low Tc.

5. Operator should restore RCS pressure and temperature within normal heatup/cooldown limits as soon as he can after transient condition stablizes if he is unable to do so earlier in transient.

   Basis - This should be normal operator response to any transient in addition to adequate core cooling.

I would recommend that you depict effect of these changes with regard to reactor vessel brittle fracture as follows:


(PSI)
RCS PRESSURE
2000
700
Unacceptable PTS Conditions
100° F/HR Cooldown Limit
50°F
40 F.
Subcooling Limi
TSAT
SI minimum Termination Limit
460
(F)
Th


(PSI)
RCS PRESSURE
1560
700
UNACCETABLE PTS Conditions
100° F/HR Cooldown Limit
50° F
40° F
Subcooling Limits
TSAT
SI minimum Termination Limit
360
(F)
Tc

Subject: Cold Pressurization of Reactor Coolant System

Reference: INPO/NSAC Significant Event Report 2-82
Turkey Point 4 Event in November 1981

Description: While in cold shutdown with the system solid at 106°F and 310 psig and on the residual heat removal (RHR) system, an RHR system inlet isolation valve closed due to a high pressure signal generated after starting a reactor coolant pump. This isolated the letdown path which connects directly to the RHR system. Since reactor coolant pump seal injection continued, system pressure increased to 1100 psig before the operator opened a relief valve. The overpressure mitigating system (OMS) did not automatically open a relief valve because a signal summator (Hagan Model #111, Part 411-084-004) had failed high, increasing the opening setpoint. Once the RHR system inlet isolation valve closed, an interlock prevented opening the isolation valve while the pressure exceeded 465 psig.

After restoring the system and plant parameters, a second RHR system inlet isolation valve closed two hours later at 355 psig due to a transmitter failure. Reactor coolant pump seal injection continued, and system pressure increased to 750 psig before the operator opened a relief valve. The transmitter failure was caused earlier by unintentionally hydrotesting the transmitter's sensor line with a leaking isolation valve to the transmitter.

Suggested Action:

Include this event in plant training as an example of the potential for overpressurizing the reactor vessel while cold and below the vessel's reference temperature for nil-ductility transition. In this case the overpressure protection system did not fuction because of an equipment failure. When in cold solid conditions, operators should not depend totally on the overpressurization protection system, but should also monitor RCS pressure and temperature conditons closely and be prepared to take necessary actions. A similar event at H. B. Robinson could entail considerable investigation and justification for a subsequent start-up because of the particular vessel chemistry and irradiation time. No action other than training emphasis appears necessary as it would require at least two failures to produce such an event.

C. IMMEDIATE ACTION

1. Automatic

   a. Reactor trip.

   b. Turbine trip.

   c. Automatic steam dump actuation.

   d. Generator breakers trip open after 1 minute time delay.

   e. Feedwater regulator valves close when Tavg decreases to 533.5°F.

2. Manual

   a. Check all control rods fully inserted (if reactor has not tripped perform Step 3 in addition to the following actions).

   b. Start a second charging pump.

   c. Check that turbine stop valves, governor valves, intercept and reheat valves are closed.

   d. Check that Tavg is decreasing.

   e. Insure auxiliaries shift to startup transformer and that generator lockout occurs 1 minute after reactor trip.

3. If the reactor did not trip automatically or more than one rod does not indicate in the bottom, perform any/or all of the following:

   a. Depress manual trip button (two available), or

   b. If manual trip did not function, immediately drive rods in manually, and

   c. Emergency borate in accordance with AP-2 and

   d. Trip Rx trip breakers and/or

   e. Trip rod drive MG sets motor and generator breakers and/or

   f. Trip rod drive MG sets from 480V buses.

tm

D. SUBSEQUENT ACTIONS

1. If the reactor trip is a result of safety injection refer to EI-1, Incident Involving Reactor Coolant System Depressurization; if the trip is a result of a loss of reactor coolant flow refer to EI-4, Loss of Reactor Coolant Flow; if the trip is a result of a loss of feedwater refer to EI-6, Loss of Feedwater; if at any time forced circulation is lost refer to GP-5A, Plant Temperature and Pressure Control using Natural Circulation.
2. Check Tavg approaching no load Tavg of 530°F. Avoid allowing the transient to bring Tavg below 530°F.
3. Insure pressurizer level returns to no load level 39.2%.
4. Check main feedwater control valves are closed when Tavg reaches 53[illegible].5°.
5. Identify reactor trip prior to resetting first out annunciators.
6. Transfer control of steam dump to main steam header pressure control when system pressure and temperature are stable. Insure steam dump maintains 530° Tavg.
7. Manually operate the feedwater system as required to maintain steam generator level approximately 39% no load level.
8. Insure pressurizer pressure returns to normal.
9. Stop both heater drain pumps and leave one condensate pump and one feedwater pump running.
10. Insure the turbine generator goes on turning gear 1 minute after zero speed alarm is received.
11. If the time to return to critical is in excess of 12 hours, and an ECP has not been performed for a planned startup, and a plant cool-down is not required, borate the reactor coolant system to the hot shutdown, xenon free concentration.
12. If the cause of the trip cannot be corrected and cooldown is required, proceed to cold shutdown as per GP-6 "Plant Cooldown From Hot Shutdown to Cold Shutdown Conditions."

as

1.0 HIGH RCS PRESSURE

1.1 Discussion

A malfunction in the RCS Pressure Control System can cause a high RCS pressure. High pressure must be avoided due to the possibility of overpressurizing the system. Three safety relief valves, which lift at 2485 psig have the combined capacity to relieve greater than the maximum surge rate resulting from complete loss of load. This procedure is to lessen or alleviate the pressure increase before it reaches that pressure.

1.2 Symptoms

1. Pressurizer Protection High Pressure Alarm
2. Pressurizer Control High/Low Pressure Alarm
3. High Pressure Indication on RTGB Indicators
4. Pressurizer Pressure Controller High Output Alarm
5. Pressurizer Power Relief Line High Temperature Alarm
6. Pressurizer Relief Tank High/Low Level-High Pressure/Temperature Alarm.
7. Pressurizer Safety Valve High Temperature.
8. Prz. PORV/Safety Valve Open Alarm.

1.3 Automatic Action

1. Power Relief Valve Operation (2335 psig)
2. Pressurizer High Pressure Reactor Trip (2376 psig)
3. Pressurizer Safety Valve Operation (2485 psig)

1.4 Immediate Actions

1.4.1 De-energize pressurizer heaters if they failed to cut off automatically.

hs

1.0 HIGH RCS PRESSURE (Continued)

1.4.2 If pressurizer spray control is in automatic and spray has not initiated, shift spray control to manual and adjust spray to decrease pressure.

1.4.3 Use auxiliary spray, if necessary, and the ΔT between the pressurizer and TE 123 (CVC charging line temp) is below 320°F.

1.5 Subsequent Actions

1.5.1 Observe pressurizer water level and reduce if high.

1.5.2 If pressurizer pressure controller PC-444J has failed, do the following steps:

1.5.2.1 Operate the controller PC-444J in manual or take manual control of pressurizer spray and heaters as stated above.

1.5.2.2 If PCV-455C has been erroneously opened, close PCV-455C. If PCV-455C will not close, then close RC-536 (block valve).

1.5.3 If pressurizer pressure controller PC-445 has failed high, and caused PCV-456 to open, close PCV-456. If PCV-456 will not close, then close RC-535.

1.5.4 If pressure cannot be controlled, trip the reactor and refer to EI-14.

1.5.5 If PCV-455C and/or PCV-456 has opened they may be closed or blocked using RC-536 and/or RC-535 when the RCS pressure has returned to or dropped below normal.

1.0 DISCUSSION

There may arise instances during operation wherein a safeguards actuation is inadvertently initiated due to human error, logic system malfunction, etc. When this occurs, it is necessary to terminate the safety injection or containment spray and return the plant to a normal condition.

If the safe efficient operation of the plant so dictates, the actions required by this procedure may be performed simultaneously or out of sequence.

2.0 SPURIOUS ACTUATION OF SAFETY INJECTION

2.1 Symptoms

2.1.1 Phase "A" isolation.

2.1.2 Starting of safeguards trains "A" and "B".

2.1.3 Reactor Trip and subsequent turbine trip.

2.1.4 Diesel Generators "A" and "B" start.

2.1.5 Both main feedwater pumps trip.

2.1.6 Steam generator main block, feed regulator, and bypass feedwater valves close.

2.1.7 All non-essential breakers trip.

2.1.8 The following valves will actuate to the positions indicated.

a. SI-867A, 867B, 870A, and 870B are opened.

b. RHR-744A and 744B are opened.

c. SI-841A and 841B are closed.

2.0 SPURIOUS ACTUATION OF SAFETY INJECTION (Continued)

2.2 Precautions

2.2.1 Refer to E.I. - 1 and verify that the safety injection initiation is indeed spurious and that the safety injection termination criteria are met.

2.2.2 If the initiation is at other than normal temperature and pressure (i.e., during a cooldown or heatup), the conditions for safety injection termination as described in E.I. - 1 should not be established if the heatup/cooldown curves would be violated. A safety injection initiation at other than normal temperature and pressure should be considered to reflect an actual condition requiring safety injection until careful observation of plant conditions verify the initiation to be spurious.

2.3 Recovery Actions (Subsequent Actions)

2.3.1 Reset safety injection, feedwater isolation, phase "A" isolation, and containment ventilation isolation.

2.3.2 Reset instrument air to containment valve IA-1716 and ensure that it indicates open.

2.3.3 Restore the electrical system to its normal lineup per OP-3.

2.3.4 Stop all operating safety injection pumps.

2.3.5 Stop both residual heat removal pumps.

2.3.6 Close the boron injection tank inlet and discharge valves SI-867A, 867B, 870A, and 870B.

tg

4.0 INSTRUCTIONS (Continued)

OVERPRESSURIZATION CAUTION: If all three reactor coolant pumps were stopped prior to heatup, after completing GP-1 perform the following. To avoid an overpressure transient, do not start a reactor coolant pump when the RCS is solid, stagnant, and the steam generator temperature is greater than the balance of the RCS. Due to the lack of installed temperature indication on the steam generators, their temperature shall be determined by measuring steam generator shell temperature approximately four feed above tube sheet. This area shall be covered with insulation prior to measuring. This temperature shall be less than or equal to temperature of loop surface at valve RHR-750. If steam generator is greater, the temperature may be equalized by either of the two following methods.

1. Allow RCS to heatup on decay heat by stopping or reducing CCW flow thru the RHR heat exchangers.
2. Cool the steam generators by filling and draining.

   A S/G Shell Temp. Temp.__________

   B S/G Shell Temp. Temp.__________

   C S/G Shell Temp. Temp.__________

   RHR 750 Temp. on loop surface Temp.__________

3. Temp. Detector (Type)________________ Serial #__________

   Calibration Date____________________

4.10 The RCP's were started during GP-1, the fill and vent procedure. If the RCP's were stopped prior to commencing the heatup, restart them.

A RCP running__________

B RCP running__________

C RCP running__________

aes

3.0 PRECAUTIONS

3.1 Be assured adequate space is available in the Gas Decay Tanks prior to degassing.

3.2 At least one Reactor Coolant Pump or the Residual Heat Removal System must be in service when a reduction is made in RCS boron concentration.

3.3 At least two steam generators shall be operable whenever the average primary coolant temperature is above 350°F.

3.3.1 For RCS temperatures above 330°F, the discharge valves of the auxiliary feedwater pumps must be in a throttled position as described in GP-2, 2.6.2.

3.4 The pressurizer cooldown rate must not exceed 200°F/Hr.

3.5 The Reactor Coolant Pumps must not be operated when the No. 1 seal differential pressure is below 200 psig, or when the VCT pressure is below 15 psig, or when RCS pressure is below 325 psig.

3.6 The Reactor Coolant System cooldown rate must not exceed that of "Reactor Coolant System Cooldown Limitations" Curve 3.4 of Volume 15, Curve Book.

3.7 Be assured the RCS has been completely degassed before the system is made solid.

3.8 If the RCS is to remain solid or if cold shutdown is to be established during the outage, complete PT-2.7 and 2.8 prior to going solid if it is suspected they will become due during the outage. These should not be run when water solid due to potential for overpressurization of the RCS.

3.9 Safety Injection Pump Power Supply Breakers must be racked out when RCS temperature is <350°F and the system is not vented to C.V.

3.10 If RCS is <350° and not vented to CV two PORV's must be operable Ref. Tech. Spec. 3.1.2.1.D.

4.0 INSTRUCTIONS (Continued)

Hydrogen (cc/kg) ________

Boron MC (ppm) ________

Boron Prz (ppm) ________

4.7 Place the reactor makeup control on "AUTO" and adjust controls for the proper shutdown concentration after the sample results confirm the boron concentration to be adequate. ________

4.8 Verify the alignment of the overpressurization protection protection system as per OP-50. Checkoff OP-50A. Completed ______

PT-5.8 Completed within last month. Completed _____

Reserve N_2 bottle pressure ≥800 PSI., PSI ________

4.9 With the steam dump via condenser or PRV on manual control, slowly increase the rate of steam dump by adjusting the pressure control setpoint. Commence reactor system cooldown. Do not exceed the cooldown limitation set below:

530°F to 350°F	100°F/Hour maximum
350°F to 300°F	60°F/Hour maximum
300°F to 250°F	30°F/Hour maximum
250°F to 200°F	15°F/Hour maximum
200°F to 160°F	10°F/Hour maximum
less than 160°F	5°F/Hour maximum

These rates were established to avoid violation of the pressure/temperature curve 3.4 (Ref. Volume 15, Curve Book) due to excessive pressure. ________

NOTE: Ensure condenser vacuum and circulating water are maintained during the cooldown operation, when condenser dump valves are being used.

rmd

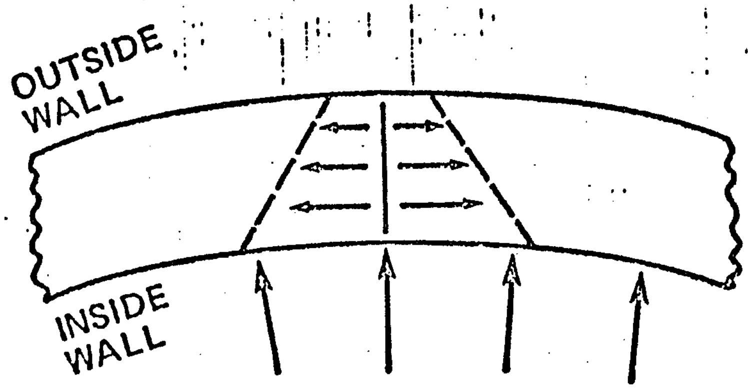
PRESSURIZED THERMAL SHOCK

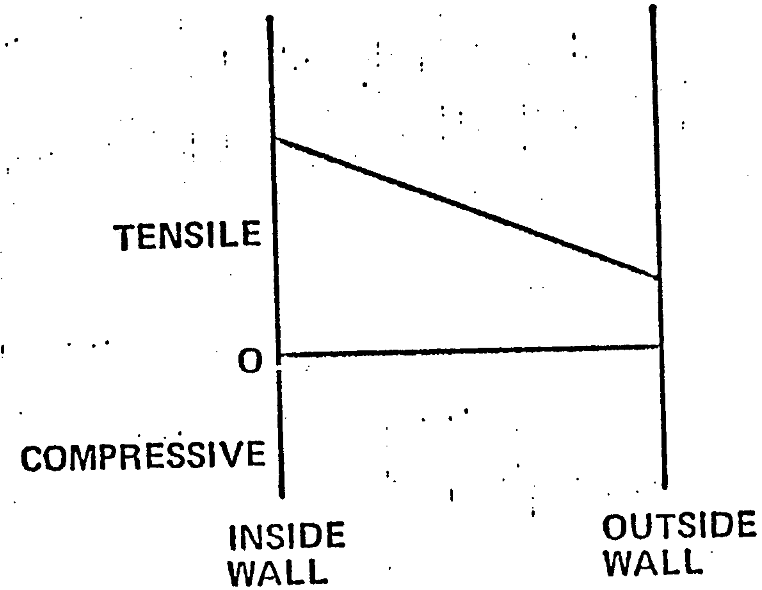
STUDENT HANDOUT
B

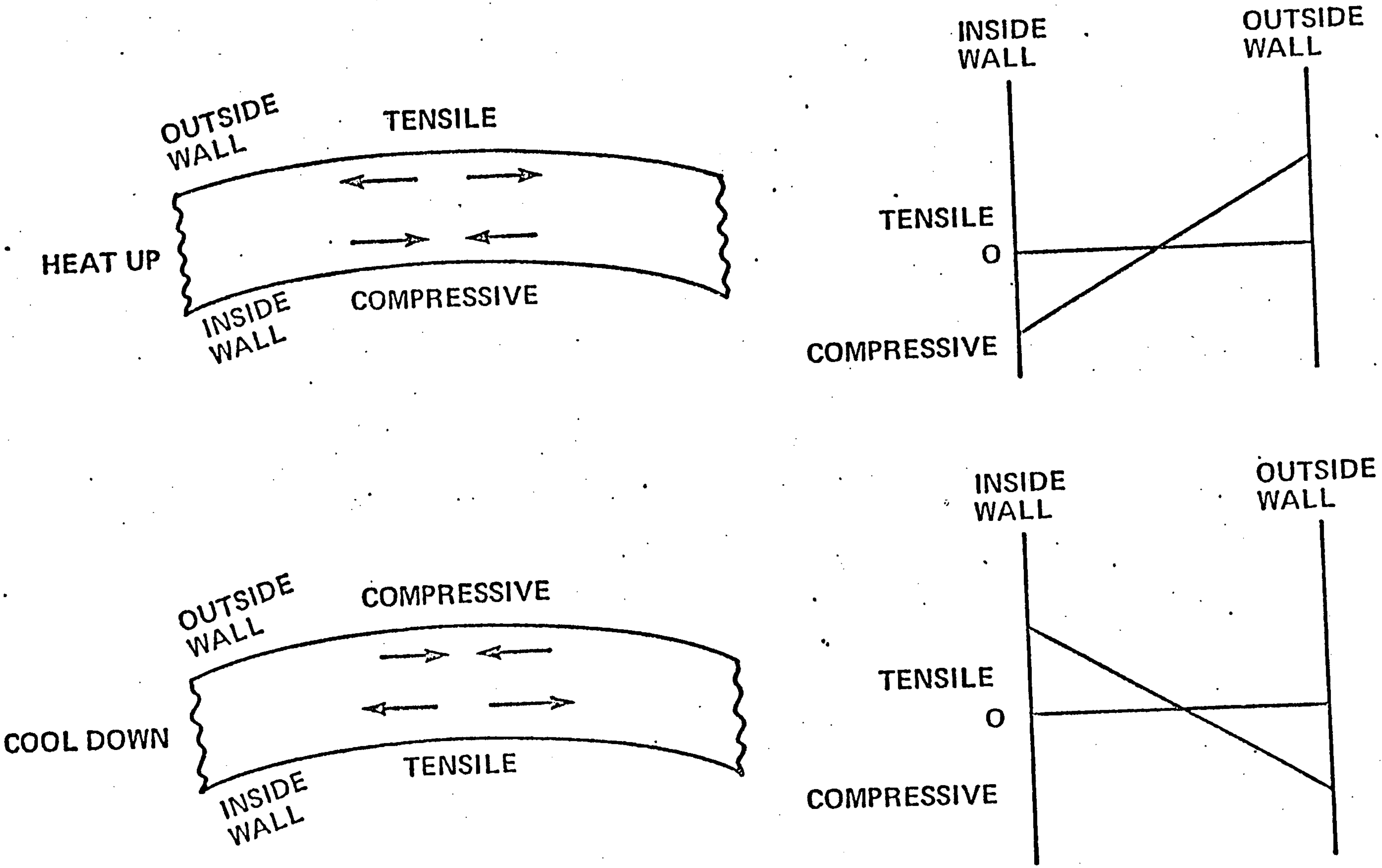
PRESSURIZED THERMAL SHOCK - STUDENT HANDOUT

