ATTACHMENT 1

GPU Nuclear

TECHNICAL DATA REPORT

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DEPARTMENT/SECTION Safety Analysis/Plant Contro

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Louis C. Lanese	1-17-84	N. G. Trikouros	1/18/84
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		J. G. Broughton	1-20-84

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ABSTRACT:

This report provides the plant specific guidelines which form the technical content of the new abnormal plant transient procedures. These guidelines are compared to the baseline documents from which they are derived. Any differences from the baseline documents are explained. The baseline documents for the guidelines are: The Oconee and TMI-1 ATOGs; a July 6, 1983 supplemental guidance to ATOG issued by B&W; and TDR 406, "Steam Generator Tube Rupture Guidelines".

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Originator L. LANESE Home Base 5450 Tel X2127

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TABLE OF CONTENTS

LIST OF FIGURES

TMI-1 PLANT SPECIFIC TECHNICAL GUIDELINES DERIVED FROM ATOG

1.0 PURPOSE

This report provides plant specific technical guidelines derived from the B&W Abnormal Transient Operating Guidelines (ATOG) developed for TMI-1. Guidelines provided in this report are the baseline document from which plant emergency procedures have been written. This report does not address the format of the procedures, nor does it include every step in the plant procedures. Other actions which are required for equipment protection, emergency plan implementation, Tech Spec compliance or which provide additional safety measures beyond the TMI-1 ATOG are not included.

This report also describes and explains differences between the TMI-1 plant specific guidelines and TMI-1 ATOG (Reference 1).

In the future in addition to other considerations regarding unreviewed safety questions, approval of the emergency procedures will include a review of the guidelines included in this report. Signature on a Procedure Change Request (PCR) will signify that the procedure meets the technical requirements of the plant specific guidelines; that the format is consistent with the procedure writers guide; and, that all other appropriate considerations have been considered i.e. that the change does not represent an unreviewed safety question.

2.0 TMI-1 PLANT SPECIFIC GUIDELINES

The TMI-1 plant specific guidelines were derived from the ATOG developed for TMI-1 by Babcock and Wilcox. That document in turn developed from the Oconee-3 ATOG which was submitted to the NRC staff for review in support of the B&W Owners Group Operator Support Committee response to staff requirements for improved emergency operating procedures.

The TMI-1 ATOG were reviewed in detail by a committee representing various disciplines. Comments from this review were discussed with B&W. As a result, the final TMI-1 ATOG was issued in April 1983. By this time, NRC staff comments on the Oconee document had in part also been incorporated into the TMI-1 volumes. Finally, on July 2, 1983, B&W provided the B&W Owners Operator Support Committee with supplementary material dealing with anticipatory transients without scram (ATWS) and interruption of natural circulation during small break LOCAs.

The plant specific guidelines were developed from the TMI-1 ATOG, the July 2, 1983 letter and existing plant emergency procedures.

Each new ATP has been compared to the baseline documents. Figures 1 through 7 provide comparisons of plant specific guidelines to the TMI-1 ATOG. ATOG steps are designated by dashed lines. Any steps deleted from ATOG are shaded. Section 3.2 explains the reasons for the differences.

The steam generator tube rupture procedures have not been compared to ATOG. The development work used to provide those guidelines not only included ATOG as source material, but also used other more recent experience and analyses. Furthermore, plant tests at TMI-1 have been used to confirm some of the analytical work upon which those procedures were based.

2.1 REACTOR TRIP (PSG 2.1)

VERIFY THE FOLLOWING:	IF VERIFICATION CANNOT BE MADE, THEN PERFORM THE FOLLOWING:
1a. REACTOR POWER DECREASING ON INTERMEDIATE RANGE AND LESS THAN 10%	o Start full HPI from the BWST o Initiate maximum letdown flow o Maintain primary to secondary heat transfer o Manually trip 1G-02 on 1L-02

NOTE: Do not take any subsequent actions which will reduce primary to secondary heat removal until power decreases below 10%.

1b. ALL RODS HAVE INSERTED	o Begin emergency boration
2. ALL MAIN TURBINE STOP VALVES SHUT	Trip EH-P-1A and EH-P-1B when power is less than 10%
3. FEEDWATER HAS RUNBACK	o Verify ICS automatically running back MFW flow. o If ICS is not controlling MFW flow, take hand control and run MFW back to control OTSG level. o If MFW flow is still excessive, then trip both MFW pumps.
4. NNI/ICS POWER ON	o If all subfeed power lights are off, then switch to alternate ICS/NNI power on console. o If any subfeed power light remains off, then refer to plant procedures for corrective action. Remaining steps in reactor trip procedure are of higher priority than restore-ation of ICS/NNI subfeed power at this point.
5. AT LEAST ONE AUXILIARY TRANS-FORMER HAS NORMAL VOLTAGE ON ITS SECONDARY	o Start or verify auto start and loading of at least one diesel generator. o Verify EFW. o Ensure a makeup pump is started and RCP seal injection is re-established. o Refer to plant procedures for loss of offsite power if either one or both diesel generators fail to start.

6. VERIFY PRESSURIZER LEVEL IS ABOVE 100 INCHES	o If unable to maintain pressurizer level then open MU-V217 o If MU tank is less than 55 inches, open MU-V14A or B as necessary to maintain MU tank level greater than 55 inches. o If unable to maintain pressurizer level above 20 inches, then initiate HPI
7. NO ESAS ALARMS	<u>RCS 1600 PSIG ALARM ON COMPUTER</u> o Verify HPI and LPI channels have actuated o Verify seal injection flow <u>HI-HI BUILDING PRESSURE</u> o Verify RB spray and RB isolation have actuated

NOTE: Do not proceed beyond Step 7 unless reactor power is below 10%.

8. NO SLRDS ALARMS	o Verify main feedwater isolation of affected OTSG
9. ADEQUATE SUBCOOLING MARGIN	o Trip all RCPs o Initiate HPI o Initiate EFW and raise OTSG level to 90-95% o Go to loss of subcooling guideline (PSG 2.2)
10. PROPER PRIMARY TO SECONDARY HEAT TRANSFER EXISTS	<u>FOR EXCESSIVE HEAT TRANSFER</u> o Throttle feedwater o Isolate the steam leak o Increase makeup as necessary o Go to guideline for excess heat transfer (PSG 2.3) <u>FOR LACK OF HEAT TRANSFER</u> o Verify MFW/EFW flow and go to lack of heat transfer guideline (PSG 2.4)
11. NO MAIN STEAM LINE OR CONDENSER OFF-GAS RADIATION MONITOR ALARMS	o Refer to OTSG tube rupture guideline (PSG 2.5)
12. PROCEED TO FOLLOW-UP ACTIONS. FURTHER ACTIONS ARE THE DECISION OF THE SHIFT SUPERVISOR.	

2.2 LOSS OF SUBCOOLED MARGIN (PSG 2.2)

1. Trip all RCPs.
2. Initiate HPI. (2 pumps full flow)
3. Verify EFW has auto started.
4. Raise OTSG level to 90-95%.
5. If excessive heat transfer exists, go to excessive heat transfer guideline (PSG 2.3).
6. Isolate possible sources of leakage.

   NOTE: Do not close the PORV or block valve if the plant has been placed on feed and bleed cooling.

   (PORV Block)
   (Spray Block)
   (Letdown Block)
7. If subcooled margin has been established, go to step 13, otherwise continue.
8. If incore thermocouples indicate superheat, then go to superheat guideline (PSG 2.8).
9. If core flood tanks are emptying, go to guideline for cooldown with a large LOCA (PSG 2.7).
10. If there is lack of primary to secondary heat transfer, go to lack of heat transfer guideline (PSG 2.4).
11. If there is indication of a SGTR, go to SGTR procedure.
12. If there is primary to secondary heat transfer and subcooled margin is not being recovered, then go to procedure governing cooldown with a small break LOCA (PSG 2.6).
13. Start RCPs, when restart criteria are met, and establish pressurizer spray as follows:

    13.1 Start one RCP per loop.

    13.2 Monitor RCS pressure while opening pressurizer spray valve to detect either a failed open spray valve or a spray line leak.

    13.3 Throttle HPI in accordance with rules for HPI throttling
14. If there is lack of primary to secondary heat transfer, go to lack of heat transfer guideline (PSG 2.4).

15. If there is indication of a SGTR, go to SGTR guideline (PSG 2.5).

16. If RCS is solid, go to procedure which governs establishment of a steam bubble or for performance of a solid RCS cooldown, otherwise continue.

17. Go to reactor trip guideline (PSG 2.1).

2.3 EXCESSIVE COOLING (PSG 2.3)

1. If HPI has not been initiated, increase makeup to maintain pressurizer level.

2. If pressurizer level cannot be maintained above 20 inches, initiate HPI.

3. If OTSG level greater than 95%, trip the mainfeed pumps.

4. Isolate the affected OTSGs (both if affected generator cannot be identified). Verify that SLRDS has actuated.

VALVE	OTSG A	OTSG B
MFW Startup	FW-V-16A	FW-V-16B
Main FW	FW-V-17A	FW-V-17B
TBV	MS-V-3D	MS-V-3A
	MS-V-3E	MS-V-3B
	MS-V-3F	MS-V-3C
ADV	MS-V-4A	MS-V-4B
MSIV	MS-V-1A	MS-V-1C
	MS-V-1B	MS-V-1D

5. If OTSG level and pressure did not stabilize, close the following valves on the OTSG with lower pressure.

VALVE	OTSG A	OTSG B
EFW	EF-V-30A	EF-V-30B
MS to EFW	MS-V-2A	MS-V-2B
TBVs & ADVs		

NOTE: If there is no discernable pressure difference, then isolate both OTSGs.

6. If OTSG pressure and level stabilize on either generator, restore main or emergency feed to the good generator(s), go to Step 9.

7. If subcooled margin is lost, go to loss of subcooling procedure.

8. If plant conditions permit restore main or emergency feed to one or both affected OTSGs.

9. If subcooled margin is lost, go to loss of subcooling procedure.

10. If OTSG tube rupture is indicated, then go to tube rupture guideline (PSG 2.5).

11. Feed one or both OTSGs to maintain level and control OTSG pressure to stabilize RCS cold leg temperature.

12. Control RCS heatup and pressurization to prevent pressurized thermal shock.

13. Control cooldown rate to limit shell/tube delta T less than 70F°.

14. Go to reactor trip guideline (PSG 2.1).

2.4 LACK OF HEAT TRANSFER (PSG 2.4)

1. If feedwater is available, go to step 7, otherwise continue.

2. If RC pressure increases to the PORV setpoint, go to step 5, otherwise continue.

3. Initiate FW.

   1.3.1 Start all the EFW pumps and open EFW injection valves.

   1.3.2 Reduce the number of RCPs to one per loop.

   1.3.3 If EFW is not available, use main FW.

   1.3.4 If neither MFW nor EFW are available, then attempt to restore EFW using plant procedure

4. If feedwater is re-established, go to step 7, otherwise continue.

5. Establish HPI Cooling.

   1.5.1 Initiate HPI (2 pumps full flow)

   1.5.2 Open PORV block valve

   1.5.3 Open PORV

   1.5.4 Run one RCP as long as adequate subcooled margin exists.

6. Go to HPI cooling guideline (PSG 2.9).

7. Attain appropriate OTSG level based on RCP availability and subcooled margin.

8. If the CFTs have emptied, then cool down using procedures that govern cooldown from a large LOCA with CFTs emptying.

9. If while attempting to re-establish heat transfer, RCS pressure increases to the PORV setpoint, then open the PORV until RCS pressure decreases to 100 psi above OTSG pressure.

10. Lower OTSG pressure until secondary Tsat is 40 to 60F° lower than incore T/C temperature. Maintain OTSG level.

11. If heat transfer is re-established, go to step 17, otherwise continue.

12. If RCPs are not available, then initiate HPI cooling and go to guideline governing HPI cooling (PSG 2.9).

13. If RCS cooldown rate is less than the maximum allowable by Tech Specs, then use RCP bumps to induce heat transfer (note: pump NPSH limits do not apply).

    Note - during the pump bumping process, continue at Step 2.13 and use all other appropriate procedures.

    13.1 Bump either RCP in the loop with the highest OTSG level.

    13.2 Allow RCS pressure to stabilize and determine whether heat transfer is established.

    13.3 If heat transfer is established, then go to 2.11, otherwise continue.

    13.4 After 15 minutes repeat 2.7.1 through 2.7.3 using another RCP. Continue until heat transfer is established or all four RCP bumps have been completed. Do not bump any one pump at less than 30 minute intervals. (Refer to OP 1101-1).

    13.5 If cooldown rate cannot be controlled below Tech Spec limit, then go to small break LOCA procedure without trying to induce primary to secondary heat transfer.

14. Lower OTSG pressure to induce heat transfer.

    14.1 Decrease OTSG pressure until secondary Tsat is 90 to 100F° lower than incore T/C temperature. Maintain OTSG level.

15. If one hour has passed since reactor trip and an RCP is operable, then start and run one RCP. Observe all pump limits, including emergency NPSH limits.

16. If heat transfer has not been re-established, then initiate HPI cooling and go to procedure governing feed and bleed cooling.

17. Verify primary to secondary heat transfer is established then recover from HPI cooling, if initiated.

    17.1 Close PORV

    17.2 If the PORV does not close, then close PORV block valve

    17.3 Throttle HPI, if permitted

18. Control OTSG pressure to stabilize RC temperature.

19. If OTSG tube rupture is indicated, then go to tube rupture procedure.

20. If subcooled margin does not exist, cooldown per procedure governing cooldown with a saturated RCS.

21. Return to reactor trip guideline (PSG 2.1).

2.5 OTSG TUBE LEAK/RUPTURE (PSG 2.5)

NOTE

Entry point condition for this guideline is either from another ATP or when tube leakage is greater than or equal to 1 gpm.

NOTE

For guidance within the abnormal transient procedure an OTSG tube leak is defined as a greater than 1 and less than 500 gpm failure, while a rupture is greater than or equal to 50 gpm failure.

IMMEDIATE ACTIONS

1. If the reactor was not tripped; THEN close MU-V-3 and begin to reduce load at a rate specified by Shift Supervisor to minimize the risk of a MSSV lifting.

2. If the reactor was tripped; Then complete the immediate actions of the reactor trip procedure and, proceed with plant cooldown per this procedure.

FOLLOW-UP ACTIONS

1. Continue to reduce power to less than 20 percent at the selected load reduction rate.

NOTE

When removing the first main feed pump (40 percent power), remove the feed pump that is being steam fed from the affected OTSG if known. Remove the feed pump per OP 1102-10.

2. By sampling OTSG's, surveying steam lines, observation of OTSG levels and feed rates, determine affected OTSG.

NOTE

Most affected OTSG should indicate higher level, lower feed rate, and/or higher Beta-Gamma, H^3, Na^{24}, I-133 and CS^{-137} sample results.

CAUTION

When the turbine is tripped it may be necessary to take manual control of turbine bypass valves to maintain secondary pressure below the main steam safety valve setpoints.

3. At less than 15 percent PWR take the turbine to manual and unload to "0" MWE. Verify that the turbine bypass valves automatically control header pressure below safety valve setpoints. At "0" MWE trip the turbine while closely monitoring OTSG pressure. Observe turbine stop valves closed.

CAUTION

The following power reduction and Rx trip will cause a significant RCS shrinkage, insure sufficient makeup to maintain normal pressurizer level. Adhere to Pressurizer Level Guide.

4. Place the diamond in manual and continue reducing Rx Pwr to less than 5%. When less than 5% reactor power, take manual control of the turbine bypass valves and then trip the reactor. Immediately adjust TBV closed to control the initial cool down following reactor trip and control OTSG pressure to prevent safety valve operation.

5. If the OTSG level rule of 90-95% is in effect, raise the unaffected OTSG to 90-95% before raising the affected OTSG to 90-95%.

6. Steam both OTSGs to reduce RCS to less than 540°F.

7. While reducing the RCS temperature to 540F, turn off PZR heaters and start pressurizer spray to depressurize RCS which minimize the subcooled margin. The pressurizer vent may be used to reduce RCS pressure. If the pressurizer vent is not sufficient, the PORV may also be used.

NOTE

Minimizing subcooling margins above 25°F will cause RCS temp/press to violate the fuel pin compression curve (OP 1102-11). This is acceptable during rupture emergencies, but requires engineering evaluation prior to next heat up. For other than tube rupture, fuel pin compression curves should not be violated.

8. When SCM has been minimized, control the turbine bypass valves and commence plant cooldown at less than 100°F/hr (1.6°F/min).

9. Reduce RCPs to one per loop, when the additional spray is no longer required to control SCM. RCPs must be reduced to less than 4 RCPs before RCS temp is decreased below 500°F.

NOTE

Keep RC-P-1A on for PZR spray.

10. Monitor shell to tube delta T and maintain it less than 70F° using MFW. If the OTSG is dry feed with minimal MFW. If the shell to tube limit is approached while steaming, reduce or secure the cooldown rate as necessary.

11. Confirm affected OTSG by sampling.

12. With RCS hot leg and incore thermocouples temperatures less than 540°F, only isolate the affected OTSG if BWST level is less than 21 ft. or off-site dose projections approach 50 mr/hr whole body or 250 mr/hr thyroid.

13. If required to isolate the affected OTSG(s), close the following:

NOTE

Assure MFP is being fed from unaffected OTSG or auxiliary steam. Assure gland steam is from the auxiliary boiler.

MS-V-1A and B or C and D
FW-V-17 A or B
FW-V-5 A or B
FW-V-16 A or B

FW-V-92 A or B
FW-V-85 A or B
EF-V-30 A or B
MS-V-92
MS-V-89 A and B or C and D
MS-V-13 A or B (close manual hand wheel)
MS-V-10 A or B
MS-V-3 D/E/F or A/B/C

14. If both OTSGs are required to be isolated and can no longer be used as a heat sink use guideline governing HPI cooling (PSG 2.9) in conjunction with this guideline.

NOTE

If OTSG pressure cannot be maintained less than 1000 psig, protect against any challenge to the MS code safety valves by opening the turbine bypass and/or atmospheric dump valves. This step must be followed regardless of other isolation criteria.

15. Affected OTSG must be steamed without exceeding the cooldown rate limits to maintain less than 95 percent on operate range and less than 70F° tube to shell delta T, unless either the BWST less than 21 ft. or off-site dose projections approach 50 mr/hr whole body or 250 mr/hr thyroid.

NOTE

Under emergency conditions, blocking/pinning of MS hangers when flooding the applicable MS lines is not necessary. If the MS lines are filled without blocking/pinning of the MS hangers, an engineering evaluation of the structural integrity of the MS lines must be performed prior to resuming normal operations.

16. Maintain less than or equal to 100F°/hr (1.6°F/min) cooldown rate by steaming both OTSGs. If the cooldown rate is greater than 100F°/hr (1.6°F/min) due to three pump HPI cooling, secure the non-ES selected MU pump and observe HPI throttling criteria below for the two ES selected MU pumps.

17. If RCS pressure is being controlled and an adequate subcooling margin exists, bypass ESAS at normal bypass pressure setpoints.

18. If subcooled margin exists, isolate CF-V-1A/B when RCS pressure is less than or equal to 700 psig.

19. For other than tube rupture, refer to NPSH curve in Figure 1 and 1A of 1102-11. Refer to Figure 1 and 1A attached for rupture emergency NPSH limits for one RCP in each loop operation.

NOTE

The emergency NPSH and SCM limits are plotted on a composite graph but are verified using different instruments. Therefore, due to differing instrument accuracies, verify correct and safe relative position using other available instrumentation (i.e. SCM meter).

20. Decay heat removal may be initiated at 300°F by first tripping all RCPs if the consequences of losing RCS loop forced flow are acceptable (i.e. hot leg steam bubble).

STEAM GENERATOR ISOLATION CONSIDERATIONS

FOR THE E/D WITH CONCURRENCE BY THE ESD

GENERAL

A. Isolation of one or both OTSGs reduces the RCS cooldown rate which increases the time to reach cold shutdown and to terminate the primary to secondary leak.

B. Isolation of one OTSG when both are leaking may increase the integrated dose since the release will continue from the unisolated OTSG for a longer period.

C. Isolation of both OTSGs requires feed and bleed cooling which could result in releases of steam or steam and water directly to the atmosphere.

D. An isolated OTSG may flood, after which it may not be possible to unisolate and return the OTSG to service.

E. Isolation of direct steam releases to the atmosphere is expected to reduce the offsite thyroid dose by a factor of at least 8.

F. Isolation for dose reduction should be based on measured dose rate to preclude premature isolation.

I. ISOLATION OF ONE OTSG SHOULD BE AVOIDED IF

A. RCPs are not available - natural circulation cooldown may not be possible with one OTSG since flow in one loop might stagnate and a bubble could form in the hot leg as primary pressure is reduced.

B. Both OTSGs leak but the difference in leak rate is less than a factor of eight. Otherwise, the delay in cooldown may negate the dose reduction from isolating one OTSG.

II. OTSG ISOLATION MAY BE DESIRABLE IF

A. RCPs are operating, the condenser is unavailable, only one OTSG is leaking and iodine dose rates are high. In this situation high iodine release rates could be terminated by isolation of the leaking OTSG.

Although cooldown time is increased, radioactivity releases will be terminated and RCP operation enables control of the RCS when in turn allows cooldown of the leaking OTSG.

III. OTSG ISOLATION CRITERIA SHOULD BE RE-EVALUATED IN THE FOLLOWING SITUATIONS

A. RCPs operating, condenser unavailable, both OTSGs leaking, iodine dose rates are high - isolation of one OTSG may be desirable if the leak rate in one OTSG is significantly (about 8) greater than in the other. The reduced dose rate from isolation of one OTSG must be weighed against the shorter cooldown time with steaming both OTSGs.

B. Condenser available - isolation of one or both OTSGs greatly increases cooldown times and increases risk of inadvertent or uncontrolled releases. A decision to isolate earlier than required by procedural guidelines should be based on measured dose rates if possible. In the absence of fuel failures, actual releases under such conditions are expected to be quite low.

C. Only one OTSG is leaking and BWST level is 21 feet - if the good OTSG is not expected to leak because shell/tube delta T is being controlled, then isolation is not required. Recall then the BWST level was based on both steam lines being flooded. If only one OTSG may be flooded, then BWST depletion could not occur until level reaches 15 ft.

TEMPORARY SHORT TERM MEASURES TO REDUCE OR TERMINATE RELEASES

A. Releases can be temporarily reduced by terminating steaming to the condenser and not steaming to atmosphere while running one (1) RCP.

B. If natural circulation is lost, steam again.
If steam generator pressure increases to 1000 psi, steam again.

NOTE: RCS heatup rate will be about 100-170F°/hr at one hour after reactor trip.

These steps may provide enough time to return an RCP to operation, restore a condenser to service, or initiate protective actions, while delaying the initiation of feed and bleed cooling.

SUMMARY

RCP	CONDENSER	ONE OTSG LEAKING OR BOTH OTSGs LEAKING WITH MORE THAN 90% TO ONE	BOTH OTSGs LEAKING LESS WITH THAN 90% TO ONE
On	Available	Avoid Isolation (III.2)	Avoid Isolation (III.2, I.2)
On	Not Available	Consider Isolation (II.1)	Avoid Isolation Of One (I.2)
OFF	Available	Avoid Isolation Of One OTSG (I.1)	Avoid Isolation Of One (I.1, I.2, III.2)
OFF	Not Available	Avoid Isolation Of One OTSG (I.1)	Avoid Isolation Of One (I.1, I.2)

2.6 COOLDOWN AFTER A SMALL BREAK LOCA (PSG 2.6)

1. Verify that loss of subcooled margin is being treated.

   1.1 HPI initiated (2 pumps full flow).
   1.2 All RCPs are tripped.
   1.3 EFW actuated and level being increased to 95%.

2. Verify that reactor trip containment isolation has occurred.

3. Verify that 1600 psi and 4 psi containment isolation has occurred.

4. If CFTs have emptied, go to large break LOCA guideline (PSG 2.7).

5. Maintain primary to secondary heat transfer by reducing OTSG pressure.

6. If primary to secondary heat transfer cannot be established in accordance with lack of heat transfer procedure, open the PORV and keep it open until heat transfer established or LPI is in operation.

7. If at any time the RCS becomes superheated, then go to ICC procedure.

8. If at any time indications of OTSG tube rupture occur, then go to tube rupture procedure.

9. Verify containment cooling.

10. Maintain RCP seal injection and seal cooling to assure long term availability of the RCPs.

11. Control HPI and restart RCPs when conditions are met.

12. If RCS is solid and subcooled, refer to guideline for establishing pressurizer steam bubble (PSG 2.9).

13. Monitor steam generator shell to tube delta T. Maintain 70F by either using MFW, steaming the OTSG, or limiting the cooldown rate.

14. Cooldown at approximately 100F°/hour (1.6F°/minute) while complying with shell to tube delta T limit.

15. If subcooling margin is regained, then core flood isolation valves may be closed when RCS pressure goes below 700 psig.

16. Monitor BWST level. If a source of borated water is available, makeup to the BWST to avoid transfer to the RB sump while the HPI pumps are on.

17. If BWST level reaches 36 inches (LO-LO level alarm) before LPI flow is established, then establish HPI/LPI operation in the "piggyback" mode. Otherwise, go to Step 21.

18. Monitor RB hydrogen levels. Start the Hydrogen Recombiner if hydrogen level reaches 0.5%.

19. Monitor RB sump for ph, boron concentration, and isotopic analysis. Add sodium hydroxide through the DHR system as required to control ph.

20. When the DHRS cut-in conditions are met and the flow in a single LPI injection line alone is sufficient to make up RC inventory, then place one LPI pump in the DH mode while the other LPI pump remains in the injection mode and recover from HPI/LPI/PORV-OPEN cooling and go to Step 20.

    20.1 Continue to supply RCP seal injection with HPI/LPI piggyback.
    20.2 Establish core cooling with LPI Loop A in DH mode.
    20.3 Maintain LPI Loop B suction from the RB sump.
    20.4 Close the PORV.
    20.5 Close the PORV block valve if necessary.
    20.6 Establish a bubble in the PZR if possible.
    20.7 Stop RCPs if on.
    20.8 Go to Step 22.

21. When DHR cut-in conditions are met, then place both LPI pumps in the DH mode and recover from HPI/LPI/PORV cooling, if in progress.

    21.1 Place both LPI pumps in the DH mode taking suction from the DH drop line. Continue to supply makeup, as necessary with the HPI pumps.
    21.2 Close the PORV.
    21.3 Close block valve, if necessary.
    21.4 Establish pressurizer bubble.
    21.5 If BWST level reaches 3 ft. then:

        a. Place one LPI in the injection mode taking suction from the sump while the other train remains in the DH mode.
        b. Continue to supply makeup by transferring HPI pump suction from the BWST to the discharge of an LPI pump.
        c. Stop any running RCPs.

22. Continue cooldown to cold shutdown

    22.1 When the RCS depressurizes to less than 150 psig, then verify closed all high point vents.
    22.2 Monitor core delta T by comparing incore thermocouple and DH cooler outlet temperature.
    22.3 Continue RCS cooldown to 140F.

2.7 COOLDOWN WITH A LARGE BREAK LOCA (PSG 2.7)

1. Verify that HPI and LPI pumps are operating and valves have opened.

2. Verify that both core flood valves are operating and that 30 psig containment isolation has occurred.

3. Verify that RB spray / RB cooling are operating.

   CAUTION: DO NOT START ANY MAJOR MOTORS SUCH AS CONDENSATE OR CONDENSATE BOOSTER PUMPS DURING BLOCK LOADING.

4. Verify RB isolation by checking the indicating lights for each valve on control room panel.

5. If only one LPI is operating, open cross-connect valves and provide at least 1000 gpm per line.

6. Monitor steam generator shell to tube delta T. Maintain 70F by either using MFW, steaming the OTSG, or limiting the cooldown rate.

7. If RCS pressure is above the maximum pressure for LPI operation, then establish primary to secondary heat transfer.

   7.1 If RCS is not below the pressure for LPI operation in about 20 minutes, then go to the procedure for cooldown from a small break LOCA.

8. Close MS-V-1A, B, C and D.

9. If superheat is indicated by incore T/C then go to ICC procedure.

   NOTE: Superheat may be indicated for 5-10 minutes after a large break LOCA.

10. Monitor BWST and Sodium Hydroxide tank levels. Verify Hydroxide is being injected to control ph.

11. Stop non-essential secondary equipment when time permits.

12. Throttle LPI/BS pumps only if required to prevent pump runout (LPI 3500 gpm, BS 1800 gpm).

13. If LPI flow has been greater than 1000 gpm in each line for 20 minutes, then, when HPI throttling criteria is met, HPI pumps may be secured.

14. Open DH-V-64 and MU-V-198 before recirculation is established from the RB sump.

15. If BWST level reaches 36 inches (LO-LO level alarm) before HPI flow can be secured, then establish HPI/LPI operation in the "piggyback" mode.

    Otherwise, switch LPI suction to the building sump when BWST level reaches 36 inches.

16. Monitor RB hydrogen levels per plant procedures.
    Start the hydrogen recombiner if hydrogen level reaches 0.5% using plant procedures.

17. Stop emergency feedwater when LPI or DHR is in operation.

18. Start spent fuel cooling if electrical load permits.

19. Stop RB spray pumps when RB pressure is less than 4 psig.

20. Assess auxiliary building radiation levels and establish one of the long term recirculation modes within 24 hours to provide a boron dilution path.

21. Monitor RB sump for ph, boron concentration, and isotopic analysis. Add sodium hydroxide through the DHR system as required to control ph.

22. Monitor the containment for hydrogen.

2.8 RCS SUPERHEAT (PSG 2.8)

1. Verify HPI and LPI have been initiated (all available pumps).

2. Verify OTSG levels between 90-95% on the operating range.

3. Decrease OTSG pressure to achieve 100F°/hr decrease in secondary saturation temperature.

4. Verify core flood valves are open.

5. Initiate 4 psig containment isolation.

6. If RCS pressure is greater than 2300 psig, open the PORV. Close the PORV when RCS pressure decreases to 100 psig above OTSG pressure.

7. Determine region on PT curve of Figure 9.

REGION	PROCEDURE
Lack of Subcooling Margin	Lack of subcooling margin procedure.
1	Steps 1-5 above
2	Step 2
3	Step 3

8. Incore Thermocouple Temperature in Region 2 of Figure 9 (clad temperature above 1400F)

   8.1 Start one RCP per loop if possible without defeating interlocks.

   8.2 Decrease OTSG pressure at 400 psig or to achieve a 100F° decrease in secondary Tsat.

   8.3 Open hot leg, head and pressurizer vents.

   8.4 Continue to decrease OTSG pressure to maintain a 100F°/hr decrease in secondary Tsat. Do not go below steam pressure required for turbine driven EFW pump (150 psig) unless both motor driven pumps or auxiliary steam is available.

   8.5 Monitor reactor building hydrogen levels, start the recombiner if hydrogen concentration is greater than 0.5% and RB pressure is less than 10 psig.

   8.6 If primary to secondary heat transfer cannot be established, open the PORV and block valve and keep them open. When RCS returns to saturation, go to HPI cooling guideline (PSG 2.9).

8.7 If primary to secondary heat transfer is established, cycle the PORV to maintain RCS pressure at 25 to 100 psig above OTSG pressure.

8.8 If the RCS returns to saturation condition, then close the high point vents and go to lack of subcooling margin guideline (PSG 2.2).

8.9 Continue to monitor incore thermocouple temperature using Step 6.

9. Incore Thermocouple Temperature in Region 3 of Figure 9 (clad temperature above 1800F).

9.1 Defeat starting interlocks and start all available RCPs. Do not defeat overload trips.

9.2 Decrease OTSG pressure as rapidly as possible. If auxiliary steam or EF-P-2A and EF-P-2B are available (150 psig if not), then decrease OTSG pressure to atmospheric pressure. Otherwise keep pressure above the minimum necessary to power the steam driven EFW pump.

9.3 Open the PORV block valve and PORV.

9.4 Open hot leg vents, head vent and pressurizer vents.

9.5 Operate all available normal and emergency RB fans to promote mixing of RB atmosphere. Caution: Do not use emergency fans in high speed.

9.6 Monitor reactor building hydrogen levels start the recombiner if hydrogen concentration is greater than 0.5% and RB pressure is less than 10 psig.

9.7 Continue full HPI and LPI and maximum available primary to secondary cooling until incore T/C temperatures reach saturation temperature, then continue.

9.8 If RCS pressure is less than 150 psig, then close the PORV and high point vents. Re-open the PORV and/or vents to maintain RCS pressure less than 150 psi.

9.9 Decrease running RCPs to one per loop.

9.10 Maintain OTSG pressure as per step 3.2.

9.11 If RCS becomes superheated, go to step 1 of this procedure.

9.12 Go to guideline governing HPI cooling (PSG 2.9).

2.9 HPI COOLING/RECOVERY FROM SOLID OPERATIONS (PSG 2.9)

1. If HPI cooling is required, then start two HPI pumps and open the PORV block and PORV.

2. Initiate 4 psig containment isolation.

3. If subcooled margin is regained, then throttle HPI and start one RCP.

4. If superheat occurs, then go to superheat procedure (PSG 2.8).

5. Attempt to establish OTSG heat removal if plant conditions permit.

6. If OTSG tube rupture is indicated, use guideline for OTSG tube rupture concurrently with this guideline.

7. Monitor shell/tube delta T. Maintain 70F° by either using MFW, steaming the OTSG, or controlling the cooldown rate, depending on equipment availability and limitation on OTSG steaming.

8. If OTSG heat transfer does not exist, go to PSG 2.6.

9. If subcooled margin is maintained and RCS pressure is below 700 psia, then the core flood tank isolation valves may be closed.

10. If OTSG heat removal is established, then recover from solid operation. Otherwise, go to Step 12.

    10.1 Run one RCP in each loop per ATP 1210-10.
    10.2 Close PORV and all high point vents, while steaming the OTSGs sufficiently to control RCS temperature and pressure.
    10.3 Establish a steam bubble in accordance with plant procedure.

11. If subcooling margin is not restored, or if a known RCS leak exists, then go to guideline governing cooldown with a small break LOCA (PSG 2.6).

12. Continue cooldown using OP 1102-11.

2.10 RULES AND GUIDELINES (PSG 2.10)

The following rules are to be followed whenever the plant is at power, heating up, or cooling down.

1. Determination Margin to Saturation

   a. The margin to saturation is determined by: The saturation monitor and/or the average of the five highest operable incore thermocouples; and RC narrow or wide range pressure indication.

   b. Minimum margin to subcooling is 25F°.

2. High Pressure Injection (HPI) Initiation Criteria

   Two HPI pumps must be initiated at full capacity when:

   a. 1600 psig ESAS has auto initiated or

   b. Subcooling margin is less than 25F°, or

   c. Neither OTSG is available as a heat sink

3. High Pressure Injection (HPI) Throttling Criteria

   Throttle HPI only if one or more of the following criteria are met:

   a. HPI must be throttled to prevent pump runout (550 gpm/pump).

      NOTE: Do not throttle to less than 500 gpm/pump unless one of the below criteria (b, c or d) is met.

   b. HPI must be throttled to prevent violation of the applicable brittle fraction/thermal shock curve limitations.

   c. HPI may be throttled if LPI flow is greater than 1000 gpm in each line and stable for 20 minutes.

   d. HPI may be throttled if the required 25F° subcooling margin exists and pressurizer level is established greater than 0".

      CAUTION: Monitor total make-up flow to maintain at least 40 gpm per pump. Open MU-V-36 and MU-V-37 whenever HPI is manually throttled to less than 400 gpm per pump.

4. Reactor Coolant Pump (RCP) Trip Criteria

a. If 25F° subcooling margin is lost, immediately trip all operating Reactor Coolant Pumps (RCPs).

NOTE: If 25F° subcooling margin is lost and all operating RCPs are not tripped within two minutes, then run one RCP per loop for at least two hours.

b. If 25F° subcooling margin is lost immediately following an RCP restart and does not return within 2 minutes, the RCPs must be tripped again and not restarted until 25F° subcooling margin is regained.

5. Emergency Feedwater (EFW) Throttling Criteria

a. To prevent RCS overcooling due to excessive feed rates, manually control EFW flow as necessary to maintain OTSG pressure to within 100 psig of desired pressure. Monitor RCS cold leg temperature to insure that EFW flow is not causing a significant RCS temperature transient.

b. To insure adequate EFW flow, verify decreasing incore T/C temperature. If incore T/C temperatures are not decreasing increase EFW flow to at least 450 gpm (225 gpm per SG) until level setpoint is reached. If incore T/C's are decreasing, the overcooling criterion takes priority.

6. OTSG Level Rule

a. If 25F° subcooling margin is lost, raise level in the operable OTSG(s) to 90-95% on the operating range.

NOTE: If the loss of subcooling margin was due to a loss of secondary system pressure, do not raise level in the affected OTSG(s) until pressure control is regained.

b. At least 30 inches startup range with RCPs on.

c. At least 50% with RCPs off.

3.0 DIFFERENCES BETWEEN PLANT SPECIFIC GUIDELINES AND ATOG

This section describes differences between the TMI-1 Abnormal Transient Operator Guidelines (ATOG) and the plant specific guidelines of Section 2.0. Each difference is described below, with an explanation of ATOG, the plant specific guidelines, and the reason for the difference.

3.1 DIFFERENCES IDENTIFIED DURING REVIEW OF FINAL ATOG

The TMI-1 ATOG Implementation Committee reviewed the final TMI-1 ATOG (issued April 1983) to confirm that it represented an appropriate basis for the plant specific guidelines. That review showed that the committee's comments on the technical content of the TMI-1 ATOG had been incorporated. However, some changes to the TMI-1 ATOG were identified as desirable before use in the plant specific guidelines. Section 3.1 discusses differences between ATOG and the plant specific guidelines which were identified by the Implementation Committee.

3.1.1 HPI Start Criteria

ATOG requires initiation of HPI whenever subcooling margin is lost or Engineered Safeguards Actuation System (ESAS) is automatically initiated. ATOG requires HPI initiation within the loss of heat transfer section if feedwater cannot be restored.

The TMI-1 plant specific guidelines require HPI to be initiated if neither OTSG is available as a heat sink rather than if feedwater cannot be restored. Moreover, this requirement was made a rule to keep all of the conditions for HPI initiation in one location. Loss of the OTSG heat sink is considered a better criterion than feedwater unavailability. At low power levels, the OTSG may take a long time to boil dry even if feedwater is unavailable. Conversely, at high power levels, loss of the OTSG as a heat sink will occur rapidly and does not require the operator to interpret when feedwater is unavailable (i.e. what efforts can be taken to restore feedwater before deciding that it is unavailable).

3.1.2 HPI Throttling Criteria

TMI-1 ATOG does not recommend the operation of all three HPI pumps except under conditions of inadequate core cooling.

The plant specific guidelines only tells the operator to shut off the third pump if the RCS cooldown rate exceeds 100F°/hr. If an ESAS signal occurs, all three HPI pumps would be running if offsite power was available. The B&W guidance would require the operator to take action to stop a pump. If the non-ES pump is tripped, it can only be restarted after operating a switch on

switchgear outside the control room. If an ES pump is tripped, it can only be restarted after the ESAS signal is bypassed. Leaving all three HPI pumps running improves overall availability. Cavitating venturies limit HPI flow, and excessive cooldown is precluded by guidance to stop the third pump if cooldown rates exceed 100F°/hr. Guidance is provided to the operator for preventing depletion of the MU tank. The elevation of the tank at Unit 1 prevents drawdown once HPI is being drawn from the BWST. On the other hand, the operator is not required to run three pumps, so that one pump can be stopped once the plant condition is stabilized.

3.1.3 RCP Trip Criteria

ATOG calls for all four reactor coolant pumps to be tripped within two minutes of a loss of subcooling margin. If the pumps are not tripped within two minutes, then all four pumps should be left on unless mechanical damage is likely. In this case, only two pumps should be left running.

The plant specific guidelines have the operator trip the pumps upon loss of SCM; however, if they are not tripped within two minutes then he should run one pump per loop, regardless of whether mechanical damage is likely. Otherwise, the plant specific guidelines are the same as ATOG. This difference in the pump trip criteria was taken because it is easier for the operator (i.e. one RCP per loop is standard practice) and eliminates an evaluation of whether mechanical damage is likely.

3.1.4 RCP Bump Criteria

ATOG calls for the bump of any one pump at no more than a one hour interval. The plant specific guidelines allow any one pump to be bumped at 30 minute intervals instead of at 1 hour intervals as specified by TMI-1 ATOG; a different pump will be bumped at 15 minute intervals. This change allows four "bumps" within an hour when only two RCPs are operable. OP 1101-1 "Plants Limits and Precautions" specifies at least 40 minutes between starts on a non-running motor after 2 consecutive starts. With two or more pumps running, the limits and precautions are met. With one pump running, that pump would be bumped at 30 minute intervals in order to meet the limits and precautions.

3.1.5 Flooding of Steam Lines

TMI-1 ATOG recommends that the steam lines should not be flooded but acknowledges that a GPU analysis indicates that the steam lines will not be damaged (TMI-1 ATOG, Volume 2, page A-2).

Flooding of the steam lines is not a preferable plant condition However, since the effects are acceptable, flooding of the steam lines will be allowed under certain tube rupture conditions.

3.1.6 Response to OTSG High Level Alarm

The ATOG reactor trip actions include tripping of the main feedwater pumps on high level if main feedwater has not run back. The basis for this action is the short response time required before the OTSG overfills (only several minutes). Since there are so many potential failures in the ICS, the ATOG philosophy is not to try and use this control system.

The plant specific guidelines do attempt to close the feedwater valves by putting the ICS in hand. The results of this action will take a very short time, and its effectiveness will be immediately recognized. If the valves can be closed, then a loss of main feedwater pumps can be avoided. Since TMI-1 has a manual control station which bypasses much of the ICS, valve closure is a prudent step to take before tripping the pumps.

3.1.7 ATWS

In a submittal dated July 2, 1983, (Reference 3) B&W provided supplemental ATOG material dealing with ATWS events. This guidance has been incorporated into the TMI-1 with certain changes.

1. ATOG recommends that the operator not proceed with the reactor trip procedure until all rods are inserted or a 1% shutdown margin has been established. The plant specific guidelines do not prevent the operator from verifying plant conditions in a number of subsequent steps in the reactor trip procedure. Both the guidelines and training material emphasize that primary to secondary heat transfer must be maintained until the core is shut down. This action is what was intended in ATOG.

2. ATOG has the operator drive rods into the core until power to the CRDMs can be interrupted. At TMI-1, however, power can be interrupted from a control room panel. Therefore, the guidance to drive in rods in the interim has been deleted.

3. ATOG tells the operator to initiate full HPI and isolate normal makeup. The plant specific guidelines do not address the isolation of normal makeup since this action is implied in any HPI initiation along with a number of other actions such as assuring that cooling and lubrication services are available to the pump.

3.1.8 PORV Cycling During Inadequate Core Cooling

When cladding temperatures are above 1400F, ATOG tells the operator to "Maintain the primary to secondary heat transfer by cycling the PORV to keep RCS pressure 25-50 psig greater than SG pressure". The basis for a lower limit on the pressure differential is to assure heat transfer into the OTSGs from the RCS. The upper limit of 50 psig limits RCS pressure, thereby minimizing HPI flow and minimizing break flow.

The plant specific guidelines specify a band of 25-100 psi in order to decrease the potential for cycling of the PORV. This action is always taken with the OTSG pressure at 400 psig or less. Therefore, a 50 psi pressure increase in the RCS will have no effect on HPI flow and a minimal effect on break flow.

3.1.9 Containment Isolation and Protection

The TMI-1 ATOG containment isolation actions were written generically for all the B&W operating plants. TMI-1 has a redundant and diverse isolation signal on all required penetrations in accordance with the general design criteria. Due to this automatic isolation scheme, less emphasis is placed on certain actions:

1. Letdown isolation after a reactor trip; this is an automatic action.

2. Verification of building isolation on 4 psig building pressure. All penetrations communicating with the RCS or containment atmosphere are isolated upon reactor trip.

3.2 DIFFERENCES IDENTIFIED DURING WRITING AND USE OF THE PROCEDURES

Once the technical guidelines and plant procedures had been written, a series of other comments had been developed. The process of writing plant procedures, using them on the B&W simulator, and putting the procedures through the safety review process showed the need for additional revisions to the guidelines. The changes to each guideline are discussed in the following sections. The discussion is keyed to Figures 1-7 which show the differences between the PSGs and TMI-1 ATOG. The figures further show the differences between the TMI-1 and Oconee ATOGs.

3.2.1 Reactor Trip

As shown in Figure 1, the reactor trip plant specific guideline (PSG-1) follows ATOG very closely. Two differences have already been discussed in Sections 3.1.6 and 3.1.9. Letdown isolation is automatic and, therefore, is not an immediate trip action. Part of the response to a high OTSG level will be to place the ICS in "HAND" and close the MFW valves. If this action is ineffective, then the MFW pumps will be tripped.

Other differences between the guideline and TMI-1 ATOG are minor. A loss of offsite power (see 7.0) will require the same basic actions as ATOG. However, several steps have been deleted. OTSG level control is a rule; therefore, there is no explicit step regarding raising level. Insuring the availability of HPI pump auxiliaries is required any time a pump is started and is addressed in other plant procedures. Instrument air is supplied by a bottled supply after a loss of power and does not require immediate verification. OTSG pressure control is covered by the EFW throttling criteria. Besides the deletion of these steps, a final difference is that the operator is referred to plant procedures which give specific detailed actions for a partial or complete loss of AC power. These additional actions enhance the operators ability to restore the plant to a normal post trip condition.

Steps have been added to assure that pressurizer and makeup tank level are properly controlled. These actions reduce the chances of uncovering the pressurizer heaters, voiding the pressurizer or losing suction to the makeup pump.

Certain actions have been removed from the response to ESAS actuation (see 8.0 on Figure 1). Makeup tank level has been already checked in the previous step, so these actions are not necessary in the response to ESAS. Seal injection is not isolated and is available as long as the "A" or "B" HPI pump is running. Closure of the PORV is verified upon lack of subcooling margin (SCM). A loss of SCM would normally occur before 4 psig building pressure. The RB spray and containment isolation functions (including NSCCW and ICCW) have already been verified. Verification of sodium hydroxide valves is performed as a follow-up. The NaOH injection system is single failure proof and automatic; therefore, immediate verification is not required.

The priority for treating excess and lack of heat transfer are modified from ATOG. ATOG considers both symptoms as an equal priority. The PSGs require, if both symptoms occur at once (e.g. one OTSG dry and the other overcooled), then excess heat transfer must be treated first.

None of these changes represents a significant difference between TMI-1 ATOG and the plant specific guidelines.

3.2.1.1 TMI-1 vs. Oconee ATOG

Besides the differences between TMI-1 ATOG and the TMI-1 PSGs, there is also a difference between TMI-1 and Oconee ATOG (indicated by the vertical lines). Oconee ATOG does not respond to a depressurized OTSG in the reactor trip procedure. TMI-1 ATOG does. This is an appropriate post-trip verification requiring immediate action, and hence is included in PSG 2.1.

3.2.2 Lack of Subcooling Margin

Figure 2 provides a comparison of the TMI-1 ATOG and PSG 2.2 "Lack of Subcooling Margin". The only differences occur in the exits to of long term cooldown procedures. ATOG exits to a guideline (CP-105) that results in a normal plant cooldown procedure when there is primary to secondary heat transfer, but subcooling margin cannot be restored. PSG 2.2 instead directs the operator to the small break LOCA guideline for cooldown. This approach exemplifies one philosophical difference between ATOG and the PSGs. If there is a RCS water going into containment, either due to a break or feed and bleed cooling, the operator follows the small break procedure. This procedure insures containment temperature/pressure control and integrity. It also assures a suction source for the ECCS equipment.

Another difference occurs between the PSG and TMI-1 ATOG if there is both primary/secondary heat transfer and adequate subcooling margin (see Figure 2, 6.0 and 12.0-15.0). In this case, the operator has two options. If the RCS is water solid, then he is directed to PSG 2.9 and re-establishes a pressurizer steam bubble. If there is a steam bubble in the pressurizer, then he returns to the reactor trip procedure, reverifies the plant condition and takes further action based on management direction (i.e. cooldown per plant procedure or start up). ATOG would direct the operator through CP-105 and into a normal cooldown procedure, so that the difference is procedural flow only. The PSGs assure that any leak is treated like a LOCA until management evaluates the situation.

3.2.2.1 TMI-1 vs. Oconee ATOG

There are several differences between TMI-1 and Oconee ATOG. First, a check is made in TMI-1 ATOG for OTSG tube rupture (see Figure 2, 10.0 and 14.0). Treating tube rupture symptoms rather than exiting to a cooldown procedure is correct and represents an enhancement of ATOG.

A second change is that Oconee ATOG checks for OTSG heat transfer before checking for a large break LOCA (see 7.0 through 8.0). Since heat transfer will be lost for a large LOCA, it is expeditious to exit before checking for OTSG heat transfer.

Oconee ATOG exits upon excessive heat transfer much later than TMI-1 ATOG (see 4.0, 12.0 and 14.0). If a loss of subcooling has resulted from an overcooling, then it is appropriate to correct the overcooling immediately after taking actions to assure that the core is cooled (1.0 through 3.0). Moreover, if excessive cooling exists at this point, it should be corrected before taking the remaining procedure steps for treating lack of SCM. Also, raising OTSG level to 95% can contribute to an overcooling and should be corrected.

A final minor difference is that Oconee has a specific step instructing (see 6.0 and 12.0) the operator to control HPI; however, the PSG HPI throttling criteria make the step unnecessary.

3.2.3 Excessive Heat Transfer

Figure 3 compares TMI-1 ATOG and PSG 2.3 "Excessive Heat Transfer". The primary difference between the two is economy of words. ATOG branches out if one or both OTSGs are affected and treats the affected and unaffected OTSGs in separate portions of the guideline. The PSG takes the same actions, but tells the operator to take those steps on the affected OTSGs and continues with all steps in series. Besides the arrangement of steps, the sequence of isolation of the affected OTSG(s) is slightly different. ATOG isolates the affected OTSGs in three steps (see Figure 3, 16.0 to 22.0). PSG 2.3 isolates the OTSG in two steps. First it isolates feedwater, closes the TBVs and ADVs, then re-evaluates the OTSG pressure response. If one exhibits a lower pressure, then steam to the EFW pumps and the inlet to the ADVs and TBVs is isolated, ATOG isolates steam to the EFW pump as a separate and final step. TMI-1 has two motor driven EFW pumps which are each capable of removing decay heat. Moreover, the turbine driven EFW pumps can be supplied steam from either OTSG from one of two valves (MSV-10 A/B or MSV-3A,B) as well as from the auxiliary boiler.

3.2.3.1 Differences Between TMI-1 and Oconee ATOG

The differences between TMI-1 and Oconee ATOG are minor (refer to Figure 3). Oconee initiates HPI at 50 inches pressurizer level while TMI-1 increases makeup at 100 inches pressurizer level and initiates HPI at 20 inches. Oconee checks for tube rupture symptoms before lack of subcooling margin (see Steps 22.0 and 23.0). TMI-1 checks in the reverse order, consistent with the priority with which these symptoms should be treated.

3.2.4 Lack of Heat Transfer

Figure 4 compares TMI-1 ATOG and PSG 2.4 "Lack of Heat Transfer". The initial check for the availability of feedwater has been deleted. This simplifies the immediate actions and has the operator follow more important steps first. If FW is established, the operator still takes the same actions in ATOG. A second difference is the exit condition if heat transfer is re-established. ATOG recovers from HPI cooling, checks for other symptoms and goes to a cooldown procedure for a saturated RCS. PSG 2.4 recovers from HPI cooling and goes to the reactor trip procedure. In reactor trip, the operator checks for other symptoms and if there are none, proceeds based on management direction.

The major area of discussion for operators during the December simulator session was the use of pump bumps. As written, the guideline appeared to hold the operator at the pump bumping steps in the guideline without proceeding to other steps (i.e. cooldown during a SB LOCA). The Implementation Committee, therefore, re-evaluated this procedure based on that experience. The procedure was clarified to assure that the operator would continue while attempting to bump pumps. If OTSG heat transfer cannot be re-established, but the RCS is cooling down at more than 100F/hr (i.e. cooldown cannot be controlled because of a saturated RCS in a LOCA condition), then pump bumps will not be required. In this situation, the operator exits the lack of heat transfer procedure, goes to reactor trip, and will proceed through PSG 2.1 and be directed to treatment of the appropriate symptoms.

3.2.4.1 Differences Between TMI-1 and Oconee ATOG

TMI-1 and Oconee ATOG treat lack of heat transfer the same with only minor exceptions. The largest difference is that in TMI-1 ATOG, the PORV is opened and HPI cooling established if RCS pressure reaches 2300 psi (see 2.0 through 5.0 and 9.0). This action is intended to decrease RCS pressure sufficiently to maximize HPI flow, reduce any break flow, yet maintain a sufficient primary/secondary temperature difference to allow heat transfer. This action improves safety margins and is, therefore, an appropriate action for the guidelines.

TMI-1 ATOG (Figure 4, 15.0) allows the operator to start an RCP one hour after reactor trip. After this period of time, mass loss out of a break in the RCS is not sufficient to cause a core uncovery if the RCPs are subsequently tripped. This step implements an action which has already been recommended in Oconee ATOG (see p. 127 "Best Methods of Equipment Protection").

3.2.5 Steam Generator Tube Rupture

As indicated previously, the OTSG tube rupture guideline was based on the existing plant procedure that is based on ATOG as well as additional analyses and plant experience. Only minor changes have been made in developing the tube rupture guideline from the existing plant procedure:

1. Pressurizer depressurization is begun immediately in order to minimize subcooling margin by the time the plant cooldown begins.

2. Some additional clarification was added for use of the feed and bleed procedure in parallel with the tube rupture procedure.

3. The addition of rules for treating a lack of subcooling margin eliminated the need for a separate section of the guideline to treat lack of subcooling margin during a tube rupture.

3.2.6 Cooldown with a Small Break LOCA

Figure 5 illustrates the differences between TMI-1 ATOG CP 103 (RC Cooldown with a Saturated RCS and OTSGs Removing Heat) and PSG 2.6 (Cooldown with a Small Break LOCA). ATOG distinguishes among LOCA cooldowns with/without primary to secondary heat transfer and subcooled cooldowns. The PSG's have all cooldowns in which RCS inventory is being put in containment controlled by the small break LOCA cooldown procedure. HPI cooling (PSG 2.9) also is controlled via this procedure. The manner of controlling the plant is not different, however. Except for the differences in exit points, PSG 2.6 varies from TMI-1 ATOG only by the addition of guidance that appears elsewhere in ATOG. One additional exit has been added to allow treatment of tube rupture symptoms.

3.2.6.1 Differences Between TMI-1 and Oconee ATOG

The differences between TMI-1 and Oconee ATOG are minor. TMI-1 uses a lack of primary to secondary heat transfer as a condition for exiting to the HPI cooling guideline. Oconee ATOG used a loss of natural circulation.

3.2.7 Cooldown with a Large Break LOCA

As discussed in Section 3.2.6, the SB LOCA procedure is used for more plant cooldowns than in ATOG. As seen in Figure 5, TMI-1 ATOG distinguishes between a small break LOCA with and without primary to secondary heat transfer. On the other hand, PSG 2.7 directs the operator to the small break LOCA guideline regardless of heat transfer. For the case where there is no primary/secondary heat transfer, TMI-1 ATOG goes to an HPI cooling guideline. Instead, PSG 2.6 initiates HPI cooling and takes the steps for HPI cooling without exiting the procedure.

3.2.7.1 Differences Between TMI-1 and Oconee ATOG

TMI-1 and Oconee ATOG differ by the deletion of several steps from Oconee. TMI-1 does not include a notification of personnel in the guideline. This is a procedural item that does not belong in guidelines. TMI-1 also deletes two steps verifying that the CFT isolation valves are open and that building spray valves have operated. Again, these are specific steps that can be treated in the plant procedure, but not in the guideline.

Oconee does not exit the large break LOCA procedure if pressure stays above LPI initiation pressure. Rather it checks for a core flood line break accident. The TMI-1 guidance handles the more generalized condition of any large small break LOCA in which the RCS does not immediately depressurize to LPI pressure.

Finally, the Oconee guidelines use a different BWST level setpoint for pump suction switchover. This is a plant specific item.

3.2.8 RCS Superheat

The TMI-1 ATOG and plant specific guidelines do not differ except for the items identified in Section 3.1.8.

3.2.8.1 Differences Between TMI-1 and Oconee ATOG

There are several differences between the TMI-1 and Oconee inadequate core cooling guidelines.

First, TMI-1 ATOG includes a step (refer to TMI-1 ATOG, 5.0) to open the PORV when RCS pressure reaches 2300 psig. This step is consistent with the lack of heat transfer guideline (see Section 3.2.4). The intention is to reduce RCS pressure and maximize HPI flow, reduce break flow and possibly reach CFT pressures. The PORV is closed at 100 psig above OTSG pressure to assure a primary/secondary differential temperature. This additional guidance increases the ability to cool the core and improves the inadequate core cooling guideline.

Step 8.2 requires the operator to continue to depressurize the OTSG at 100F°/hr after the initial depressurization called for in this step. This step is more explicit than the Oconee step which only calls for a step decrease in temperature. The continued cooldown of the OTSG enhances the chances of inducing natural circulation or a cooldown of the RCS.

Step 14.0 of TMI-1 ATOG adds a step requiring that high point vents as well as the PORV be opened when fuel clad temperature goes above 1400F. The vents are intended to remove noncondensible gases which could potentially be blocking natural circulation.

Oconee ATOG Step 11.3 differs from TMI-1. The step relates to loss of RC pump service. TMI-1 requires tripping of the RCP on loss of motor cooling in the pump operating procedure.

Step 16.0 of Oconee ATOG (see Oconee ATOG) requires isolation of the core flood tanks. This step is deleted in TMI-1 ATOG. The step is taken after the RCS returns to saturation. Since it is possible that the CFTs are the only source of core cooling, they should not be isolated.

Step 16.0 of TMI-1 ATOG does not exist in Oconee ATOG. It directs the operators to close the high point vents when RCS pressure goes below 150 psig, but to reopen them if pressure increases above this value. Oconee ATOG did not address high point vents. The step tries to close RCS leakage paths at a condition when LPI operating and relief of non-condensible gases is no longer important. If the vents are helping to control RCS pressure, then they should be reopened to prevent a loss of LPI flow.

Step 18.0 of TMI-1 ATOG emphasizes that SG pressure should be maintained as low as possible. Oconee does not. This step occurs in the section dealing with return to saturation from 1800F clad temperatures. Previous steps (refer to Oconee Step 12.0 and TMI-1 Step 13.0) in the guideline have already required the operator to reduce the SG pressure as low as possible. There is no actual change to the procedural steps, just a re-emphasis of the action to be taken.

Finally, Oconee and TMI-1 ATOG differ in the location of the guidance for cooldown once the RCS is saturated. Oconee ATOG maintains the operator within the ICC guideline but duplicates the guidance of CP-103. TMI-1 directs the operator to CP-103. The TMI-1 PSG directs the operator to loss of subcooling margin, which would result in cooldown via the small break LOCA procedure. Once again, however, the guidance is put in a different location rather than representing difference guidance.

3.2.9 Feed and Bleed Cooling

The differences between PSG 2.9 and TMI-1 ATOG (CPs 104, 105) are illustrated in Figure 7. The reason for the differences flows from the PSG concept of the small break LOCA procedure. The PSG 2.6 provides guidance that ATOG provides in the HPI cooling procedure. PSG 2.9 assures that if HPI cooling is required, it is initiated. The operator is directed to PSG 2.6. Another difference is that the TMI-1 ATOG for establishing a bubble in the pressurizer has been incorporated into PSG 2.9. If a bubble is established in the pressurizer and there is no RCS leak, the operator is then directed to a normal cooldown. If a bubble is not re-established, then the operator cools down within the small break LOCA procedure, whereas ATOG would cool down using a normal plant procedure. The advantage of being in the LOCA procedure for this case is the guidance available for the transition to DHR system operation. The differences between ATOG and the PSGs represent a re-arrangement of material.

3.2.9.1 Differences Between TMI-1 and Oconee ATOG

Figure 7a depicts the Oconee ATOG HPI cooling guideline (CP-104). Because the two ATOGs were arranged differently, it was not possible to represent all their re-arrangement on one figure. However, they both share the same common elements. First, each maintains full HPI flow with the PORV open in order to assure core cooling. Second, the plant is maintained within allowable pressurized thermal shock limits (TMI-1 accomplishes this by virtue of a general guideline to do so, as specified in plant procedure ATP 12[illegible].

If the OTSG becomes available as a heat sink, the operator attempts to restore heat transfer by pump bumps and pressure reduction.

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3. D. D. Whitney. "Supplement to ONS-3 Final ATOG". Letter from D. D. Whitney to D. G. Eisenhut. July 2, 1983.

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5. Darrell G. Eisenhut. Safety Evaluation of 'Abnormal Transient Operating Guidelines' (Generic Letter 83-31). September 19, 1983. U. S. NRC. Washington, DC.

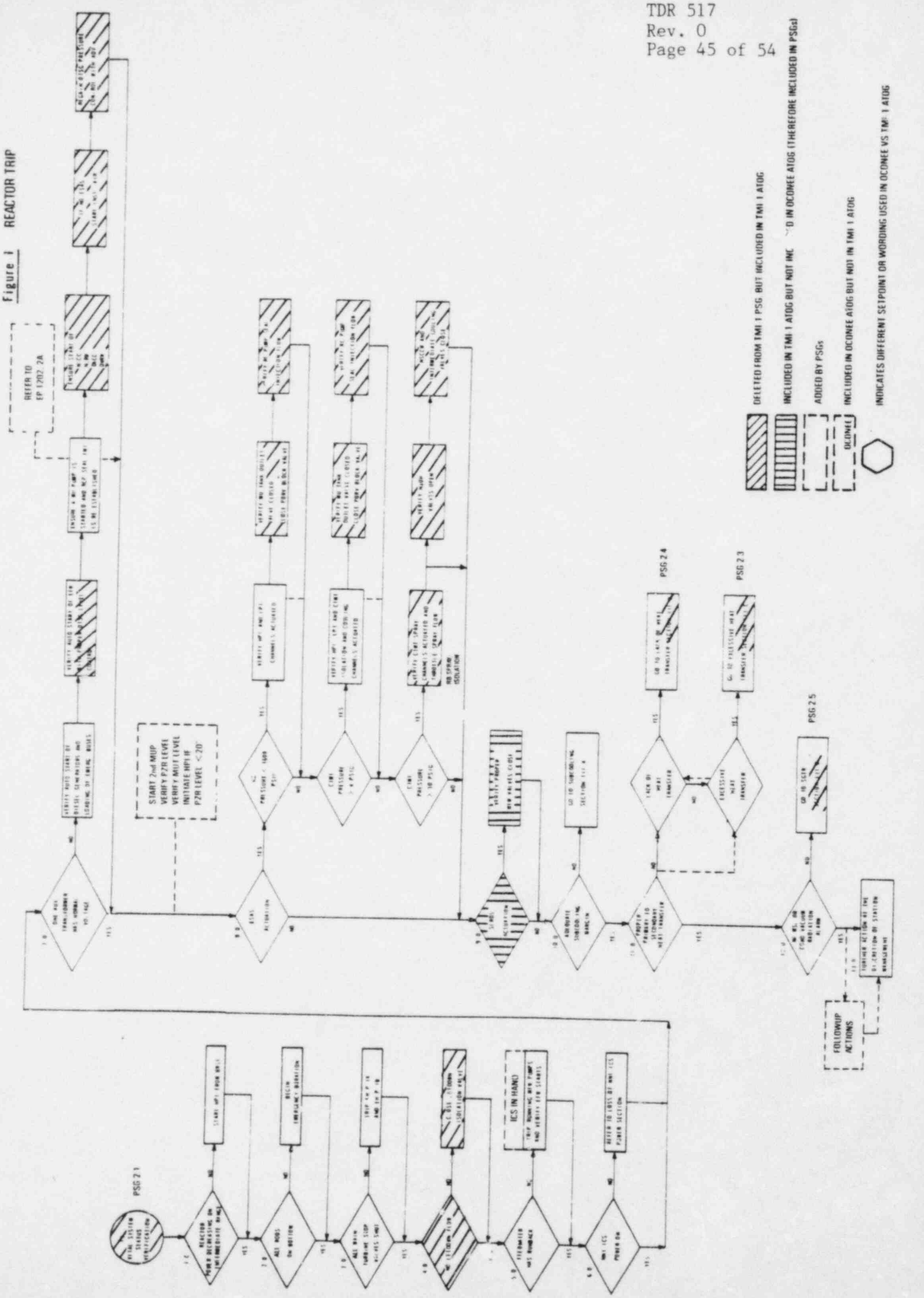

Figure 1 REACTOR TRIP

Figure 2 LACK OF ADEQUATE SUBCOOLING MARGIN

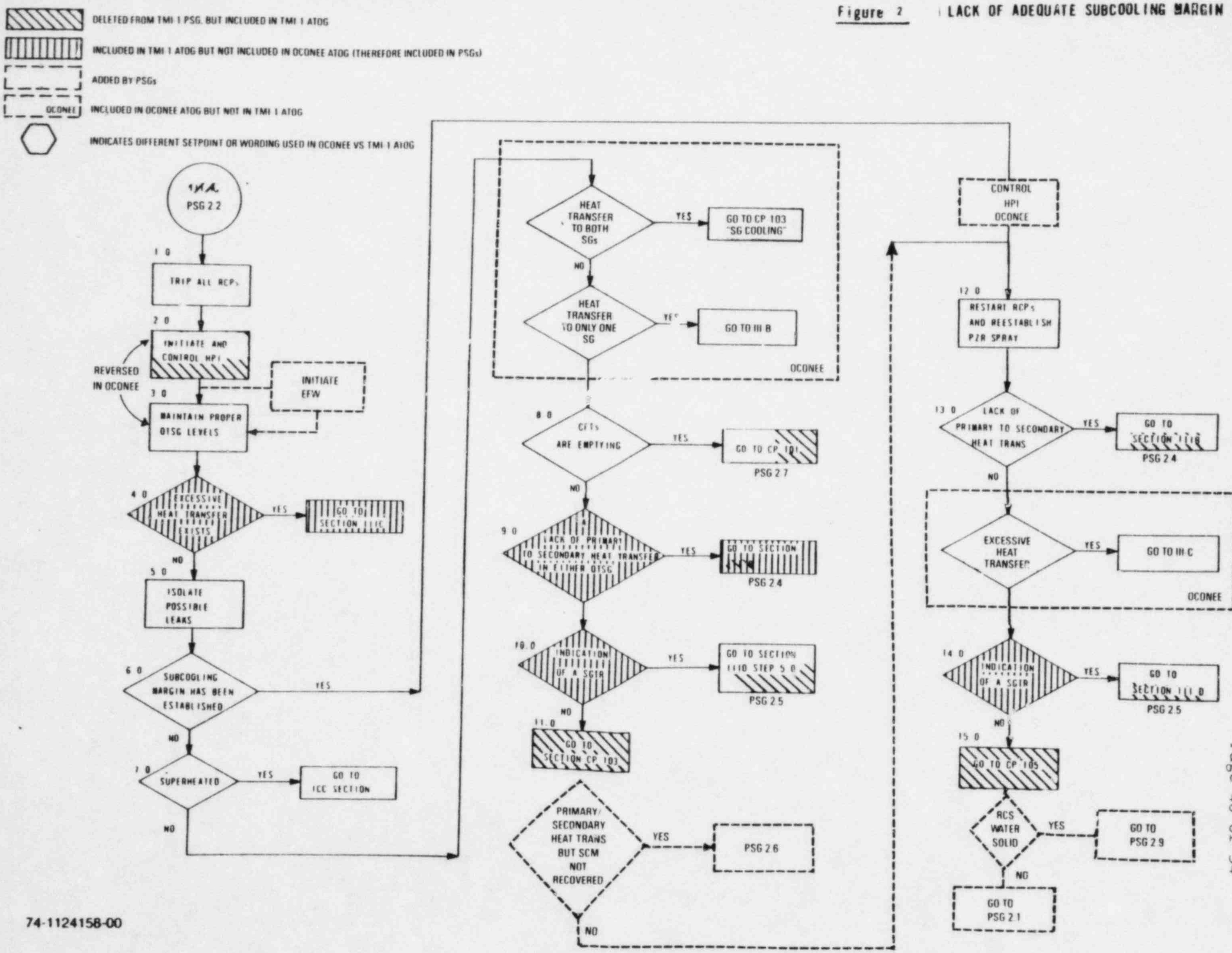

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Figure 3 EXCESSIVE HEAT TRANSFER

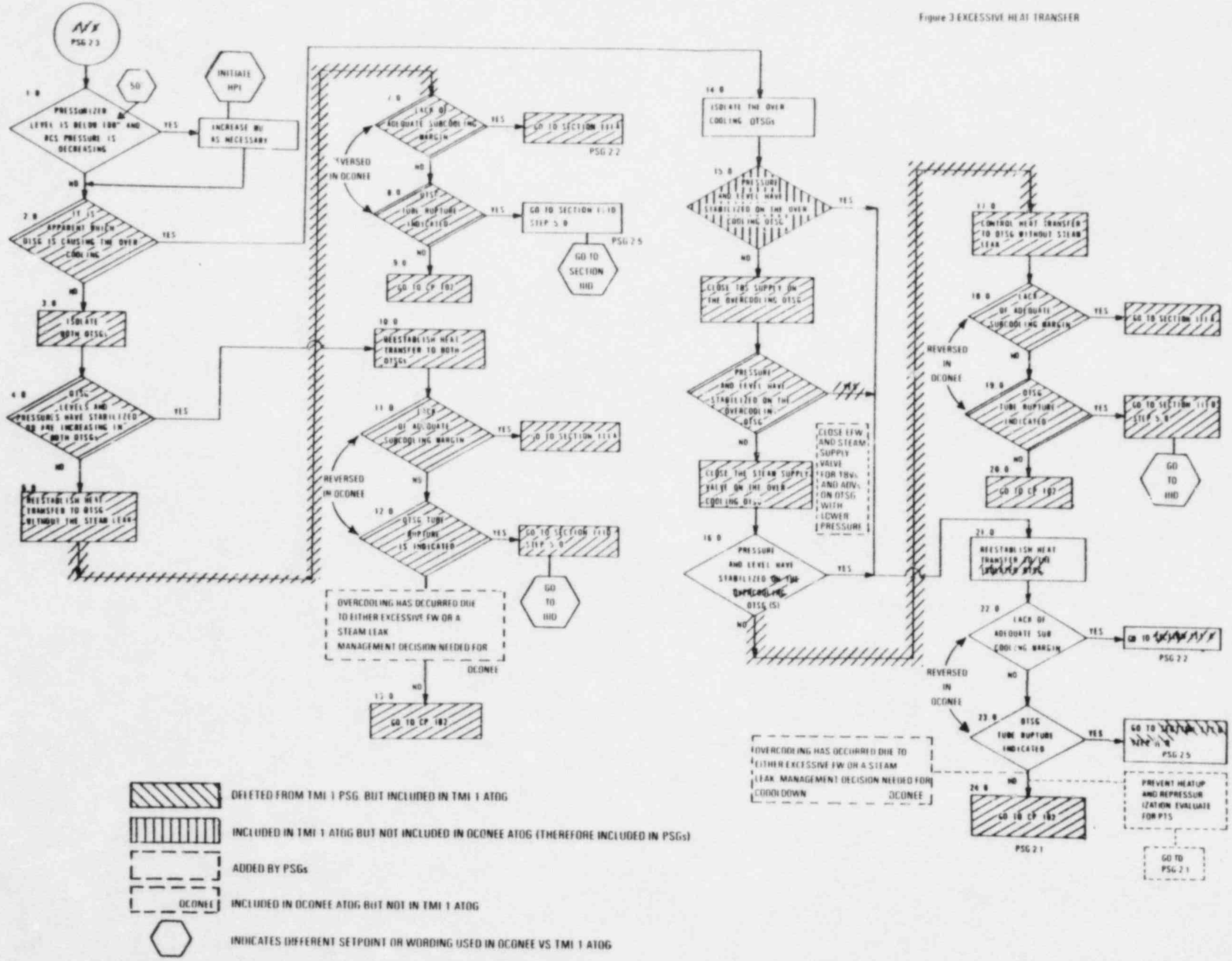
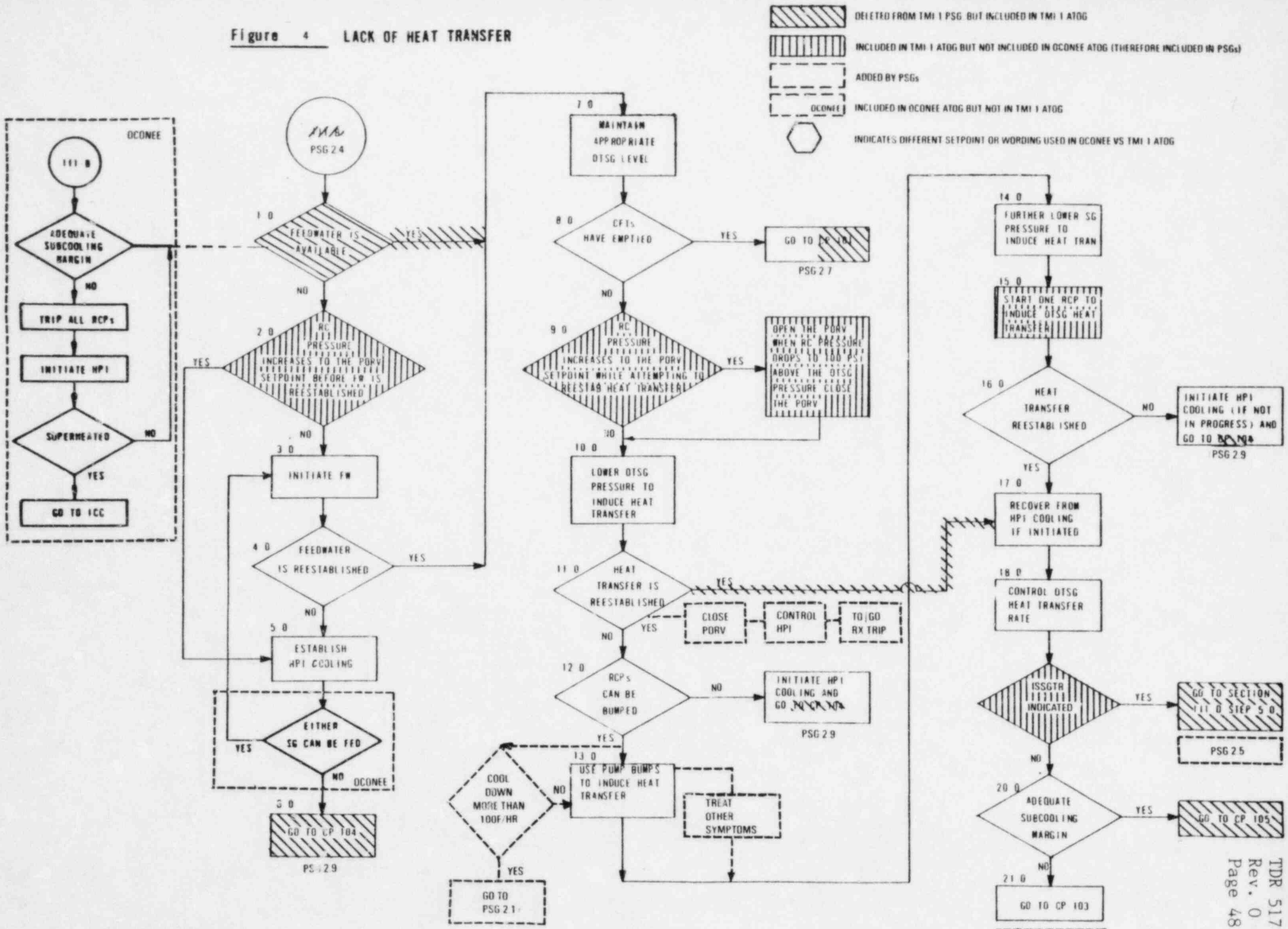