TABLE OF CONTENTS

TRANSPARENCY 15-3
PRESSURE STRESS ON REACTOR VESSEL

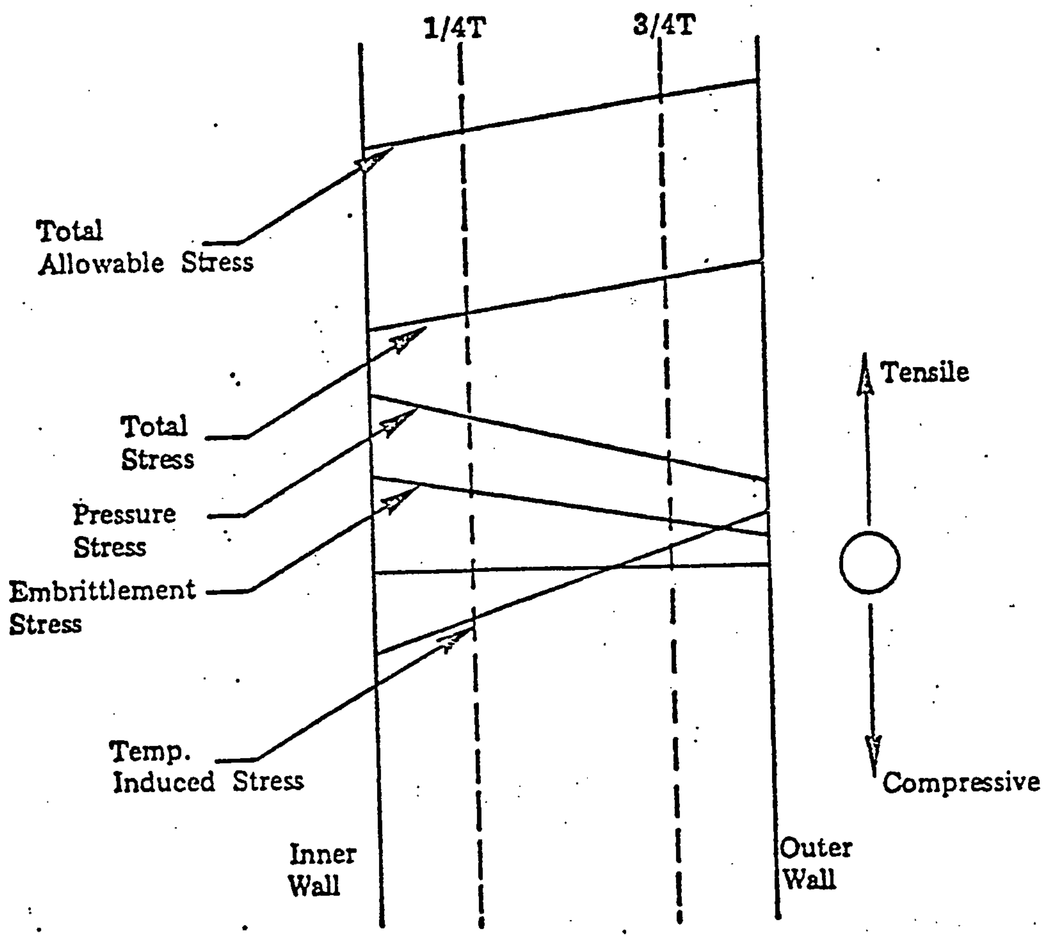






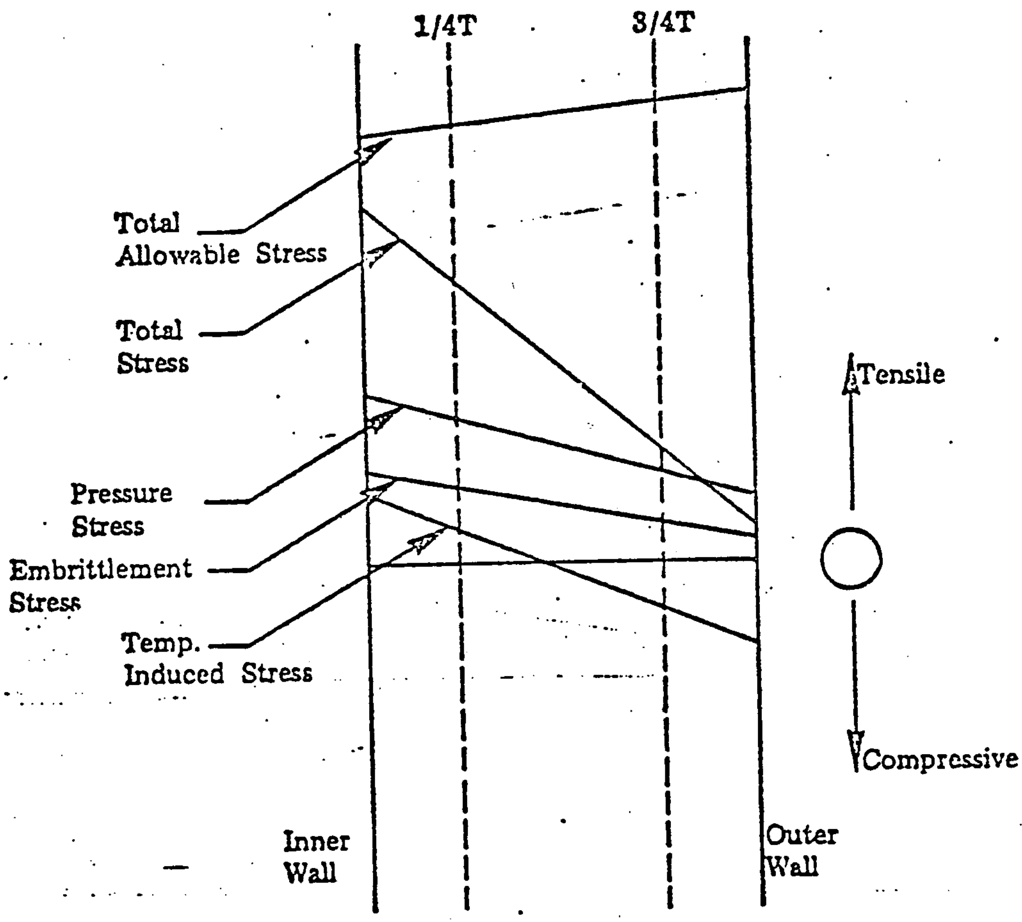
(2)

TRANSPARENCY 15-4
TEMPERATURE STRESS ON REACTOR VESSEL



TRANSPARENCY 15-5

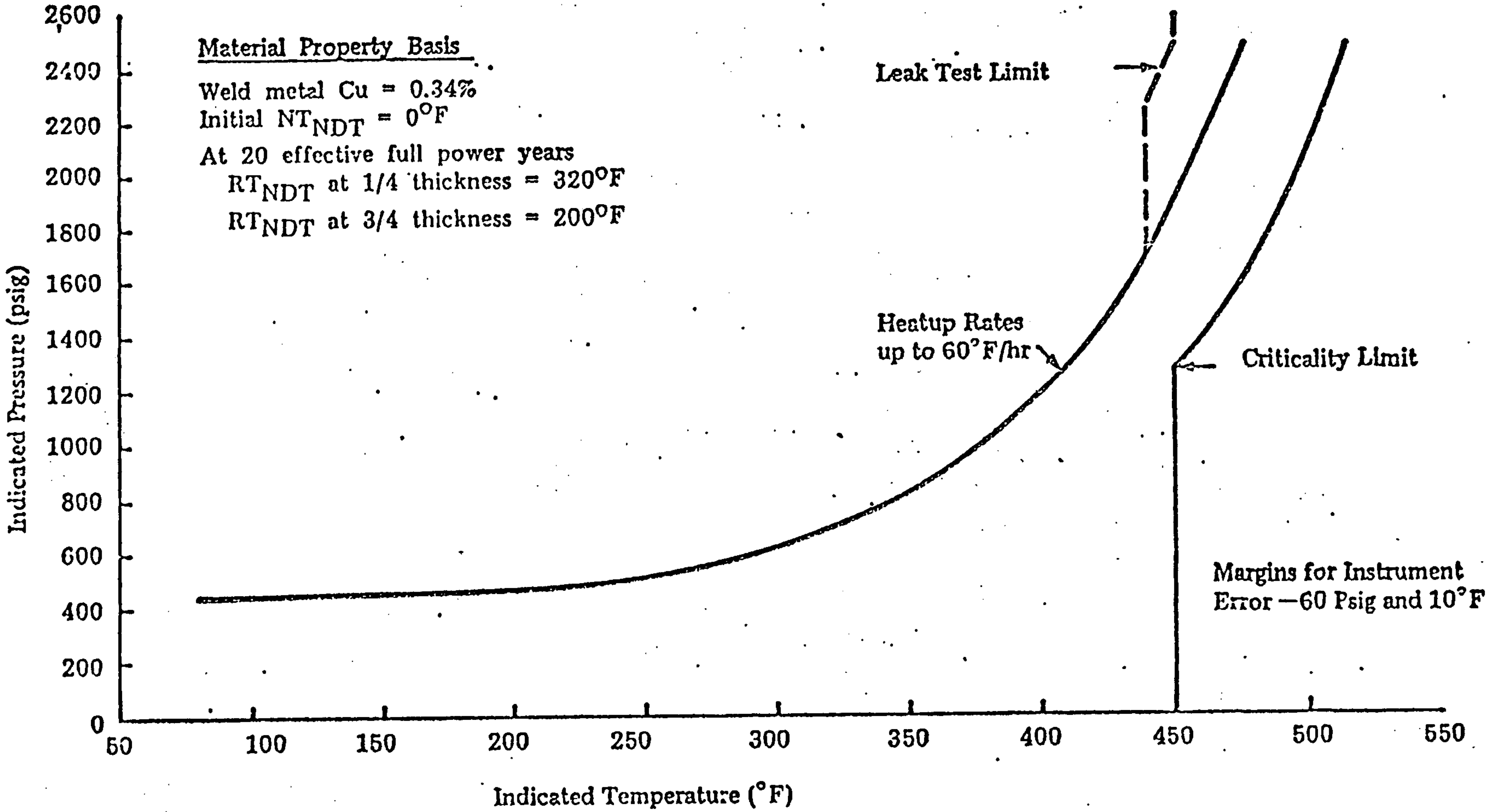
Heatup Stress Profile



TRANSPARENCY 15-6

Cooldown Stress Profile

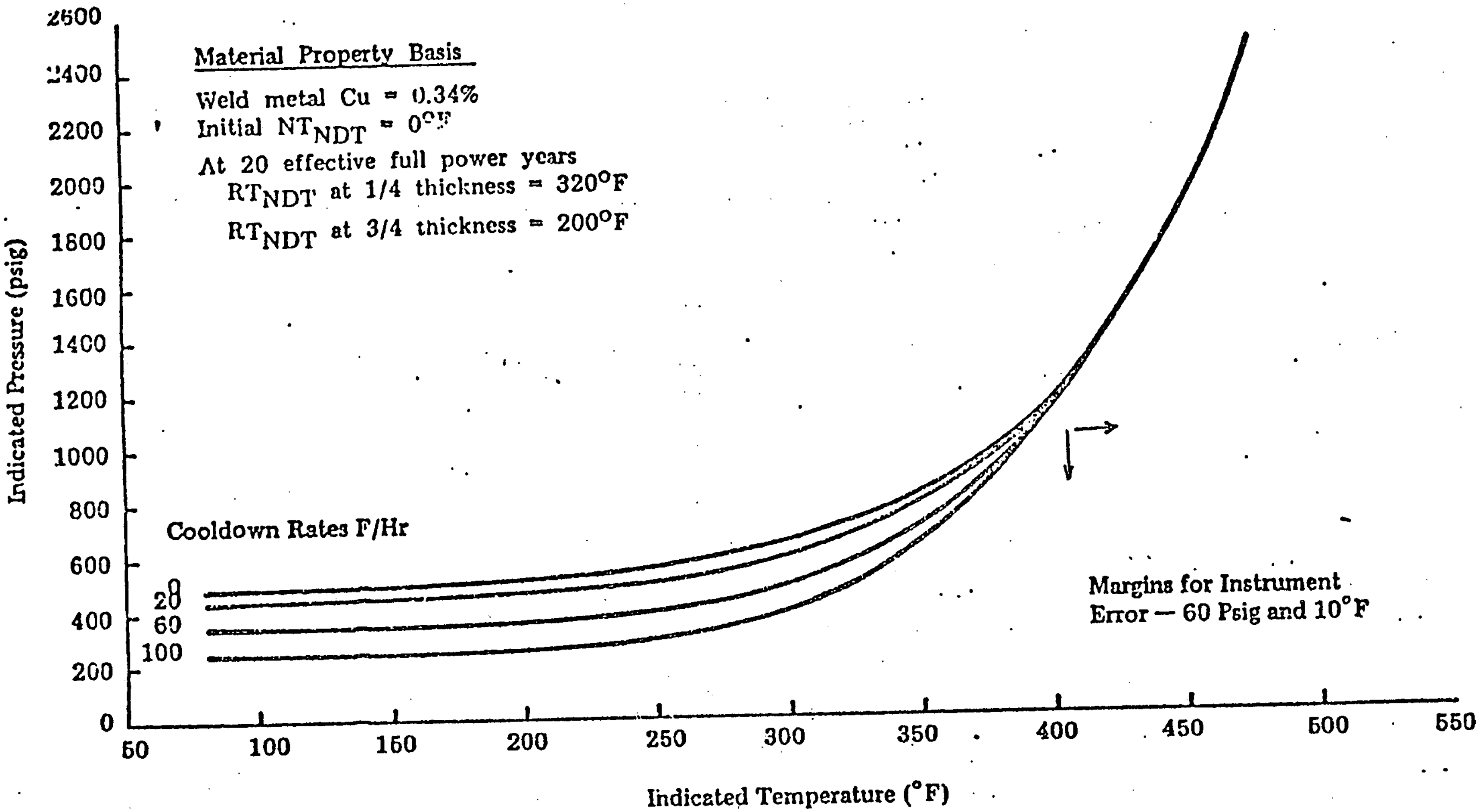
TRANSPARENCY 16-5



H.B. ROBINSON UNIT NO. 2

REACTOR COOLANT SYSTEM HEATUP LIMITATIONS

(APPLICABLE FOR PERIODS UP TO 20 EFFECTIVE FULL POWER YEARS)



(9)

H.B. ROBINSON UNIT NO. 2

REACTOR COOLANT SYSTEM COOLDOWN LIMITATIONS
(APPLICABLE FOR PERIODS UP TO 20 EFFECTIVE FULL POWER YEARS)

The following curves (figures III. 1-16, 1-13, 1-15 & 1-12) are based on the following initial conditions and assumptions.

1. Small break LOCAs (1-4 inches)
2. Analyzed to obtain minimum fluid temperature in reactor vessel downcomer and maximize pressure in the RCS.

   a. All systems that provide cooling to the RCS are assumed to operate at maximum capability (i.e., all trains of SI, all aux. feedwater pumps, etc.)
   b. All warm sources at conservatively low temperature (40°F)
   c. Core heat generation at a nominal value

3. Hot leg break location selected because

   a. Ensures all SI flow delivered to the downcomer
   b. Reduces primary load flow required for break energy removal
   c. Cold leg remains filled with subcooled liquid
   d. Maximum cooldown rate for a given break size

4. Automatic no-load Tave steam dump & max. AFW flow with condensate storage tank at 40°F, S/G level maintained in narrow range

5. RCP trip is assumed to occur coincident with reactor trip

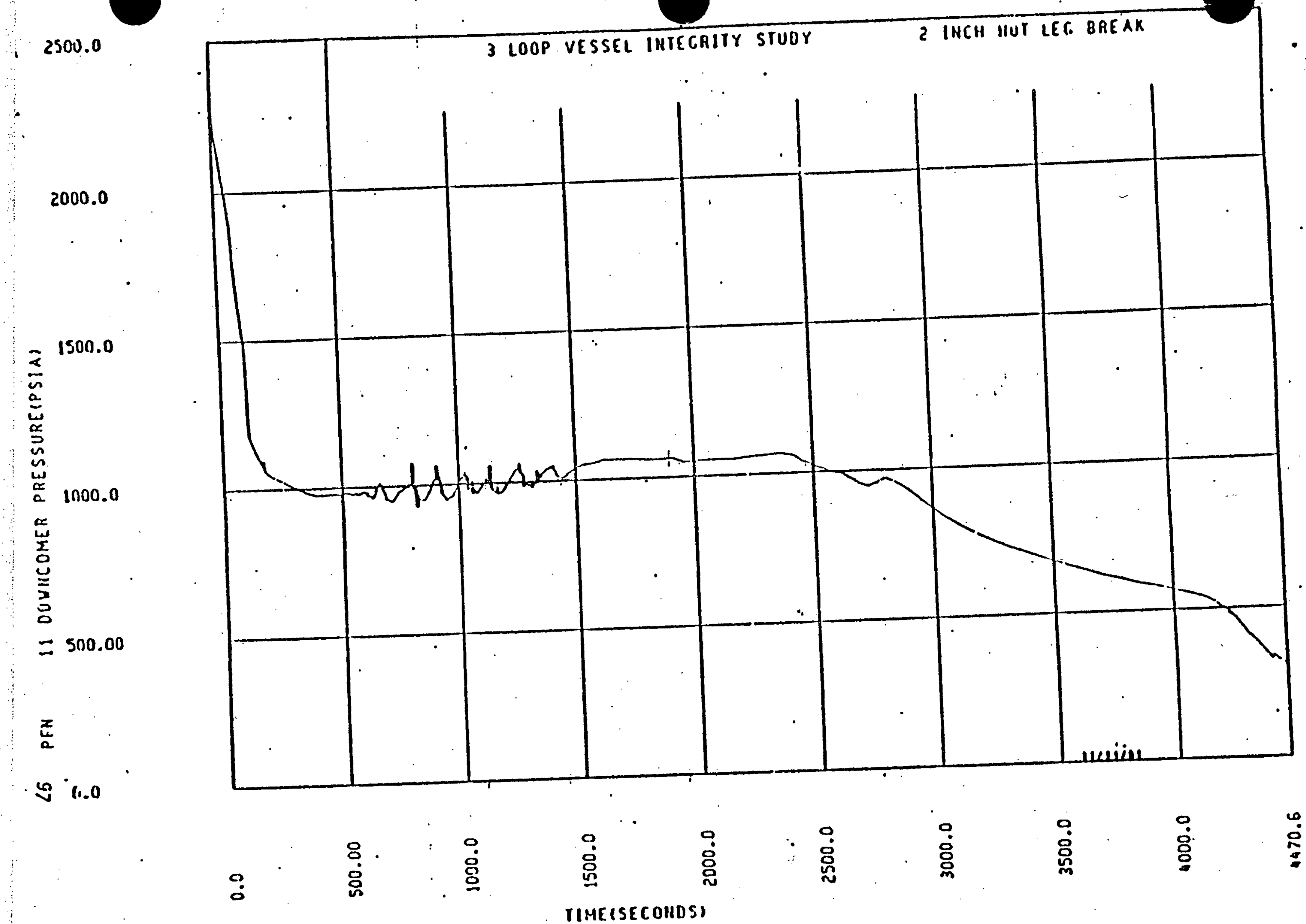


Figure III.1-16 Downcomer Pressure

TP-6

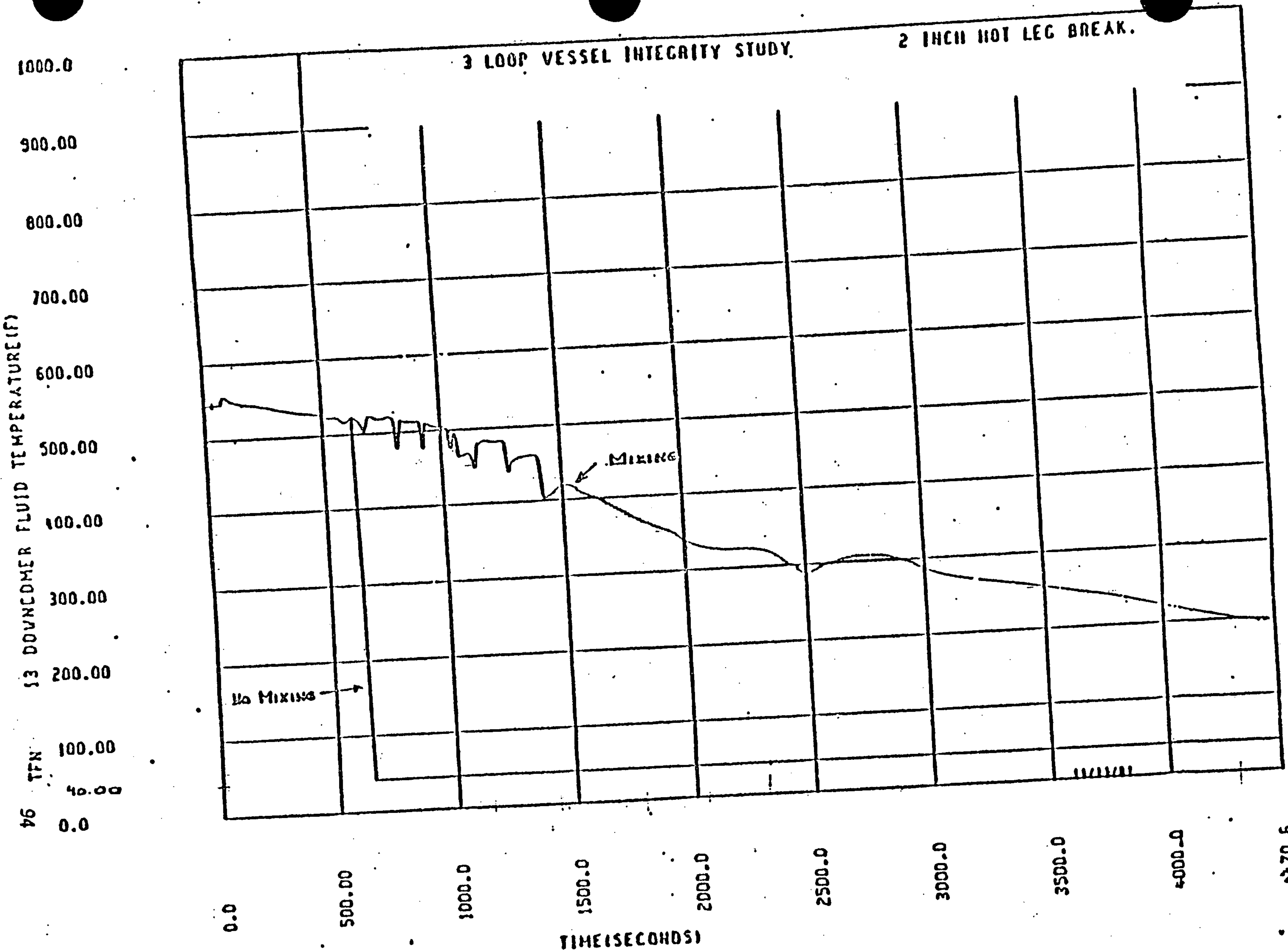


Figure III.1-13 Downcomer Fluid Temperature

(9)

TP-8

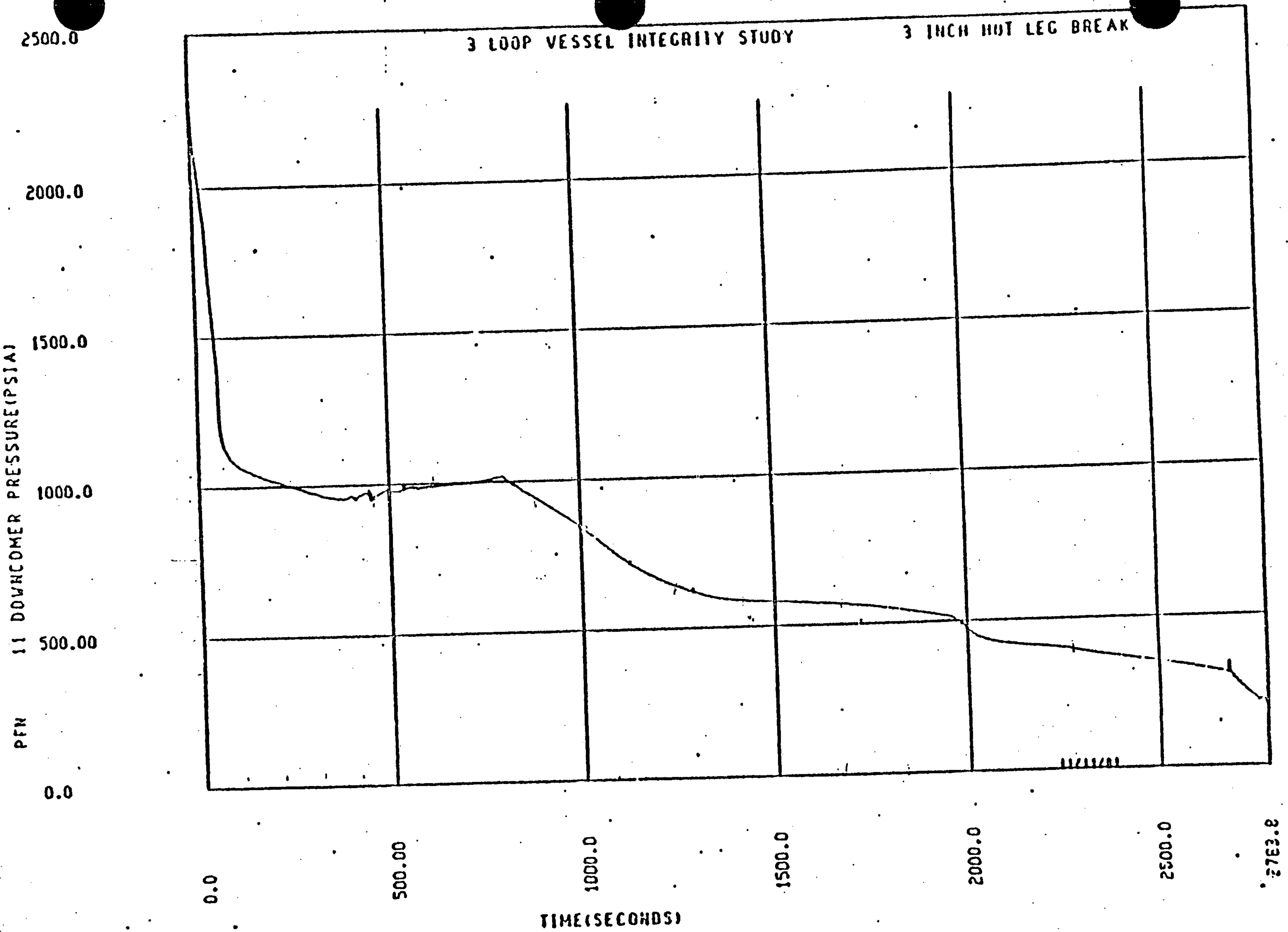


Figure III.1-15 Downcomer Pressure

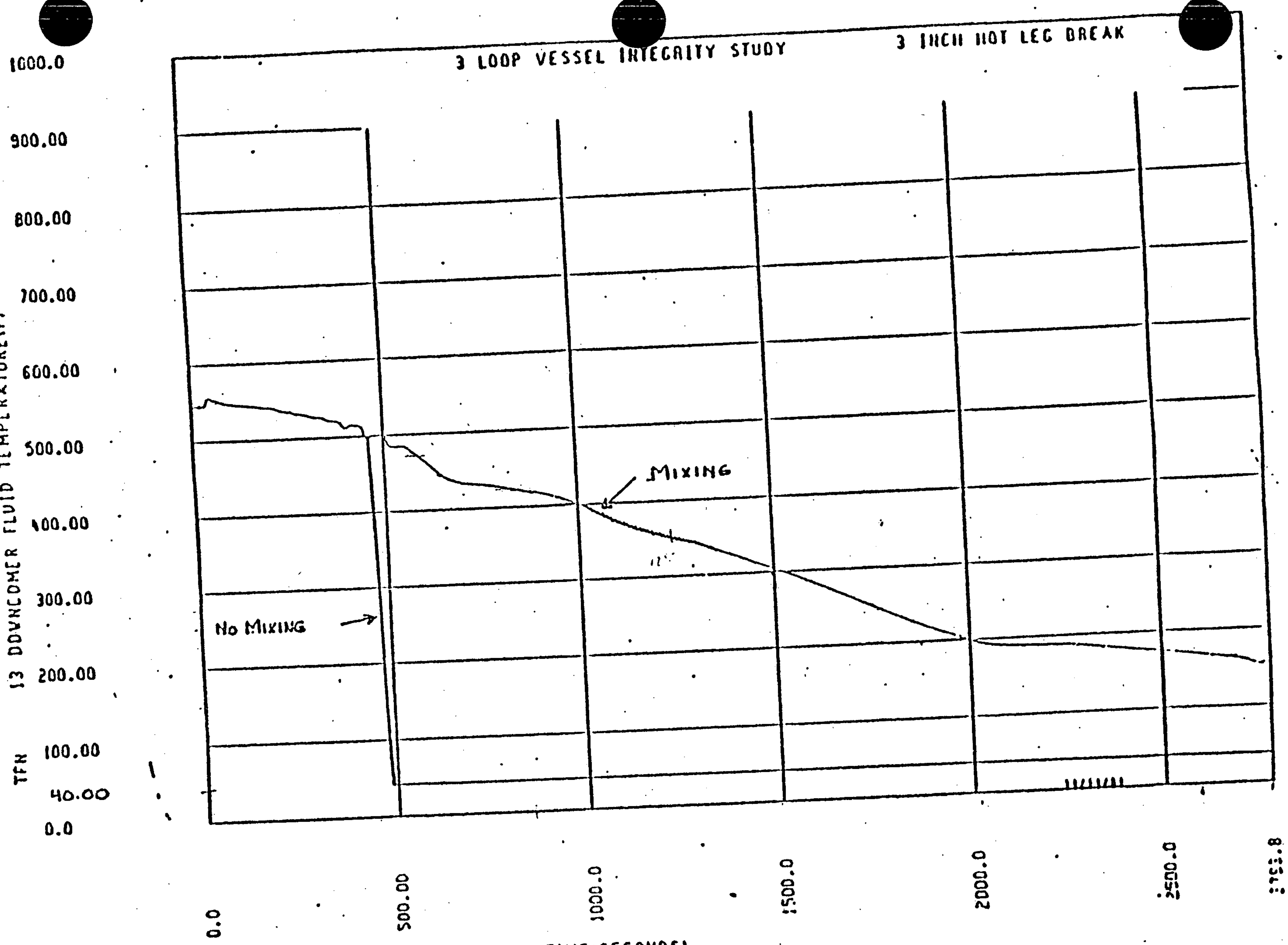


Figure III.1-12 Downcomer Fluid Temperature
3 Loop 3 Inch Hot Leg Break

(11)

Assumptions & Conditions:
1. Maximum SI and AFW flow rates
2. Minimum injected fluid temperature
3. No decay heat (maximum cooldown case)
4. Initiating event is double ended guillotine severence
5. SI causes repressurization following initial depressurization
6. SI & AFW flow assumed to start at time of break
7. Operator action terminates AFW flow and SI flow after 10 minutes

2.333

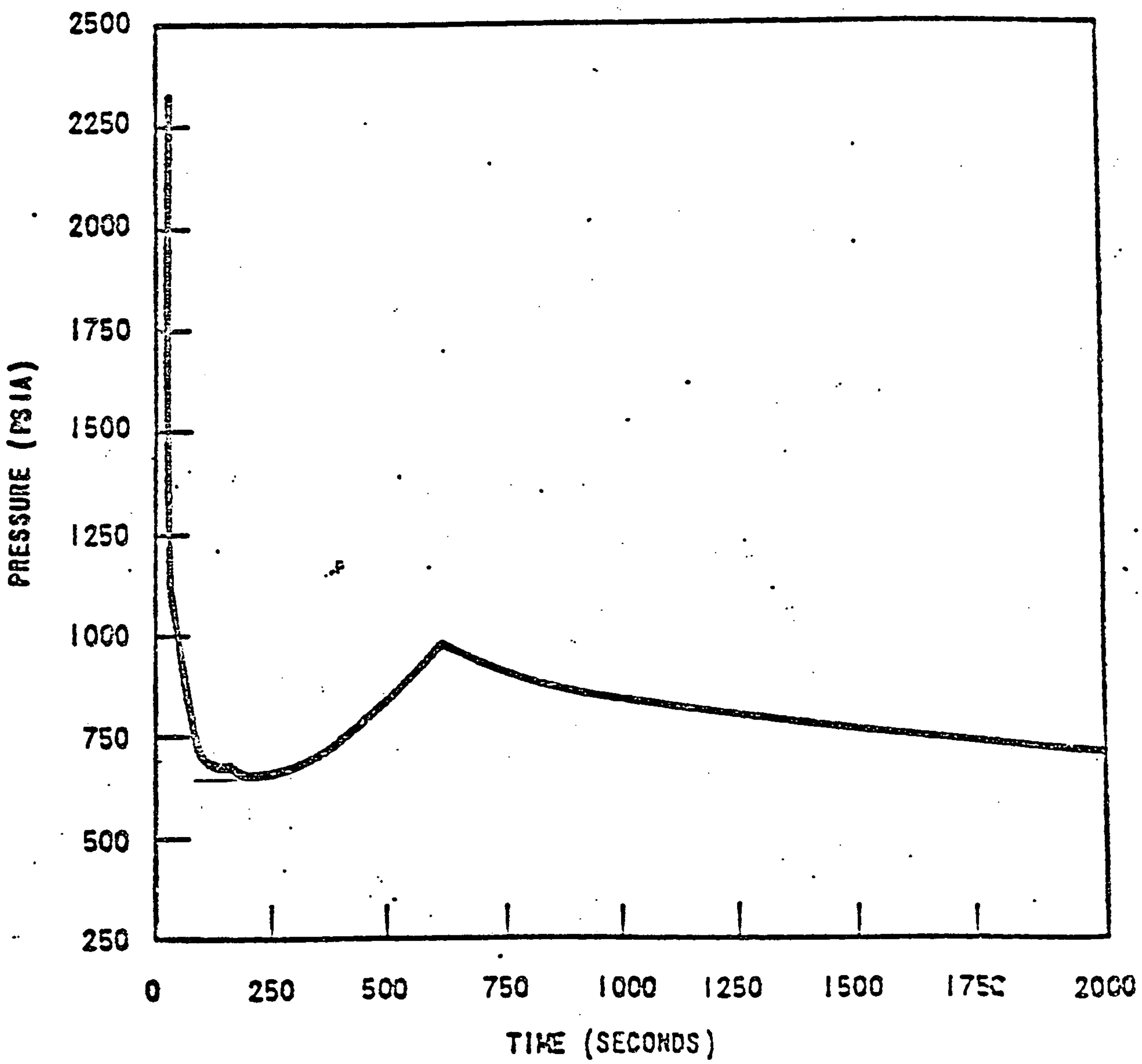


Figure III.1-27 Large Steamline Break With Reactor Coolant Pumps Running.
Reactor Coolant Pressure Versus Time

Assumptions and Conditions

1. Maximum SI and AFW flow rate
2. Minimum injected fluid temperature 12.C39-6
3. No decay heat (Maximum Cooldown Case)
4. Initiating event is double-ended guillotine severence
5. SI causes repressurization following initial depressurization
6. SI and AFW flow assumed to start at time of break
7. Operator action terminates AFW flow and SI flow after 10 minutes

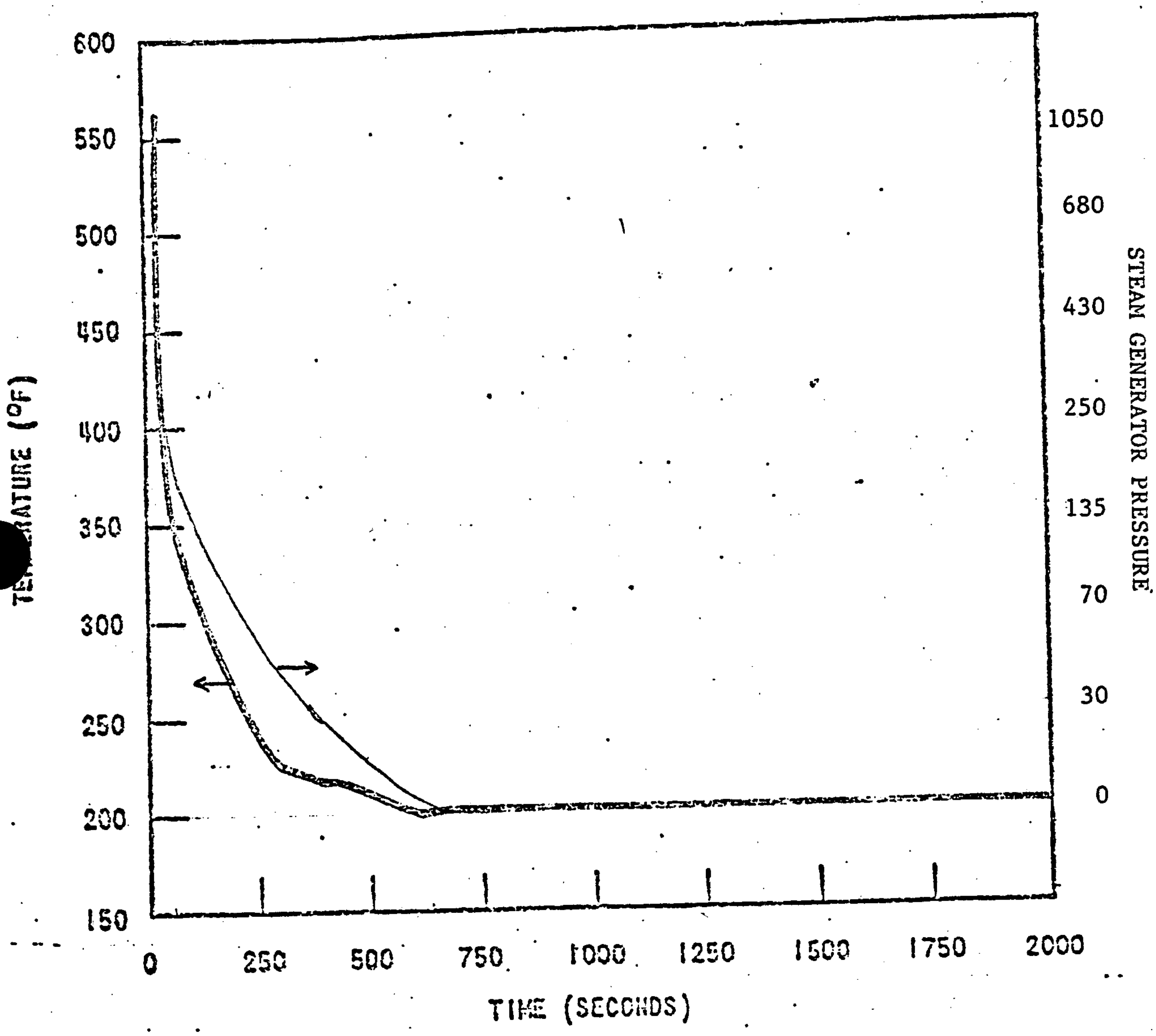


Figure III.1- 28 Large Steamline Break With Reactor Coolant Pumps Running. Cold Leg Temperature Versus Time