Figure 4 LACK OF HEAT TRANSFER



74-1124158-00

Figure 5

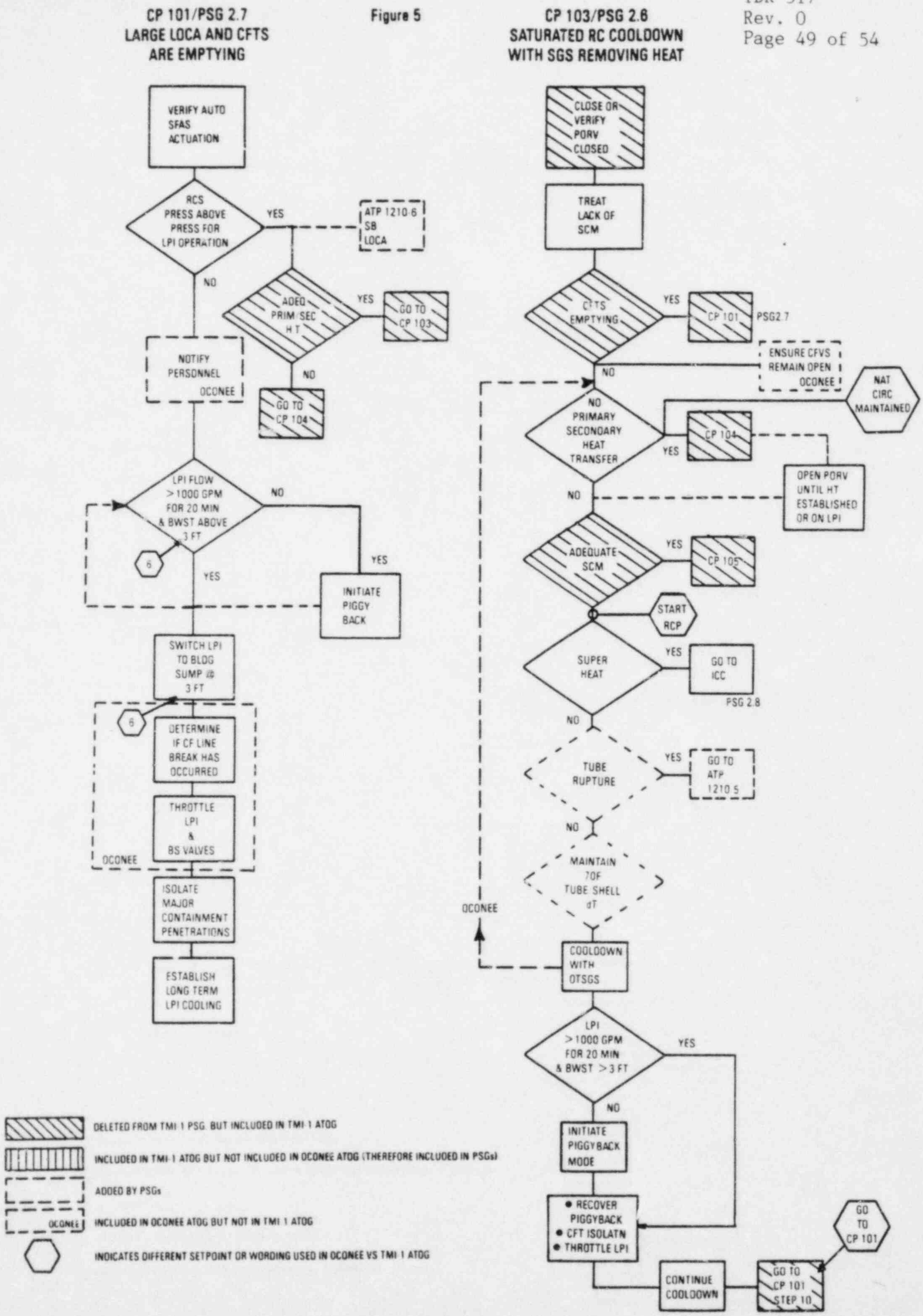

CP 101/PSG 2.7
LARGE LOCA AND CFTS ARE EMPTYING
VERIFY AUTO SFAS ACTUATION
RCS PRESS ABOVE PRESS FOR LPI OPERATION
YES
ATP 1210-6 SB LOCA
NO
ADEQ PRIM/SEC H T
YES
GO TO CP 103
NO
GO TO CP 104
NOTIFY PERSONNEL
OCONEE
LPI FLOW >1000 GPM FOR 20 MIN & BWST ABOVE 3 FT
NO
YES
6
YES
INITIATE PIGGY BACK
SWITCH LPI TO BLDG SUMP @ 3 FT
6
DETERMINE IF CF LINE BREAK HAS OCCURRED
THROTTLE LPI & BS VALVES
OCONEE
ISOLATE MAJOR CONTAINMENT PENETRATIONS
ESTABLISH LONG TERM LPI COOLING
CP 103/PSG 2.6
SATURATED RC COOLDOWN WITH SGS REMOVING HEAT
CLOSE OR VERIFY PORV CLOSED
TREAT LACK OF SCM
CFTS EMPTYING
YES
CP 101
PSG2.7
ENSURE CFVS REMAIN OPEN
OCONEE
NO
NAT CIRC MAINTAINED
NO PRIMARY SECONDARY HEAT TRANSFER
CP 104
YES
OPEN PORV UNTIL HT ESTABLISHED OR ON LPI
NO
ADEQUATE SCM
YES
CP 105
START RCP
SUPER HEAT
YES
GO TO ICC
PSG 2.8
NO
TUBE RUPTURE
YES
GO TO ATP 1210.5
NO
MAINTAIN 70F TUBE SHELL dT
OCONEE
COOLDOWN WITH OTSGS
LPI >1000 GPM FOR 20 MIN & BWST >3 FT
YES
NO
INITIATE PIGGYBACK MODE
• RECOVER PIGGYBACK
• CFT ISOLATN
• THROTTLE LPI
CONTINUE COOLDOWN
GO TO CP 101 STEP 10
GO TO CP 101
DELETED FROM TMI 1 PSG BUT INCLUDED IN TMI 1 ATOG
INCLUDED IN TMI 1 ATOG BUT NOT INCLUDED IN OCONEE ATOG (THEREFORE INCLUDED IN PSGs)
ADDED BY PSGs
OCONEE
INCLUDED IN OCONEE ATOG BUT NOT IN TMI 1 ATOG
INDICATES DIFFERENT SETPOINT OR WORDING USED IN OCONEE VS TMI 1 ATOG

Figure 6

CP 102/OP 1102-16&11
COOLDOWN ON ONE OR TWO OTSGS
RCS SUBCOOLED & PZR STEAM BUBBLE

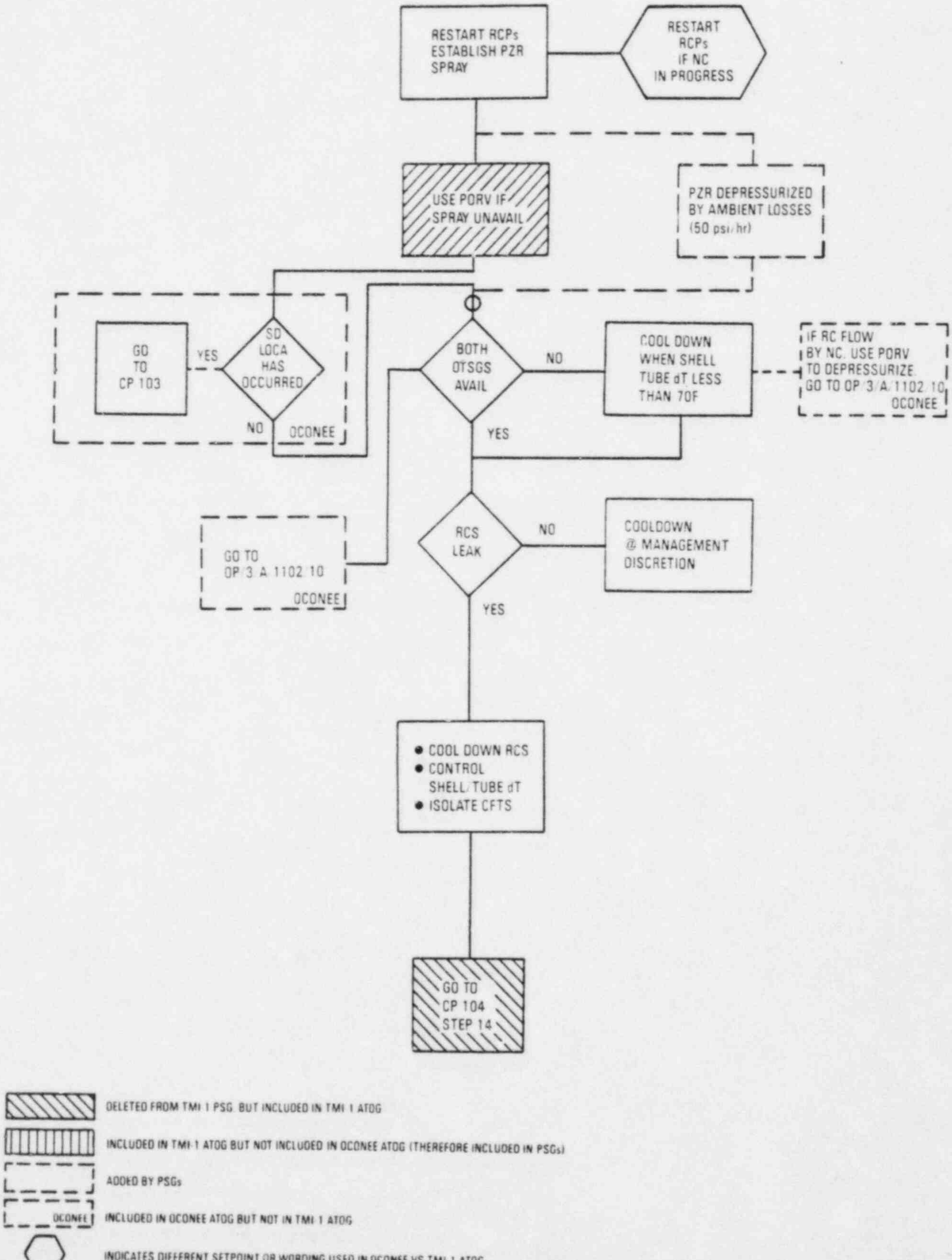
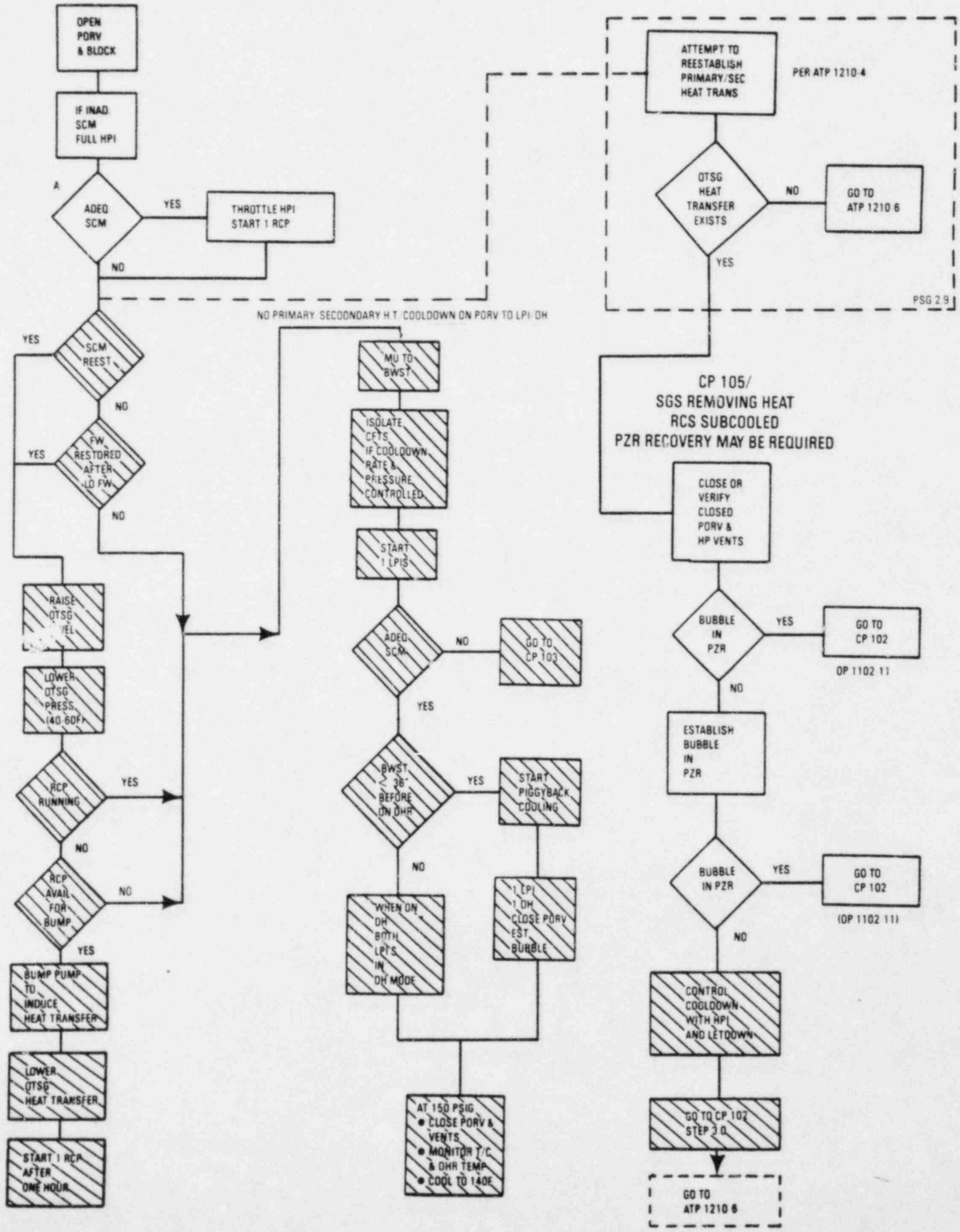


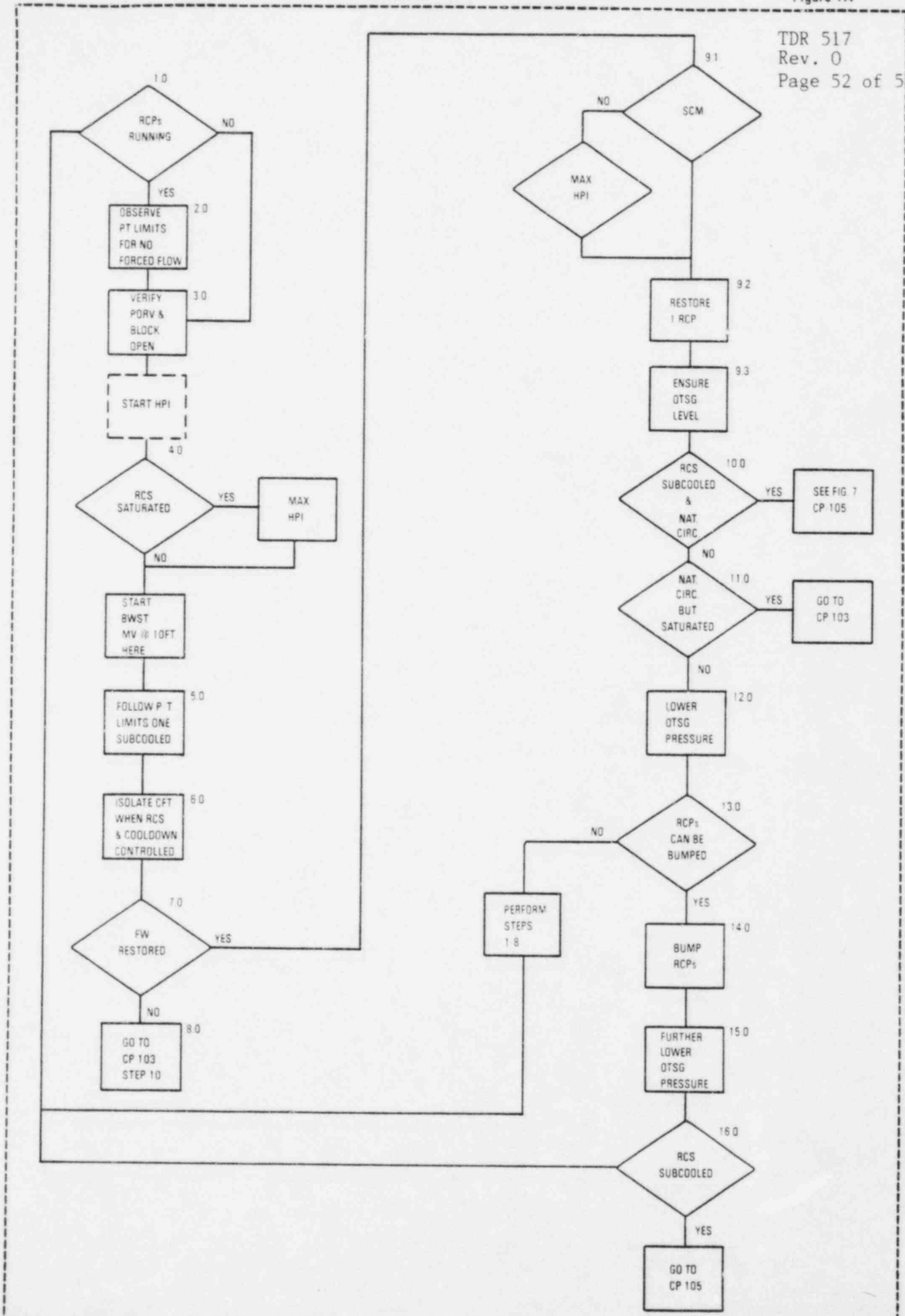
Figure 7

CP 104 AND 105/PSG 2.9 HPI COOLING HPI/PORV-OPEN COOLING WITHOUT SG(S) REMOVING HEAT



OCONEE CP 104

Figure 7A



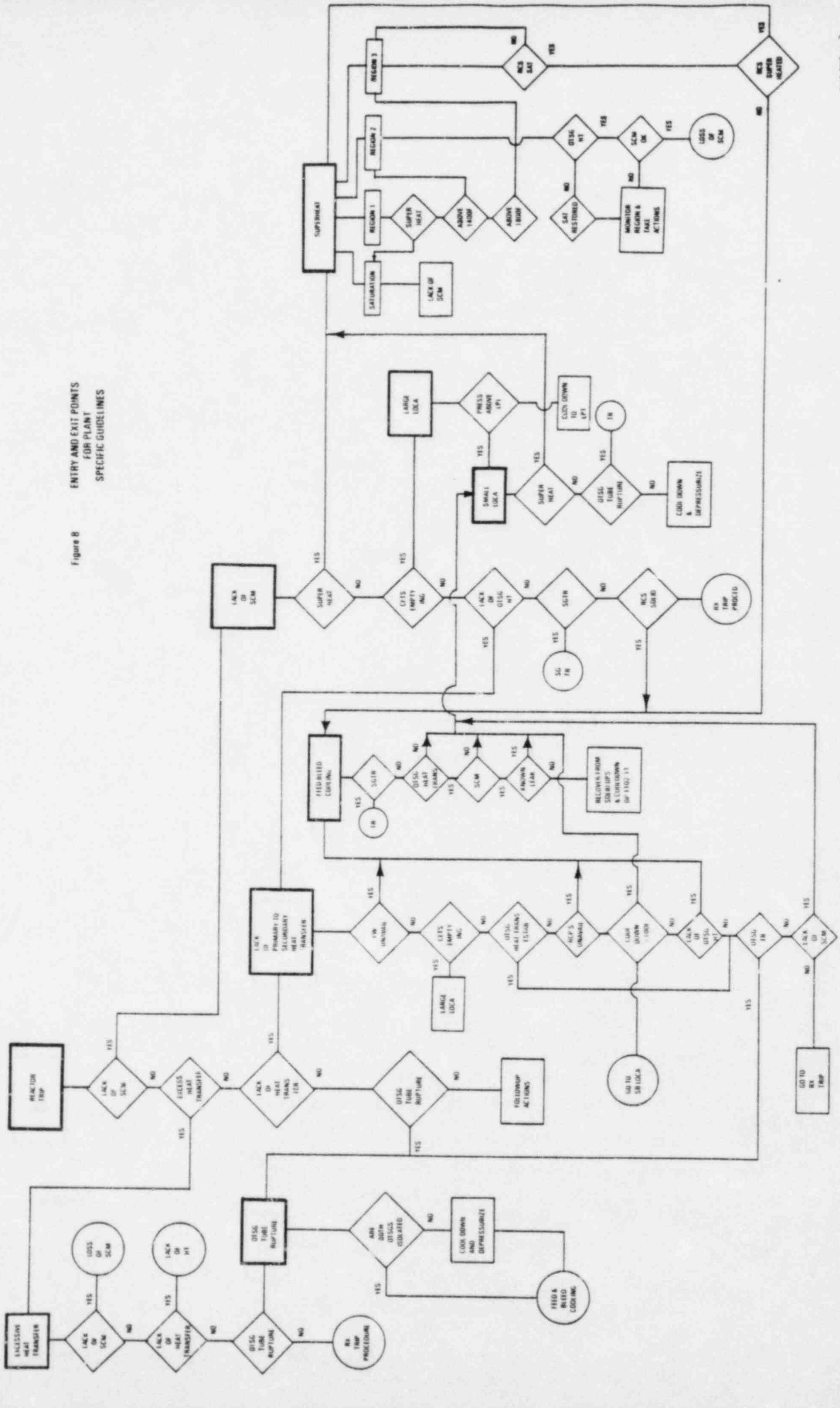
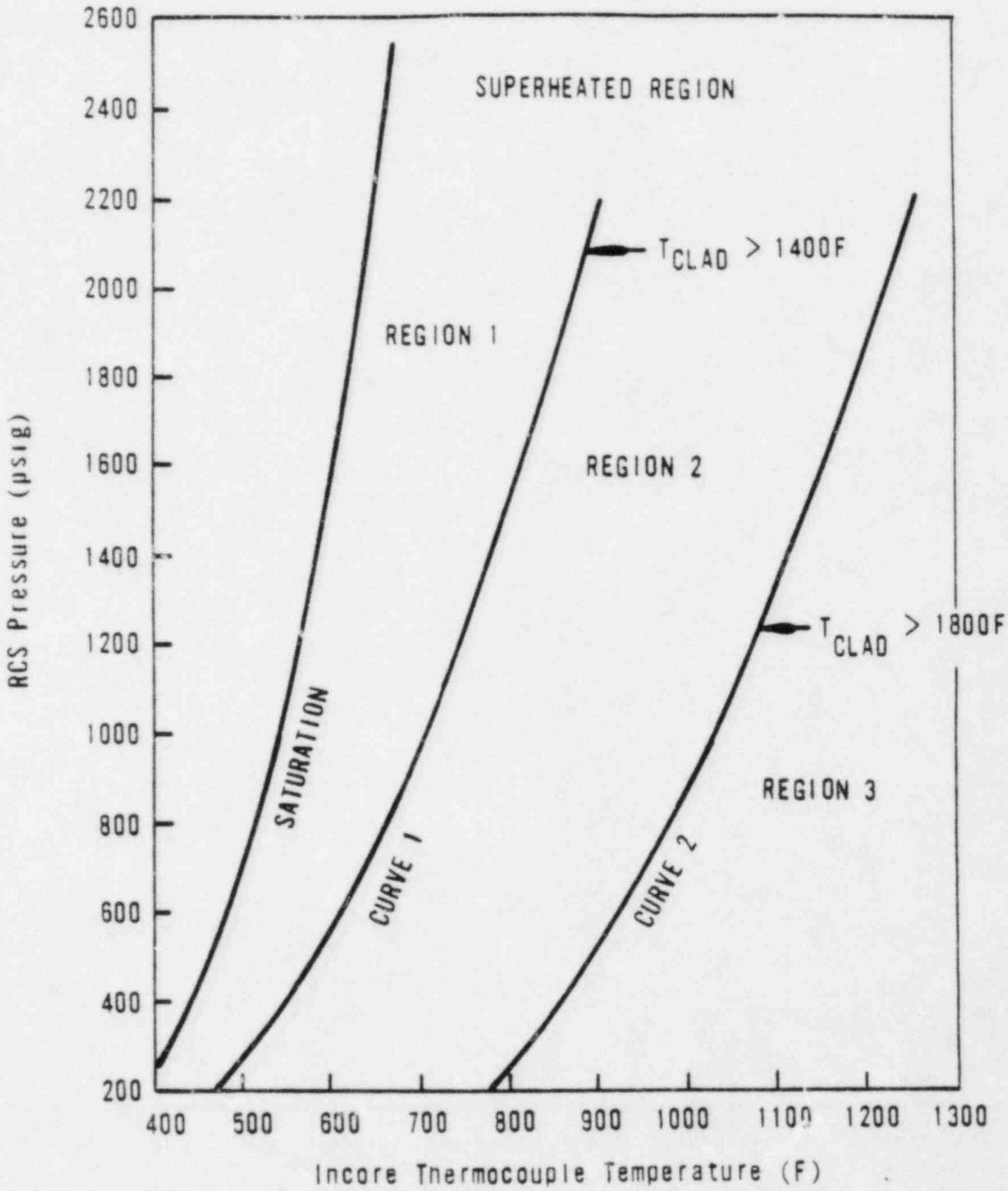


Figure 8 ENTRY AND EXIT POINTS FOR PLANT SPECIFIC GUIDELINES

Figure 9 CORE EXIT FLUID TEMPERATURE FOR INADEQUATE CORE COOLING



ATTACHMENT 2

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PART-MARK/TASK-GROUP-SEQ.	B&W DOCUMENT NO.	DOCUMENT TITLE	PUL STAT.	RRL. NO.
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TYPE: ___RESEARCH & DEVELOPMENT ___SAFETY ANALYSIS REPORT ___NUC. SERV. INPUT ___DESIGN RQMT. ___DESIGN VERIF. ✓ OTHER

TITLE ATOG ANO-1/TMI-1 SYSTEMS COMPARISON

PREPARED BY PHILIP R. BOYLAN REVIEWED BY Lawrence J. Rudy

TITLE ASSISTANT ENGINEER DATE 12/4/80 TITLE Assoc. Eng. DATE 12/5/80

PURPOSE:

TO ASSEMBLE A REFERENCABLE DOCUMENT WHICH COMPARES ANO-1 WITH TMI-1; THE RESULTS OF WHICH WILL BE USED IN ANALYSIS FOR THE TMI-1 ABNORMAL TRANSIENT OPERATING GUIDELINES PROGRAM.

SUMMARY OF RESULTS (INCLUDE DOC. ID'S OF PREVIOUS TRANSMITTALS & SOURCE CALCULATIONAL PACKAGES FOR THIS TRANSMITTAL)

FOR References, SEE PAGES 4 and 5.

(SUMMARY OF RESULTS IS N/A FOR THIS DOCUMENT)

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A COMPARISON OF ARKANSAS NUCLEAR ONE
(UNIT 1) AND THREE MILE ISLAND (UNIT 1)
FOR THE ABNORMAL TRANSIENTS OPERATING
GUIDELINES PROGRAM

SEPTEMBER 15, 1980

P.R. Boylan Philip R. Boylan
L.J. Rudy Lawrence J. Rudy
E.A. Hiltunen Edwin A. Hiltunen

32-1121199-00

TABLE OF CONTENTS

3/29

72-1121199-00

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2. B&W Document 86-1106932-00, Makeup Line and HPI Flow Rates vs. RC Pressure for NSS-8 for ATOG Program, (Contract #582-7108) 12/13/79
3. Gilbert Assoc. Inc., TMI-1 Makeup & Purification Piping Flow Diagram, C-302-661, Rev. 18, 10/17/77. B&W Document No. 16-1108694D-00
4. ANO-1 FSAR
5. TMI Emergency Procedure #1202-121 Rev. 10 and #1202-36 Rev. 6, B&W Document No. 03-1108718-00
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19. TMI-1 Main Steam System Description (provided by Met-Ed for ATOG program), B&W Document Nos. 15-1108782-00 and 15-1108795-00
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22. ANO-1 List of Components Loaded on Diesel Generators, B&W Document No. 40-1097627-00
23. Deleted

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25. LOOP and Loss of Inst. Air, TMI-1, Valve Failure and Diesel Loading - block information, B&W Document No. 38-1108796-00

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28. "TMI-1 Technical Specifications", B&W Document No. 05-0002-36, 2/28/80

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-00

In order to insure safe shutdown of a B&W NSS, five major areas of plant control must be achieved. These control areas are reactivity, primary system pressure, primary system inventory, secondary system pressure, and secondary system inventory. Because these control functions are discussed either directly or indirectly in all ATOG work, a comparison between plants should naturally start with the systems which directly affect those key areas.

The following paragraphs are intended to review the means by which TMI-1 and ANO-1 achieve plant control.

Reactivity control is achieved in all PWR's through control rod insertion and boron shim control. The functioning of the CRDMs and boron addition systems for ANO-1 and TMI-1 are essentially the same. (Differences in the MU system will be addressed later.) The reactor trip setpoints for TMI-1 and ANO-1 are as follows: (from plant technical specification)

6/29

32-1121199-00

I. TMI-1 - Rx Trip Setpoints - ANO-1

TMI-1 (Reference 28)	ANO-1 (Reference 6)
1. Power > 105.5%	1. Power > 105.5%
2. Flux/flow/inbalance - 1.08 x rated flow(%) minus reduction due to imbalance	2. Flux/flow imbalance - 1.057 x rated flow(%) minus reduction due to imbalance
3. High RCS pressure (2300 psig)	3. High RCS pressure (2300 psig)
4. Low RCS pressure (1800 psig)	4. Low RCS pressure (1800 psig)
5. Variable low RCS pressure (11.75)(T_{out}) - 5103 psig	5. Variable low RCS pressure (11.75) T_{out} - 5103 psig
6. RC max. temperature = 619°F	6. Max. RC temperature = 619°F
7. High reactor building pressure (4 psig)	7. High reactor building pressure (4 psig)
8. Loss of FW pumps	8. Loss of FW pumps
9. Turbine trip	9. Turbine trip

Primary system pressure control is achieved through the interaction of several systems and components. These are the pressurizer heaters, pressurizer spray, PORV, pressurizer safety valves, makeup, and letdown. The TMI-1 and ANO-1 pressurizers are identical in all important respects.* The PORV and safeties are identical in design, while the effects of the pressurizer spray and heaters are similar. Although MU/HPI and letdown control is important in controlling primary pressure, its main function is to control primary inventory. Therefore MU/HPI and letdown will be addressed in the next section.

*TMI-1 has a 0-400 "Pressurizer level range, while that for ANO-1 is 0-320."

7/29

2-112199-02

II. PRESSURIZER HEATERS

Bank-On Setpoint	ANO-1	Reference	TMI-1	Reference
1	<2135 psig	10	<2135	7
2	<2135 psig	10	<2135	7
3	2135 psig	10	2135	7
4	2120 psig	10	2120	7
5	2105 psig	10	2105	7
Bank-Off Setpoint				
1	>2155 psig	10	2155	7
2	>2155 psig	10	2155	7
3	2155 psig	10	2147	7
4	2140 psig	10	2140	7
5	2125 psig	10	2125	7
Bank Power				
1	84 kw	10	(Power output	
2	84 kw	10	by Bank not	
3	378 kw	10	available)	
4	504 kw	10		
5	588 kw	10		8
TOTAL	1638 kw		1638 kw	
Banks Powered After Loop	1 + 2	22	No (With 126 kw manual load ability, however)	12, 25

Primary inventory is controlled by makeup and letdown. Attachment 1 shows simplified P+ID's for TMI-1 and ANO-1 makeup system. HPI and makeup pump flowrates and capabilities are compared for each plant in Section III. Note that the makeup systems for each plant are almost identical, except that ANO-1 does not isolate RCP seal injection during ESAS actuation as does TMI-1.

82-112-179-02

III. MAKEUP AND LETDOWN SYSTEM

(A) Makeup

	ANO-1	Ref.	TMI-1	Ref.
Normal Makeup -	25 gpm	1		
Normal Seal Injection -	8 gpm/RCP	1	8 gpm/pump	7
Normal Seal Return -	1 gpm/RCP	1	3 gpm/pump	7
Makeup Flow vs. Pressure with Makeup Control Valve Fully Open -	2200 psig 140 gpm	2	(HPI/MU pump curves not available at present)	
	1800 psig 180 gpm	2		
	2000 psig 160 gpm	2		
	1600 psig 200 gpm	2		
HPI Flow vs. Pressure for Two MU Pumps with Control Valves Full Open -	2600 psig 400 gpm	2		
	2400 psig 495 gpm	2		
	2200 psig 580 gpm	2		
	2000 psig 645 gpm	2		
	1800 psig 705 gpm	2		
	1600 psig 755 gpm	2		
	1400 psig 805 gpm	2		
Failure Position of MU Control Valve on LOOP -	Air is not lost to the valve	22	FC on loss of air FC on loss of solenoid power	25
Is RCP Seal Injection Isolated After ESAS	No	4	Yes	3

9/29

32-1121199-00

III. MAKEUP AND LETDOWN SYSTEM

(B) Letdown

	ANO-1	Ref.	TMI-1	Ref.
Normal Letdown	53 gpm	1, P.14	45 gpm	7
Letdown Temperature	120	1, P.14	120	24
Letdown Control Valve Failure Position on LOOP -	Closed	11	FC loss of air FC loss of solenoid power	25
Cooling Water Supplied To Letdown Coolers After LOOP?	No	11	Yes on LOOP but will be locked out on ES+UV	12

10/29

IV. Secondary System pressure is controlled mainly by the action of components in the main steam system. Most plants differ somewhat in the design and operation of the seconday system, and there are significant differences between ANO-1 and TMI-1 in this respect.

In the event of a major loss of steam pressure (i.e., steam line break) the SLBIC system at ANO-1 and the SLRD system at TMI-1 actuate when OTSG steam pressure reaches 600 psig. The response of each system is quite different, however, as the following comparison shows:

ANO-1 'SLBIC'	Ref.	TMI-1 'SLRDS'	Ref.
Actuation Setpoint = 600 psig	10	Actuation Setpoint = 600 psig	19
- Actions Taken By System-		- Actions Taken By System -	
1. Closes MSIVs for both OTSG's	14	1. Closes MFW block and control valves to affected OTSG only.	19
2. Closes MFW isolation valve to affected OTSG.	14	2. Closes startup FW block and control valves to affected OTSG only.	19
3. Opens steam supply valve to steam-driven EFW pump.	14	3. Closes EFW control valves to affected OTSG only.	19
4. EFW isolation valve opens on EFW initiation signals to both OTSGs.	14	4. Performs identical operations on the other OTSG if low steam pressure is detected in that loop.	19
5. Closes MFW isolation valve for the other OTSG if a SLBIC signal subsequently originates from that steam loop.	14		

Other characteristics of the ANO-1 and TMI-1 steam systems are as follows:

The steam system begins at the OTSG outlet nozzle and continues through the steam line piping, turbine, and condenser.

11/29

A. MAD VALVES

	ANO-1	Reference	TMI-1	Reference
# Valves	2	4, Fig. 10-1	2	15
Lift Pressure*	1020 psig	10	1026	19
Full Open Pressure*	1045 psig	10	1052	19
Capacity (Total)	5%	10	6.4%	19

*The Mad Valve setpoints are a function of plant condition (reactor trip, turbine trip, or normal plant operation).

B. SAFETY VALVES

	ANO-1	Reference	TMI-1	Reference
# Valves	16	4, Fig. 10-1	18	19
Safety Valves	4 @ 1050 psig	9	2 @ 1040 psig	19
Lift Pressure	4 @ 1070 psig	9	4 @ 1050 psig	19
	4 @ 1090 psig	9	4 @ 1060 psig	19
	4 @ 1100 psig	9	4 @ 1080 psig	19
			4 @ 1092.5 psig	19
Safety Valve Flow	235 lbm/valve sec	9		

C. CONDENSER DUMP (Turbine Bypass)

	ANO-1	Reference	TMI-1	Reference
Lift Pressure*	1020 psig	10	1020 psig	19
Full Open Pressure*	1045 psig	10	1052 psig	19
Capacity (Total)	15%	10	15%	19

*Condenser Dump setpoints are a function of plant conditions. Setpoints shown are for reactor trip.

)-00

Secondary system inventory is controlled by either the main feedwater system or the emergency feedwater system depending on plant conditions. Section V and VI cover these systems.

Section VII, the final section, compares how each plant responds to a loss of offsite/onsite electrical power. Because loss of power affects all five major areas of plant control, it must be addressed separately.

MAIN FEEDWATER SYSTEM

The primary differences which are apparent from the feedwater P+ID's are in cross-connect design and flow control valve arrangement. The ANO-1 feedwater trains are completely separate except for a normally closed ICS controlled cross-connect just downstream of the main feedwater pumps. The TMI-1 trains feed into common headers both before and after the 4th and 2nd stage feedwater heaters. There are no valves to impede flow from pump A to OTSG B or from pump B to OTSG A.

ANO-1 has a low load bypass in addition to the normal startup bypass. TMI-1 has only the startup bypass line. TMI-1 has diaphragm actuated flow control valves, whereas all major valves at ANO-1 are motor actuated.

Other data which characterizes the MFW systems in each plant is as follows:

A. Design Data

Parameter	ANO-1	Reference	TMI-1	Reference
Normal Flow, Both Pumps (lb/hr)	11.1×10^6	26	10.6×10^6	7
Temperature (°F)	457	26	457	16
Pump Discharge Pressure (psia)	1088	26	1225	16

B. Signals That Trip the MFW Pumps

Signal	ANO-1	Reference	TMI-1	Reference
Thrust Bearing Wear Forward (mils)	5.	27	Trips, but set-points	
Reverse	35.	27	Unknown	18
Rotor Vibration (mils)	6.5	27	Unknown	
Turbine Overspeed (rpm)	62.15	27	Yes, setpoint unknown	18
Bearing Oil Pressure Low (psig)	10.	27	<4psi	18

B. Signals That Trip the MFW Pumps (Cont'd)

Signal	ANO-1	Reference	TMI-1	Reference
FW Discharge Pressure High (psig)	1150	27	Unknown	
FW Pump Suction Pressure Low (psig)	230	27	Pump suction valve closed	18
FW Pump Low Flow (gpm)	1600	27	1000 gpm	16
Vacuum			<23" Hg	18
Other			Number of condensate/ condensate booster pumps less than the number of feedwater pumps running will trip the FW pump turbine that was reset last.	18

C. Valve Control Logic

1. ANO-1 (Reference 29)

a. Low Load Block Valve

The low load block valve opens when the startup valve reaches 80% open. The low load block valve closes when the startup valve reaches 50% closed.

b. Startup Valve

The startup valve is controlled by the ICS which maintains feed flow proportional to reactor power level.

c. Main Block Valve

The main block valve opens when feedwater demand exceeds 50%. The main block valve closes if feedwater demand drops below 45%.

d. Reactor Trip

A reactor trip causes the main block valve and the low load block valve to shut. Also, a preselected feedwater pump is tripped.

e. Feedwater Pump Trip

A feedwater pump trip causes the main block valve and the low load block valve associated with that pump to close. Also, after a single feedwater pump trip, the ICS opens the cross-connect valve.

f. Reactor Coolant Pumps

Trip of all four reactor coolant pumps causes the low-load block valve to close.

g. Pump Speed

After the main block valve opens, the ICS controls feedwater flow by adjusting pump speed. Until the main block valve is opened, the feedwater flow is controlled by the pressure drop across the startup or low-load valve.

2. TMI-1

a. Low Load Block Valve

There is no low load block valve at TMI-1

b. Startup Valve

Normally ICS controlled. S/U and MFW control valves operate sequentially. When S/U control valve flow approaches capacity during startup, the main control valve begins to open. (Ref. 16)

c. Main Block Valve

The main block valve opens when the startup valve reaches approximately 90% open. The block valve closes when the startup valve reaches approximately 70% closed. (Ref. 18)

d. Reactor Trip

(No information available at time of writing)

e. Feedwater Pump Trip

(No information available at time of writing)

-00

f. Reactor Coolant Pumps Tripped

A trip of all four reactor coolant pumps will result in a closing of the main feedwater valves. (Ref. 30)

g. FW Pump Speed

Feed pumps are variable speed and are controlled by feedwater valve ΔP and demand as a function of load. During normal operation the position of the regulating valves and the speed of the feedwater pumps is controlled by the ICS; however, manual control can be instituted at any time. (Ref. 18)

32-1121199-00

VI. EFW SYSTEM

ANO-1 has one turbine driven EFW pump and one motor driven pump of approximately equal capacity. TMI-1 has one turbine driven pump and two motor driven pumps. The motor driven pumps together are equal to the capacity of the turbine driven pump.

The diagrams show that all EFW pumps in each plant are capable of feeding either OTSG if necessary. Note that ANO-1 has bypass lines (CV-2627 and CV-2626) in case the EFW control valves CV-2670 and/or CV-2620 fail shut, whereas TMI-1 does not have this feature.

The following gives characteristics of the EFW system in each plant:

	ANO-1	Ref.	TMI-1	Ref.
#Motor Driven Pumps	1	4,Fig 10-1	2	16
Capacity	780 gpm @ 2700 ft.H_2O	14	460 gpm @ 2700 ft. H_2O	16
#Steam Driven Pumps	1	4,Fig 10-1	1	16
Capacity	720 gpm @ 2700 ft.H_2O	14	920 gpm @ 2700 ft. H_2O	16
Initiating Signals	a. Low OTSG level (18")	14	*a. Loss of both MFWPs	16
	b. Trip of both MFWPs (if RP >5%)		*b. Trip of all RCPs	16
			*c. Low MFWP P signal	16
	c. Trip of all RCPs		d. Manual	16
	d. SLBIC start steam driven pump		*Starts only TDEFWP automatically. MDEFWPs are started manually if TDEFWP is unavailable or steam pressure is insufficient.	16
	e. Manual			
EFW Isolation Valve(& Controller)	CV-2620 (motor)	14	EF-V30A (Pneumatic)	20
	CV-2670 (motor)	14	EF-V30B (Pneumatic)	20

	ANO-1	Ref.	TMI-1	Ref.
EFW Isolation Valve(s) Stroke Time	23.3 sec (CV-2670) 23.3 sec (CV-2620)		No information available for control valves EFW-30 A/B	
Power Supply for EFW Isolation/Control Valve(s)	CV-2620 - B61 CV-2670 - B53	14 14	EF-V30 A Plant air; EF-V30 B "	25 25
Power Lost to EFW Isolation/Control Valve After Loop	No	14	Only if inst. air lost	25
Failure Position of EFW Isolation/Control Valve on Loss of AIR	As Is	14	Fail As Is	25
Instrument AIR Compressors Shed After Loop	No	22	Yes	25
Steam Supply Valve to EFWP Turbine	CV-2617 CV-2667	14 14	MSV-13A MSV-13B	16 16
Power Supply for Steam Supply Valve	B62 (D/G Backed) B52 (D/G Backed)	14 14	Plant AIR Plant AIR	25 25
Failure Position of Steam Supply Valve After Loop	Air not lost	14	FO if air lost FO if solenoid de-energized	25
Flow vs. Head for Motor Driven Pump 2 at TMI-1 1 at ANO-1	200 gpm 3400 ft.	10	(EFW Pump Curves Not Available At This Time)	
	300 gpm 3400 ft.	10		
	400 gpm 3300 ft.	10	"	
	500 gpm 3200 ft.	10	"	
	600 gpm 3000 ft.	10	"	
	700 gpm 2800 ft.	10	"	
Flow vs. Head for Steam Driven Pump 1 at Each Plant	200 gpm 3500 ft.	10	"	
	400 gpm 3350 ft.	10	"	
	600 gpm 3000 ft.	10	"	
	800 gpm 2550 ft.	10	"	
	1000 gpm 1850 ft.	10	"	

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VII. POWER

At ANO, the diesels start and load-on in approximately 15 seconds (Ref. 11). At TMI-2, the diesels start in 10 seconds and are auto-loaded in 5 blocks at 5 second intervals (at 10, 15, 20, 25, and 30 seconds after receipt of the starting signal) and selected manual on-loadings can be made thereafter.

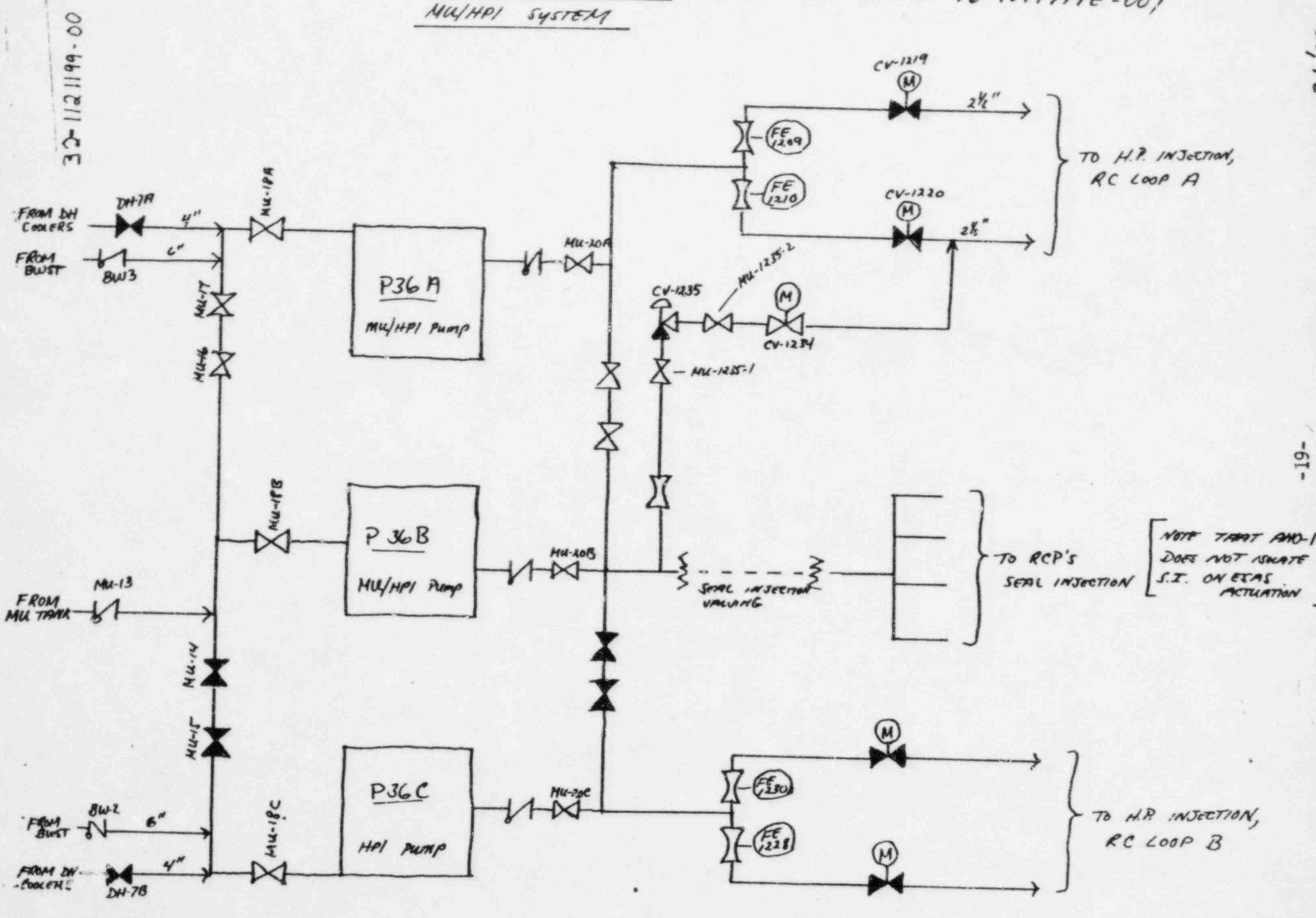
Each DG at TMI-1 is rated 3000 KW (at 2000 hr), and a single DG can handle all auto-loads along with selected manual loads. The DG's are air-started, with a separate diesel driven air compressor to recharge the air receivers should they become empty during an attempted startup.

Load blocks are listed in Ref. 25 and 12. Selected manual loads not normally connected to the ES busses P,R,S, or T can be loaded manually via cross-connects through the bus N. The instrument air system has yet to be updated; it's presently based on verbally transmitted data from Ted Book, along with Ref. 28.

A. Diesel Loadings Comparison

Item	ANO-1	Reference	TMI-1	Block	Reference
RC Pumps	No	11	No	---	12
Condensate Pumps	No	11	No	---	12
Cond. Booster Pumps	No	11	No	---	12
Circ. Water Pumps	No	11	No	---	12
Makeup Pumps	Yes	11	Yes	1	25
Intermed. Cooling Water Pump	No	11	Yes	M	5
			Yes		12
Pzr. Heaters	Yes	11	Yes(126 KW)	M	25
Inst. Air Comp.	Yes	11	Yes(Normal)	M	25
EFWP (motor driven)	Yes	11	Yes	5	25
EFW Isol. Valve	Yes	11	Yes		17
EFWP Turbine Steam Isolation Valve	Yes	11	(PNEUMATIC)		17
Service Water Pump	Yes	17	Yes	3	5
Decay Heat Pump	Yes	17	Yes	1	25
Bldg. Spray Pumps	Yes	17	Yes	4	25

ANO-1 SIMPLIFIED MU/HPI SYSTEM (Ref. B+W Doc. No. 16-1097719E-00)



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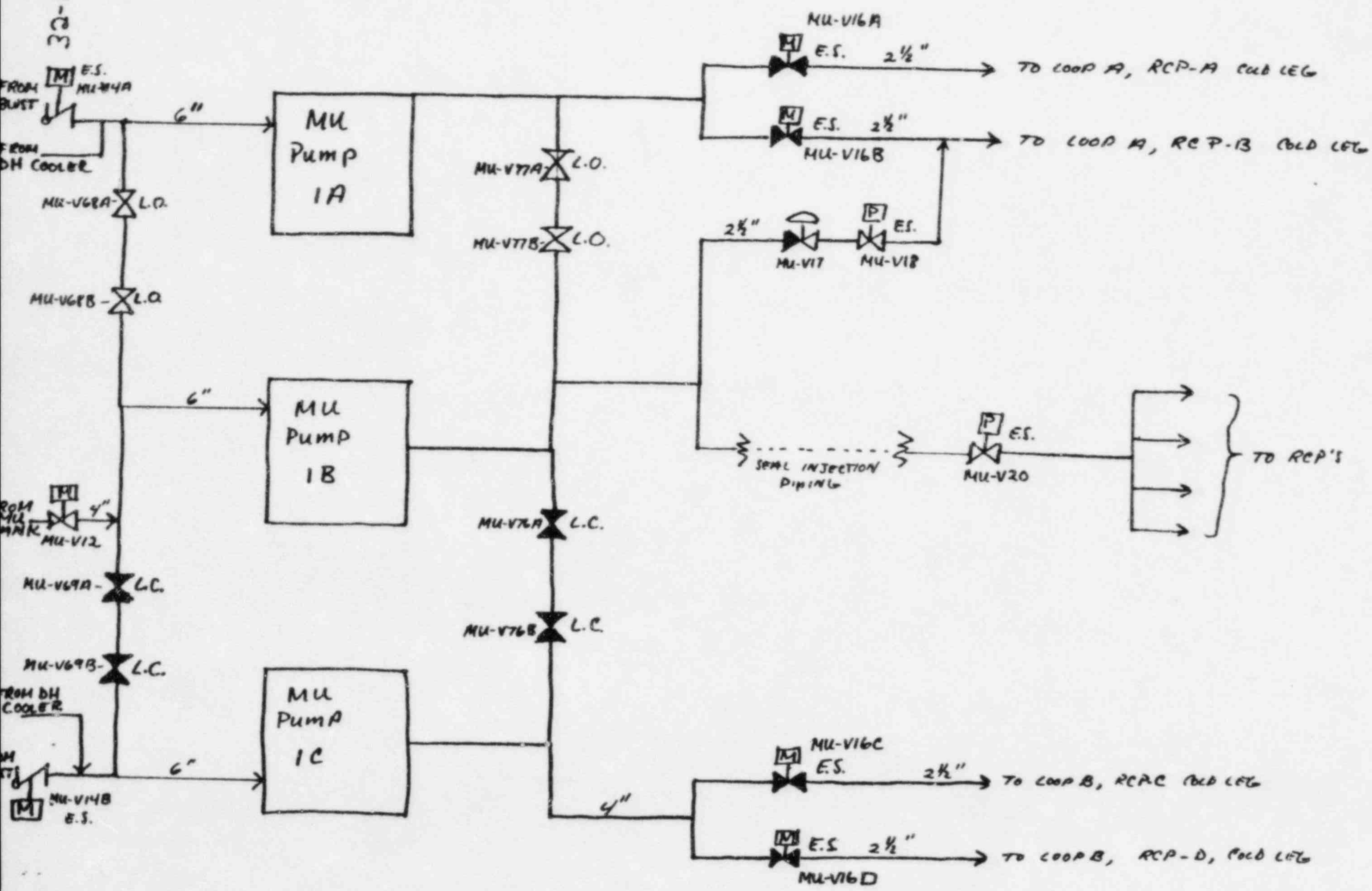
16-1108693D-00, 16-1108694D-00

33-1121199-00

TMI-1 SIMPLIFIED MU/HPI SYSTEM



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ANO-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

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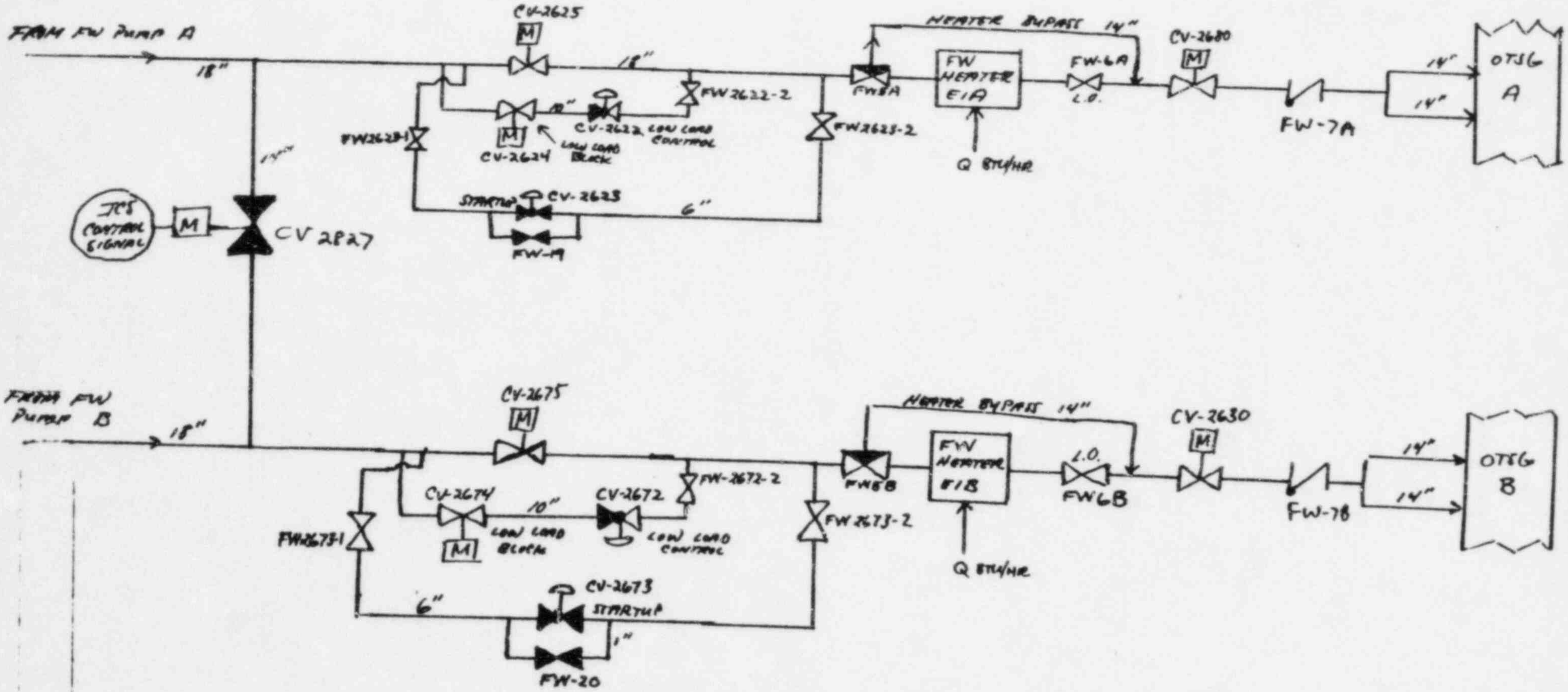

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TMI-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

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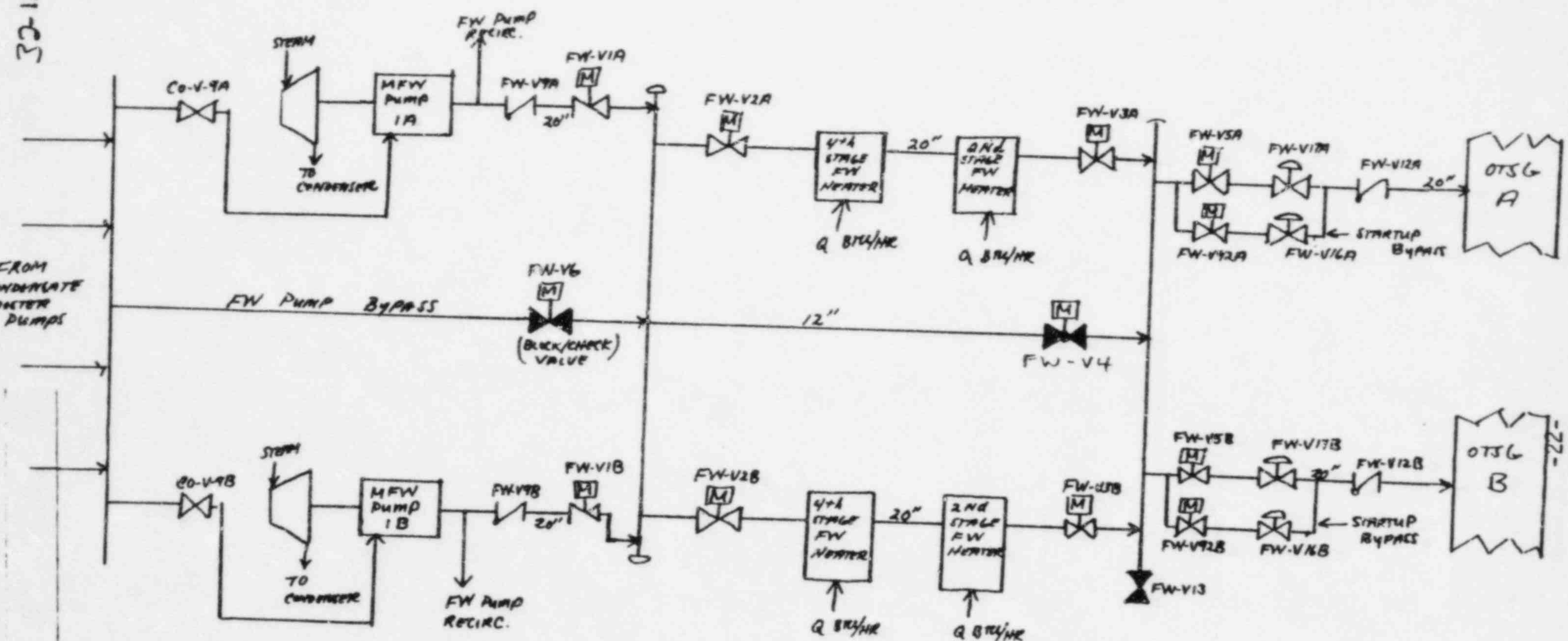

ANO-1 SIMPLIFIED EFW SYSTEM

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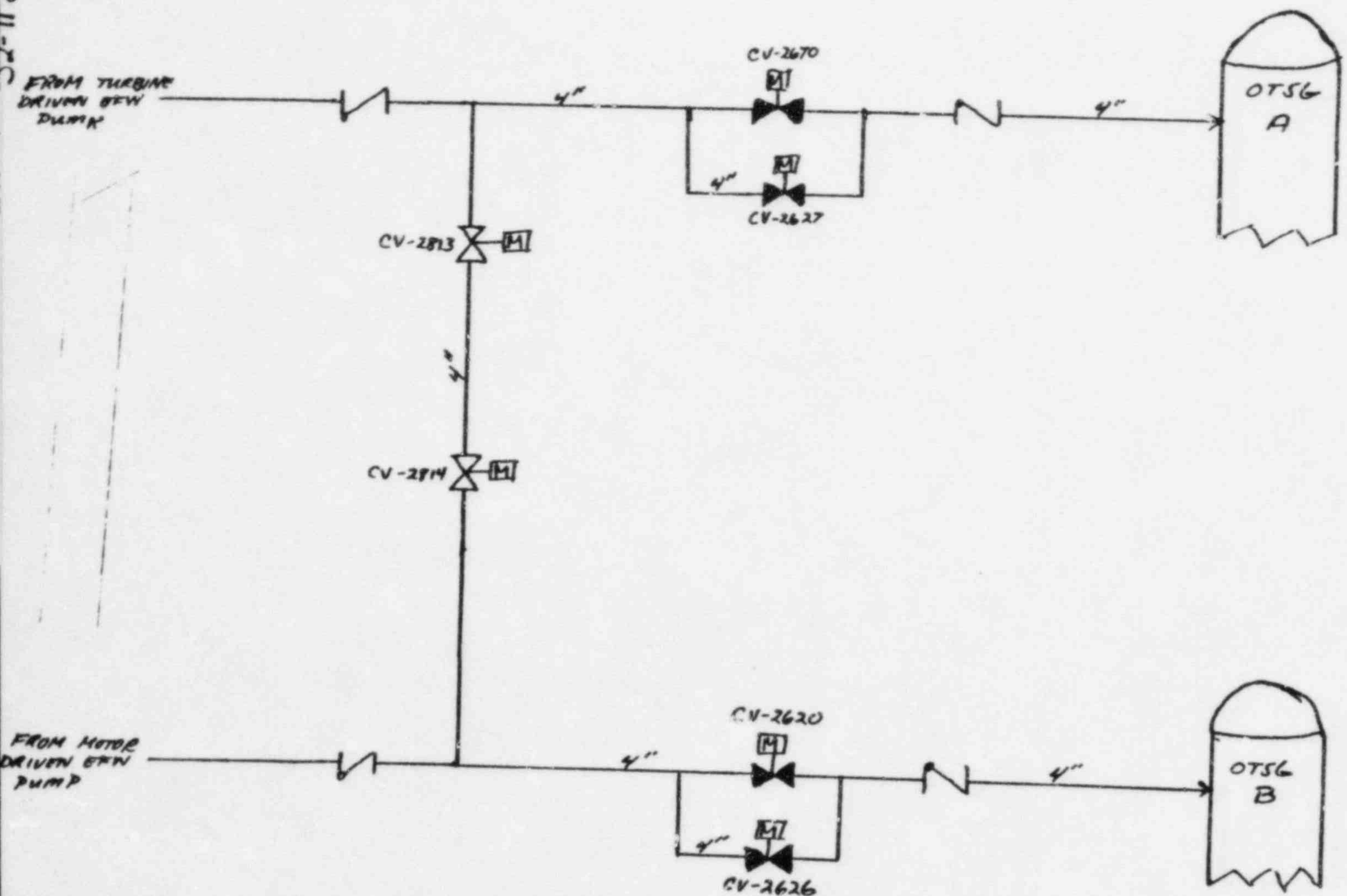

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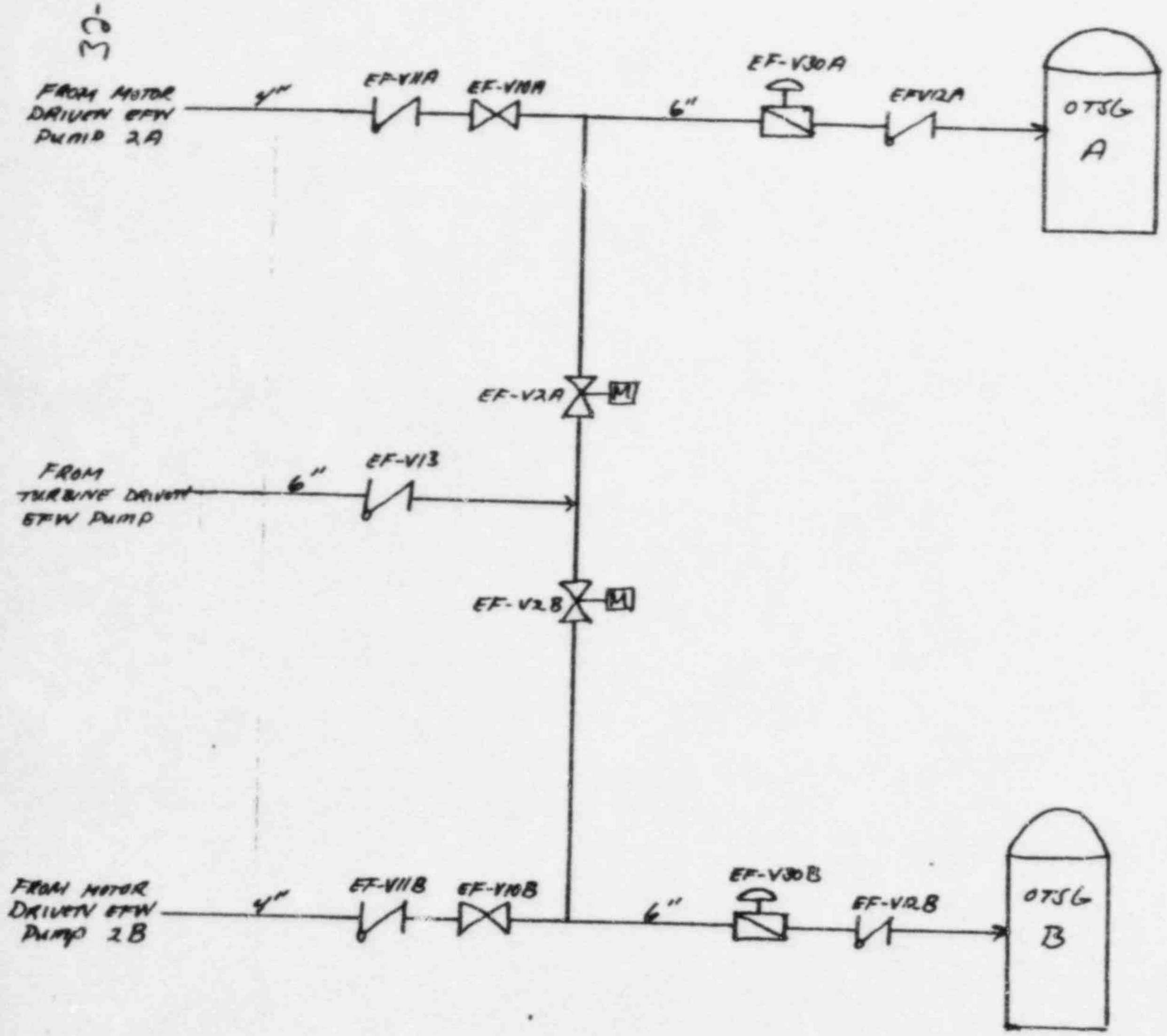

TMI-1 SIMPLIFIED EFW SYSTEM

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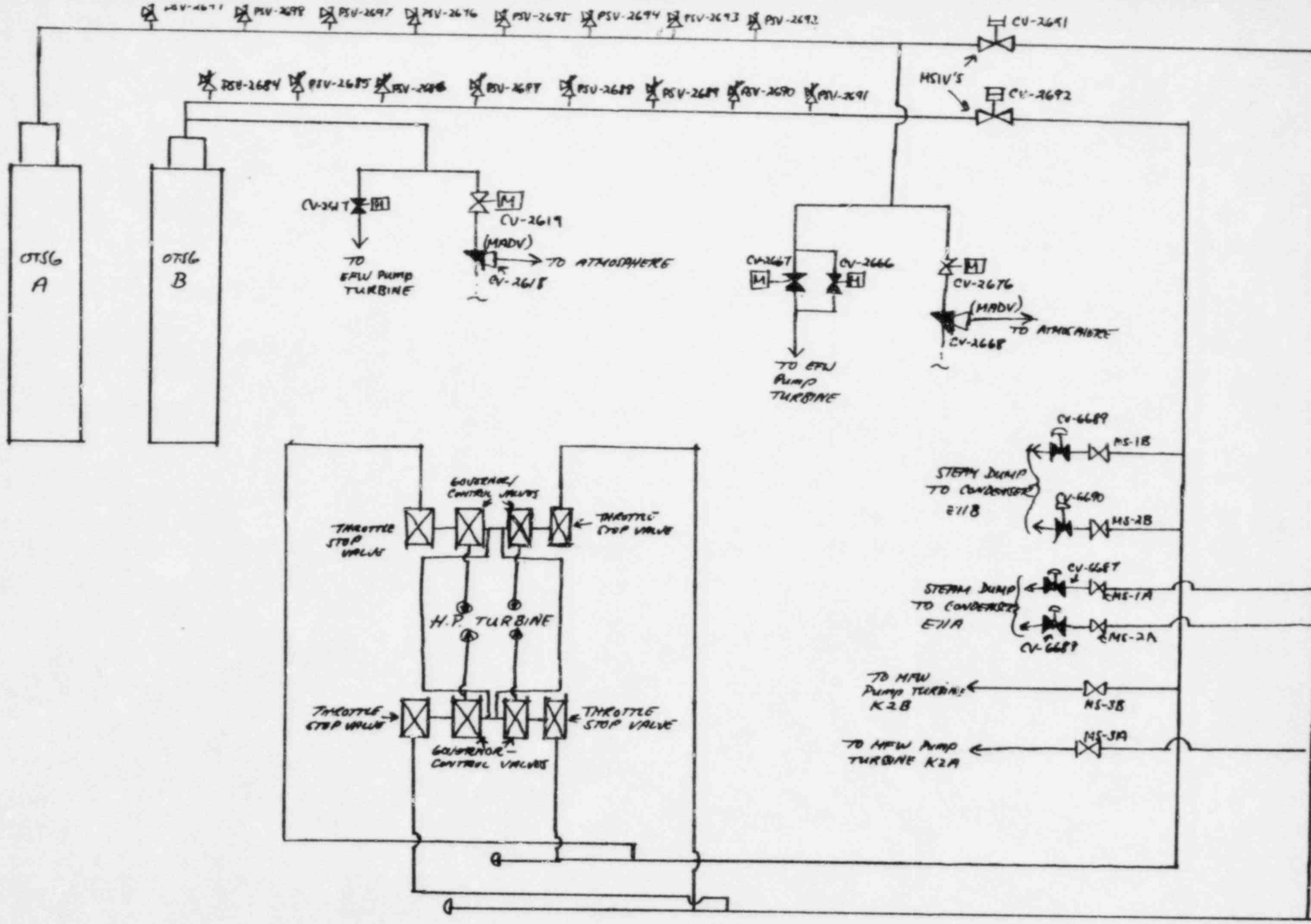

ANO-1 SIMPLIFIED MAIN STEAM SYSTEM

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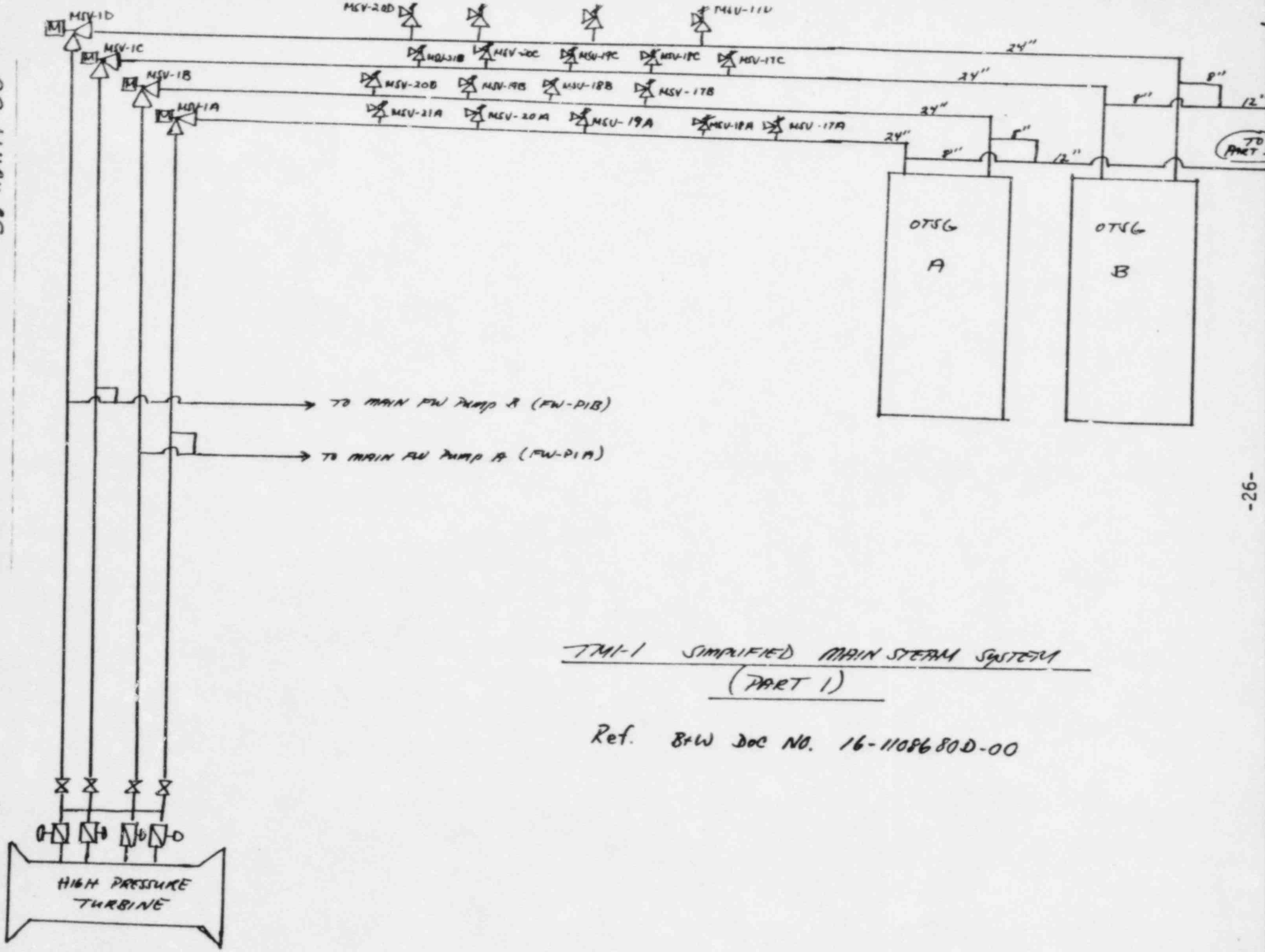
33-1121199-00



TMI-1 SIMPLIFIED MAIN STEAM SYSTEM
(PART 1)

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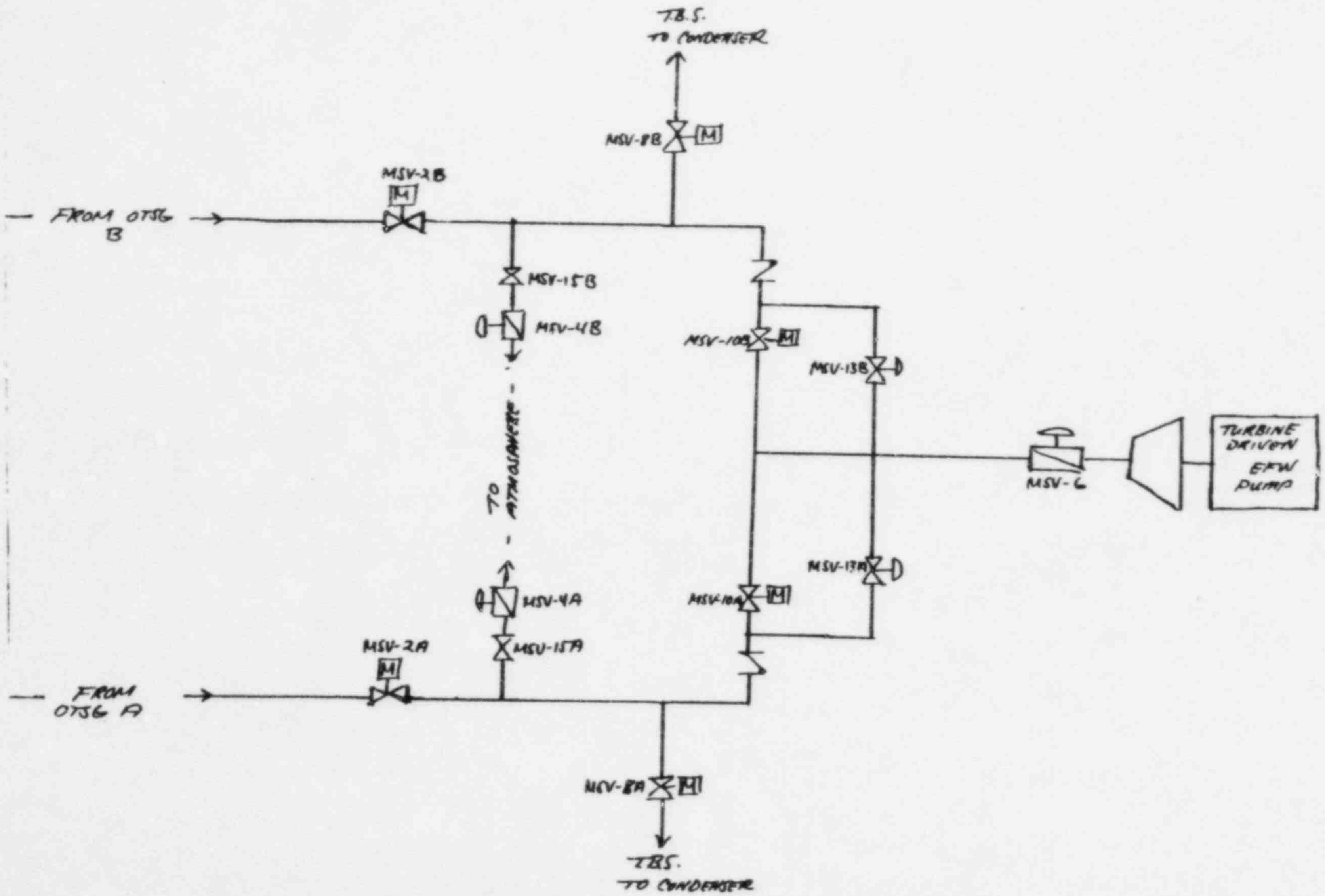

TMI-1 SIMPLIFIED MAIN STEAM SYSTEM (PART 2)

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09-001-001	86-1123876-00	TMI-1 Excessive Main Feedwater Transient Information Document	N	N/A

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TITLE TMI-1 Excessive Main Feedwater Transient Information Document

PREPARED BY L. J. Rudy LJR REVIEWED BY M. E. Newlin M.E.N.

TITLE Assoc. Engr. DATE 2/27/81 TITLE Engineer DATE 2/27/81

PURPOSE:

To summarize the analytical basis for the Abnormal Transient Operating Guidelines for an Excessive Main Feedwater transient at the Three Mile Island-Unit One nuclear station.

SUMMARY OF RESULTS (INCLUDE DOC. ID'S OF PREVIOUS TRANSMITTALS & SOURCE CALCULATIONAL PACKAGES FOR THIS TRANSMITTAL)

The attached writeup summarizes the ATOG analytical basis.
Note: The revised P-T diagrams will be sent via separate transmittal.

DISTRIBUTION

TABLE OF CONTENTS

I. Introduction

The final output of the ATOG program is a set of operator guidelines which is applicable to a series of selected plant transients. As such, it is necessary for the writer of these guidelines to obtain well-documented analytical results for each of these transients so that he will have an established basis for the guidelines. In essence, this document will supply the guidelines writer with the necessary analytical information and will act as a traceable link between the guidelines and the analysis.

This Transient Information Document (TID) summarizes the analytical results for the Excessive Main Feedwater transient and is applicable to Metropolitan Edison Company's Three Mile Island - Unit One (TMI-1) reactor. In effect, it will:

- Discuss the major system differences between TMI-1 and Arkansas Power and Light Company's Arkansas Nuclear One - Unit One (ANO-1).
- Depict actual plant data for an excessive main feedwater transient.
- Define the ANO-1 results which can be used or modified for this event.

Reference 1 is the associated event tree for this transient.

II. Major Plant Differences

Any plant can be brought to a safe shutdown if control is acheived in the following five areas of plant response:

1. Reactivity
2. Primary Inventory
3. Primary Pressure
4. Secondary Inventory
5. Secondary Pressure

The plant systems used to achieve control of these parameters are the subjects of the following discussion, with particular attention given to differences between the corresponding TMI-1 and ANO-1 systems that affect plant performance during an excessive main feedwater transient.

A. Reactivity

Short term reactivity control is achieved when the reactor trips and the control rods fall into the reactor core. The following table is a

listing of the various signals that trip the reactor at TMI-1 and at ANO-1. During an excessive main feedwater transient, TMI-1 will behave similarly to ANO-1 insofar as the actions of the reactor protection system are concerned. Longer term reactivity control is attained through the use of soluble boron to compensate for the decay of equilibrium xenon and the reactivity temperature deficit. Both TMI-1 and ANO-1 utilize the makeup/high pressure injection and chemical addition systems to bring the plant to a safe shutdown following a reactor trip. A comparison of the TMI-1 and ANO-1 makeup and letdown/high pressure injection systems can be found in Section II. B. Since ATOG does not address the effects of the chemical additon system (i.e., long term reactivity control is not considered), no comparison of the respective systems is made.

TABLE 1

RPS Trip Setpoints for TMI-1 and ANO-1

TMI-1 (Ref. 2)	ANO-1 (Ref. 3)
Power >105.5%	Power > 105.5%
Flux/flow/imbalance - 1.08 times rated flow (%) minus reduction due to imbalance	Flux/flow/imbalance - 1.057 times rated flow (%) minus reduction due to imbalance
High RCS pressure (2300 PSIG) (Ref. 34)	High RCS pressure (2300 PSIG) (Ref. 34)
Low RCS pressure (1800 PSIG)	Low RCS pressure (1800 PSIG)
Variable low RCS pressure- (11.75 T_{out} - 5103) PSIG	Variable low RCS pressure- (11.75 T_{out} - 5103) PSIG
RC max. temperature (619F)	RC max. temperature (619F)
High RB pressure (4 PSIG)	High RB pressure (4 PSIG)
Additional Signals that Trip the Reactor	
Loss of FWPS (Ref. 38)	Loss of FWPS (Ref. 38)
Turbine Trip (Ref. 38)	Turbine Trip (Ref. 38)

Conclusion: Both plants behave similarily from the standpoint of reactivity control during an excessive main feedwater transient. Therefore, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

B. Primary Inventory

Primary inventory is controlled by makeup and letdown. Attached are simplified P & IDs of the makeup and letdown/high pressure injection system at each plant. Pertinent MU and LD/HPI system data for this transient is listed in Table 2 below.

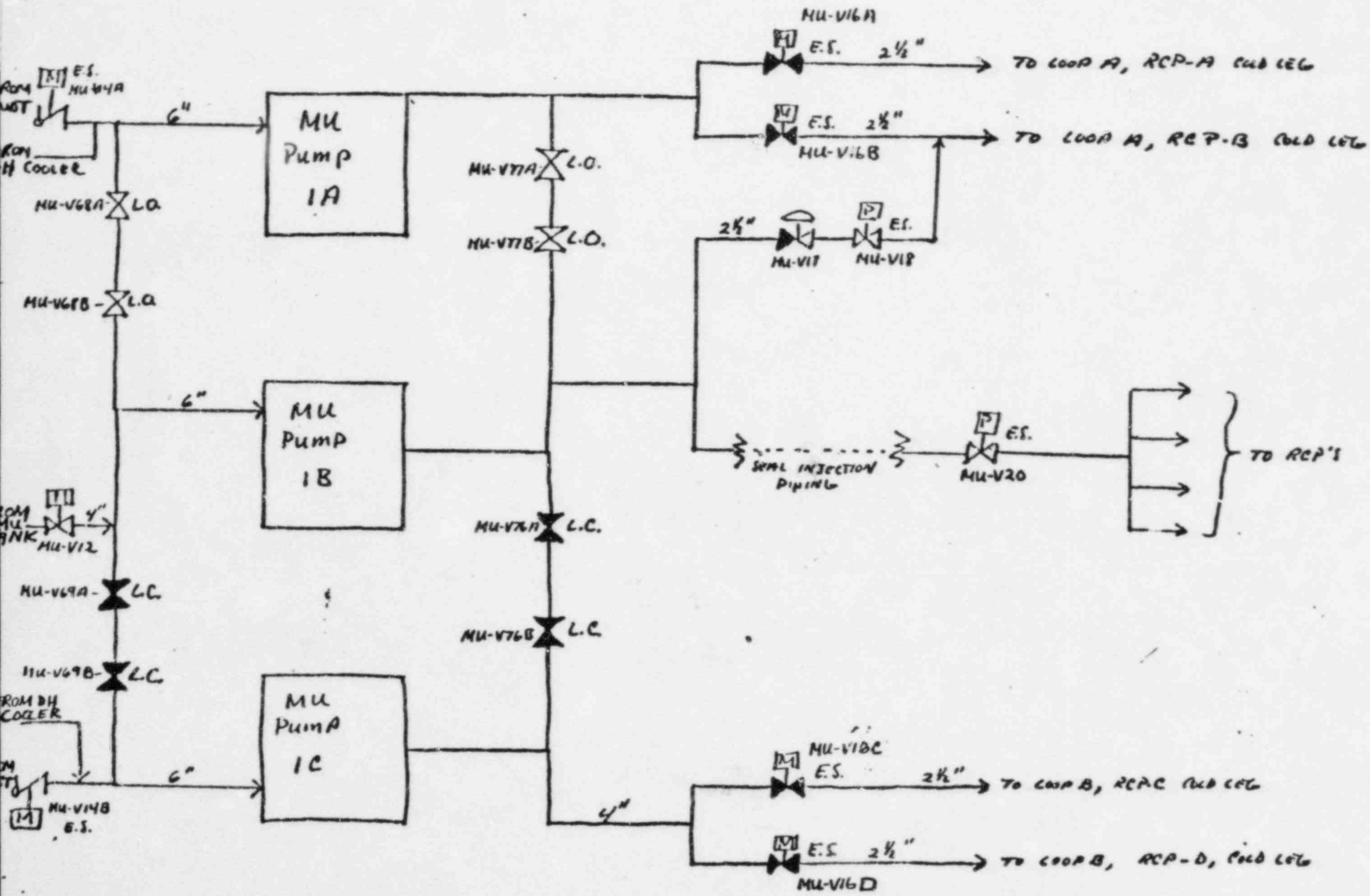
TABLE 2

Makeup and Letdown/High Pressure Injection System Performance Data

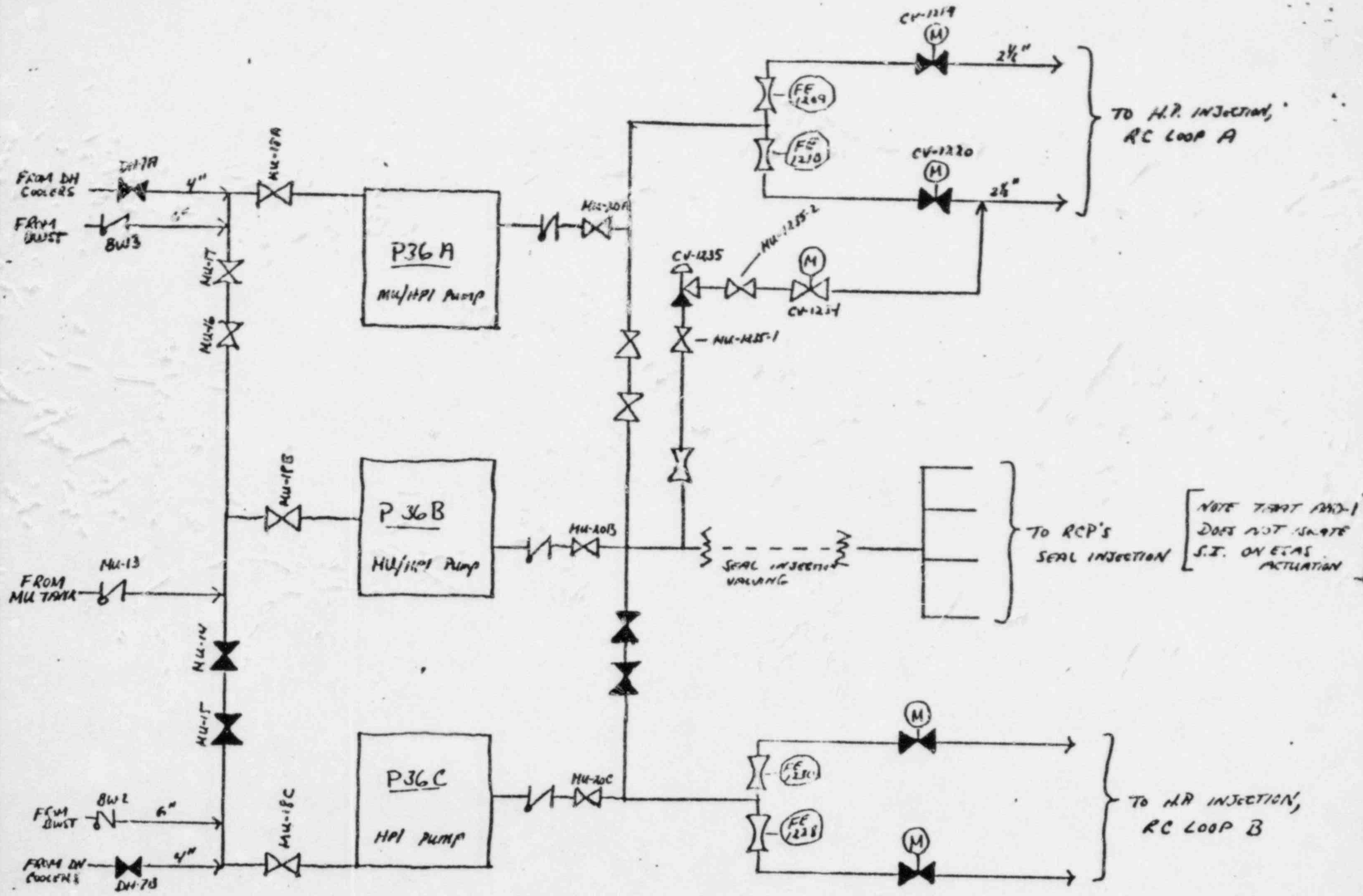
	TMI-1	Ref.	ANO-1	Ref.
Normal makeup	25 GPM	8	25 GPM	7
Normal seal injection	8 GPM/RCP	8	8 GPM/RCP	7
Normal seal return	3 GPM/RCP	8	1 GPM/RCP	7
Makeup flow vs. pressure with make-up control valve fully open	2200 PSIG 130 GPM 2000 PSIG 150 GPM 1800 PSIG 170 GPM 1600 PSIG 190 GPM	39 39 39 39	2200 PSIG 140 GPM 2000 PSIG 160 GPM 1800 PSIG 180 GPM 1600 PSIG 200 GPM	9 9 9 9
Normal letdown	45 GPM	8	53 GPM	7
Letdown temperature	120 F	10	120 F	7
HPI flow vs. pressure for two HPI pumps with control valves fully open	2600 PSIG 420 GPM 2400 PSIG 525 GPM 2200 PSIG 600 GPM 2000 PSIG 670 GPM 1800 PSIG 730 GPM 1600 PSIG 785 GPM 1400 PSIG 835 GPM	39 39 39 39 39 39 39	2600 PSIG 400 GPM 2400 PSIG 495 GPM 2200 PSIG 580 GPM 2000 PSIG 645 GPM 1800 PSIG 705 GPM 1600 PSIG 755 GPM 1400 PSIG 805 GPM	9 9 9 9 9 9 9
RCP seal injection isolated after ESAS?	yes	11	no	6
ESAS actuation set-point	1600 PSIG	38	1500 PSIG	14

Ref. B+W DWGs No.
16-1108693D-00, 16-1108694D-00

TMI-1 SIMPLIFIED MU/HPI SYSTEM



ANO-1 SIMPLIFIED MU/HPI SYSTEM (Ref. B+W Doc. No. 16-1097719E-00)



Conclusion: Both plants behave similarly from the standpoint of primary inventory control during an excessive main feedwater transient. Therefore, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

C. Primary Pressure

Primary pressure control is achieved by the pressurizer heaters, pressurizer spray system, relief, and code safety valves. System data for TMI-1 and ANO-1 are tabulated below.

TABLE 3

Primary Pressure Control System Data for TMI-1 and ANO-1

	TMI-1	Ref.	ANO-1	Ref.
Pressurizer heater bank-on setpoints				
1	<2135 PSIG	8	<2135 PSIG	7
2	<2135 PSIG	8	<2135 PSIG	7
3	2135 PSIG	8	2135 PSIG	7
4	2120 PSIG	8	2120 PSIG	7
5	2105 PSIG	8	2105 PSIG	7
Pressurizer heater bank-off setpoints				
1	2155 PSIG	8	>2155 PSIG	7
2	2155 PSIG	8	>2155 PSIG	7
3	2147 PSIG	8	2155 PSIG	7
4	2140 PSIG	8	2140 PSIG	7
5	2125 PSIG	8	2125 PSIG	7
Pressurizer heater bank power				
1	Power output by bank not available		84 KW	15
2			84 KW	15
3			378 KW	15
4			504 KW	15
5			588 KW	15
Total	1638 KW	16	1638 KW	
Pressurizer spray valve				
open	2205 PSIG	17	2205 PSIG	18
close	2155 PSIG	17	2155 PSIG	18

Pressurizer elect-romatic relief valve				
open	2450 PSIG	34	2450 PSIG	34
close	2400 PSIG	34	2400 PSIG	34
capacity	100,000 LB/H	17	100,000 LB/H	17
Pressurizer code safety valves				
open	2435 PSIG*	17	2500 PSIG	18
close	~2285 PSIG*	35	Not available	
capacity	623,400 LB/H	17	600,000 LB/H	18

Conclusion: Both plants behave similarly from the standpoint of primary pressure control during an excessive main feedwater transient. Therefore, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

D. Secondary Inventory

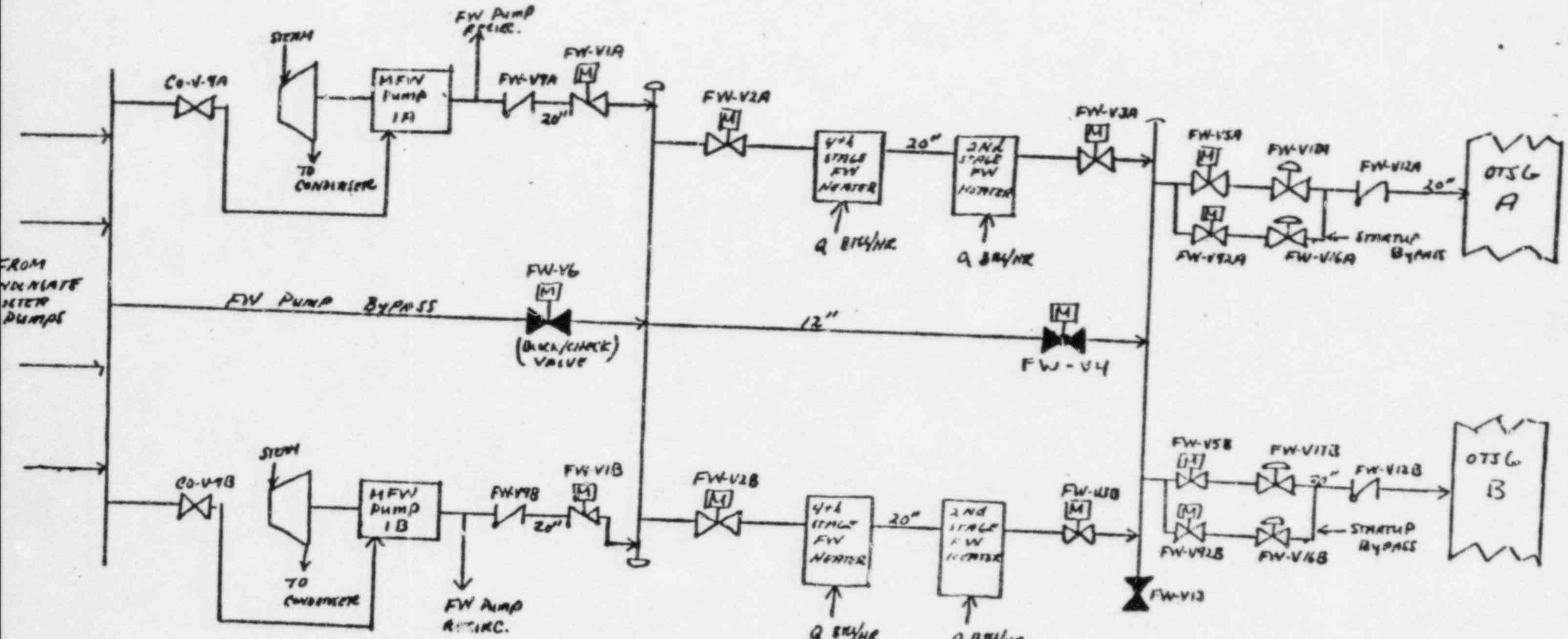
Secondary inventory is controlled via the main and emergency feedwater systems. Attached are simplified P & IDs of these systems for TMI-1 and ANO-1. The primary differences which are apparent from these diagrams are in cross-connect design and flow control valve arrangement. The ANO-1 feedwater trains are completely separate except for a normally closed ICS controlled cross-connect valve just downstream of the main feedwater pumps. The TMI-1 trains feed into common headers both before and after the fourth and second stage feedwater heaters. There are no valves to impede flow from pump A to OTSG B or from pump B to OTSG A.

ANO-1 has a low load bypass in addition to the normal startup bypass. TMI-1 has only the startup bypass line. TMI-1 has diaphragm-actuated flow control valves, whereas all major valves at ANO-1 are motor actuated. Table 4 lists pertinent data for the TMI-1 and ANO-1 main feedwater systems.

*Although these values appear at first sight to be incorrect, all available reference data indicates that the safety valve lift setpoint is below that of the ERV. This is currently under review by PS&C.

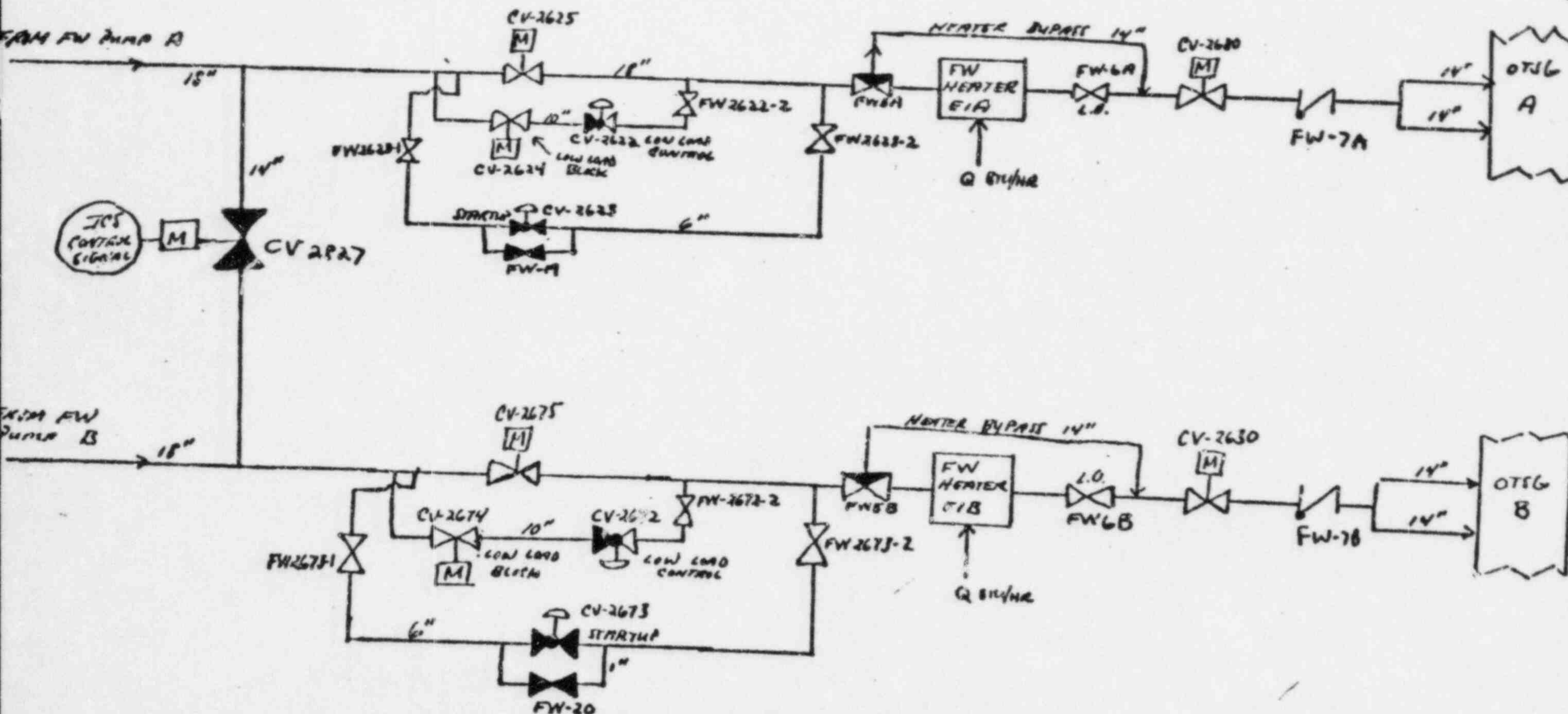
TMI-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

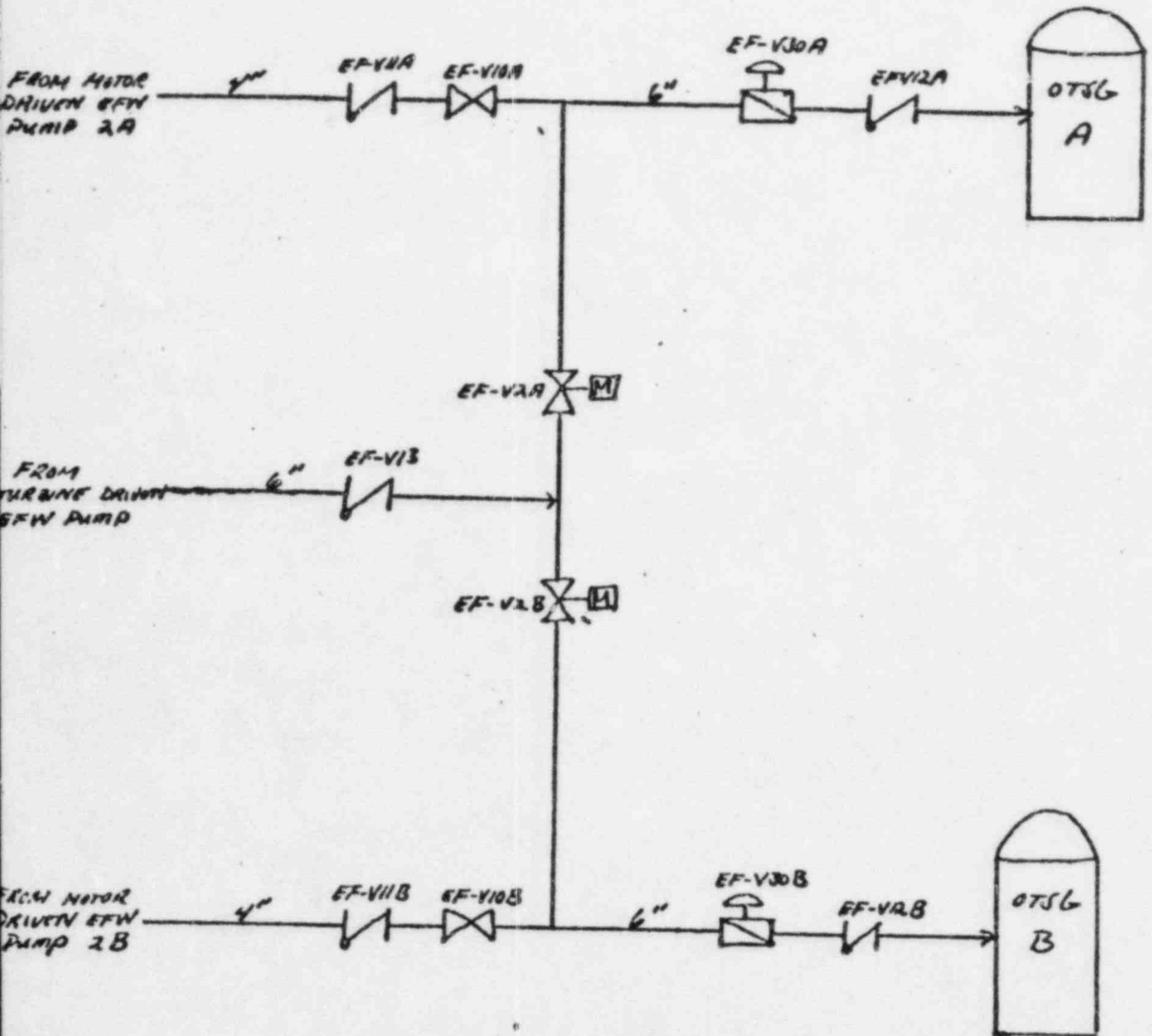
Ref. B&W DWGs No. 16-1108682D-00



ANO-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

(Ref. B&W DOC. NO. 16-1097712E-00)





TMI-1 SIMPLIFIED EFW SYSTEM

Ref. B+W Doc. No. 16-1103682D-00

ANO-1 SIMPLIFIED EFW SYSTEM

(Ref. B+W Doc. No. 16-1097712E-00)

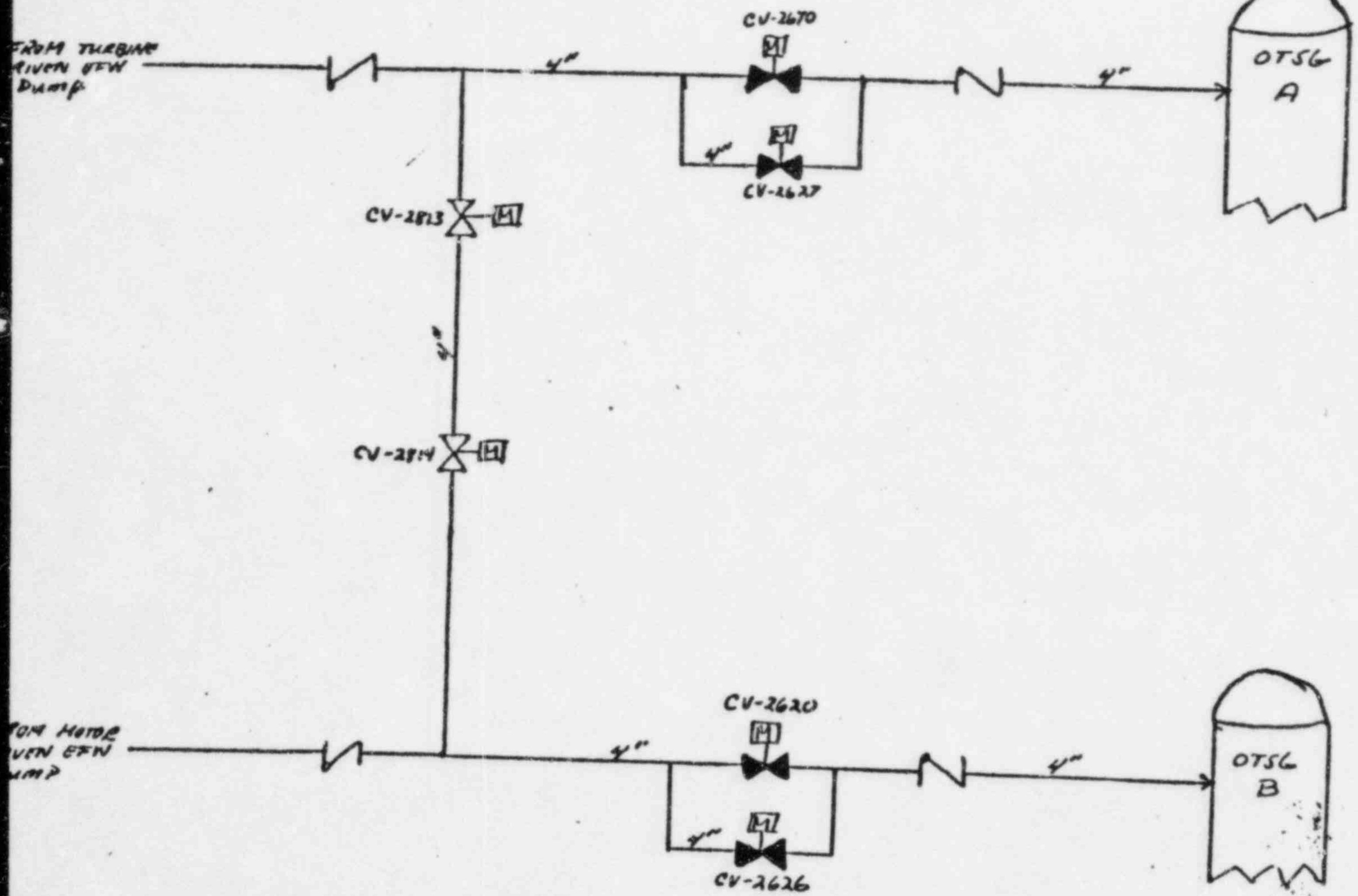


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TABLE 4

TMI-1 and ANO-1 Main Feedwater System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
Normal flow, both pumps	10.6×10^6 LB/H	23	11.1×10^6	22
Feedwater temperature	457 F	23	457	22
Pump discharge pressure	1225 PSIA	36	1088	22
Signals that trip MFWPS				
Thrust bearing wear				
forward	Trips, setpoint unknown	37	5 MILS	25
reverse	Trips, setpoint unknown	37	35 MILS	25
Rotor vibration	unknown		6.5 MILS	25
Turbine Overspeed	~15% above max. full load speed	24	6215 RPM	25
Bearing oil pressure low	<4 PSIG	37	10 PSIG	25
FWP discharge pressure high	unknown		1150 PSIG	25
FWP suction pressure low	pump suction valve closed	37	230 PSIG	25
FWP low flow	1000 GPM	36	1600 GPM	25
Vacuum	<23 IN. HG	17		
Other	(1) Number of condensate/ condensate booster pumps less than the number of feedwater pumps running will trip the FWP turbine that was reset last	37		
	(2) Manual			

Feedwater valve control logic -

TMI-1

— Low Load Block Valve
There is no low load block valve at TMI-1.

— Startup Valve
Normally ICS controlled. S/U and MFW control valves operate sequentially. When S/U control valve flow approaches capacity during startup, the main control valve begins to open. (Ref. 36)

— Main Block Valve
The main block valve opens when the startup valve reaches approximately 90% open. The block valve closes when the startup valve reaches approximately 70% closed. (Ref. 37)

-- Reactor Trip
No actions occur.

— Feedwater Pump Trip
No actions occur.

— Reactor Coolant Pumps Tripped
A trip of all four reactor coolant pumps will result in EFW initiation to 50% on the operating range and therefore, in a closing of the main feedwater valves. (Ref. 26)

— FW Pump Speed
Feed pumps are variable speed and are controlled by feedwater valve ΔP and demand as a function of load. During normal operation the position of the regulating valves and the speed of the feedwater pumps is controlled by the ICS; however, manual control can be instituted at any time. (Refs. 24, 37)

ANO-1 (Ref. 27)

— Low Load Block Valve
The low load block valve opens when the startup valve reaches 80% open. The low load block valve closes when the startup valve reaches 50% closed.

- Startup Valve
  The startup valve is controlled by the ICS which maintains feed flow proportional to reactor power level.

- Main Block Valve
  The main block valve opens when feedwater demand exceeds 50%. The main block valve closes if feedwater demand drops below 45%.

- Reactor Trip
  A reactor trip causes the main block valve and the low load block valve to shut. Also, a preselected feedwater pump is tripped.

- Feedwater Pump Trip
  A feedwater pump trip causes the main block valve and the low load block valve associated with that pump to close. Also, after a single feedwater pump trip, the ICS opens the cross-connect valve.

- Reactor Coolant Pumps Tripped
  Trip of all four reactor coolant pumps causes the low-load block valve to close.

- FW Pump Speed
  After the main block valve opens, the ICS controls feedwater flow by adjusting pump speed. Until the main block valve is opened, the feedwater flow is controlled by the pressure drop across the startup or low-load valve.

Note from the emergency feedwater system P & IDs that all EFW pumps in each plant are capable of feeding either OTSG if necessary. ANO-1 has bypass lines (CV-2627 and CV-2626) in case the EFW control valves CV-2670 and/or CV-2620 fail shut, whereas TMI-1 does not have this feature. Table 5 below lists EFW system performance data for each plant.

TABLE 5

TMI-1 and ANO-1 Emergency Feedwater System Performance Data

	TMI-1			Ref.	ANO-1	Ref.
# of motor-driven EFWPS	2			36	1	12
Capacity	460 GPM @ 2700 FT. H_2O			36	780 GPM @ 2700 Ft. H_2O	28
# of steam-driven EFWPS	1			36	1	12
Capacity	920 GPM @ 2700 FT. H_2O			36	720 GPM @ 2700 FT. H_2O	28
Initiating signals	Loss of both MFWPS			38	Low OTSG level (18 in.)	28
	Trip of all RCPS			38	Trip of both MFWPS (if Rx power >5%)	28
	Manual			38	Trip of all RCPS	28
					SLBIC starts steam - driven pump	28
					Manual	28
		EF-P1A	EF-P1B			
Flow vs. head for motor-driven pump	100 GPM	3250 FT	3250 FT	40	200 GPM 3400 FT	15
	200 GPM	3200 FT	3200 FT	40	300 GPM 3400 FT	15
	300 GPM	3090 FT	3090 FT	40	400 GPM 3300 FT	15
	400 GPM	2900 FT	2900 FT	40	500 GPM 3200 FT	15
	500 GPM	2630 FT	2625 FT	40	600 GPM 3000 FT	15
	600 GPM	2200 FT	2180 FT	40	700 GPM 2800 FT	15
Flow vs. head for steam-driven pump	200 GPM	2990 FT		40	200 GPM 3500 FT	15
	400 GPM	2950 FT		40	400 GPM 3350 FT	15
	600 GPM	2870 FT		40	600 GPM 3000 FT	15
	800 GPM	2760 FT		40	800 GPM 2550 FT	15
	1000 GPM	2550 FT		40	1000 GPM 1850 FT	15

One other system affects control of secondary inventory at TMI-1 and at ANO-1. This is a steam and/or feedwater isolation system which actuates to isolate one or both steam generators following a steam line break. The TMI-1 steam line rupture detection system (SLRDS) and the steam line break instrumentation and control (SLBIC) system at ANO-1 perform the following functions:

TABLE 6

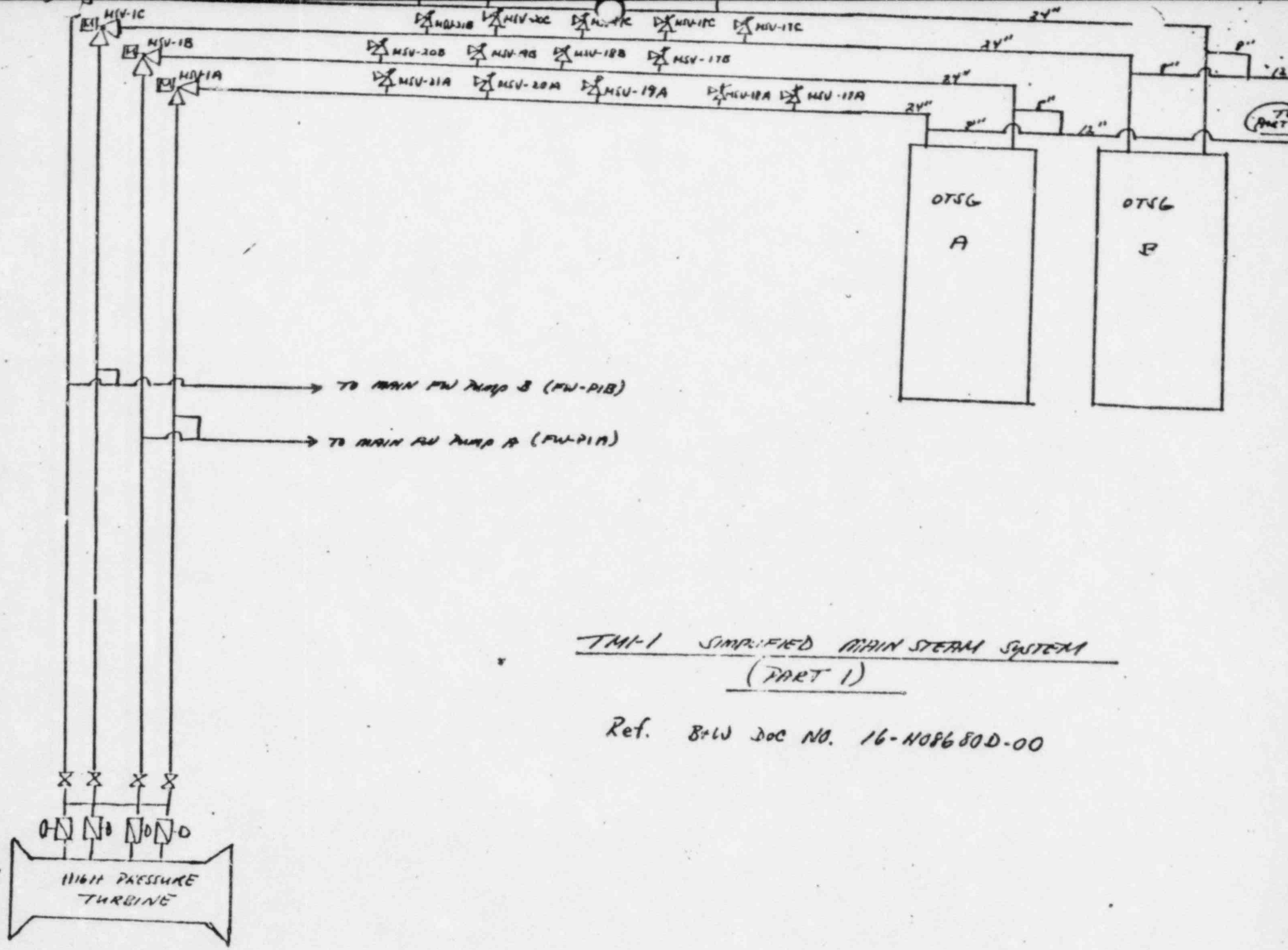
Comparison of TMI-1 SLRDS and ANO-1 SLBIC System

SLRDS (TMI-1)	Ref.	SLBIC (ANO-1)	Ref.
Actuation Setpoint = 600 psig Actions Taken By System —	29	Actuation Setpoint = 600 psig Actions Taken By System —	15
— Closes MFW block and control valves to affected OTSG only.	29	— Closes MSIVs for both OTSG's.	28
— Closes startup MFW block and control valves to affected OTSG only.	29	— Closes MFW isolation valve to affected OTSG.	28
— Closes EFW control valve to affected OTSG only.	29	— Opens steam supply valve to steam-driven EFW pump.	28
— Performs identical operations on the other OTSG if low steam pressure is detected in that loop.	29	— EFW isolation valve opens on EFW initiation signals to both OTSGs.	28
		— Closes MFW isolation valve for the other OTSG if a SLBIC signal subsequently originates from that steam loop.	28

Conclusion: Due to differences between the systems used to control secondary inventory at TMI-1 and at ANO-1, each plant will respond differently to an excessive main feedwater transient. The actual plant responses will be discussed in Section IV.

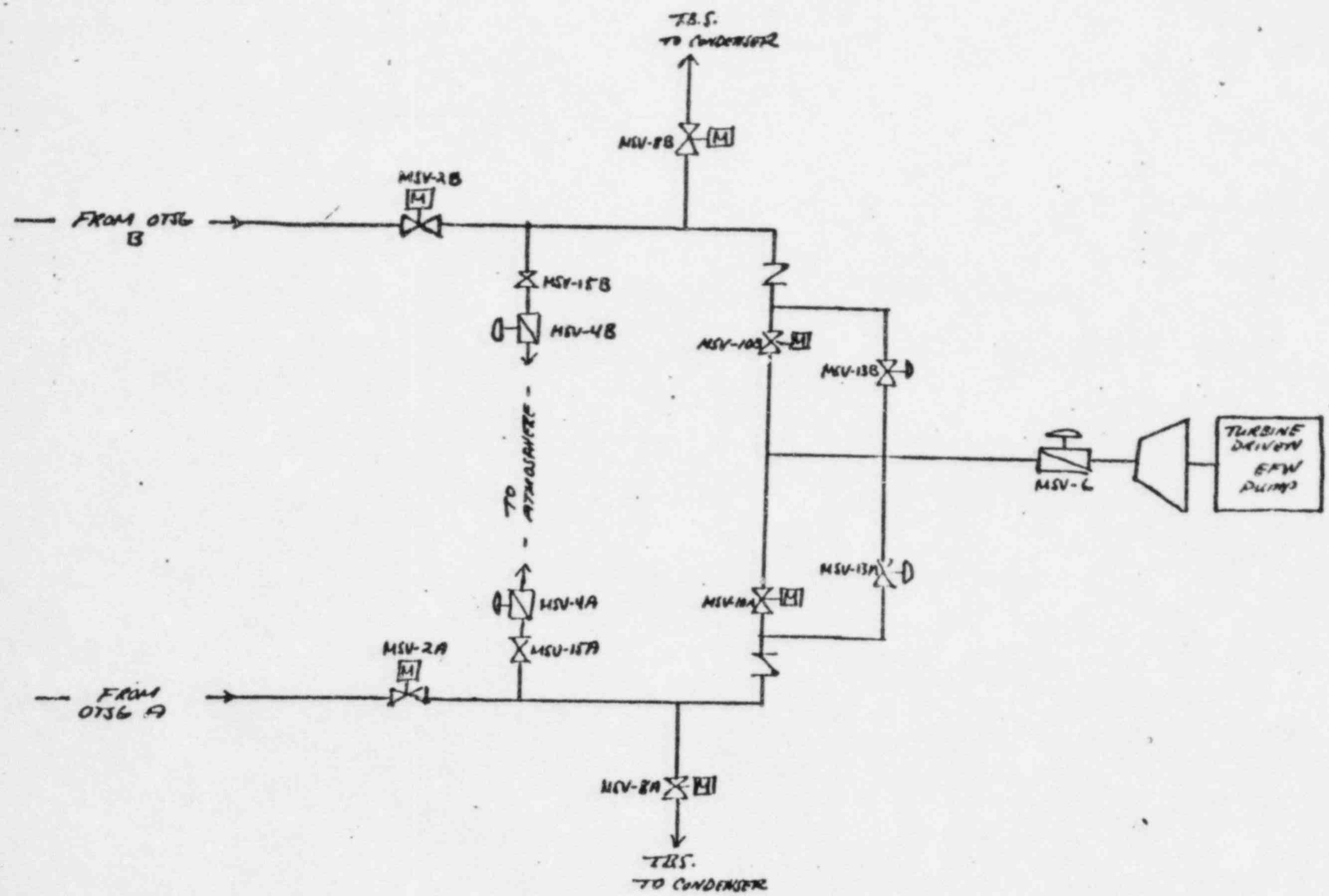
E. Secondary Pressure

Secondary pressure is controlled by the action of the modulating atmospheric dump (MAD) valves, the main steam code safety valves, and the condenser dump (turbine bypass) system. Attached are simplified P & IDs of the main steam systems for TMI-1 and ANO-1.



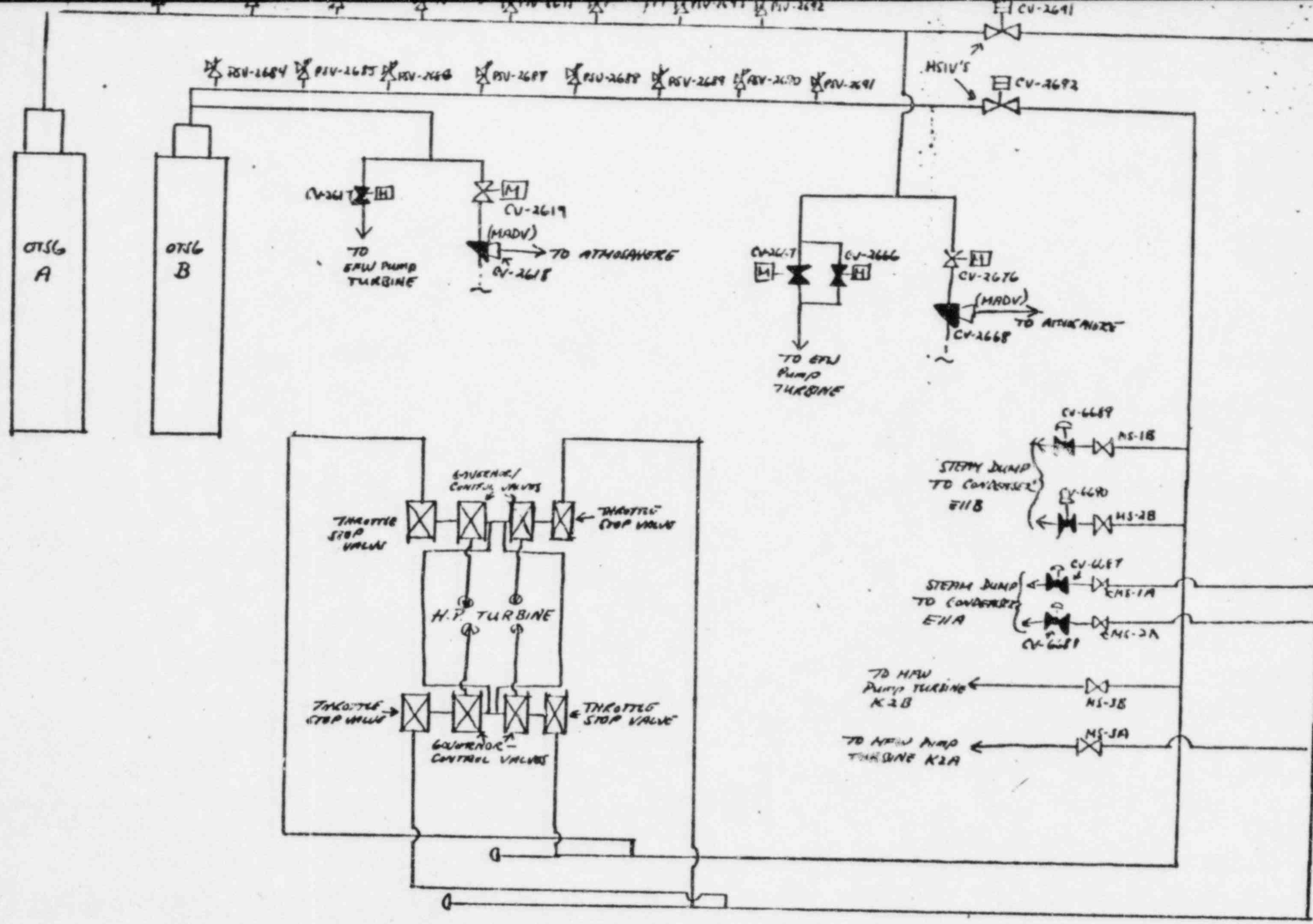
TMI-1 SIMPLIFIED MAIN STEAM SYSTEM
(PART 1)

Ref. B&W DOC NO. 16-N08680D-00



TMI-1 SIMPLIFIED MAIN STEAM SYSTEM (PART 2)

Ref. B&W Doc. NO. 16-1108680D-00



ANO-1 SIMPLIFIED MAIN STEAM SYSTEM

(Ref. B+W DOC. NO. 16-1097721E-00)

TABLE 7

Main Steam System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
MAD Valves				
# of valves	2	32	2	12
Lift pressure	1026 PSIG	29	1020 PSIG	15
Full open pressure	1052 PSIG	29	1045 PSIG	15
Capacity (Total)	6.4%	29	5%	15
Safety Valves				
# of valves	18	29	16	12
Lift pressure	2 @ 1040 PSIG 4 @ 1050 PSIG 4 @ 1060 PSIG 4 @ 1080 PSIG 4 @ 1092.5 PSIG	29 29 29 29 29	4 @ 1050 PSIG 4 @ 1070 PSIG 4 @ 1090 PSIG 4 @ 1100 PSIG	33 33 33 33
Condenser Dump (Turbine bypass) system				
Lift pressure*	1010 PSIG	29	1020 PSIG	15
Full open pressure*	1052 PSIG	29	1045 PSIG	15
Capacity (Total)	15%	29	15%	15

* Condenser dump setpoints are a function of plant conditions. Setpoints shown are for a reactor trip.

Conclusion: TMI-1 and ANO-1 will respond differently to an excessive main feedwater transient insofar as the area of secondary pressure control is concerned. This is primarily due to differences between the TMI-1 SLRDS and the ANO-1 SLBIC system. Plant performance is discussed in Section IV.

III. Plant Data

Data from an actual excessive main feedwater transient at a B&W 177-FA plant is important as a basis for the guidelines because it:

- Provides information on plant response, and
- Yields confirmation of TRAP2 predictions.

Following is a description of an excessive main feedwater transient that occurred at TMI-1 on June 20, 1974. The overfill resulted in a low pressure trip from 17.8% power.

Summary

During turbine overspeed testing malfunctioning turbine bypass valves caused a condition where the B turbine bypass valves and the B OTSG connected turbine stop valves were open (1 & 2), and the A OTSG connected turbine stop valves closed (3 & 4). The B turbine header pressure was reduced sufficiently low to actuate the steam line rupture detection system. Actuation of the steam line rupture detection system secured the feedwater flow to the B OTSG boiling it down to zero inches. The rupture detection system was bypassed while the feedwater ICS station was in automatic causing the feedwater to demand full flow. This cooled and depressurized the primary system to the low pressure trip setpoint causing a reactor trip on low RCS pressure.

Plant Conditions Prior To Transient

1. Reactor Power Level 17.8%
2. Tave 578°F
3. Makeup Tank Level 50 inches
4. RC System Press 2155 psig
5. RC Flow 100%
6. Pressurizer Level 220 inches
7. Effective Full Power Days .75
8. RC Boron 1351 ppm
9. ICS Hand/Auto Station Status
    a. Steam Generator/Reactor Demand - Manual
    b. Reactor Demand (Bailey) - Manual
    c. Turbine Generator - Manual
    d. Feedwater Valves - Auto

e. Loop A and Loop B Bypass Valves - Auto

f. Feedwater Pumps A & B - Manual

10. "A" Loop Header Pressure Selected For Indication

Sequence of Events

A. Generator Unloaded

Generator unloaded, generator breakers opened, and field breaker opened. During this period the A bypass valves appeared to operate properly to maintain indicated header press. The "B" bypass valve demand increased to 50% and held. When the generator breakers were opened the indicated header pressure increased and the A bypass valves demand increased to 50%, and the "B" bypass valve demand increased to 100%. The indicated header pressure (A) stabilized at setpoint.

B. Turbine Overspeed Trip Test (Prior to Reactor Trip)

1. Operator verified header pressure stable from indication and turbine.
2. Operator placed turbine rate of speed change to slow (60 rpm/min) and pushed the turbine "Overspeed Test" pushbutton.
3. The turbine overspeed trip occurred in approximately 2.5 minutes at approximately 1960 rpm.
4. Indicated header pressure increased when the turbine tripped.
   a. The "A" bypass valves received a demand to open and in fact indicated header pressure did stabilize at setpoint.
   b. The "B" bypass valves received a demand to close at turbine trip and then demand slowly increased to 100% open in approximately 3 minutes.

C. Prepared for second overspeed trip as planned. (Lead to Reactor Trip)

1. Operator verified that indicated header pressure was stable, reset the turbine trip (Turbine speed approximately 1700 rpm), and placed the rate of turbine increase to "Fast" (180 rpm/min).
2. Operator pushed the "1800" rpm speed set.

NOTE: At time the turbine was reset the "B" bypass valves demand was nearly 100% open.

D. Transient (See Attached Figures)

1. When 1800 speed set was pushed, the #1 and #2 turbine stop valves from the B steam generator opened properly. The #3 and #4 stop valves from the "A" steam generator did not open. According to the GE representative this will happen if the differential pressure across the valves is greater than 13% of 900#. The valves were tested several times after occurrence and found to be operating properly. This would indicate that the pressure in the B header was already at least 120 psig less than the A header pressure.
2. Because the B bypass valves were open and the B steam generator was supplying the entire demand of the turbine, the pressure in the B turbine header started decreasing rapidly.
3. The pressure in the B steam header dropped to below 600 psig actuating one channel of the steam line rupture detection system. The CRO promptly "Defeated" the remaining three actuation channels. The steam line rupture actuation automatically secured the feedwater to the B OTSG causing it to boil dry and remain in that condition for about 2.5 minutes.
4. Tave and RC system pressure were increasing rapidly. When Tave reached approximately 600°F, the CRO placed the diamond control panel in manual and drove control rods in to stop pressure and temperature increase. Letdown was manually increased to take care of reactor coolant expansion.
5. At about this time the CRO took manual control of both bypass valves and closed them both.
6. Another CRO tripped the turbine and defeated the actuated steam line rupture detection system on the B loop. This immediately restored the signal to the ICS feedwater stations which were still in automatic to maintain minimum level in the B OTSG (approximately 30").
7. The sudden influx of feedwater into the steam generator caused Tave and RCS pressure to drop rapidly. The CRO immediately took manual control of the B feedwater valve and started to close it. The transient was too rapid however and the reactor protection system low pressure trip was actuated, shutting down the reactor approximately 1 minute after the steam line rupture detection system for the "B" loop was completely defeated.

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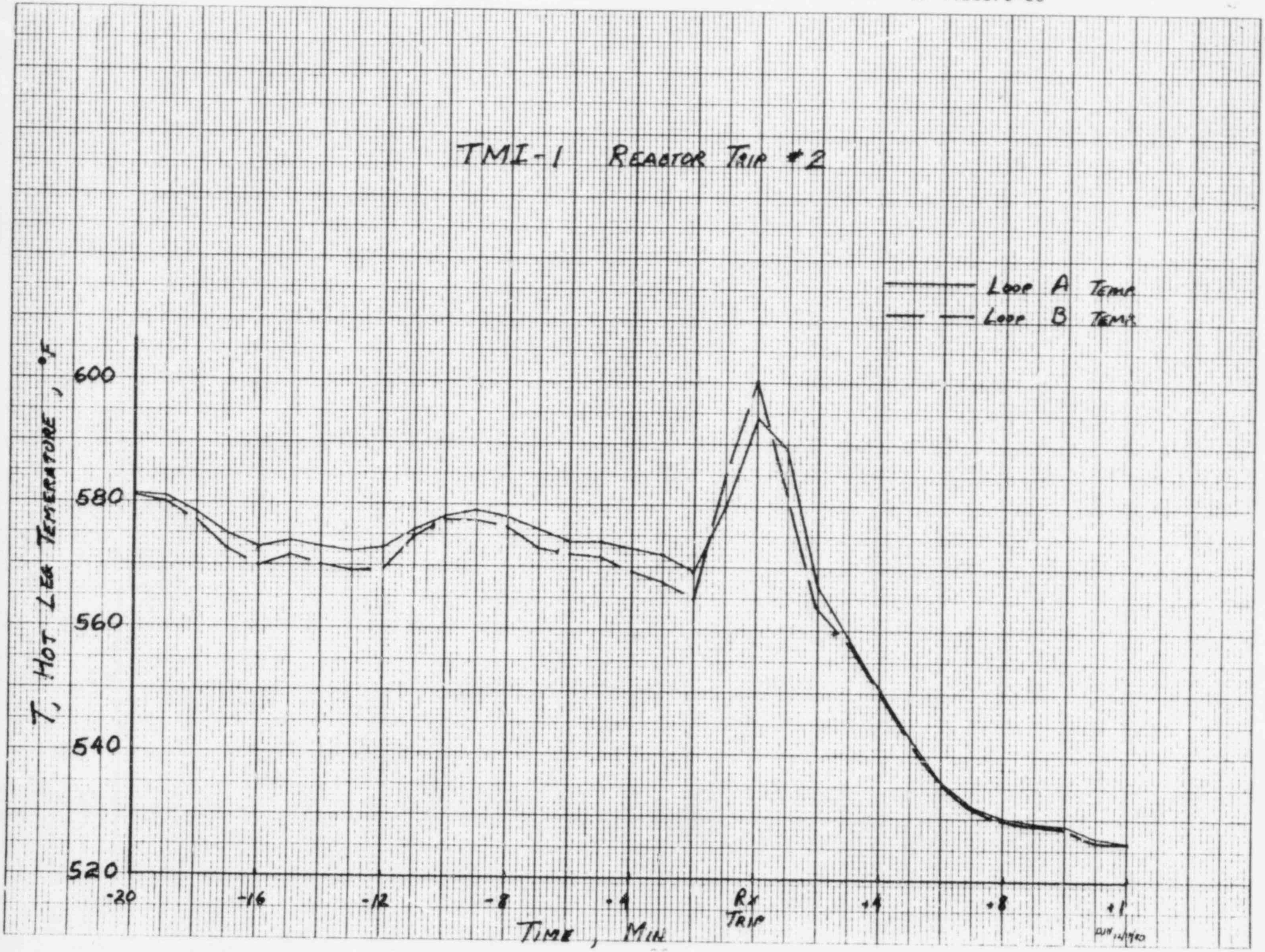

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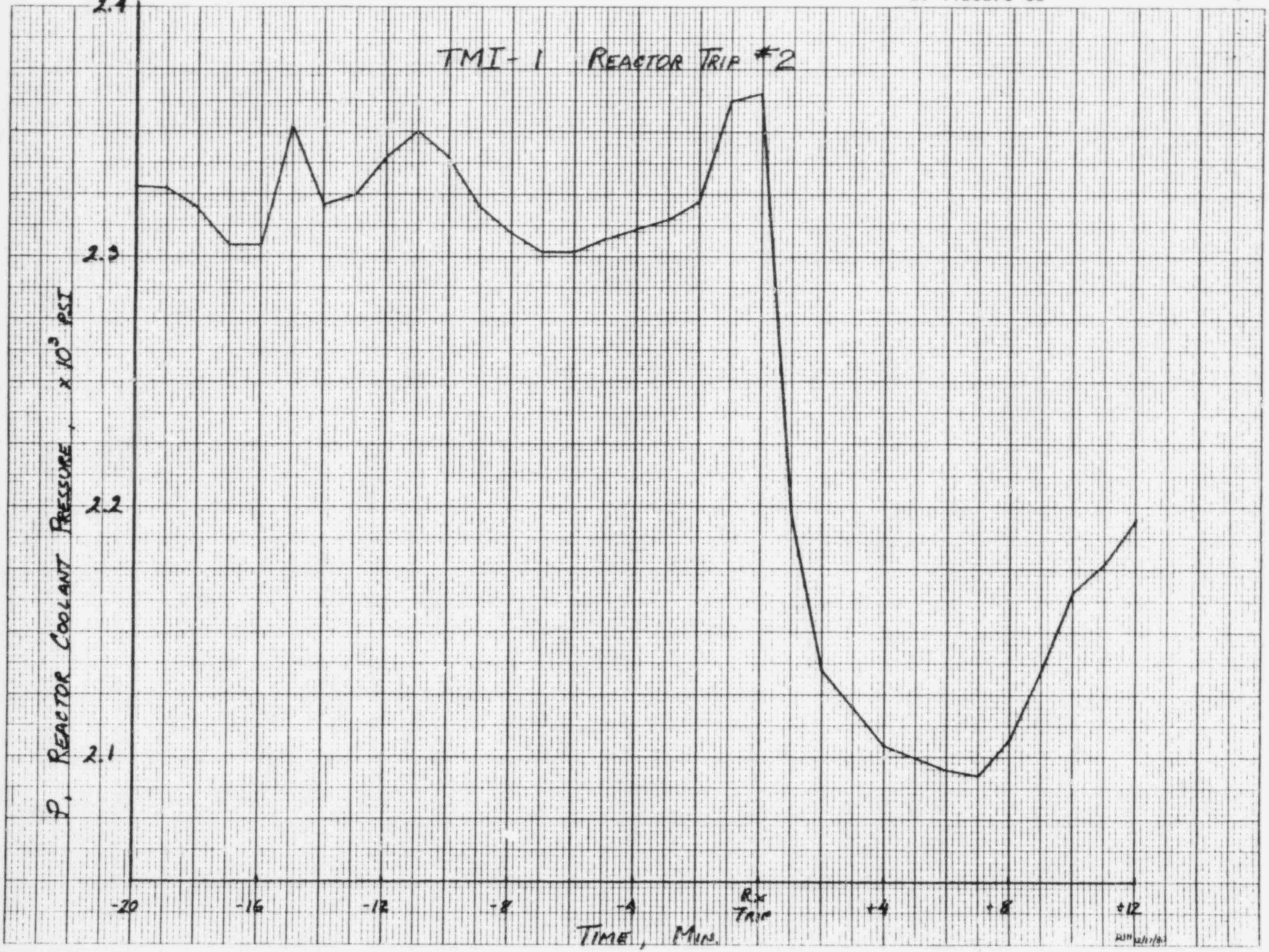
TMI-1 Reactor Trip #2

86-1123876-00



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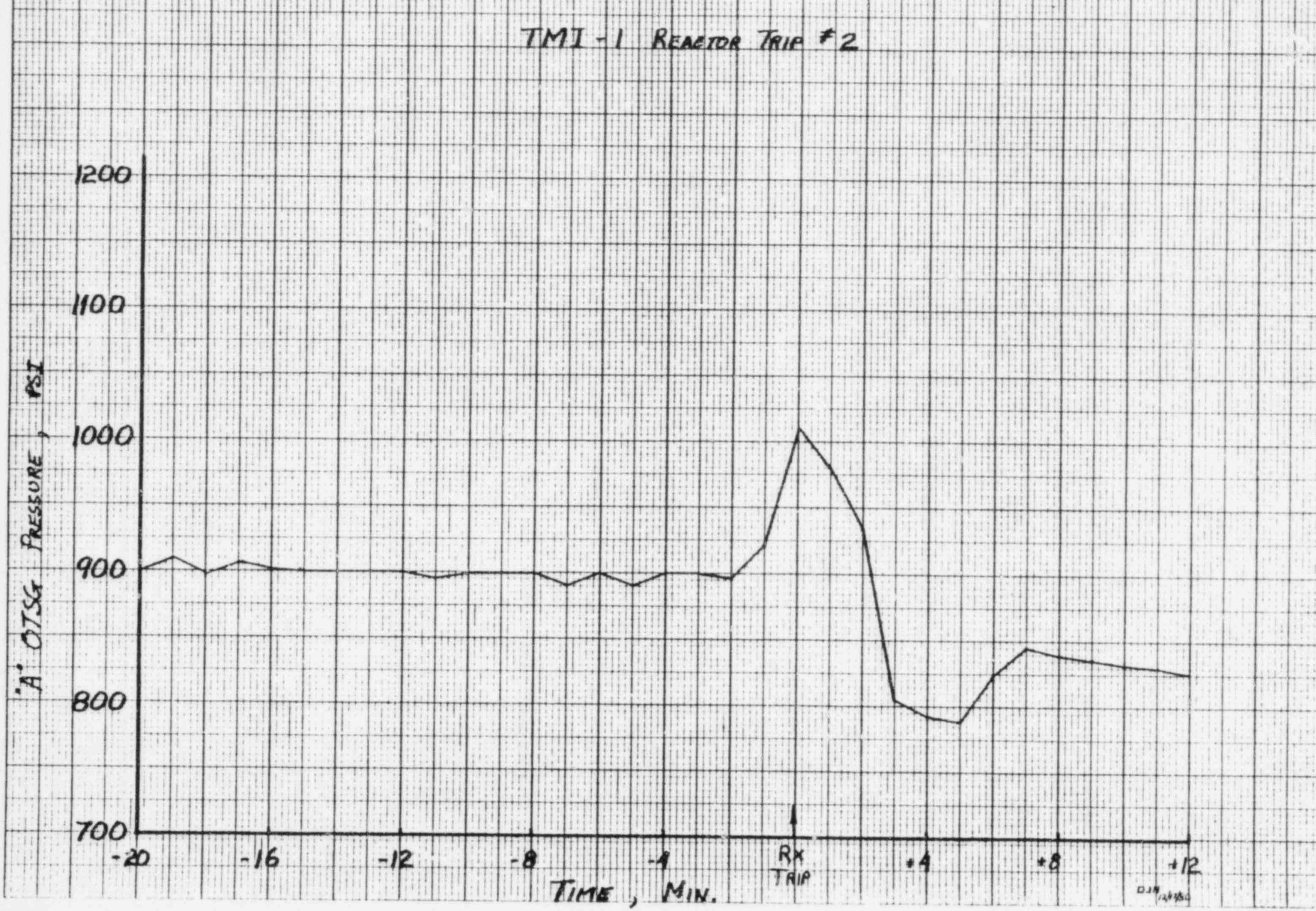

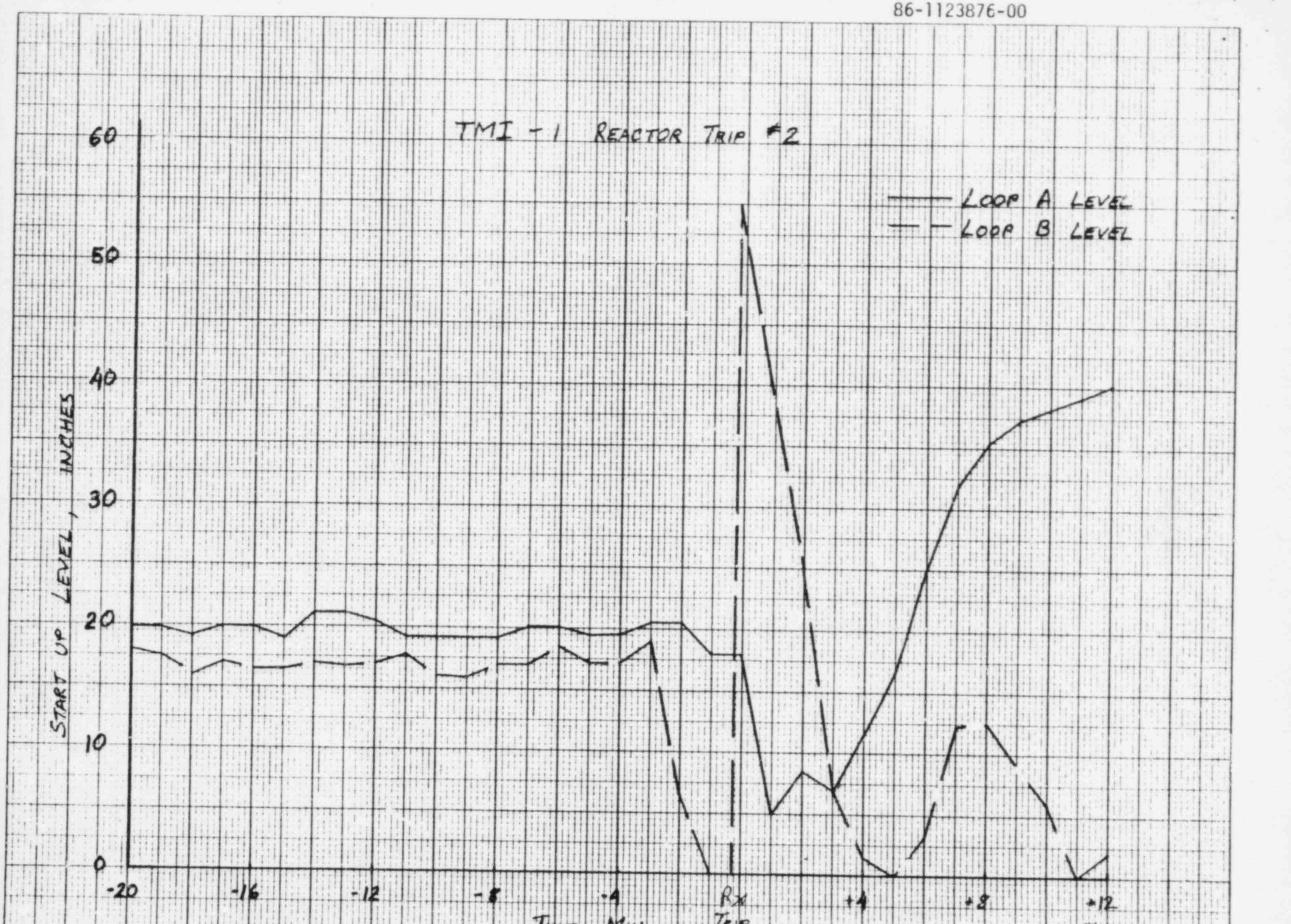
TMI - 1 REACTOR TRIP #2
LOOP A LEVEL
LOOP B LEVEL
START UP LEVEL, INCHES
60
50
40
30
20
10
0
-20
-16
-12
-8
-4
Rx TRIP
+4
+8
+12
TIME, MIN.

Parameter Swings During Transient

	MAX.	MIN.
Tave	600°F	560°F
R.C. Pressure	2280 psig	1650 psig
Tout A	596°F	550°F
Tout B	602°F	550°F
Tin A	593°F	550°F
Tin B	600°F	548°F
Subcooling	60°F	55°F

Tave just prior to "B" OTSG feedwater isolation 567.6
Tave just prior to defeat of feedwater isolation 595
Time duration "B" steam generator isolated 2.5 min
Tave at reactor trip 570
Time duration from feedwater isolation defeat to reactor trip 1 min.

IV. Predicted Plant Performance

The purpose of this section is to discuss the TMI-1 plant response to an excessive main feedwater transient and to see how this response compares with that of ANO-1. Also, required changes to Appendix A of Part II Volume 2 of the ANO-1 ATOG will be pointed out here. In order to determine the correct TMI-1 response during this transient, four sources of information will be drawn upon. These are:

- TRAP2 analysis for ANO-1
- TRAP2 analysis made for later contracts
- Plant data as documented in Section III
- Plant comparisons as documented in Section II

A discussion of each section of Appendix A follows in sequence.

1.0 General Transient Description - Most of this section is a general description of an excessive main feedwater transient and as such is generic in its applicability. An exception is the reference to the ANO-1 SLBIC system. It should be noted that at TMI-1, an overfill will not be stopped as it is at ANO-1, since the TMI-1 main steam isolation valves do not close upon a SLRDS signal. If a SLRDS signal is received in the non-overfilling generator, the

result will be that MFW and EFW will be isolated to that generator only and the overfill will continue to the other OTSG. Figure A-2 should reflect this fact. The ATOG account of an actual plant excessive feedwater transient illustrates well this type of event and is applicable for use with the TMI-1 ATOG as well. This can be included in addition to the transient data found in Part III of this document. Note that in the transient described on Figure A-2, while ANO-1 has an ICS-controlled MFW cross-connect valve, at TMI-1, both MFWP's feed into common headers.

2.0 Operator Actions Summary -

Immediate Actions - It should be noted here that TMI-1 has no capability for pre-selecting a MFWP to trip following a reactor trip. Also, EFW automatically starts at TMI-1 following receipt of certain signals (discussed in Section II "Major Plant Differences"). The low-low level interlock at TMI-1 is 80 inches versus 40 at ANO-1.

Identifying Symptoms - On page A-11, reference to SLBIC should be deleted or changed to reflect TMI-1's SLRDS. (Note that SLRDS will not stop the overfill as will SLBIC, however). On page A-12, transient under discussion should be modified to reflect the fact that there is no MFWP pre-selected trip or ICS-controlled MFW cross-connect valve at TMI-1. At TMI-1, both MFWP's feed into common headers. During this transient, water spillage into the steam lines will cause wet steam to enter the MFWP turbines which could result in damage or pump trip. All following references to SLBIC should be changed. Substantial changes will be required to pages A-12 through A-17 depending upon changes made to Part I of ATOG.

3.0 Excessive Main Feedwater With Other Plant Failures -

Introduction - This section remains unchanged.

Branch Discussion - This section remains basically unaltered; however, references to other sections of the ATOG may have to be changed.

Loss of Reactor Inventory Control (High) - On page A-21, the reference to the MSBV's being shut should be deleted, since at TMI-1 they do not close upon a SLRDS signal. The remainder of the discussion of this particular failure is applicable as is to TMI-1.

Loss of Reactor Inventory Control (Low) - The reference to failure of the HPI system should be deleted, as ATOG does not address failure of safety-grade equipment.

Loss of Secondary Inventory Control (High) - References to procedure steps may have to be changed depending upon changes in procedures. On page A-25, the reference to feeding the good OTSG with both EFWP's should be changed to reflect the fact that TMI-1 has three pumps.

Loss of Secondary Inventory Control (Low) - No changes are required to this paragraph.

Loss of Steam Pressure Control - This paragraph should be changed to reflect the fact that TMI-1's MSIV's are not closed during a loss of steam pressure control unless the operator chooses to do so manually.

Figure A-7 Excessive Feedwater Logic Diagram -

1. All references to SLBIC on this diagram should be changed such that the situation depicted is indicative of the action of TMI-1's SLRDS.
2. In the P-T curve encountered on the main success path, "Limits Important to this Event" states that the operator should reduce the TBS or MADV setpoints to a value close to the saturation pressure for the existing RC temperature to limit RC heatup and swell. "Existing RC temperature" should be changed to "Existing cold leg temperature."
3. All references to "ERV" should be changed to "PORV".
4. It should be again stressed that TMI-1's MSIV's are not closed by SLRDS. They are available, however, for manual isolation of a steam leak by the operator if he so desires, although their stroke time is on the order of several minutes. The logic diagram should reflect this.
5. Similar to 2. Located in "Limits Important to this Event" on branch entitled "EFW controlled '+'".
6. In "Corrective Actions" on same branch, it should be noted that TMI-1 has three EFWP's.
7. The block dealing with makeup and letdown control should be a non-operator action block.
8. EFW pumps auto start upon loss of both MFWP's or trip of RCP's.
9. The main success path should proceed down the page with failure paths branching off to the sides. Hence, "ESAS initiated 'yes'" should represent a failure (i.e., severe overcooling which triggers ESAS), and therefore, this path should branch to the right or left.
10. The RCP's should be tripped after a loss of subcooling margin, not after ESAS.

V. References

1. B&W Dwg. No. 11[illegible]1F-00, "Three Mile Island Unit One (TMI-1) Excessive Main Feedwater Event Tree." October 6, 1980.

2. B&W Doc. No. 05-0002-36, "TMI-1 Technical Specifications," Table 2.3-1 February 28, 1980.

3. B&W Doc. No. 05-0003-19, "ANO-1 Technical Specifications," Table 2.3-1 November 30, 1979.

4. B&W #16-1108693D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit 1 Piping Flow Diagram Makeup & Purification," March 3, 1971.

5. B&W #16-1108694D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit 1 Piping Flow Diagram Makeup & Purification," July 11, 1969.

6. B&W #16-1097719E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Makeup & Purification System," February 1979.

7. B&W Doc. No. DP-1101-02, "Plant Setpoints," ANO-1.

8. B&W Doc. No. DP-1101-02-00, "Plant Setpoints," TMI-1.

9. B&W Doc. No. 86-1106932-00, "Makeup Line and HPI Flow Rates vs. RC Pressure for NSS-8 for ATOG Program," (Contract #582-7108), December 13, 1979.

10. B&W Doc. No. 15-1108790-00, "Prelim. System Description, MU & Purification System TMI-1," August 14, 1969.

11. B&W Doc. No. 16-1108694D-00, "TMI-1 MU&P Piping Flow Diagram."

12. ANO-1 FSAR Vol. II Fig. 10-1.

13. TMI-1 FSAR Vol. 3 Page 5-6.

14. ANO-1 FSAR Vol. II Page 6-29.

15. B&W Doc. No. 86-1118178-00, "ANO Analytical Input Data for ATOG."

16. TMI FSAR, Section 3, Table 3-1, p. 79; Section 4, Tables 4-1 to 4-11, pp. 38-49.

17. TMI-1 FSAR Vol. 1 Page 4-38.

18. ANO-1 FSAR Vol. I Page 4-38.

19. B&W #16-1108682D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit #1 Piping Flow Diagram Feedwater," March 14, 1969.

20. B&W #16-1097712E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Condensate & Feedwater," October 4, 1979.

21. Deleted.

22. ATOG Document List NSS-08, Doc. No. 29-097590-00.

23. B&W Doc. No. 15-1108780-00, "TMI-1 Feedwater System Description."

24. B&W Doc. Nos. 15-1108784-00 and 15-1108780-00, "TMI-1 Main Feedwater Lesson Plan."

25. B&W Doc. No. 03-1097635-00, "ANO Operating Procedure 1203.12, Annunicator K07 F-6 Mn Fw Pump 1P1A Turb 1K2 Trip," Rev. 00, November 30, 1977.

26. B&W Doc. No. 03-1108728-00," TMI-1 Emergency Procedure No. 1202-14," Rev. 5.

27. B&W Dwg. Nos. 620-0008, 21-00-307-05, 21-00-309-02, "Steam Generator Feedwater Control ICS Digital Logic."

28. B&W Doc. No. 86-1118379-02, "EFW Reliability Analysis," ANO-1, December 1979.

29. B&W Doc. Nos. 15-1108782-00 and 15-1108795-00, "TMI-1 Main Steam System Description."

30. B&W #16-1108680D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit #1 Piping Flow Diagram Main Steam, " April 29, 1969.

31. B&W #16-1097721E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Main Steam," May 18, 1979.

32. B&W Doc. No. 16-1108680D-00, "Gilbert Assoc. Inc., TMI-1 Main Steam Piping Flow Diagram," January 8, 1979.

33. B&W Dwg. No. 38-41-602-00, "Consolidated Safety Valves."

34. Letter from D.F. Hallman to J.D. Phinney (attached), "Recommended Modifications to Plant Operations and Setpoints," April 21, 1979.