Assumptions and Conditions

12.093-7

1. Maximum SI and AFW flow rate
2. Minimum injected fluid temperature
3. No decay heat (Maximum Cooldown Case)
4. Initiating event is double-ended guillotine severence
5. SI causes repressurization following initial depressurization
6. SI and AFW flow assumed to start at time of break
7. Operator action terminates AFW flow and SI flow after 10 minutes
8. RCP's tripped at time of steam break

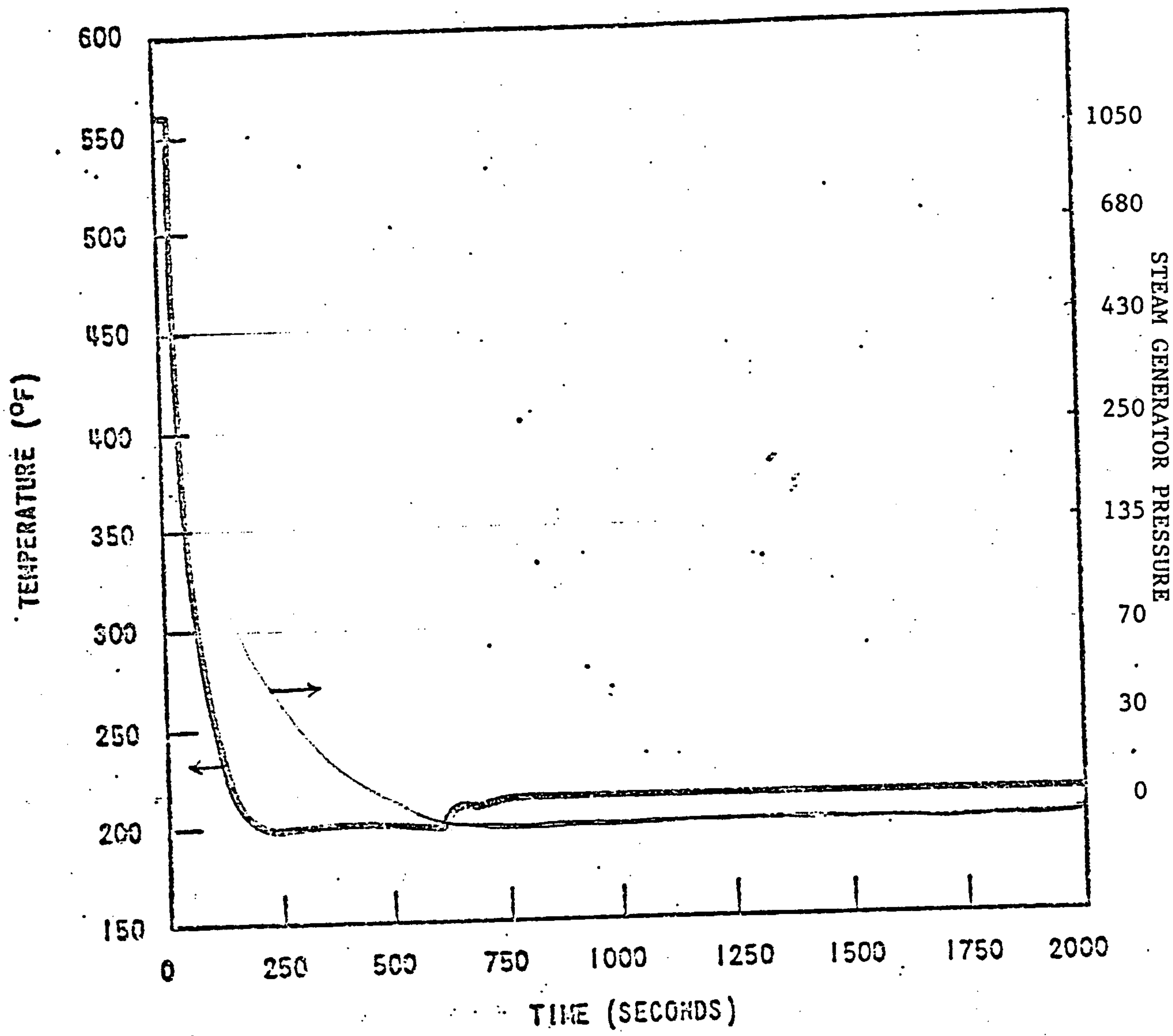


Figure III.1-30 Large Steamline Break With Reactor Coolant Pumps Tripped. Cold Leg Temperature Versus Time

Assumptions & Conditions 12.083-6

1. Maximum SI and AFW flow rate
2. Minimum injected fluid temperature
3. No decay heat (maximum cooldown case)
4. Initiating event is double ended guillotine severence
5. SI causes repressurization following initial depressurization
6. SI & AFW flow assumed to start at time of break
7. Operator action terminates AFW flow and SI flow after 10 minutes
8. RCP's tripped when steam break occurred

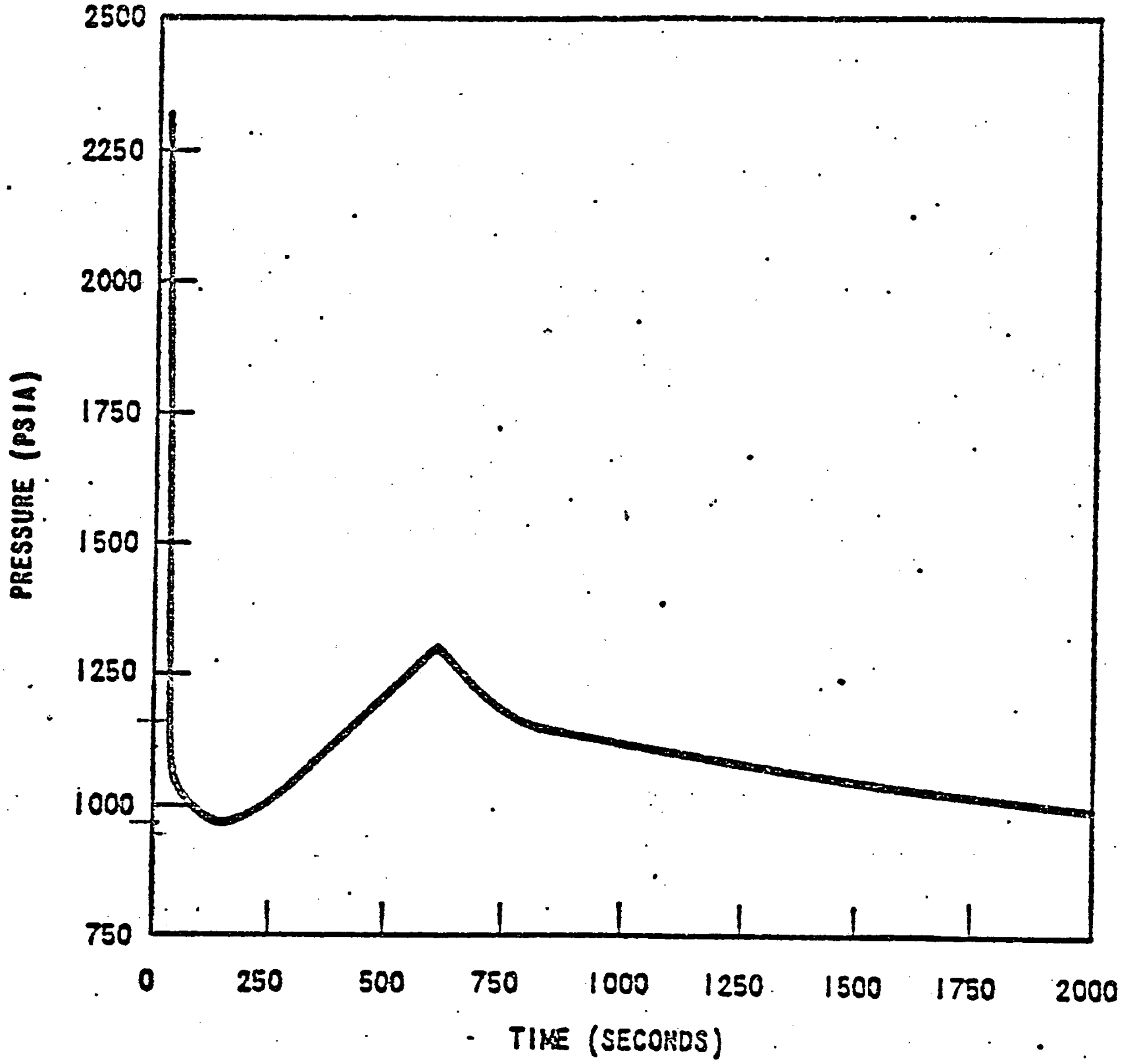


Figure III.1-29 Large Steamline Break With Reactor Coolant Pumps Tripped. Reactor Coolant Pressure Versus Time

Assumptions & Conditions
1. Maximum SI and AFW flow rate
2. Minimum injected fluid temperature
3. No decay heat (maximum cooldown case)
4. Initiating event is double ended guillotine severence
5. SI causes repressurization following initial depressurization
6. SI & AFW flow assumed to start at time of break
7. Operator action terminates AFW flow and SI flow after 10 minutes

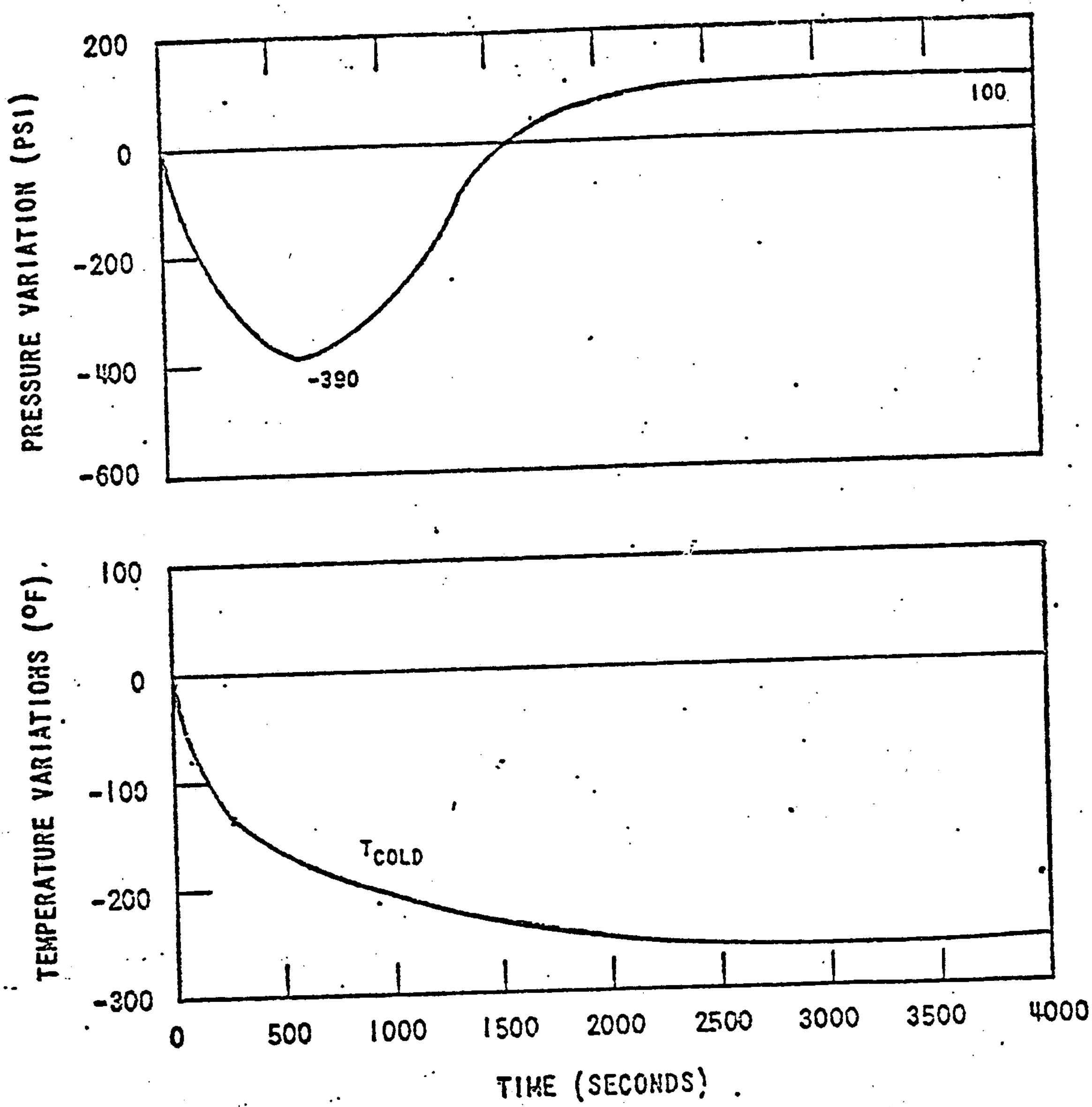


Figure III.1-32 Small Steam Break - Reactor Coolant Pressure and Temperature Variations

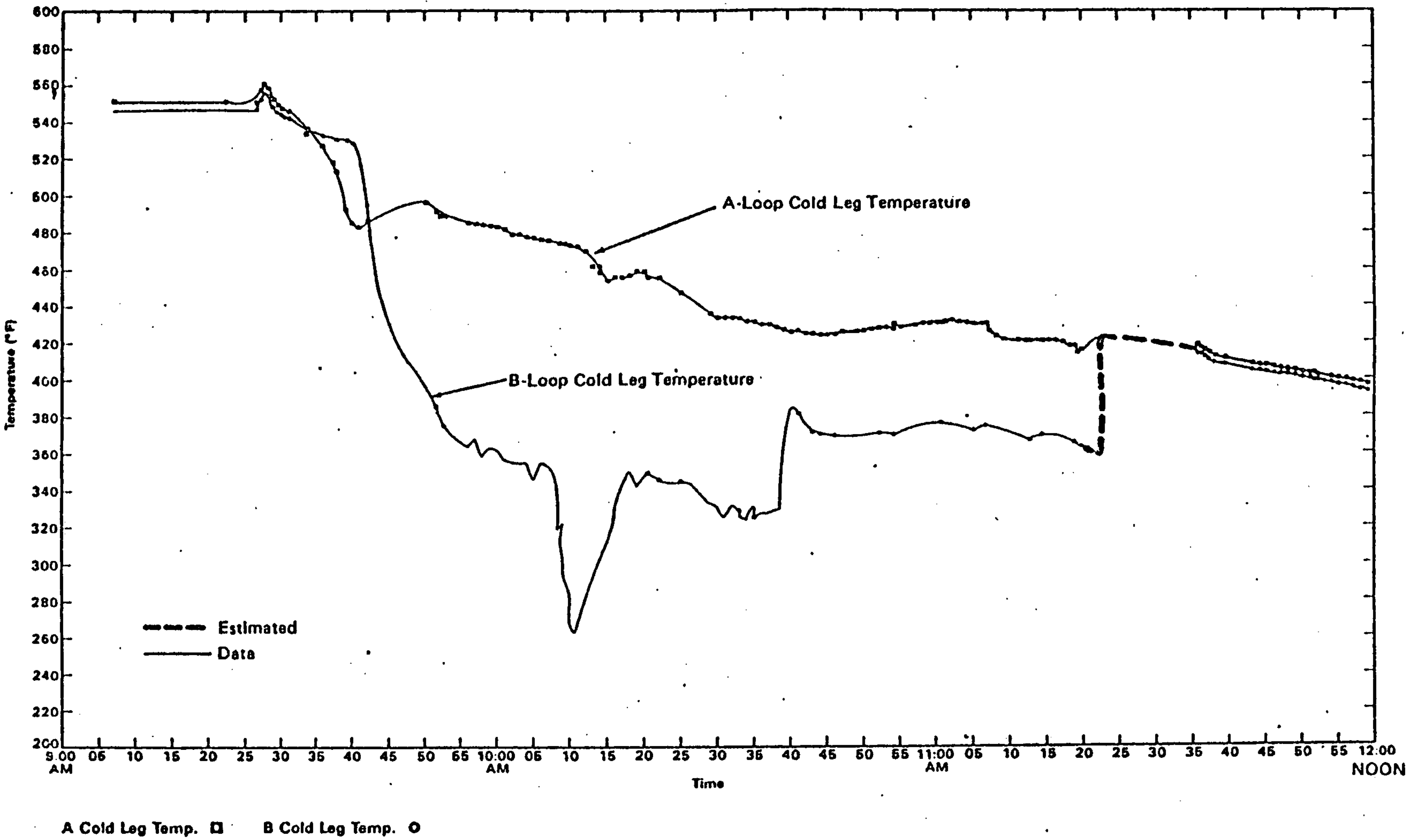


Figure 3.3 Reactor coolant loop cold-leg temperature as a function of time, January 25, 1982