35. B&W Doc. Id. DP-1101-02-00, "Plant Setpoints, TMI-1."

36. B&W Doc. No. 15-1108779-00, "Preliminary System Description on Feedwater" Section C (of plant manual) Chapter 33.

37. B&W Doc. No. 38-1108797-00.

38. Recommended Requirements for Restart of Three Mile Island Nuclear Station Unit 1, docket number 50-289, operating license number DPR-50.

39. B&W Doc. No. 86-1121912, "Makeup Line and HPI Flow Rates vs. RC Pressure for NSS-5 for ATOG Program (Contract #582-7108)," October 24, 1980.

40. B&W Doc. No. 86-1121207-00, "ATOG Analytical Input Data, 5.A.16."

86-1123876-00

1/30?, 8, 12, 11, 13, 14, 346

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. D. PHINNEY - MANAGER - OPS

D. F. HALLMAN - MANAGER - PPSS DF Hallman

BDS 663-5

ALL OPERATING PLANTS	File No. or Ref.
RECOMMENDED MODIFICATIONS TO PLANT OPERATIONS AND SETPOINTS	Date 04/21/79 1245

This letter to cover one customer and one subject only.

BASED ON EXTENDED DISCUSSIONS BETWEEN B&W AND THE NRC, THE NRC HAS REQUESTED THAT B&W TAKE STEPS TO PRECLUDE ACTUATING THE PILOT OPERATED RELIEF VALVE ON THE PRESSURIZER DURING ANTICIPATED TRANSIENTS. WE ANTICIPATE THE NRC WILL ISSUE A BULLETIN TO OUR OPERATING PLANTS REQUIRING THIS ACTION. ATTACHMENT 1.0 PROVIDES B&W'S RECOMMENDED METHOD FOR ACCOMPLISHING THIS TASK. ATTACHMENTS 1.1 AND 1.2 PROVIDE DETAILED INSTRUCTIONS FOR SETPOINT CHANGES DELINEATED IN ATTACHMENT 1.0.

PLEASE PASS THIS INFORMATION TO OUR CUSTOMER.

DFH/SM

CC: E. A. Womack
J. H. Taylor
J. F. Walters
A. E. Paulson
J. A. Castanes
R. E. Kosiba

4/21/79

REVIEWED FOR ACCURACY
ENGINEERING: [signature] DATE: 4/21/79
NUCLEAR SERVICE: J F Walters DATE: 4/21/79

REDUCTION OF REACTOR HIGH PRESSURE TRIP SETPOINT VALUE AND INCREASE OF SETPOINT VALUE FOR THE PRESSURIZER PILOT OPERATED RELIEF VALVE

THESE SETPOINT CHANGES WILL HAVE THE EFFECT OF ELIMINATING THE LIFTING OF THE PRESSURIZER PILOT OPERATED RELIEF VALVE FOLLOWING ANTICIPATED TRANSIENTS SUCH AS LOSS OF MAIN FEEDWATER AND TURBINE TRIP. THE FOLLOWING POINTS SHOULD BE CONSIDERED AS BACKGROUND FOR THESE CHANGES:

A. ALL SAFETY ANALYSES FOR B&W NSS'S IS PERFORMED WITHOUT TAKING CREDIT FOR THE VENTING AND RELIEF CAPACITY OF THE PILOT OPERATED RELIEF VALVE. THEREFORE, THE REDUCTION OF ITS RELIEF PRESSURE SETPOINT DOES NOT MODIFY EXISTING APPROVED SAFETY ANALYSES.

B. THE PRESENT NOMINAL VALUES FOR PRESSURE SETPOINTS ARE AS FOLLOWS:

SAFETY VALVE - 2500 PSIG
REACTOR HIGH PRESSURE TRIP - 2355 PSIG
PILOT OPERATED RELIEF VALVE - 2255 PSIG
NOMINAL SYSTEM OPERATING PRESSURE - 2155 PSIG

B&W HAS PERFORMED CALCULATIONS USING REALISTICALLY CONSERVATIVE ASSUMPTIONS, WHICH INDICATE THAT SYSTEM PRESSURE WILL REMAIN BELOW 2400 PSIG DURING LOSS OF MAIN FEEDWATER TRANSIENTS AND TURBINE TRIP TRANSIENTS IF THE REACTOR HIGH PRESSURE TRIP SETPOINT IS RESET DOWNWARDS TO 2300 PSIG FROM ITS PRESENT SETPOINT OF 2355 PSIG. REVISING THE RELIEF SETPOINT FOR THE PILOT OPERATED RELIEF VALVE TO 2450 PSIG IN CONJUNCTION WITH REDUCTION OF THE REACTOR HIGH PRESSURE TRIP SETPOINT WILL AVOID ACTUATION OF THE PILOT OPERATED RELIEF VALVE DURING ANTICIPATED TRANSIENTS.

THEREFORE, WE RECOMMEND THE FOLLOWING ACTIONS:

A. REVISE THE REACTOR PROTECTION SYSTEM TRIP SETPOINT FOR REACTOR PRESSURE HIGH FROM 2355 PSIG TO 2300 PSIG USING THE ATTACHED PROCEDURE (ATTACHMENT 1.1).

B. REVISE THE RELIEF SETPOINT FOR THE PILOT OPERATED RELIEF VALVE FROM 2255 PSIG TO 2450 PSIG USING THE ATTACHED PROCEDURES (ATTACHMENT 1.2).

THE REACTOR PLANT OPERATING POINT (2155 PSIG) AND RELIEF PRESSURE SETPOINT OF THE ASME CODE PRESSURIZER SAFETY VALVES (2500 PSIG) SHOULD REMAIN UNCHANGED.

THE PROCEDURES PRESENTED IN THE ATTACHMENTS ARE INTENDED TO SUPPLEMENT THE NORMAL PLANT ADMINISTRATIVE PROCEDURE APPLICABLE TO CALIBRATIONS AND ADJUSTMENTS IN THE REACTOR PROTECTION SYSTEMS. THIS IS ESPECIALLY IMPORTANT IN VIEW OF THE FACT THAT ALL FOUR CHANNELS WILL BE RESET WITHIN A VERY SHORT TIMESPAN AND THE POTENTIAL FOR COMMON ERRORS IN THE FOUR CHANNELS MUST BE ELIMINATED.

ATTACHMENT 1.1

PROCEDURE FOR SETTING RPS HIGH RC PRESSURE TRIP SETPOINT

PURPOSE

THE PURPOSE OF THIS PROCEDURE IS TO SET THE TRIP SETPOINT OF THE RPS HIGH RC PRESSURE BISTABLE TO 2300 PSIG. THIS PROCEDURE IS APPLICABLE TO AN RPS NARROW RANGE RC PRESSURE CHANNEL WITH A RANGE OF 1700 TO 2500 PSIG.

.0 REFERENCE

BCCO PRODUCT INSTRUCTION E92-341

.0 EQUIPMENT

DVM READABLE TO 0.0001 VOLTS, 100 MΩ OR BETTER IMPEDANCE, 0.01% OR BETTER ACCURACY.

0 PROCEDURE

CAUTION: THE INSTRUMENTATION SETTINGS GIVEN ARE BASED ON TRANSMITTERS WITH AN ASSUMED RANGE OF 1700 PSIG TO 2500 PSIG. THIS RANGE MUST BE CONFIRMED AND CALIBRATION SETTINGS ADJUSTED TO REFLECT THE INSTALLED EQUIPMENT. CONTACT B&W IMMEDIATELY IF AS-INSTALLED RANGES DIFFER AND ASSISTANCE IS REQUIRED.

WARNING - THIS PROCEDURE MAY TRIP THE CHANNEL. PLACE THE CHANNEL IN BYPASS DURING THIS PROCEDURE IF A CHANNEL TRIP TO THE REACTOR TRIP MODULES IS NOT DESIRED.

ALLOW BISTABLE TO WARM UP AT LEAST 15 MINUTES.

CONNECT THE DVM TO THE "SETPOINT" TEST JACK OF THE "HIGH RC PRESSURE TRIP" BISTABLE. ADJUST THE "SETPOINT" VERNIER DIAL ON THE BISTABLE FOR A DVM READING OF 7.500 (+0.000, -0.005) VDC (2300 PSIG).

RECORD THE READING. ________________VDC.

PROCEED WITH VERIFICATION OF HIGH PRESSURE TRIP SETPOINT PER 5.0. REPEAT FOR OTHER THREE CHANNELS.

0 VERIFICATION OF HIGH RC PRESSURE TRIP BISTABLE SETTING

DISCUSSION: THE FOLLOWING DESCRIBES THE CHECKS AND TESTS REQUIRED FOR PRESSURE INPUT VARIABLES TO THE RPS. THE TESTS BELOW ARE APPLICABLE TO ONE RPS SUBSYSTEM. BECAUSE THERE ARE FOUR IDENTICAL RPS SYBSYSTEMS, THE TESTS MUST BE REPEATED, ONE SUBSYSTEM AT A TIME, ON THE REMAINING THREE.

.1 NOTE:

PRIOR TO ROTATING THE TEST SWITCH AWAY FROM THE OPERATE POSITION (AT THE TEST MODULE ASSOCIATED WITH THE SUBSYSTEM UNDER TEST), PLACE THAT SUBSYSTEM IN BYPASS. THIS WILL PREVENT THE OUTPUT LOGIC FROM GOING INTO A 1 OUT OF 3. THIS REQUIREMENT IS NOT NECESSARY WHEN USING THESE CHECKS AS PART OF THE PRE-CRITICAL CHECKS.

5.1.1 PLACE THE PRESSURE TEST MODULE IN TEST OPERATE. THE ON TEST LAMP SHOULD GO FROM DIM TO BRIGHT, AS SHOULD THE TEST TRIP LAMP AT THE REACTOR TRIP MODULE. USING THE 10 VOLT TEST JACK ON THE FRONT FACE OF THE PRESSURE TEST MODULE, MEASURE THE REFERENCE VOLTAGE. IT SHOULD READ +10.00 TO +10.01 VOLTS. IF IT DOES NOT, DETERMINE IF THE ERROR IS AT THE TEST MODULE OR WITHIN THE ORIGINAL VOLTMETER. IF THE REFERENCE VOLTAGE IS IN ERROR, ADJUST THE APPLICABLE INTERNAL POTENTIOMETER UNTIL THE REFERENCE IS WITHIN THE 10 MV RANGE.

5.1.2 PLACE THE PRESSURE TEST MODULE AT ZERO. THE METER ON THE FRONT FACE OF THE BUFFER AMPLIFIER SHOULD READ 1700 PLUS OR MINUS 16 PSI. THE SCALED OUTPUT VOLTAGE AT THE BUFFER AMPLIFIER SHOULD READ 0.00 PLUS OR MINUS 0.01 VOLTS DC. IF IT DOES NOT, ADJUST THE BALANCE POTENTIOMETER ACCESSIBLE FROM THE FRONT PLATE.

5.1.3 PLACE THE TEST SWITCH AT THE RANGE POSITION. MOVE THE TOGGLE SWITCH TO THE 100 PERCENT POSITION. THE BUFFER AMPLIFIER METER SHOULD READ 2500 PLUS OR MINUS 16 PSI. THE SCALED OUTPUT SHOULD READ +10.00 PLUS OR MINUS 0.01 VOLTS DC. IF IT DOES NOT, CONSULT THE PRODUCT INSTRUCTION MANUAL.

5.1.4 PLACE THE TEST SWITCH AT CAL OUT (CALIBRATED OUTPUT). ASSUMING THE CALIBRATION KNOB IS INITIALLY AT ONE EXTREME OR THE OTHER, EITHER THE HIGH OR LOW PRESSURE BISTABLE WILL TRIP. ROTATE THE CAL OUT KNOB TO ITS COUNTER CLOCKWISE STOP AND RESET THE HIGH PRESSURE BISTABLE, IF NECESSARY. THE LOW PRESSURE BISTABLE SHOULD BE TRIPPED.

5.1.5 WITH THE DIGITAL VOLTMETER CONNECTED TO THE INPUT JACK OF THE HIGH PRESSURE BISTABLE, ROTATE THE CAL OUT KNOB ON THE FRONT PLATE OF THE PRESSURE TEST MODULE UNTIL THE HIGH PRESSURE BISTABLE JUST TRIPS. THE DIGITAL VOLTMETER SHOULD READ 7.500 PLUS OR MINUS 0.015 VOLTS DC. (EQUIVALENT TO 2300 PSI METER INDICATION.)

ATTACHMENT 1.2

PROCEDURE FOR RE SETTING THE SETPOINT OF THE PRESSURIZER PILOT OPERATED RELIEF VALVE (PORV) TO 2450 PSIG

PURPOSE

THE PURPOSE OF THIS PROCEDURE IS TO SET THE TRIP SETPOINT OF THE PORV IN THE NNI SYSTEM TO 2450 PSIG. THIS PROCEDURE IS APPLICABLE TO A NARROW RANGE RC PRESSURE TRANSMITTER WITH SIGNAL RANGE OF 1700 TO 2500 PSIG.

CALIBRATION OF THE HIGH PRESSURE SETPOINT FOR THE PORV REQUIRES THE ADJUSTMENT OF AN "OPEN" AND A "CLOSE" SETTING AND IS ACCOMPLISHED BY ADJUSTING BOTH THE HIGH AND LOW ADJUSTMENT KNOB OF THE HIGH-LOW SIGNAL MONITOR PER THE PROCEDURE BELOW.

REFERENCE

BCCo PRODUCT INSTRUCTION E92-4.

EQUIPMENT

DVM, READABLE TO 0.0001 VOLTS, 100 MΩ OR BETTER IMPEDANCE, 0.01% OR BETTER ACCURACY.

PROCEDURE

CAUTION: THE INSTRUMENTATION SETTINGS BELOW ARE BASED ON TRANSMITTERS WITH AN ASSUMED RANGE OF 1700 PSIG TO 2500 PSIG. THIS RANGE MUST BE CONFIRMED AND CALIBRATION SETTINGS ADJUSTED TO REFLECT THE INSTALLED EQUIPMENT. CONTACT B&W IMMEDIATELY IF AS-INSTALLED RANGES DIFFER AND ASSISTANCE IS REQUIRED.

A) ISOLATE THE PRESSURIZER PILOT-OPERATED RELIEF VALVE BY CLOSING THE PORV BLOCK VALVE.

B) LOCATE THE CORRECT HIGH-LOW SIGNAL MONITOR MODULE PER NNI INSTRUMENT INSTRUCTION MANUAL AND REMOVE THE MODULE FROM ITS CABINET MOUNTING. BENCH CALIBRATE PER BCCo PRODUCT INSTRUCTION E92-4, PAGE 5.

NOTE: REMOVAL OF THE MODULE WILL NOT INTERFERE WITH THE OPERATION OF THE BALANCE OF THE INSTRUMENT STRING.

C) RETAIN POSITION OF SWITCH S_1 AND S_2 PER INSTRUCTION MANUAL AND PREVIOUS OPERATION.

D) ADJUST "HIGH" (VALVE TO OPEN) SETPOINT TO ACTUATE AT A VOLTAGE INPUT READING OF 9.375 $\binom{+0.000}{-0.010}$ VDC (2450 PSIG). RECORD THE READING ____________ VDC.

E) ADJUST "LOW" (VALVE TO CLOSE) SETPOINT TO ACTUATE AT A VOLTAGE INPUT READING OF 8.500 ($\pm$0.010) VDC (2380 PSIG).

RECORD THE READING ______________ VDC.

RETURN THE MODULE TO SERVICE.

THE PORV CAN NOW BE RETURNED TO SERVICE BY OPENING THE PORV BLOCK VALVE.

BWNP-20032A-5 (11-80)

CONTRACT/STANDARD NO.		DOCUMENT RELEASE NOTICE (DRN)
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TITLE TMI-1 Loss of Main Feedwater Transient Information Document

PREPARED BY M. E. Newlin REVIEWED BY ______

TITLE Engineer DATE TITLE DATE

PURPOSE:

This TID summarizes the analytical basis for the Abnormal Transient Operating Guidelines for a Loss of Main Feedwater transient at the TMI-1 nuclear station.

SUMMARY OF RESULTS (INCLUDE DOC. ID'S OF PREVIOUS TRANSMITTALS & SOURCE CALCULATIONAL PACKAGES FOR THIS TRANSMITTAL)

The attached writeup summarizes the ATOG analytical basis.

DISTRIBUTION

86-1125051-00

TRANSIENT INFORMATION DOCUMENT

For A

Loss of Feedwater

At

THREE MILE ISLAND I NUCLEAR STATION

Prepared By
Nuclear Power Generation Division
Babcock and Wilcox Company

Table of Contents

I. Introduction

The final output of the ATOG program is a set of operator guidelines which is applicable to a series of selected plant transients. As such, it is necessary for the writer of these guidelines to obtain well-documented analytical results for each of these transients so that he will have an established basis for the guidelines. This document will supply the guidelines writer with the necessary analytical information and will act as a traceable link between the guidelines and the analysis.

This Transient Information Document (TID) summarizes the analytical results for the Loss of Main Feedwater transient and is applicable to Metropolitan Edison Company's Three Mile Island - Unit One (TMI-1) reactor. It will:

- Discuss the major system differences between TMI-1 and Arkansas Power and Light Company's Arkansas Nuclear One - Unit One (ANO-1)
- Depicit actual plant data for a loss of main feedwater transient.
- Define the ANO-1 results which can be used or modified for this event.

Reference 1 is the associated event tree for this transient.

II. Major Plant Differences

A B&W NSS can be brought to a safe shutdown if control is acheived in the following five areas of plant response:

1. Reactivity
2. Primary Inventory
3. Primary Pressure
4. Secondary Inventory
5. Secondary Pressure

The plant systems used to achieve control of these parameters are the subjects of the following discussion, with particular attention given to differences between the corresponding TMI-1 and ANO-1 systems that affect plant performance during a loss of main feedwater transient.

A. Reactivity

Short term reactivity control is achieved when the reactor trips and the control rods fall into the reactor core. The following table is a

listing of the various signals that trip the reactor at TMI-1 and at ANO-1. During a Loss of main feedwater transient, TMI-1 will behave similarly to ANO-1 insofar as the actions of the reactor protection system are concerned. Longer term reactivity control is attained through the use of soluble boron to compensate for the decay of equilibrium xenon and the reactivity temperature deficit. Both TMI-1 and ANO-1 utilize the makeup/high pressure injection and chemical addition systems to bring the plant to a safe shutdown following a reactor trip. A comparision of the TMI-1 and ANO-1 makeup and letdown/high pressure injection systems can be found in Section II. B. Since ATOG does not address the effects of the chemical addition system (i.e., long term reactivity control is not considered), no comparison of the respective systems is made.

TABLE 1

RPS Trip Setpoints for TMI-1 and ANO-1

TMI-1 (Ref. 2)	ANO-1 (Ref. 3)
Power > 105.5%	Power > 105.5%
Flux/flow/imbalance - 1.08 times rated flow (%) minus reduction due to imbalance	Flux/flow/imbalance - 1.057 times rated flow (%) minus reduction due to imbalance
High RCS pressure (2300 PSIG) (Ref. 34)	High RCS pressure (2300 PSIG) (Ref. 34)
Low RCS pressure (1800 PSIG)	Low RCS pressure (1800 PSIG)
Variable low RCS pressure- (11.75 T_{out} - 5103) PSIG	Variable low RCS pressure- (11.75 T_{out} - 5103) PSIG
RC max. temperature (619F)	RC max. temperature (619F)
High RB pressure (4 PSIG)	High RB pressure (4 PSIG)
Additional Signals that Trip the Reactor	
Loss of FWPS (Ref. 38)	Loss of FWPS (Ref. 38)
Turbine Trip (Ref. 38)	Turbine Trip (Ref. 38)

Conclusion: Both plants behave similarily from the standpoint of reactivity control during a Loss of main feedwater transient. Therefore, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

B. Primary Inventory

Primary inventory is controlled by makeup and letdown. Attached are simplifted P & IDs of the makeup and letdown/high pressure injection system at each plant. Pertinent MU and LD/HPI system data for this transient is listed in Table 2 below.

TABLE 2

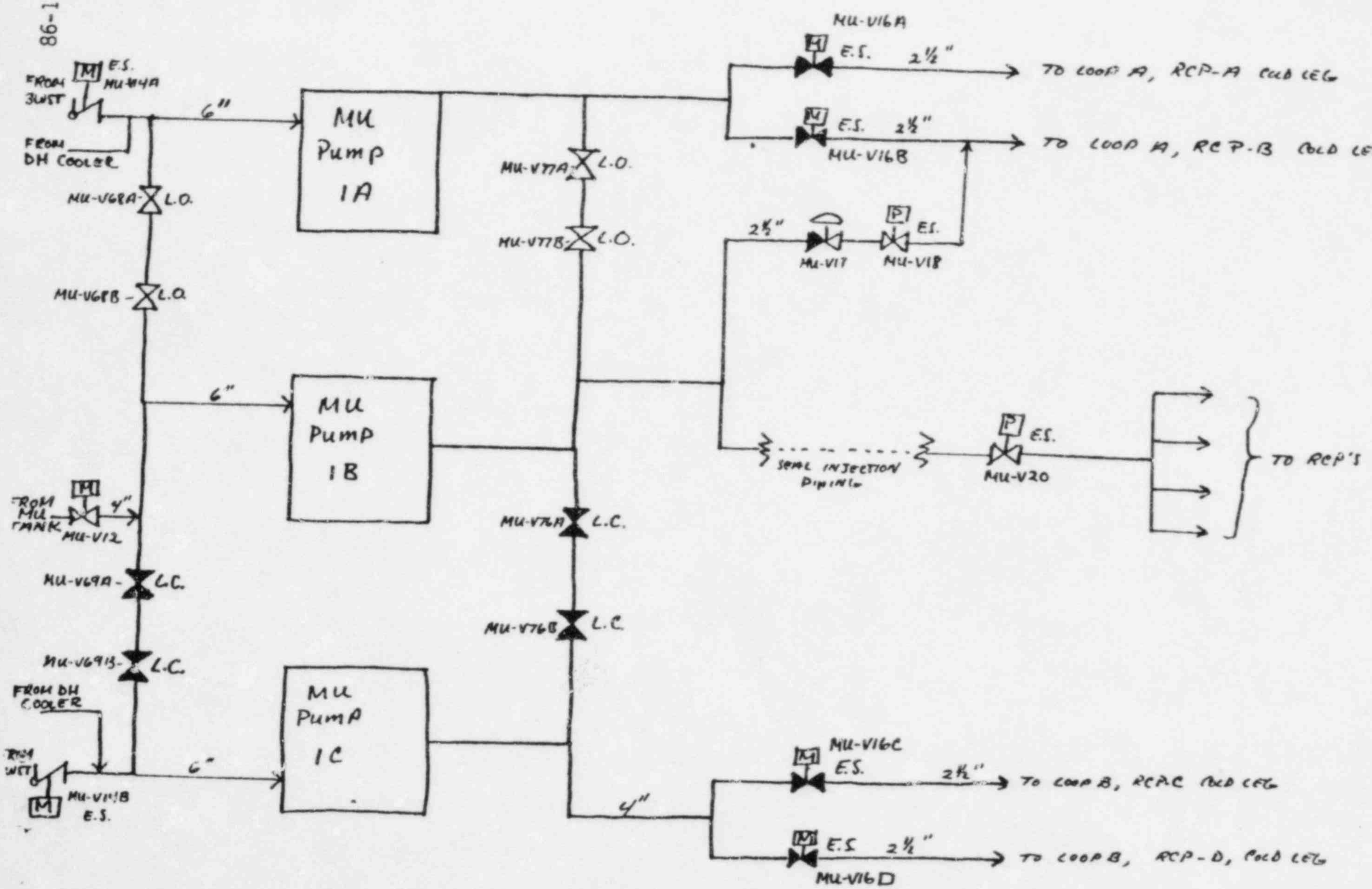
Makeup and Letdown/High Pressure Injection System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
Normal makeup	25 GPM	8	25 GPM	7
Normal seal injection	8 GPM/RCP	8	8 GPM/RCP	7
Normal seal return	3 GPM/RCP	8	1 GPM	7
Makeup flow vs. pressure with makeup control valve fully open	2200 PSIG 130 GPM 2000 PSIG 150 GPM 1800 PSIG 170 GPM 1600 PSIG 190 GPM	39 39 39 39	2200 PSIG 140 GPM 2000 PSIG 160 GPM 1800 PSIG 180 GPM 1600 PSIG 200 GPM	9 9 9 9
Normal letdown	45 GPM	8	53 GPM	7
Letdown temperature	120 F	10	120 F	7
HPI flow vs. pressure for two HPI pumps with control valves fully open	2600 PSIG 420 GPM 2400 PSIG 525 GPM 2200 PSIG 600 GPM 2000 PSIG 670 GPM 1800 PSIG 730 GPM 1600 PSIG 785 GPM 1400 PSIG 835 GPM	39 39 39 39 39 39 39	2600 PSIG 400 GPM 2400 PSIG 495 GPM 2200 PSIG 580 GPM 2000 PSIG 645 GPM 1800 PSIG 705 GPM 1600 PSIG 755 GPM 1400 PSIG 805 GPM	9 9 9 9 9 9 9
RCP seal injection isolated after ESAS?	yes	11	no	6
ESAS actuation setpoint	1600 PSIG	38	1500 PSIG	14

86-1125051-00

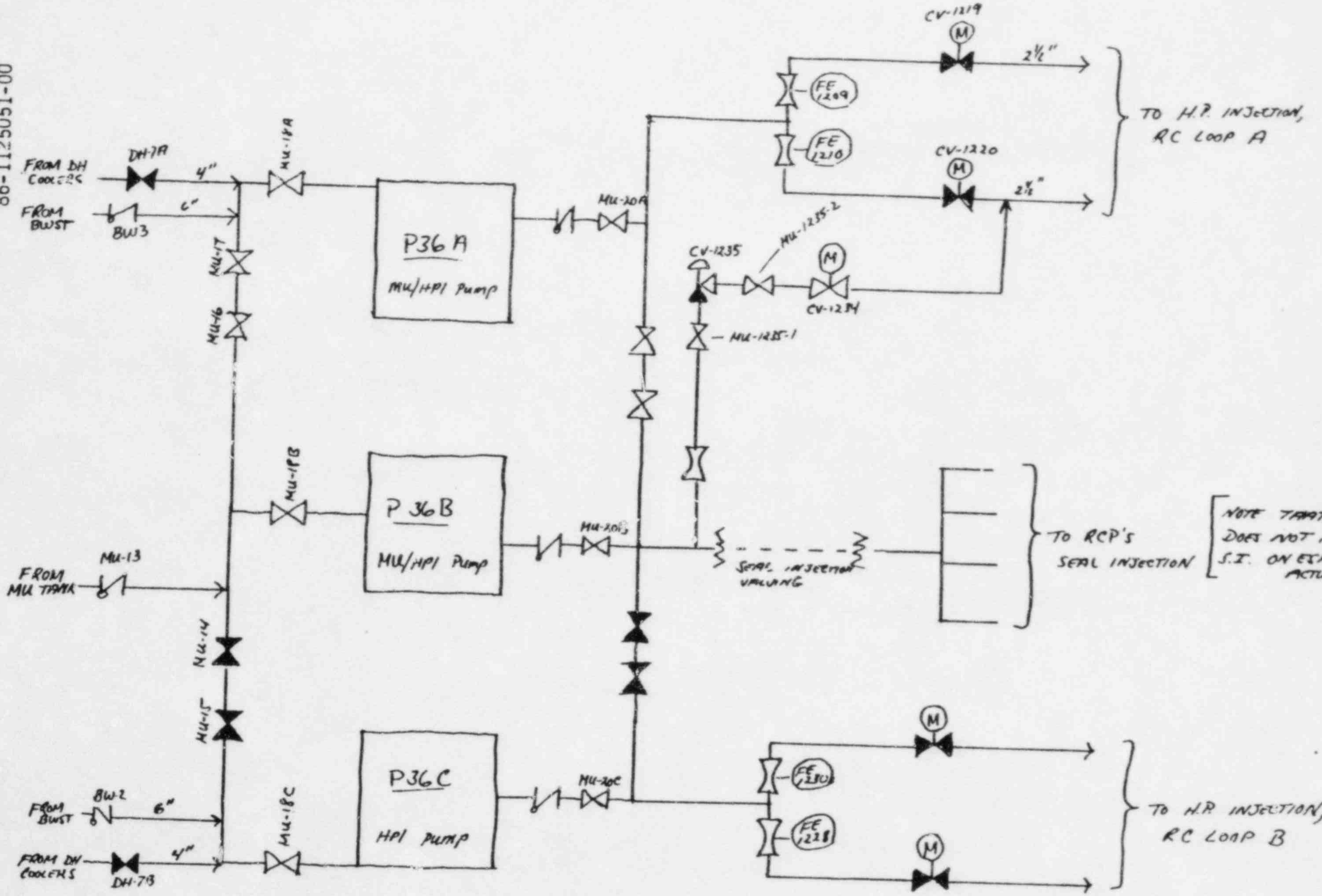
Ref. B+W DWGs NO.
16-1108693D-00, 16-1108694D-0

TMI-1 SIMPLIFIED MU/HPI SYSTEM



7/42

ANO-1 SIMPLIFIED MU/HPI SYSTEM (Ref. B+W Doc. No. 16-1097719E-00)



8/42

86-1125051-00

Conclusion: Both plants behave similarly from the standpoint of primary inventory control during an excessive main feedwater transient. Therefore, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

C. Primary Pressure

Primary pressure control is achieved by the pressurizer heaters, pressurizer spray system, relief, and code safety valves. System data for TMI-1 and ANO-1 are tabulated below.

TABLE 3

Primary Pressure Control System Data for TMI-1 and ANO-1

	TMI-1	Ref.	ANO-1	Ref.
Pressurizer heater bank-on setpoints				
1	<2135 PSIG	8	<2135 PSIG	7
2	<2135 PSIG	8	<2135 PSIG	7
3	2135 PSIG	8	2135 PSIG	7
4	2120 PSIG	8	2120 PSIG	7
5	2105 PSIG	8	2105 PSIG	7
Pressurizer heater bank-off setpoints				
1	2155 PSIG	8	>2155 PSIG	7
2	2155 PSIG	8	>2155 PSIG	7
3	2147 PSIG	8	2155 PSIG	7
4	2140 PSIG	8	2140 PSIG	7
5	2125 PSIG	8	2125 PSIG	7
Pressurizer heater bank power				
1	Power output by bank not available		84 KW	15
2			84 KW	15
3			378 KW	15
4			504 KW	15
5			588 KW	15
Total	1638 KW	16	1638 KW	
Pressurizer spray valve				
open	2205 PSIG	17	2205 PSIG	18
close	2155 PSIG	17	2155 PSIG	18

Pressurizer electromatic relief valve				
open	2450 PSIG	34	2450 PSIG	34
close	2400 PSIG	34	2400 PSIG	34
capacity	100,000 LB/H	17	100,000 LB/H	17
Pressurizer code safety valves				
open	2435 PSIG*	17	2500 PSIG	18
close	~2285 PSIG*	35	Not available	
capacity	623,400 LB/H	17	600,000 LB/H	18

Conclusion: Both plants behave similarly from the standpoint of primary pressure control during a Loss of main feedwater transient. Therefore, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

D. Secondary Inventory

Secondary inventory is controlled via the main and emergency feedwater systems. Attached are simplified P & IDs of these systems for TMI-1 and ANO-1. The primary differences which are apparent from these diagrams are in cross-connect design and flow control valve arrangement. The ANO-1 feedwater trains are completely separate except for a normally closed ICS controlled cross-connect valve just downsteam of the main feedwater pumps. The TMI-1 trains feed into common headers both before and after the fourth and second stage feedwater heaters. There are no valves to impede flow from pump A to OTSG B or from pump B to OTSG A.

ANO-1 has a low load bypass in addition to the normal startup bypass. TMI-1 has only the startup bypass line. Table 4 lists pertinent data for the TMI-1 and ANO-1 main feedwater system.

*Although these values appear at first sight to be incorrect, all available reference data indicates that the safety valve lift setpoint is below that of the ERV. This setpoint is currently being checked through TECO.

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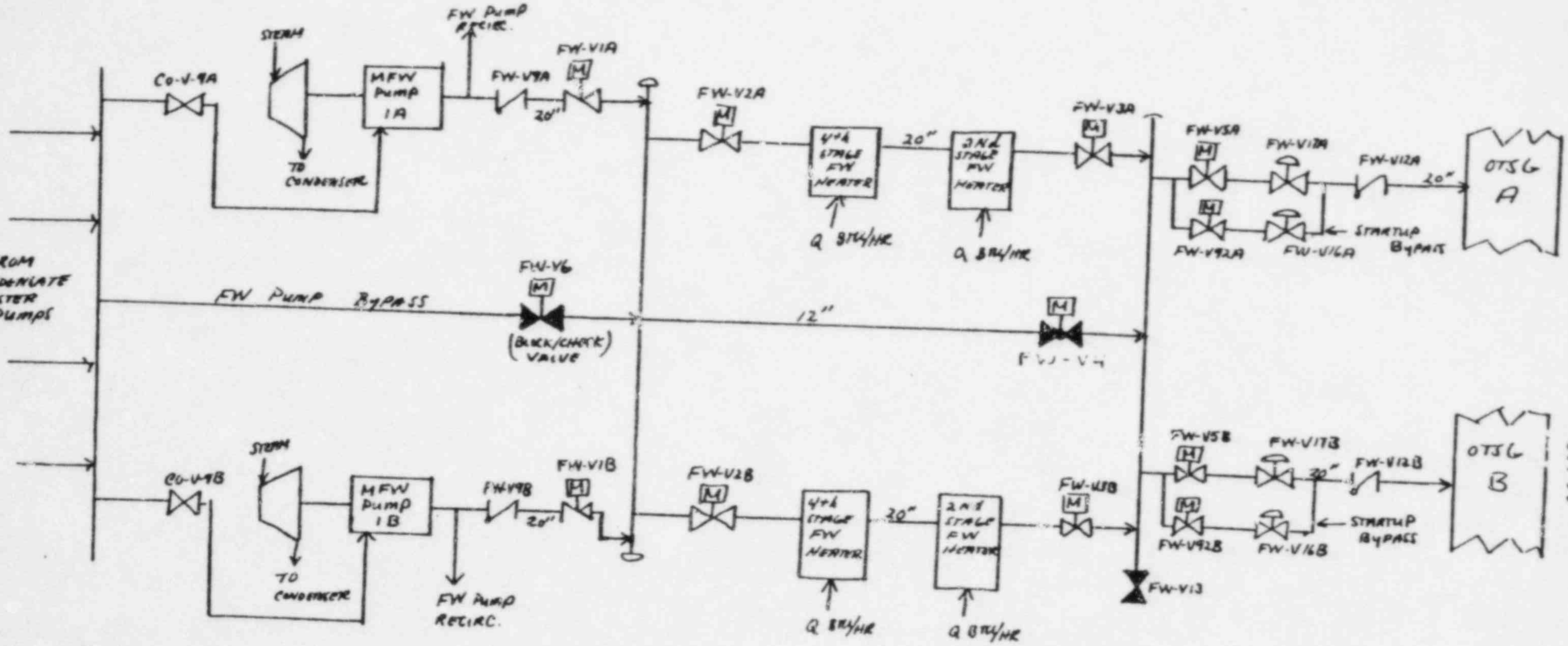
TMI-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

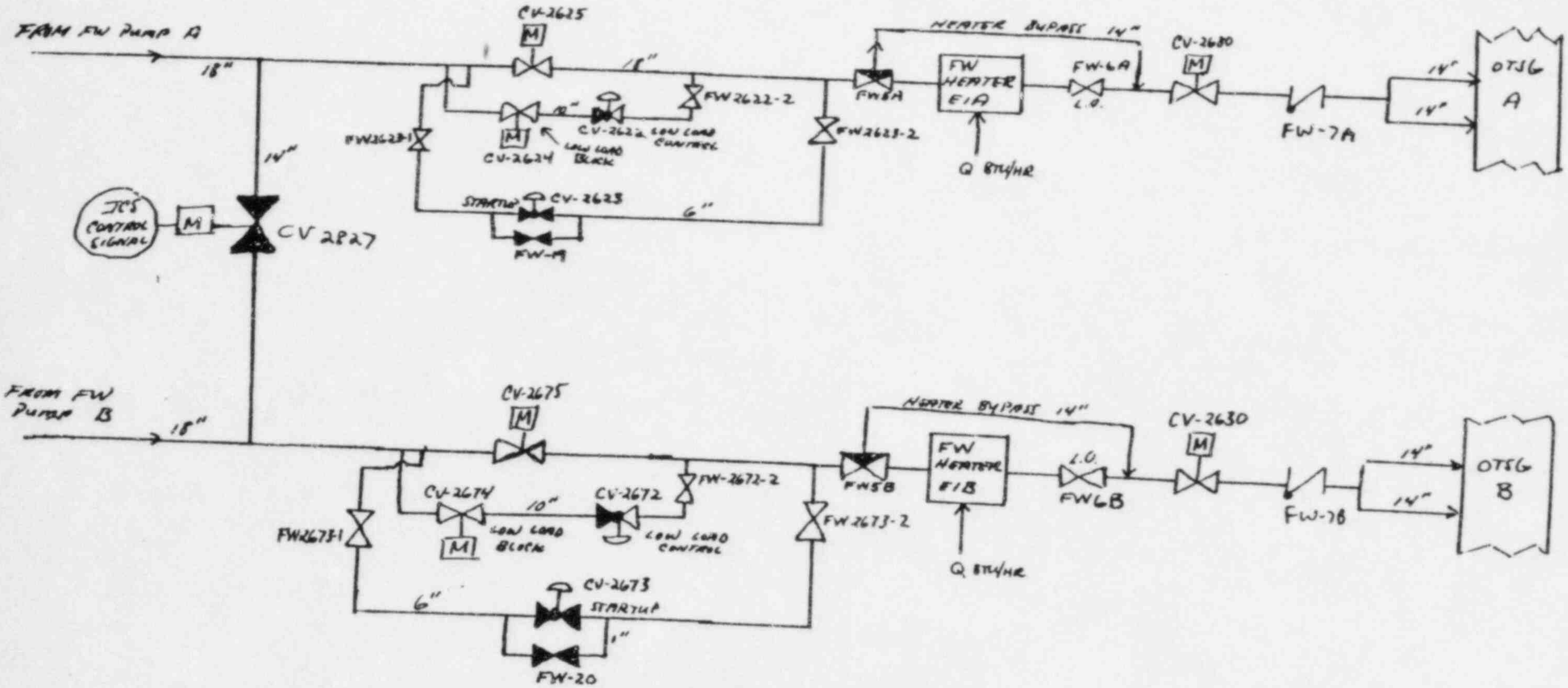
Ref. B&W DWGs No. 16-1108682D-00



11/42

ANO-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

(Ref. B&W DOC. NO. 16-1097712E-00)



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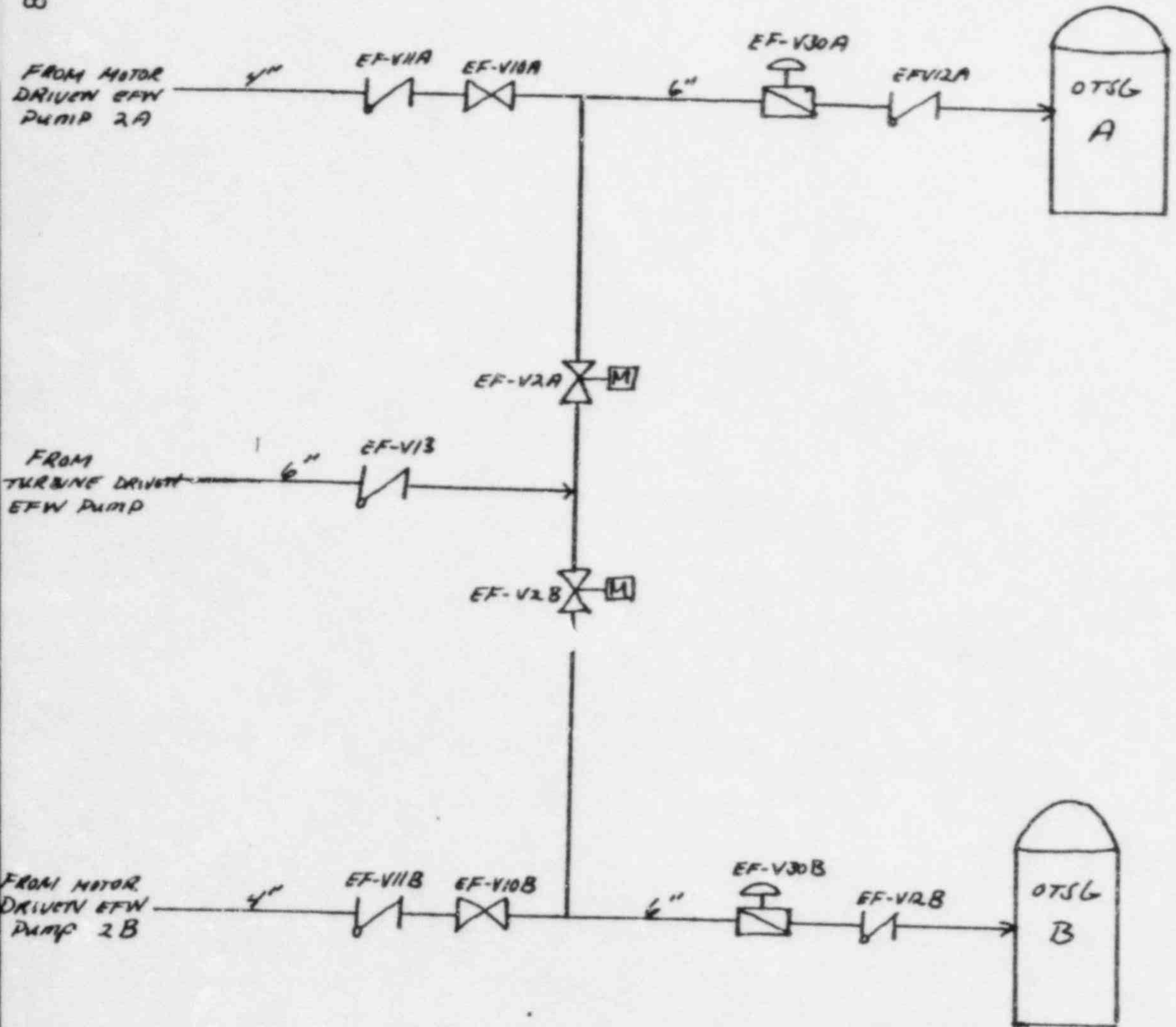
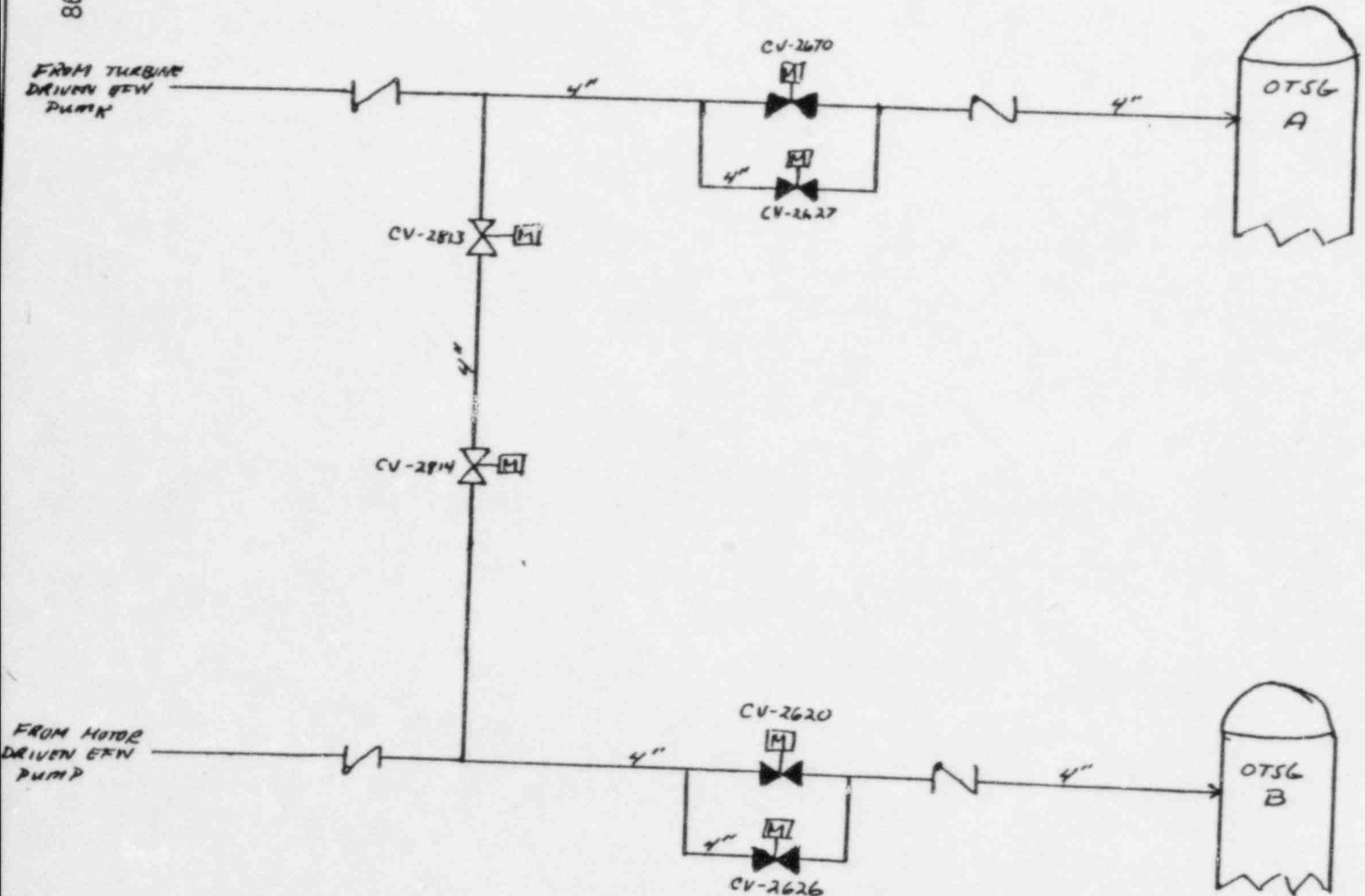


TMI-1 SIMPLIFIED EFW SYSTEM

Ref. B+W Doc. No. 16-1108682D-00

ANO-1 SIMPLIFIED EFW SYSTEM

(Ref. B+W Doc. No. 16-1097712E-00)



14/42

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TABLE 4

TMI-1 and ANO-1 Main Feedwater System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
Normal flow, both pumps	10.6×10^6 LB/H	23	11.1×10^6	22
Feedwater temperature	457 F	23	457	22
Pump discharge pressure	1225 PSIA	36	1088	22
Signals that trip MFWPS				
Thrust bearing wear				
forward	Trips, setpoint unknown	37	5 MILS	25
reverse	Trips, setpoint unknown	37	35 MILS	25
Rotor vibration	unknown		6.5 MILS	25
Turbine Overspeed	∿15% above max. full load speed	24	6215 RPM	25
Bearing oil pressure low	<4 PSIG	37	10 PSIG	25
FWP discharge pressure high	unknown		1150 PSIG	25
FWP suction pressure low	pump suction valve closed	37	230 PSIG	25
FWP low flow	1000 GPM	36	1600 GPM	25
Vacuum	<23 IN. HG	17		
Other	(1) Number of condensate/condensate booster pumps less than the number of feedwater pumps running will trip the FWP turbine that was reset last	37		
	(2) Manual			

Feedwater valve control logic -

TMI-1

- Low Load Block Valve
  There is no low load block valve at TMI-1.

- Startup Valve
  Normally ICS controlled. S/U and MFW control valves operate sequentially. When S/U control valve flow approaches capacity during startup, the main control valve begins to open. (Ref. 36)

- Main Block Valve
  The main block valve opens when the startup valve reaches approximately 90% open. The block valve closes when the startup valve reaches approximately 70% closed. (Ref. 37)

- Reactor Trip
  No actions occur.

- Feedwater Pump Trip
  No actions occur.

- Reactor Coolant Pumps Tripped
  A trip of all four reactor coolant pumps will result in EFW initiation to 50% on the operating range and therefore, in a closing of the main feedwater valves. (Ref. 26)

- FW Pump Speed
  Feed pumps are variable speed and are controlled by feedwater valve ΔP and demand as a function of load. During normal operation the position of the regulating valves and the speed of the feedwater pumps is controlled by the ICS; however, manual control can be instituted at any time. (Refs. 24, 37)

ANO-1 (Ref. 27)

- Low Load Block Valve
  The low load block valve opens when the startup valve reaches 80% open. The low load block valve closes when the startup valve reaches 50% closed.

— Startup Valve

The startup valve is controlled by the ICS which maintains feed flow proportional to reactor power level.

— Main Block Valve

The main block valve opens when feedwater demand exceeds 50%. The main block valve closes if feedwater demand drops below 45%.

— Reactor Trip

A reactor trip causes the main block valve and the low load block valve to shut. Also, a preselected feedwater pump is tripped.

— Feedwater Pump Trip

A feedwater pump trip causes the main block valve and the low load block valve associated with that pump to close. Also, after a single feedwater pump trip, the ICS opens the cross-connect valve.

— Reactor Coolant Pumps Tripped

Trip of all four reactor coolant pumps causes the low-load block valve to close.

— FW Pump Speed

After the main block valve opens, the ICS controls feedwater flow by adjusting pump speed. Until the main block valve is opened, the feedwater flow is controlled by the pressure drop across the startup or low-load valve.

Note from the emergency feedwater system P & IDs that all EFW pumps in each plant are capable of feeding either OTSG if necessary. ANO-1 has bypass lines (CV-2627 and CV-2626) in case the EFW control valves CV-2670 and/or CV-2620 fail shut, whereas TMI-1 does not have this feature. Table 5 below lists EFW system performance data for each plant.

TABLE 5

TMI-1 and ANO-1 Emergency Feedwater System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
# of motor-driven EFWPS	2	36	1	12
Capacity	460 GPM @ 2700 FT. H_2O	36	780 GPM @ 2700 Ft. H_2O	28
# of steam-driven EFWPS	1	36	1	12
Capacity	920 GPM @ 2700 FT. H_2O	36	720 GPM @ 2700 FT. H_2O	28
Initiating signals	Loss of both MFWPS	38	Low OTSG level (18 in.)	28
	Trip of all RCPS	38	Trip of both MFWPS (if Rx power >5%)	28
	Manual	38	Trip of all RCPS	28
			SLBIC starts steam - driven pump	28
			Manual	28

	TMI-1 EF-P1A	TMI-1 EF-P1B	Ref.	ANO-1	Ref.
Flow vs. head for motor-driven pump	100 GPM 3250 FT	3250 FT	40	200 GPM 3400 FT	15
	200 GPM 3200 FT	3200 FT	40	300 GPM 3400 FT	15
	300 GPM 3090 FT	3090 FT	40	400 GPM 3300 FT	15
	400 GPM 2900 FT	2900 FT	40	500 GPM 3200 FT	15
	500 GPM 2630 FT	2625 FT	40	600 GPM 3000 FT	15
	600 GPM 2200 FT	2180 FT	40	700 GPM 2800 FT	15
Flow vs. head for steam-driven pump	200 GPM 2990 FT		40	200 GPM 3500 FT	15
	400 GPM 2950 FT		40	400 GPM 3350 FT	15
	600 GPM 2870 FT		40	600 GPM 3000 FT	15
	800 GPM 2760 FT		40	800 GPM 2550 FT	15
	1000 GPM 2550 FT		40	1000 GPM 1850 FT	15

One other system affects control of secondary inventory at TMI-1 and at ANO-1. This is a steam and/or feedwater isolation system which actuates to isolate one or both steam generators following a steam line break. The TMI-1 steam line rupture detection system (SLRDS) and the steam line break instrumentation and control (SLBIC) system at ANO-1 perform the following functions:

TABLE 6

Comparison of TMI-1 SLRDS and ANO-1 SLBIC System

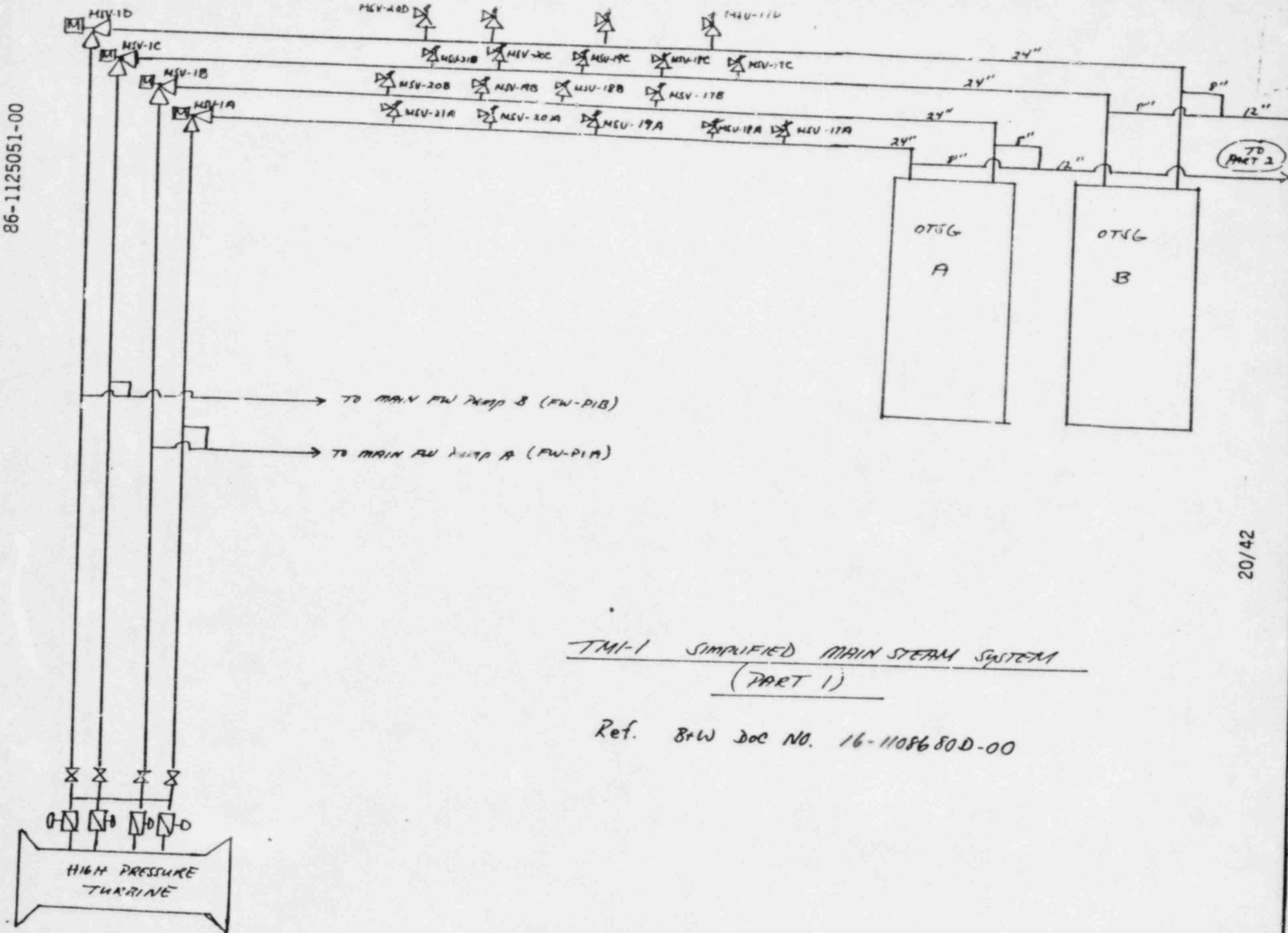
SLRDS (TMI-1)	Ref.	SLBIC (ANO-1)	Ref.
Actuation Setpoint = 600 psig	29	Actuation Setpoint = 600 psig	15
Actions Taken By System —		Actions Taken By System —	
— Closes MFW block and control valves to affected OTSG only.	29	— Closes MSIVs for both OTSG's.	28
— Closes startup MFW block and control valves to affected OTSG only.	29	— Closes MFW isolation valve to affected OTSG.	28
— Closes EFW control valve to affected OTSG only.	29	— Open steam supply valve to steam-driven EFW pump.	28
— Performs identical operations on the other OTSG if low steam pressure is detected in that loop.	29	— EFW isolation valve opens on EFW initiation signals to both OTSGs.	28
		— Closes MFW isolation valve for the other OTSG if a SLBIC signal subsequently originates from that steam loop.	28

Conclusion: Due to differences between the systems used to control secondary inventory at TMI-1 and at ANO-1, each plant will respond differently to a Loss of main feedwater transient.

E. Secondary Pressure

Secondary pressure is controlled by the action of the modulating atmospheric dump (MAD) valves, the main steam code safety valves, and the condenser dump (turbine bypass) system. Attached are simplified P & IDs of the main steam systems for TMI-1 and ANO-1.

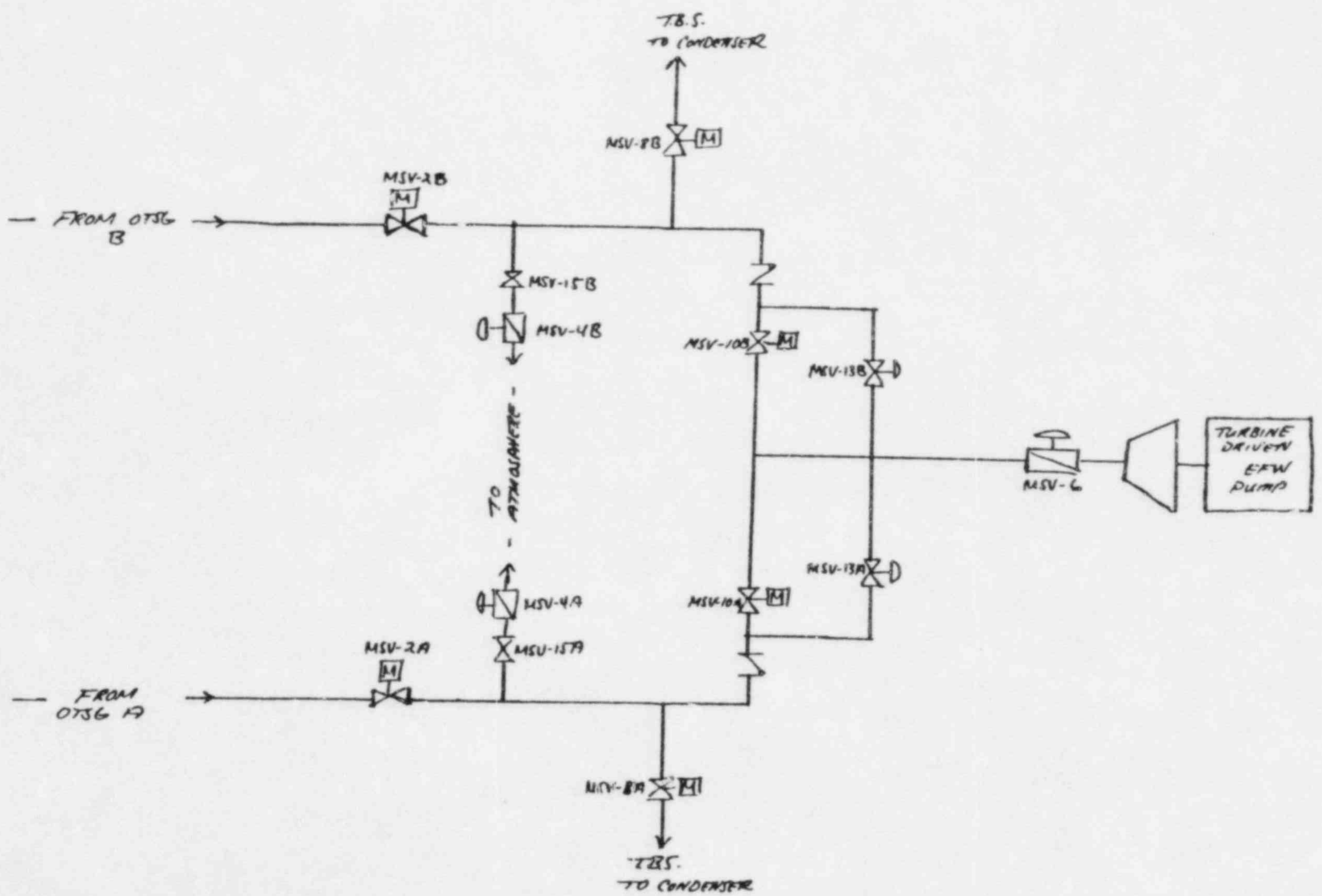
The main difference is in the SLRDS. SLRDS does not close the MSIVs at TMI, but SLBIC does at ANO-1. Therefore, a failure of the turbine to trip is more severe at TMI, than ANO. In addition, SLBIC does not isolate EFW while SLRDS does. There are significant differences which will affect feedwater overfeed and steam leaks.



20/42

TMI-1 SIMPLIFIED MAIN STEAM SYSTEM
(PART 1)

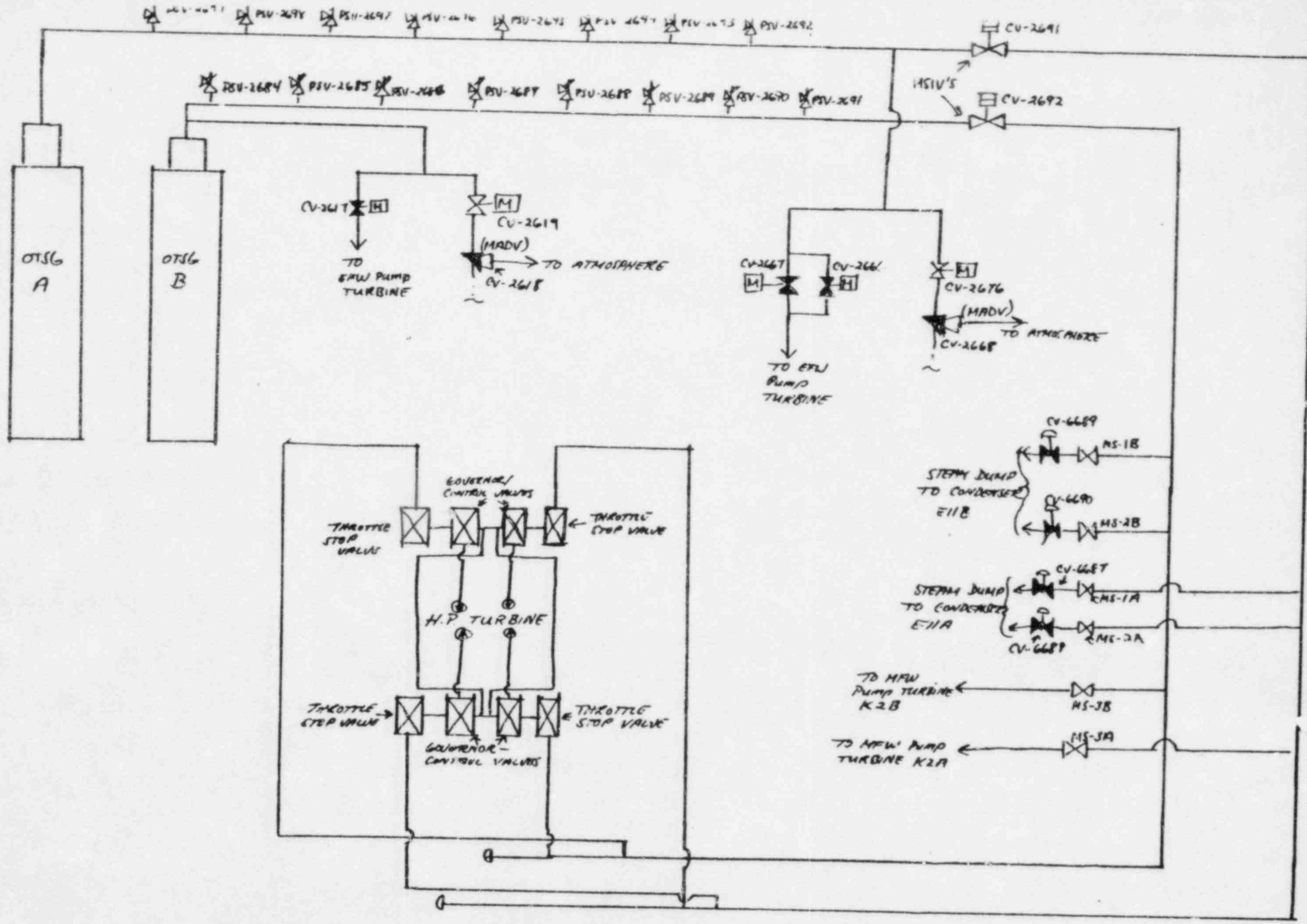
Ref. B+W DOC NO. 16-1108680D-00



TMI-1 SIMPLIFIED MAIN STEAM SYSTEM (PART 2)

Ref. B&W Doc. NO. 16-1108680D-00

86-1125051-00



ANO-1 SIMPLIFIED MAIN STEAM SYSTEM

(Ref. B+W DOC. NO. 15-1097721E-00)

TABLE 7

Main Steam System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
MAD Valves				
# of valves	2	32	2	12
Lift pressure	1026 PSIG	29	1020 PSIG	15
Full open pressure	1052 PSIG	29	1045 PSIG	15
Capacity (Total)	6.4%	29	5%	15
Safety Valves				
# of valves	18	29	16	12
Lift pressure	2 @ 1040 PSIG 4 @ 1050 PSIG 4 @ 1060 PSIG 4 @ 1080 PSIG 4 @ 1092.5 PSIG	29 29 29 29 29	4 @ 1050 PSIG 4 @ 1070 PSIG 4 @ 1090 PSIG 4 @ 1100 PSIG	33 33 33 33
Condenser Dump (Turbine bypass) system				
Lift pressure*	1010 PSIG	29	1020 PSIG	15
Full open pressure*	1052 PSIG	29	1045 PSIG	15
Capacity (Total)	15%	29	15%	15

* Condenser dump setpoints are a function of plant conditions. Setpoints shown are for a reactor trip.

Conclusion: TMI-1 and ANO-1 will respond differently to a Loss of main feedwater transient insofar as the area of secondary pressure control is concerned. This is primarily due to differences between the TMI-1 SLRDS and the ANO-1 SLBIC system. Plant performance is discussed in Section IV.

III. Plant Data

Discussion

On November 3, 1978, the Three Mile Island II reactor tripped from 90% power on high RC pressure. An I&C technician open a control power breaker to the condensate polisher control panel by mistake. This error shut the condensate polisher outlet valves, resulting in a trip of the condensate booster and main feedwater pumps.

Pre-Trip Conditions

Power Level 90%

Tave 582 °F

Makeup Tank Level 78 inches

RC Boron 1104 ppm.

Reactor Coolant System Pressure 2155 psig

Reactor Coolant System Flow 100%

Pressurizer Level 220 inches H_2O

FPD 13.66

Control Rod Positions (withdrawn)

Group 1 100%	Group 3 100%	Group 5 100%	Group 7 97%
Group 2 100%	Group 4 100%	Group 6 97%	Group 8 28%

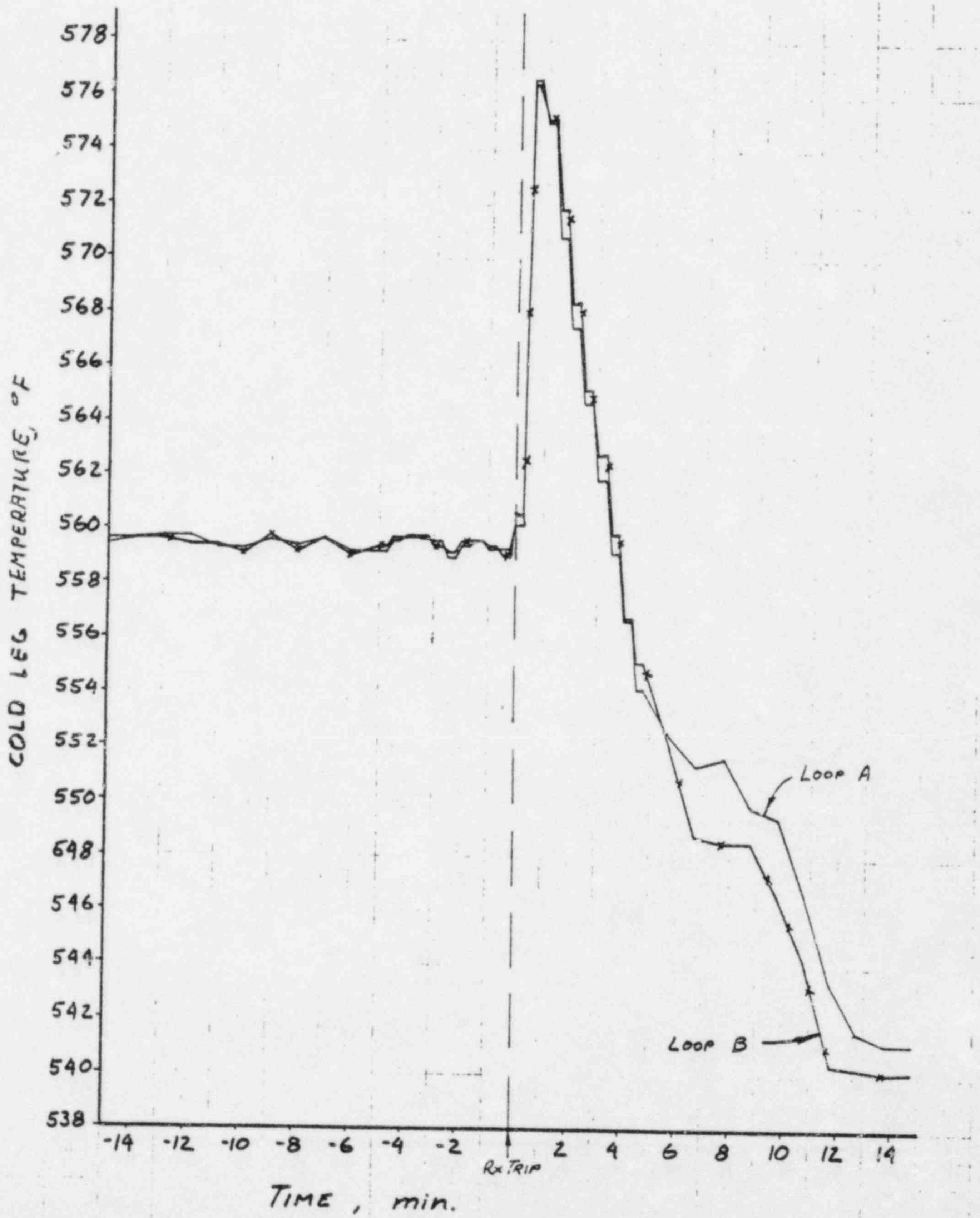
ICS Stations in Hand

None

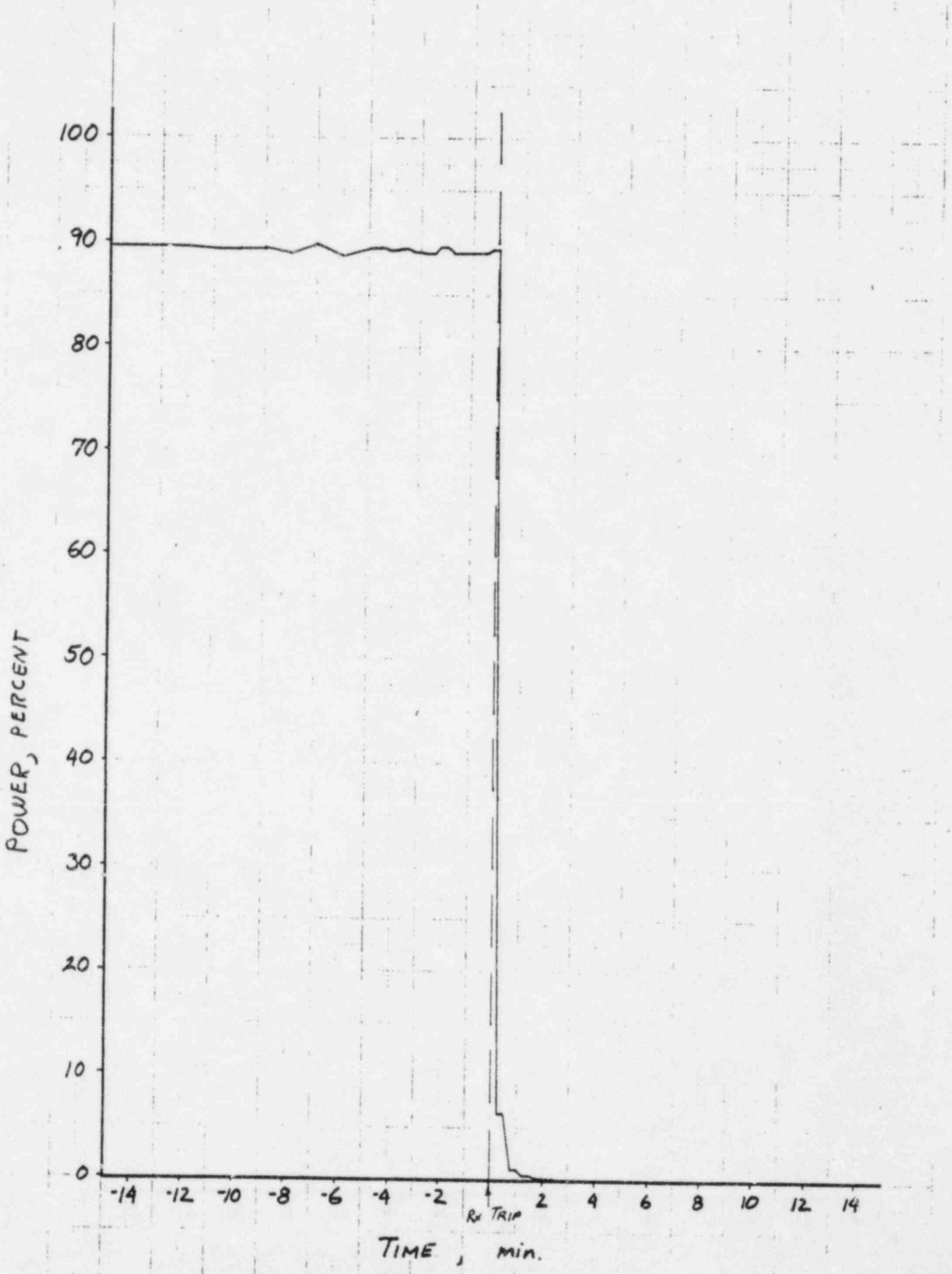
SEQUENCE OF EVENTS REVIEW

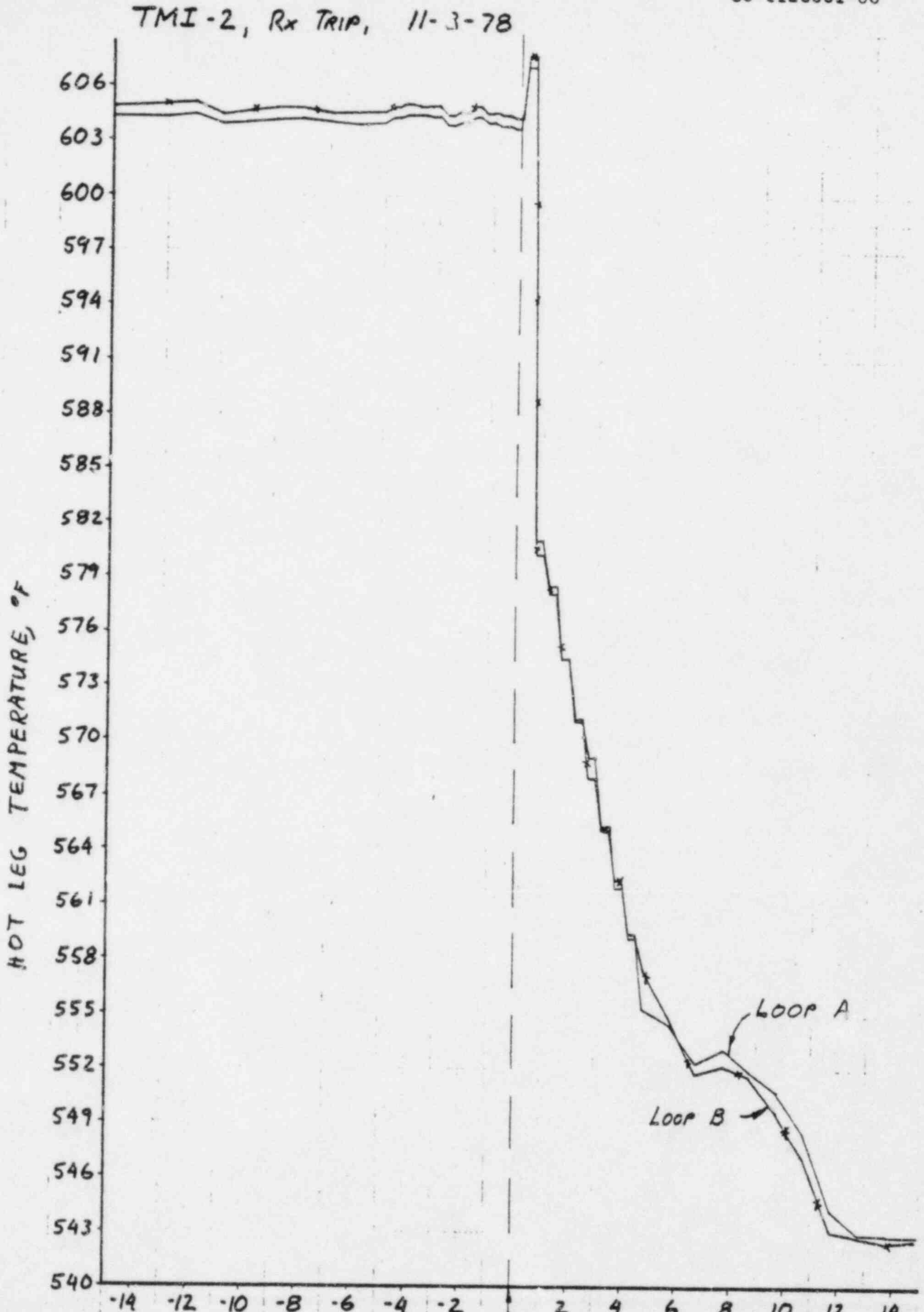
23:48:22:333	3137	500 KV MN XFMR BKR B2-02	TRIP
23:48:24:452	3100	TD MAIN FW PMP FW-P-1B	TRIP
23:48:24:882	3103	TD MAIN FW PMP FW-P-1A	TRIP
23:48:24:972	3153	MAIN GENERATOR DIFF	TRIP
23:48:24:981	3113	EHC AUTO STOP TRIPPED	TRIP
23:48:25:011	3126	TURBINE TRIPPED	TRIP
23:48:25:269	3138	500 KV MN XFMR BKR B2-2602	TRIP
23:48:25:286	3133	TURB INTERCEPT VALVE NO 1 CLOSED	CLSD
23:48:25:288	3137	500 KV MN XFMR BKR B2-01	TRIP
23:48:25:290	3136	TURB INTERCEPT VALVE NO 4 CLOSED	CLSD
23:48:25:297	3134	TURB INTERCEPT VALVE NO 2 CLOSED	CLSD
23:48:25:303	3135	TURB INTERCEPT VALVE NO 3 CLOSED	CLSD
23:48:25:340	3131	TURBINE STOP VALVE NO 3 CLOSED	CLSD
23:48:25:377	3132	TURBINE STOP VALVE NO 4 CLOSED	CLSD
23:48:25:384	3129	TURBINE STOP VALVE NO 1 CLOSED	CLSD
23:48:25:423	3130	TURBINE STOP VALVE NO 2 CLOSED	CLSD
23:48:31:113	3178	RP BLUE CH RC HI PRESS TRIP	HIGH
23:48:31:147	3177	RP YELLOW CH RC HI PRESS TRIP	HIGH
23:48:31:211	3176	RP GREEN CH RC HI PRESS TRIP	HIGH
23:48:31:221	3175	RP RED CH RC HI PRESS TRIP	HIGH
23:48:37:432	3171	REACTOR MANUAL TRIP	TRIP
23:49:26:833	3173	RC MAKE-UP PMP 1B TRIPPED	TRIP
23:56:18:939	3173	RC MAKE-UP PMP 1B TRIPPED	TRIP
23:52:16:162	3109	TD MAIN FW PMP FW-P-1B	TRIP
23:55:39:833	3115	EHC LOSS OF DC POWER	TRIP

TMI-2, Rx Trip, 11-3-78

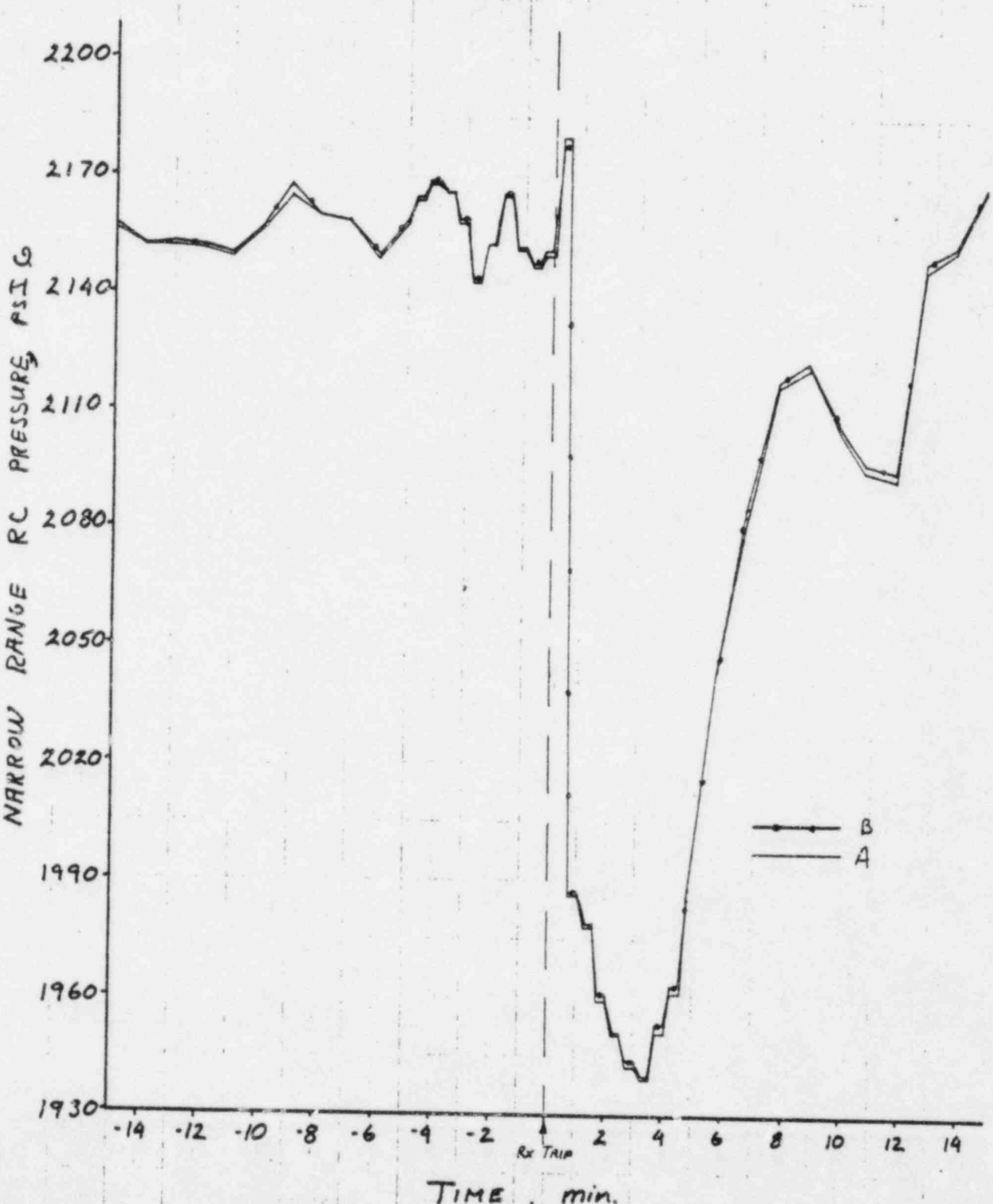


TMI-2, Rx TRIP, 11-3-78




TMI-2, Rx TRIP, 11-3-78
HOT LEG TEMPERATURE, °F
606
603
600
597
594
591
588
585
582
579
576
573
570
567
564
561
558
555
552
549
546
543
540
-14 -12 -10 -8 -6 -4 -2 0 2 4 6 8 10 12 14
Rx TRIP
TIME, min.
LOOP A
LOOP B

TMI-2, Rx Trip, 11-3-78



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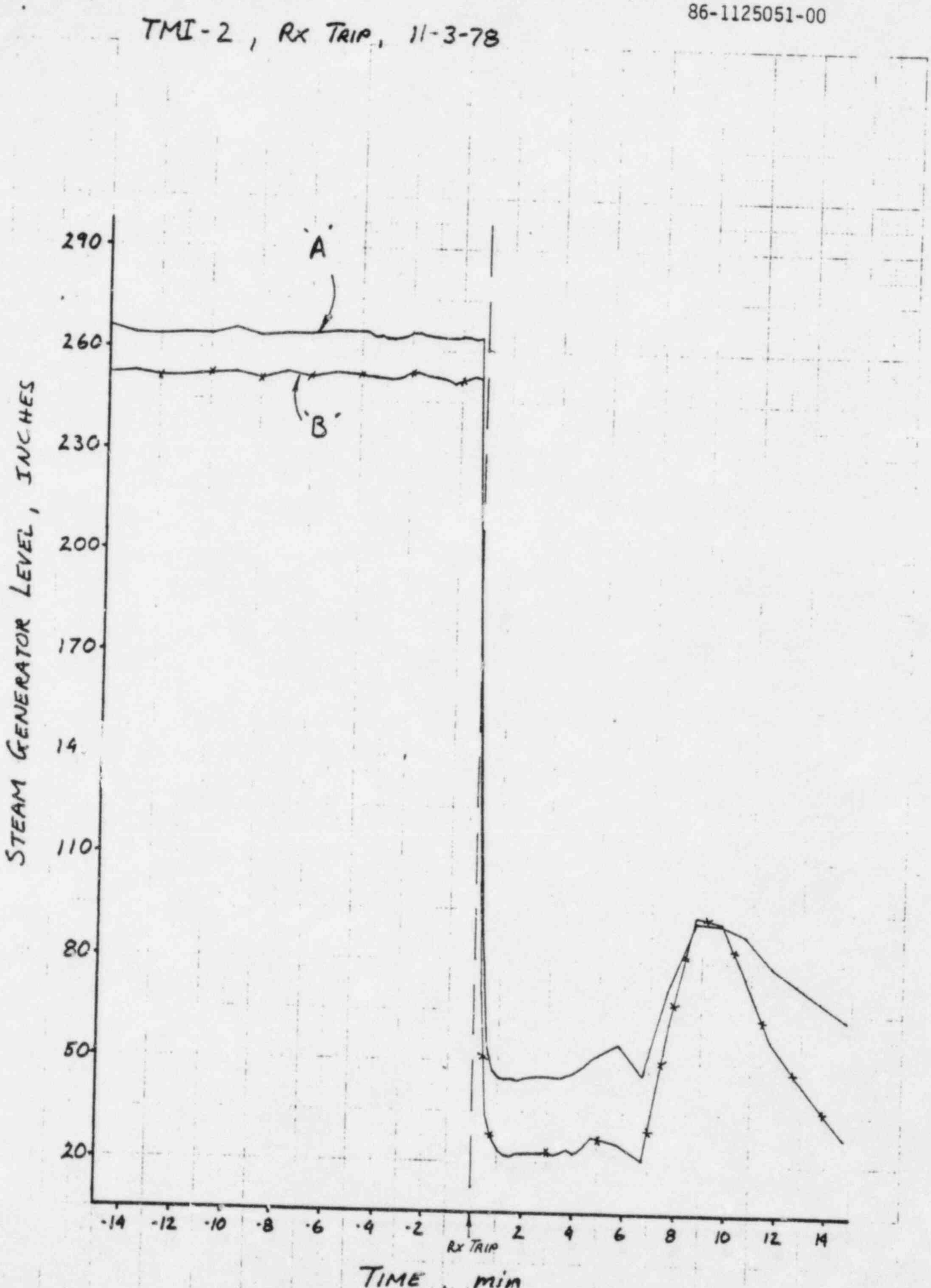

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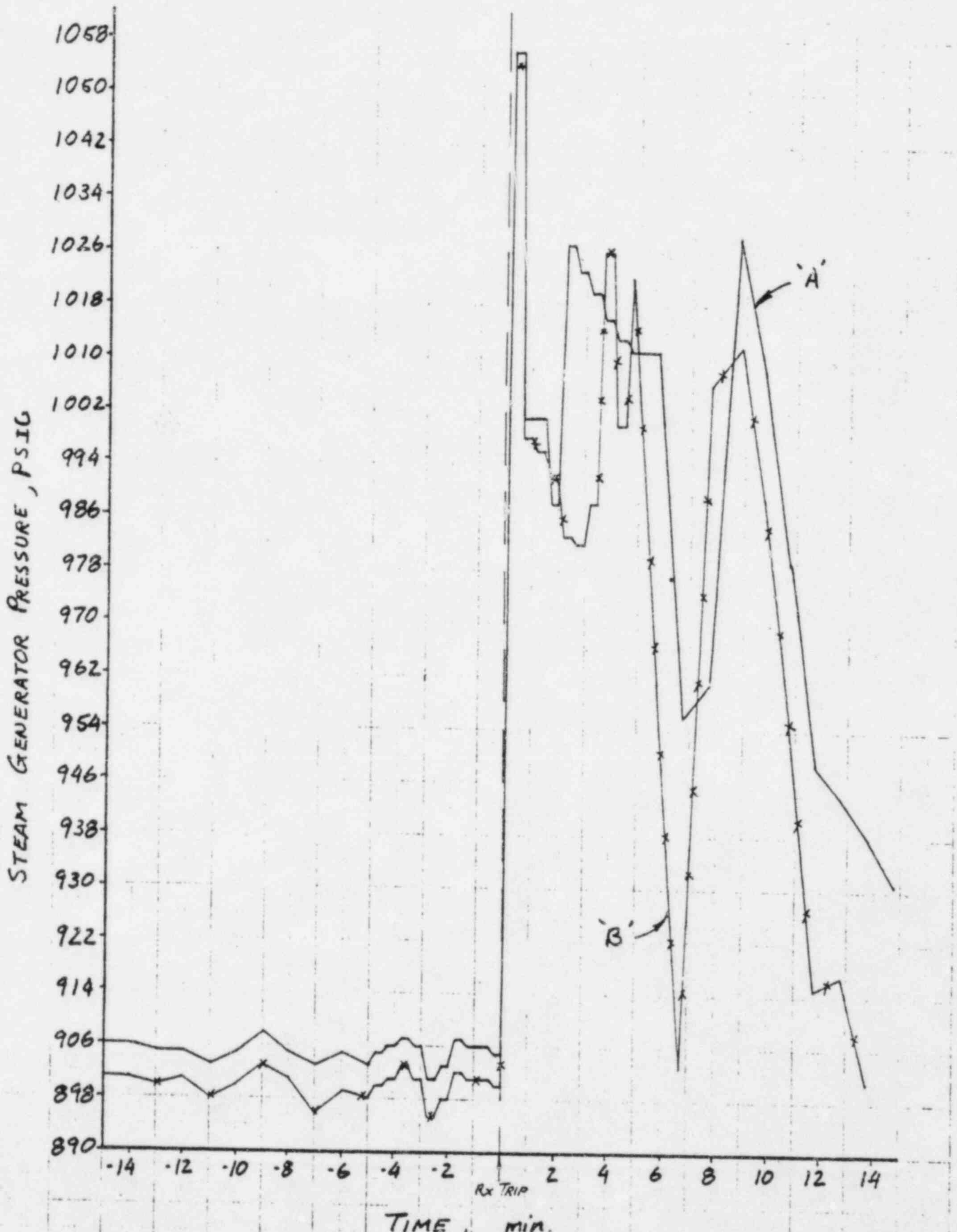
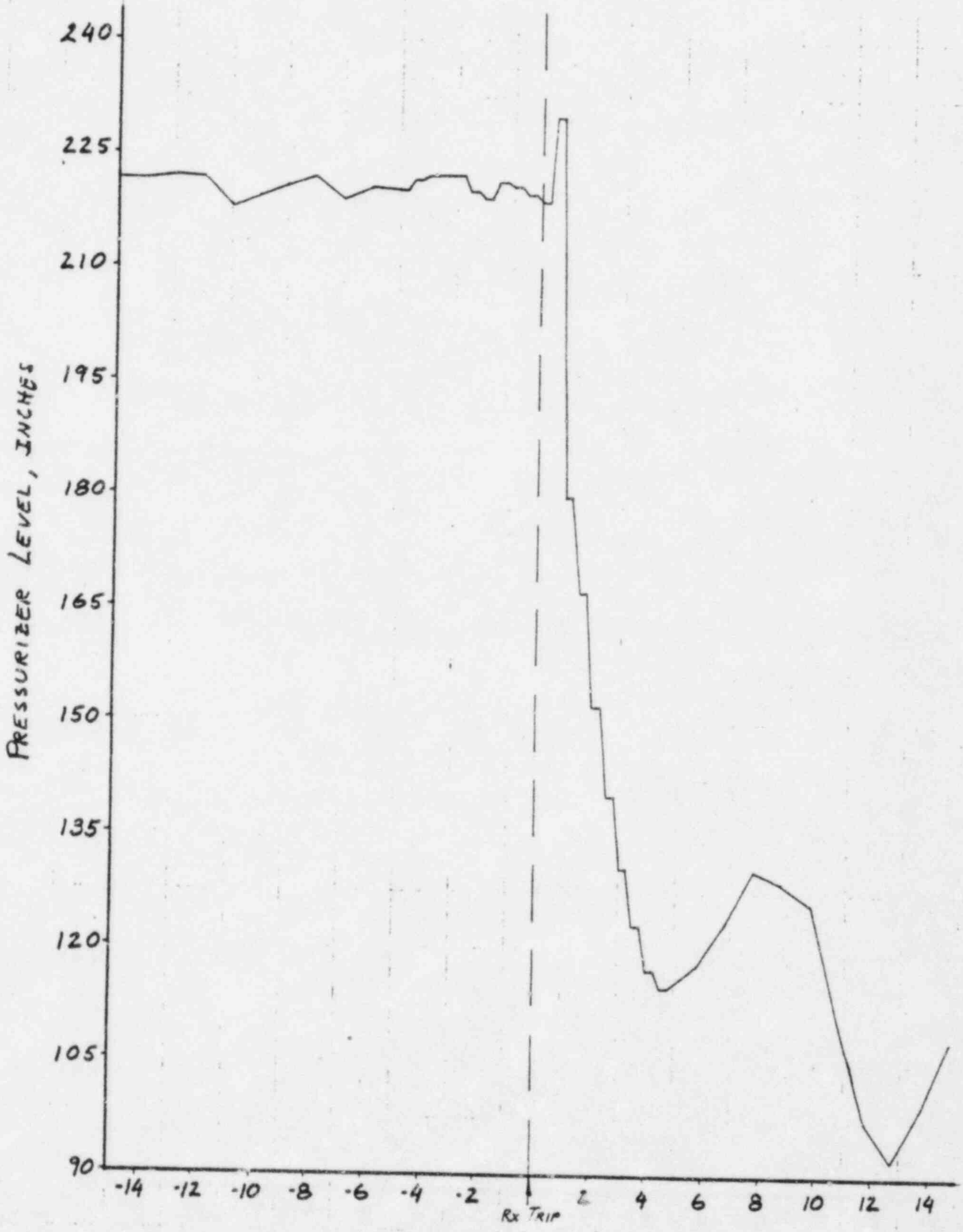
TMI-2, Rx Trip, 11-3-78

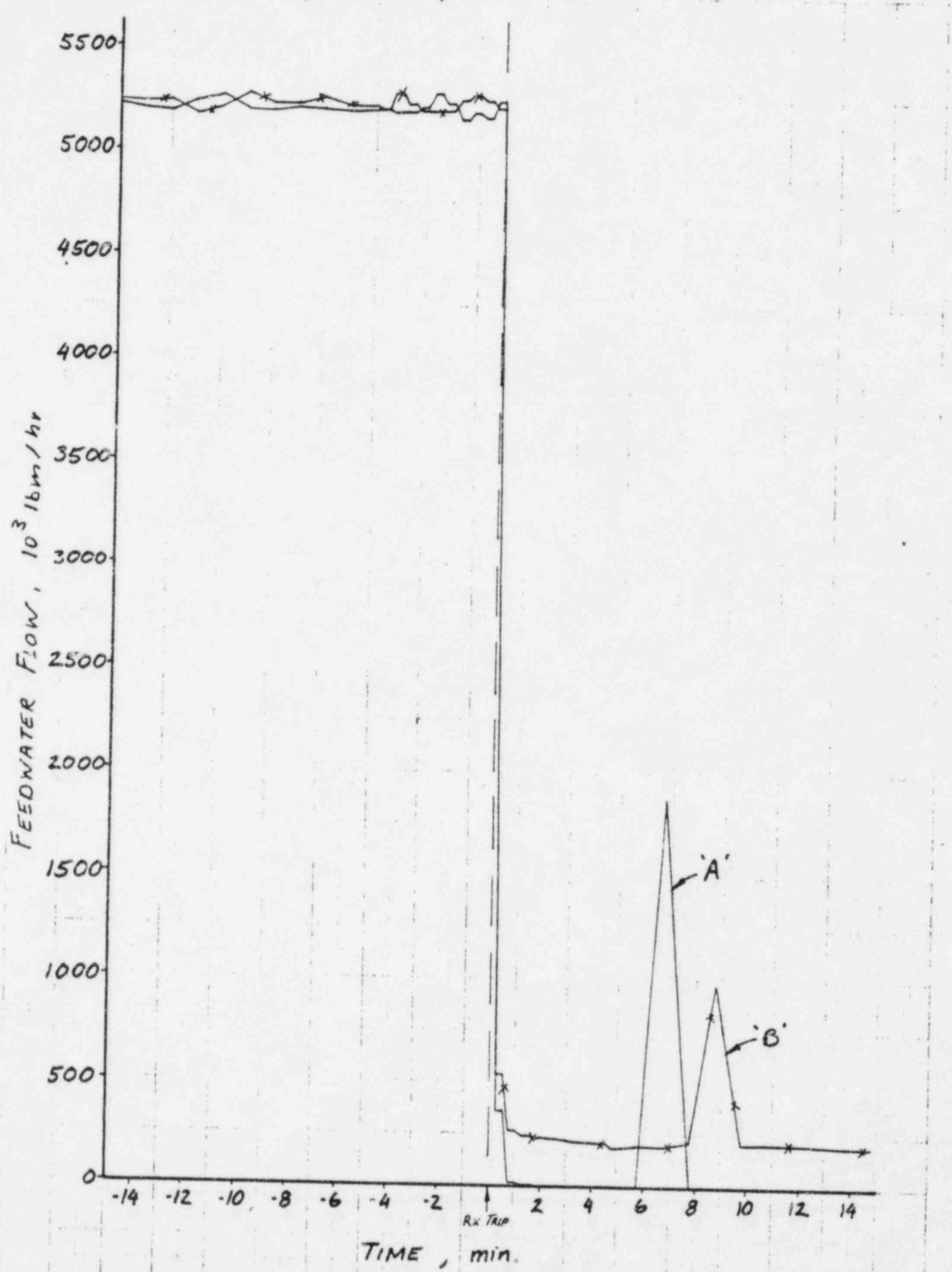


86-1125051-00

TMI-2, Rx Trip, 11-3-78



TMI - 2 , Rx TRIP, 11-3-78



Discussion of Event

The loss of feedwater discussed in this section occurred before the anticipatory reactor trip on loss of both MFW pumps was installed. Therefore, the plant tripped on high RC pressure. The attached plot of RC pressure vs. time does not show a substantial RC pressure increase due to the large increments between data (∿ 30 seconds).

At five minutes, steam pressure decreased to ∿ 900 psig in loop B and ∿ 960 psig in loop A. These pressures are considerably below the expected 1010 psig post trip setpoint. This decrease may have been caused by a steam leak (leading MSSV's or TBS) or operator action (i.e., lowering the TBS setpoint).

The remaining post trip response follows the expected response on page B-2 to B-6 of the ANO ATOG.

IV. Predicted Plant Response

A. TRAP Analysis of LOFW/Stuck Open TBS

(1.0) Description

Failures of the turbine bypass system were analyzed using version 6.0 of the TRAP2 code (Ref. 41) in Ref. 42. The operator's ability to cope with failure of the TBS in an open position on both one and two OTSGs was investigated. Specifically, after diagnosis of overcooling, can the operator take actions to stop the overcooling and prevent ESAS or SLRDS? Path C of the TMI loss of main feedwater event tree (Ref. 1) shows the possible sequence of events. The exact scenario will be determined by analysis.

(1.1) Initial Conditions (in TRAP model)

- 100% Power/2565 MWt
- All RC pumps running
- Total RC flow = 1.313×10^8 lbm/hr
- Hot Leg Temperature = 603.6 °F
- Cold Leg Temperature = 554.0 °F
- RCS pressure = 2193.0 psia

— Pressurizer Level = 216 inches

— Steam generator outlet pressure = 915.8 psia

— MFW flow = 1549.8 lbm/sec. = $5.58 \times 10^6 \frac{lbm}{m}$

(1.2) Sequence of Events

(i) TBS Failed Open on One OTSG

Time (sec)	Event
0.0	(a) Loss of main feedwater due to trip of both MFW pumps (b) MFW begins six second linear ramp to zero
0.4	(a) Anticipatory reactor trip on trip of both MFW pumps
0.9	(a) Turbine trip on interlock
1.4	(a) Turbine stop valves closed
3.0	(a) RCS pressure reaches peak of 2293 psia and begins decreasing (b) Steam pressure increasing
3.5	(a) Pressurizer level at maximum
4.5	(a) TBS valves lift as steam pressure increases to greater than 1020 psig in both loops.
5.0	(a) MSSV bank 1 open in both loops as steam pressure increases to greater than 1040 psig (b) TBS near capacity flow
5.5	(a) MSSV banks 2 and 3 open in both loops as steam pressure increase to greater than 1060 psig
7.0	(a) Peak steam pressure reached of ~ 1090 psia in both loops (b) Steam pressure begins decreasing
9.0	(a) TBS at capacity flow in both loops
32.0	(a) All MSSVs reseated in loop B (b) All TBS in Loop B stuck wide open

Continued Time (sec.)	Event
38.0	(a) All MSSV's reseated in Loop A
59.0	(a) EFW flow begins to OTSG B as level falls to 30" startup range (b) TBS on B stuck open; TBS on A partially open (c) Steam pressure in OTSG A has fallen to 1048 psia (d) Steam pressure in OTSG B has fallen to 966 psia
98.0	(a) OTSG B essentially dry (i.e., zero liquid mass) (b) OTSG A not yet receiving EFW (c) OTSG A steam pressure = 1036 psia (d) OTSG B steam pressure = 876 psia
98	(e) OTSG B steam pressure < 960 psig and T_{cold} < 542°F; Guidelines indicates overcooling (f) Operator indicates action to shut off EFW
113	(a) Operator action has shut off EFW to OTSG B (b) OTSG B steam pressure = 736 psia (c) OTSG A steam pressure = 1035 psia (d) RCS pressure = 178 psia
122	(a) SLRDS actuation on OTSG B; Actions already taken by operator
123	(a) Cooldown ended; Analysis stopped (b) RC pressure = 1817 psia and increasing (c) Hot leg temperature = 549.7°F and increasing (d) Loop A cold leg temperature = 549°F and increasing (e) Loop B cold leg temperature = 547.7°F and increasing (f) OTSG B isolated; No MFW or EFW (g) OTSG A steam pressure = 1035 psia (h) OTSG B steam pressure = 586 psia and decreasing

(ii) TBS Failed Open in Both OTSGs

Time (sec.)	Event
0.0-37.0	(a) Sequence of events are the same as for case (i) (b) TBS stuck open on both loops
55.0	(a) EFW starts to OTSG A (b) Steam Pressure = 969.6 psia in OTSG A; 965 psia in OTSG B (c) RC pressure = 1831.5 psia
59.0	(a) EFW starts to OTSG B
78.0	(a) Operator detects overcooling; (Steam pressure = 960 psia and T_{cold} < 542°F) (b) Operator indicates action to shut off EFW (c) RC pressure = 1705 psia (d) Steam pressure ∿ 915 psia in both OTSGs
98	(a) ESAS actuates; RC pressure = 1615 psia (b) Steam pressure ∿ 832 psia in both loops
103	(a) HPI actuates after a 5 second delay
121	(a) Both OTSGs dry (i.e., zero liquid mass) (b) SLRDS actuation stops EFW to both OTSGs (c) RC pressure = 1570 psia (d) Steam pressure = 613 psia in OTSG A; 663 psia in OTSG B (e) Hot leg temperature = 533°F (f) T_{cold} = 530.3°F in loop A; T_{cold} = 528.9°F in loop B; (g) Analysis ended.

(3.0) Conclusion/Limitations

(a) With the TBS failed open on one OTSG, tee operator ran diagnose overcooling (i.e., 542°F T_C and 960 psig steam) relatively quickly (~ 98 seconds). He should have adequate time (i.e., > 15 seconds) to isolate the generators (i.e., stop EFW) before SLRDS or ESAS actuates.

(b) With TBS failed open on both OTSGs, the operator can diagnose overcooling at ~ 78 seconds. However, ESAS and SLRDS actuation occur rather quickly after this (20 seconds and 43 seconds after overcooling diagnosis, respectively). Therefore, he may not be able to prevent actuation of these systems.

(c) The pressurizer <u>may</u> drain if both TBS fail open. The indicated level will be offscale low. When only one TBS fails, pressurizer level should be maintained on scale.

B. Recommended Changes to ANO ATOG, Part II, Appendix B

(1.0) General Transient Behavior

This section is general in nature and should remain unchanged. The raised plots B-1, B-2 and B-3 are shown on the next three pages. There plots also remain unchanged except for the new TMI P-T plot format.

(2.0) Operator Actions Summary

This section remains basically unchanged. However, since the SLRDS system does not close the MSIVs, the operator should verify the turbine has tripped immediately after trip.

TRAP analysis (See section IV. A) has shown the difficulty in diagnosing that TBS is failed open. Therefore, the operator should verify TBS, ADVs and MSSVs have reseated properly after trip.

(3.0) Loss of Main Feedwater with Other Plant Failures

(i) Introduction

This section remains unchanged

(ii) Loss of Secondary Inventory Control (Low)

This section remains basically unchanged except for the following deviation.

On page B-9, EFW is controlled at 30 inches on the startup range. It will initiate upon trip of both MFW pumps. (Ref. 43)

Figure B-4 should remain basically unchanged.

(iii) Loss of Secondary Inventory Control (High)

This section remains basically unchanged. In contrast to ANO's SLBIC system, TMI SLRDS isolates EFW on a steam pressure of 600 psig. Therefore, the SLRDS will automatically stop rapid EFW overfills which result in steam pressure quenching.

Davis Besse ATOG analysis (Ref. 44) has shown that the steam quenching effort will not be as great when only one OTSG overfeeds. This may lead to EFW entering the steam line <u>before</u> SLRDS actuation occurs. Therefore, the operator should verify proper EFW control.

(iv) Loss of Secondary Pressure Control

This section remains basically unchanged. The guideline writer may want to discuss the findings of the TRAP simulation documented in section IV A.

V. References

1. B&W Dwg. No. 1120125F-00, "Three Mile Island Unit One (TMI-1) Loss of Main Feedwater Event Tree."
2. B&W Doc. No. 05-0002-36, "TMI-1 Technical Specifications," Table 2.3-1 February 28, 1980.
3. B&W Doc. No. 05-0003-19, "ANO-1 Technical Specifications," Table 2.3-1 November 30, 1979.
4. B&W #16-1108693D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit 1 Piping Flow Diagram Makeup & Purification," March 3, 1971.
5. B&W #16-1108694D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit 1 Piping Flow Diagram Makeup & Purification," July 11, 1969.
6. B&W #16-1097719E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Makeup & Purification System," February 1979.
7. B&W Doc. No. DP-1101-02, "Plant Setpoints," ANO-1.
8. B&W Doc. No. DP-1101-02-00, "Plant Setpoints," TMI-1.
9. B&W Doc. No. 86-1106932-00, "Makeup Line and HPI Flow Rates vs. RC Pressure for NSS-8 for ATOG Program," (Contract #582-7108), December 13, 1979.
10. B&W Doc. No. 15-1108790-00, "Prelim. System Description, MU & Purification System TMI-1," August 14, 1969.
11. B&W Doc. No. 16-1108694D-00, "TMI-1 MU&P Piping Flow Diagram."
12. ANO-1 FSAR Vol. II Fig. 10-1.
13. TMI-1 FSAR Vol. 3 Page 5-6.
14. ANO-1 FSAR Vol. II Page 6-29.
15. B&W Doc. No. 86-1118178-00, "ANO Analytical Input Data for ATOG."
16. TMI FSAR, Section 3, Table 3-1, p. 79; Section 4, Tables 4-1 to 4-11, pp. 38-49.
17. TMI-1 FSAR Vol. 1 Page 4-38.
18. ANO-1 FSAR Vol. I Page 4-38.
19. B&W #16-1108682D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit #1 Piping Flow Diagram Feedwater," March 14, 1969.

20. B&W #16-1097712E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Condensate & Feedwater," October 4, 1979.

21. Deleted.

22. ATOG Document List NSS-08, Doc. No. 29-097590-00.

23. B&W Doc. No. 15-1108780-00, "TMI-1 Feedwater System Description."

24. B&W Doc. Nos. 15-1108784-00 and 15-1108780-00, "TMI-1 Main Feedwater Lesson Plan."

25. B&W Doc. No. 03-1097635-00, "ANO Operating Procedure 1203.12, Annunicator K07 F-6 Mn Fw Pump 1P1A Turb 1K2 Trip," Rev. 00, November 30, 1977.

26. B&W Doc. No. 03-1108728-00," TMI-1 Emergency Procedure No. 1202-14," Rev. 5.

27. B&W Dwg. Nos. 620-0008, 21-00-307-05, 21-00-309-02, "Steam Generator Feedwater Control ICS Digital Logic."

28. B&W Doc. No. 86-1118379-02, "EFW Reliability Analysis," ANO-1, December 1979.

29. B&W Doc. Nos. 15-1108782-00 and 15-1108795-00, "TMI-1 Main Steam System Description."

30. B&W #16-1108680D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit #1 Piping Flow Diagram Main Steam, " April 29, 1969.

31. B&W #16-1097721E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Main Steam," May 18, 1979.

32. B&W Doc. No. 16-1108680D-00, "Gilbert Assoc. Inc., TMI-1 Main Steam Piping Flow Diagram," January 8, 1979.

33. B&W Dwg. No. 38-41-602-00, "Consolidated Safety Valves."

34. Letter from D.F. Hallman to J.D. Phinney (attached), "Recommended Modifications to Plant Operations and Setpoints," April 21, 1979.

35. B&W Doc. Id. DP-1101-02-00, "Plant Setpoints, TMI-1."

36. B&W Doc. No. 15-1108779-00, "Preliminary System Description on Feedwater" Section C (of plant manual) Chapter 33.

37. B&W Doc. No. 38-1108797-00.

38. Recommended Requirements for Restart of Three Mile Island Nuclear Station Unit 1, docket number 50-289, operating license number DPR-50.

39. B&W Doc. No. 86-1121912, "Makeup Line and HPI Flow Rates vs. RC Pressure for NSS-5 for ATOG Program (Contract #582-7108)," October 24, 1980.

40. B&W Doc. No. 86-1121207-00, "ATOG Analytical Input Data, 5.A.16."

41. B&W Document NPGD-TM-414, Rev. 3 (Rev. J), "TRAP2 Manual," May , 1980.

42. B&W Document 32-1123291-00, "ATOG Analysis for TMI-1 LOFW Event with TBS Failed Open," R.B. Brownell, 3-4-1981.

43. B&W Drawing 02-1094689D-00, "TMI-1 LOFW SSD," EDS Nuclear Drawing EDS-0116-011-002, TMI-1.

BWNP-20032A-5 (11-80)

CONTRACT/STANDARD NO.		DOCUMENT RELEASE NOTICE (DRN)
582-7108		
RELEASE DATE: 4-24-81	PAGE 1 OF 1	

PART-MARK/TASK-GROUP-SEQ.	B&W DOCUMENT NO.	DOCUMENT TITLE	PUL STAT.	RRL.NO.
14-001-001	86-1123784-00	TMI-1 ATOG TRANSIENT INFORMATION DOCUMENT FOR SSLB	N/A	N/A

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REVIEWED BY: (initials)

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DOCUMENT IDENTIFIER

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TYPE: ___RESEARCH & DEVELOPMENT ___SAFETY ANALYSIS REPORT ___NUC. SERV. INPUT ___DESIGN RQMT. ___DESIGN VERIF. ___OTHER

TITLE TMI-1 ATOG TRANSIENT INFORMATION DOCUMENT FOR SSLB

PREPARED BY J S Schwenn REVIEWED BY R J Schomaker

TITLE Asst Engineer DATE 3/3/81 TITLE Supervisory Eng DATE 3/31/81

PURPOSE:

To summarize the analytical basis for the Abnormal Transient Operating Guidelines for a Small Steam Line Break at the Three Mile Island - Unit One nuclear station.

SUMMARY OF RESULTS (INCLUDE DOC. ID'S OF PREVIOUS TRANSMITTALS & SOURCE CALCULATIONAL PACKAGES FOR THIS TRANSMITTAL)

The attached writeup summarizes the ATOG analytical basis.
Note: The revised P-T diagrams will be sent via a separate transmittal.

DISTRIBUTION

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TABLE OF CONTENTS

I. INTRODUCTION

While the ultimate goal of the Abnormal Transient Operating Guidelines (ATOG) program is to provide operating guidelines for B&W NSSS operators, the final output of the ATOG analysts is the Transient Information Document (TID).

The basis of the operating guidelines is the extensive engineering analysis performed using event trees, computer simulation, and actual plant data for the following transients:

a. Loss of Main Feedwater (LOFW)
b. Excessive Main Feedwater (EFW)
c. Loss of Offsite/Onsite Power (LOOP)
d. Small Steam Line Break (SSLB)
e. Steam Generator Tube Rupture (SGTR)

This transient information document discusses the small steam line break at the Three Mile Island, Unit 1, Nuclear Station. The major scenarios following a SSLB are shown in the respective TMI-1 SSLB event tree (Ref. 26).

The TID, when used with the event tree, forms the basis of the ATOG analytical work. This analytical work either justifies the applicability of the ATOG guidelines for the Arkansas Nuclear (Unit) One (ANO) for use in this analysis and/or specifies where changes must be made.

The purpose of the TID is to provide information to assist Customer Service and Plant Performance Engineering in writing the ATOG guidelines and to provide a documented link between the analysis and the guidelines. Since the TID is the final output of the ATOG analytical effort, it will:

a. Summarize the analysis results.

b. Document the information needed by the guideline writer.

II. MAJOR PLANT DIFFERENCES

A. Control Function and Systems

As discussed in the ATOG guidelines for Arkansas, there are five major functions which must be controlled to ensure a safe shutdown of a plant following an event. They are:

1. Reactivity.
2. Primary inventory.
3. Primary pressure.
4. Secondary inventory.
5. Secondary pressure.

The systems which control these functions are:

Function	Controlling System(s)
Reactivity	Control Rods Boration Systems Reactor Protection System
Primary Inventory	Makeup Letdown High Pressure Injection
Primary Pressure	Pressurizer PORV Pressurizer Code Safety Valves Pressurizer Heaters
Secondary Inventory	Main Feedwater Emergency Feedwater

Function	Controlling System
Secondary Pressure	Turbine Bypass Valves
	Atmospheric Dump Valves
	Steam Safety Valves

It is important to emphasize that while the systems above are the major systems, they are not the only systems that influence plant control. Other supporting systems may affect the control of the five funtions. Failures in the supporting systems may in turn cause the main controlling systems to fail.

B. System Comparison

This section will compare the main systems needed for control after a small steam line break event at ANO-1 and TMI-1. This comparison will concentrate on those features which will influence plant repsonse to a transient. Two systems will be considered similar and have comparable effects on plant response if:

a. System properties (flow, pressures, capacities, etc.) are similar.
b. The system "functions" similarly. (For example, what initiates the system and what does it do once initiated?)

If two systems are considerably different, the ANO guidelines should be modified to reflect the effect of this difference.

b.1. Reactivity Control

There are two major systems which are used for reactor shutdown. The Reactor Protection System (RPS) senses the approach of the reactor to an unsafe condition and provides the reactor trip signal (i.e., insert the control rods). The control rods (groups 1 to 7) are inserted to provide enough negative reactivity to shut the reactor down (i.e., to make the

reactor subcritical). The ground rules for ATOG analysis assumed that these two systems always work. Therefore, Anticipated Transients Without Scram (ATWS) were not considered.

Tables 1 and 2 present the RPS setpoints for ANO-1 and TMI-1 respectively.

TABLE 1

Reactor Protection System Trip Setting Limits for ANO-1

	Four RC pumps operating (nominal operating power, 100%)	Three RC pumps operating (nominal operating power, 75%)	One RC pump operating in each loop (nominal operating power, 49%)	Shutdown bypass
Nuclear power, % of rated, max	105.5	105.5	105.5	5.0[a]
Nuclear power based on flow[b] and imbalance, % of rated, max	1.07 times flow minus reduction due to imbalance(s)	1.07 times flow minus reduction due to imbalance(s)	1.07 times flow minus reduction due to imbalance(s)	Bypassed
Nuclear power based on pump monitors, % of rated, max[c]	NA	NA	55	Bypassed
High RC system pressure, psig, max	2300	2300	2300	1720[a]
Low RC system pressure, psig, min	1800	1800	1800	Bypassed
Variable low RC system pressure, psig, min.	$11.75\ T_{out} - 5103$[d]	$11.75\ T_{out} - 5103$[d]	$11.75\ T_{out} - 5103$[d]	Bypassed
RC temp., F max	619	619	619	619
High reactor building pressure, psig, max	4(18.7 psia)	4(18.7 psia)	4(18.7 psia)	4(18.7 psia)

[a]Automatically set when other segments of the RPS (as specified) are bypassed.

[b]Reactor coolant system flow.

[c]The pump monitors also produce a trip on (a) loss of two RC pumps in one RC loop, and (b) loss of one or two RC pumps during two-pump operation.

[d]T_{out} is given in degrees Fahrenheit (F).

TABLE 2

Reactor Protection System Trip Setting Limits For TMI-1

	Four reactor coolant pumps operating (nominal operating power - 100%)	Three reactor coolant pumps operating (nominal operating power - 75%)	One reactor coolant pump operating in each loop (nominal operating power - 49%)	Shutdown bypass
Nuclear power, % of rated power, max.	105.5	105.5	105.5	5.0(3)
Nuclear power based on flow(2) and imbalance of rated power, max	1.08 times flow minus reduction due to imbalance(s)	1.08 times flow minus reduction due to imbalance(s)	1.08 times flow minus reduction due to imbalance(s)	Bypassed
Nuclear power based(5) on pump monitors, % of rated power, max	NA	NA	91%	Bypassed
High reactor coolant system pressure, psig, max	2300	2300	2300	1720(4)
Low reactor coolant system pressure, psig, min	1800	1800	1800	Bypassed
Variable low reactor coolant system pressure psig, min	$(11.75\ T_{out}-5103)$(1)	$(11.75\ T_{out}-5103)$(1)	$(11.75\ T_{out}-5103)$(1)	Bypassed
Reactor coolant temp. F., max.	619	619	619	619
High reactor building pressure, psig, max	4	4	4	4

(1) T_{out} is in degrees Fahrenheit (F).
(2) Reactor coolant system flow, %.
(3) Administratively controlled reduction set only during reactor shutdown.
(4) Automatically set when other segments of the RPS (as specified) are bypassed.
(5) The pump monitors also produce a trip on: (a) loss of two reactor coolant pumps in one reactor coolant loop, and (b) loss of one or two reactor coolant pumps during two-pump operation.
(6) Trip settings limits are setting limits on the setpoint side of the protection system bistable comparators.

All of the RPS setpoints are approximately the same for the two plants. Specifically, the low RCS pressure trip setpoint is 1800 psig at both plants. B&W plants usually trip on low RCS pressure while operating at low power levels (40%), and high flux at high power levels during an excessive feedwater event.

The control rods at both plants are designed to ensure no less than a 1% k/k shutdown margin with the highest worth control rod withdrawn (Ref. 6). Since the ATOG analyses does not predict a return to criticality after trip, no further consideration is given to difference in control rod design.

The other system used to control reactivity is the Makeup and Chemical Addition Systems. This system can increase (i.e., feed) or decrease (i.e., bleed) boron concentration in the RCS. However, boron is only used to (1) bring the plant to a cold shutdown and (2) control long term reactivity effects such as fuel burnup, xenon and samarium transients, etc. Since neither of these effects are considered in the ATOG analysis, no comparison was made of the chemical addition systems.

Conclusions: No changes should be made in the ATOG based on differences in reactivity control.

B.2. Primary Inventory Control

Primary inventory is controlled by the makeup/HPI and letdown systems. The pressurizer relief valves can also influence primary inventory. However, their basic purpose is to control primary pressure, and they will be compared in Section B.3. Other instrument lines and primary penetrations could decrease primary inventory if they should break. The HPI system is designed to compensate for such breaks. This would be a loss of coolant accident that is outside the scope of this analysis.

Section III of Reference 22 compares the makeup and letdown systems at ANO and TMI-1. The letdown systems are very similar at both plants. The letdown valve closes and stops letdown after an emergency safeguards actuation.

Reference 22, Section IIIA compares the makeup/HPI system at the two plants. The makeup flow vs. pressure is very similar at both plants. Both plants use one makeup pump for normal addition of coolant to the RCS. The normal makeup flow rates are small (25 gpm for both ANO-1 and TMI-1). The makeup flow vs. pressure curve for one pump shows TMI-1 has makeup capacity no more than 10% greater than ANO-1 flow (Table 3).

For HPI flow rates, a similar table is also included in Table 3. Both plants have emergency safeguards actuation at 1500 psia RCS pressure (Ref. 11 and 7). The net flow rates shown in Table 3 indicate that TMI-1 HPI flow is at most 10% greater than ANO-1 flow at low RCS pressures, and 10% greater at higher RCS pressures.

The larger HPI flow at TMI-1 will result in faster recovery of RCS pressure and pressurizer level than at ANO-1. TMI-1 can withstand a more severe overcooling event.

Conclusions: Differences in the primary inventory control systems do not require changes to the ANO ATOG.

TABLE 3

MAKEUP FLOW VS. PRESSURE FOR ANO-1 AND TMI-1

	ANO-1		Ref.	TMI-1	Ref.
Normal Makeup	25 gpm		22	25 gpm	22
Normal Seal Injection	8 gpm/RCP		22	8 gpm/RCP	22
Normal Seal Return	[illegible] gpm/RCP		22	3 gpm/RCP	22
Normal Makeup Flow vs. RCS Pressure for one MU Pump with Makeup Control Valve Fully Open	2200 psig	140 gpm	8	160 gpm	8
	2000	160	8	180	8
	1800	180	8	205	8
	1600	200	8	220	8

HPI FLOW VS. PRESSURE FOR ANO-I AND TMI-1

RCS Pressure (psig)	Flow for[1] Two HPI Pumps at ANO-1 (gpm)	Ref.	Flow for[1] Two HPI Pumps at TMI-1 (gpm)	Ref.
2600	400	8	425	9
2400	495	8	520	9
2200	580	8	605	9
2000	645	8	670	9
1800	705	8	730	9
1600	755	8	785	9

[1]These flows assume one HPI pump feeding each train.

B.3 Primary Pressure Control

RCS primary pressure is controlled through the use of pressurizer heaters, pressurizer spray, the PORV, and the pressurizer safety valves. Although makeup and letdown plays some role in primary pressure control, its main function is in controlling primary inventory and is discussed in Section III B above.

The pressurizer heater bank arrangement in respect to capacity per bank may be different for the two plants. However, the total capacity of all the heater banks is the same for both plants. The total heater capacity is 1638 kw. As shown in Section II of Reference 22, the difference in heater bank grouping is insignificant and would not cause a difference in plant performance during an overcooling event.

The pressurizer spray flow and setpoints for both plants are identical. Pressurizer spray flow is 190 gpm (Ref. 11 and 7). The actuation pressure is 2220 psia and the termination pressure is 2170 psia (Ref. 11 and 7). Therefore, since all the major characteristics of the pressurizer spray are identical, the plant response to spray at ANO and TMI should be similar.

The pressurizer PORV and safeties lift at 2450 and 2500 psig, respectively at both plants (Ref. 15 and 14). The valves themselves are identical.

NOTE: TMI-1 has a 0-400" pressurizer level range, while that for ANO-1 is 0-320".

Conclusion: No changes in the ATOG should be required due to differences in the primary pressure control system.

B.4 Secondary Inventory Control

The main feedwater and the emergency feedwater systems are used to control secondary inventory. Since the main feedwater systems at ANO and TMI are fairly different, the following discussion will not compare the systems per se, but will discuss each system in detail.

B.4.1 Main Feedwater System

The primary differences which are apparent from the feedwater P&ID's are in cross-connect design and flow control valve arrangement. The ANO-1 feedwater trains are completely separate except for a normally closed ICS controlled cross-connect just downstream of the main feedwater pumps. The TMI-1 trains feed into common headers both before and after the 4th and 2nd stage feedwater heaters. There are no valves to impede flow from pump A to OTSG B or from pump B to OTSG A. The main feedwater piping configuration for each plant are shown in figures 1 and 2.

ANO-1 has a low load bypass in addition to the normal startup bypass. TMI-1 has only the startup bypass line. TMI-1 has diaphragm actuated flow control valves, whereas all major valves at ANO-1 are motor actuated.

Other data which characterizes the MFW systems in each plant is as follows:

A. Design Data

Parameter	ANO-1	Reference	TMI-1	Reference
Normal Flow, Both Pumps (lb/hr)	11.1×10^6	19	10.6×10^6	7
Temperature (F)	457	19	457	18
Pump Discharge Pressure (psia)	1088	19	1225	18

B. Signals That Trip the MFW Pumps

Signal	ANO-1	Reference	TMI-1	Reference
Thrust Bearing Wear Forward (mils)	5.0	25	Trips, but setpoints unknown	16
Reverse	35.0	25	Unknown	16
Rotor Vibration (mils)	6.5	25	Unknown	16
Turbine Overspeed (rpm)	6215.0	25	Yes, setpoint unknown	26
Bearing Oil Pressure Low (psig)	10.0	25	4 psi	16
FW Discharge Pressure High (psig)	1150.0	25	Unknown	16
FW Pump Suction Pressure Low (psig)	230.0	25	Pump suction valve closed	16
FW Pump Low Flow (gpm)	1600.0	25	1000 gpm 23" Hg	18 16
Vacuum Other			Number of condensate/condensate booster pumps less than the number of feedwater pumps running will trip the FW pump turbine that was reset last	16

C. Valve Control Logic

1. ANO-1 (Reference 24)

a. Low Load Block Valve
The low load block valve opens when the startup valve reaches 80% open. The low load block valve closes when the startup valve reaches 50% closed.

b. Startup Valve
The startup valve is controlled by the ICS which maintains feed flow proportional to reactor power level.

c. Main Block Valve
The main block valve opens when feedwater demand exceeds 50%. The main block valve closes if feedwater demand drops below 45%.

d. Reactor Trip
A reactor trip causes the main block valve and the low load block valve to shut. Also, a preselected feedwater pump is tripped.

e. Feedwater Pump Trip
A feedwater pump trip causes the main block valve and the low load block valve associated with that pump to close. Also, after a single feedwater pump trip, the ICS opens the cross-connect valve.

f. Reactor Coolant Pumps
Trip all four reactor coolant pumps causes the low-load block valve to close.

g. Pump Speed

After the main block valve opens, the ICS controls feedwater flow by adjusting pump speed. Until the main block valve is opened, the feedwater flow is controlled by the pressure drop across the startup or low-load valve.

2. TMI-1

a. Low Load Block Valve

There is no low load block valve at TMI-1.

b. Startup Valve

Normally ICS controlled. S/U and MFW control valves operate sequentially. When S/U control valve flow approaches capacity during startup, the main control valve begins to open (Ref. 18).

c. Main Block V ve

The main block valve opens when the startup valve reaches approximately 90% open. The block valve closes when the startup valve reaches approximately 70% closed. (Ref. 16)

d. Reactor Trip

(No information available at time of writing)

e. Feedwater Pump Trip

(No information available at time of writing)

f. Reactor Coolant Pumps Tripped

A trip of all four reactor coolant pumps will result in a closing of the main feedwater valves. (Ref. 13)

g. FW Pump Speed

Feed pumps are variable speed and are controlled by feedwater valve P and demand as a function of load. During normal operation the position of the regulating valves and the speed of the feedwater pumps is controlled by the ICS; however, manual control can be instituted at any time. (Ref. 16)

B.4.2 EFW System

ANO-1 has one turbine driven EFW pump and one motor driven pump of approximately equal capacity. TMI-1 has one turbine driven pump and two motor driven pumps. The motor driven pumps together are equal to the capacity of the turbine driven pump.

The diagrams show that all EFW pumps in each plant are capable of feeding either OTSG if necessary. Note that ANO-1 has bypass lines (CV-2627 and CV-2626) in case the EFW control valves CV-2670 and/or CV-2620 fail shut, whereas TMI-1 does not have this feature.

The EFW piping configurations for both plants are contained in figures 3 and 4.

The following gives characteristics of the EFW system in each plant:

	ANO-1	Ref.	TMI-1	Ref.
# Motor Driven Pumps	1	21	2	18
Capacity	780 gpm @ 2700 ft.H_2O	17	460 gpm @ 2700 ft.H_2O	18
# Steam Driven Pumps	1	21	1	18
Capacity	720 gpm @ 2700 ft.H_2O	17	920 gpm @ 2700 ft.H_2O	18
Initiating Signals	a. Low OTSG level (18")	17	a. Loss of both MFWPs	18
	b. Trip of both MFWPs (if RP 5%)		b. Trip of all RCPs	18
	c. Trip of all RCPs		c. Low MFWP P signal	18
	d. SLBIC start steam driven pump		d. Manual	18
	e. Manual			
EFW Isolation Valve (& Controller)	CV-2620 (motor)	17	EF-V30A (Pneumatic)	12
	CV-2670 (motor)	17	EF-V30B (Pneumatic)	12
EFW Isolation Valve(s) Stroke Time	23.3 sec (CV-2670)	17	No information available for control valves EFW-30 A/B	
	23.8 sec (CV-2620)	17		
Power Supply for EFW Isolation/ Control Valve(s)	CV-2620 - B61	17	EF-V30A Plant air;	3
	CV-2670 - B53	17	EF-V30B Plant air;	3
Power Lost to EFW Isolation/Control Valve After Loop	No	17	Only if inst. air lost	3

	ANO-1		Ref.	TMI-1			Ref.
Failure Position of EFW Isolation/ Control Valves on Loss of AIR	As Is		17	Fail As Is			3
Instrument AIR Compressors Shed After Loop	No		10	Yes			3
Steam Supply Valve to EFWP Turbine	CV-2617		17	MSV-13A			18
	CV-1667		17	MSV-13B			18
Power Supply for Steam Supply Valve	B62 (D/G Backed)		17	Plant AIR			3
	B52 (D/G Backed)		17	Plant AIR			3
Failure Position of Steam Supply Valve After Loop	Air not lost		17	FO is air lost			3
				FO is solenoid de-energized			3
				Flow	EF-P1A	EF-P1B	
Flow vs. Head for Motor Driven Pump 2 at TMI-1 1 at ANO-1	200 gpm	3400 ft	20	100 gpm	3250 ft	3250 ft	5
	300 gpm	3400 ft.	20	200 gpm	3200 ft	3200 ft	5
	400 gpm	3300 ft.	20	300 gpm	3090 ft	3090 ft	5
	500 gpm	3200 ft.	20	400 gpm	2900 ft	2900 ft	5
	600 gpm	3000 ft.	20	500 gpm	2630 ft	2625 ft	5
	700 gpm	2800 ft.	20	600 gpm	2200 ft	2180 ft	5
Flow vs. Head for Steam Driven Pump 1 at Each Plant	200 gpm	3500 ft.	20	200 gpm	2990 ft		5
	400 gpm	3350 ft.	20	400 gpm	2950 ft		5
	600 gpm	3000 ft.	20	600 gpm	2870 ft		5
	800 gpm	2550 ft.	20	800 gpm	2760 ft		5
	1000 gpm	1850 ft.	20	1000 gpm	2550 ft		5

Secondary inventory is also affected by the Steam Line Break Isolation and Control (SLBIC) System on ANO-1. This system actuates on low steam pressure (600 psig, Ref. 22) and initiates steam flow to the turbine driven EFW pump. SLBIC also closes the MSIVs and the MFW isolation valves. TMI-1 has a comparable system (SLRDS) and slow-closing MSIVs. This system is detailed in a discussion of secondary pressure control. However, the inability to isolate the OTSG from main steam systems is a significant plant difference only for events involving uncontrolled steam flow and pressure. For both plants EFW remains operationally independent of SLBIC. A comparison of the SLBIC and SLRDS systems is contained in table 9.

Conclusion: The main feedwater systems at ANO and TMI are different in layout and control. The design data for both systems is basically the same. The ATOG guidelines for ANO must be changed to reflect what operator and automatic action is required to maintain control of feedwater.

The EFW systems at ANO and TMI are nearly the same. TMI has a lower EFW pump capacity and could produce a less severe overcooling transient.

B.5 Secondary Pressure Control

Secondary system pressure control is attained by the action of components in the main steam system. The components which are most important include atmospheric dump valves, main steam safety valves, the turbine bypass system, and a steam line rupture response system. The only major differences between ANO-1 and TMI-1 for these components are the steam line rupture system and the fact that the main steam line splits so that the TBS is upstream of the MSIVs. In the event of a major loss of steam pressure (such as a SSLB), the SLBIC system at ANO-1 and the SLRD system at TMI-1 actuate at an OTSG steam pressure of 600 psig. The SLBIC system responds by closing

the MSIVs for both OTSGs, closing the MFW isolation valve to the affected loop, initiating steam to the steam-driven EFW pump, and opening EFW isolation valves on initiation signal to both OTSGs. This essentially terminates MFW to the affected loop, starts EFW to both OTSGs and isolates both OTSGs with the MSIVs. The ANO-1 operator is then instructed to terminate EFW to the affected loop and control EFW to the good loop.

The SLRD system closes MFW block and control valves to the affected loop, closes startup FW block control valves to the affected loop and closes EFW control valves to the affected loop. Thus all feedwater is terminated to the affected loop. (See table 9 for a comparison of these systems.) The operator must manually close the MSIVs to isolate the break, and he must then control feedwater to the good loop. At this point, both plants are in similar conditions.

If dual SLRDS signals are reached, the affected loop must be determined, if possible, and feedwater re-established to SG in the good loop. Failure of the full turbine bypass system (TBS) must be isolated, as this is the only case considered possible in which both loops continue depressurization following closure of the MSIVs and feedwater re-established in order to proceed with cooldown.

However, the main differences are that the MSIVs at ANO-1 are fast-closing, while the TMI-1 MSIVs are manual and slow-closing (up to five minutes), and availability of the TBS at TMI-1. Therefore, the path which is questionable in comparison with the ANO-1 event tree is the path where the turbine bypass valves fail to close.

Since the turbine bypass system splits off the main steam line upstream of the MSIVs, a failure of the TBS in the open position results in an unisolated leak and uncontrolled cooldown. This is unlike ANO-1, where the TBS is downstream of the MSIVs.

At all B&W plants there are three sets of valves provided to control secondary pressure after a trip. They are:

1. Main steam safety valves (steam dump to the atmosphere),
2. Atmospheric dump valves (steam dump to the atmosphere), and
3. Turbine bypass valves (steam dump to the condenser).

At ANO-1, the circulating water pumps which provide cooling water to the condenser are not powered after a LOOP. Therefore, the condenser cannot be used as a steam dump and the ICS isolates the turbine bypass valves (Ref. 22). The same is true for TMI-1 in the event of a LOOP (Ref. 12).

The ADVs are needed at both ANO and TMI to prevent unnecessary main steam safety valve cycling and to allow plant cooldown.

Section IV of Ref. 22 compares the MADVs of ANO with the MADVs of TMI-1. Their setpoints upon reactor trip are very similar. The major difference is the capacity of the two systems. ANO has 5% MAD valve capacity while TMI-1 has 6.4% MADV capacity. This capacity difference not only affects how long the MSSVs remain open, but it also increases the overcooling that will occur if a TBS valve sticks open. Table 6 shows the setpoints and capacity of the MAD valves for both plants.

The two plants have similar safety valve setpoints and capacities. TMI has 114.0% main steam safety valve capacity, and ANO has 122% capacity. After a reactor trip at either plant from high power, usually only the first two banks of main steam safeties lift. Therefore, the capacity difference between the two plants is of little importance. Table 7 shows the number of valves, capacities, and setpoints of the main steam safety valves for both plants.

Also, the plants have very similar Turbine Bypass Systems. The major similarity is that the TBS at ANO and TMI are rated at 15%. The similarity is more significant in terms of capacity per turbine bypass valve: ANO has 3.75% per valve and TMI has 3.75% per valve. This would not significantly change the cooldown rate for a stuck open turbine bypass valve at TMI versus ANO. Table 8 shows the comparison of data for TMI and ANO on the TBS.

Conclusion: The systems which control secondary pressure at ANO and TMI are nearly the same as far as the valves (MSSVs, MADVs, and TBVs) which are provided. The differences which occur are concerned with the steam line rupture systems and the location of the TBS. The following differences would affect plant performance:

a. SLBIC closes the MSIVs at ANO; the operator must close the MSIVs at TMI.
b. The MSIVs at ANO are fast-closing; the MSIVs at TMI are slow-closing.
c. SLBIC initiates EFW flow to both SGs; SLRDS does not initiate EFW, the operator must initiate flow (however, SLRDS does close EFIVs to affected SG)
d. For signals on both SGs: SLBIC terminated MFW to both SGs and initiates EFW flow to both SGs; SLRDS terminates MFW to both SG but the operator must establish EFW to the SGs.
e. The TBS at ANO is downstream of the MSIVs, while the TBS is upstream of the MSIVs at TMI.
f. A stuck open TBV at ANO is isolated by SLBIC; however, at TMI the operator must isolate the TBS (or face an uncontrolled cooldown through the TBVs).

TABLE 6

MAD VALVES

	ANO-1	Reference	TMI-1	Reference
# Valves	2	21	2	1
Lift Pressure*	1020 psig	20	1026	2
Full Open Pressure*	1045 psig	20	1052	2
Capacity (Total)	5%	20	6.4%	2

*The MAD Valve setpoints are a function of plant condition (reactor trip, turbine trip, or normal plant operation).

TABLE 7

SAFETY VALVES

	ANO-1	Reference	TMI-1	Reference
# Valves	16	21	18	2
Safety Valves Lift Pressure	4 @ 1050 psig	23	2 @ 1040 psig	2
	4 @ 1070 psig	23	4 @ 1050 psig	2
	4 @ 1090 psig	23	4 @ 1060 psig	2
	4 @ 1100 psig	23	4 @ 1080 psig	2
			4 @ 1092.5 psig	2
Safety Valve Flow	235 lbm/s-valve	23	197.0 lbm/s-valve	2

TABLE 8

CONDENSER DUMP
(Turbine Bypass)

	ANO-1	Reference	TMI-1	Reference
Lift Pressure*	1020 psig	20	1020 psig	2
Full Open Pressure*	1045 psig	20	1052 psig	2
Capacity (Total)	15%	20	15%	2

*Condenser Dump setpoints are a function of plant conditions. Setpoints shown are for reactor trip.

TABLE 9

STEAM LINE RUPTURE DETECTION SYSTEMS

ANO-1	Ref.	TMI-1	Ref.
'SLBIC'		'SLRDS'	
Actuation Setpoint = 600 psig	20	Actuation Setpoint = 600 psig	2
- Actions Taken by System -		- Actions Taken By System -	
1. Closes MSIVs for both OTSGs	17	1. Closes MFW block and control valves to affected OTSG only.	2
2. Closes MFW isolation valve to affected OTSG.		2. Closes startup FW block and control valves to affected OTSG only.	2
3. Opens steam supply valve to steam-driven EFW pump.	17	3. Closes EFW control valves to affected OTSG only.	2
4. EFW isolation valves open on EFW initiation signals to both OTSGs.	17	4. Performs identical operations on the other OTSG if low steam pressure is detected in that loop.	2
5. Closes MFW isolation valve for the other OTSG if a SLBIC signal subsequently originates from that steam loop.	17		

[redacted]

FIGURE 1: ANO-1 SIMPLIFIED MAIN FEEDWATER SYSTEM
(Ref. B&W DOC. NO. 16-1097712E-00)

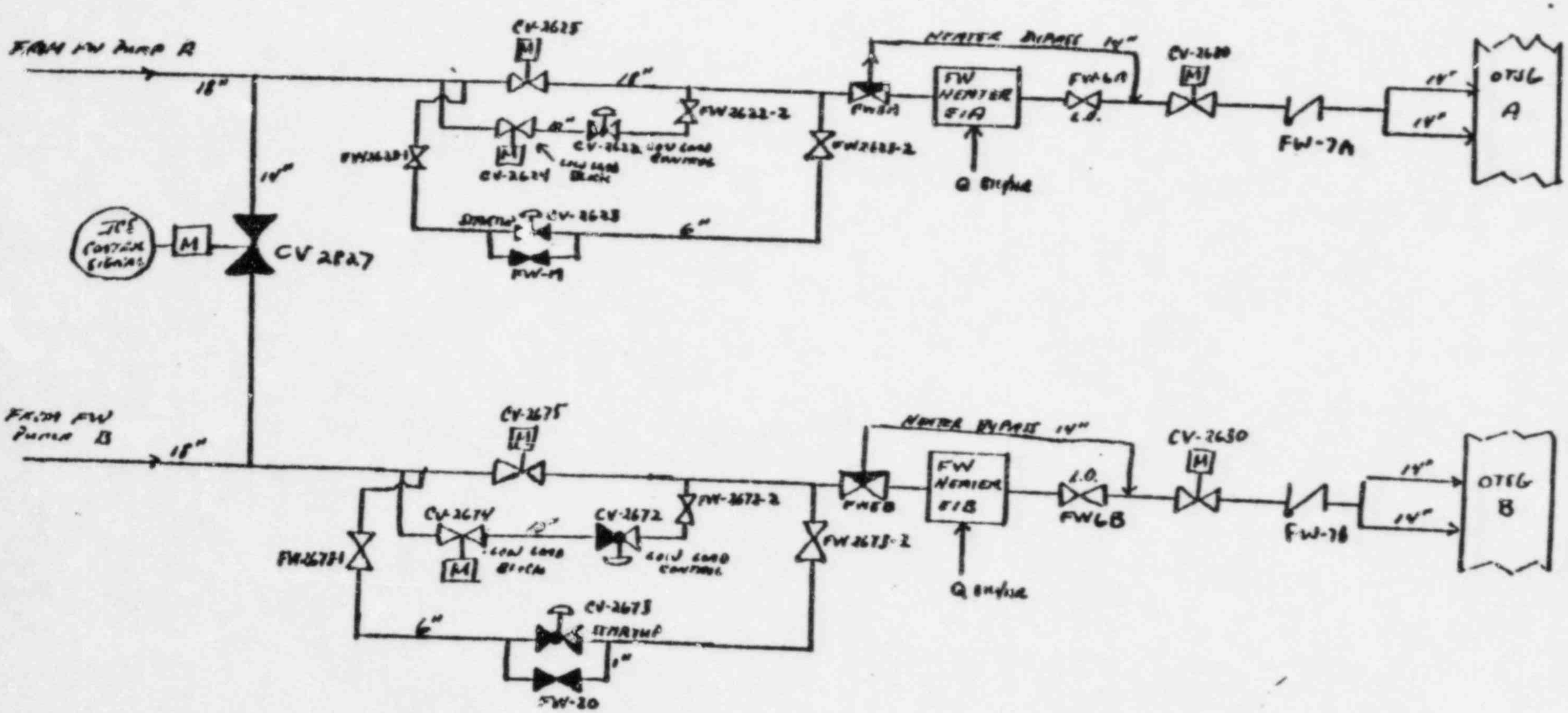

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FIGURE 2: TMI-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

Ref. B&W DWGs No. 16-1108682D-00

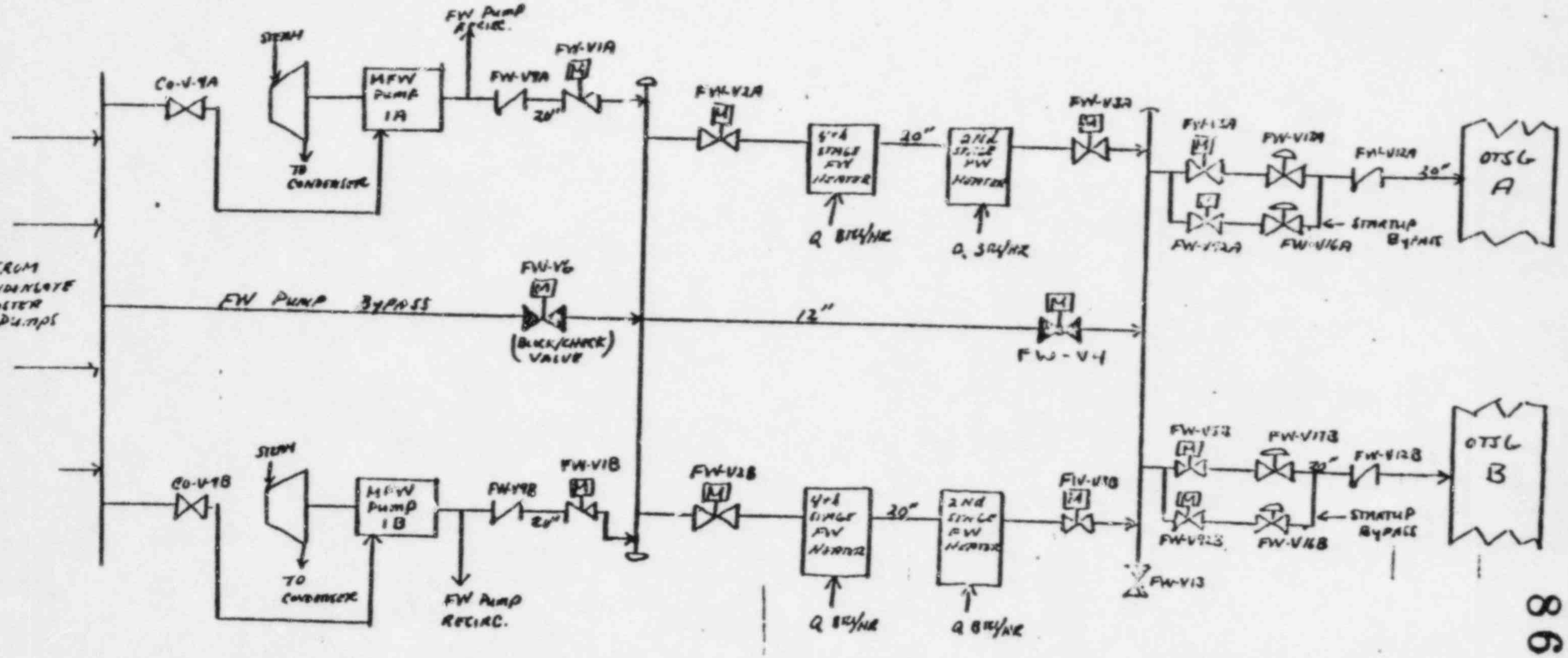

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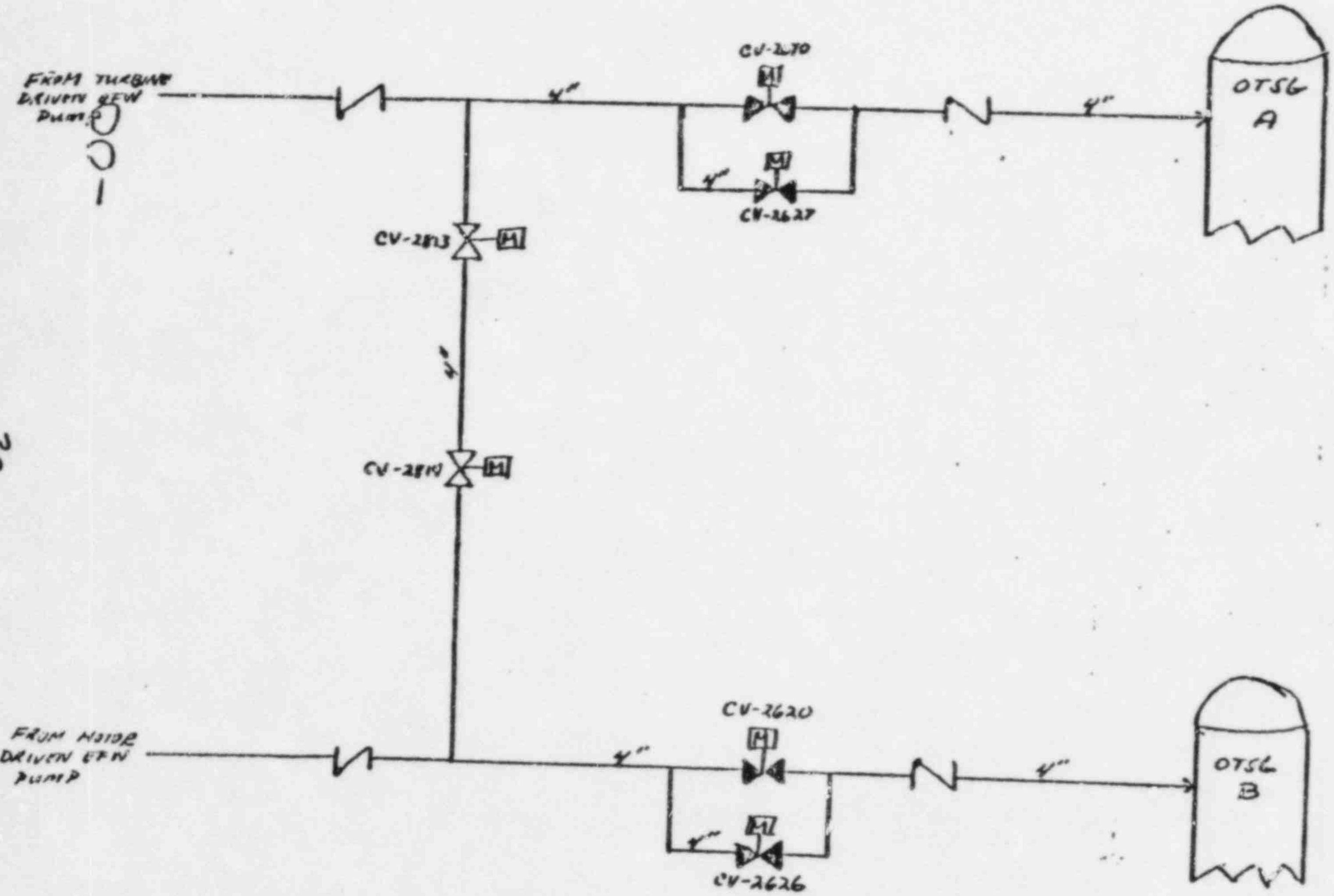
FIGURE 3: ANO-1 SIMPLIFIED EFW SYSTEM

(Ref. B+W Doc. No. 16-1097712E-00)



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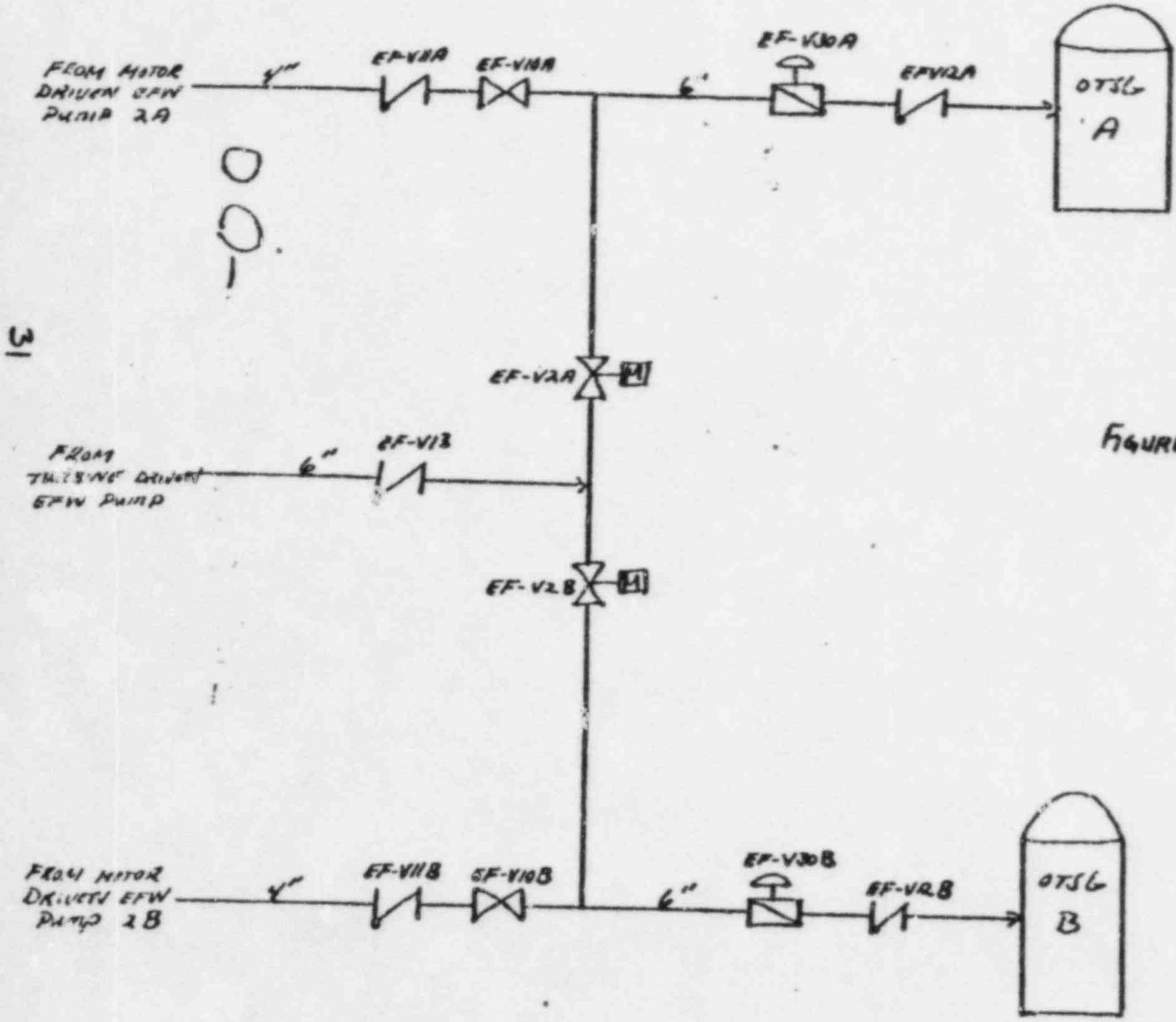

Figure 4: TMI-1 SIMPLIFIED EFW SYSTEM

Ref. B+W Doc. No. 16-1108682D-00

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III. PLANT DATA

This section presents a discussion of a representative small steam line break, in the form of failed open turbine bypass valves. While this incident occured at low power and is not modeled in our TRAP analyses, this case is representative of the trends experienced in a full power case.

The transient data avialable for this event are reported in the following: Three Mile Island, Reactor Trip Report #2, June 20, 1974.

The plant conditions prior to the trip were recovering from a turbine overspeed trip test and GE (General Electric) was restoring turbine to operation when an unbalanced condition occured in the turbine steam headers due to only 2 of 4 turbine stop valves opening on signal. The following plant conditions existed prior to this imbalanced condition: the reactor power level was 17.8% FP, T_{ave} was 578F, the RC system pressure was 2155 psig, the RC flow was 100%, and the pressurizer level was 220 inches.