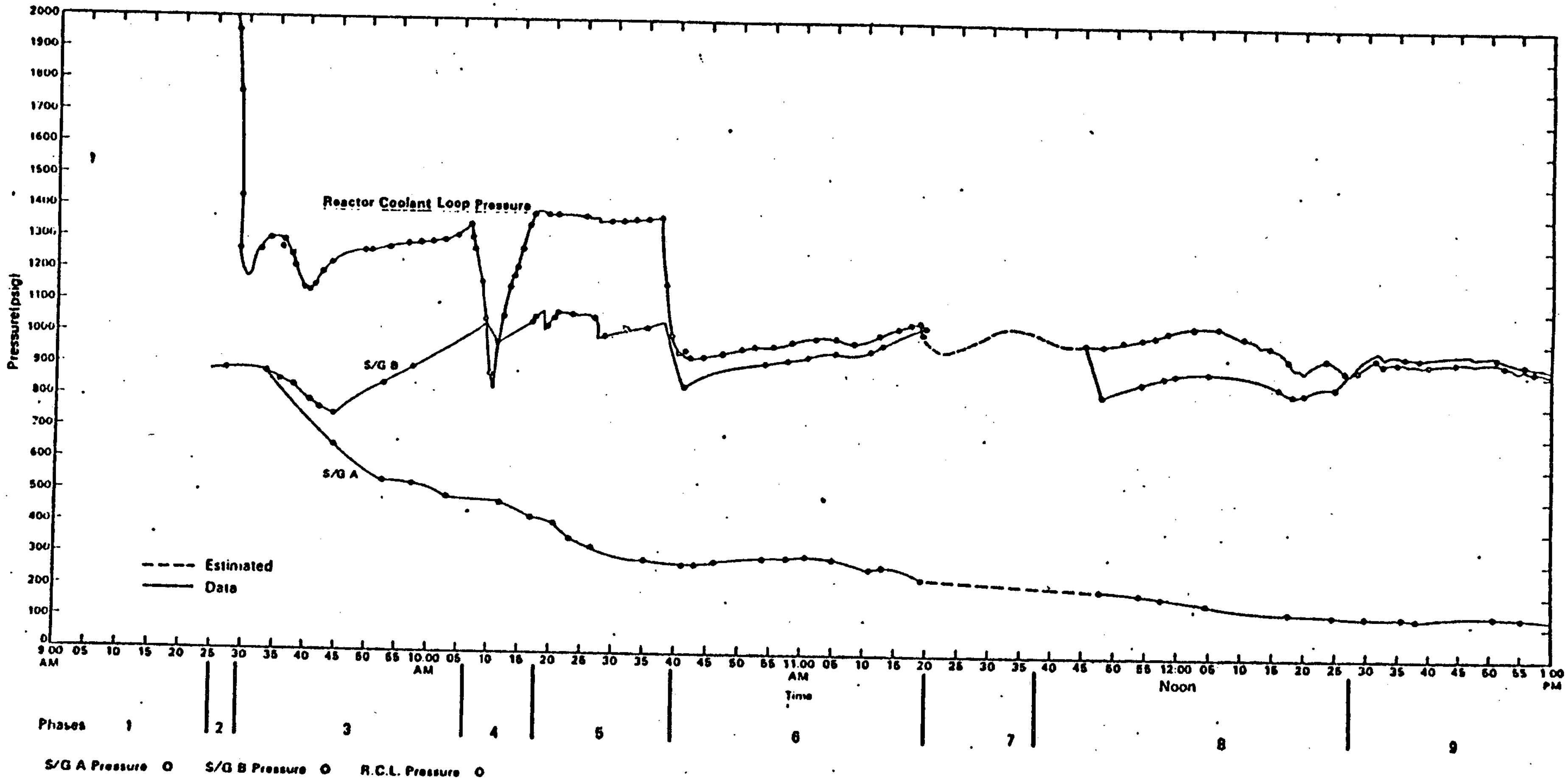


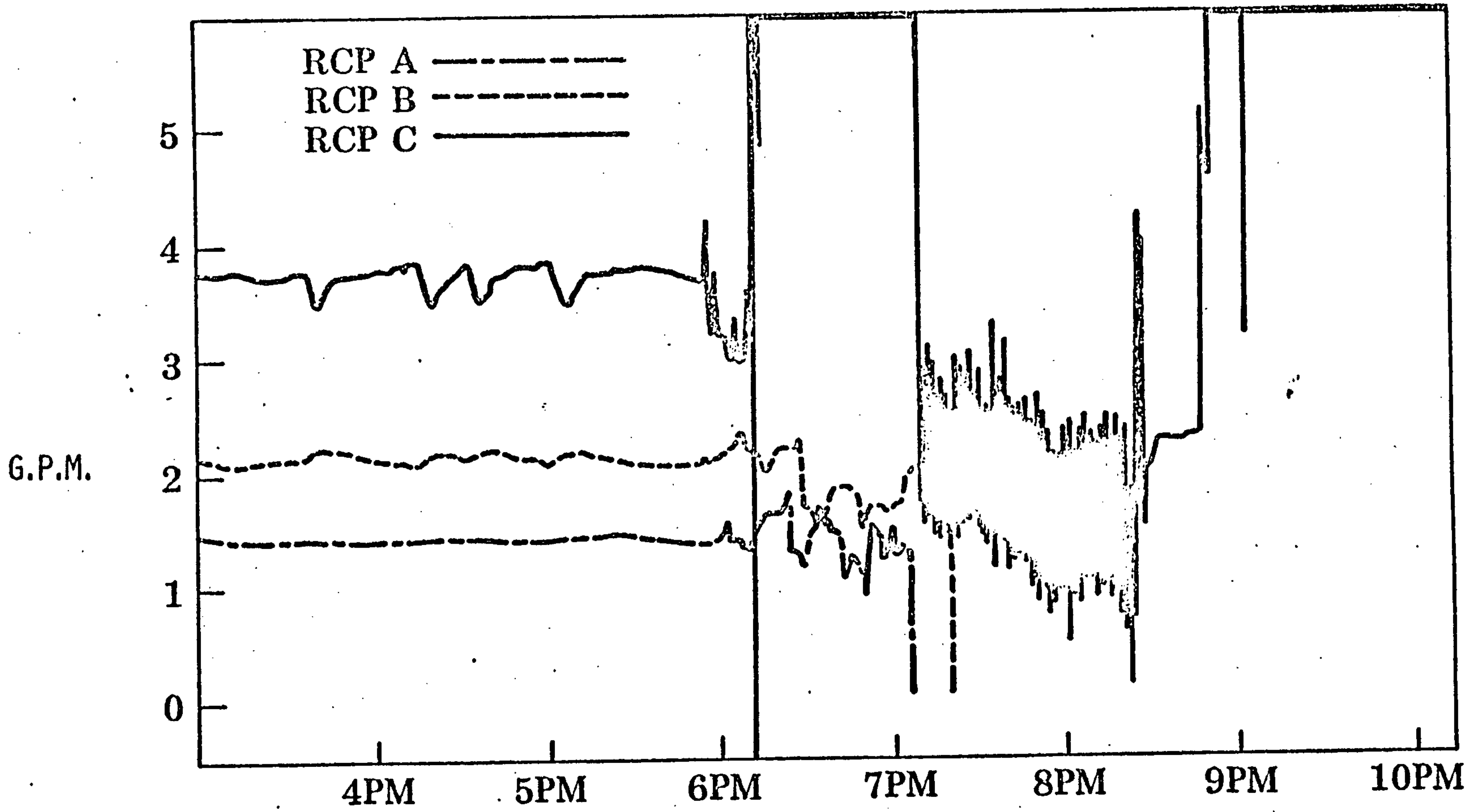
Figure 3.1 Reactor coolant system and steam generator pressure response as a function of time, January 25, 1982

Graphs and charts for the seal failure event at H. B. Robinson will be included in the student handout by 5-10-82.

These include:

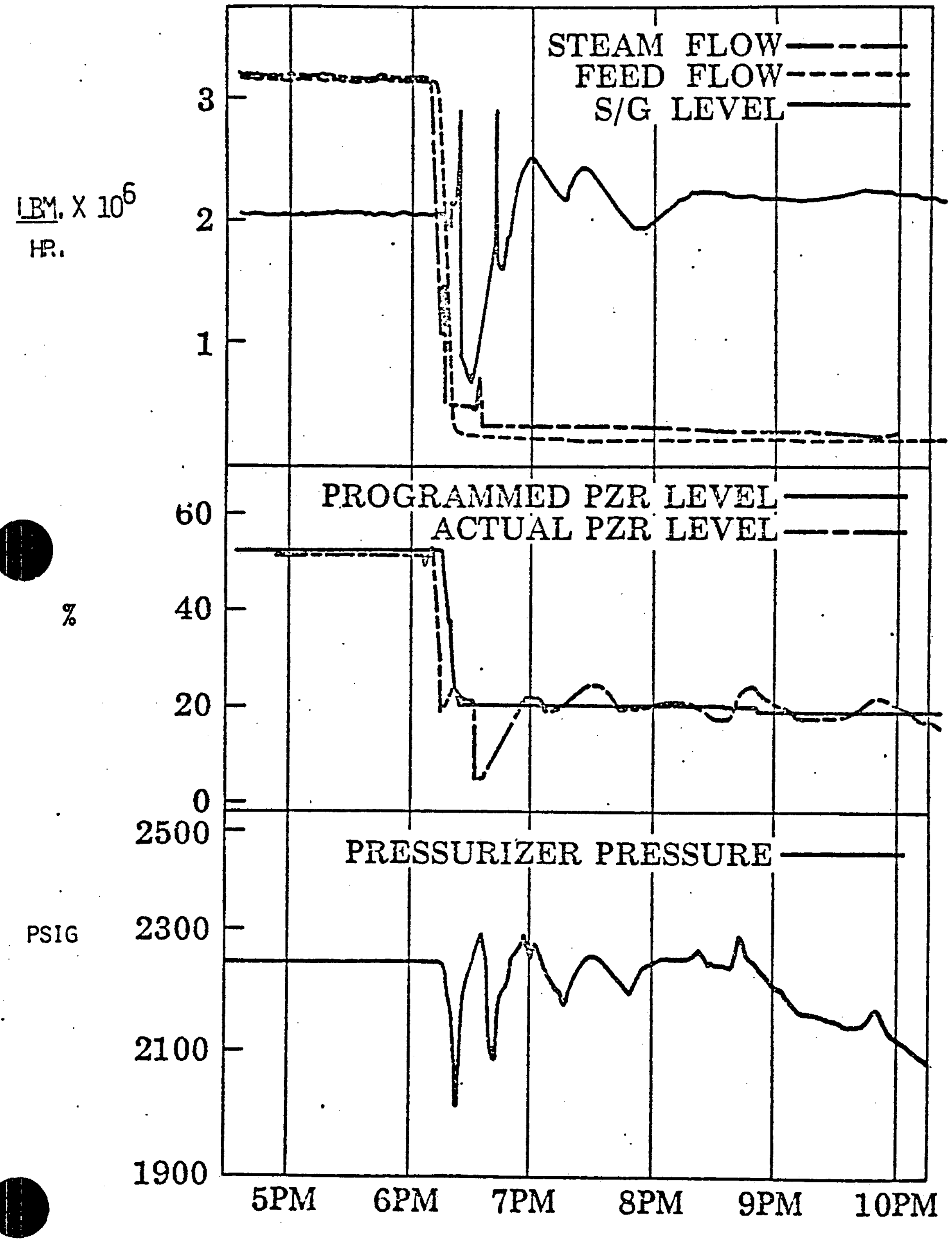
- Seal Flow
- Initial accident S/G level, steam flow, pressurizer level and pressure
- Pressurizer level and pressure during subsequent running of RCP "C"
- RHR and pressurizer pressure

TRANSPARENCY 16-2
RCPs SEAL WATER FLOW

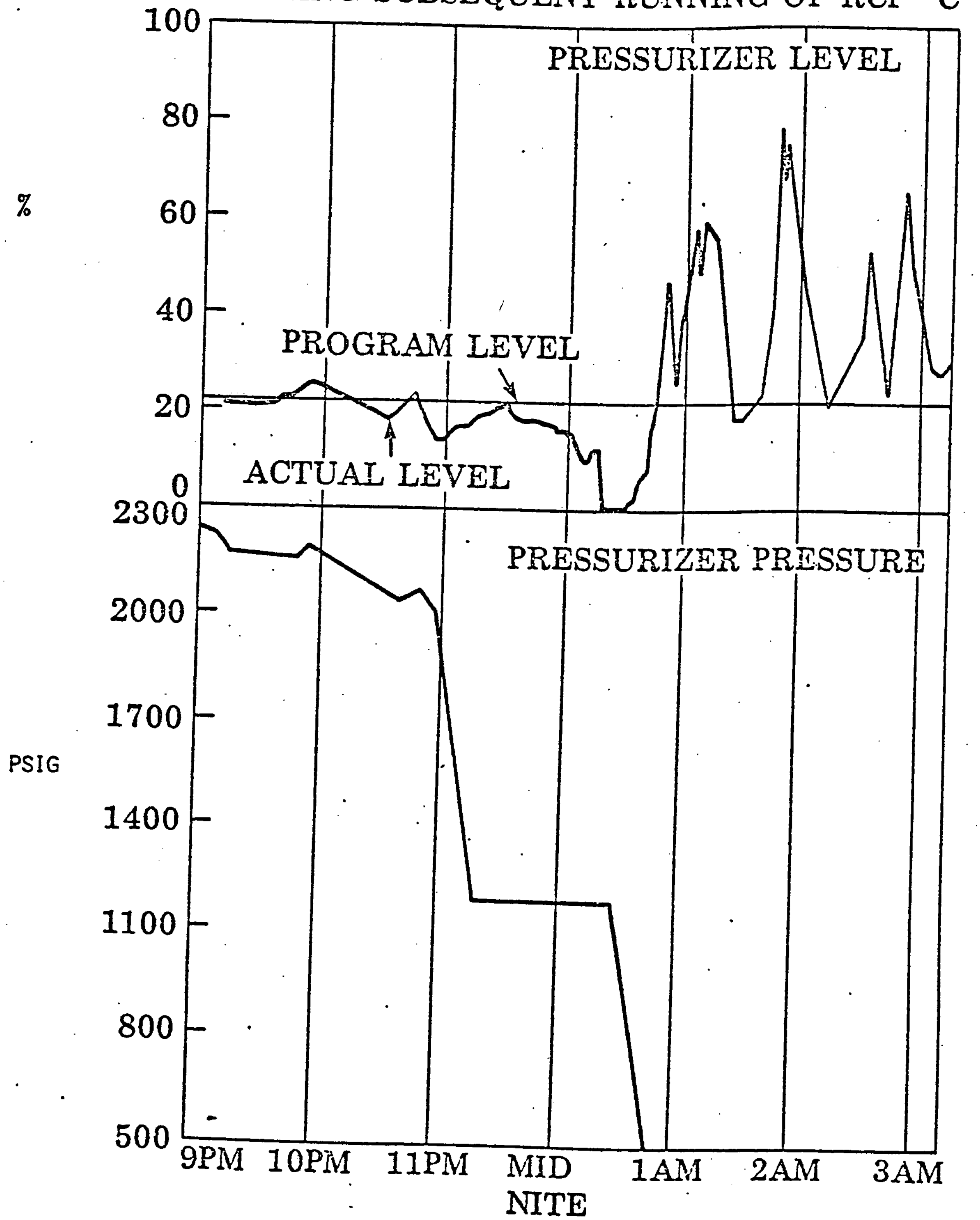


(19)

TRANSPARENCY 16-3
INITIAL ACCIDENT S/G LEVEL,
STEAM FLOW, PRESSURIZER LEVEL, AND PRESSURE

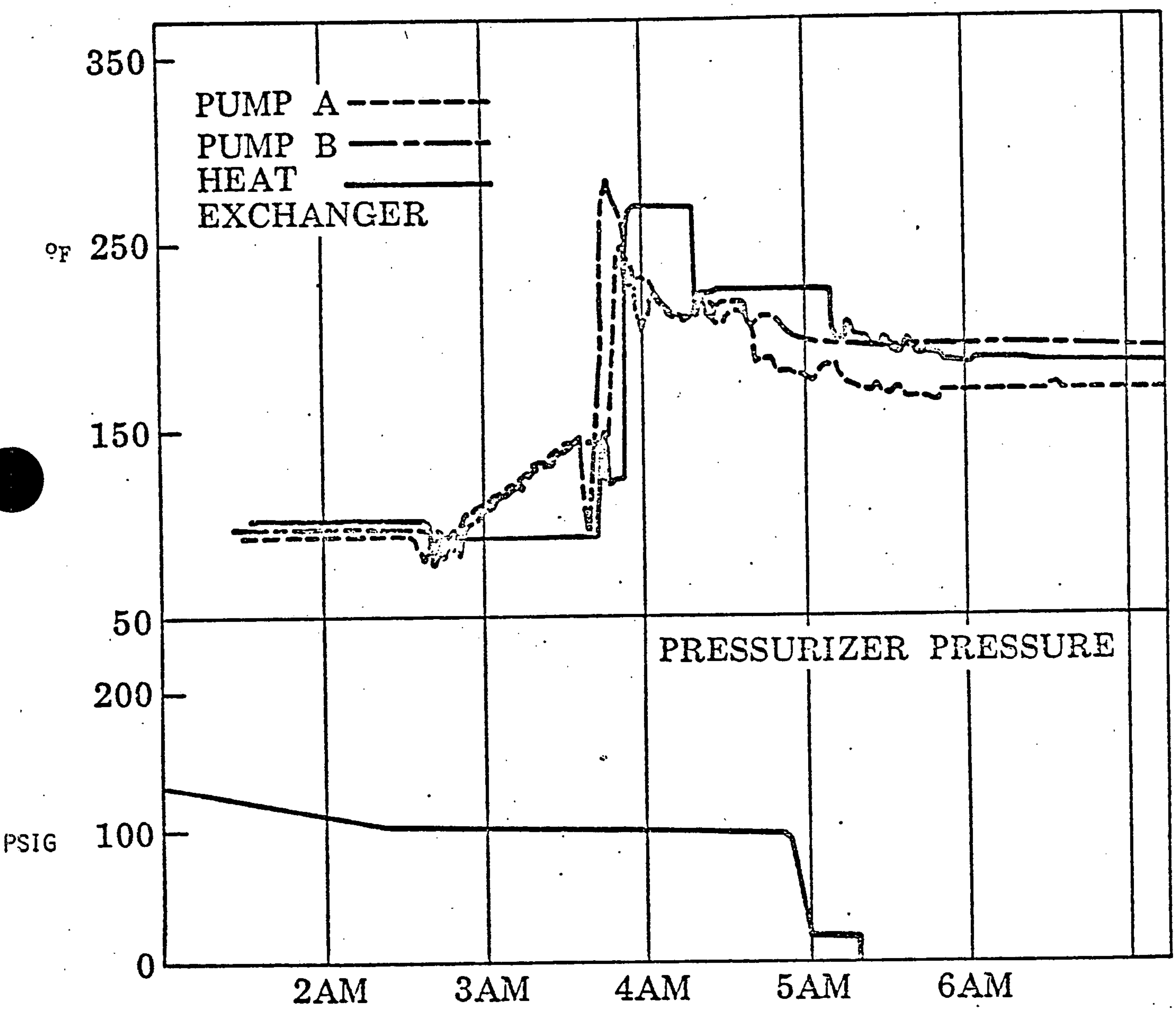


TRANSPARENCY 16-4
PZR LEVEL AND PRESSURE
DURING SUBSEQUENT RUNNING OF RCP "C"



TRANSPARENCY 16-5

RHR TEMP. AND PRESSURIZER PRESSURE



PRESSURIZED THERMAL SHOCK

Student Handout C

Sequence of Events
for Case Histories

Abnormal Occurrence Report

1. Report Number   50-261/75-9

2a. Report Date   May 9, 1975

2b. Occurrence Date   May 1, 1975

3. Facility   H.B. Robinson Unit No. 2

4. Identification of Occurrence

Failure of reactor coolant pump (RCP) seal resulting in discharge of reactor coolant fluid to containment floor.

5. Condition Prior to Occurrence

The reactor was operating at full power. All systems were normal. Dilution of the primary coolant boron concentration was in progress to compensate for the buildup of Xenon. The plant had just reached full power operation early in the morning on May 1, 1975 following a maintenance outage.

6. Description of Occurrence

During dilution of primary coolant boron concentration, No. 1 seal leakoff from "C" pump flow responded sensitively to all additions. This sensitivity had existed since its replacement earlier during the week. Since the leakoff was within the prescribed limits and the variations in flow were gradual instead of "spiking", it was considered safe to operate with this seal.

The dilution was still in process when the following events transpired:

May 1, 1975:

1750 - "C" Reactor Coolant Pump leakoff "spiked" several times. The pump was monitored for vibrations and found to be normal.

1811 - "C" RCP seal leakoff oscillated full range several times and then stabilized high with a seal flow greater than 6 gpm. A load reduction was commenced at a rate of 10% per minute so that "C" pump could be idled as per plant operating procedures.

1817 - Just prior to reducing load below 38% power, component cooling water valve 626 closed due to high flow from the reactor coolant pump thermal barrier. This was caused by sudden steam formation in the thermal barrier created when the pump seal failed open. The open seal allowed hot (540°F) primary coolant to surge upward through the thermal barrier. Load reduction was stopped at 36% power.

1818 - "C" RCP was deenergized.

1819 - Reactor trip occurred due to turbine trip on high level in "B" steam generator. Level instabilities created from the rapid load reduction induced the high level.

1832 - Stopped "A" and "B" Reactor Coolant Pumps. It was the Shift Foreman's decision to stop "A" and "B" RCP's when flashing of primary coolant in the seal water return line threatened to cause loss of seal flow due to the pressure surges. The flashing of primary coolant was created by the high flow rate of coolant through the No. 1 seal of "C" RCP. Valve 303C, leakoff isolation from "C" RCP, was not closed prior to stopping RCP's "A" and "B".

1841 - Received automatic letdown isolation due to low level in the pressurizer. Supply to charging pump suction changed from volume control tank, (VCT), to refueling water storage tank, (RWST).

1854 - Pressurizer level returned above letdown isolation setpoint. Returned charging pump suction to VCT.

1915 - Seal flow was lost on "A" RCP. Closed valve 303C to decrease pressure surges in letdown line.

1928 - Seal flow was lost on "B" RCP. Opened valve WD-1708 to relieve pressure in Reactor Coolant Drain Tank (RCDT). Pressure buildup was due to leakage through No. 2 seal of "C" RCP. WD-1708 allows drainage of RCDT to containment sump.

1942 - First entry following seal failure was made into containment. Purpose of the entry was to observe "C" RCP and to close valve CCW-728C, "C" pump thermal barrier outlet manual isolation valve. The control panel-operated valve CCW-303C had not fully isolated the leakoff and was still causing steam formation in the thermal barrier. It was not possible to enter "C" RCP bay due to steam escaping from No. 3 seal. It was previously thought that the thermal barrier on "C" RCP had failed, but with no increase on R-17, Component Cooling Water Radiation Monitor, and the high flow through No. 1 seal it was determined that steam formation in the thermal barrier had caused surges in the outlet line. The surges in flow caused automatic closure of CCW-626, which isolated all three RCP thermal barriers.