The unbalanced condition in the turbine steam headers was caused during plant recovery when the #1 and #2 turbine stop valves from the 'B' steam generator opened properly (at the 1800 rpm turbine speed) and the #3 and #4 turbine stop valves from the 'A' steam generator failed to open. Because the 'B' bypass valves were open and the 'B' steam generator was supplying the entire demand of the turbine, the pressure in the 'B' turbine header started decreasing rapidly.

The pressure in the 'B' steam header dropped below 600 psig, actuating one channel of the steam line rupture detection system (SLRDS). (The remaining three actuation channels were defeated.) The steam line rupture actuation automatically secured feedwater to the 'B' OTSG causing it to boil dry and

remain in that condition for about 2.5 minutes. The RC system pressure and T_{ave} were increasing rapidly. When T_{ave} reached approximately 600F, the control rods were manually inserted to stop pressure and temperature increase, while letdown was manually increased to take care of reactor coolant expansion.

At this point, both bypass valves were manually closed, the turbine was manually tripped, and the steam line rupture detection system (SLRDS) on the 'B' loop was defeated. This immediately restored the signal to the ICS feedwater station, which was still in automatic, to maintain minimum level in the 'B' OTSG (approximately 30"). The sudden influx of feedwater into the steam generator caused T_{ave} and RCS pressure to drop rapidly. The transient occured so rapidly as to actuate the RPS low pressure trip, which shut down the reactor approximately one minute after the SLRDS for the 'B' loop was completely defeated.

The data received as part of the trip report are contained in this document as Appendix A. Figure 1 contains plots of the turbine bypass valve position demand, the turbine 'A' header pressure (psia), and total feedwater demand (%) vs time. Figure 2 contains both steam generator startup levels (inches) vs time. Figure 3 shows in more detail the 'A' and 'B' loop startup levels and the 'A' OTSG pressure vs time. Finally, figure 4 shows the OTSG hot and cold leg temperatures, and RCS pressure, vs time.

IV. PREDICTED PLANT PERFORMANCE

The small steam line break event has been analyzed for ANO-1 using the TRAP computer code. Utilizing this past analysis in conjunction with information in sections II and III of this report, the ANO Abnormal Operating Transient Guidelines (Part II, Appendix E) have been reviewed and modified for applicability to TMI-1.

Changes to Section 1.0 - General Transient Description

- All references to MSBVs must be changed to MSIVs.
- References to SLBIC must be changed to SLRDS, in accordance with the operation of this system.
- SLRDS will not isolate the break (i.e., by closing the MSIVs) and will not start EFW directly. The operator must manually close the MSIVs (which take about four minutes to fully close) and manually initiate EFW to the unaffected OTSG only.
- Note that in the event of a TBS failure in the open position at TMI-1, closure of the MSIVs will not isolate the break since the TBS splits off the main steam line upstream of the MSIVs. In this case, the operator must diagnose and manually close the stuck-open turbine bypass valve in order to prevent an uncontrolled and unisolated steam leak.
- In the event that the leak is upstream of the MSIVs (or the operator fails to close the stuck-open TBVs, the operator must initiate EFW to the unaffected OTSG and must ensure that all feedwater is terminated to the affected OTSG to boil it dry.
- Note that stuck-open TBS valves cannot be automatically terminated.
- Figure E-1 is modified to include a plot of T_{cold} vs SG Pressure.
- Figure E-1 is changed in the sequence of events (remarks) as follows:

Reference point	Revised remark
4	SLRDS actuates, EFW pumps started and EFW and MFW valves to affected OTSG closed; operator controls EFW to unaffected OTSG to limit overcooling effects; operator must close failed open TBS valves and must manually close the MSIVs in order to isolate the break.

Changes to Section 2.0 - Operator Actions Summary

- o Note in comments received from GPU on the SSLB event tree, it was suggested that in order to determine the affected OTSG the operator should terminate all feedwater to one generator at a time and note which OTSG is experiencing the fastest level decrease (or depressurization). The operator must restart feedwater to the generator which repressurizes. (the unaffected OTSG). Only one OTSG should be isolated at a time in order to prevent a complete loss of heat sink. Also note that the operator should utilize the plot of OTSG pressure versus cold leg temperature for diagnosis.
- o If SLRDS actuates and both generators repressurize (i.e., the break is isolated) feedwater should be fed to both generators until the affected loop is determined; if only one generator repressurizes, SLRDS did not isolate the leak and the operator must initiate EFW to the unaffected generator (the one which repressurizes) and ensure that all feedwater is stopped to the generator which did not repressurize (the affected OTSG).
- o Figure E-2 is modified to show T_{cold} vs SG Pressure (as requested by GPU). This modified plot is included in this document.
- o For the case in which failure of the TBVs was such that it prevented manual closure, the leak would be unisolable and uncontrolled, even if the MSIVs are closed, since the TBVs are upstream of the MSIVs at

TMI-1. The operator must decrease feedwater flow to maintain tube-to-shell temperature limits and control the cooldown. The operator must also initiate (or verify) HPI in order to maintain RCS pressure and ensure that a pressurizer level exists.

- o Note that closure of the MSIVs does not isolate the TBVs at TMI-1.
- o Note again that the only way to isolate the failed open TBVs at TMI-1 is to manually close them.
- o SLRDS would not automatically isolate the steam leak or initiate EFW for this example (failed open TBVs) and the above operator actions must still be taken.
- o The transient of most concern at TMI-1 is one where the leak will not be isolated and the overcooling will not be terminated. For TMI-1, this transient would be a leak upstream of the MSIV (or the failed open TBVs which cannot be manually closed). HPI actuation on ESAS would occur and SLRDS would actuate isolating the leak from the good OTSG and terminating MFW to the affected OTSG.
- o The operator must initiate EFW flow to the unaffected SG (as SLRDS does not directly start EFW) and ensure that no feedwater is fed to the affected SG. The operator must allow the affected SG to boil dry, after which he would return to stable shutdown conditions by controlling decay heat removal with the unaffected SG.
- o For a leak inside the RB for which SLRDS has not been actuated, the operator must determine which SG is affected. GPU responses have indicated a preference to terminate all feedwater to one SG at a time and determine which SG is affected by observing SG levels and pressures. Note that operator should also close the TBVs and ADVs (to prevent inadvertant diagnosis of failed open TBVs as a separate steam leak).
- o If SLRDS is actuated, the operator must direct EFW to the unaffected SG and control decay heat removal with this generator.

Changes to Section 3.0 - Small Steam Leak with Other Plant Failures

Branch Discussion

- Replace SLBIC with SLRDS.

Loss of Reactor Inventory Control (High)

- No changes.

Loss of Reactor Inventory Control (Low)

- No changes.

Loss of Secondary Inventory Control (High)

- No changes.

Loss of Secondary Inventory Control (Low)

- No changes.

Loss of Steam Pressure Control

- No changes.

Changes to Figure E-3 (Time Relationship of Key Parameters)

- Change "SLBIC isolates leak" to "SLRDS and operator isolate leak".

V. REFERENCES

1. Gilbert Assoc. Inc., TMI-1 Main Steam Piping Flow Diagram; C-302-011, Rev. 22; January 8, 1979; B&W Document No. 16-1108680D-00.

2. TMI-1 Main Steam System Description, B&W Document Nos. 15-1108782-00 and 15-1108795-00.

3. LOOP and Loss of Inst. Air, TMI-1, Valve Failure and Diesel Loading - block information, B&W Document No. 38-1108796-00.

4. B&W Report BAW-1066, "Arkansas Nuclear One, Unit I, Cycle 5 Reload Report", July, 1980, Table 8.1.

5. B&W Document No. 86-1121207-00, "ATOG Analytical Input Data - TMI," 5.A.16.

6. B&W Report BAW-1066, "Arkansas Nuclaer One, Unit I, Cycle 5 Reload Report", July, 1980, Section 3.5.2.

7. B&W Document DP-1101-02-00, TMI-1 Plant Setpoints.

8. B&W Document No. 86-1106932-00, "Makeup Line and HPI Flow Rates vs RC Pressure for NSS-8 for ATOG Program (Contract # 582-7108)", J. W. Merchent, December 13, 1979.

9. B&W Document No. 86-1121912-00, "Makeup Line and HPI Flow Rates vs RC Pressure for NSS-5 for ATOG Program (Contract # 582-7108)", J. W. Merchent, January 21, 1981.

10. ANO-1 List of Components Loaded on Diesel Generators, B&W Document No. 40-1097627-00.

11. B&W Document DP-1101-02-00, "Plant Setpoints for Arkansas Power and Light", Arkansas Nuclear One, September 25, 1974.

12. Gilbert Assoc. Inc., "TMI-1 Feedwater System Piping Flow Diagram", B&W Document No. 16-1108682D-00.

13. TMI-1 Emergency Procedure No. 1202-14, Rev. 5, B&W Document No. 03-1108728-00.

14. EDS Nuclear Drawing 0116-011-002, "TMI-1 Loss of Feedwater Safety Sequence Diagram", B&W Drawing 02-1094688D-00.

15. EDS Nuclear Drawing 0111-011-002, "ANO Loss of Feedwater Safety Sequence Diagram", B&W Drawing 02-0197501D-00.

16. TMI-1 Main Feedwater Lesson Plan, B&W Document Nos. 15-1108784 and 15-1108795-00.

17. B&W Document No. 86-1119379-00, "EFW Reliability Analysis for ANO-1, Unit 1", W. W. Weaver, et. al., December, 1979.

18. TMI-1 Feedwater System Description, B&W Document No. 15-1108780-00.

19. ATOG Document List NSS-08, Document No. 29-097590-00.

20. B&W Document No. 86-1118178-00, "Analytical Input Summary," ANO.

21. Arkansas Nuclear One FSAR.

22. B&W Document No. 32-1121199-00, "ATOG ANO-1/TMI-1 Systems Comparisons", December 10, 1980.

23. B&W Drawing No. 38-41-602-00, "Consolidated Safety Valves".

24. B&W Drawing 620-0008 (21-00-307-05), "Steam Generator Feedwater Control Digital Logic for Arkansas Power and Light Company".

25. B&W Document No. 03-1097635-00, "Annunciator Corrective Action", Section - Annunciator K07 F-6 MN FW Pump 1P1A TURB TK 2A Trip, Rev. 00, November 30, 1977.

26. B&W Drawing 1120141F-00, "ATOG: TMI-1 Small Steam Line Break Event Tree".

APPENDIX A

REACTOR TRIP REPORT

NUMBER 2

Date and Time of Trip 6/20/74 @ 1214

Cause: RPS - "RC Low Pressure"

by: C.F. Gilbert
W.W. Cotter
C.E. Hartman

86-1123784-00

SUMMARY

During turbine overspeed testing malfunctioning turbine bypass valves caused a condition where the B turbine bypass valves and the B OTSG connected turbine stop valves were open (1 & 2), and the A OTSG connected turbine stop valves closed (3 & 4). The B turbine header pressure was reduced sufficiently low to actuate the steam line rupture detection system. Actuation of the steam line rupture detection system secured the feedwater flow to the B OTSG boiling it down to zero inches. The rupture detection system was bypassed while the feedwater ICS station was in automatic causing the feedwater to demand full flow. This cooled and depressurized the primary system to the low pressure trip setpoint causing a reactor trip on low RCS pressure.

CAUSE OF TRIP

Malfunction of B turbine bypass valves compounded by operator error.

Data from an actual excessive main feedwater transient at a B&W 177-FA plant is important as a basis for the guidelines because it:

- Provides information on plant response, and
- Yields confirmation of TRAP2 predictions.

Following is a description of an excessive main feedwater transient that occurred at TMI-1 on June 20, 1974. The overfill resulted in a low pressure trip from 17.8% power.

Summary

During turbine overspeed testing malfunctioning turbine bypass valves caused a condition where the B turbine bypass valves and the B OTSG connected turbine stop valves were open (1 & 2), and the A OTSG connected turbine stop valves closed (3 & 4). The B turbine header pressure was reduced sufficiently low to actuate the steam line rupture detection system. Actuation of the steam line rupture detection system secured the feedwater flow to the B OTSG boiling it down to zero inches. The rupture detection system was bypassed while the feedwater ICS station was in automatic causing the feedwater to demand full flow. This cooled and depressurized the primary system to the low pressure trip setpoint causing a reactor trip on low RCS pressure.

Plant Conditions Prior To Transient

1. Reactor Power Level 17.8%
2. Tave 578°F
3. Makeup Tank Level 50 inches
4. RC System Press 2155 psig
5. RC Flow 100%
6. Pressurizer Level 220 inches
7. Effective Full Power Days .75
8. RC Boron 1351 ppm
9. ICS Hand/Auto Station Status
   a. Steam Generator/Reactor Demand - Manual
   b. Reactor Demand (Bailey) - Manual
   c. Turbine Generator - Manual
   d. Feedwater Valves - Auto

e. Loop A and Loop B Bypass Valves - Auto
f. Feedwater Pumps A & B - Manual

10. "A" Loop Header Pressure Selected For Indication

Sequence of Events

A. Generator Unloaded

Generator unloaded, generator breakers opened, and field breaker opened. During this period the A bypass valves appeared to operate properly to maintain indicated header press. The "B" bypass valve demand increased to 50% and held. When the generator breakers were opened the indicated header pressure increased and the A bypass valves demand increased to 50%, and the "B" bypass valve demand increased to 100%. The indicated header pressure (A) stabilized at setpoint.

B. Turbine Overspeed Trip Test (Prior to Reactor Trip)

1. Operator verified header pressure stable from indication and turbine.
2. Operator placed turbine rate of speed change to slow (60 rpm/min) and pushed the turbine "Overspeed Test" pushbutton.
3. The turbine overspeed trip occurred in approximately 2.5 minutes at approximately 1960 rpm.
4. Indicated header pressure increased when the turbine tripped.
   a. The "A" bypass valves received a demand to open and in fact indicated header pressure did stabilize at setpoint.
   b. The "B" bypass valves received a demand to close at turbine trip and then demand slowly increased to 100% open in approximately 3 minutes.

C. Prepared for second overspeed trip as planned. (Lead to Reactor Trip)

1. Operator verified that indicated header pressure was stable, reset the turbine trip (Turbine speed approximately 1700 rpm), and placed the rate of turbine increase to "Fast" (180 rpm/min).
2. Operator pushed the "1800" rpm speed set.

NOTE: At time the turbine was reset the "B" bypass valves demand was nearly 100% open.

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D. Transient (See Attached Figures)

1. When 1800 speed set was pushed, the #1 and #2 turbine stop valves from the B steam generator opened properly. The #3 and #4 stop valves from the "A" steam generator did not open. According to the GE representative this will happen if the differential pressure across the valves is greater than 13% of 900#. The valves were tested several times after occurrence and found to be operating properly. This would indicate that the pressure in the B header was already at least 120 psig less than the A header pressure.
2. Because the B bypass valves were open and the B steam generator was supplying the entire demand of the turbine, the pressure in the B turbine header started decreasing rapidly.
3. The pressure in the B steam header dropped to below 600 psig actuating one channel of the steam line rupture detection system. The CRO promptly "Defeated" the remaining three actuation channels. The steam line rupture actuation automatically secured the feedwater to the B OTSG causing it to boil dry and remain in that condition for about 2.5 minutes.
4. Tave and RC system pressure were increasing rapidly. When Tave reached approximately 600°F, the CRO placed the diamond control panel in manual and drove control rods in to stop pressure and temperature increase. Letdown was manually increased to take care of reactor coolant expansion.
5. At about this time the CRO took manual control of both bypass valves and closed them both.
6. Another CRO tripped the turbine and defeated the actuated steam line rupture detection system on the B loop. This immediately restored the signal to the ICS feedwater stations which were still in automatic to maintain minimum level in the B OTSG (approximately 30").
7. The sudden influx of feedwater into the steam generator caused Tave and RCS pressure to drop rapidly. The CRO immediately took manual control of the B feedwater valve and started to close it. The transient was too rapid however and the reactor protection system low pressure trip was actuated, shutting down the reactor approximately 1 minute after the steam line rupture detection system for the "B" loop was completely defeated.

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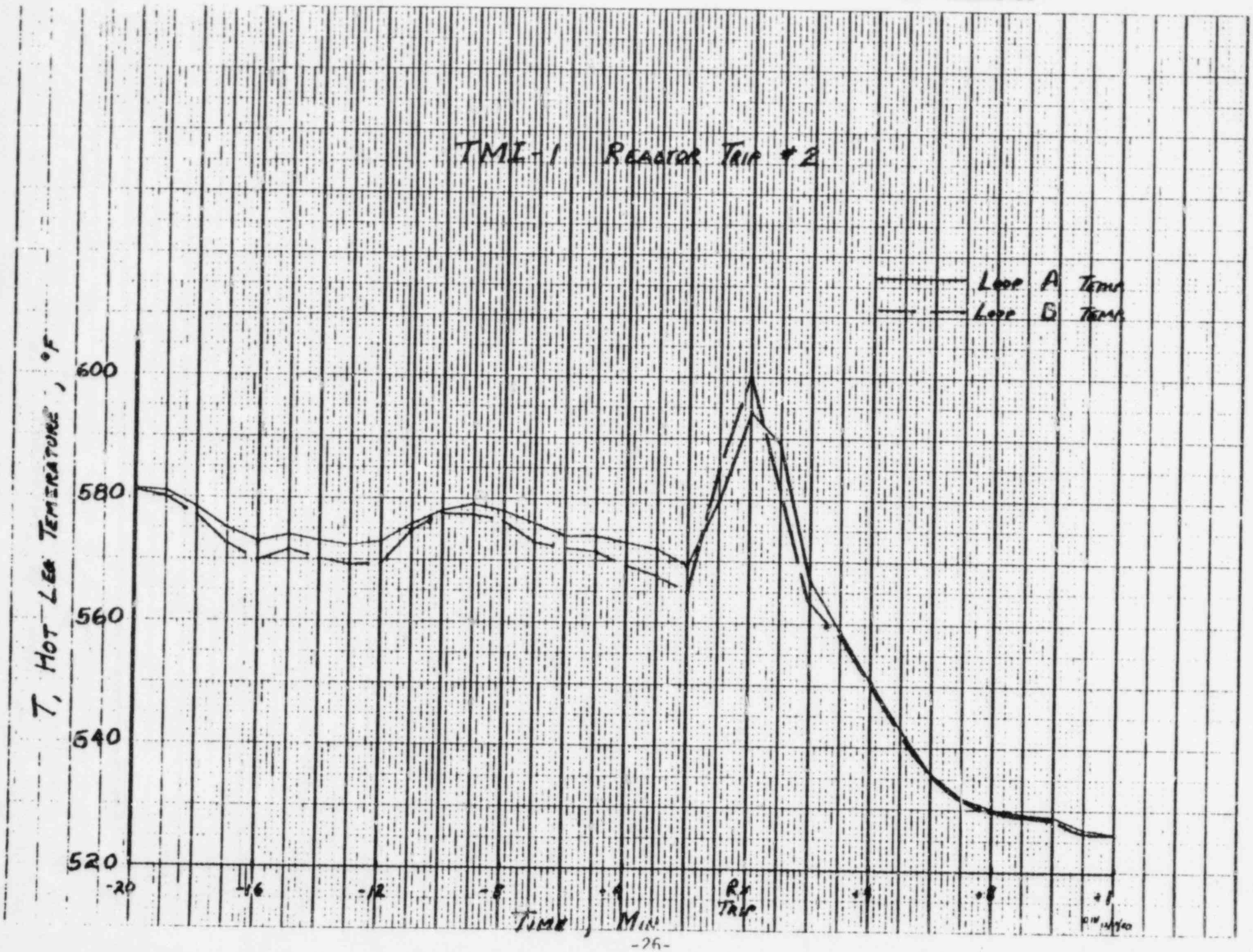

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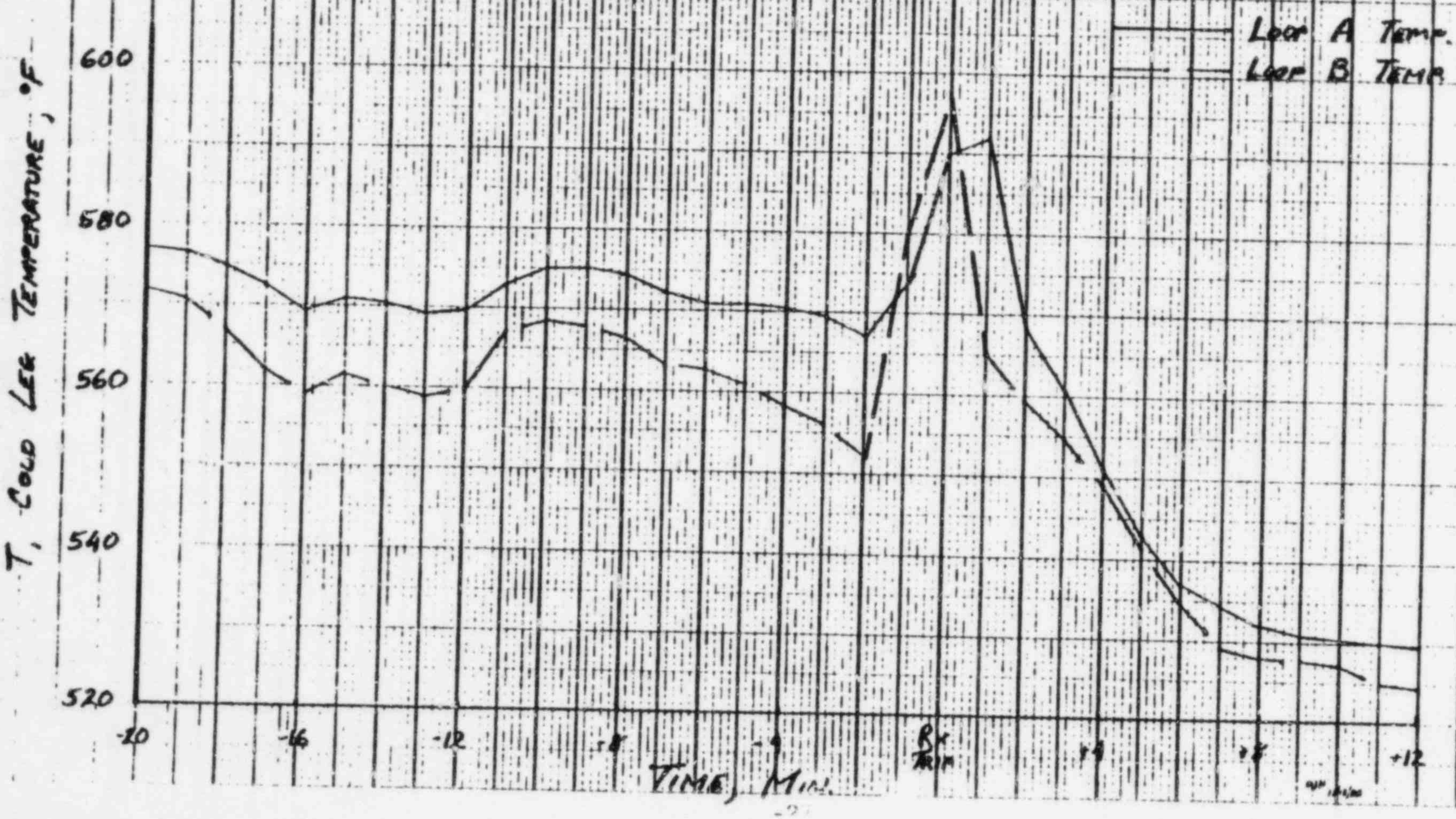
TMI-1 REACTOR TRIP #2



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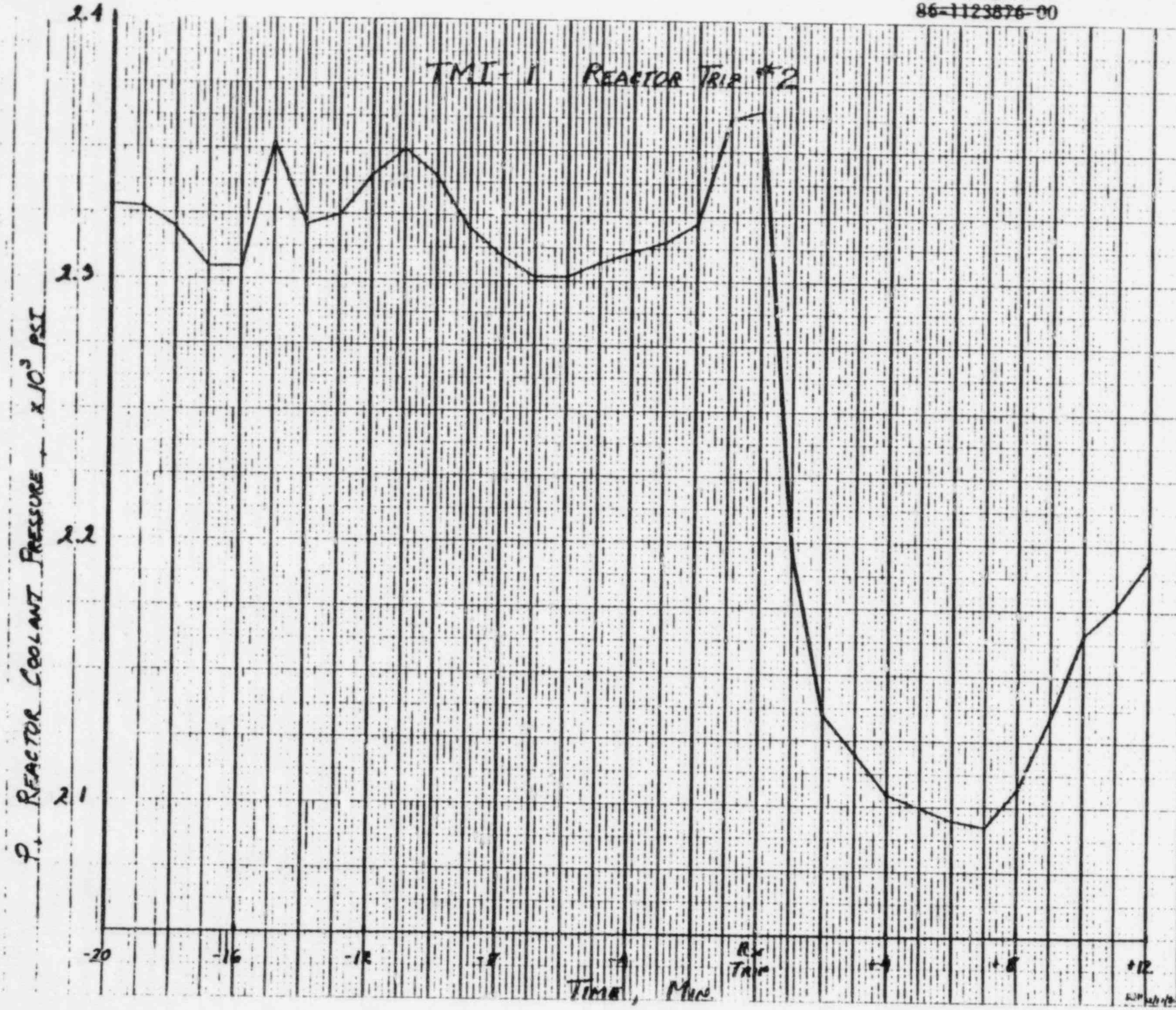
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TMI-1 REACTOR TRIP #2
P_t REACTOR COOLANT PRESSURE, $\times 10^3$ PSI
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2.3
2.2
2.1
-20
-16
-12
-8
-4
Rx TRIP
+4
+8
+12
TIME, MIN

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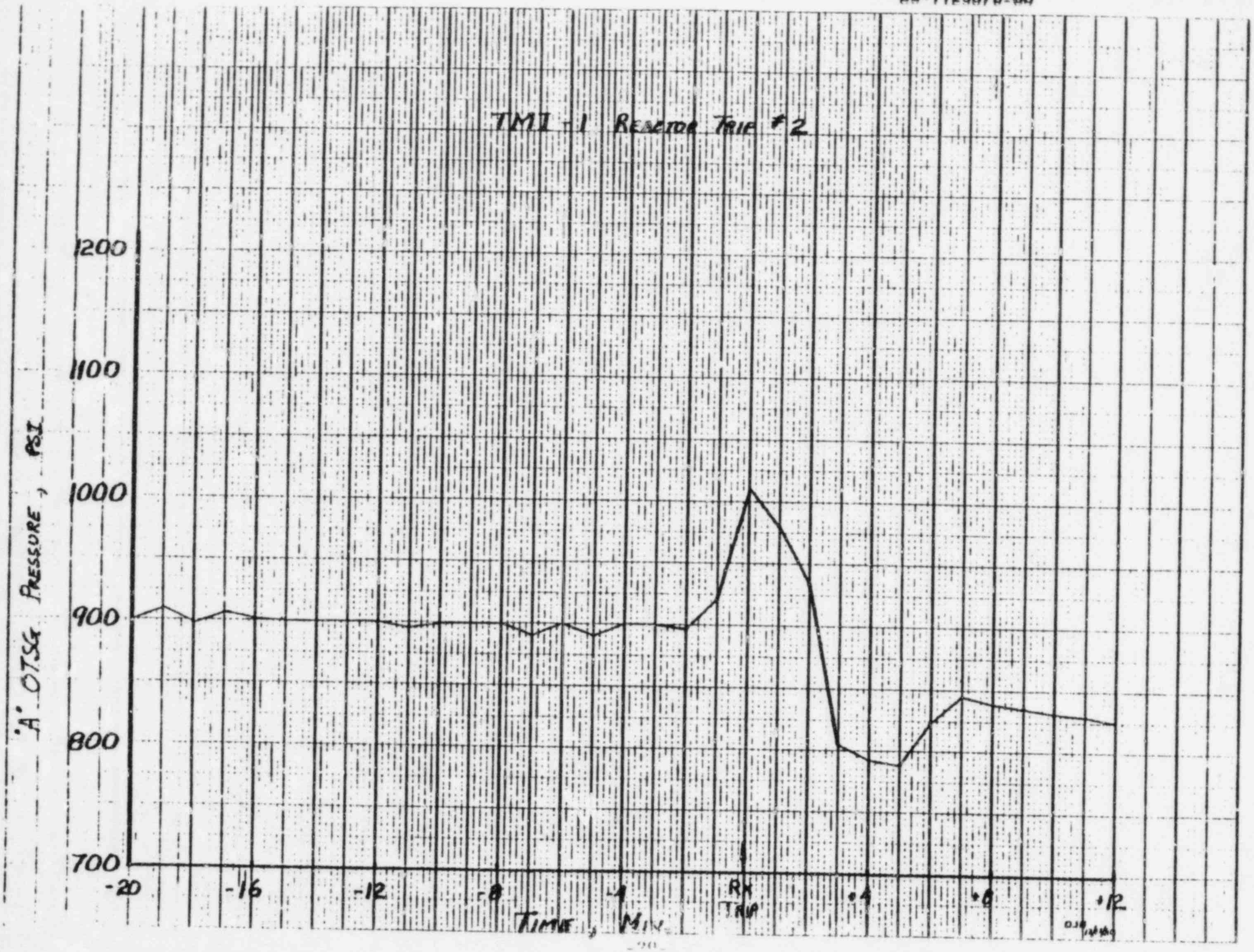

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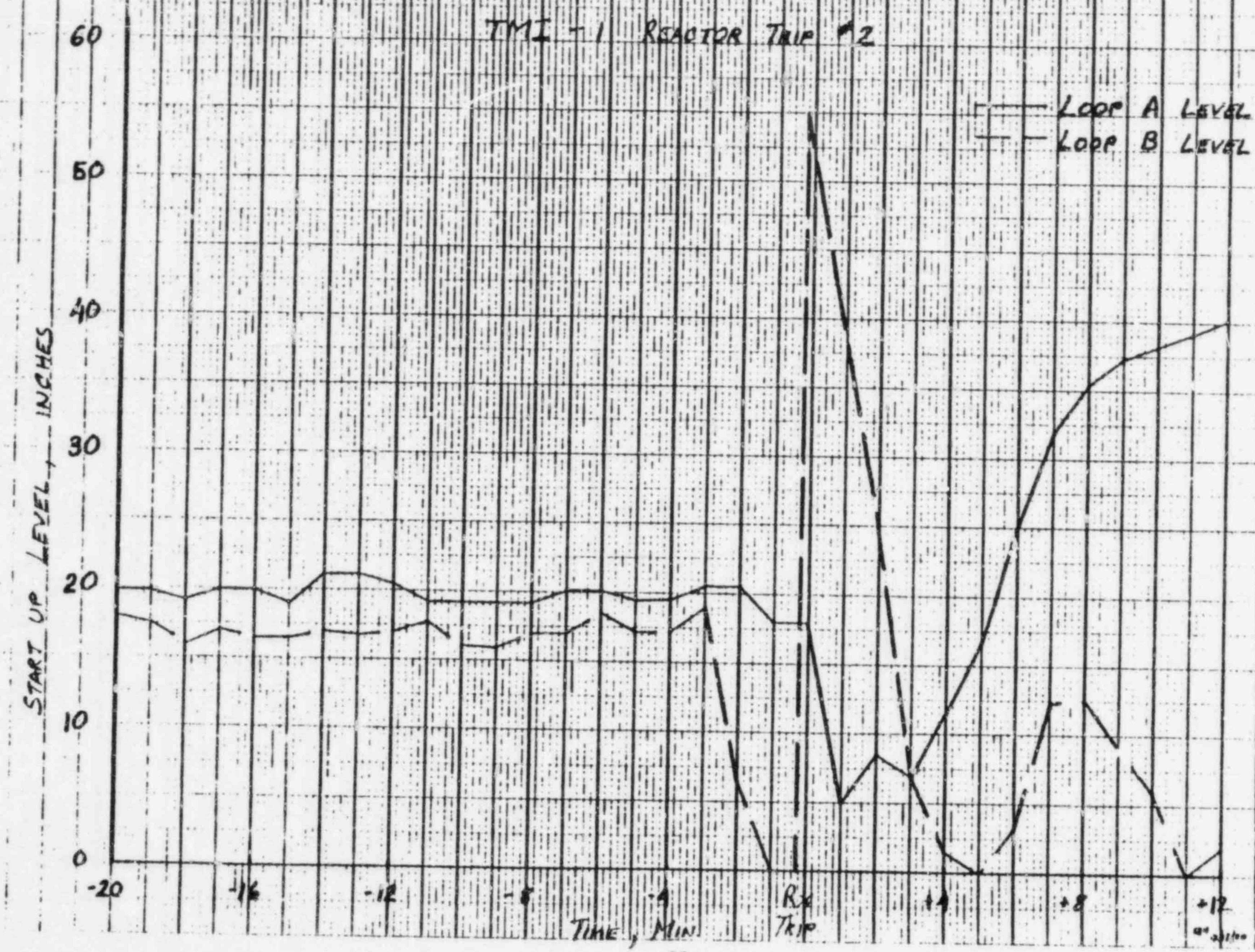

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TITLE ATOG Transient Information Document: Loss of Offsite/Onsite Power - TMI-1

PREPARED BY E. A. Hiltunen EAH REVIEWED BY M. E. Newkirk

TITLE Asst. Engineer DATE 4-29-81 TITLE Engineer DATE 5-4-81

PURPOSE:

This document summarizes the analytical basis of the Abnormal Transient Operating Guidelines for a Loss of Offsite/Onsite Power Event at GPU's Three Mile Island-Unit One.

SUMMARY OF RESULTS (INCLUDE DOC. ID'S OF PREVIOUS TRANSMITTALS & SOURCE CALCULATIONAL PACKAGES FOR THIS TRANSMITTAL)

The ATOG analytical basis is summarized in the attached writeup.

Note: 1. Revisions to the existing P-T plots used in Appendix D of the ANO-1 ATOG were produced for this contract. These plots, drawn using the TMI-1 natural circulation P-T plotting format have been released separately (see 86-1125356-00).

2. The TRAP analytical results for the TMI-1 LOOP event have also been released separately (see 86-1125435-00).

DISTRIBUTION

86-1123921-00

TRANSIENT INFORMATION DOCUMENT

for

Loss of Offsite/Onsite Power

at

Three Mile Island-Unit 1

Originated by: Edwin F. Hiltunen

Reviewed by: M. E. Newlin

TABLE OF CONTENTS

I. INTRODUCTION

The following Transient Information Document (TID) covers the Loss of Offsite/Onsite Power (LOOP) event for GPU's Three Mile Island Unit 1. The major scenarios based upon this initiating event are shown on the LOOP Event Tree, B&W Drawing Number 02-1120153F, Rev. 1 (Ref. 1).

The analysis was made using the TRAP code (Reference 21). The selected path includes correct recovery of MU and EFW, with a full open failure of one MSSV on OTSG-B. The path originates at grid location F-22, sheet 1 of 3, on the TMI-1 LOOP Event Tree and deviates from the main success path at grid location E-19, sheet 1 of 3. A separate transmittal contains the analytical results for this event (see Reference 55).

The intent of this document is to provide the guideline writers with the necessary analytical information and to serve as a documented link between the guidelines and the analysis. A comparison of characteristics of the major systems at TMI-1 and Arkansas Nuclear One Unit One (ANO-1) is included along with specific modifications needed to write the TMI-1 Appendix D based upon the ANO-1 ATOG Appendix D.

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6″

II. MAJOR PLANT PARAMETERS

A. Control Functions and Systems

The ATOG Program assumes that a plant can be brought to a safe shutdown if five "functions" are controlled.

Function	Major System Used to Attain Control
Reactivity	Control Rods Boration Systems Reactor Protection System
Primary Inventroy	Makeup/HPI Letdown
Primary Pressure	Pressurizer PORV Pressurizer Safeties Pressurizer Heaters Pressurizer Spray
Secondary Inventory	Main Feedwater Emergency Feedwater
Secondary Pressure	Turbine Bypass Valves Atmospheric Dump Valves Steam Safety Valves

Though these are the major systems, they are not the only ones which influence plant control. Other supporting systems may affect the control of the five functions. However, these effects would also be covered by the analysis results. For example, the makeup pumps each have a lube oil system which, if it failed, might eventually lead to the failure of the makeup pumps and a loss of primary inventory control (low).

B. System Comparison

This section will compare the main systems needed for control after a Loss of Offsite/Onsite Power at ANO-1 and TMI-1, and will concentrate on those features that influence a plant's response to a transient. Two systems will be considered similar and have comparable effects on plant response if:

a. System properties (flow, pressures, capacities, etc.) are similar.

b. The system "functions" similarly. (For example, what initiates the system and what does it do once initiated.)

If two systems are considerably different, the ANO guidelines should be modified to reflect the effect of this difference.

B.1 Reactivity Control

Short term reactivity control is achieved when the reactor trips and the control rods fall into the reactor core. The following table is a listing of the various signals that trip the reactor at TMI-1 and at ANO-1. During a LOOP event the actions of both plants' reactor protection systems are similar. Longer term reactivity control is attained through the use of soluble boron to compensate for the decay of equilibrium xenon and the reactivity temperature deficit. Both TMI-1 and ANO-1 utilize the makeup/high pressure injection and chemical addition systems to bring the plant to a safe shutdown following a reactor trip. A comparison of the TMI-1 and ANO-1 letdown and makeup/high pressure injection systems can be found in Section B.2. Since ATOG does not address the effects of the chemical

addition system (i.e., long term reactivity control is not considered), no comparison of the respective systems is made. Other assumptions in the ATOG program are that the RPS, the control rods, and all safety grade systems (exclusive of the EFW and diesel generators) always work. Therefore, Anticipated Transients Without Scram (ATWS) were not considered.

TABLE 1

RPS Trip Setpoints for TMI-1 and ANO-1

TMI-1 (Reference 2)	ANO-1 (Reference 3)
Power > 105.5%	Power > 105.5%
Flux/flow/imbalance - 1.08 times rated flow (%) minus reduction due to imbalance	Flux/flow imbalance - 1.057 times rated flow (%) minus reduction due to imbalance
High RCS pressure (2300 psig) (Reference 34)	High RCS pressure (2300 psig) (Reference 34)
Low RCS pressure (1800 psig)	Low RCS pressure (1800 psig)
Variable low RCS pressure - (11.75 T_{out} - 5103) psig	Variable low RCS pressure - (11.75 T_{out} - 5103) psig
RC max. temperature (619°F)	RC max. temperature (619°F)
High RB pressure (4 psig)	High RB pressure (4 psig)

Additional Signals that Trip the Reactor

Loss of MFWPs (Reference 38)	Loss of MFWPs (Reference 38)
Turbine Trip (Ref. 38)	Turbine Trip (Reference 38)

Conclusion: Both plants behave similarly from the standpoint of reactivity control. Thus, the ANO-1 guidelines require minor modification to fit TMI-1 insofar as this area of plant response is concerned.

B.2 Primary Inventory

Primary inventory is controlled by makeup and letdown. Attached are simplified P&IDs of the makeup/high pressure injection system for each plant. Pertinent MU and LD/HPI system data for this transient is listed in Table 2.

TABLE 2

Makeup and Letdown/High Pressure Injection System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
Normal makeup	25 GPM	8	25 GPM	7
Normal seal injection	8 GPM/RCP	8	8 GPM/RCP	7
Normal seal return	3 GPM/RCP	8	1 GPM/RCP	7
Makeup flow vs. pressure with make-up control valve fully open	2200 psig 130 GPM 2000 psig 150 GPM 1800 psig 170 GPM 1600 psig 190 GPM	39 39 39 39	2200 psig 140 gpm 2000 psig 160 GPM 1800 psig 180 GPM 1600 psig 200 GPM	9 9 9 9
Normal letdown	45 GPM	8	53 GPM	7
Letdown temperature	120°F	10	120°F	7
Letdown isolation on reactor trip	yes	46	N/A	-
HPI flow vs. pressure for two HPI pumps with control valves fully open	2600 psig 420 GPM 2400 psig 525 GPM 2200 psig 600 GPM 2000 psig 670 GPM 1800 psig 730 GPM 1600 psig 785 GPM 1400 psig 835 GPM	39 39 39 39 39 39 39	2600 psig 400 GPM 2400 psig 495 GPM 2200 psig 580 GPM 2000 psig 645 GPM 1800 psig 705 GPM 1600 psig 755 GPM 1400 psig 805 GPM	9 9 9 9 9 9 9
ESAS actuation set-point	1600 psig	38	1500 psig	14

Conclusion: Both plants behave similarly from the standpoint of primary inventory control, aside from the ESAS setpoints. Therefore, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

B.3 Primary Pressure

Primary pressure control is achieved by the pressurizer heaters, pressurizer spray system, relief, and code safety valves. System data for TMI-1 and ANO-1 are tabulated below.

TABLE 3

Primary Pressure Control System Data for TMI-1 and ANO-1

	TMI-1	Ref.	ANO-1	Ref.
Pressurizer heater bank-on setpoints				
1	<2135 psig	8	<2135 psig	15
2	<2135 psig	8	<2135 psig	15
3	2135 psig	8	2135 psig	15
4	2120 psig	8	2120 psig	15
5	2105 psig	8	2105 psig	15
Pressurizer heater bank-off setpoints				
1	2155 psig	8	>2155 psig	15
2	2155 psig	8	>2155 psig	15
3	2147 psig	8	2155 psig	15
4	2140 psig	8	2140 psig	15
5	2125 psig	8	2125 psig	15
Pressurizer heater bank power				
1	Power output by bank not available		84 KW	51
2			84 KW	51
3			378 KW	51
4			504 KW	51
5			588 KW	51
Total	1638 KW	16	1638 KW	51
Pressurizer heaters powered by diesel generators post LOOP	126 KW	43	168 KW	42

	TMI-1	Ref.	ANO-1	Ref.
Pressurizer spray valve*				
open	2205 psig	17	2205 psig	18
close	2155 psig	17	2155 psig	18
Pressurizer electromatic relief valve				
open	2450 psig	34	2450 psig	34
close	2400 psig	34	2400 psig	34
capacity	100,000 LB/H	17	100,000 LB/H	17
Pressurizer code safety valves				
open	2500 psig	34	2500 psig	18
capacity	623,400 LB/H	17	600,000 LB/H	18

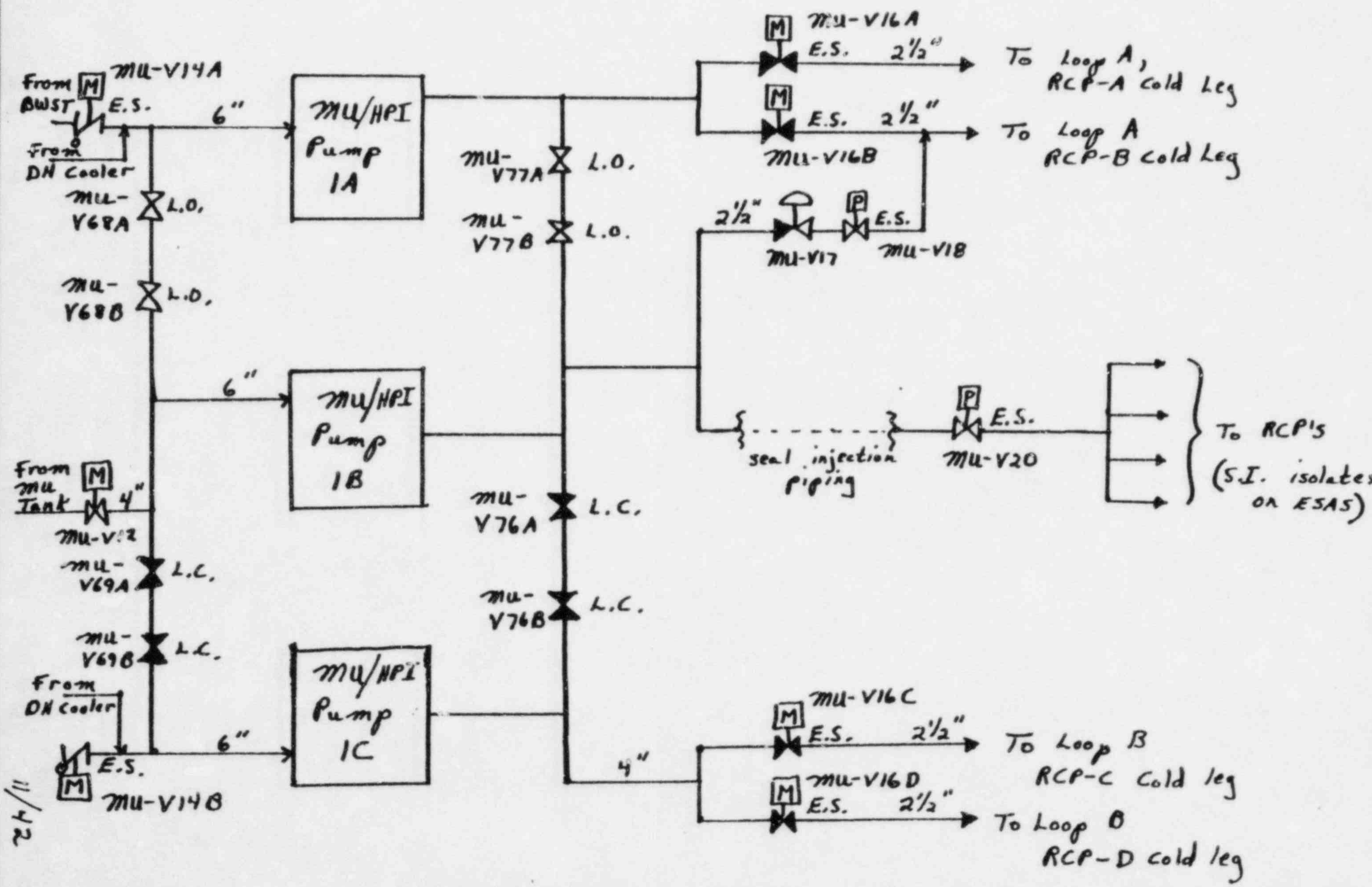
Conclusion: Both plants behave similarly from the standpoint of primary pressure control. Thus, the ANO-1 guidelines will be applicable to TMI-1 insofar as this area of plant response is concerned.

*The pressurizer spray is unavailable during a LOOP at both plants because the RCPs have tripped.

86-1123921-00

ref. dwgs no.
16-1108693D-00,
16-1108694D-00
(ref. 4 + ref. 5)

TMI-1 simplified MU/HPI System



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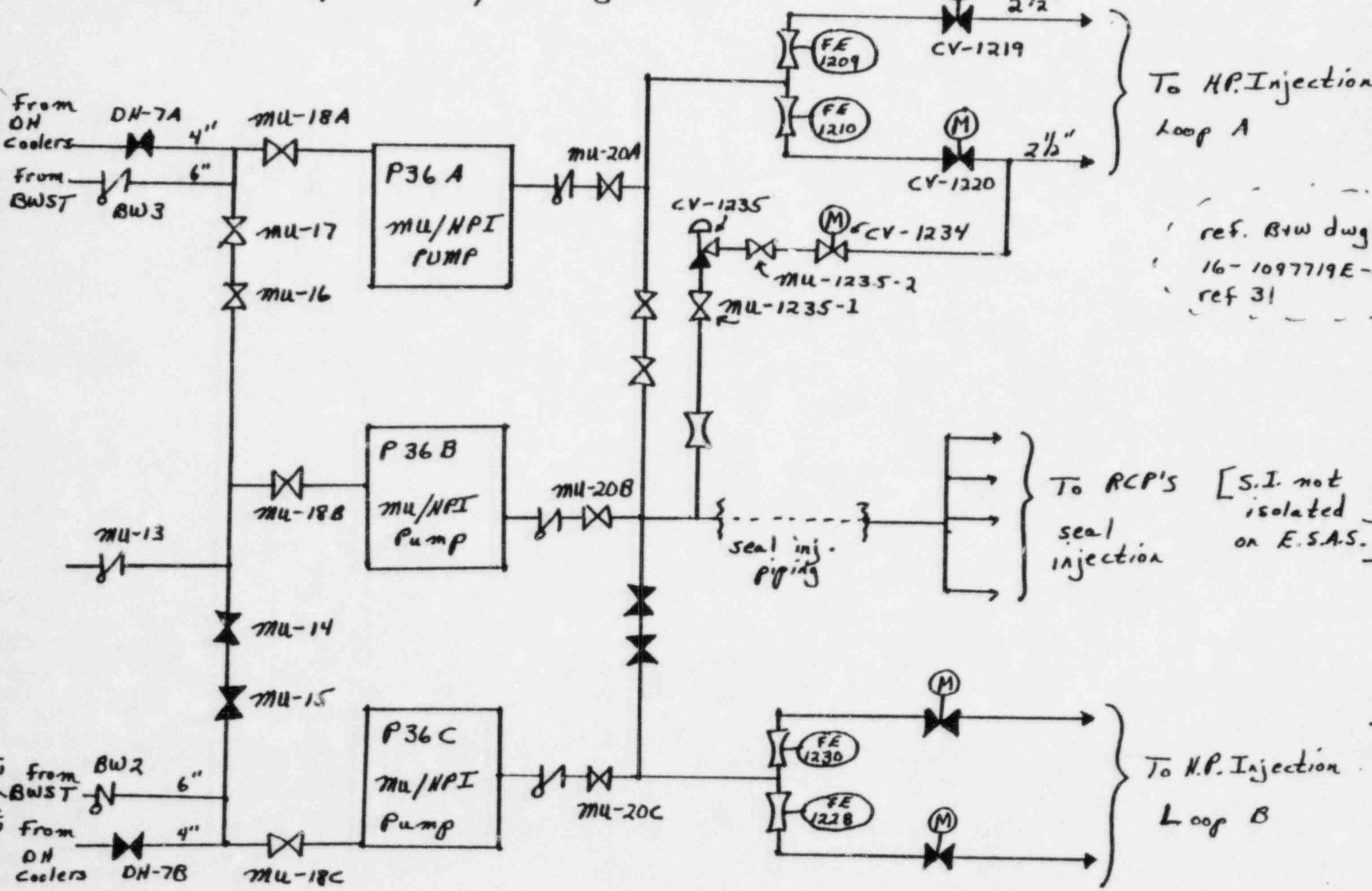
86-1123921-00

ANO-1 Simplified MU/HPI system



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B.4 Secondary Inventory

Secondary inventory is controlled via the main and emergency feedwater systems. Attached are simplified P&IDs of these systems for TMI-1 and ANO-1. The primary differences which are apparent from these diagrams are in cross-connect design and flow control valve arrangement. The ANO-1 feedwater trains are completely separate except for a normally closed ICS controlled cross-connect valve just downstream of the main feedwater pumps. The TMI-1 trains feed into common headers both before and after the fourth and second stage feedwater heaters. There are no valves to impede flow from pump A to OTSG B or from pump B to OTSG A.

ANO-1 has a low load bypass in addition to the normal start-up bypass. TMI-1 has only the start-up bypass line. TMI-1 has diaphragm-actuated flow control valves, whereas all major valves at ANO-1 are motor actuated. Table 4 lists pertinent data for the TMI-1 and ANO-1 main feedwater systems.

TABLE 4

TMI-1 and ANO-1 Main Feedwater System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
Normal flow, both pumps	10.6×10^6 LB/H	23	11.1×10^6	22
Feedwater temperature	457°F	23	457°F	22
Pump discharge pressure	1225 psia	36	1088 psia	22
Signals that trip MFWPS				
Thrust bearing wear				
forward	Trips, setpoint unknown	37	5 MILS	25
reverse	Trips, setpoint unknown	37	35 MILS	25
Rotor vibration	unknown		6.5 MILS	25
Turbine Overspeed	15% above max. full load speed	24	6215 RPM	25
Bearing oil pressure low	<4 psig	37	10 psig	25
FWP discharge pressure high	unknown		1150 psig	25
FWP suction pressure low	pump suction valve closed	37	230 psig	25
FWP low flow	1000 GPM	36	1600 GPM	25
Vacuum	<23 IN. HG	37		
Other	(1) Number of condensate/ condensate booster pumps less than the number of feedwater pumps running will trip the FWP turbine that was reset last. (2) Manual.	37		

Feedwater valve control logic -

TMI-1

- Low Load Block Valve
  There is no low load block valve at TMI-1.

- Start-up Valve
  Normally ICS controlled. SU and MFW control valves operate sequentially. When SU control valve flow approaches capacity during start-up, the main control valve begins to open (Reference 36).

- Main Block Valve
  The main block valve opens when the start-up valve reaches approximately 90% open. The block valve closes when the start-up valve reaches approximately 70% closed (Reference 37).

- Reactor Trip
  No actions occur.

- Feedwater Pump Trip
  No actions occur.

- Reactor Coolant Pumps Tripped
  A trip of all four reactor coolant pumps will result in EFW initiation to 50% on the operating range and, therefore, in a closing of the main feedwater valves (Reference 26).

- FW Pump Speed
  Feed pumps are variable speed and are controlled by feedwater valve P and demand as a function of load. During normal operation, the position of the regulating valves and the speed of the feedwater pumps is controlled by the ICS; however, manual control can be instituted at any time (References 24, 37).

ANO-1 (Reference 27)

- Low Load Block Valve
  The low load block valve opens when the start-up valve reaches 80% open. The low load block valve closes when the start-up valve reaches 50% closed.

- Start-up Valve
  The start-up valve is controlled by the ICS which maintains feed flow proportional to reactor power level.

- Main Block Valve
  The main block valve opens when feedwater demand exceeds 50%. The main block valve closes if feedwater demand drops below 45%.

- Reactor Trip
  A reactor trip causes the main block valve and the low load block valve to shut. Also, a preselected feedwater pump is tripped.

- Feedwater Pump Trip
  A feedwater pump trip causes the main block valve and the low load block valve associated with that pump to close. Also, after a single feedwater pump trip, the ICS opens the cross-connect valve.

- Reactor Coolant Pumps Tripped
  Trip of all four reactor coolant pumps causes the low-load block valve to close.

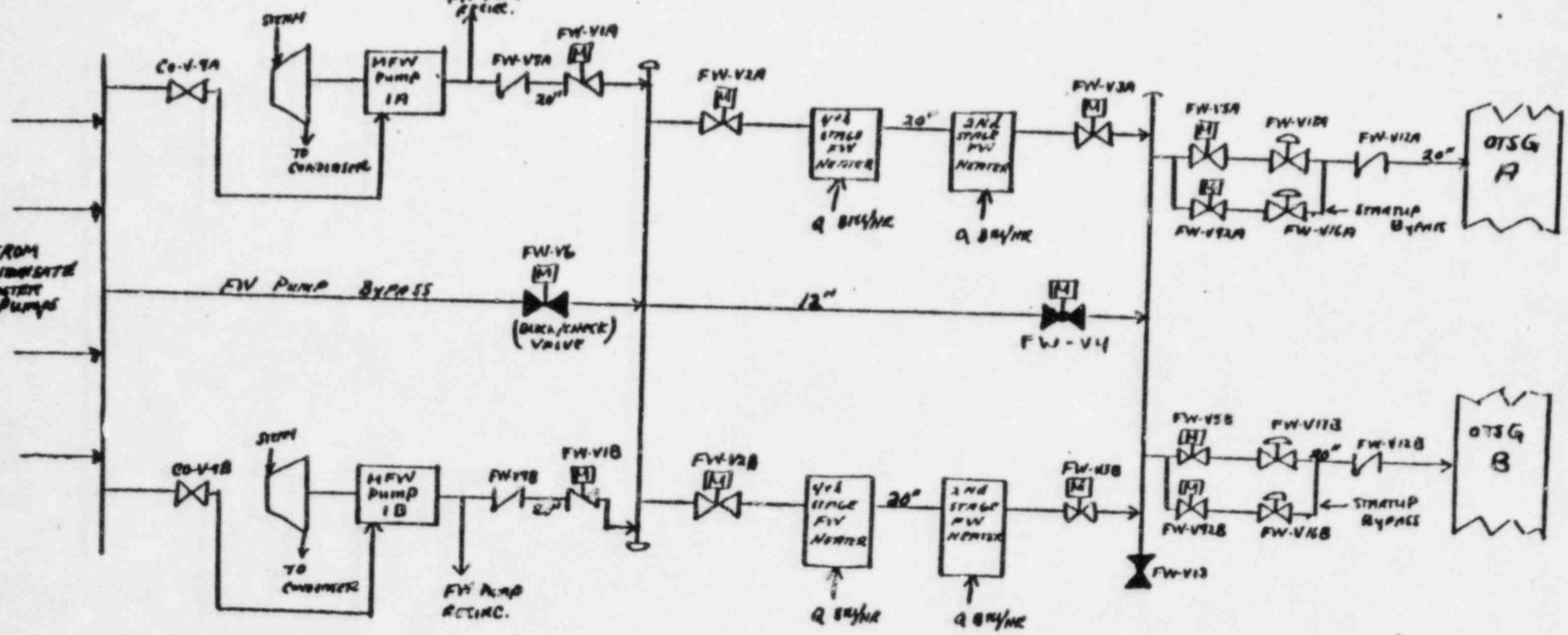
- FW Pump Speed
  After the main block valve opens, the ICS controls feedwater flow by adjusting pump speed. Until the main block valve is opened, the feedwater flow is controlled

by the pressure drop across the start-up or low-load valve.

Note from the emergency feedwater system P&IDs that all EFW pumps in each plant are capable of feeding either OTSG if necessary. ANO-1 has bypass lines (CV-2627 and CV-2626) in case the EFW control valves CV-2670 and/or CV-2620 fail shut, whereas TMI-1 does not have this feature. Table 5 lists EFW system performance data for each plant.

TMI-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

Ref. B&W DWGs No. 16-1086 82D-00
ref. 19



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ANO-1 SIMPLIFIED MAIN FEEDWATER SYSTEM

(Ref. B&W DOC. NO. 16-1097712E-00)
ref. 20

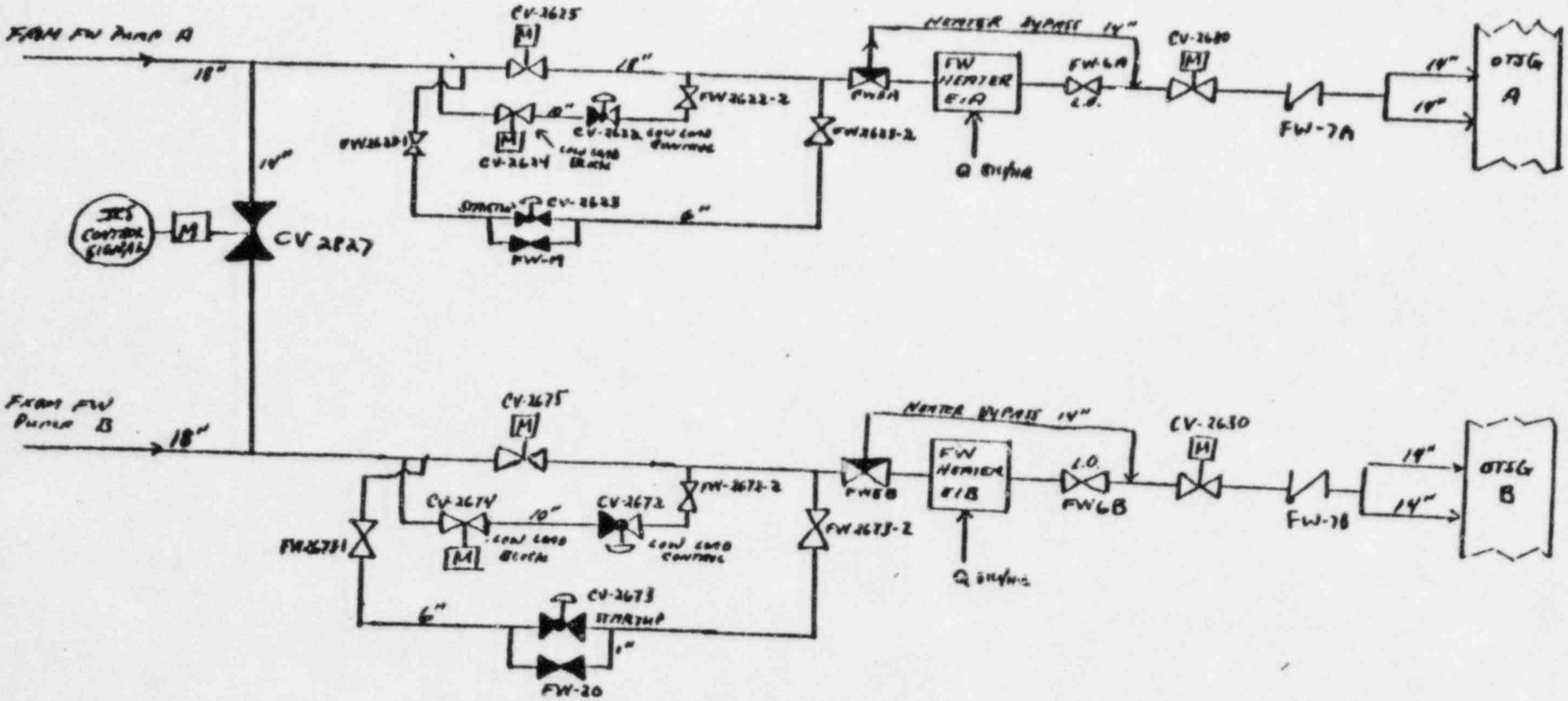

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TABLE 5

TMI-1 and ANO-1 Emergency Feedwater System Performance Data

	TMI-1	Ref.	ANO-1	Ref.
Number of motor-driven EFWPs	2	36	1	12
Capacity	460 GPM @ 2700 FT H_2O (EACH)	36	780 GPM @ 2700 FT H_2O	28
Number of steam-driven EFWPs	1	36	1	12
Capacity	920 GPM @ 2700 FT H_2O	36	720 GPM @ 2700 FT H_2O	28
Initiating signals	- Loss of both MFWPs	38	- Low OTSG level (18 in.)	28
	- Trip of all RCPS	38	- Trip of both MFWPs (if Rx power >5%)	28
	- Manual	38	- Trip of all RCPS	28
			- SLBIC starts steam-driven pump	28
			- Manual	28
Initiation time after MFWP trip with LOOP	TDEFWP - immediate	44	TDEFWP - immediate	52
	MDEFWP's -		MDEFWP - 100 sec.	52
	Non-ESAS 15. sec.	44		
	ESAS 30. sec.	44		

EFWP Design Capacities:

	TMI-1 EF-PIA	TMI-1 EF-PIB	Ref.	ANO-1	Ref.
Flow vs. head for motor-driven pump	100 GPM 3250 FT	3250 FT	40	200 GPM 3400 FT	15
	200 GPM 3200 FT	3200 FT	40	300 GPM 3400 FT	15
	300 GPM 3090 FT	3090 FT	40	400 GPM 3300 FT	15
	400 GPM 2900 FT	2900 FT	40	500 GPM 3200 FT	15
	500 GPM 2630 FT	2625 FT	40	600 GPM 3000 FT	15
	600 GPM 2200 FT	2180 FT	40	700 GPM 2800 FT	15
Flow vs. head for steam-driven pump	200 GPM 2990 FT		40	200 GPM 3500 FT	15
	400 GPM 2950 FT		40	400 GPM 3350 FT	15
	600 GPM 2870 FT		40	600 GPM 3000 FT	15
	800 GPM 2760 FT		40	800 GPM 2550 FT	15
	1000 GPM 2550 FT		40	1000 GPM 1850 FT	15

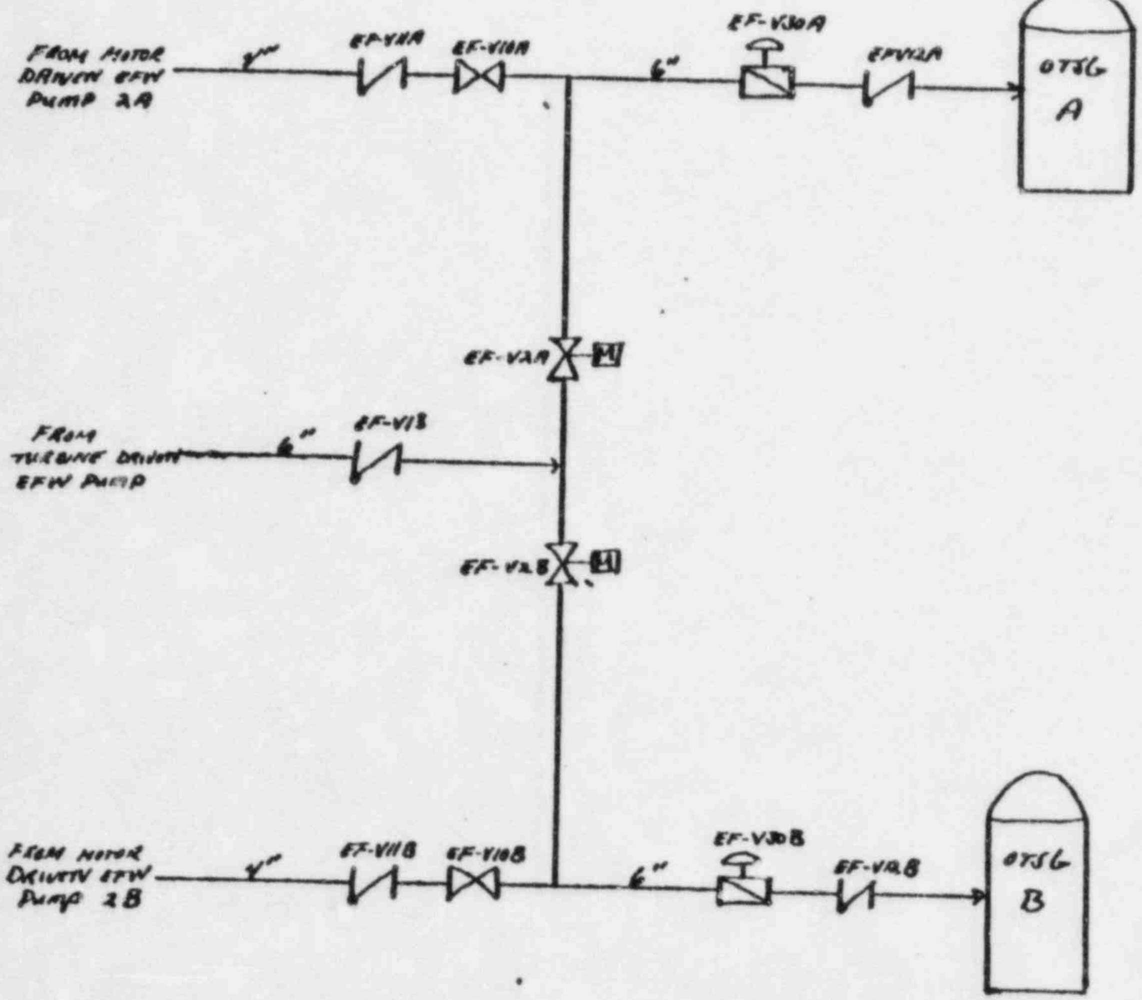
One other system affects control of secondary inventory at TMI-1 and at ANO-1. This is a steam and/or feedwater isolation system which actuates to isolate one or both steam generators following a steam line break. The TMI-1 steam line rupture detection system (SLRDS) and the steam line break instrumentation and control (SLBIC) system at ANO-1 perform the following functions:

TABLE 6

Comparison of TMI-1 SLRDS and ANO-1 SLBIC System

SLRDS (TMI-1)	Ref.	SLBIC (ANO-1)	Ref.
Actuation Setpoint = 600 psig -Actions Taken By System-	29	Actuation Setpoint = 600 psig -Actions Taken By System-	15
- Closes MFW block and control valves to affected OTSG only.	29	- Closes MSIVs for both OTSGs.	28
- Closes start-up MFW block and control valves to affected OTSG only.		- Closes MFW isolation valve to affected OTSG.	28
- Closes EFW control valve to affected OTSG only.	29	- Opens steam supply valve to steam-driven EFW pump.	28
- Performs identical operations on the other OTSG if low steam pressure is detected in that loop.	29	- EFW isolation valve opens on EFW initiation signals to both OTSGs.	28
		- Closes MFW isolation valve for the other OTSG if a SLBIC signal subsequently originates from that steam loop.	28

Conclusion: Due to differences between the systems used to control secondary inventory at TMI-1 and at ANO-1, each plant will respond differently to a transient in which a secondary-side depressurization occurs. The guidelines must be modified to reflect this difference.



TMI-1 SIMPLIFIED EFW SYSTEM

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ref 19

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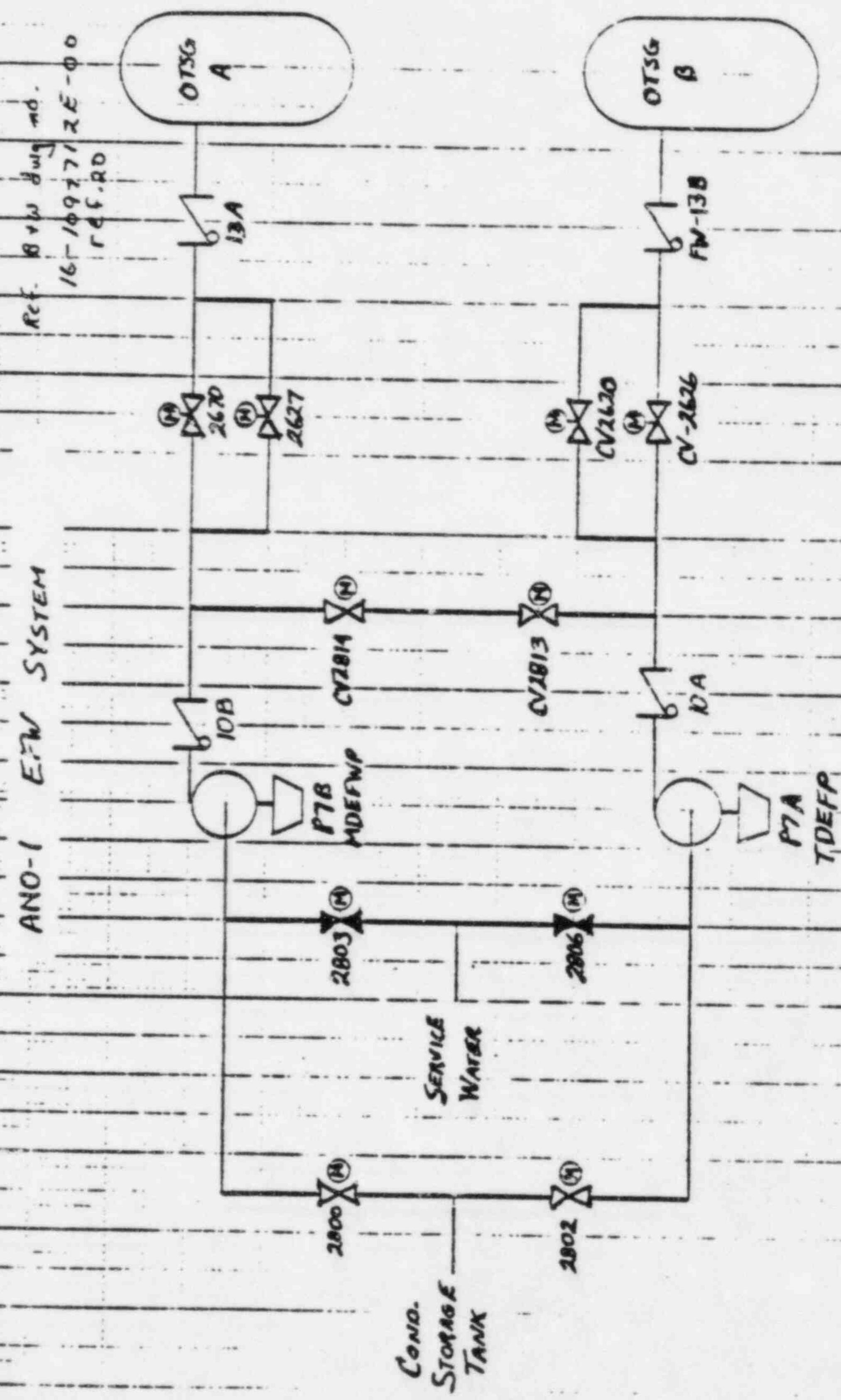


B.5 Secondary Pressure

Secondary pressure is controlled by the action of the modulating atmospheric dump (MAD) valves, the main steam code safety valves, and the condenser dump (turbine bypass) system. Attached are simplified P&IDs of the main steam systems for TMI-1 and ANO-1.

B.6 Backup Power Supplies

Power to the plant auxiliaries is not one of the ATOG control functions. However, maintaining power to these auxiliaries affects the control of all five control functions.

If offsite power is lost at ANO-1 and both Units 1 and 2 are tripped, the only backup supply is a pair of diesel generators. These can be started and loading begun in approximately 15 seconds after offsite power is lost (Reference 50). It is important to emphasize that if ESAS actuation occurs after a LOOP at ANO, some components are "shed" from the diesel generators.

If offsite power is lost at TMI-1, the situation is similar to that at ANO-1. The two emergency diesel generators rated at 3000 KW each can be started and loading begun in approximately 10 seconds after offsite power is lost (Reference 43). If an ESAS actuation occurs after a LOOP at TMI-1, selected loads are "shed" from the diesel generators.

Both plants have station batteries which maintain plant DC and vital AC power.

Conclusion: The backup power supplies are similar at ANO-1 and TMI-1.

a. Both ANO-1 and TMI-1 have diesel generators to provide backup power.

b. Upon ESAS, selected loads are shed at both plants.

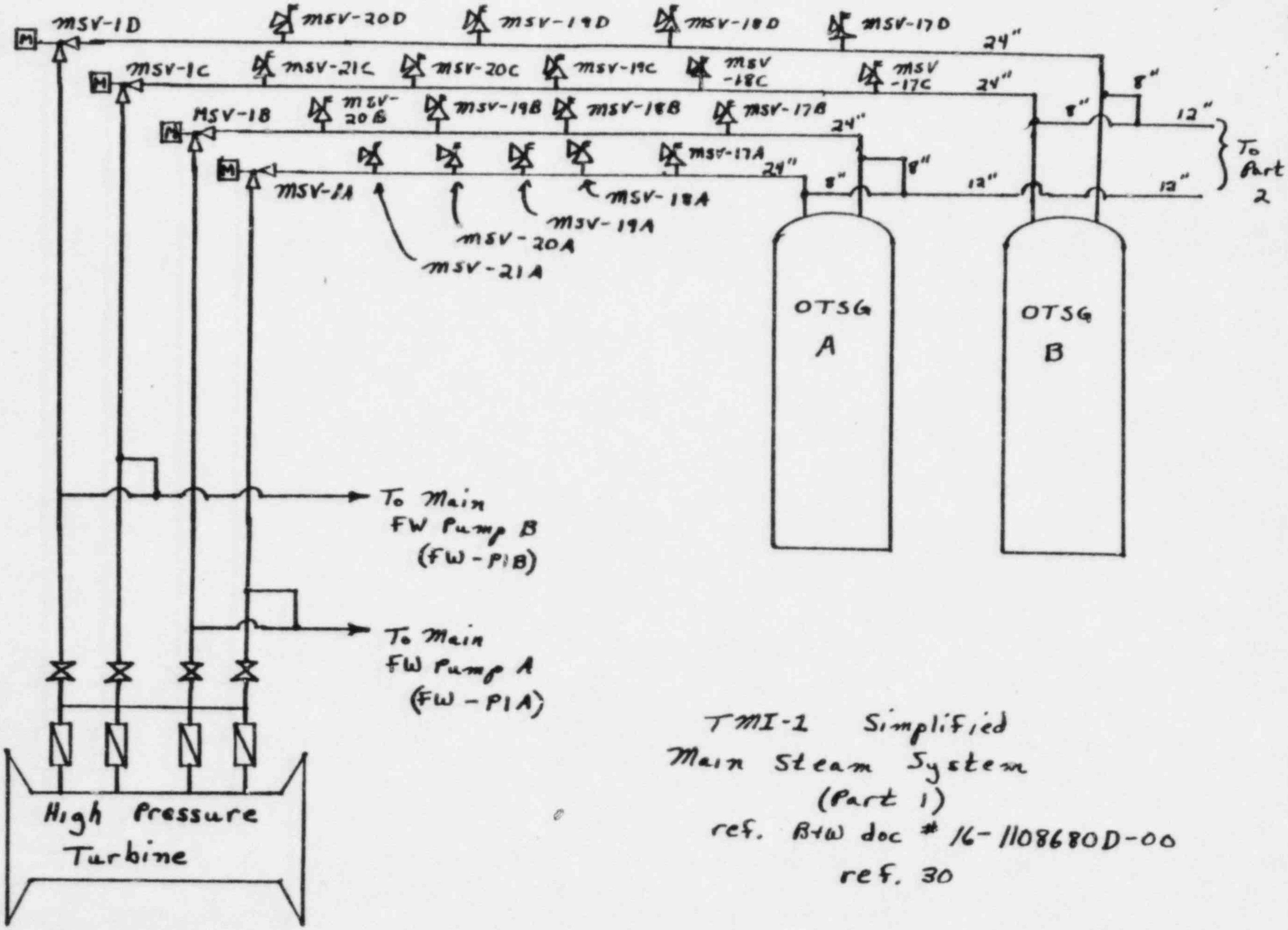
c. The components powered at ANO-1 and TMI-1 after a LOOP are similar.

TABLE 7

Main Steam System Performance Data

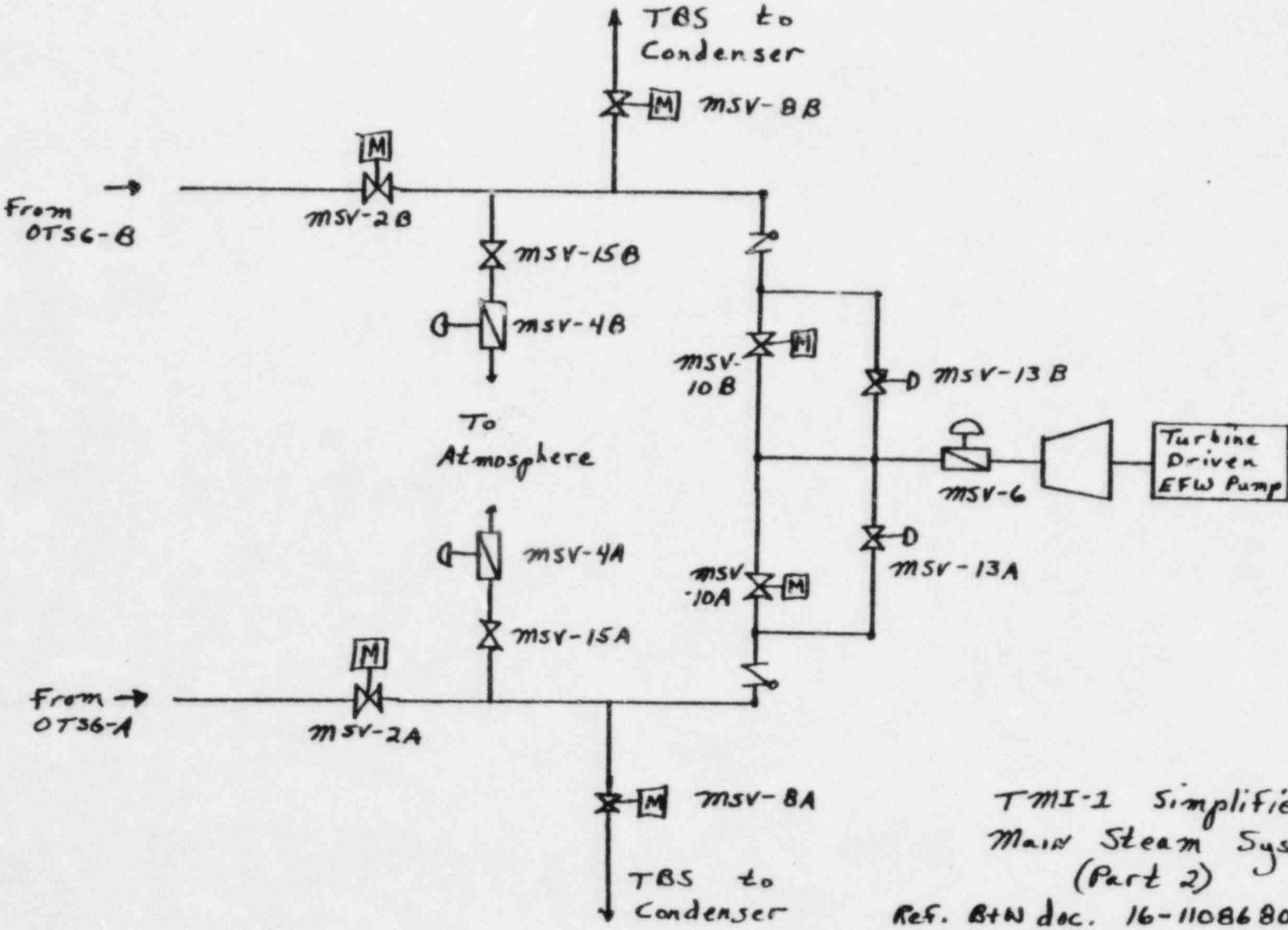
	TMI-1	Ref.	ANO-1	Ref.
MAD Valves				
Number of Valves	2	32	2	12
Lift Pressure	1026 psig	29	1020 psig	15
Full Open Pressure	1052 psig	29	1045 psig	15
Capacity (Total)	6.4%	29	5%	15
Safety Valves				
Number of Valves	18	29	16	12
Lift Pressure	2 @ 1040 psig 4 @ 1050 psig 4 @ 1060 psig 4 @ 1080 psig 4 @ 1092.5 psig	29 29 29 29 29	4 @ 1050 psig 4 @ 1070 psig 4 @ 1090 psig 4 @ 1100 psig	33 33 33 33
Condenser Dump System (Turbine Bypass)	[System unavailable post-trip in LOOP event]			

Conclusion: TMI-1 and ANO-1 will respond differently to the Loss of Offsite/Onsite Power transient insofar as the area of secondary pressure control is concerned. This is primarily due to differences between TMI-1's SLRDS and ANO-1's SLBIC systems, and due to the different capacities of the EFW systems during the first 100 seconds after the trip.



TMI-1 Simplified
Main Steam System
(Part 1)
ref. B+W doc # 16-1108680D-00
ref. 30

86-1123921-00



TMI-1 Simplified Main Steam System (Part 2)

Ref. B+W doc. 16-1108680D-00 ref. 30

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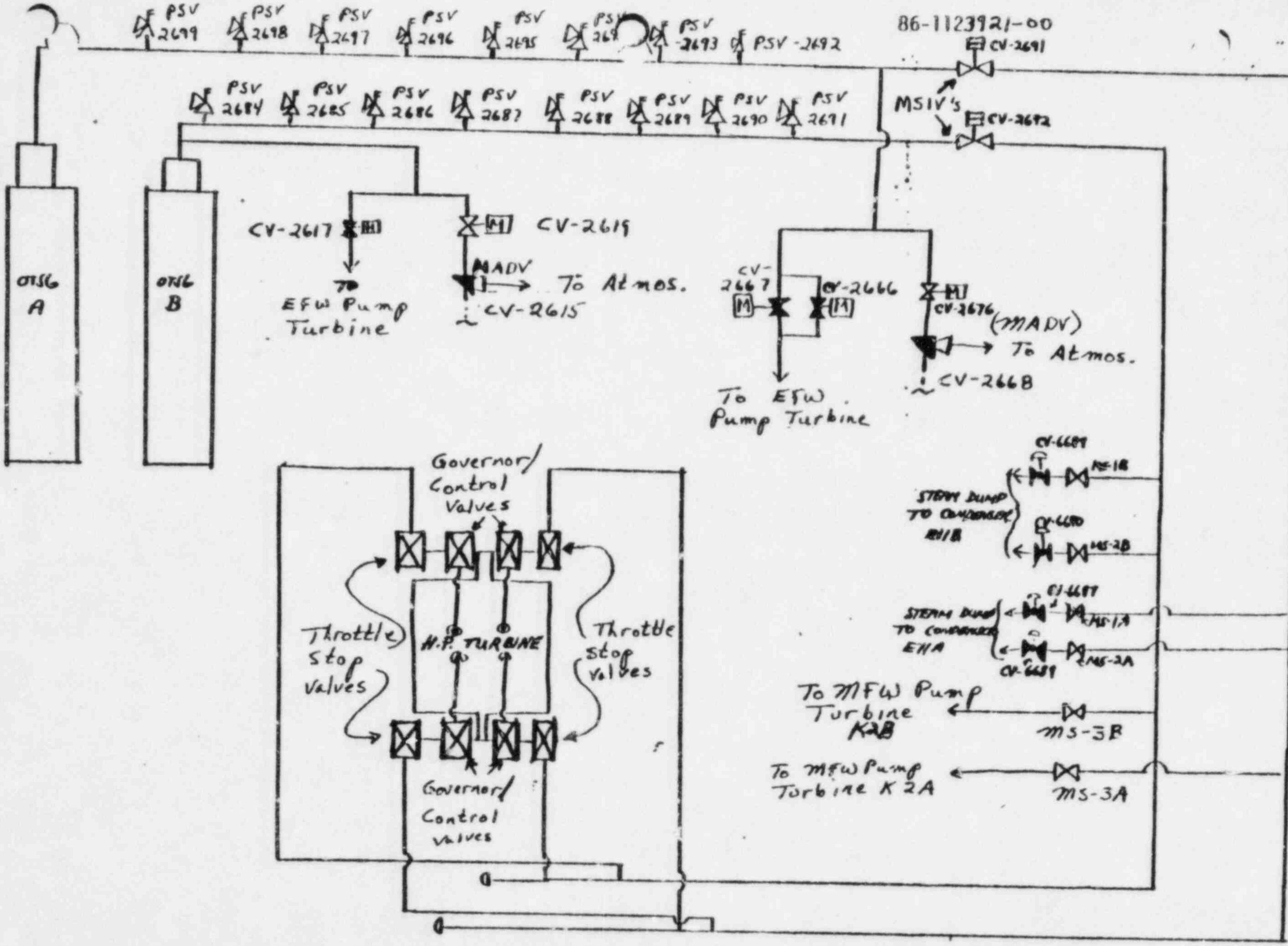

ANO-1 SIMPLIFIED MAIN STEAM SYSTEM

(Ref. B+W DOC. NO. 16-1097721E-00)

ref 31

29/42.

86-1123921-00

III. PLANT DATA

A search of the PS&C Plant Data Library was made for TMI-1 LOOP events. However, TMI-1 has not experienced a Loss of Offsite Power other than a test from 15% FP on June 25, 1974.

There have been three reactor trips at ANO which demonstrate the characteristics of a LOOP. A Loss of Offsite Power resulted in a reactor trip at ANO on February 22, 1975. This trip was used as an example for the ANO ATOG and is documented in Appendix D of ANO ATOG. The data for the trip shows the diverging hot leg and cold leg temperature during development of natural circulation.

In addition, ANO experienced a LOOP and consequent reactor trip on two other occasions, April 7, 1980 and on June 24, 1980. Appendix items A and B of this document contain descriptions of these trips. The data in Appendix B demonstrates the effects of EFW "quenching" of steam pressure and long term natural circulation. The April 7, 1980 ANO reactor trip shows about a 50 psi/min. steam pressure decrease for full EFW flow. TRAP2 has predicted a 30 psi/min. decrease for maximum EFW flow (Reference 45). Any among these three could be used as an example for the TMI-1 ATOG. As discussed in Section II, the plant differences must be taken into account when modifying the ANO guidelines.

IV. CHANGES TO ANO-1 ATOG, PART II, VOLUME 2, APPENDIX D

The Loss of Offsite/Onsite Power event is covered in Appendix D, Part 2, of the ANO-1 ATOG. The computer simulations run for ANO-1 (Reference 47) are part of the basis for Appendix D. The following is a review of the changes needed to make this portion of the ANO-1 ATOG valid for TMI-1.

1.0 General Transient Description

The major changes to this section pertain to the power distribtuion system at TMI-1 and to the SLRDS system.

1.1 Power Distribution System

The accompanying sketch (Figure 1.1A) shows a simplified diagram of this system at TMI-1. It is based upon the drawing on page 60 of Reference 53. A one line diagram of the substation is in Appendix G of this document. Though the sketch shown is non-referencable, it is included to show the substation arrangement prior to Unit 2's completion.

During normal operation, the plant auxiliaries are powered from offsite lines through the switchyard. In the event of a grid upset, the plant is powered by the turbine generator following fast transfers in the switchyard. If either auxiliary transformer (1A or 1B) is inoperable, its normal loads can be carried by the other auxiliary transformer (Reference 53). Unlike ANO-1, TMI-1 does not have start-up transformers.

Once a successful fast transfer has been completed, the load on the turbine generator amounts to approximately 4% FP. The descriptions of turbine runback and reactor trip on high RCS pressure given in the ANO-1 ATOG remain valid. The PORV, PSSV, and High Pressure Trip setpoints are the same at each plant.

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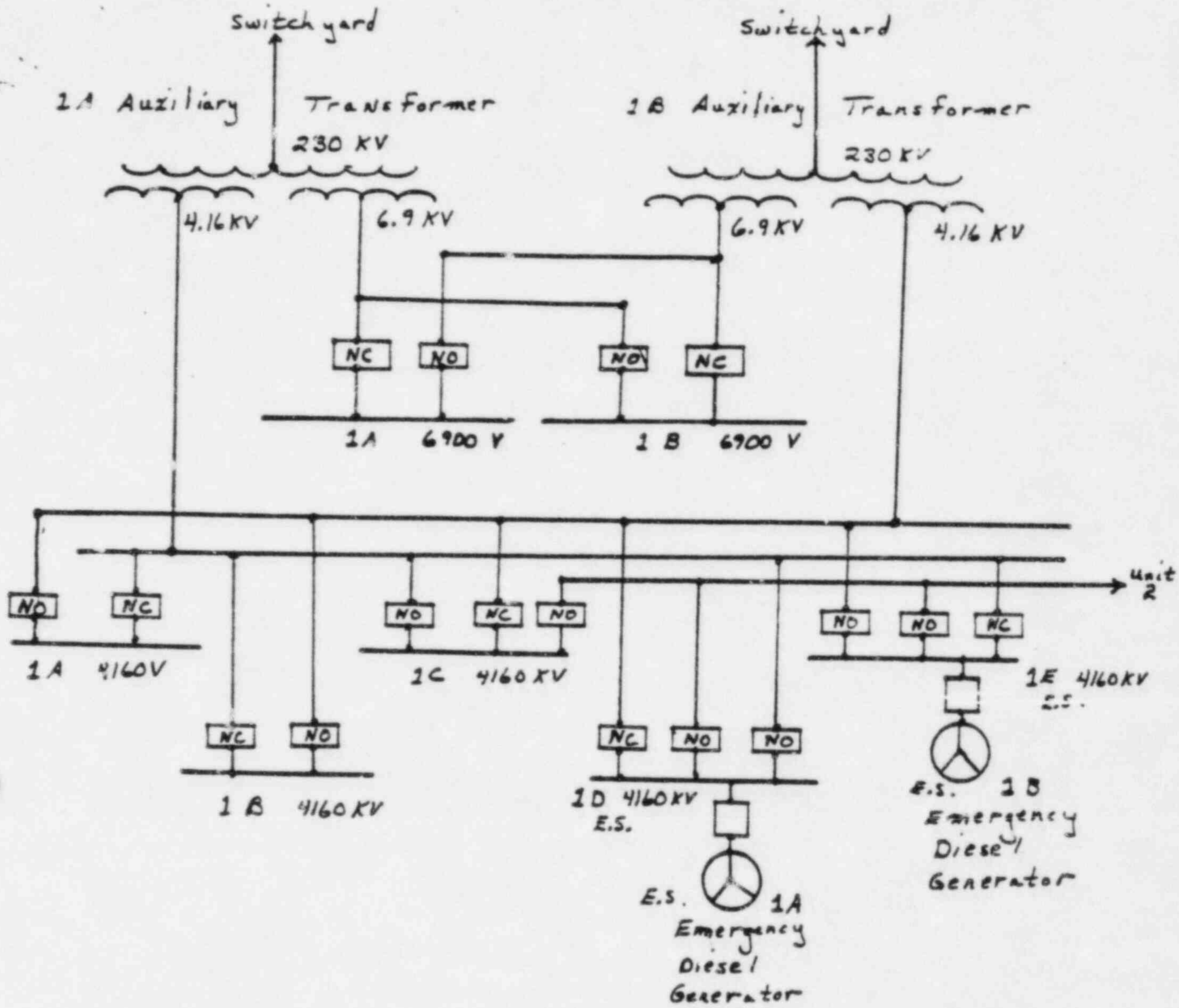


Figure 1.1A
based on p. 60, ref. 53

The 125/250 V DC and 120 V AC vital distribution systems are described in Reference 53, pages 42 through 55. In brief, the DC system is composed of the station batteries, battery chargers, DC panels 1A, 1B, 1C, 1D, 1E, 1F, 1H, 1J, 1M, and 120 V AC Vital Power Panels VBA, VBB, VBC, and VBD.

The two engineering safeguards 4KV buses are 1D and 1E (Reference 53, page 28). Diesel loading begins 10 seconds after the start signal (Reference 43) on sensed undervoltage.

Emergency feedwater is supplied by one turbine driven EFWP and two motor driven EFWPs. The TDEFWP is auto started on the loss of both main feedwater pumps. The two MDEFWPs are powered from the emergency diesel generators at 15 seconds after MFWP trip on LOOP with no ESAS, or at 30 seconds after MFWP trip in the event of a LOOP with ESAS.

TRAP analysis for the LOOP event at TMI-1 has shown a drop in steam pressure which could be attributed to quenching by EFW of approximately 100 psi/minute in OTSG A (Reference 46, T = 110. to 170. seconds). This exceeds the range listed in the ANO-1 ATOG. The indicated decrease in steam pressure is due to EFW quenching rather than the failed MSSV on OTSG B. This was shown by the recovery of steam pressure that occurred when EFW was throttled in OTSG A. Emphasis should be given to EFW throttling as a means of reducing this overcooling phenomena; since full EFW capacity is available within the first half minute at TMI-1 rather than after about 100 seconds as at ANO-1.

Condenser unavailability and reliance on the MADVs and MSSVs occurs after a LOOP at TMI-2. The MSSVs have reseated and secondary pressure control is via the MADVs within the first minute post-trip. As listed in the comparison section of this transmittal, the secondary pressure control functions are similar at each plant. The exception is the steam line break system configuration at each site. Refer to Table 6 in Section II. B. preceding.

1.2 Actual Plant Loss of Offsite Power

The LOOP event at ANO-1 of February 22, 1975 remains a valid example. Two additional cases are available for review, though neither occurred at TMI-1: 6/24/80, ANO-1 (Appendix A, this Document), 4/7/80, ANO-1 (Appendix B, this Document). Figures D-1 through D-6 remain valid. Revised P-T plots were drawn using the TMI-1 natural circulation format (Reference 48) for figure D-7, and were released separately (Reference 54).

2.0 Operator Actions Summary

2.1 Immediate Actions

The actions listed remain valid. The analytical results from the three EFWP case TRAP analysis for TMI-1 demonstrates the quenching effect of EFW flow. Emphasis should be given to EFW throttling. The instrument air compressor must be manually loaded on.

2.2 Identifying Symptoms

This section requires rewording to reflect the design of TMI-1's power distribution system. Also, Figure D-11 shows a "typical" P-T plot for a LOOP event. The preliminary repressurization "hump" which is shown might not be valid for TMI-1. Analytical results (Reference 46) for an asymmetric overcooling event at TMI-1, using an improved version of the TRAP code (Reference 21), did not show a repressurization during the same time frame. The PORV setpoint was reached and primary inventory (~ 100 lb.) was released, according to the analyses made for TMI-1 LOOP (Reference 46).

3.0 Loss of Offsite AC Power with Other Plant Failures

3.1 Loss of Reactor Inventory Control (Low)

The letdown isolation valve, MU-V3, is closed on high temperature interlock. The balance of this topic remains valid.

3.2 Loss of Reactor Inventory Control (High)

The makeup control valve is MU-V17. The letdown isolation valve is MU-V3. No bypass is available to route full letdown flow around the letdown coolers or isolation valve MU-V3 (Reference 13, Figure 9-2).

3.3 Loss of Secondary Inventory (Low)

The discussion given in the ANO-1 ATOG, page D-16 remains valid. An additional concern is the effect of SLRDS actuation. If a depressurization of an OTSG occurs during a LOOP event at TMI-1, the EFW flow to that OTSG will be terminated once the SLRDS setpoint has been reached. The TRAP analyses made for TMI-1 are for an asymmetric overcooling event with a SLRDS actuation. The effect of this upon natural circulation flow is shown in References 46 and 55.

3.4 Loss of Primary Pressure Control (Low)

The ESAS setpoint is 1600 psig at TMI-1 (Reference 38).

3.5 Loss of Steam Pressure Control (Low)

Review the operation of the SLRDS system as shown in Section II. B., Table 6, preceding.

3.6 Loss of All Power Except Batteries

This event is best described in the applicable emergency procedure for LOOP at TMI-1, Reference 56.

4.0 Figures:

Figures D-8 and D-9 remain valid, though the pressurizer level and RCS pressure rebounds shown on Figure D-8 were not seen during the TMI-1 TRAP analyses (Reference 55). Revised P-T plots for use in Figures D-10 and D-11 were released separately (Reference 54).

5.0 Revision of Table D-1

Major components loaded onto diesel generator following a LOOP (Reference 43). Non-ESAS loading table is unavailable at time of writing. In item 3.5.1 of ref. 57 the non-ESAS auto load is stated to be block 1 only; others are manual

Component	Time after LOOP (sec)
Makeup pump	10 WO/ESAS, 10 W/ESAS
MDEFWPs 2A and 2B (Ref. 44)	15 WO/ESAS, 30 W/ESAS
Decay heat pumps	20 W/ESAS
Nuclear Service closed cooling	20 W/ESAS
PZR proportional heater banks (manual)	35 W/ESAS
Battery charge and inverters	10 WO/ESAS, 10 W/ESAS
R.B. spray pump	20 W/ESAS
Instrument air compressor (manual)	35 W/ESAS

Lose Power During a LOOP

All RC Pumps
All Condensate Booster Pumps
All Circulating Water Pumps
On-Off Pressurizer Heater Banks

V. CONTINUITY

The analyses made for the LOOP event at TMI-1 are found in four related transmittals. They are as follows:

32-1120510-00**	"TMI-1 Loss of Offsite/Onsite Power; One MSSV Failed Open on SG B". This calculation package supports the TRAP analytical results for TMI-1 LOOP.
86-1123921-00	"ATOG Transient Information Document: Loss of Offsite/Onsite Power, TMI-1". (This transmittal.)
86-1125356-00	"P-T Plots for TMI-1 ATOG: ANO-1 LOOP data Plotted per the TMI-1 Format". This transmittal presents replots of the P-T data generated during the ANO-1 TRAP/DYSID analyses for LOOP. The revised P-T plots will be used in Appendix D of the TMI-1 ATOG.
86-1125435-00	"TRAP analytical results for TMI-1 Loss of Offsite/Onsite Power; One MSSV Failed Open on SG B". This transmittal presents the results obtained in 32-1120510-00.

** Note: Rev. 01 is expected by mid-July, 1981.

VI. REFERENCES

1. B&W Drawing Number 1120153F-01, "Loss of Offsite/Onsite Power, ATOG Event Tree, TMI-1".

2. B&W Document Number 05-0002-36, "TMI-1 Technical Specifications", Table 2.3-1, February 28, 1980.

3. B&W Document Number 05-0003-19, "ANO-1 Technical Specifications", Table 2.3-1, November 30, 1979.

4. B&W Number 16-1108693D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit 1 Piping Flow Diagram Makeup & Purification", March 3, 1971.

5. B&W Number 16-1108694D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit 1 Piping Flow Diagram Makeup & Purification", July 11, 1969.

6. B&W Number 16-1097719E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Makeup & Purification System", February, 1979.

7. B&W Document Number DP-1101-02, "Plant Setpoints", ANO-1.

8. B&W Document Number DP-1101-02-00, "Plant Setpoints", TMI-1.

9. B&W Document Number 86-1106932-00, "Makeup Line and HPI Flow Rates vs. RC Pressure for NSS-8 for ATOG Program", (Contract #582-7108), December 13, 1979.

10. B&W Document Number 15-1108790-00, "Preliminary System Description, MU and Purification System TMI-1, August 14, 1969.

11. B&W Document Number 16-1108694D-00, "TMI-1 MU&P Piping Flow Diagram".

12. ANO-1 FSAR Volume II, Figure 10-1.

13. TMI-1 FSAR Volume III, Pages 5-6.

14. ANO-1 FSAR Volume II, Pages 6-29.

15. B&W Document Number 86-1118178-00, "ANO Analytical Input Data for ATOG".

16. TMI FSAR, Section 3, Table 3-1, Page 79; Section 4, Tables 4-1 to 4-11, Pages 38-49.

17. TMI-1 FSAR, Volume I, Pages 4-38.

18. ANO-1 FSAR, Volume I, Pages 4-38.

19. B&W Number 16-1108682D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit #1 Piping Flow Diagram Feedwater", March 14, 1969.

20. B&W Number 16-1097712E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Condensate & Feedwater", October 4, 1979.

21. NPGD-TM-414; Rev. 3, Rev. J, May, 1980; TRAP Simulation Code, Version 2.6.

22. ATOG Document List NSS-08, Document Number 29-097590-00.

23. B&W Document Number 15-1108780-00, "TMI-1 Feedwater System Description".

24. B&W Document Numbers 15-1108784-00 and 15-1108780-00, "TMI-1 Main Feedwater Lesson Plan".

25. B&W Document Number 03-1097635-00, "ANO Operating Procedure 1203.12, Annunciator K07 F-6 Main Feedwater Pump 1P1A Turbine 1K2 Trip", Rev. 00, November 30, 1977.

26. B&W Document Number 03-1108728-00, "TMI-1 Emergency Procedure Number 1202-14", Rev. 5.

27. B&W Drawing Numbers 620-0008, 21-00-307-05, 21-00-309-02, "Steam Generator Feedwater Control ICS Digital Logic".

28. B&W Document Number 86-1118379-02, "EFW Reliability Analysis", ANO-1, December, 1979.

29. B&W Document Numbers 15-1108782-00 and 15-1108795-00, "TMI-1 Main Steam System Description".

30. B&W Number 16-1108680D-00, "Metropolitan Edison Company Three Mile Island Nuclear Station Unit #1 Piping Flow Diagram Main Steam", April 29, 1969.

31. B&W Number 16-1097721E-00, "Arkansas Power & Light Company Arkansas Nuclear One Piping & Instrument Diagram Main Steam", May 18, 1979.

32. B&W Document Number 16-1108680D-00, "Gilbert Assoc., Inc., TMI-1 Main Steam Piping Flow Diagram", January 8, 1979.

33. B&W Drawing Number 38-41-602-00, "Consolidated Safety Valves".

34. Letter from D. F. Hallman to J. D. Phinney, "Recommended Modifications to Plant Operations and Setpoints", April 21, 1979, attached in Appendix F of this Document.

35. B&W Document ID DP-1101-02-00, "Plant Setpoints, TMI-1".

86-1123921-00

36. B&W Document Number 15-1108779-0C, "Preliminary System Description on Feedwater" Section C (of plant manual) Chapter 33.

37. B&W Document Number 38-1108797-00, "Feedwater System Description".

38. Recommended Requirements for Restart of Three Mile Island Nuclear Station Unit 1, Docket Number 50-289, Operating License Number DPR-50.

39. B&W Document Number 86-1121912, "Makeup Line and HPI Flow Rates vs. RC Pressure for NSS-5 for ATOG Program (Contract #582-7108)", October 24, 1980.

40. B&W Document Number 86-1121207-00, "ATOG Analytical Input Data, 5.A.16".

41. GPU Comments to Rev. 0 of TMI-1 Event Trees, October 29, 1980; December 12, 1980; January 15, 1980 (T1.1; 620-005).

42. B&W Document Number 86-1118159-00, "ANO LOOP - No EFW; ATOG", March 6, 1980.

43. B&W Document Number 38-1108796-00.

44. TMI-1 Restart Report, Amendment 22, attached in Appendix C.

45. B&W Document Number 86-1119255-00, "Main Success Path; Loss of Offsite Power - ATOG", ANO-1, May 21, 1980.

46. B&W Document Number 32-1120510-00, "TMI-1 LOOP ATOG Analysis Calculational Package".

47. Data for ANO-1 LOOP P-T Diagrams, revised to TMI-1 format. B&W Document Numbers 32-1106949-00, 32-1106953-00, 32-1106954-00, 32-1106955-00, and 32-1118539-00.

48. Open Shop Code "PTNAT", attached in Appendix D of this Document.

49. "TMI-1 Excessive Main Feedwater Transient Information Document", 86-1123876-00.

50. ANO-1 FSAR, Chapter 8.

51. Letter, July 26, 1974; B&W to E. H. Smith of Bechtel Corp., attached in Appendix E of this Document.

52. B&W Document Number 32-1106949-01, "Main Success Path; Loss of Offsite Power", ANO-1, April 23, 1980.

53. B&W Document Number 38-1108798-0C, "TMI-1 Unit 1 Operator Accel. Retraining Program Module 3, Electrical Distribution System".

54. B&W Document Number 86-1125356-00, "P-T Plots for TMI-1 ATOG: ANO-1 LOOP Data Plotted per the TMI-1 Format".

55. B&W Document Number 86-1125435-00, "TRAP Analytical Results for TMI-1 Loss of Offsite/Onsite Power; One MSSV Failed Open on SG B".

56. B&W Document Number 03-1108718-00, "Station Blackout and Station Blackout with Loss of Both Diesel Generators".

57. B&W Document No. 15-1108763-00," Class 1E Electrical Systems" Decsription.

VII. Appendix

Item	Topic
A	Reports on June 24,1980 ANO-1 Reactor Trip
B	Report on April 7, 1980 ANO-1 Reactor Trip
C	Excerpts from TMI-1 Restart Report
D	Open Shop Code "PTNAT"
E	Pressurizer Heater Capacities for ANO-1
F	Modification of PORV and PSSV Setpoints at Operating Plants
G	Substation One-line

Appendix A

Reports on June 24, 1980 ANO Reactor Trip

Appendix A contains information of a proprietary nature to another utility company and has been deleted from the GPU submittal.

86-1123921-00

APPENDIX B

REPORT ON APRIL 7, 1980 ANO REACTOR TRIP

THE BABCOCK & WILCOX COMPANY
POWER GENERATION GROUP

86-1123921-00

To: R. C. Luken, Service Manager

From: D. F. Hallman, Manager, Plant Performance Services
J. D. Carlton, Manager, PS&C Unit, Plant Engineering

BDS 663.5

Cust.: Arkansas Power & Light

File No. or Ref.:

Subj.: April 7, 1980, Reactor Trip

Date: April 24, 1980

This letter to cover one customer and one subject only.

Enclosed is a Preliminary Assessment Report for the April 7, 1980, reactor trip at ANO-1. Please have Arkansas review the report, provide any comments, and return so that we can distribute the report to the 177 FA utilities. If there are any questions, please contact D. F. Hallman or J. D. Carlton.

D F Hallman

D. F. Hallman

JD Carlton

J. D. Carlton

DFH/JDC/fch
Attachment

86-1123921-00

PRELIMINARY

ASSESSMENT REPORT

REACTOR TRIP

AT

ARKANSAS NUCLEAR ONE

ON

APRIL 7, 1980

PREPARED BY

NUCLEAR POWER GENERATION DIVISION

THE BABCOCK & WILCOX CO.

LYNCHBURG, VA.

REPORT NO. 8-80-01, REV. 00

PREPARED BY: ____________

REVIEWED BY: D F Hallman 4/25/80

REVIEWED BY: J D Carlton 4/25/80

REVIEWED BY: ____________ 5/1/80

APPROVED FOR RELEASE TO 177 OWNERS:

____

B-2

TABLE OF CONTENTS

I. EVENT SYNOPSIS

On April 7, 1980, Arkansas Nuclear One-Unit 1 was operating at 100% full power. At 1848 hours, ANO-1 experienced a reactor trip caused by a loss of offsite power. The diesel generator #1 had been started prior to loss of offsite power due to tornado warnings. The sequence of events which contributed to the occurrence:

1728	Lost 500 KVA line to Fort Smith
1825	Lost 500 KVA line to Mabelvale
1833	Electrical system was struck by lightning
1848	Lost offsite power Turbine trip/reactor trip Lost computer and post-trip data Manual initiation of High Pressure Injection (HPI)
1858	HPI was throttled
1859	Both OTSG's at 50% on operate range
1900	Natural circulation confirmed
1924	Offsite power was restored
1948	HPI was stopped
2030	Closed atmospheric dump valves. Condenser back in operation
2108	Started "C" Reactor Coolant Pump (RCP)

2117 Started "A" RCP

2354 Deenergized diesel generator #1

2356 Deenergized diesel generator #2

II. PERFORMANCE EVALUATION

A. Expected Plant Performance and Performance Deviation

1. Initiating Event - Loss of Offsite Power

A main generator electrical trip was caused by loss of offsite power.

2. Reactor Trip - Anticipatory

An electrical trip of the generator will trip the Main Turbine and cause an anticipatory reactor trip.

3. Reactor Coolant System Pressure Response

Following the 2200 psig pressure peak (caused by turbine stop valve closure), the pressure dropped to approximately 1860 psig due to the cooldown of the Reactor Coolant System (RCS). It then increased due to operator initiated HPI and RCS heatup. The pressure increase was stopped by the Pilot Operated Relief Valve (PORV) at approximately 2440 psig and then decreased to approximately 2350 psig. The PORV operated for at least three more cycles, over a period of approximately 20 minutes, and was caused by the combination of plant heatup and HPI flow.

HPI flow into the RCS, in an amount greater than needed to compensate for RCS shrinkage, will cause the steam bubble in the pressurizer to be compressed. This will increase the RCS pressure and increase the water inventory in the pressurizer. A result of this action is to reduce the temperature of the water in the pressurizer to a temperature below saturation. As the steam bubble compression increases and excess pressure is relieved by PORV operation, the pressurizer water is being further subcooled. Any heat removal of the RCS by the Emergency Feedwater (EFW) System will cause a rapid decrease in RCS pressure because the subcooled pressurizer water cannot "flash" steam to maintain system pressure. RCS pressure will decrease to the saturation pressure of the water in the pressurizer.

Changes in the OTSG level and HPI operation can produce large pressure swings in the RCS. These changes will be aggrevated as the pressurizer is filled and the steam bubble is reduced. These effects were seen in the transient, and after several of these pressure changes, the pressure was decreased to approximately 1830 psig. After a level was reestablished, pressurizer heaters restored RCS pressure to the normal operating values.

4. <u>Pressurizer Level Response</u>

Pressurizer level rose approximately 5 inches from its initial 180 inches because of the initial RCS heatup caused by the turbine trip and then dropped to approximately 40 inches due to the cooling of the RCS by Main

Steam Safety Valves. Pressurizer level then began increasing to approximately 320 inches and remained there or above for approximately 45 minutes. This level increase was due to continued HPI operation (in excess of that needed to maintain approximately 50°F subcooling) in combination with plant heatup caused by decay heat. Level was then decreased back to approximately 80 inches over approximately 2-3/4 hours by operator action.

5. Reactor Coolant System Temperature Response

RCS average temperature (Tave) will normally decrease approximately 30°F following a reactor trip. Excessive Emergency Feedwater (EFW) flow rate to the OTSG caused the Tave to decrease to approximately 532°F. Tave then increased to approximately 544°F at approximately 45 minutes after the trip. This increase was caused by decay heat and by reducing EFW flow which led to a corresponding increase in OTSG pressure.

Over the next 1-1/2 hours, Tave decreased gradually to approximately 511°F due to a decrease in OTSG pressure and a reduction of decay heat. Reactor coolant pumps were started and Tave was restored to approximately 538°F.

6. Steam Pressure Response

Steam pressure prior to the trip was approximately 850 psig. When the trip occurred, the pressure increased to approximately 1050 psig immediately and was decreased by the MSSV's. The drop in OTSG pressure

stopped at approximately 680 psig after approximately 7 minutes: this was the result of excessive feeding of cold EFW to the OTSG's which sprayed cooler feedwater on the steam bubble in the OTSG reducing the steam generator pressure. During the next approximately 30 minutes, pressure increased to approximately 800 psig. Then pressure was manually controlled within a range of 60 psig (690 psig - 750 psig) until reactor coolant pumps were restarted. Pressure was then restored to the normal range, approximately 880 psig.

7. Feedwater Response

All main feedwater was lost due to the loss of offsite power. The loss of all reactor coolant pumps automatically initiated a start of the emergency feedwater system to fill the OTSG's to 50% on the operate range level indication. Because this fill to 50% occurred at a maximum system flow rate, OTSG pressure and subsequently reactor coolant temperature decreased below normal values.

8. OTSG Water Level Response

OTSG level initially decreased to approximately 5% (equivalent to minimum indication) on the operating range - this is normally expected. It was then restored to approximately 50% indication by the emergency feedwater system. This assured that natural circulation was initiated. Later, when the RCP's were started, OTSG levels were restored to the low level limit of approximately 25 inches.

B. Safety Implications

The event caused by a loss of offsite power did not result in any violation of safety limits. The reactor trip was expected; however, actions after the reactor trip did create a primary system response which deviates from desired operation. In particular, the power operated relief valve (PORV) was unnecessarily operated and pressurizer level indication went off scale.

It is desirable to maintain RCS pressure so as to minimize the possibility of unnecessary PORV operation. Maintenance of pressurizer level within the level instrumentation range provides the operator with an important system input, and prevents the unpredictable RC pressure behavior that can accompany a solid pressurizer.

C. Conclusions

1. EFW fill rate of the OTSG's under automatic control is too great and caused excessive cooling of the RCS.

2. The only means of OTSG pressure control was the MSSV's. Control of the Atmospheric Dump Valves was not available because of loss of electrical power to the block valves which were shut. The condenser was not available because the circulating water pumps were lost on the loss of offsite power.

3. Cycling of the PORV when the pressurizer is in a solid or near solid condition has the potential for damaging this valve and discharge systems.

4. The loss of the plant computer greatly hindered post-trip data and information analysis.

5. Letdown (L/D) flow could have aided in the RCS pressure control during the transient but was not available because of a lack of cooling water to the L/D cooler.

6. Combatting the loss of offsite power required the use of ANO procedures, Degraded Power 1202.05, Loss of RCP's 1202.14, Loss of S/G Feed 1202.26, Reactor Trip 1202.04. These procedures do contain the steps necessary to control the plant during the selected and identified condition. However, the procedures do not give specifics that the operator could readily follow to utilize the four procedures simultaneously.

D. Recommendations

1. Modify the control system for the Atmospheric Dump Valves and block valves so that the system is operable on loss of offsite power and station blackout.

2. Change procedures 1202.04 and 1202.14 to provide for operator control of emergency feedwater after actuation to limit RCS Tcold decrease to 550°F when the RCS is at least 20°F subcooled.

3. Modify the Emergency Feedwater Control System to limit the rise rate in OTSG level. Further recommendations in this area will be made by ATOG.

4. Develop a specific procedure for loss of offsite power which integrates the steps included in procedures Degraded Power 1202.05, Loss of RCP 1202.14,

Loss of Steam Generator Feed 1202.26, and Reactor Trip 1202.04 required for plant stabilization. Loss of power from tornado damage to power lines appears to be a sufficiently frequent transient to warrant an expanded procedure specific for ANO. Further recommendations will be made in these procedures by ATOG.

5. Modify procedure 1202.04 reactor trip to eliminate the instructions in 2.6 requiring that if pressurizer level decreases to 40 inches or primary pressure decreases to 1800 psig, manual initiation of HPI is required. Unnecessary initiating of HPI provides additional thermal cycles on the HPI injection nozzles and may cause unneeded thermal shock damage to the reactor coolant pump seals.

6. Ensure alternate AC power to the plant computer is available to allow the computer to remain operable during a loss of power incident.

7. Conduct training on the thermodynamic process in the pressurizer including specific student worked problems to demonstrate the effects of subcooling in the pressurizer on pressure control. Specific attention should be given to the reasons for large pressure decreases during pressurizer outsurges.

8. Emphasize in training and operational discussions that the use of HPI cooling should not be used as long as 50°F subcooling of the primary can be maintained. The use of HPI cooling is conservative; however, there is a significant possibility of creating a long term LOCA because of a safety valve failure.

9. Modify the Nuclear Service cooling ~~water~~ system or electrical supplies to the cooling water pumps to maintain cooling to the letdown coolers on loss of power to facilitate primary pressure and pressurizer level control.

III. EVENT DETAILS AND INPUT DATA

A. Initial Plant Conditions

The following table of data summarizes the initial plant conditions.

Time of Reactor Trip: April 7, 1980, 1848 hours

Reactor Power: 100% Full Power

RCS Temperature (Tave): 579°F

RCS Pressure: 2155 psig

Pressurizer Level: 180 inches

Number of RC Pumps Operating: 4

Steam Pressure: 900 psig

Number of Main Feedwater Pumps Operating: 2

ICS Mode: Automatic

Cause of Reactor Trip: Anticipatory caused by turbine trip

B. Plots of Major Parameters

All of the following parameters were obtained from the reactimeter data recording.

Figure 1 RCS Pressure vs Time

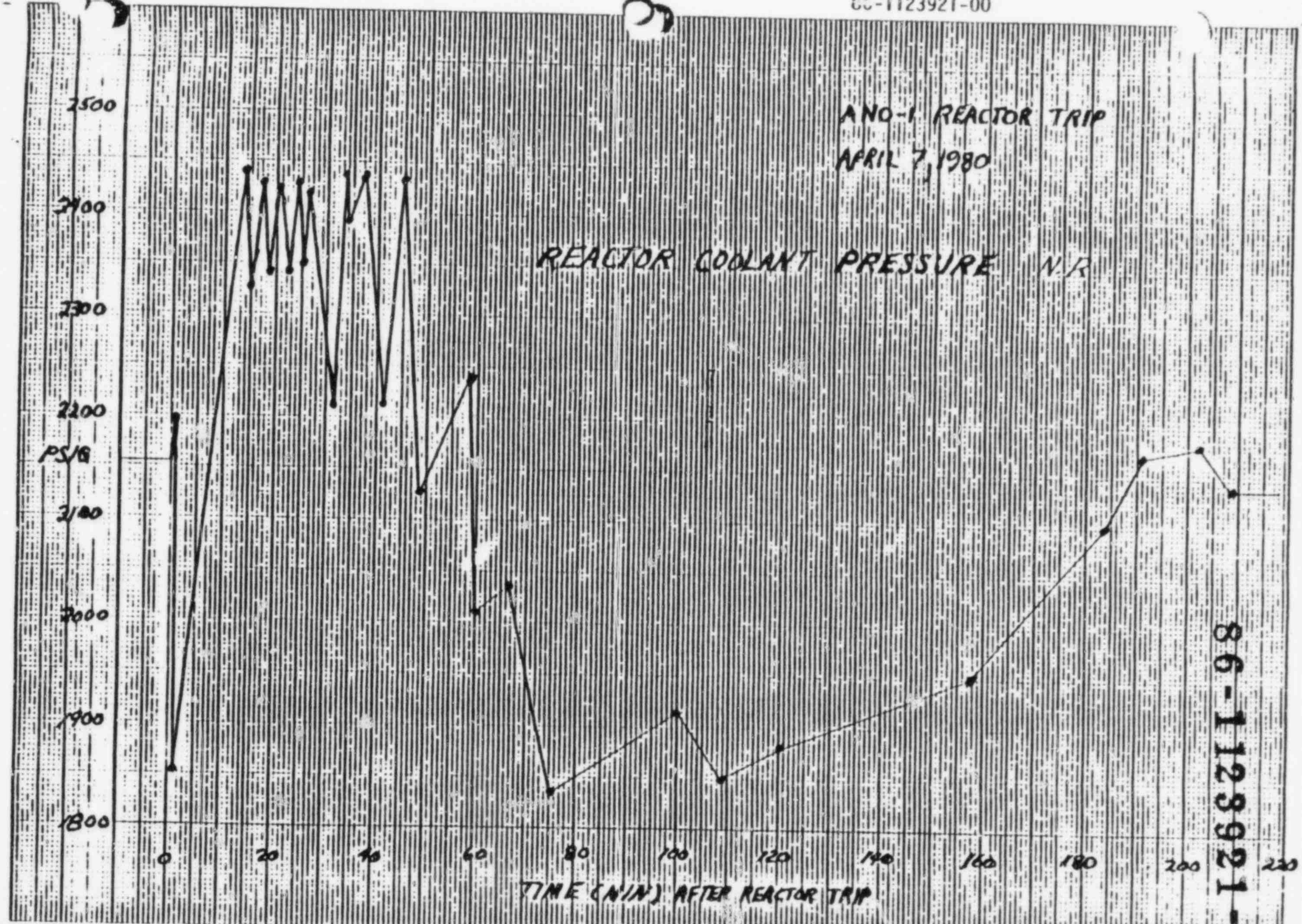
Figure 2 Pressurizer Level vs Time

Figure 3 RCS Tave vs Time

Figure 4 Steam Pressure vs Time

Figure 5 OTSG Level "A" vs Time

86-1123921-00

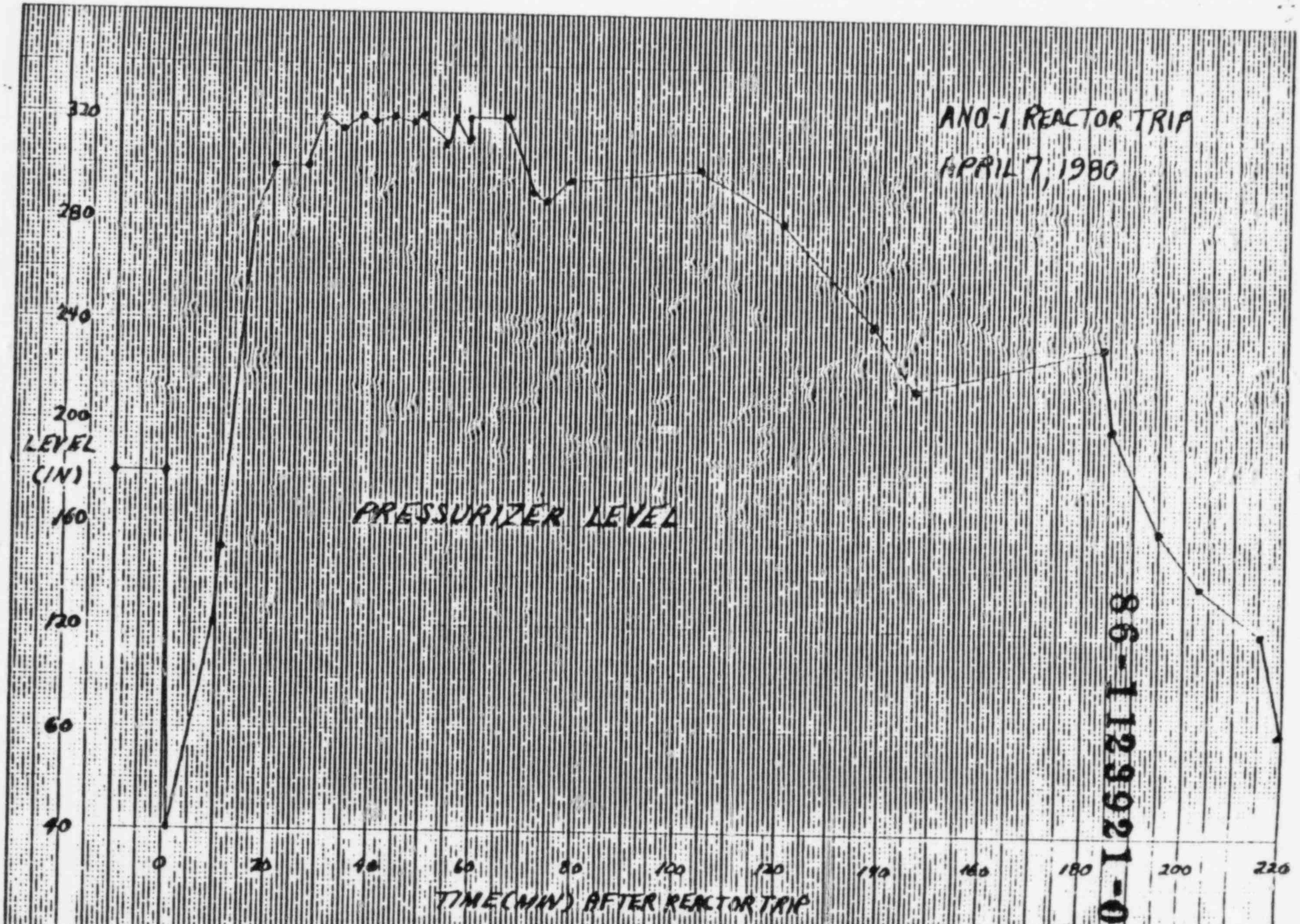


B-15

K+E 10 X 10 TO THE CENTIMETER 18 X 25 CM.
KEUFFEL & ESSER CO. MADE IN U.S.A.

46 1510

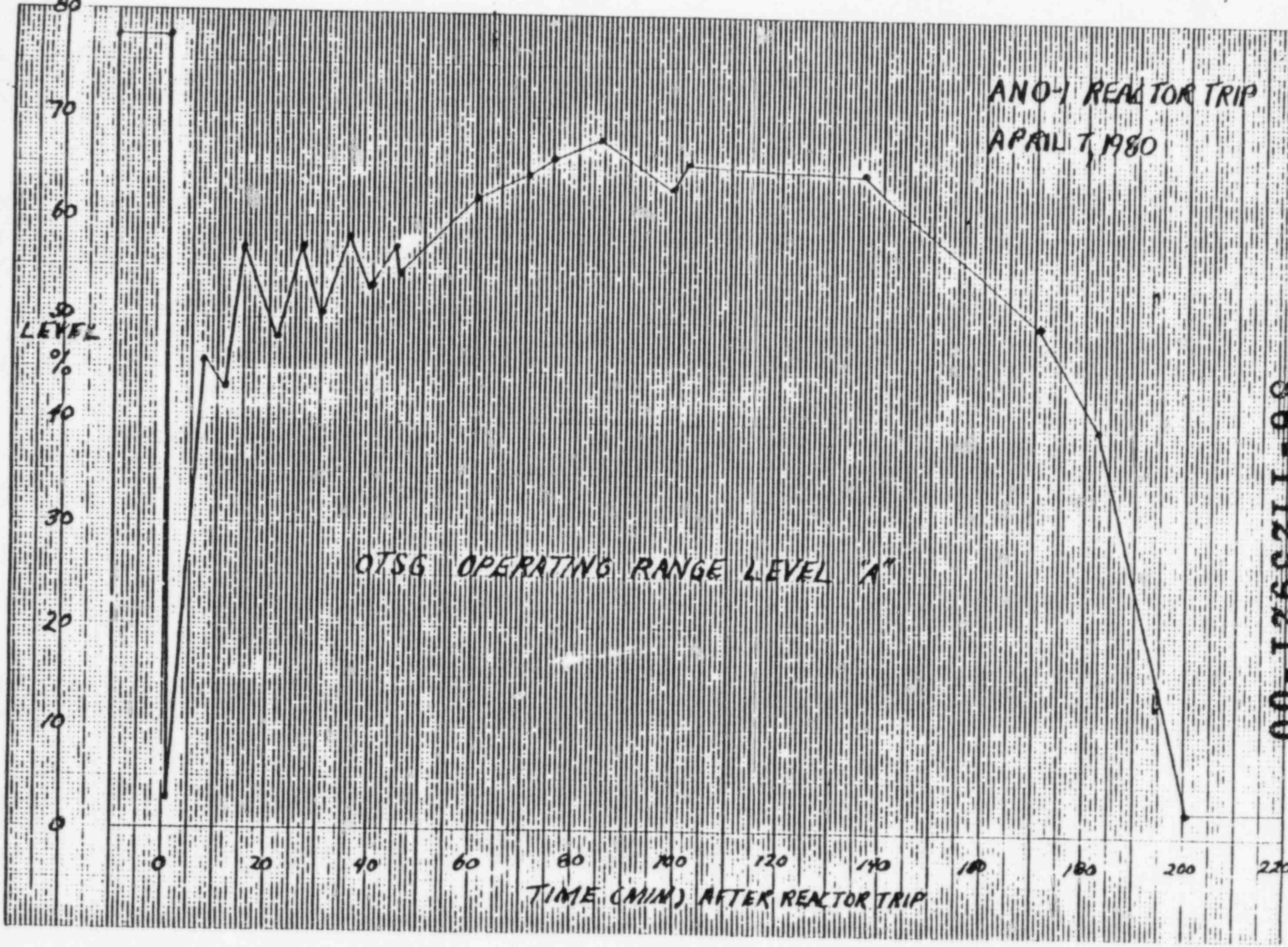
86-1123921-00



K·E 10 X 10 TO THE CENTIMETER 18 X 25 CM. KEUFFEL & ESSER CO. MADE IN U.S.A.

46 1510

86-1123921-00



86-1123921-00

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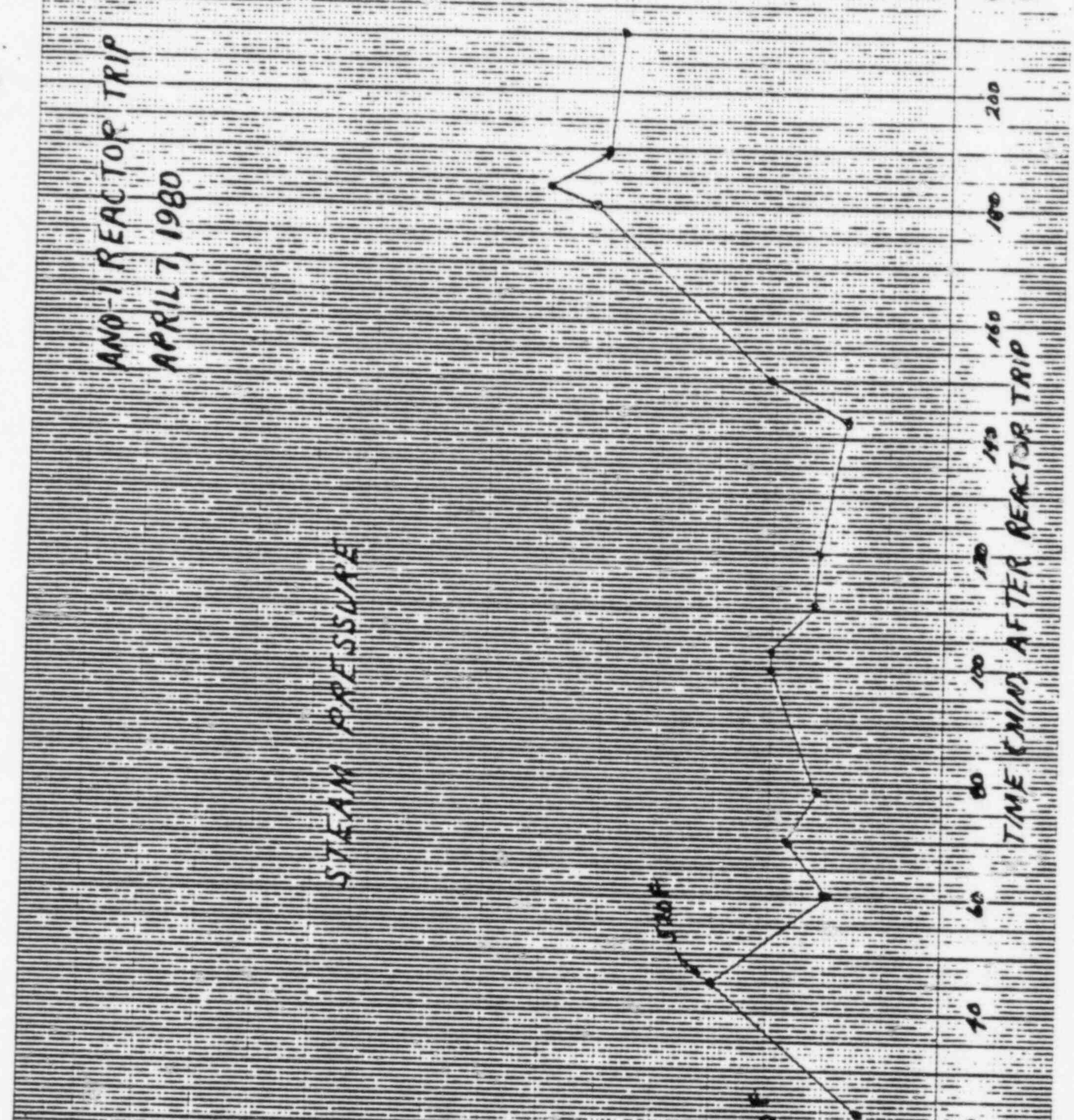

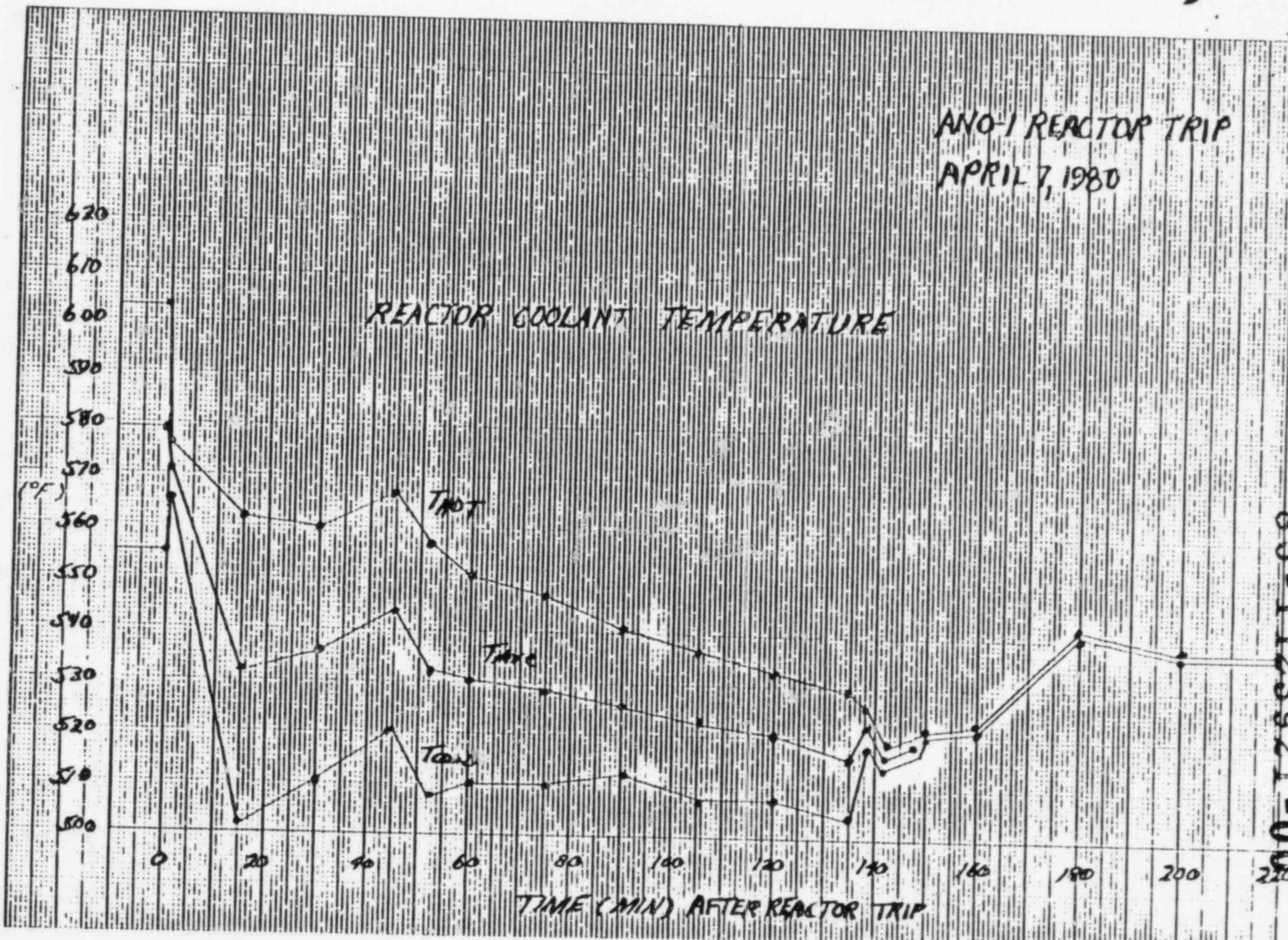
ANO-I REACTOR TRIP
APRIL 7, 1980
REACTOR COOLANT TEMPERATURE
(°F)
620
610
600
590
580
570
560
550
540
530
520
510
500
THOT
TAVG
TCOLD
0
20
40
60
80
100
120
140
160
180
200
220
TIME (MIN) AFTER REACTOR TRIP
86-1123921-00

IV. OPERATING TRANSIENT CLASSIFICATION

This transient is classifed as Type 15, reactor trip per B&W document CS(F)-3-92 NSS-8 new 0372 for Arkansas Nuclear One-1, and should be accounted for in the plant records.

V. GENERIC APPLICABILITY

This transient can apply to all B&W plants.

VI. REFERENCES

1. ANO-1 control room strip charts.

2. ANO-1 control room logs.

86-1123921-00

Appendix C

Excerpts from TMI-1 Restart Report

Excerpt from the TMI-1 Restart Report

2.1.1.7 Auxiliary Feedwater Modifications

2.1.1.7.1 System Description

86-1123921-00

The TMI Unit #1 Emergency Feedwater System is being modified so that:

1. Both of the motor driven Auxiliary Feedwater (AFW) pumps automatically start upon loss of both main feedwater pumps or loss of four (4) Reactor Coolant Pumps.
2. The motor driven AFW pumps are automatically loaded on the diesel generator during loss of offsite power.
3. Indication is available in the control room of AFW flow to each steam generator.
4. Manual control of the AFW flow to each steam generator independent of the Integrated Control System (ICS) is available to the operator in the control room.
5. Control room annunciation for all auto start conditions of the AFW system is available.

X

2.1.1.7.2 Design Bases

The TMI-1 Auxiliary Feedwater System (AFW) is being modified so that a single failure will not result in the loss of auxiliary feedwater system function during a Loss of Coolant Accident. To accomplish this the requirements of NUREG-0578 Section 2.1.7a and 2.1.7b will be met. In addition, the emergency feedwater control valves are being modified such that they fail open on loss of instrument air in order to meet the single failure criteria.

2.1.1.7.3 System Design

As indicated in Chapter 10 of TMI Unit #1 FSAR, the Emergency Feedwater System was designed to operate: 1) on loss of all four Reactor Coolant pumps or 2) if both main feedwater pumps fail.

The original system design was based on use of three auxiliary feedwater pumps. One of the three pumps is turbine driven and has a capacity of 920 gpm. The remaining two pumps are motor driven and have a capacity of 460 gpm each. The three pumps are located in the Intermediate Building which is designed to withstand seismic events, tornado, missiles and a hypothetical aircraft incident. The turbine driven pump is physically separated from the motor driven units. One of the motor driven pumps is powered from the class 1E 4160 volt bus 1D while the other motor driven pump is powered from the redundant class 1E 4160 volt bus 1E. The design

C-1

of the 1D and 1E Bus has been changed so that they continue to supply power to the motor-driven pumps during all loss of off-site power conditions with or without ESAS actuation. To limit voltage dip on the diesel generator during loss of offsite power and coincident ESAS actuation condition, the motor driven pumps will be loaded as a block 5 load (i.e. will be loaded 5 seconds after block 4 loading). For a loss of offsite power only motor driven pumps will be loaded 5 seconds after the diesel generator has started. Power to the turbine driven pumps remains unchanged and is described in Chapter 10 of the FSAR.

X

Both of the motor driven and turbine-driven emergency feedwater pumps receive an auto-start signal on loss of all four reactor coolant pumps or loss of both main feedwater pumps. This is accomplished by utilizing contacts from the Reactor Coolant Pump power monitors and by sensing the differential pressure across the main feedwater pumps. The RC pump power monitors are a safety grade system and are described in chapter 7 of the TMI-1 FSAR. The main feed pump differential pressure sensing equipment is control grade. Both of the above initiation signals and circuits are designed so that a single failure will not result in the auxiliary feedwater system not functioning.

To accomplish this, the actuation system is arranged into two trains. Each train contains two differential pressure switches (one for each main feedwater pump), and four contacts from the RC pump power monitors (one for each pump).

Power for the "A" train is from the 120 V. AC Vital Distribution Panel VBA. Panel VBA can receive power either from the "A" station battery or from the "A" diesel generator through the 1A inverter. The "B" actuation train utilizes redundant pressure switches and RC pump power monitors and is powered from the 120 V. A.C. Vital Distribution Panel VBB. Panel VBB can receive power from either the "B" station battery or from the "B" diesel generator through the 1B inverter.

All three emergency feedwater pumps discharge into a common header. From this common header a separate six inch line delivers water to each steam generator. Each of the two supply lines contains an air operated control valve (EF-V30 A/B).

Under normal operations, air for the control of these valves is supplied from the instrument air system. The instrument air system is described in chapter 5 of the TMI-1 FSAR. In the event the main source of instrument air is not available, a back-up source of instrument air has been provided. The back-up air supply is received from an 80 gal. reservoir which is supplied by an 18 SCFM air compressor. Transfer to the back-up air supply is automatic and no operator action is required. The back-up air compressor is powered from the 1A 480V Engineered Safeguards

APPENDIX D

Open Shop Code "PTNAT" Used to

Produce P-T Plots in the

TMI-1 Natural Circulation Format

1

```
      PROGRAM PTNAT(INPUT,OUTPUT,TAPE5,TAPE8=OUTPUT,TAPE1=/160,
     *TAPE2=/160)
      DIMENSION PDATA(500),TDATA(500),X1(20),Y1(20),XAXIS(10)
      DIMENSION YAXIS(10),ITITLE(40),LABEL1(9),LABEL2(9)
      DIMENSION LABEL3(6)
      DATA YAXIS/10HRC PRESSUR,8HE  PSIG /
      DATA XAXIS/10HTEMPERATUR,6HE ('F)/
      DATA ITITLE/78,65,84,85,82,65,76,32,67,73,82,67,85,76,65,84

     *73,79,78,32,80,79,83,84,32,84,82,73,80,32,68,73,65,71,82,
     *65,77/
      DATA LABEL2/83,117,112,101,114,104,101,97,116/
      DATA LABEL1/83,117,98,99,111,111,108,101,100/
      DATA LABEL3/82,101,103,105,111,110/
      CALL INITT(120)
      CALL TERM(3,4096)
      CALL BINITT
      WRITE (8,1040)
      CALL TINPUT(C)
      CALL ERASE
      READ (5,*) NPT
      CALL NPTS(NPT)
      READ (5,*) (PDATA(I),TDATA(I),I=1,NPT)
      CALL DLIMX(400.,700.)
      CALL DLIMY(200.,2600.)
      CALL YTICS(12)
      CALL XTICS(6)
      CALL XMTCS(10)
      CALL YMTCS(5)
      CALL XFRM(2)
```

- Open Sig Code "PTNAT"

86-1123921-00

D-1

```
      CALL YFRM(2)
      CALL XMFRM(2)
      CALL YMFRM(2)
      CALL FRAME
      CALL CHECK(TDATA,PDATA)
      CALL DSPLAY(TDATA,PDATA)
      CALL MOVABS(30,2500)
      CALL KAM2AS(18,YAXIS,Y1)
      CALL VLABEL(18,Y1)
      CALL KAM2AS(16,XAXIS,X1)
      CALL NOTATE(1750,20,16,X1)
      CALL MOVEA(476.94,550.)
      CALL DRAWA(510.84,750.)
      CALL DRAWA(538.39,950.)
      CALL DRAWA(561.82,1150.)
      CALL DRAWA(582.315,1350.)
      CALL DRAWA(600.585,1550.)
      CALL DRAWA(617.115,1750.)
      CALL DRAWA(632.22,1950.)
      CALL DRAWA(646.13,2150.)
      CALL DRAWA(659.03,2350.)
      CALL DRAWA(671.04,2550.)
      CALL MOVEA(444.89,550.)
      CALL DASHA(481.67,750.,3)
      CALL DASHA(513.09,950.,3)
      CALL DASHA(538.46,1150.,3)
      CALL DASHA(560.185,1350.,3)
      CALL DASHA(579.265,1550.,3)
      CALL DASHA(596.615,1750.,3)
      CALL DASHA(610.82,1950.,3)
      CALL DASHA(625.24,2150.,3)
      CALL DASHA(638.65,2350.,3)
      CALL DASHA(651.07,2550.,3)
```

86-1123921-00

```
      CALL MOVEA(400.,2300.)
      CALL DASHA(658.,2300.,1)
      CALL MOVEA(542.,720.)
      CALL DASHA(542.,2600.,1)
      CALL MOVEA(542.,720.)
      CALL DASHA(580.,980.,1)
      CALL DASHA(580.,1311.17,1)
      CALL MOVEA(555.,2100.)
      CALL DRAWA(555.,2200.)
      CALL DRAWA(600.,2200.)
      CALL DRAWA(600.,2100.)
      CALL DRAWA(555.,2100.)
      CALL MOVEA(610.,1646.6)
      CALL DASHA(610.,2600.,1)
      CALL MOVEA(545.,950.)
      CALL DRAWA(545.,1020.)
      CALL DRAWA(555.,1020.)
      CALL DRAWA(555.,950.)
      CALL DRAWA(545.,950.)
      CALL MOVABS(1150,2900)
      CALL ANSTR(37,ITITLE)
      CALL CHRSIZ(2)
      CALL MOVEA(450.,1600.)
      CALL ANSTR(9,LABEL1)
      CALL MOVEA(450.,1600.)
      CALL LINEF
      CALL ANSTR(6,LABEL3)
      CALL MOVEA(625.,900.)
      CALL ANSTR(9.LABEL2)
```

```
      CALL MOVEA(625.,900.)
      CALL LINEF
      CALL ANSTR(6,LABEL3)
      CALL HOME
      CALL TINPUT(C)
      CALL FINITT(0,4096)
      STOP
 1040 FORMAT(1X,'ENTER A 'C' TO CONTINUE')
      END
*EOR
*EOF
```

86-1123921-00

Appendix E

Pressurizer Heaters

Capacities

for

ANO-1

Babcock & Wilcox

Power Generation Group

P.O. Box 1260, Lynchburg, Va. 24505
Telephone: (804) 384-5111

July 26, 1974

86-1123921-00

Mr. E. H. Smith
Project Engineer
Bechtel Corporation
50 Beale Street
San Francisco, California 94105

Subject: Arkansas Nuclear One
Rearrangement of Pressurizer Heater Bundles
Job No. 6600
B&W Reference NSS-8

Dear Mr. Smith:

The following proposal is offered as a temporary solution to the high ambient heat loss (~160 KW) on the pressurizer.

ANO-1 has five heater banks

#1	84 KW	SCR Controlled
2	84 KW	SCR Controlled
3	378 KW	On/Off By Press
4	504 KW	On/Off By Press
5	588 KW	On/Off By Press

Total available KW 1638 KW

We propose that six heater elements (~ 80KW) from bank #5 be rewired through a separate key-operated manual switch so that this new heater bank will remain energized all the time and work in conjunction with SCR initiated heater bank #1 to meet the ambient heat loss. Heater bank #2 can be used as the regulated heat source to control small pressure transients. This new temporary heater bank should also be interlocked with the Lo-Lo level signal.

We have examined the effect of this change on system behavior during large pressure transients such as reactor trips and have concluded that system response will not be significantly effected.

If you have further questions, please advise.

Appendix F

Modifications

of

PORV and PSSV Setpoints

at

Operating Plants

86-1123921-00

...ABCOCK & WILCOX COMPANY
... GENERATION GROUP

SITE INSTRUCTION NO. 3,4,9,11,? 5/...
DISTRIBUTION 3,4,5,7,8,9,11,14
RESPONSE REQ'D FROM 3,4,5,6,7,8,9,11,14
APPROVED D. D. Phinney 4/21/79

BDS 663-5

To: D. D. PHINNEY - MANAGER - OPS	
From: D. F. HALLMAN - MANAGER - PPSS D. F. Hallman	
Cust. ALL OPERATING PLANTS	File No. or Ref.
Subj. RECOMMENDED MODIFICATIONS TO PLANT OPERATIONS AND SETPOINTS	Date 04/21/79 1245

This letter to cover one customer and one subject only.

BASED ON EXTENDED DISCUSSIONS BETWEEN B&W AND THE NRC, THE NRC HAS REQUESTED THAT B&W TAKE STEPS TO PRECLUDE ACTUATING THE PILOT OPERATED RELIEF VALVE ON THE PRESSURIZER DURING ANTICIPATED TRANSIENTS. WE ANTICIPATE THE NRC WILL ISSUE A BULLETIN TO OUR OPERATING PLANTS REQUIRING THIS ACTION. ATTACHMENT 1.0 PROVIDES B&W'S RECOMMENDED METHOD FOR ACCOMPLISHING THIS TASK. ATTACHMENTS 1.1 AND 1.2 PROVIDE DETAILED INSTRUCTIONS FOR SETPOINT CHANGES DELINEATED IN ATTACHMENT 1.0.

PLEASE PASS THIS INFORMATION TO OUR CUSTOMER.

DFH/SM

CC: E. A. Womack
J. H. Taylor
J. F. Walters
A. E. Paulson
J. A. Castanes
R. E. Kosiba

4/21/79

REVIEWED FOR ACCURACY
ENGINEERING: [signature] DATE: 4/21/79
NUCLEAR SERVICE: [signature] DATE: 4/21/79

REDUCTION OF REACTOR HIGH PRESSURE TRIP SETPOINT VALUE AND INCREASE OF SETPOINT VALUE FOR THE PRESSURIZER PILOT OPERATED RELIEF VALVE

THESE SETPOINT CHANGES WILL HAVE THE EFFECT OF ELIMINATING THE LIFTING OF THE PRESSURIZER PILOT OPERATED RELIEF VALVE FOLLOWING ANTICIPATED TRANSIENTS SUCH AS LOSS OF MAIN FEEDWATER AND TURBINE TRIP. THE FOLLOWING POINTS SHOULD BE CONSIDERED AS BACKGROUND FOR THESE CHANGES:

A. ALL SAFETY ANALYSES FOR B&W NSS'S IS PERFORMED WITHOUT TAKING CREDIT FOR THE VENTING AND RELIEF CAPACITY OF THE PILOT OPERATED RELIEF VALVE. THEREFORE, THE REDUCTION OF ITS RELIEF PRESSURE SETPOINT DOES NOT MODIFY EXISTING APPROVED SAFETY ANALYSES.

B. THE PRESENT NOMINAL VALUES FOR PRESSURE SETPOINTS ARE AS FOLLOWS:

SAFETY VALVE - 2500 PSIG
REACTOR HIGH PRESSURE TRIP - 2355 PSIG
PILOT OPERATED RELIEF VALVE - 2255 PSIG
NOMINAL SYSTEM OPERATING PRESSURE - 2155 PSIG

C. B&W HAS PERFORMED CALCULATIONS USING REALISTICALLY CONSERVATIVE ASSUMPTIONS, WHICH INDICATE THAT SYSTEM PRESSURE WILL REMAIN BELOW 2400 PSIG DURING LOSS OF MAIN FEEDWATER TRANSIENTS AND TURBINE TRIP TRANSIENTS IF THE REACTOR HIGH PRESSURE TRIP SETPOINT IS RESET DOWNWARDS TO 2300 PSIG FROM ITS PRESENT SETPOINT OF 2355 PSIG. REVISING THE RELIEF SETPOINT FOR THE PILOT OPERATED RELIEF VALVE TO 2450 PSIG IN CONJUNCTION WITH REDUCTION OF THE REACTOR HIGH PRESSURE TRIP SETPOINT WILL AVOID ACTUATION OF THE PILOT OPERATED RELIEF VALVE DURING ANTICIPATED TRANSIENTS.

THEREFORE, WE RECOMMEND THE FOLLOWING ACTIONS:

A. REVISE THE REACTOR PROTECTION SYSTEM TRIP SETPOINT FOR REACTOR PRESSURE HIGH FROM 2355 PSIG TO 2300 PSIG USING THE ATTACHED PROCEDURE (ATTACHMENT 1.1).

B. REVISE THE RELIEF SETPOINT FOR THE PILOT OPERATED RELIEF VALVE FROM 2255 PSIG TO 2450 PSIG USING THE ATTACHED PROCEDURES (ATTACHMENT 1.2).

F. THE REACTOR PLANT OPERATING POINT (2155 PSIG) AND RELIEF PRESSURE SETPOINT OF THE ASME CODE PRESSURIZER SAFETY VALVES (2500 PSIG) SHOULD REMAIN UNCHANGED.

THE PROCEDURES PRESENTED IN THE ATTACHMENTS ARE INTENDED TO SUPPLEMENT THE NORMAL PLANT ADMINISTRATIVE PROCEDURE APPLICABLE TO CALIBRATIONS AND ADJUSTMENTS IN THE REACTOR PROTECTION SYSTEMS. THIS IS ESPECIALLY IMPORTANT IN VIEW OF THE FACT THAT ALL FOUR CHANNELS WILL BE RESET WITHIN A VERY SHORT TIMESPAN AND THE POTENTIAL FOR COMMON ERRORS IN THE FOUR CHANNELS MUST BE ELIMINATED.

ATTACHMENT 1.1

PROCEDURE FOR SETTING RPS HIGH RC PRESSURE TRIP SETPOINT

1.0 PURPOSE

THE PURPOSE OF THIS PROCEDURE IS TO SET THE TRIP SETPOINT OF THE RPS HIGH RC PRESSURE BISTABLE TO 2300 PSIG. THIS PROCEDURE IS APPLICABLE TO AN RPS NARROW RANGE RC PRESSURE CHANNEL WITH A RANGE OF 1700 TO 2500 PSIG.

2.0 REFERENCE

BCCO PRODUCT INSTRUCTION E92-341

3.0 EQUIPMENT

DVM READABLE TO 0.0001 VOLTS, 100 MΩ OR BETTER IMPEDANCE, 0.01% OR BETTER ACCURACY.

4.0 PROCEDURE

CAUTION: THE INSTRUMENTATION SETTINGS GIVEN ARE BASED ON TRANSMITTERS WITH AN ASSUMED RANGE OF 1700 PSIG TO 2500 PSIG. THIS RANGE MUST BE CONFIRMED AND CALIBRATION SETTINGS ADJUSTED TO REFLECT THE INSTALLED EQUIPMENT. CONTACT B&W IMMEDIATELY IF AS-INSTALLED RANGES DIFFER AND ASSISTANCE IS REQUIRED.