1945 - Valve CCW-626 was manually blocked open. This allowed cooling water to flow through the thermal barriers thus reducing temperatures below the boiling point in "C" RCP. After temperatures were reduced CCW-626 was unblocked and returned to normal operation in the open position.

1950 - Containment inspection complete. All personnel exited containment and entrance locked.

2000 - Breakers were pulled on containment sump pumps to prevent overfilling of waste holdup tank. Water was originating from reactor coolant drain tank and floor drains in "C" RCP bay.

2007 - Personnel entered containment to take air samples and noted no steam or leakage from RCP's.

2013 - Started "B" RCP bearing oil lift pump in an attempt to lower shaft, provide more seal clearance and re-establish seal flow.

2015 - Stopped "B" RCP bearing oil lift pump. Failed to establish seal flow through No. 1 seal.

2026 - Personnel exited containment.

2110 - An entry was made into containment to manually rotate "A" and "B" RCP's in an effort to re-establish seal flow. No inspection of "C" pump was performed during this entry.

2206 - Personnel exited containment. Failed to establish seal flow through No. 1 seals.

2215 - The Operating Supervisor called Westinghouse project engineer and notified him that seal flows on "A" and "B" Reactor Coolant Pumps were lost, and that "C" pumps's No. 1 seal had opened. It was decided that coolant pump operation was desirable for proper mixing of boron in preparation for cooldown. Also a more controlled cooldown would be possible with pump operation. Westinghouse advised that "C" pump could be operated with No. 1 seal leakoff isolated as long as No. 2 seal remained intact.

2242 - Started "C" RCP.

2257 - Prepared for cooldown by use of main condenser.

2308 - Blocked valve CCW-626 open to prevent possible loss of thermal barrier cooling water.

2310 - Increased seal water injection flow to RCP "C" by a factor of 5 to prevent possible overheating of pump bearing.

2316 - Received control panel indication of 0.5 ft. of water in containment sump not later than 2316 hours.

2330 - Reactor Coolant System boron concentration was 1038 ppm which is approximately cold shutdown concentration.

0015 - Pressurizer level started falling rapidly due to failure of No. 2 and No. 3 seals of "C" RCP. Stopped "C" reactor coolant pump.

0016 - Started "A safety injection (SI) pump. Opened valves SI-866A and SI-866B, hot leg safety injection to loops "B" and "C". Lowest level reached in pressurizer was 6% on level indicator LI-462 (cold calibration). Strip chart indication reached zero and remained there for about 10 minutes.

0018 - Started "B" and "C" safety injection pumps. Pressurizer level decrease stopped.

0035 - Opened valve CVC-307, seal water bypass, in an attempt to reduce a source of the loss of primary coolant to containment.

0036 - Diverted charging flow from the cold leg of loop "B" to auxiliary pressurizer spray (opened valve CVC-311) to reduce Reactor Coolant System pressure, (1150 psig at this time). The pressurizer steam void was rapidly collapsed by the auxiliary spray and pressure dropped accordingly. It was necessary to use auxiliary spray since normal spray was lost when the coolant pumps were stopped.

0039 - Stopped "C" SI pump due to rising pressurizer level. The safety injection pumps and valve CVC-311 were used during the remainder of the cooldown to control pressurizer level and pressure.

0043 - Started HVH unit no. 4, (containment recirculation fan and cooler) to reduce containment pressure and temperature. Prior to startup of the fourth unit, three HVH units were in operation.

0048 - The SI accumulators partially discharged their volumes into the primary system. The discharge isolation valves were closed at this time to terminate this injection phase.

0100 - Reactor coolant system boron concentration at 1521 ppm. Containment internal pressure reached a maximum of 3 psig.

0145 - Opened condenser vacuum breaker in preparation to terminate cooldown through the main condenser.

0151 - Started "D" Service Water Pump and "B" Service Water Booster Pump (cooling water to HVH units) to aid in the reduction of containment pressure and temperature.

0215 - Shut main steam isolation valves. Cooldown through the main condenser was terminated.

0223 - Started "A" component cooling water pump in preparation to go on residual heat removal system (RHR).

0230 - Started operating RHR pumps one at a time and opened valves 744A and 744B (discharge valves) and 750 and 751 (suction valves) to warmup RHR system. Pressure in the primary system was approximately 400 psig. Proceeded with plant cooldown as per General Operating Procedure GP-1D.

0330 - Reactor coolant system boron concentration at 1861 ppm.

0341 - Residual Heat Removal System in service. Cooldown proceeding as per GP-1D.

0440 - Stopped using S.I. system to maintain level.

0448 - Reactor coolant system at cold shutdown, (less than 200°F).

0517 - Commenced decreasing primary system pressure from 100 psig to 0 psig.

0629 - Entry into containment was made for purpose of inspection. Contained air supply packs, (Scott Air Packs), were used during entry. The bottom floor of containment was flooded to a height of 8 to 10 inches. No further inspection was made. Recovery phase initiated at this time.

7. Designation of Apparent Cause of Occurrence

The failure of the reactor coolant pump seal system created the occurrence. This is classified as an abnormal occurrence under Technical Specification 1.8.e, abnormal degradation of one of the several boundaries designed to contain the radioactive materials resulting from the fission process. This seal system consists of three seal surfaces - No. 1 seal is the point of primary pressure drop, No. 2 seal maintains back pressure on No. 1 and diverts seal leakoff from No. 1 seal to the volume control tank, and No. 3 seal helps maintain standpipe backpressure on No. 2 seal. Both No. 1 and No. 2 seals are designed to maintain system pressure.

8. Analysis of Occurrence

The occurrence resulted in no offsite releases or exposures. At no time was there any danger to the personnel involved. Due to the seal failure, overheating of the pump shaft and seal housing occurred. This will necessitate the replacement of the seals and housing, pump shaft, and associated equipment.

During the transient, there was no reversal in coolant flow and the core remained covered. Maximum temperature reached at the core exit was approximately 550°F shortly after the trip. About the time that cold shutdown conditions were reached, it was determined that another steam bubble existed in the RCS. To reduce the leak rate it was desirable to reduce system pressure. This was attempted by opening valve 311 (auxiliary spray) to collapse the pressurizer bubble. When valve 311 was opened the RCS pressure did not drop noticeably, but the pressurizer level increased rapidly (more rapidly than charging and SI would raise it). When valve 311 was shut, pressurizer level decreased rapidly as the bubble reformed in the pressurizer. Core thermocouple temperatures showed the reactor temperature to be stable and later when the reactor head vent was opened, little gas or steam escaped. The second bubble probably existed in the steam generator tubes. Due to loss of RCS circulation and the limited steam that had been drawn during the cooldown, none after placing RHR in service, the steam generators remained relatively hot. When pressure in the system was reduced from 400 psig to 100 psig, a bubble could have formed in one or more steam generators.

Proper operation of safeguards equipment and actions taken by the control operators prevented more extensive damage after the seal failure. All systems functioned as designed during the transient and the expected results were achieved.

Apparently pressure surges and high seal leakoff temperatures damaged the No. 2 seal of "C" RCP.

As a result of this incident several other abnormal occurrences took place which were a direct result of the original problem. The primary leakage exceeded those limits given in Section 3.1.5 of the Technical Specifications. This is classified as an Abnormal Occurrence under specification 1.8.b, violation of a limiting condition for operation established in the Technical Specifications. As the leak increased in magnitude the containment pressure, (3 psig at maximum) exceeded 2 psig

internal pressure, which is a violation of specification 3.6.2. This is also classified as an abnormal occurrence under specification 1.8.b. As a result of the subsequent forced cooldown, excessive cooldown rates were experienced, resulting in a violation of Section 3.1.2 of the Technical Specifications.

9. Corrective Action

Plant cooldown was initiated as soon as conditions permitted. When No. 2 and No. 3 seal failed, operations personnel started depressurizing as fast as conditions would allow in order to reduce the coolant loss through the seal. Safeguards equipment was used as needed in order to maintain the reactor in a safe condition. Proper operating and emergency procedures were used to reduce pressure and temperature to cold shutdown conditions.

To prevent reoccurrence of this situtation new seal and associated parts are being installed under the direction of pump vendor representatives and CP&L job coordinators. All parts being installed shall be certified and necessary quality assurance documentation and control maintained.

Since this was the first major incident involving a sizable loss of coolant at H.B. Robinson, the special procedures used to gain control over the transient will be reviewed to determine if any areas warrant revision.

10. Failure Data

No previous seal failures that resulted in loss of primary coolant to containment free space have occurred at H.B. Robinson.

CAROLINA POWER AND LIGHT COMPANY

H.B. ROBINSON STEAM ELECTRIC PLANT

UNIT NO. 2

INCIDENT REPORT NO. 4

MAY 5, 1970

Robinson File No. 2-0.1-a

At 3:20 P.M. on April 28, 1970, while setting safety valves on the secondary side of the three steam generators, a rupture occurred which resulted in a partial depressurization of the RCS and an uncontrolled steam release from No. 3 steam generator. This incident occurred during a period of Hot Functional testing before any fuel had been loaded in the reactor.

Seven men were testing and observing the safety valves in close proximity to the failed component. At the time of failure they suffered burns and other injuries as a result of the erupting steam.

Five of the seven were admitted to a hospital after emergency treatment. Three additional men were on the turbine deck at the time of the failure and witnessed flying debris before taking cover.

Initial Conditions

A. Primary System

1. Three (3) reactor coolant pumps in operation.
2. RCS pressure on automatic control at approximately 2225 psig.
3. RCS temperature was approximately 533°F, being controlled by pump heat and steam generator blowdown in conjunction with limited feedwater addition.
4. One (1) charging pump in service on automatic control.

5. Makeup to the volume control tank from the two monitor tanks was being controlled automatically.
6. Letdown was through the 45 gpm orifice and through "A" mixed-bed demineralizer.

B. Secondary System

1. Steam pressure was being controlled at 880 to 900 psig by control of the RCS temperature. These pressures were being verified by local pressure gauges at the safety valve level.
2. All three steam generator isolation valves were closed.
3. All three steam generator isolation bypass valves were closed.
4. The motor driven auxiliary feedwater pumps were lined up to take suction from the condensate tank and feed the steam generators as needed to maintain proper levels.
5. The steam generator bottom blowdown valves to the S.G. blowdown tank were open and the needle valves at the blowdown tank throttled to approximately one half turn open on all three generators.
6. All three steam generators were being maintained at approximately 70% level as indicated on the wide range level recorder.

Cause of Steam Release

Representatives of Crosby Valve Company had been at work on the secondary safety valves since 8:00 A.M., checking lift pressures, Westinghouse, Carolina Power and Light Company, and construction personnel were observing and assisting in these tests. At approximately 3:00 P.M. all safety valves on steam generators 1 and 2 had been checked and the control room notified that the crew was moving to steam generator No. 3. The test rig was set up on the safety valve located nearest the turbine deck. This valve was "factory" set to lift at 1140 psig. At 3:20 P.M., an exceptionally loud steam release was heard. Subsequent investigation revealed that the pipe stub from the No. 3 steam generator main steam line to the 1140 psig lift pressure safety valve had ruptured. This rupture was a complete 360° circumferential break, resulting in the safety valve being blown "clear" and leaving a 6" diameter hole open to atmosphere with no isolation valve between the rupture and the steam generator.

Operator Action

The operator immediately observed a sharp decrease in the following:

1. Pressurizer pressure
2. Pressurizer level
3. No. 3 steam generator level
4. RCS temperature

The following action was taken:

1. All reactor coolant pumps were immediately tripped.
2. Two additional charging pumps were put in service and all pumps set at maximum flow.
3. All pressurizer heaters were manually tripped off.
4. All letdown was secured.
5. Approximately five minutes later, the blowdown valves from No. 1 and 2 steam generators were closed and No. 3 steam generator blowdown opened full. Approximately ten minutes later, the bypass around the restriction orifice in the No. 3 steam generator blowdown line was fully opened.
6. Two boric acid pumps were started, taking suction from the Boric Acid tanks (which contained primary grade water) and discharging through valve 350 to the charging pump suction.
7. The demineralized water system was put in service and makeup supplied to the boric acid tanks and the monitor tanks.

Transients

1. Pressurizer pressure decreased to a low of 1862 psig in approximately ten minutes.
2. Pressurizer level immediately dropped from an indicated 23% to 0%.
3. RCS temperature dropped from 533°F to 320°F in approximately 55 minutes before stabilizing.
4. No. 3 steam generator level decreased from approximately 68% to 0% as indicated on the wide range recorder in 50 minutes. No. 1 and 2 steam generator levels remained relatively constant.

Recoveries

1. Pressurizer pressure decrease was terminated after ten minutes. As pressure increased, one charging pump was stopped to provide better control of the pressure increase.
2. Pressurizer level indication was regained in approximately 30 minutes and was increased to normal operating level (no load, 22%) thirty minutes later. At 20% level the second charging pump was stopped, the control group of heaters energized and at 22% level the level control was placed in automatic control.
3. The boric acid pumps were stopped and VCT makeup system was once again in a normal operating condition.
4. Twenty minutes after pressurizer level had been leveled out at 22%, feedwater was added to No. 1 and No. 2 steam generators and the blowdown valves to the steam generator blowdown tank set as follows: No. 1 and No. 2 open three turns, No. 3 closed. This was done to aid in equalizing temperatures between the primary and secondary system prior to restarting the reactor coolant pumps. A maximum of 100°F differential was desired.
5. At 5:17 P.M. steam generator No. 1 had 830 psig and steam generator No. 2 had 825 psig. Steam generator No. 3 had zero pressure and all valves closed which could enable water to be added under any circumstances.
6. At 5:30 P.M. No. 1 and No. 2 steam generator isolation valve bypass valves were opened and the reheater purge lines opened to atmosphere to lower pressure and temperature in the steam generators.
7. At 200 psig on No. 1 and No. 2 steam generators (which corresponds to approximately 387°F sat. temp.) "C" RCP was started with the RCS temperature at 320°F and RCS pressure at 1260 psig. "C" RCP was chosen as No. 3 steam generator was cooler than No. 1 and No. 2, therefore, the expected pressure spike would be less. The RCS pressure increased slowly to 1300 psig and RCS temperature increased rapidly to 360°F. The reheater purge lines were used in conjunction with the steam generator bottom blowdown and intermittent feedwater addition to cool the system to 425 psig and 345°F in preparation for putting the RHR system in service.

8. Due to necessity of completing the required run time on the reactor internals with three reactor coolant pumps operating, it was decided that the RHR system would be placed in service, RCS pressure maintained at 425 psig, RCS temperature decreased to 180°F and all three RCP's kept in service for approximately 36 hours.

9. With 425 psig and 345°F on the RCS, valve 142 was opened to pressurize the RHR system, valves 750 and 751 (No. 2 loop to RHR pumps suction) were opened and flow established through valve 142 (RHR letdown to the purification system) to warm up the RHR loop piping.

10. At 12:10 A.M., April 29, 1970 "B" RHR pump was put in service and run for five minutes. "A" pump as started and run for forty minutes at which time "B" pump was restarted.

11. At 1:08 A.M. valves 744 "A" and "B" (RHR return to RCS) were opened with all flow bypassing the RHR HEX's.

12. All steam dump to atmosphere on the secondary side was secured to prevent excessive cooldown rates.

13. Pressurizer level was increased by increasing charging flow and RCS temperature decrease to collapse the steam bubble in the pressurizer. Minimum temperature in the RCS were 260°F while maintaining 450°F in the pressurizer.

14. The system went solid at 5:15 A.M. and sprays were used to cool the pressurizer to RCS temperature.

15. At 7:30 A.M. with 230°F on the RCS, the reheater purge valves were reopened to prevent pulling a vacuum on the steam generators as cooling decreased below 212°F on the primary system.

16. RCS temperature was decreased to 180°F until such time as the reactor coolant pumps were stopped.

Points of Interest

1. The steam generator isolation valves and the steam generator isolation valves bypass valves had been closed approximately 30 hours prior to the incident.

2. The steam line from No. 2 steam generator had been used to supply steam to operate the steam driven auxiliary feedwater pump for test purposes approximately three hours prior to the incident.

3. "B" and "C" steam generator steam line drains had been blown before the incident. "B" was blown down for at least one hour dicharging a mixture of steam and water. "C" was blown only a short time with the same results.
4. An operator was dispatched to the charging pump room during the blowdown and reported no unusual occurrence while operating three charging pumps at maximum speed.
5. All operators on duty outside of control room had reported in person within two or three minutes
6. The P.A. system was useless during the blowdown due to excessive noise.

MALFUNCTION OF POWER OPERATED RELIEF VALVE #2

INITIAL CONDITIONS

Prior to the incident reactor power had been reduced to approximately 70% at 2330 on November 4, 1972, in preparation for running the turbine valve test. Problems had been encountered with the left stop valve. On the first test this valve would not close. The valve did close after being struck with a hammer. A Westinghouse representative involved in the valve test indicated that a buildup of phosphate between the valve shaft and bushings was the probable cause of the valve sticking. It was recommended that the valve be exercised several times. The valve was exercised approximately fifteen times and was left operating satisfactorily.

Testing then proceeded to the right valve group. The right governor valves were closed, and the right stop valve was ready for testing. When the right stop valve test push button was depressed, a simultaneous rapid load decrease from 520 MW to 150 MW was observed on the gross output meter. As the load decrease showed no sign of stabilizing, the reactor was manually tripped at 0103 hours on November 5, 1972. The reactor trip tripped the turbine. After the trip, steam dump was commenced. When the no load T_{avg} was reached, power operated relief valve RV-1 remained open for five minutes causing plant cooldown to 509°F. During this event the control operator commenced emergency boration and secured it after two minutes as conditions had stabilized. Startup requirements were insured and at 0156 the shutdown banks were pulled. At 0326 reactor startup was commenced. At this time the Reactor Coolant System temperature was being maintained at approximately 546°F using the condenser steam dump valves and power operated relief valves. The power operated relief valves were being used primarily to trim the steam generator levels.

SEQUENCE OF EVENTS

At 0333 while maintaining the reactor coolant temperature at 546°F, with the reactor subcritical, the power operated relief valve, RV-2 opened and failed to close, thereby, initiating a cooldown of the primary system. Efforts were made by the control operator to close the valve with no success. The valve is a fail close valve but isolation of control air and pulling of electrical fuses failed to close the valve. The control and shutdown rod banks were inserted, and the

rod bottom signals received for all rods by 0346. Emergency boration was begun 0345. At 0349 safety injection occurred as a result of coincident low pressurizer pressure and low level. Main steam isolation valve V1-3B was closed at 0402 with the intention of allowing the "B" steam generator to blow down and thereby minimize the primary system temperature and pressure transient. At 0430 it was decided to cool the plant to the cold shutdown conditions. Emergency boration was secured at 0440. At 0506 the safety injection pumps were secured. At 0508 an increase from a 70% level prior to the incident to a 98% level was noted in the pressurizer relief tank. The tank drain and vent valves were opened to reduce the tank level. At 0509 a containment sump high level light indication 0.5 feet level was received. Shortly thereafter valve VD-170B was opened to dump the pressurizer relief tank to the containment sump. At 0515 radiation monitor R-11 alarmed at 130,000 cpm and at 0520 the following information was conveyed to the control operator from the auxiliary operator:

1. A high level alarm existed on the condensate collection system on EV-CMS-1 at 1.5 feet, and level was continuing to increase.

   Point number 3 on the dew point recorder increased from $160^{\circ}F$ to $170^{\circ}F$.

At 0540 it was noted that component cooling water surge tank level had dropped from 49% to abut 4%. A short containment vessel inspection was performed at 0607 with the following observations:

1. Small amounts of water were observed on the containment vessel floor in the vicinity of the reactor coolant drain tank. The RHR pump suction from the containment floor, the excess letdown heat exchanger, and the area beneath the refueling canal.

2. No visible damage was apparent.

A second containment vessel inspection was performed at 0705, and a ruptured disc was discovered on the west end of the pressurizer relief tank. The other disc was deformed and possibly ruptured. An estimated depth of four feet of water was found in the reactor vessel sump. At 0900 the residual heat removal system was placed in service, and by 1500 the reactor coolant system temperature was

approximately 200°F with preparations being made for repairing the components damaged during the incident. During these events the reactor coolant system had been borated to a concentration of 1780 ppm of boron. By 1700 this concentration had been reduced to approximately 1075 ppm of boron which is 200 ppm above cold shutdown concentration.

CAUSE OF THE INCIDENT

The indicent was a result of the power operated relief valve, RV-2, having stuck in the "open" position while controlling reactor coolant system temperature. After disassembling the valve, the valve's inner valve and inner valve guide bushing were found to have been scored. This caused the valve to jam in the "open" position.

CORRECTIVE ACTION

Action taken to correct the cause of the incident consisted of removing and repairing the power operated relief valves RV-2. The surface of the inner valve and the valve guide bushing were polished correcting the cause of RV-2 having jammed. The same disassembly and repair was performed on RV-1 and RV-3 as a precautionary measure. Additional maintenance was done on other components as necessitated and convenienced by the incident. These are discussed later.

COMMENTS

The rapid load decrease occurring at 0103 on November 5, 1972, resulted in a pressurizer pressure of approximately 2320 psig. The pressurizer relief valves are set at 2335 psig and did not lift. An analysis of the attached data indicates that the differential pressure across the steam generator tubes did not exceed that of normal operation at 100% power.

The primary system cooldown rate is shown plotted for the transient indicating that cooldown due to the relief valve (RV-1) remaining open was within Technical Specifications.

The steam generator differential pressure and the reactor coolant system temperature during the transient resulting from RV-2 hanging open is shown on the attached data. Cooldown of the primary system was within specifications.

Maximum differential pressure of the S/G tubes occurred at 0408 with the pressurizer pressure being 1760 psig and secondary pressure being approximately 364 psig.

The maximum steam generator differential pressure during the entire incident was 1376 psig. The safeguards equipment performed its intended function during this incident. All safeguards equipment operated properly except valve SI-867A which did not open. The redundant valve in this system (867B) performed as designed allowing the safeguards system to perform its intended function. This valve was checked immediately follwing the incident and was found torqued out. The torque switch was reset and the valve was test operated satisfactorily. The valve was then test operated several times with satisfactory results. During safety injection the boron injection tank concentration of boron changed from 21,424 ppm to 10,785 ppm. Approximately 690 gallons of refueling storage tank water of 2,228 ppm boron going into the safety injection system would result in this concentration in the boron injection tank. The refueling storage tank water was at 70°F during most of the 77 minutes of operation of the safety injection pumps, the pumps were dead headed as primary system pressure remained above the pump discharge pressure.

Several events occurred during the safety injection which explain the reason for some of the observations made during the incident. Several low level alarms were received on the colume control tank resulting in charging pump header supply being provided from the refueling water storage tank through LCV-1188. The loss of component cooling water surge tank level from 49% to 4% (900 gallons) was a result of relief valve CS-715 dumping component cooling water to the containment vessel sump. This occurred due to the safety injection isolation of return component cooling water from the excess letdown heat exchanger. The pressurizer relief tank disk rupture occurred as a result of the low pressure letdown relief valve, valve 203, lifting and remaining open. With safety injection the isolation valves on both sides of this valve had closed. In the attempt to re-establish letdown flow following safety injection, the control operator opened the upstream isolation valve before the downstream valve was opened. As a result, valve 203 opened to relieve the pressure. The valve remained opened following the pressure decrease and continued to fill the pressurizer relief tank. This later also resulted in difficulties while trying to establish letdown

flow to go onto RHR as letdown was being dumped to the pressurizer relief tank. Later investigation into this problem revealed that the valve bellows had unscrewed from the valve stem and caused the valve to jam open.

The consequences of the safety injection have been investigated, and it is concluded that the primary system has not been degraded in any way. Thermal effects were minimal as only a small quantity of water was injected by SI, and whatever was injected was added at a slow rate. Data is attached showing the time response of the primary system temperature. No safety limits were exceeded during the injection. Westinghouse was conferred with, and it was also their conclusion that no degradation of the primary system occurred as the conditions of this incident were less damaging than those of analysis done previously on other similar plants. A copy of the letter from Westinghouse substantiating this is attached.

The release of activity from the relief valve RV-2 has been calculated. Gross beta and gamma activity released was 0.217 millicuries. Particulate activity released was 0.217 millicuries, and tritium activity released was 1.561 millicuries. These values are very small and well within the release rates permitted.

As a result of the investigation of the incident, several repairs were made to correct or improve the plant equipment. The turbine stop valves were disassembled. A phosphase buildup between the valve shaft and valve bushing was found as anticipated. The valves were cleaned, then reassembled. The problem of the phosphate buildup will be analyzed furhter. A carryover test will be conducted follwoing the return to power.

The low pressure letdown relief valve was disassembled, repaired, and reinstalled.

New rupture discs were installed on the pressurizer relief tank.

Maintenance was performed on the power operated relief valves as discussed under corrective actions. The relief valve vendor, W.K.H. Company, was consulted, and they indicated that the valves could be returned to service. A possible future

modification of the valve material was discussed as a preventative measure to prevent future valve scoring problems. This will be investigated further and action taken if it is deemed necessary. Valve operation will be minimized until a conclusion is made.

On November 5, 1972, the plant nuclear safety committee held a meeting to discuss the incident. It was concluded during the meeting that the safety of the plant was insured. The committee decided that the incident should be reported to the A.E.C.

A meeting of the company nuclear safety committee was held on November 7, 1972. It was recommemded that a leak check of the primary system and an inspection of all safety injection penetrations into the primary system be made prior to making the reactor critical.

On November 8, 1972, the plant nuclear safety committee met to discuss the incident further. After reviewing the data it was concluded that no safety question was unresolved; and therefore, the plant could return to power following the precautions recommended by the company nuclear safety committee.

As recommended, the Reactor Coolant System piping was inspected at the following conditions prior to startup:

DATE	PRIMARY TEMPERATURE °F	PRIMARY PRESSURE PSIG
11/7/72	255	400
11/8/72	410	650
11/8/72	500	1500
11/8/72	500	2235

The areas where SI penetrations enter the primary system were given a thorough visual inspection, and no abnormal condition was observed.

At 1317, on November 8, 1972, a primary system leakage rate test was performed with a normal leakage rate of 0.17 cpm being determined.

The three power operated relief valves on the steam lines were also test operated successfully by fully opening and closing the valves at secondary pressures of 85 psig and 700 psig. The later test was observed by Mr. Dick Cubitt of the A.E.C.

SEQUENCE OF IMPORTANT EVENTS FOR INCIDENT AT R.E. GINNA POWER PLANT

9:25	The following alarms and indications were received: (1) Charging pump speed alarm (2) B S/G level deviation alarm (3) B S/G steam-flow/feed flow mismatch alarm (4) Pressurizer level and pressure deviation alarms (5) Air ejector radiation monitor (R-15) alarm (6) Pressurizer low pressure alarm (2185 psig)
9:26	Power reduction commenced; steam dumps armed
9:27	Third charging pump started
9:28	Steam dumps modulating shut Automatic reactor trip (Lo-Press 1873 psig) Automatic safety injection (1723 psig) Feedwater isolation - automatic start Motor driven AFW pumps start
9:29	RCP's tripped manually Pressurizer indicated empty Turbin driven AFW pump started (Lo-Lo Level in S/G)
9:30	Initial RCS depressurization stopped at 1200 psig
9:32	'B' S/G steam supply to turbine driven AFW pump secured
9:38	Operator used steam dumps in manual to cooldown plant
9:40	Isolated 'B' S/G Cold leg temperature for 'B' loop dropped to approximately 340°F
9:48	Secured AFW pumps to control level in 'A' S/G

9:53	Shut manual isolation valve to 'B' S/G PORV
9:55	'B' S/G level off-scale high on narrow range indication
9:57	SI and containment isolation reset
10:07	Operator cycled pressurizer PORV-twice
10:09	Cycled pressurizer PORV again this time the valve sticks open
10:11	Pressurizer PORV valve fully closed. Pressurizer level off-scale high
10:19	'B' S/G safety valve lifted and closed (safety valve lifted four more times during event)
10:38	Safety injection flow terminated
10:42	Energized pressurizer heaters to re-establish pressurizer steam bubble
11:21	Started 'A' RCP
14:00	Plant cooldown and depressurization in progress

PTS FINAL EXAM

1. State three stresses associated with the reactor vessel. (1.5)

2. Why is there a shift of RT_{NDT} during a reactor vessel's lifetime? (1.0)

3. Using the given heatup and cooldown curves, state whether the following temperatures and pressures for the moderator are permissible.

   a. Heatup rate of 20°F/hour with temperature at 450°F and pressure at 2000 psig. (0.5)

   b. Cooldown rate of 30°F/hour with temperature of 400°F and pressure is 800 psig. (0.5)

4. What changes in boron concentration could be observed in an RCS in which significant boiling is occurring? Why? (1.0)

5. What are four indications of a loss of coolant accident? (1.0)

6. What instrumentation would you use to determine whether or not you had exceeded pressure-temperature limits for the reactor vessel? (Be specific) Explain why. (1.0)

7. On a large steam break accident what is the SI termination criteria? (2.0)

8. Define - Pressurized thermal shock (PTS). (1.0)

9. What are three indications of a steam generator tube rupture? (1.5)

10. After the operator has depressurized the RCS to 870 psig during the recovery from a steam generator tube rupture, what criteria is then used for SI termination? (1.0)

11. Why is a large LOCA not a PTS (pressurized thermal shock) concern? (1.0)

12. a. For a LOCA, which is the most limiting case for PTS (pressurized thermal shock) consideration? (1.0)

    b. Why?

13. On a large steam break transient how may the operator halt the pressure increase? (1.0)

14. Make a graph of:

    a. Pressure vs. time (1.0)

    b. Temperature vs. time (1.0)

    for a main steam line break with RCP's running

15. During a spurious safeguard actuation, is the operator required to meet the EI-1 termination criteria prior to securing the safety injection system? Explain. (1.0)

16. Of the following conditions, state if a PTS issue is or is not a concern.

    a. Reactor trip, turbine valves stick open (.5)

    b. Reactor trip one rod stuck out (.5)

    c. Solid plant, PCV-145 fails shut while charging (.5)

    d. Refueling outage and steam generator overfilled (.5)

17. The low pressure setpoint for SI pump termination in a LOCA has been changed. (1.0)

    a. What is the setpoint?

    b. Why was it changed?

18. On November 5, 1972, HBR experienced a S/G PORV malfunction. What two factors contributed to the uncontrolled cooldown? (1.0)

19. a. What were the initial indications (alarms) that were received in the R.E. Ginna incident? (1.0)

    b. Were these indications adequate to alert the operators to the magnitude of the problem? (.5)

    c. When the PORV stuck open, it resulted in a rapid pressure decrease and increase in pressurizer level. What did this indicate to the operator? (1.0)

SIMULATOR EXERCISE GUIDE

EXERCISE: Stm. Gen. PORV Failure **FILE NO.** PTS-1 **TIME** 2 Hrs.

OBJECTIVES: Upon completion of this exercise, the student will be able to:

1. Correctly analyze a small steam line break accident.
2. Take the proper actions to minimize the plant cooldown following a steam break in accordance with EI-1.
3. Limit RCS repressurization following S/G dryout to ensure limits of the cooldown curve.

REFERENCES - RELATED LER'S:

HBR incidents: 1) Separation of steam gen. safety valve
2) PORV failed open ≡ power

INITIAL CONDITIONS: IC 12

Present		Previous
100%	PWR	100%
586°	T_{avg}	586°
380 ppm	Boron	380 ppm
208 D	Rod Hgt.	208 D

INSTRUCTOR GUIDE:

Update Prodac.

SHIFT TURNOVER INFORMATION:

Give plant conditions. Equilibrium full power conditions. Air is isolated to "A" MSIV to repair fitting (accumulator is holding valve open). Anticipate 15-30 mins. to repair. "A" S/U transformer 00S for routine maintenance. All other conditions normal.

MALFUNCTIONS	OVERRIDES	REMOTE OPS.
T-O HBR Runback T-0 S/U Trans Failure (Both) T-10 "A" Main Steam PORV open	T-10 "A" MSIV shut T-0 "A" S/U Trans Differential Trip Annunciator (Ann. Tableau)	

SUPPLEMENTAL INFORMATION:

Trip results from stm. line flow SI. Blackout follows & cannot be restored. This causes a 100°F cooldown in approx. 15 mins. on "A" reactor coolant loop.

EXPECTED RESPONSE: AS PER EXERCISE PERFORMANCE CHECKOFF PTS-1

SUCCESSFUL COMPLETION OF THIS EXERCISE FULFILLS THE FOLLOWING NRC AND INPO REQUIREMENTS:

Control Room Guide
(Points to Stress)

1. Inserts reactor trip
   a. Full power plus PORV
   b. KW/ft limits
   c. Verifies reactor trip and safety injection

2. Blackout
   a. D/G starts
   b. Blackout sequence

3. "A" PORV
   a. Realize it's stuck
   b. Trys to close - all means
   c. Isoslates feed flow
   d. Limit cooldown and cooldown rate

4. Anticipates S/G dryout
   a. Uses all available indications
   b. Understands potential consequences
      (1) Repressurization
      (2) Thermal shock vs. subcooling
   c. Saturated conditions
   d. Uses Tc indications and knows why

5. Stabilizes plant

   a. Uses good S/Gs

   b. Temp-press "in bounds" (depressurizes if necessary)

   c. Core being cooled (maintain adequate subcooling)

   d. Meets SI termination criteria

      (1) Understands criteria

      (2) Stops SI to limit repressurization

      (3) Monitors wide range Tc

SIMULATOR EXERCISE PERFORMANCE/OBSERVATION RECORD

Course ________________ Group ____________ Date ________________

Instructors ________________ (Lead) ________________

Grading: S = Satisfactory U = Unsatisfactory

I. Exercise ______________________________

A. Initial Conditions/Scenario--Exercise Guide __________

B. Shift Assignments

			R_X Su		ρ Manipulations	
			Per.	Sup.	Per.	Sup.
1.	SF					
2.	SRO					
3.	RO					
4.	BOP					
5.	STA					

II. Evaluation

	SF	SRO	RO	BOP	STA
A. General					
1. Supervisory ability--effective direction of others					
2. Operator communications--passes along info accurately and promptly					
3. Annunciator response--immediately responds--uses alarm procedure					
4. Use of procedures--pulls procedure and utilizes					
5. Coordination--systematic and logical approach					
6. Dexterity--performs with ease; can perform more than one task at a time					
7. Periodic checks of instruments					
a. Compares redundant channels					
b. Compares meter to recorder					
c. Recorder pens inking					
8. Alertness--awareness of surroundings; watchfulness					
9. Attitude--constructive; positive					
10. Accuracy--use of curves, etc.					
B. Shift Routines					
1. Shift turnover					
2. Hourly logs					
3. Chart recorders					
4. Review control board					
5. Test annunciator lights					

C. Exercise Performance (File No. PTS-1)

	SF	SRO	RO	BOP	STA
1. "A" MSIV shut					
a. Insert reactor trip	___	___	___	___	___
b. Verify reactor trip	___	___	___	___	___
(1) Rods bottom					
(2) Turbine valves shut					
(3) Tavg approaching no load					
(4) EI-14					
c. Verify safety injection (EI-1)	___	___	___	___	___
2. Blackout					
a. Immediate actions	___	___	___	___	___
(1) Emergency lights					
(2) D/G starts					
(3) Verifies loads					
(4) EI-7					
b. Subsequent actions	___	___	___	___	___
(1) Starts other needed components					
(2) Verifies S/G PORVs maintaining Tavg at no load					
(3) Initiates P.E.P.	___	___	___	___	___
3. Stuck open PORV					
a. Attempts to close	___	___	___	___	___
(1) At RTGB					
(2) Locally					

	SF	SRO	RO	BOP	STA
b. Isolates feed to faulted S/G	___	___	___	___	___
c. Refers to EI-1., App. B	___	___	___	___	___
4. S/G dryout					
a. Monitor RCS	___	___	___	___	___
(1) Temp.					
(2) Press.					
(3) Cooldown rate					
b. Anticipates dryout	___	___	___	___	___
(1) Use good S/Gs					
(2) Press. control					
c. Cooldown curve	___	___	___	___	___
(1) Depressurize (cold loop)					
(2) Subcool (hot loops?)					
5. Stabilize plant	___	___	___	___	___
a. Meets termination criteria					
b. Terminates SI					

Part C:

Exercise Critique:

Overall Group Evaluation (sat/unsat) ____

Part D:

Students Constructive Comments, Simulation Improvement:

Instructor's signature ____

SIMULATOR EXERCISE GUIDE

EXERCISE: Small Break LOCA - PZR PORV Fails Open **FILE NO.** PTS-2 **TIME** 2 Hrs.

OBJECTIVES: Upon completion of this exercise, the student will be able to:

1. Recognize saturated conditions in the reactor coolant system and take the correct actions to keep the core cooled.
2. Limit the RCS cooldown and resultant thermal shock on the pressure vessel.
3. Maintain the temperature & pressure of the reactor coolant system within the bounds of the cooldown curves.

REFERENCES - RELATED LER'S:

Three Mile Island
HBR - PORV failed open due to incorrect spring pressure & block valve failed to close.

INITIAL CONDITIONS: IC 4

Present		Previous
0	PWR	100%
557°	T_{avg}	586°
1068 ppm	Boron	840 ppm
228 S/D Banks	Rod Hgt.	202 S/D Banks

INSTRUCTOR GUIDE:

Update Prodac.

SHIFT TURNOVER INFORMATION:

Give plant conditions. Reactor is shut down at the end of a planned maintenance outage. "B" containment spray pump out of service for repair (failed PT). Reactor S/U due after spray pump is repaired. Only one reactor coolant pump running due to conservation. Plant has been shut down for 122 hours.

MALFUNCTIONS	OVERRIDES	REMOTE OPS.
T-O HBR Runback	T-10 PK-444A Failed high T-10 PCV 444B Failed open T-10 PORV Isolation Valve 8000C Failed Open	T-O "B" CV spray pump BKR open

SUPPLEMENTAL INFORMATION:

PK-444A failure of card in control CKT
PCV-444A jammed on backseat
Block valve motor burned up (If operators give maintenance a "free hand" at repairing, remove the isolation valve malfunction when pressure has returned to 1400 psig)

EXPECTED RESPONSE: AS PER EXERCISE PERFORMANCE CHECKOFF PTS-2

SUCCESSFUL COMPLETION OF THIS EXERCISE FULFILLS THE FOLLOWING NRC AND INPO REQUIREMENTS:

Control Room Guide
(Points to Stress)

1. Identifies PK-444 failure
   a. Checks relief line temp.
   b. Isolates PORVs
   c. Manually shut spray valves
   d. Attempt to keep pressure up w/heaters

2. Identifies PORV stuck open
   a. Made attempts to shut
   b. Made attempts to isolate
   c. Recognize pressure decrease will continue

3. Safety injection
   a. Manually insert on pressure decrease
   b. Components checked
   c. RCP secured at 1300 psig
   d. Phase A isolation checked
   e. Uses EI-1, Appendix B

4. During depressurization
   a. Awareness of subcooling
      (1) Incore temps
      (2) T_C & T_H
      (3) Monitor pressure

(4) Saturation

b. Cooldown rate considerations

(1) Estimates of rate

(2) What is causing cooldown

(3) Check cooldown curve

(4) Continue to monitor temp. and pressure

5. During repressurization

a. Operator awareness of SI Flow $\geq$ leak flow

(1) Monitor pressurizer level

(2) Monitor pressure

b. Operator actions to reduce pressure increase

(1) Why necessary

(2) Ensure PZR heaters off

(3) SI termination

(4) Limit SI flow

(5) Letdown and reduce charging

(6) Open another PORV

6. Operators recognize this as P.E.P. event

a. PEP procedures out

b. Can identify appropriate plan

c. Initiating announcement and calls made

7. SI termination

a. Termination criteria verified and met (may require management concurrence to terminate if pressure <1560 psig)

- b. Unnecessary equipment secured
- c. Terminate or control SI flow (limit cooldown)
- d. Control cooldown rate to within limits
- e. Control depressurization (do not repressurize)
- f. Stabilize plant

8. Operators recognize need for cooldown and depresssurization
   - a. Procedures out
   - b. Discussion of course of action
   - c. Monitoring containment pressure and sump levels
   - d. Monitoring containment radiation levels

SIMULATOR EXERCISE PERFORMANCE/OBSERVATION RECORD

Course ______________________ Group ____________ Date ________________

Instructors ______________________ (Lead) ________________________

Grading: S = Satisfactory U = Unsatisfactory

I. Exercise ____

A. Initial Conditions/Scenario--Exercise Guide ________

B. Shift Assignments

			R_X Su		ρ Manipulations	
			Per.	Sup.	Per.	Sup.
1.	SF					
2.	SRO					
3.	RO					
4.	BOP					
5.	STA					

II. Evaluation

	SF	SRO	RO	BOP	STA
A. General					
1. Supervisory ability--effective direction of others					
2. Operator communications--passes along info accurately and promptly					
3. Annunciator response--immediately responds--uses alarm procedure					
4. Use of procedures--pulls procedure and utilizes					
5. Coordination--systematic and logical approach					
6. Dexterity--performs with ease; can perform more than one task at a time					
7. Periodic checks of instruments					
a. Compares redundant channels					
b. Compares meter to recorder					
c. Recorder pens inking					
8. Alertness--awareness of surroundings; watchfulness					
9. Attitude--constructive; positive					
10. Accuracy--use of curves, etc.					
B. Shift Routines					
1. Shift turnover					
2. Hourly logs					
3. Chart recorders					
4. Review control board					
5. Test annunciator lights					

C. Exercise Performancce (File No. PTS-2)

	SF	SRO	RO	BOP	STA
1. PK-444 failure	___	___	___	___	___
a. Attempts to isolate PORV					
1. Close valve					
2. Shut block valve					
b. Shuts spray valves					
2. Verify safety injection	___	___	___	___	___
a. S/D banks tripped					
b. Equipment started					
c. Phase "A" isolation					
d. EI-1, App. A					
3. Depressurization					
a. Trips RCP	___	___	___	___	___
b. Recognizes saturation	___	___	___	___	___
1. Incore temp.					
2. Pressure					
3. Saturation curve					
c. Monitors cooldown	___	___	___	___	___
1. Tc indication					
2. Pressure					
3. Cooldown curve					
4. Estimates rate of cooldown					
5. Can explain core cooling mechanism					

Item	SF	SRO	RO	BOP	STA
4. Repressurization					
a. Recognized by operator	___	___	___	___	___
(1) PZR level increasing					
(2) Pressure increasing					
b. Operator takes steps to minimize					
(1) Can SI be terminated					
(2) Reduce charging/SI flow					
(3) PZR heaters off					
(4) Letdown					
c. Operator aware of P.T.S. conditions	___	___	___	___	___
5. Initiates plant emergency procedures	___	___	___	___	___
a. Procedure used					
b. Less than one hour					
6. SI termination	___	___	___	___	___
a. Meets criteria					
b. Secures unneeded equipment					
c. Stop SI flow to limit repressurization (Management concurrence if <560 psig)					
d. Stabilize plant					
e. Control cooldown/depressurization					
7. Plant shutdown/cooldown commenced	___	___	___	___	___
a. Operators aware of containment pressure					
b. Operators aware of containment radiation levels					

Part C:

Exercise Critique:

Overall Group Evaluation (sat/unsat) ____

Part D:

Students Constructive Comments, Simulation Improvement:

Instructor's signature ____________

SIMULATOR EXERCISE GUIDE

EXERCISE: Main Stream Break (Downstream MSIV) **FILE NO.** PTS-3 **TIME** ____

OBJECTIVES: Upon completion of this exercise, the student will be able to:

1. Analyze a main steam line break and take actions to stabilize the plant following S/G dryout.
2. Monitor an uncontrolled cooldown and take the correct actions to minimize the pressure-temperature shock to the reactor vessel.
3. Control RCS pressure during and following an uncontrolled cooldown while maintaining the reactor in a subcooled condition.

REFERENCES - RELATED LER'S:

HBR - Inadvertent steam dump actuation at hot zero power.
Safety valve failure during hot functional tests

INITIAL CONDITIONS: IC 6

Present		Previous
100%	PWR	100%
586°	T_{avg}	586°
840 ppm	Boron	840 ppm
191 D	Rod Hgt.	208 D

INSTRUCTOR GUIDE:

Update Prodac.

SHIFT TURNOVER INFORMATION:

Give plant conditions. Dispatcher has given permission to come down to 70% to conduct turbine valve test.

MALFUNCTIONS	OVERRIDES	REMOTE OPS.
T-0 HBR Runback T-40 DEH control power failure T-41 "A" stm. line break downstream of MSIV	T-0 "A" MSIV failed open T-O "B" MSIV failed open	

SUPPLEMENTAL INFORMATION:

DEH failure causes turbine & reactor trip. Steam line separation due to "shock" of trip. Potential for SI actuation if MSIVs not closed promptly.

EXPECTED RESPONSE: AS PER EXERCISE PERFORMANCE CHECKOFF PTS-3

SUCCESSFUL COMPLETION OF THIS EXERCISE FULFILLS THE FOLLOWING NRC AND INPO REQUIREMENTS:

Control Room Guide
(Points to Stress)

1. Verify reactor trip
   a. All indications checked
   b. Done out load - communications
   c. Consults procedure

2. Main steam break
   a. Identifies break location
      (1) "A" S/G vs. "B" & "C" S/Gs - close "A" MSIV
      (2) Identifies downstream - shut all MSIVs
   b. Safety injection (if it occurs)
      (1) Checks components
      (2) Checks status light box
      (3) Verifies M.S. isolation - if not already done manually
   c. Uses EI-1, Appendix B
   d. Identifies "A" & "B" MSIVs stuck open
      (1) Attempt to close
      (2) Isolate feedwater
   e. During S/G blowdown
      (1) Trip RCPs at 1300 psig
      (2) Anticipates dryout
         (a) W.R. level
         (b) Steam pressure
      (3) Initiates P.E.P.

(4) Cooldown curve

3. Following dryout

   a. Maintain or reduce pressure

   b. Establish heat removal - good S/G

   c. Meets SI termination criteria

      (1) Understands criteria

      (2) Stops SI to limit repressurization

      (3) Monitors wide-range Tc

   d. Stabilizes plant

SIMULATOR EXERCISE PERFORMANCE/OBSERVATION RECORD

Course ______________________ Group ____________ Date ________________

Instructors ________________________ (Lead) ________________________

Grading: S = Satisfactory U = Unsatisfactory

I. Exercise ____

A. Initial Conditions/Scenario--Exercise Guide _________

B. Shift Assignments

		R_x Su		ρ Manipulations	
		Per.	Sup.	Per.	Sup.
1. SF	____	____	____	____	____
2. SRO	____	____	____	____	____
3. RO	____	____	____	____	____
4. BOP	____	____	____	____	____
5. STA	____	____	____	____	____

II. Evaluation

	SF	SRO	RO	BOP	STA
A. General					
1. Supervisory ability--effective direction of others	____	____	____	____	____
2. Operator communications--passes along info accurately and promptly	____	____	____	____	____
3. Annunciator response--immediately responds--uses alarm procedure	____	____	____	____	____
4. Use of procedures--pulls procedure and utilizes	____	____	____	____	____
5. Coordination--systematic and logical approach	____	____	____	____	____
6. Dexterity--performs with ease; can perform more than one task at a time	____	____	____	____	____
7. Periodic checks of instruments					
a. Compares redundant channels	____	____	____	____	____
b. Compares meter to recorder	____	____	____	____	____
c. Recorder pens inking	____	____	____	____	____
8. Alertness--awareness of surroundings; watchfulness	____	____	____	____	____
9. Attitude--constructive; positive	____	____	____	____	____
10. Accuracy--use of curves, etc.	____	____	____	____	____
B. Shift Routines					
1. Shift turnover	____	____	____	____	____
2. Hourly logs	____	____	____	____	____
3. Chart recorders	____	____	____	____	____
4. Review control board	____	____	____	____	____
5. Test annunciator lights	____	____	____	____	____

C. Exercise Performance (File No. PTS-3)

	SF	SRO	RO	BOP	STA
1. Verify reactor trip	___	___	___	___	___
a. Rods on bottom					
b. Turbine valves shut					
c. Tavg approaching no load					
d. Aux. transfer					
e. Uses procedure					
2. Main steam line break					
a. Identification	___	___	___	___	___
(1) High steam flow					
(2) Low steam pressure					
(3) Low S/G levels					
(4) Audible noise					
b. Immediate actions	___	___	___	___	___
(1) Shut MSIVs					
(2) Verify SI (if it occurs)					
(a) Components start					
(b) Phase "A" isolation					
(c) Steam line isolation					
(3) Refers to EI-1, App. B	___	___	___	___	___
c. Subsequent actions					
(1) Trys to close "A" & "B" MSIV	___	___	___	___	___
(a) RTGB					
(b) Locally					

	SF	SRO	RO	BOP	STA
(2) Isolates feed to "A" & "B" S/G	___	___	___	___	___
(3) Trip RCPs at 1300 psig	___	___	___	___	___
(4) Reset SI	___	___	___	___	___
(a) Stop RHR pumps					
(b) Stop D/Gs					
d. "A" & "B" S/G dryout					
(1) Monitor RCS	___	___	___	___	___
(a) Temperature					
(b) Pressure					
(2) Stabilize RCS					
(a) Use good S/G					
(b) Press. control					
(c) Control of AFW to "C" S/G					
(3) Cooldown curve	___	___	___	___	___
(a) Refers to curve					
(b) Depressurize to restore					
(c) Subcooling maintained					
e. SI termination					
(1) Meets criteria	___	___	___	___	___
(2) Holds pressure	___	___	___	___	___
(a) Stop pumps					
(b) PZR PORV					
(3) Secures equipment not needed	___	___	___	___	___
f. Begins cooldown	___	___	___	___	___
(1) GP-5A or					
(2) GP-6					

	SF	SRO	RO	BOP	STA
3. Initiates P.E.P.	___	___	___	___	___
a. Procedure used					
b. < 1 hour					
4. Added malfunctions					
a. ____________________	___	___	___	___	___
b. ____________________	___	___	___	___	___
c. ____________________	___	___	___	___	___

Part C:

Exercise Critique:

Overall Group Evaluation (sat/unsat) ____

Part D:

Students Constructive Comments, Simulation Improvement:

Instructor's signature ____________

SIMULATOR EXERCISE GUIDE

EXERCISE: Pressurizer Safety Leak Without Automatic Turbine Trip

FILE NO. PTS-4 **TIME** _____

OBJECTIVES: Upon completion of this exercise, the student will be able to:

1. Analyze and correctly identify a pressurizer safety valve leak.
2. Identify that the turbine did not trip automatically and take actions to secure the turbine.
3. Take actions to maintain subcooling and minimize potential pressurized thermal shock to the reactor vessel.

REFERENCES - RELATED LER'S:

INITIAL CONDITIONS: IC 6

Present		Previous
100%	PWR	100%
586°	T_{avg}	586°
840 ppm	Boron	840 ppm
191 D	Rod Hgt.	208 D

INSTRUCTOR GUIDE:
Update Prodac.

SHIFT TURNOVER INFORMATION:
Give plant conditions. No 00S equipment nor limiting conditions.

MALFUNCTIONS	OVERRIDES	REMOTE OPS.
T-0 HBR Runback	T-0 Turbine will not trip (Must use Card Reader)	
T-15 PZR Safety Leak (2%) T-20 Increase Leak to 20% T-45 Remove Safety Leak		

SUPPLEMENTAL INFORMATION: PZR safety valve starts to leak by. After about five minutes the safety fully opens resulting in rapid pressure decrease which results in reactor trip and SI. Turbine does not trip but can be secured by shutting MSIVs, securing EH pumps, or locally. Safety valve reseats when pressure restored due to high temperature in CU -spring expanded.

EXPECTED RESPONSE: AS PER EXERCISE PERFORMANCE CHECKOFF

SUCCESSFUL COMPLETION OF THIS EXERCISE FULFILLS THE FOLLOWING NRC AND INPO REQUIREMENTS:

b. Operator Actions to Reduce Pressure Increase
   (1) Why Necessary
   (2) Ensure PZR Heaters Off
   (3) Limit Charging Flow
   (4) Reset SI and Secure Unnecessary Components
   (5) Reestablish letdown
c. Operator Aware When Safety Goes Shut

7. **Operators Recognize as P.E.P. Event**

a. P.E.P. Procedures Out
b. Can Identify Appropriate Plan
c. Initiating Announcement and Cause Made

8. **SI Termination**

a. Termination Criteria Checked and Verified
b. Terminate or Control SI Flow (May Have to Consult Management if Pressure <1560 PSIG
c. Establish Cooldown
d. Control Cooldown Rate
e. Control Pressure
f. Stabilize Plant

9. **Operators Recognize Need for Cooldown and Depressurization**

a. Procedures Out
b. Discussion of Course of Action
c. Monitoring Containment Pressure and Sump Levels
d. Monitoring Containment Radiation Levels
e. Shutdown Margin

CONTROL ROOM GUIDE

(Points to Stress)

1. **Identify Safety Valve Leakage**

    a. Relief Line High Temperature Alarm
    b. Shut PORV Block Valves
    c. When Temp. Does Not decay Off - Must be a Safety
    d. Reopen PORV Block Valves

2. **Safety Full Open**

    a. Identify Rapid Pressure Decrease
    b. Manually Insert Reactor Trip
    c. Manually Insert Safety Injection
    d. Verify Reactor Trip

3. **No Turbine Trip**

    a. Identify Turbine Did Not trip
    b. Insert Manual Turbine Trip
    c. Take Other Steps to Stop Turbine
        (1) Shut MSIVs
        (2) Stop and Lock Out EH Pumps
        (3) Order Outside Auxiliary to Trip Turbine Locally

4. **Safety Injection**

    a. Components Checked
    b. RCPs Secured at 1300 PSIG
    c. Phase A Isolation Checked
    d. Use EI-1, Appendix A

5. **During Resultant Depressurization**

    a. Awareness of Subcooling
        (1) Incore Temperatures
        (2) T_e and T_H
        (3) Monitor Pressure
        (4) Saturation
    b. Cooldown Rate Considerations
        (1) Estimates of Rate
        (2) Understand What is Causing Cooldown
        (3) Check Cooldown Curve
        (4) Continue to Monitor Temperatures and Pressure

6. **During Repressurization**

    a. Operator Awareness of SI Flow $\geq$ Leak Flow
        (1) Monitor Pressurizer Level
        (2) Monitor Pressure

SIMULATOR EXERCISE PERFORMANCE/OBSERVATION RECORD

Course ______________________ Group ____________ Date ________________

Instructors ______________________ (Lead) ________________________

Grading: S = Satisfactory U = Unsatisfactory

I. Exercise ____

A. Initial Conditions/Scenario--Exercise Guide ________

B. Shift Assignments

			R_X Su		ρ Manipulations	
			Per.	Sup.	Per.	Sup.
1.	SF	________	____	____	____	____
2.	SRO	________	____	____	____	____
3.	RO	________	____	____	____	____
4.	BOP	________	____	____	____	____
5.	STA	________	____	____	____	____

II. Evaluation

	SF	SRO	RO	BOP	STA
A. General					
1. Supervisory ability--effective direction of others	____	____	____	____	____
2. Operator communications--passes along info accurately and promptly	____	____	____	____	____
3. Annunciator response--immediately responds--uses alarm procedure	____	____	____	____	____
4. Use of procedures--pulls procedure and utilizes	____	____	____	____	____
5. Coordination--systematic and logical approach	____	____	____	____	____
6. Dexterity--performs with ease; can perform more than one task at a time	____	____	____	____	____
7. Periodic checks of instruments					
a. Compares redundant channels	____	____	____	____	____
b. Compares meter to recorder	____	____	____	____	____
c. Recorder pens inking	____	____	____	____	____
8. Alertness--awareness of surroundings; watchfulness	____	____	____	____	____
9. Attitude--constructive; positive	____	____	____	____	____
10. Accuracy--use of curves, etc.	____	____	____	____	____
B. Shift Routines					
1. Shift turnover	____	____	____	____	____
2. Hourly logs	____	____	____	____	____
3. Chart recorders	____	____	____	____	____
4. Review control board	____	____	____	____	____
5. Test annunciator lights	____	____	____	____	____

C. EXERCISE PERFORMANCE (File No. PTS-4)	SF	SRO	RO	BOP	STA
1. Safety Valve Leakage	___	___	___	___	___
a. Actions on Reliefline High Temp. Alarm	___	___	___	___	___
(1) Close PORV Block Valves					
(2) Monitor Relief Line Temp.					
(3) Recognize as Safety					
(4) Reopen PORV Block valves					
b. Actions on Safety Full Open					
(1) Recognition (Pressure Decrease)	___	___	___	___	___
(2) Insert Reactor Trip					
(3) Insert SI					
2. Verify Reactor Trip	___	___	___	___	___
a. Rods on Bottom					
b. Temp., PZR Level, S/G Levels					
c. Use EI-14					
3. No Turbine Trip	___	___	___	___	___
a. Recognize Turbine Not Tripping					
b. Actions to Trip Turbine					
(1) Insert Manual Turbine Trip	___	___	___	___	___
(2) Shut All MSIVs					
(3) Stop and Lock Out EH Pumps					
(4) Trip Locally					
4. Verify Safety Injection	___	___	___	___	___
a. RCPs Secured at 1300 PSIG					
b. Equipment Started					
c. Phase A Isolation					
d. Use EI-1, Appendix A					
5. Depressurization					
a. Aware of Subcooling Status	___	___	___	___	___
(1) Check Core Thermocouples					
(2) Monitor T_C and T_H					
(3) Monitor Pressure					
(4) Check for Saturation					
b. Consider Cooldown	___	___	___	___	___
(1) Understand Cooldown Mechanism	___	___	___	___	___
(2) Check Cooldown Curve	___	___	___	___	___
(3) Concern About Repressurization					
(4) Continue to Monitor Temp. & Pressure					
6. Repressurization					
a. Recognized by Operator					
(1) PZR Level Increasing	___	___	___	___	___
(2) Pressure Increase					
(3) Can Explain SI Flow $\geq$ Leak Flow					

C. EXERCISE PERFORMANCE (File No. PTS-4) | SF | SRO | RO | BOP | STA

6. **Repressurization (Continued)**

   b. Operator Actions to Minimize
      (1) PZR Heaters
      (2) Charging Flow
      (3) Letdown
      (4) Consider SI Termination
   c. Operator Recognize Safety Reclosing

7. **P.E.P. Considerations**

   a. Operators Recognize
   b. P.E.P. Procedures Used
   c. Initiating Calls and Announcements Made
   d. Less Than One Hour

8. **SI Termination**

   a. Meet Criteria (May Have to Consult Management if Pressure <1560 PSIG)
   b. Secures Unnecessary Equipment
   c. Establish and Monitor Cooldown
   d. Control Pressure
   f. Stabilize Plant

9. **Plant Shutdown/Cooldown**

   a. Operators Aware of Need to Shutdown/Cooldown
   b. Containment Pressure Monitored
   c. Containment Radiation Levels Monitored
   d. Adequate Shutdown Margin
   e. Consult and Use Procedures