WARNING - THIS PROCEDURE MAY TRIP THE CHANNEL. PLACE THE CHANNEL IN BYPASS DURING THIS PROCEDURE IF A CHANNEL TRIP TO THE REACTOR TRIP MODULES IS NOT DESIRED.

ALLOW BISTABLE TO WARM UP AT LEAST 15 MINUTES.

CONNECT THE DVM TO THE "SETPOINT" TEST JACK OF THE "HIGH RC PRESSURE TRIP" BISTABLE. ADJUST THE "SETPOINT" VERNIER DIAL ON THE BISTABLE FOR A DVM READING OF 7.500 (+0.000, -0.005) VDC (2300 PSIG).

RECORD THE READING. ________________VDC.

PROCEED WITH VERIFICATION OF HIGH PRESSURE TRIP SETPOINT PER 5.0. REPEAT FOR OTHER THREE CHANNELS.

5.0 VERIFICATION OF HIGH RC PRESSURE TRIP BISTABLE SETTING

DISCUSSION: THE FOLLOWING DESCRIBES THE CHECKS AND TESTS REQUIRED FOR PRESSURE INPUT VARIABLES TO THE RPS. THE TESTS BELOW ARE APPLICABLE TO ONE RPS SUBSYSTEM. BECAUSE THERE ARE FOUR IDENTICAL RPS SYDSYSTEMS, THE TESTS MUST BE REPEATED, ONE SUBSYSTEM AT A TIME, ON THE REMAINING THREE.

NOTE:

PRIOR TO ROTATING THE TEST SWITCH AWAY FROM THE OPERATE POSITION (AT THE TEST MODULE ASSOCIATED WITH THE SUBSYSTEM UNDER TEST), PLACE THAT SUBSYSTEM IN BYPASS. THIS WILL PREVENT THE OUTPUT LOGIC FROM GOING INTO A 1 OUT OF 3. THIS REQUIREMENT IS NOT NECESSARY WHEN USING THESE CHECKS AS PART OF THE PRE-CRITICAL CHECKS.

5.1.1 PLACE THE PRESSURE TEST MODULE IN TEST OPERATE. THE ON TEST LAMP SHOULD GO FROM DIM TO BRIGHT, AS SHOULD THE TEST TRIP LAMP AT THE REACTOR TRIP MODULE. USING THE 10 VOLT TEST JACK ON THE FRONT FACE OF THE PRESSURE TEST MODULE, MEASURE THE REFERENCE VOLTAGE. IT SHOULD READ +10.00 TO +10.01 VOLTS. IF IT DOES NOT, DETERMINE IF THE ERROR IS AT THE TEST MODULE OR WITHIN THE ORIGINAL VOLTMETER. IF THE REFERENCE VOLTAGE IS IN ERROR, ADJUST THE APPLICABLE INTERNAL POTENTIOMETER UNTIL THE REFERENCE IS WITHIN THE 10 MV RANGE.

5.1.2 PLACE THE PRESSURE TEST MODULE AT ZERO. THE METER ON THE FRONT FACE OF THE BUFFER AMPLIFIER SHOULD READ 1700 PLUS OR MINUS 16 PSI. THE SCALED OUTPUT VOLTAGE AT THE BUFFER AMPLIFIER SHOULD READ 0.00 PLUS OR MINUS 0.01 VOLTS DC. IF IT DOES NOT, ADJUST THE BALANCE POTENTIOMETER ACCESSIBLE FROM THE FRONT PLATE.

5.1.3 PLACE THE TEST SWITCH AT THE RANGE POSITION. MOVE THE TOGGLE SWITCH TO THE 100 PERCENT POSITION. THE BUFFER AMPLIFIER METER SHOULD READ 2500 PLUS OR MINUS 16 PSI. THE SCALED OUTPUT SHOULD READ +10.00 PLUS OR MINUS 0.01 VOLTS DC. IF IT DOES NOT, CONSULT THE PRODUCT INSTRUCTION MANUAL.

5.1.4 PLACE THE TEST SWITCH AT CAL OUT (CALIBRATED OUTPUT). ASSUMING THE CALIBRATION KNOB IS INITIALLY AT ONE EXTREME OR THE OTHER, EITHER THE HIGH OR LOW PRESSURE BISTABLE WILL TRIP. ROTATE THE CAL OUT KNOB TO ITS COUNTER CLOCKWISE STOP AND RESET THE HIGH PRESSURE BISTABLE, IF NECESSARY. THE LOW PRESSURE BISTABLE SHOULD BE TRIPPED.

5.1.5 WITH THE DIGITAL VOLTMETER CONNECTED TO THE INPUT JACK OF THE HIGH PRESSURE BISTABLE, ROTATE THE CAL OUT KNOB ON THE FRONT PLATE OF THE PRESSURE TEST MODULE UNTIL THE HIGH PRESSURE BISTABLE JUST TRIPS. THE DIGITAL VOLTMETER SHOULD READ 7.500 PLUS OR MINUS 0.015 VOLTS DC. (EQUIVALENT TO 2300 PSI METER INDICATION.)

ATTACHMENT 1.2

PROCEDURE FOR RE SETTING THE SETPOINT OF THE PRESSURIZER PILOT OPERATED RELIEF VALVE (PORV) TO 2450 PSIG

1. PURPOSE

THE PURPOSE OF THIS PROCEDURE IS TO SET THE TRIP SETPOINT OF THE PORV IN THE NNI SYSTEM TO 2450 PSIG. THIS PROCEDURE IS APPLICABLE TO A NARROW RANGE RC PRESSURE TRANSMITTER WITH SIGNAL RANGE OF 1700 TO 2500 PSIG.

CALIBRATION OF THE HIGH PRESSURE SETPOINT FOR THE PORV REQUIRES THE ADJUSTMENT OF AN "OPEN" AND A "CLOSE" SETTING AND IS ACCOMPLISHED BY ADJUSTING BOTH THE HIGH AND LOW ADJUSTMENT KNOB OF THE HIGH-LOW SIGNAL MONITOR PER THE PROCEDURE BELOW.

2. REFERENCE

BCCo PRODUCT INSTRUCTION E92-4.

3. EQUIPMENT

DVM, READABLE TO 0.0001 VOLTS, 100 MΩ OR BETTER IMPEDANCE, 0.01% OR BETTER ACCURACY.

4. PROCEDURE

CAUTION: THE INSTRUMENTATION SETTINGS BELOW ARE BASED ON TRANSMITTERS WITH AN ASSUMED RANGE OF 1700 PSIG TO 2500 PSIG. THIS RANGE MUST BE CONFIRMED AND CALIBRATION SETTINGS ADJUSTED TO REFLECT THE INSTALLED EQUIPMENT. CONTACT B&W IMMEDIATELY IF AS-INSTALLED RANGES DIFFER AND ASSISTANCE IS REQUIRED.

A) ISOLATE THE PRESSURIZER PILOT-OPERATED RELIEF VALVE BY CLOSING THE PORV BLOCK VALVE.

B) LOCATE THE CORRECT HIGH-LOW SIGNAL MONITOR MODULE PER NNI INSTRUMENT INSTRUCTION MANUAL AND REMOVE THE MODULE FROM ITS CABINET MOUNTING. BENCH CALIBRATE PER BCCo PRODUCT INSTRUCTION E92-4, PAGE 5.

NOTE: REMOVAL OF THE MODULE WILL NOT INTERFERE WITH THE OPERATION OF THE BALANCE OF THE INSTRUMENT STRING.

C) RETAIN POSITION OF SWITCH S_1 AND S_2 PER INSTRUCTION MANUAL AND PREVIOUS OPERATION.

D) ADJUST "HIGH" (VALVE TO OPEN) SETPOINT TO ACTUATE AT A VOLTAGE INPUT READING OF 9.375 $\left(^{+0.000}_{-0.010}\right)$ VDC (2450 PSIG). RECORD THE READING ____________ VDC.

E) ADJUST "LOW" (VALVE TO CLOSE) SETPOINT TO ACTUATE AT A VOLTAGE INPUT READING OF 8.500 (±0.010) VDC (2380 PSIG).

86-1123921-00

RECORD ~~CORD~~ THE READING ____________ VDC.

F) RETURN THE MODULE TO SERVICE.

G) THE PORV CAN NOW BE RETURNED TO SERVICE BY OPENING THE PORV BLOCK VALVE.

FOR USE IN UNIT I ONLY

1001E
Revision 0
01/05/84

IMPORTANT TO SAFETY
NON-ENVIRONMENTAL IMPACT RELATED

CONTROLLED COPY FOR
USE IN UNIT I ONLY

THREE MILE ISLAND NUCLEAR STATION
UNIT NO. 1 ADMINISTRATIVE PROCEDURE 1001E
WRITER'S GUIDE FOR ABNORMAL TRANSIENT PROCEDURES

PROCEDURE COORDINATOR
UNIT 1

Table of Effective Pages

Page	Revision	Page	Revision	Page	Revision	Page	Revision
1.0	0						
2.0	0						
3.0	0						
4.0	0						
5.0	0						
6.0	0						
7.0	0						
8.0	0						
9.0	0						
10.0	0						
11.0	0						
12.0	0						
13.0	0						
14.0	0						
15.0	0						
16.0	0						
17.0	0						
18.0	0						
19.0	0						
20.0	0						
21.0	0						
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M A Nelson — Signature — 1/4/84 — Date

R J Toole — Signature — 1-4-84 — Date

H D Hukill — Signature — 1-5-84 — Date

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FOR USE IN UNIT I ONLY

THREE MILE ISLAND NUCLEAR STATION
UNIT NO. 1 ADMINISTRATIVE PROCEDURE 1001E
WRITER'S GUIDE FOR ABNORMAL TRANSIENT PROCEDURES

Table of Contents

1.0 GENERAL

1.1 Purpose

This procedure provides guidance for the preparation or revision of Abnormal Transient Procedures (ATP's) by a writer knowledgeable in the area of Abnormal Transient Operating Guidelines (ATOG).

1.2 Scope

This procedure applies to personnel who prepare, review, or approve ATP's for Three Mile Island Unit 1.

1.3 References

1.3.1 B and W Abnormal Transient Operating Guidelines

1.3.2 NUREG-0899, Guidelines for the Preparation of Emergency Operating Procedures

2.0 RESPONSIBILITIES

2.1 Preparers, reviewers, and approvers of ATP's shall conform to the guidance presented in this procedure.

3.0 REQUIREMENTS

3.1 Abnormal Transient Procedure System

3.1.1 ATOG is a symptom oriented approach to provide improved guidance for core cooling and radioactive releases.

3.1.2 If an abnormal transient occurs, ATP 1210-1, Reactor/Turbine Trip procedure shall be followed.

3.1.3 If other symptoms are present, ATP 1210-1 shall direct the user to other ATP's or other procedures.

3.1.4 ATP 1210-10 differs from the other ATP's in that it shall be a list of Rules, Guides, Graphs and Tables which apply generically to the ATP procedures.

3.1.5 The Immediate Actions and Follow-up Actions shall be listed in order of priority.

3.1.6 The ATP system shall interface with, but shall be separate from, emergency operating procedures, abnormal procedures, alarm responses and normal operating procedures.

3.1.7 In writing the ATP's, the preparer shall consider the limitations imposed by the number of operators available on a shift crew. The procedures shall be structured not to conflict with these limitations.

3.2 Format and Content

3.2.1 General Format

a. Cover Page

The ATP cover page shall be the standard procedure cover page as presented in Administrative Procedure 1001D.

b. Subsequent pages shall be as described in 1001D.

c. Title and Procedure Number

1. The title shall be brief and descriptive of the contents of the procedure.

2. The procedure number shall be in the 1210 series and serialized as for other TMI-1 procedures as described in 1001D.

d. Major Sections

1. Each procedure (except 1210-10) shall contain an Immediate Action section which shall provide

positive steps which must be performed before there is opportunity to refer to the appropriate procedure.

2. Each procedure (except 1210-10) shall contain a Follow-up Action section which provides steps to return the plant to a normal, stable, or safe, steady-state condition.
3. On a case basis, additional sections may be provided if required.
4. Sections and steps shall be numbered as described in 1001-D, beginning with "1.0" for the first section of a procedure.
5. Attachments, tables and other supplementary guidance shall be appended at the end of the procedure, if provided.
6. A table of contents may be provided if judged helpful.
7. The major sections of ATP 1210-10 shall consist of a Rules section, a Guides section, and a Graphs and Tables section.

e. Step Format

1. Steps shall be presented as direct commands or as conditional commands.
2. Direct commands shall be presented as command verb, object, modifier. For example: "Start Second Make-up Pump"

3. Conditional commands shall be presented as "<u>IF</u> condition", "<u>THEN</u> command". For example: "<u>IF</u> OTSG level greater than 95 percent; <u>THEN</u> trip the MFW pumps".

4. When the word "verify" is used as a command, it means to determine the status <u>and</u> if the status is not as required, then <u>put</u> it in the required status.

5. Follow-up Action steps shall be preceded by a blank line for marking completed steps.

6. Use the phrase "go to" when the operator is to discontinue use of the first procedure and stay in the referenced procedure.

7. Use the phrase "refer to" when the operator will be returning to the following step in the first procedure.

f. Cautions and Notes

1. Caution statements provide precautionary information. They shall be located prior to the action step with which they are associated.

2. Notes provide supplementary or advisory information. Notes should be located prior to the associated action step, unless the note content dictates other placement.

3. Do not provide action steps in caution statements or notes.

3.3 Style Guidance

3.3.1 Vocabulary

The vocabulary used in procedures should be easily read and understood by control room operators.

a. Use specific control board nomenclature and terminology which operators and other plant personnel understand.

b. Use short, commonly found words. Common words of not more than two syllables are preferred. However this does not apply to industry terms which are commonly used or technical words which are required to define or clarify the subject.

c. Use specific words that precisely describe the task or action of the operator. Avoid ambiguous instructions such as "check frequently" or "throttle slowly". Where possible, use specific intervals or guidelines.

d. Do not use contractions such as "don't" or "can't". Instead, use "do not" and "cannot".

3.3.2 Abbreviations, Acronyms, and Symbols

Only those abbreviations, acronyms, or symbols which are unambiguously recognized by operators should be used.

a. Generally, avoid abbreviating words, phrases, or names unless the system or component is frequently and commonly referred to by an abbreviated form.

b. When referring to specific nomenclature, use the precise labeling, including abbreviations, acronyms, or symbols.

c. The following symbols may be used, but are not mandatory:

1.	Equal to	=
2.	Approximately	~
3.	Greater than	>
4.	Less than	<
5.	Greater than or equal to	$\geq$
6.	Less than or equal to	$\leq$
7.	Percent	%
8.	Delta	Δ
9.	Degrees Fahrenheit	°F
10.	Degrees Celsius	°C
11.	Plus	+
12.	Minus	-
13.	Inches	"
14.	Feet	'

3.3.3 Sentence Structure

Sentence structure affects the rate at which a sentence is read and understood. The following guidelines will aid in developing sentences which are quickly read and easily understood.

a. Use short sentences.

b. Write action steps as simple command statements.

c. Use the same sentence style for main steps as well as substeps.

d. Write instructional or procedural steps as imperative statements, i.e., as direct command statements. (Passive statements may be used for emphasis in precautions, cautions, or notes. See below.)

   For example:

   This – Open Valve AB.

   Not this – Valve AB is opened.

e. Write instructional or procedural steps as positive statements. Generally positively stated sentences are more readily comprehended.

   This – Cover container when not in use.

   Not this – Do not leave container uncovered when not is use.

f. For instructional or procedural steps, use the understood "you" as the subject of each sentence. When a step is written, such as "check steam generator levels", the understood subject is the control room operator reading the procedure. Where actions stated in the procedure are to be performed by someone other than the control room operator, identify the performer of the action. For example:

   Direct Rad Chem to take a chemical sample.

g. Write caution statements to provide information used to prevent actions which could result in damage to equipment, loss of plant stability, or hazards to personnel or public.

Write note statements to provide brief information essential to performance of an action or sequence of steps.

Use a passive sentence structure (usually using "shall", "should", or "may") for emphasis in cautions and notes.

For example:

: <u>CAUTION</u>: This pump should not be operated with valve closed. :

: <u>NOTE</u>: The conditions below should be monitored during the remainder of this procedure. :

Select "shall", "should", or "may" as follows:

1. "Shall" implies a mandatory requirement.
2. "Should" implies a nonmandatory, preferred, or desired method.
3. "May" implies an operation which is possible but perhaps is not necessary.

3.3.4 Punctuation

Generally, standard American English rules for grammar and punctuation should be used.

a. Do not use contractions as they are often sources of confusion.

b. Place colons after the following:

1. Major steps which are followed by substeps.

2. Statements which are followed by lists, such as symptom statements followed by lists of symptoms.

c. Place parentheses around component nomenclature which follows a component number.

3.3.5 Capitalization

Capitalization may be used for emphasis or attention. Use capitalization as described below.

a. Initially capitalize (i.e., capitalize the first letter of) the following:

1. Each word in subsection titles

2. First word in a sentence

3. First word in a phrase used in a list

4. Each word in a component nomenclature

5. Each word in a system or component reference

6. Proper nouns, such as system names

b. Write the following items in all capital letters:

1. Procedure titles

2. Acronyms

3. The word CAUTION in a caution statement

4. The word NOTE in notes

5. Procedure major section titles

c. Capitalize and underline <u>IF</u> and <u>THEN</u> when used in conditional commands.

3.6 Units and Numerals

a. Use the units of measurement which actually appear on the instruments specified.

b. Use units of measurement familiar to the operator

c. Use Arabic numerals unless specific nomenclature dictates otherwise.

3.7 Tolerances

a. Tolerances should be provided where practical. Give ranges in immediately understood terms, avoiding the need for interpretation. For example:

Maintain tank level between 47 feet and 52 feet.

b. Use the same units of measurement that appear on meters and gauges.

3.8 Formulas and Calculations

Avoid the use of formulas and calculations where possible. Where calculations are necessary, provide space for notations.

3.9 Conditional Statements

If writing conditional statements, write the condition (the "IF" statement) as the first clause, and the contingency (the "THEN" statement) as the second clause. Structure conditional statements (<u>IF</u> ... <u>THEN</u> ...) as shown in the example in the Enclosure.

3.10 Sequencing

Technical necessity and instrument arrangement should be considered in sequencing tasks and action steps. Write action steps in the order in which they are to be performed or verified to have occurred.

3.11 Verification Steps

Include steps to cue the operator to verify whether equipment responses or operator actions are occurring and are correct. For example:

Verify all rods on bottom.

3.12 Diagnostic Steps

To aid operators in verifying that they are in the correct procedure, and to direct them to the correct procedure when necessary, diagnostic steps should be included in emergency procedures. For diagnostic steps, first instruct the operator to verify or check for a condition. Follow this with a conditional statement. For example:

Verify maximum HPI flow.

IF HPI flow cannot be verified in both loops: THEN . .

3.13 Caution Statements

When cautionary information is identified as necessary, it should be written in such a manner as to surely gain the operator's attention.

a. Place cautions immediately before the steps to which they apply.

b. Write cautions across the page, from margin to margin.

c. The word CAUTION shall be centered and the caution statement shall be boxed.

d. Do not write action steps in cautionary statements. If an action is required, write a step, not a caution.

e. Passive sentences (usually using "shall", "should", or "may") may be used to provide emphasis to cautionary statements, and to clearly separate them from steps.

f. Make caution statements as brief as practical, still including essential information.

3.14 Note Statements

Note statements are included to provide information to the operator concerning specific steps or specific sequences of steps. Notes generally should contain information which is of most use to the inexperienced operator to aid in interpreting step information or making a decision. Notes must be brief and easily understood. Notes should not contain lengthy information which is available in control room reference documents, such as Technical Specifications.

a. Place notes immediately before the step to which they apply, unless they should more logically follow.

b. Write notes across the page, from margin to margin.

c. The word NOTE shall be centered and the note statement shall be boxed.

d. Do not write action steps in notes. If an action is required, write a step, not a note.

e. Passive sentences (usually using "shall", "should", or "may") may be used to provide emphasis to notes, and to clearly separate them from steps.

3.15 Location Information

Assume that the action occurs in the control room for most steps in emergency procedures. Only identify the location of actions or components which are located outside the control room, unless a very infrequently used component is involved.

ENCLOSURE 1

IMPORTANT TO SAFETY
NON-ENVIRONMENTAL IMPACT RELATED

THREE MILE ISLAND NUCLEAR STATION
UNIT NO. 1 ABNORMAL TRANSIENT PROCEDURE 1210-1
REACTOR/TURBINE TRIP

Table of Effective Pages

Page	Revision	Page	Revision	Page	Revision	Page	Revision
1.0	0						
2.0	0						
3.0	0						
4.0	0						
5.0	0						
6.0	0						
7.0	0						
8.0	0						

Signature   Date

Signature   Date

Document ID: 00030

ENCLOSURE 1 (Cont'd)

THREE MILE ISLAND NUCLEAR STATION
UNIT NO. 1 ABNORMAL TRANSIENT PROCEDURE 1210-1
REACTOR/TURBINE TRIP

1.0 ENTRY CONDITION - Control Rod Drive Mechanisms have received an Automatic or Manual trip signal.

> NOTE: The following sequence represents a predetermined prioritization of immediate actions. Although some or all steps may be performed in parallel it is essential that all immediate actions be performed at least once and within several minutes.

2.0 IMMEDIATE ACTION - (Vital System Action, Status Verification, and Remedial Action).

1. Manually trip Reactor.

   Verify less than 10% power.

IF power is not less than 10% power;	THEN initiate HPI, maximize letdown, trip 1G-02 and 1L-02 (panel PR), and maintain primary to secondary heat transfer.

   Verify Groups 1-7 rod bottom lights.

IF one or more rods are stuck out.	THEN emergency borate

2. Manually trip Turbine.

   Verify T/G stop valves closed.

   Verify Generator Breakers open.

IF T/G stop valves are not closed;	THEN trip EHC-P-1A/B.
IF generator breakers remain closed;	THEN manually trip GB1-12, GB1-02 and locally trip field breaker.

ENCLOSURE 1 (Cont'd)

3. Decrease Main Feedwater Flow.

Verify ICS automatically is running back MFW flow.

IF ICS is not controlling MFW flow;	THEN take Hand control of the MFW regulating valves and run MFW back to control OTSG level.
IF MFW flow is still excessive;	THEN trip both MFW pumps.

4. Verify ICS/NNI Power On (PCL)

IF all subfeed power lights are off;	THEN trip MFW pumps, establish Primary to Secondary heat transfer using backup manual loader stations for EFW and TBV. Refer to EP 1202-40.
IF any subfeed power light remains off;	THEN refer to EP 1202-40/41/42.

5. Verify 4160 volt buses 1A, 1B, 1C, 1D and 1E energized (CR and PR)

IF loss of offsite power has occurred;	THEN verify or manually start and load at least one D/G. Restore Make-up, seal injection and EFW. Refer to EP 1202-2.
IF both D/G fail to start;	THEN refer to EP 1202-2A.

6. Start 2nd Make-up Pump.

Verify pressurizer level is greater than 100 inches.

IF unable to maintain pressurizer level;	THEN open MU-V-217 as necessary.
IF MU Tank is less than 55";	THEN open MU-V-14A or B as necessary to maintain MU Tank level greater than 55".
IF unable to maintain pressurizer level greater than 20 inches;	THEN initiate HPI.

ENCLOSURE 1 (Cont'd)

7. Verify Safety System Status.

Verify RCS greater than 1600 psig and RB less than 4 psig.

IF ESAS 1600 psig/or 4 psig actuation has occurred;	THEN verify HPI/LPI components started and RB isolation.
IF RB greater than 30 psig;	THEN verify RB spray and RB Isolation.

Verify OTSG greater than 600 psig.

IF SLRDS has actuated;	THEN verify affected OTSG MFW isolation.

8. Announce Reactor Trip over plant page.

9. Verify subcooled margin greater than or equal to 25°F.

IF subcooled margin is less than 25°;	THEN trip all RCP's, initiate full HPI, initiate EFW, raise OTSG level to 90-95% and go to ATP 1210-2.

10. Verify RCS temperature/pressure and OTSG pressure approaching post trip temperatures and pressures within 2-5 minutes.

IF excessive Primary/ Secondary Heat Transfer	THEN throttle MFW/EFW isolate steam leak, increase RCS make-up as necessary and absent other priority symptoms go to ATP 1210-3.
IF lack of Primary/ Secondary Heat Transfer	THEN absent other priority symptoms verify MFW/EFW and go to ATP 1210-4.

11. Verify RM-A-5 (or equivalent if RM-A-5 is OOS) normal.

IF an OTSG Tube Leak/ Rupture has occurred;	THEN absent other priority symptoms go to ATP 1210-5.

3.0 FOLLOW-UP ACTION

OBJECTIVE:	The objective of this procedure is to place the balance of plant components in a stable configuration and maintain RCS conditions stable until restart or cooldown direction is decided.

ENCLOSURE 1 (Cont'd)

1. Close the following extraction valves:

_____ EX-V-1A	_____ EX-V-5C
_____ EX-V-1B	_____ EX-V-5D
_____ EX-V-4A	_____ EX-V-6A
_____ EX-V-4B	_____ EX-V-6B
_____ EX-V-5A	_____ EX-V-6C
_____ EX-V-5B	_____ EX-V-6D

_____2. Verify OTSG level is being maintained at proper level.

_____3. Verify that turbine bypass valves (or, if vacuum is lost, atmospheric relief valves) are controlling at desired pressure.

_____4. Verify RCS pressure stabilizes within normal pressure limits.

5. IF 1G-02 and 1L-02 were opened to trip the reactor, THEN:

_____a. Dispatch an operator to 338' elevation (3rd floor) Control Tower to trip main (Unit 10) and Secondary (Unit 11) AC CRDM Supply Breakers.

_____b. Once Unit 10 and 11 Supply Breakers are open, then reclose 1G-02 and 1L-02 on Control Room Panel (PR).

_____c. Restart previously running equipment fed from:

1. Pretreatment MCC
2. 1A Radwaste MCC
3. 1A Reactor Plant MCC
4. 1B Radwaste MCC
5. 1B Reactor Plant MCC
6. A.C. Dist. Panel D-9

6. Verify the following T/G support pumps are operating:

_____a. AC Motor Suction Pump
_____b. Turning Gear Oil Pump
_____c. Bearing Lift Pumps

_____7. Reduce pressurizer level controller setpoint to 100 inches (25%).

_____8. IF a turbine rotating component failure occurs causing the Reactor Trip; THEN declare an Unusual Event (carry out EPIP 1004.1).

_____9. IF the Reactor trip is coincident with a total loss of forced reactor coolant flow; THEN declare an Unusual Event (carry out EPIP 1004.1).

_____10. IF the Reactor trip is coincident with a total loss of the ability to feed the OTSGs; THEN declare an Unusual Event (carry out EPIP 1004.1).

ENCLOSURE 1 (Cont'd)

____11. IF an unplanned ESAS actuation occurs following Reactor Trip; THEN declare an Unusual Event (carry out EPIP 1004.1).

____12. IF a turbine failure occurs resulting in casing penetration THEN declare an Alert (carry out EPIP 1004.2).

____13. IF the Reactor trip is coincident with either reactor coolant outlet temperature greater than or equal to 620°F; THEN declare an Alert (carry out EPIP 1004.2).

____14. IF the Reactor trip is coincident with a reactor building pressure greater than or equal to 4 psig; THEN declare an Alert (carry out EPIP 1004.2).

____15. IF more than one control rod is stuck out of the core following a Reactor trip; THEN declare an Alert (carry out EPIP 1004.2).

16. Verify the following Reactor trip RB isolation valves closed:

RB Sump

______WDL-V-534 ______WDL-V-535

RC Drain Tank

______WDG-V-3 ______WDL-V-303
______WDG-V-4 ______WDL-V-304

RCS Sample

______CA-V-1 ______CA-V-3
______CA-V-2 ______CA-V-13

RB Purge

______AH-V-1A ______AH-V-1C
______AH-V-1B ______AH-V-1D

Core Flood Tank

______CF-V-2A ______CF-V-2B
______CF-V-19A ______CF-V-19B
______CF-V-20A ______CF-V-20B

Demin Water

______CA-V-189

ENCLOSURE 1 (Cont'd)

OTSG Sample

______CA-V-4A ______CA-V-5A
______CA-V-4B ______CA-V-5B

Letdown Cooler

______MU-V-3

_____17. Reduce the running balance of plant equipment to that which is required to maintain plant conditions (i.e. one FW-P-1, one CO-P-2, one CO-P-1, No HD-P-1).

_____18. To open Containment Isolation Valves (CIV's) automatically closed refer to ATP 1210-10.

_____19. Determine shutdown margin per OP 1103-15, Reactivity Balance Calculation.

_____20. Determine and evaluate cause of Reactor trip per Attachment I.

_____21. Take hand control of TBV, reset the reactor trip and maintain hot shutdown conditions until decision on direction of plant movement is obtained.

ENCLOSURE 1 (Cont'd)

ATTACHMENT 1

THREE MILE ISLAND UNIT 1 REACTOR TRIP REPORT

1. Reactor Trip No.:____________(Yr. - Trip No.)

2. Date:________________________(Month - Day - Year) Time______________

3. Cause of Reactor Trip:

4. Plant Conditions prior to trip:

   Reactor Power Level____________________. Tave____________________.

   RCS Pressure____________________. RCP Combination____________.

   MU Tank Level____________________. Pressurizer Level__________.

   RCS Boron____________________. EFPD____________________.

   CRDM Percent withdrawn:

   Group 1____% Group 3____% Group 5____% Group 7____%

   Group 2____% Group 4____% Group 6____% Group 8____%

   MU Pump Operating____________________.

5. ICS Stations in Hand: ______________________________.

6. Evolutions in progress prior to trip (include major components unavailable prior to trip).

7. Description of Transient (include any abnormal systems responses).

8. Maximum RCS pressure during transient ____________. Did PORV actuate (Yes/No)_____.

9. Minimum pressurizer level during transient________________. Were additional pumps started? (Yes/No - Tag No.)

10. Record the reset pressure at which the last main steam relief valve closed. (Use observation of steam reliefs or chart recorder for this information).

11. Did RPS/ESAS/EFW systems appear to auto function at the required setpoint and in the appropriate time frame? (Indicate N/A if setpoints not reached).______________________

12. Were any Technical Specification L.C.O's violated? (Yes/No - Specify)______________________ (Submit 1044 as necessary).

ENCLOSURE 1 (Cont'd)

ATTACHMENT 1 (Cont'd)

13. Corrective Action taken to prevent future re-occurrence.

14. Radiological Impact of Transient (describe any abnormal readings from RMS).

15. Was the Emergency Plan Actuated? (Yes/No).
What level? ____________ ____________.

16. Review Transient Cycle Log book and record component cycles as necessary. List affected components:

17. Notify the Operations and Maintenance Director or designee to make the B and W trip notification using the "Notepad" Systems and Format. Person Notified:____________________.

18. Attach copies of the Bailey 855 sequence of events and any pertinent MOD Comp. Transient Monitor graphs.

19. Time and Date of next Reactor Criticality____________________________.

20. Completed by: ____.

21. Reviewed by Shift Supervisor: ________________________________.

22. Review by Manager Plant Operations: ____________________________.

cc: Chairman - Plant Review Group
Director - Systems Engineering (Parsippany)
Director - Operations and Maintenance
Vice President - TMI Unit 1

COMPARISON OF WRITERS GUIDE FOR ABNORMAL TRANSIENT PROCEDURES WITH NUREG 0899 (GUIDELINES FOR THE PREPARATION OF EMERGENCY OPERATING PROCEDURES)

Introduction:

The objectives of the Writers Guide for the Abnormal Transient Procedures (ATP's) are to assure that the procedures are (1) consistent in format and style, (2) usable by the control room personnel, (3) concise and (4) accurate.

The procedures were developed by the ATOG committee over a period of about two years. During that period procedure development was influenced by the following resources:

1. B&W ATOG Procedural Guidelines.
2. Draft INPO Writers Guide for Emergency Operating Procedures, January 23, 1982.
3. INPO, The Role of Verification and Validation in the Development Process for Emergency Operating Procedures, February 16, 1982.
4. Human Factors Guidance
5. NUREG 0899, August 1982.

The ATP format and style depart from the event oriented Emergency procedures. It took some period of time to gain confidence in the function (symptom) oriented procedure concept. Use of the procedures on the simulator by Committee members and Operations personnel was instrumental in establishing confidence in the procedures. The Writers Guide was not finalized until the procedure concept was accepted.

The emergency procedures contained guidance that was the result of previous commitments or requirements. The ATP's were reviewed to assure that this guidance was not inadvertently dropped.

Compliance with NUREG 0899:

NUREG 0899 was utilized in the finalization of the procedures and in the preparation of the writers guide. There are minor differences between the procedures and the NUREG however, the goals of the NUREG have been met.

The following tabulation compares the TMI-1 ATOG program to the NUREG paragraphs on the writers guide (Numbering refers to NUREG section numbers.).

5.1 Preparation of the Plant Specific Writers Guide

The TMI-1 Writers Guide was not formalized until after the procedures were developed. The procedures were developed by the ATOG committee using the resources listed in the Introduction. The committee approach maintained consistency and resource material assured adequacy of the final product.

The Writers Guide is essential to document the accepted practices and to maintain consistency in future revisions when additional personnel will be proposing changes.

5.2 General Guidance

5.2.1 Consistency Among the Procedures

The ATP's meet this objective with exception of a few steps that have been detected during simulator training and subsequent review.

5.2.2 Cross-Referencing Within and Among Procedures

The objective of minimizing cross-references has been met. The use of guidelines in a centralized location results in references, however, this is less disruptive to procedure continuity than detailing routine operations within the procedure.

The writers guide addresses the acceptable method of referencing (refer to) and exiting to another procedure (go to).

5.2.3 Operator Aids

Graphs and tables are used and are located in the applicable procedure for unique information and have been located in a central location ATP 1210-10 for general information.

Flow charts have not been utilized. Conditional statements in the "IF, ... THEN ..." format provide sufficient guidance in lieu of flow charts.

5.3 Presentation of Information for Readability

The Human Factors representative on the ATOG committee and operator input were utilized to enhance readability.

5.4 Organization of EOP's

5.4.1 Cover Page

ATP's comply.

5.4.2 Table of Contents

A table of contents is not used because the procedures are very short and (except for ATP 1210-10) have a uniform format. ATP 1210-10 has a table of contents.

5.4.3 Scope

The procedures do not have a scope section. The title of the procedure describes the condition that the procedure addresses. The directions within the procedures specify when other procedures are entered.

5.4.4 Entry Conditions

ATP 1210-1 Reactor/Turbine Trip has an entry condition section. The remaining ATP's do not have this section. ATP 1210-1 is the normal entry point in this procedure series. The procedure steps direct entry into other procedures as appropriate.

Training is an important feature in entry to the procedures. Since the procedures are symptom oriented, entry into the procedures is required when symptoms indicate that an important function is lost.

5.4.5 Automatic Actions

Automatic actions are not identified in a separate section. Since the procedures are symptom oriented the automatic actions are not readily identified as in event procedures. Verification steps within the procedures assure that the necessary equipment has operated.

5.4.6 Immediate Operator Actions

ATP's comply.

5.4.7 Subsequent Operator Actions

ATP's comply (identified as Followup Actions).

5.4.8 Supporting Material

Unique Supporting Material is attached to the affected procedure. Supporting material that is universal is collected into ATP 1210-10.

5.5 <u>Format of EOP's</u>

5.5.1 Identifying Information

ATP's comply.

5.5.2 Page Layout

ATP's comply with the NUREG except for minor exceptions. The word processing equipment performs the page break automatically; however, if the step is longer than 4 lines it may be broken.

5.5.3 Warning, Caution and Note Statements

ATP's comply.

5.5.4 Placekeeping Aids

The Immediate Actions must be memorized. In practice they are subsequently read and confirmed as complete. Followup steps have a block to initial.

5.5.5 Divisions, Headings, and Numbering

ATP's comply.

5.5.6 Emphasis

Emphasis is accomplished with the use of Caution statements, capitalization, and underlining.

5.5.7 Identification of Sections within a Procedure or Subprocedure

The ATP's are tabulated in the control room binder for quick identification. No special identification is required for subsections.

5.5.8 Figures and Tables

Figures and Tables have been provided. Access and usability have been found to be adequate.

5.5.9 Use of Flow Charts

Not used. See 5.2.3.

5.6 Style of Expression and Presentation

5.6.1 Vocabulary

5.6.2 Abbreviations, Acronyms, and Symbols

5.6.3 Sentence Structure

5.6.4 Punctuation

5.6.5 Capitalization

5.6.6 Units

5.6.7 Numerals

5.6.8 Tolerances

5.6.9 Formulas and Calculations

5.6.10 Conditional Statements

The Writers Guide addresses each of these areas and is in compliance with the goals of NUREG 0899 except that no list of abbreviations has been provided. The abbreviations used are familiar to the operators.

5.7 Content of EOP's

5.7.1 Sequencing

The sequencing of the steps in the ATP's have been based on prioritization of the tasks. The sequence of steps is acceptable for the physical layout of the control room.

5.7.2 Verification Steps

Verification steps are utilized within the procedure and the operators are trained to routinely reverify the functions related to core cooling.

5.7.3 Non Sequential Steps

Non sequential steps are utilized and are identified by specific criteria where practical.

5.7.4 Equally Acceptable Steps

Use of equally acceptable alternatives has been made. The wording utilized makes clear that one of the alternatives must be accomplished.

5.7.5 Recurrent Steps

5.7.6 Time Dependent Steps

Recurrent and Time Dependent steps have criteria such as plant condition where practical. In some cases frequency will depend on rate of change of a parameter and quantitative guidelines were not provided.

5.7.7 Concurrent Steps

The use of concurrent steps has been minimized. Where used, the number of actions are within the control room staff limitations.

5.7.8 Diagnostic Steps

5.7.9 Warning and Caution Statements

5.7.10 Note Statements

5.7.11 Location Information

Instructions are contained in Writers Guide and the ATP's comply.

5.8 Control Room Staffing and Division of Responsibilities

5.8.1 Consistency between Staffing and Procedures

5.8.2 Division of Responsibility

5.8.3 Staffing of the Control Room

The ATP's have been written in a sequential pattern so that they could be followed by a single control room operator to accomplish the objectives of core cooling and minimizing radioactive release.

Administrative Procedure 1001G addresses responsibility of control room personnel in emergency situations including use of procedures.

The evaluation of simulator performance includes the crew concept where the interface of different crew members is verified as acceptable using the procedures.

The prioritization of steps, definition of roles, and evaluation of crew performance as a team assures that the procedures are acceptable for the available control room staffing.

Conclusion:

GPUN endorses the objectives of NUREG 0899 pertaining to ATP procedure content, format, style, and usability. The NUREG was used for guidance during procedure development and has been incorporated in the ATP Writers Guide.

The exceptions to the NUREG are not in conflict with the objective and we consider the justification for the differences adequate.

ATOG Operator Training Program

The training program designed for licensed operator training is divided into three main categories of instruction:

(1) Introductory Classroom Training

(2) Simulator Classroom Training

(3) Simulator Operational Training

These categories were designed to provide the operator with an introduction to ATOG and an intense review of the Abnormal Transient Procedures, to include both classroom and simulator training.

The design and development of the ATOG training program was a joint effort between GPU Operations, Technical Functions, and Training Groups. During the scheduled meetings for the ATOG committee, specific topics were identified as potential areas requiring training. These topics were presented to the Training Department for review and were proposed for inclusion in the training program.

The training program is divided into two phases. Phase One is a classroom introduction to ATOG and Phase Two is a combination of both classroom and simulator training. Separation of the training program into two phases was to provide each operator with time to review the proposed procedures and to provide feedback to the ATOG committee and Training Department in order to enhance the second phase of training.

The objectives for Phase One of the ATOG training were developed to ensure that trainees understand the following:

(1) The philosophy behind the approach to the Abnormal Transient Procedures (ATPs)

(2) ATOG history

(3) ATOG implementations

(4) ATOG control concepts

Objectives were developed by the TMI-1 ATOG committee and approved by the Operations and Training Groups. During Phase One classroom training, the proposed ATPs were reviewed step by step and operators were given the opportunity to provide feedback to the Operations and Training Groups regarding the procedure format and sequence. The training material used during this phase of training was included as Attachment I to letter 5211-83-377 dated December 23, 1983. Phase One training was completed during December, 1983.

Phase Two of the ATOG Operator Training Program includes both classroom and simulator training. This phase of training is being conducted at the Babcock and Wilcox Training Center in Lynchburg, Virginia. The objectives for the classroom portion were developed by the Training Department with input from the TMI-1 ATOG committee. Upon completion of the initial draft, these objectives underwent review, comment, and approval by the Operations and Technical Functions Groups. These approved TMI ATOG training objectives were used by the Training Department to prepare lesson plans for use in the classroom portion of Phase Two training. The following is a list of areas to be emphasized during the classroom training in Phase Two:

- Technical bases of ATPs
- Review of Procedures
- Immediate Actions and Reasons for Each
- Recognition of Symptoms
- Entry and Exit Points for Procedures

- Prioritization of Actions
- ATP Rules and Guidelines, and their application
- Major Component Operation
- Verification Requirements

The lesson plans developed for Phase Two of the ATOG program underwent review, comment, and approval by the Operations and Technical Functions Groups and were presented to B&W for use in the training program.

The initial week of training conducted at B&W during the week of January 2, 1984, was attended by key members of Operations, Training, and the TMI-1 ATOG Committee. This week was used as a prototype program to finalize the program presentation, and to provide feedback to B&W instructors. The comments generated during this first week of training were incorporated into the lesson plans. These approved lesson plans will be used to train operating crews commencing January 16, 1984. The approved lesson plans are provided as an attachment.

The remainder of the training program involves simulator training for each operator on the ATPs. The objectives of the simulator program are as follows:

- The operators must demonstrate an understanding of the ATP Structure and the Symptom Oriented Approach to transient and accident mitigation, including:
    - Control of safety functions
    - Accident evaluation and diagnosis
    - Achievement of safe, stable, or shutdown conditions

- The operators must demonstrate an understanding of plant systems and component relationships to ATPs, plus their function and use during accidents and transients.
- The operators must demonstrate a working knowledge of the technical content of the ATPs in order to achieve ATP objectives.
- The operators must demonstrate the ability to execute all ATPs (as individuals and as teams) under simulated accident and transient conditions.

The simulator training includes a variety of scenarios incorporating multiple failures (simultaneous and sequential). For each drill used during the training program, a drill guide is used to provide the simulator instructor with plant specific information for each drill. Each drill guide contains the following:

- General description of drill
- Drill objectives
- Method of initiation
- Sequence of expected action
- Point of termination
- Procedure flow chart

A sample drill guide is included with this submittal. The sequence of drills scheduled for the program is also provided. All ATPs will be exercised by each Operator at the B&W Simulator. Additionally training will be provided to each crew utilizing control room walkthroughs.

ATOG Training Program evaluation will be conducted using several evaluation methods. Licensed Operators will be evaluated on two occasions.

At the end of each week of training, a written exam and simulator exam will be administered to each licensed operator covering selected lesson objectives presented during the week. Evaluations of the ATOG Operator Training Program will be performed by GPUN Management. The evaluation form used is included with this submittal. Student evaluations will be requested from each operator at the completion of each week of training. The comment form is included with this submittal. Feedback provided by these evaluations will be used to upgrade the training program.

ATOG TRAINING INTRODUCTION

I. WHY IMPLEMENT ATOG?

A. Prioritization of major responses seen as major benefit.

1. Main reason is operator responds to highest priority item first-

SCM. This assures the core will be kept cooled and covered with water.

B. Formating, thru Human Engineering, made easier to read, easier to follow, less total pages.

1. This makes procedures more manageable during an emergency when steps must be read aloud.

2. Condensing of steps, which are often repeated, into a rules and guidelines procedure reduced the size of the procedures to be handled during a casualty (HPI Throttling criteria, EFW response, etc.).

C. NuReg 737, Supp. 1. required a long term upgrade of emergency procedures.

1. Owners group using ATOG as part of satisfaction of NuReg.

II. ATOG IMPLEMENTATION

A. Abnormal Transient Procedures (ATP) are the ATOG procedures and are in-place in Unit 1 Control Room.

1. This implementation resulted in major revisions to many Emergency and Abnormal Procedures and several Operating Procedures.
2. The ATOG Committee wrote the ATP's using the B & W guidelines, then reviewed each EP and AP to make necessary changes to them.
3. Prior to implementation several SRO's from plant exercised the procedures at the simulator. Their comments were then entered into final draft.

III. PURPOSE OF THIS SIMULATOR SESSION

A. Reinforce confidence and develop familiarization of ATP's thru use on simulator.

B. Classroom review of each step of all the ATP's with explanation of basis for each technical change.

C. Practice using the ATP's to respond to simulator transients.
   1. Emphasizing procedure utilization.
   2. Perform step-by-step verification and reverification.
   3. Make transition from ATP's to event procedures or operating procedures.
   4. Practice crew concept to transient control using ATP's.

D. Technical Specification Training on the Simulator.
   1. NRC concerned over number of possible LCO violations we could have during startup.

2. TMI-1 Tech Specs do not give guidence on certain LCO violations so management committed to follow Standard Tech Specs for LCO's where no guidance is given.

3. Where no guidance is given:

   a. When LCO is violated and has no action statement within one (1) hour initiate action to place plant in a condition where LCO is not required.

   b. Within an additional six (6) hours the plant will be in hot standby.

   c. Within an additional six (6) hours the plant will be in hot shutdown.

   d. Within an additional twenty-four (24) hours the plant will be in cold shutdown.

Inter-Office Memorandum

GPU Nuclear

Date January 10, 1984

Subject SIMULATOR CREW EVALUATION SCHEDULE

3210-84-0009

To H. D. HUKILL, DIRECTOR UNIT I
J. J. COLITZ, PLANT ENGINEERING DIRECTOR
R. J. TOOLE, OPERATIONS AND MAINTENANCE DIRECTOR
C. E. HARTMAN, LEAD ELECTRICAL ENGINEER
L. C. LANESE, GPU PARSIPPANY
D. J. BOLTZ, SUPERVISOR SIMULATOR INSTRUCTOR
H. B. SHIPMAN, OPERATIONS ENGINEER SENIOR II

Location Three Mile Island

Below is a schedule for the Duty Superintendent and ATOG Member evaluation of our crews at the simulator.

SHIFT	WEEK OF	DUTY SUPT./EXAMINER	ATOG MEMBER
D	01/16/84	M. J. Ross	L. C. Lanese
E	01/23/84	H. D. Hukill/M. J. Ross	C. E. Hartman
F	01/30/84	R. J. Toole	R. J. Toole
A	02/06/84	M. J. Ross	L. C. Lanese
B	02/13/84	J. J. Colitz	D. J. Boltz
C	02/20/84	M. J. Ross or R. J. Toole	H. B. Shipman

Any problems with the schedule, please call.

M J. Ross

M. J. Ross
Manager, Plant Operations
Ext. 8015

MJR/dds

cc: B. P. Leonard, Operator Training Manager
S. L. Newton, Mananger, Plant Training
L. L. Ritter, Administrator II, Plant Operations

A0000648

Inter-Office Memorandum

GPU Nuclear

Date January 10, 1984

Subject SIMULATOR CREW EVALUATION

3210-84-0008

To DUTY SUPERINTENDENTS
ATOG COMMITTEE MEMBERS

Location Three Mile Island

Attached is an evaluation sheet to be used during ATOG Crew Exams at Lynchburg, VA. Listed below are the guidelines and rules for performing these evaluations.

1. Drill Scenarios

   Scenarios are confidential and are only to be seen by you and the B&W Simulator Operator at the time of examination. Ensure you recover all copies given to B&W Instructors. Approximately eight (8) scenarios will be provided to you. Depending on time, you should run 2-4 drills and evaluations.

2. Evaluations

   Each crew must be assigned a pass/fail grade. A failure grade will result in that crew's removal from operating duties until such time a satisfactory evaluation can be performed. Besides a crew evaluation, the ATOG member or Duty Superintendent will during that week evaluate crew and individual performance. The evaluator for this period will document any individual training problems on the simulator evaluation sheet with proposed corrective action. Deficiencies significant enough to be listed must also have a proposed corrective action on the simulator sheet. Recommended corrective actions must be satisfactorily disposed of by the Manager of Plant Operations. Completion of these actions must be documented on the simulator evaluation sheet.

Submitted by M. J. Ross
M. J. Ross
Manager, Plant Operations
Ext. 8015

Approved by R J Toole
R. J. Toole
Operations and Maintenance Director
Ext. 8005

RJT/MJR/dds

cc: B. P. Leonard, Operator Training Manager
S. L. Newton, Manager, Plant Training

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SIMULATOR EVALUATION SHEET

EVALUATOR NAME/TITLE ____________________

DATE: ________________

CREW: ________

LIST NAMES AND POSITIONS

NAMES	POSITION	OBSERVERS

	SATISFACTORY	UNSATISFACTORY
1. Proper use of Procedure.		
A. Operators know manual actions.	_____	_____
B. Procedures read aloud.	_____	_____
C. Verification of actions independently.	_____	_____
D. Ability to move from one procedure to another.	_____	_____
2. Followed Emergency Plan.	_____	_____
3. Team work and communications.	_____	_____
4. Shift Foreman involvement.	_____	_____
5. Shift Supervisors command status and ability to maintain big picture and overall control.	_____	_____
6. Plant control (actual control manipulation).	_____	_____
7. Use and communication with STA.	_____	_____

8.	Crew attitude toward training received and participation in simulator activities. (ATOG Acceptance).	____		____
9.	Alertness to overhead alarms.	____		____
10.	Ability to combat casualities given to them.	____		____
11.	Knowledge and execution of 50.72/50.73 reporting requirements.	____		____
12.	Overall evaluation. Pass	____	Fail	____

COMMENTS ON PERFORMANCE OF CREW:

RECOMMENDED CORRECTIVE ACTIONS:

ATOG EVALUATION TO BE COMPLETED DURING SIMULATOR TRAINING WEEK

ATOG INDIVIDUAL EVALUATION
(Practical only Written Exam will be given)

NAMES	CRITERIA (CHECK IF OKAY OR LIST CORRECTIVE ACTION REQUIRED BELOW)					
	#1	#2	#3	#4	#5	#6

CRITERIA

1. Knowledge of procedure flow.
2. Knowledge of Rules/Guidelines.
3. Proper attitude about ATOG and its use.
4. Demonstrated knowledge of ATOG priorities.
5. Ability to recognize ATOG symptoms.

   A. Loss of subcooling.
   B. Excessive heat transfer.
   C. Lack of heat transfer.
   D. OTSG Tube rupture.
   E. Superheat.

6. Ability to intergrate lower level event casualties while maintaining ATOG procedure

INDIVIDUAL CORRECTIVE ACTION REQUIRED LIST

NAME	ACTION REQUIRED	ACTION COMPLETED (MGR. PLANT OPS)

Signature of ATOG Evaluator Date

cc: Manager, Plant Operations
Operations and Maintenance Director
Vice President TMI-I
Training Manager

PROGRAM: ATOG TRAINING

UNIT I

WEEK OF ____________ TO ____________

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY
INTRODUCTION 1210-10 Abnormal Transient Rules, Guides & Graphs 1210-1 Reactor Trip Prioritization of Cooling Methods	1210-2 Loss of Subcooling Margin 1210-6 Small Break LOCA 1210-7 Large Break LOCA	1210-3 Excessive Cooling 1210-4 Lack of Heat Transfer	1210-8 RCS Superheated 1210-9 HPI Cooling/ Recovery from Solid Operations	1210-5 OTSG Tube Rupture Written Exam
Simulator: Unannounced Casualties & LER Drills	Simulator: Unannounced Casualties & LER Drills	Simulator: Unannounced Casualties	Simulator: Unannounced Casualties	Simulator: Unannounced Casualties Management Evaluation

CLASSROOM: 0800 - 1130 SIMULATOR: 1200 - 1500

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev**
PRIORITIZATION OF COOLING METHODS		P

Objectives

A. Be able to list the means of heat removal which are availible to remove decay heat.

B. Explain why steam generator heat removal is the preferred method over all others, even during an OTSG tube leak.

C. Given various plant conditions select the preferred method of heat removal.

Responsibility		Signature	Title	Date
Origination		Charles Hetzel	Sup. NLO Trng	1/2/84
Review/Concurrence		HB Shipman	W1 Operations Eng.	1/2/84
		M J Ross	Mgr PLT OPS	1/2/84
		Lou Lanese	SAPC Engineer	1/5/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-2-84
	Final	Bruce Leonard	Operator Training Manager	1-2-84

6210-ADM-12..01-1 (12/82)

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LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: PRIORITIZATION OF COOLING METHODS

TRAINING SECTION: OPERATOR TRAINING

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	01/12/84						
2.0	P	01/12/84						
3.0	P	01/12/84						
4.0	P	01/12/84						
5.0	P	01/12/84						
6.0	P	01/12/84						
7.0	P	01/12/84						

Revision P
01/12/84

INSTRUCTOR NOTES

I. TITLE: Prioritization of Cooling Methods

II. LESSON OBJECTIVES:

A. Be able to list the means of heat removal which are availible to remove decay heat.

B. Explain why steam generator heat removal is the preferred method over all others, even during an OTSG tube leak.

C. Given various plant conditions select the preferred method of heat removal.

III. REFERENCES:

A. TMI Unit One ATP's, E/P's, AP's

B. Babcock and Wilcox ATOG Part I and Part II

IV. MATERIAL REQUIRED:

V. CLASSROOM OR AREA REQUIREMENTS:

A. As deemed necessary according to the number of persons in attendance

VI. TIME:

A. 1 hr

VII. INTRODUCTION:

A. During a casualty situation it may be necessary, due to equipment failure, to utilize more than one means of decay heat removal.

INSTRUCTOR NOTES

List methods in intro: OTSG - Natural Circ & forced, DH,HPI,feed & bleed

B. The selection of the most desirable means of decay heat removal needs to be make considering equipment availibility and best method of operation and offsite doses.

C. Due to present decay heat level these guidelines are superseded by OPS Memo 83-6 provided by Tech. Functions. Until 5% power is achieved this memo will be in effect.

1. Following a loss of primary to secondary heat transfer or forced circulation establish a stable plant using the letdown coolers as a heat sink. Guidelines and curves are provided in the memo to assure a safe, stable condition is maintained.

VIII. PRESENTATION:

A. Steam Generator heat removal

1. Main feedwater supplied; steaming to condenser is preferred

   a. Steaming to atmosphere-need to consider water inventory

2. Emergency feedwater supplied; steaming to condenser

   a. stress to tubes

INSTRUCTOR NOTES

b. steam from EF-P-I going to atmosphere may be contaminated if tube leakage exists.

c. suction source selection from ATP 1210-10: CO T-1, hot well, 10 E6 tank, river

3. Forced circulation results in less cooldown time

a. Natural circulation cooldown rate may be slow due to Rx vessel head bubble concern

10^{0}F/hr limit- Crystal River CD rate 30-35F^{0} without getting head bubble

b. If only one OTSG available then tube to shell delta-T limit of 70^{0}F may slow cooldown.

4. OTSG tube leakage requires concern for offsite radiation doses.

a. steaming both OTSG's reduces cooldown time resulting in less release to public

b. condenser give partitioning factor

c. isolation results in tube to shell delta-T problem on affected OTSG limiting cooldown rate, increasing offsite dose.

d. must prevent lifting MS safeties

INSTRUCTOR NOTES

e. avoid filling steam lines with water by steaming OTSG

f. get on DH removal ASAP at higher RCS temperature-new limit 300°F.

B. HPI Cooling

1. Going out the PORV causes RB contamination with potential for PORV to stick open

2. SBLOCA may require both HPI and OTSG cooling

a. OTSG needed to reduce RCS pressure

b. boiler - condenser cooling may result

3. Without OTSG heat removal may form bubbles in hot legs and head which will "hold up" RCS pressure

a. Pump-bump is best method of removal-need OTSG level or FW flow

4. Add to BWST to eliminate need to recirc. from RB.

a. must not flood instruments in RB

b. ensure no boron reduction occurs

5. HPI cooling with SCM: run one RCP to provide mixing reducing PTS concerns.

C. Low Pressure Injection/Long Term Cooling

1. Large breads result in depressurization to LPI pressure - can secure HPI if criteria is met

INSTRUCTOR NOTES

2. Core flood tanks will hold RCS pressure up until empty
   a. should then isolate
3. No need for OTSG cooling but should be filled to 90 - 95°/o in case RCS repressurizes and refill.
4. Can establish decay heat removal operation at 300°F.
5. Establish normal drop line recirc. or other long term cooling method prescribed in OP

Show TP from OP 1104-4

IX. SUMMARY:

A. Review Objectives listing means of heat removal and Prioritize cooling methods.

B. Give class general scenarios and let them select preferred method.

Training Content Record		
Lesson Course Title	Number	
Lesson Plan Title ATP 1210-1 REACTOR TURBINE TRIP	Number	Rev

Objectives

1. Be able to list the manual actions required to be recognized and performed, in the proper order.

2. Given the inability to accomplish any action/verification, list the actions which must be taken.

3. Upon determination of; loss of subcooled margin, improper heat transfer, or RMA-5 increasing, give the action which must be taken and the ATP to proceed to.

4. Explain the relationship between the reactor/turbine trip ATP and the other ATP's.

5. Explain why fast response to the ATWS, Abnormal Transient Without Scram, event is critical.

Responsibility		Signature	Title	Date
Origination		[illegible]	Sr. Nonlicensed Op Trng	1/11/84
Review/Concurrence		HB Shipman	U-1 Ops Sup	1/12/84
		M. J. Ross	Mgr PLT OPs	1/12/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-12-84
	Final	Bruce Leonard	Operator Training Manager	1-12-84

6210-ADM-12[illegible]1.1 (12/82)

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Revision P
12/15/83

LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-1 REACTOR/TURBINE TRIP

TRAINING SECTION: OPERATOR TRAINING

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						
5.0	P	12/29/83						
6.0	P	12/29/83						

Revision P
12/29/83

INSTRUCTOR NOTES

I. TITLE: ATP 1210-1 REACTOR/TURBINE TRIP

II. LESSON OBJECTIVES

1. Be able to list the manual actions required to be recognized and performed, in the proper order.

2. Given the inability to accomplish any action/verification, list the actions which must be taken.

3. Upon determination of; loss of subcooled margin, improper heat transfer, or RMA-5 increasing, give the action which must be taken and the procedure to be used.

4. Explain the relationship between the reactor/turbine trip ATP and the other ATP's.

5. Explain why fast response to the ATWS, Abnormal Transient Without Scram, event is critical.

III. REFERENCES

A. Current Revision of ATP 1210-1

B. Babcock & Wilcox ATOG Part I and Part II

IV. MATERIAL REQUIRED

A. Student handout

B. Copy of ATP 1210-1 for student

V. CLASSROOM OR AREA REQUIREMENTS

A. Adequate for number of students.

INSTRUCTOR NOTES

VI. TIME: 2 Hours

VII. INTRODUCTION

A. Name

B. No smoking while class is in session

C. Procedures have been reviewed. This session is to emphasize some of the finer points of ATOG procedure use and the entry procedure.

VIII. PRESENTATION

Emphasize any manual trip requires entry

A. Entry Condition

1. Review entry condition and note.

Emphasize the difference between "refer to" and "go to".

B. Immediate Action

1. Review actions 1 through 8 going through verification and the IF - THEN statements.

a. Must finish Step 1 before going further (ATWS) but consider steps 3 thru 8 while performing step 1.

b. Do not take any action which could reduce secondary plants ability to remove heat.

INSTRUCTOR NOTES

Note:

(show TP of PT plot forced and NC)

2. Review Step 9 and the IF - THEN statement.
3. Review Step 10 and the IF - THEN statement.

Verify Temp and Pressure:

Forced flow

RCS press 2100-2200#

RCS temp 545-555^{O}F

OSTG press 950# to ^{T}sat for 545^{O}F

OSTG temp 950^{3} from 545^{O}F to 555^{O}F

950# to 1030# @ 555^{O}F

555^{O}F to ^{T}sat at 1030#

Natural Circulation

RCS press 2100-2200

RCS temp 555-600^{O}F

OTSG press same as forced flow

OTSG temp same as forced flow

a. Definition: Excessive Heat Transfer is heat being removed at a rate causing overcooling of the RCS as indicated by rapidly decreasing RCS temperature.

b. Definition: Lack of Heat Transfer is insufficient heat being removed resulting in overheating as indicated by rapidly increasing RCS temperatures.

INSTRUCTOR NOTES

4. Review Step 11 and the IF - THEN statement.

5. Emphasize the review and repeated review of all 11 steps on a routine basis.

   a. Significance of priority of order in Steps 9 - 11

   b. Go to other ATP if necesssary then return to 1210-1 follow-up action or go to follow-up actions

C. Follow-Up Action

   1. Review objectiveof followup action section.

   2. Brief review of follow-up actions.

      a. Emphasize as changes from old EP's

   3. Point out reference to ATP 1210-10 when further guidance or information may be needed as in Follow-Up Action 18.

   4. Trip report attached for convenience - form is changing.

   5. Exit from procedure may be to operating procedure or event related EP or AP

      a. Cooldown, Startup

      b. Loss of Inst. Air, Blackout, Loss of Feed to one OTSG, etc.

IX. SUMMARY

A. Review lesson objectives quizzing students.

Training Content Record

Lesson Course Title	Number	

Lesson Plan Title	Number	Rev.
ATP 1210-2 LOSS OF SUBCOOLED MARGIN		0

Objectives

A. Describe the condition which requires entry into this procedure.

B. Explain why 3 HPI pumps may be too many operating and list the conditions when the 3rd pump should be run.

C. Recite the Reactor Coolant Pump Trip Rule and explain the caution associated with the rule.

D. Recite the OTSG Level Rule and conditions governing rate of level increase using EFW.

E. Given various plant conditions be able to determine if Reactor Coolant Pump Restart is allowed, using the RCP Restart Guide.

F. List the four methods used to verify natural circulation as described in ATP 1210-10.

G. Explain why it may be extremely important, during certain LOCAs, to establish primary to secondary heat transfer.

Responsibility		Signature	Title	Date
Origination		[illegible]	[illegible]	1/11/84
Review/Concurrence		AB Sungman	U-1 Ops Eng	1/12/84
		M. J. Ross	Mgr PLT OPS-1	1/12/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-12-84
	Final	Bruce Leonard	Operator Training Manager	1-12-84

1.0

6210-ADM-1[illegible]01-1 (12/82)

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LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-2 LOSS OF SUBCOOLED MARGIN

TRAINING SECTION: Operations

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						
5.0	P	12/29/83						
6.0	P	12/29/83						
7.0	P	12/29/83						

INSTRUCTOR NOTES

I. TITLE: ATP 1210-2 Loss of Subcooled Margin

II. LESSON OBJECTIVES:

A. Describe the condition which requires entry into this procedure.

B. Explain why 3 HPI pumps may be too many operating and list the conditions when the 3rd pump should be run.

C. Recite the Reactor Coolant Pump Trip Rule and explain the caution associated with the rule.

D. Recite the OTSG Level Rule and conditions governing rate of level increase using EFW.

E. Given various plant conditions be able to determine if Reactor Coolant Pump Restart is allowed, using the RCP Restart Guide.

F. List the four methods used to verify natural circulation as described in ATP 1210-10.

G. Explain why it may be extremely important, during certain LOCAs, to establish primary to secondary heat transfer.

III. REFERENCES:

A. Current Revision of ATP 1210-2 Loss of Subcooled Margin

INSTRUCTOR NOTES

B. Babcock and Wilcox ATOG Part I & II

C. Current Revision of ATP 1210-10 Rules, Guides, Graphs

D. S/G Tube Rupture Procedure Guilelines TDR #406 Rev 3.

IV. MATERIAL REQUIRED:

A. Student Handouts

B. Current revision of ATP 1210-2 Loss of Subcooled Margin

V. CLASSROOM OR AREA REQUIREMENTS:

A. Large enough for size of class

VI. TIME:

A.

VII. INTRODUCTION:

A. The Loss of Subcooled Margin procedure should be used anytime you have less than 25F^{0} subcooled margin. This procedure is an interim procedure used primarily to ensure actions are taken to correct the subcooled margin loss and direct you to the problem which caused the subcooled margin to be lost.

VIII. PRESENTATION:

A. Immediate Actions

1. May already have been done if entering from

INSTRUCTOR NOTES

reactor/turbine trip.

2. Must be used any time margin is less than 25F°.

3. Trip all RCP's following the RCP Trip rule in ATP 1210-10.

this is to save the stopped RCP's in case a problem arises with the pumps left running

a. if not tripped within 2 minutes leave running (1/loop) for at least 2 hours

b. if one of running pumps trips or must be stopped; start the other pump in that loop.

c. this protects from core uncovery for small break LOCA while in the critical area.

"Pig's Liver Curve"

4. Initiate HPI (-2 pumps full flow) ATP 1210-10

Emphasize components vise system actuation and the pros and cons of each approach

a. 3 MUP's may be too many as decay heat drops

b. must have sufficient flow to cause incore T/C temp to be decreasing

c. only need 3 HPI pumps if RCS is superheated

d. with only 1 HPI pump you could get heating for 70 minutes with peak temp less than 650°F

5. Verify EFW has auto started: from loss of all four RCP's

INSTRUCTOR NOTES

a. using guide for EFW actuation in ATP 1210-10 ; 2.3 ensure proper EFW response

6. Raise OTSG level to 90-95°/o on the operating range.

   a. follow OTSG level rule in ATP 1210-10; 1.6 regrading loss of pressure in one OTSG

   b. follow EFW throttle criteria, of ATP 1210-10; 1.5 regarding feed rate control

   c. must maintain feedwater effectiveness if incore T/C is not decreasing

B. Follow Up Actions

Do not isolate PORV if it's being used for HPI cooling (Procedure is being changed)

1. Review Steps 1 thru 9

   a. review methods for verification of natural circulation from ATP 1210-10

   b. During some small break LOCAs there is not enough cooling thru the break, therefore establishing primary to secondary heat transfer is very important.

2. Restart RCP's as directed following guide in ATP 1210-10 and throttle HPI per ATP 1210-10, [illegible] Throttle Criteria

   a. review the caution regarding opening of

Revision P
12/29/83

INSTRUCTOR NOTES

HPI pump recirc. valves while throttling

IX. SUMMARY:

Review exit possibilities	A. Review Objectives

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev.**
ATP 1210-3 EXCESSIVE COOLING		P

Objectives

A. Be able to list the actions to be taken to mitigate or terminate the overcooling event for each condition listed in the procedure which could be the cause for overcooling.

B. Be able to state the OTSG level that requires tripping the Main Feed Water Pumps.

C. Be able to state the action required if a steam line break occurs in the Intermediate Building.

D. Explain why it is important to prevent heatup and repressurization following an overcooling event.

Responsibility		Signature	Title	Date
Origination		Charles Hitchcock	Supv. LO Trng	1/2/84
Review/Concurrence		H B Simpman	U-1 Operations Eng.	1/2/84
		[illegible] Ross	Mgr PLT OPS	1/2/84
		Lou Kanese	SAPC Engineer	1/5/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-2-84
	Final	Bruce Leonard	Operator Training Manager	1-2-84

LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-3 EXCESSIVE COOLING

TRAINING SECTION: OPERATIONS

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/15/83						
2.0	P	12/15/83						
3.0	P	12/15/83						
4.0	P	12/15/83						
5.0	P	12/15/83						

INSTRUCTOR NOTES

I. TITLE: ATP 1210-3 Excessive Cooling

II. LESSON OBJECTIVES:

A. Be able to list the actions to be taken to mitigate or terminate the overcooling event for each condition listed in the procedure which could be the cause for overcooling.

B. Be able to state the OTSG level that requires tripping the Main Feed Water Pumps.

C. Be able to state the action required if a steam line break occurs in the Intermediate Building.

D. Explain why it is important to prevent heatup and repressurization following an overcooling event.

III. REFERENCES:

A. Current Revision of ATP 1210-3; 1210-1

B. Babcock & Wilcox ATOG Part I & II

C. Current Revision 1210-10

IV. MATERIAL REQUIRED:

A. Student Handout

B. Copy of ATP 1210-3 for Student

V. CLASSROOM OR AREA REQUIREMENTS:

A. Adequate for number of students

VI. TIME:

A. Hours

INSTRUCTOR NOTES

VII. INTRODUCTION:

A. Instructor's Name

B. Now that the students have had an opportunity to review this procedure, we will now study the procedure in detail to examine how the operator will enter, use and exit this portion of ATOG.

VIII. PRESENTATION:

A. Review entry condition at Step #10 in ATP 1210-1

1. Examine the if/then statement and discuss how the operator will decide to go to 1210-3. (i.e., what meters/gauges the operator will view to make his decision)

B. Immediate Actions

Objective #1

1. Review actions 1 thru 5

Objective #2

2. Explain why OTSG level of greater than 95% requires tripping MFP's.

a. Flood MS lines

C. Follow-up actions

1. Review Actions 1 thru 8

Objective #3

Stress importance of determining leak location and loss of equip. in Inter. Bldg. Show TP of location determination aids.

2. Explain the basis for concern in action #3

a. Steam line rupture in the I.B. may result in equipment failures (i.e; IA, EFP, Atmos Dumps) or structural failure of the building.

INSTRUCTOR NOTES

Objective #4

3. Review PTS concerns in step #7 using figures from ATP 1210-10

Review exit possibilities

IX. SUMMARY:

A. Review Objectives

1. Use questions to review objectives

B. Review entry to 1210-3 from 1210-1

C. Ask if there are any questions from students

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev.**
ATP 1210-4 LACK OF HEAT TRANSFER		P

Objectives

A. Describe the method of core cooling to be used if neither Main or Emergency Feedwater is available.

B. State why it is recommeded to run one RCP while on HPI cooling (no feedwater available) if required subcooling margin exists.

C. Given the following three transient conditions, state the required OTSG level for each, according to ATP 1210-10:
   a. Loss of 25°F subcooling margin
   b. Reactor coolant pumps on and greater than 25°SCM.
   c. Reactor coolant pumps off and greater than 25°SCM.

D. Define "Pump Bump" with regard to RC pumps.

E. Describe how to verify heat transfer by the OTSG's is established.

F. List the indications of interruption of Natural Circulation and the actions to be taken to regain N.C.

Responsibility		Signature	Title	Date
Origination		Chuck Hirsch	Supv NLO Trng	1/2/84
Review/Concurrence		HB Shipman	U-1 Operations Eng	1/2/84
		MJ Ross	Mgr PLT OPS	1/2/84
		Lou Kanere	SAPC Engineer	1/5/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-2-84
	Final	Bruce Leonard	Operator Training Manager	1-2-84

6210-ADM-1[illegible]01.1 (12/82)

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LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-4 LACK OF HEAT TRANSFER

TRAINING SECTION: OPERATIONS

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						
5.0	P	12/29/83						
6.0	P	12/29/83						

INSTRUCTOR NOTES

I. TITLE: ATP 1210-4 Lack of Heat Transfer

II. LESSON OBJECTIVES:

A. Describe the method of core cooling to be used if neither Main or Emergency Feedwater is available.

B. State why it is recommended to run one RCP while on HPI cooling (no feedwater available) if required subcooling margin exists.

C. Given the following three transient conditions, state the required OTSG level for each, according to ATP 1210-10:

a. Loss of 25^{o}F subcooled margin

b. Reactor coolant pumps on and greater than 25^{o}SCM.

c. Reactor coolant pumps off and greater than 25^{o}SCM.

D. Define "Pump Bump" with regard to RC pumps.

E. Describe how to verify heat transfer by the OTSG's is established.

F. List the indications of interruption of Natural Circulation and the actions to be taken to regain N.C.

III. REFERENCES:

A. Current revision of ATP 1210-4, 1210-1

INSTRUCTOR NOTES

B. Babcock and Wilcox ATOG Part I & II

C. Current revision of ATP 1210-10

IV. MATERIAL REQUIRED:

A. Student Handout

B. Copy of ATP 1210-4 for student

V. CLASSROOM OR AREA REQUIREMENTS:

A. Adequate for number of students

VI. TIME:

A. Hours

VII. INTRODUCTION:

A. Instructor's Name

B. Now that the student has had an opportunity to review this procedure, we will now study the procedure in detail to examine how the operator will enter, use and exit this portion of ATOG.

C. This procedure contains the steps from the Inadequate Core Cooling Procedure which dealt with a saturated RCS. The steps which dealt with superheated RCS are in ATP 1210-8.

VIII. PRESENTATION:

A. Review entry condition at Step #10 in ATP 1210-1

1. Examine the if/then statement and discuss how the operator will decide to go to 1210-4. (i.e. what meters/gauges the operator will view to make his decision)

INSTRUCTOR NOTES

	B. Immediate Actions
	1. Review Actions 1 thru 3
Objective #1	2. For Step 2.3, review rule # 1.2 in 1210-10
Objective #B	3. For Step 3.4 explain why we run a RCP with no MFW/EFW while on HPI cooling
Define"Pump Bump" as bkr closed for 10 sec.	a. avoid PTS concerns
	C. Follow Up Actions
	1. Review Follow Up Actions 1 thru 16
Objective #D	2. Use Step 8 to explain pump bump criteria
Point out that could also be doing steps in other procedures while waiting 15 minutes	a. Old bump criteria from Inadequate Core Cooling procedure had you wait until uncoupling was verified; then only if FW was available.
	b. new criteria attempts to reestablish natural circ. sooner while previous steps of procedure establish conditions conducive to heat transfer.
Show TP of Limits and Precautions for RCP starts.	c. Bump operable pumps following Limits and Precautions for maximum number of restarts.
Objective #C	3. Go to 1210-10 to explain HPI throttling (rule 1.3) and OTSG level rule (rule 1.6)
Objective #E	4. Discuss method for verifying heat transfer by the OTSG's is established.

INSTRUCTOR NOTES

See followup action steps 8-10 for operator actions

a. Discuss indications of loss of N.C. and operator actions to recover.

b. Discuss repressurization of RCS during SBLOCA and the importance of OTSG heat removal in depressurization of RCS.

c. Review Boiler - Condenser cooling and how cyclic B-C cooling can occur during SBLOCAs.

IX. SUMMARY:

A. Review objectives by questioning students

B. Review entry from 1210-1 Step #10

C. Ask for question from students

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev.**
ATP 1210-5 OTSG LEAK RUPTURE		

Objectives

1. Explain the process of taking the turbine off the line, the necessity of adhering to this sequence, and the caution regarding bypass valve operation.

2. Explain why the unaffected OTSG level is raised to 90-95% prior to the affected OTSG level being raised.

3. List the approved methods for RCS pressure reduction, prior to commencing the cooldown, and the priority associated with their use.

4. Explain why it is important that SCM be reduced to 25F^{o} prior to commencing the cooldown.

5. Give the only condition which allows violation of the fuel pin compression limit.

6. List the conditions which require isolation of the affected OTSG.

7. Describe the consequence of allowing the main steam lines to be flooded with water.

8. Give the limits which must be met to place normal Decay Heat Removal System into operation.

Responsibility		Signature	Title	Date
Origination		Charles Heuthel	Supv NO Trng	1/2/84
Review/Concurrence		H B Shipman	Act Operations Engr	1/2/84
		M J Ross	Mgr PLT OPS	1/5/84
		Lou Lanese	SAPC Engineer	1/5/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-2-84
	Final	Bruce Leonard	Operator Training Manager	1-2-84

Revision P
12/16/83

LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-5 OTSG LEAK RUPTURE

TRAINING SECTION: OPERATOR TRAINING

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						
5.0	P	12/29/83						
6.0	P	12/29/83						
7.0	P	12/29/83						
8.0	P	12/29/83						

Revision P
12/29/83

INSTRUCTOR NOTES

I. TITLE: ATP 1210-5 OTSG/LEAK RUPTURE

II. LESSON OBJECTIVES

1. Explain the process of taking the turbine off the line, the necessity of adhering to this sequence, and the caution regarding bypass valve operation.

2. Explain why the unaffected OTSG level is raised to 90-95% prior to the affected OTSG level being raised.

3. List the approved methods for RCS pressure reduction, prior to commencing the cooldown, and the priority associated with their use.

4. Explain why it is important that SCM be reduced to 25F^{o} prior to commencing the cooldown.

5. Give the only condition which allows violation of the fuel pin compression limit.

6. List the conditions which require isolation of the affected OTSG.

7. Describe the consequence of allowing the main steam lines to be flooded with water.

8. Give the limits which must be met to place normal Decay Heat Removal System into operation.

INSTRUCTOR NOTES

III. REFERENCES

A. Current revision of ATP 1210-5

B. B&W ATOG Part 1 and Part II

C. S/G Tube Rupture Procedure Guidelines TDR #406, Revision 3.

IV. MATERIAL REQUIRED

A. ATP 1210-5 OTSG Leak/Rupture

V. CLASSROOM OR AREA REQUIREMENTS

A. Large enough for size of class

VI. TIME: ___

VII. INTRODUCTION

The goal of this lesson is to review ATP 1210-5 OTSG Leak/Rupture. There will be special emphasis on particular steps in the procedure for clarification purposes.

VIII. PRESENTATION

A. Entry to ATP 1210-5 - Discuss indications of Tube Leak

1. As directed by other ATP's

B. Tube Leak vs. Tube Rupture

1. Leak: greater than 1 GPM but less than 50 GPM

2. Rupture: greater than 50 GPM

Obj. 5

a. For a tube rupture only violation of the

INSTRUCTOR NOTES

NOTE: Violation of F.P. compression requires engineering evaluation prior to next heatup.

Fuel Pin Compression is acceptable to minimize subcooling margin above 25^{o}F.

C. Review immediate actions - per ATP 1210-5

1. Discuss importance of controlled load reduction. Minimize risk of a M.S. safety valve lifting.

D. Review follow up actions - per ATP 1210-5

Points of emphasis:

Caution and step 3, Obj. 1

1. Tripping Turbine/Taking Turbine Off Line.

a. Turbine bypass control - must maintain press. control to prevent lifting of M.S. Safeties

b. Manual control may be necessary to prevent lifting of M.S. Safeties

Step 5

O.T.S.G. Level Rule

ATP 1210-10

2. O.T.S.G. Level Rule 90 - 95% in effect.

a. Raise unaffected generator to 90% - 95% FIRST.

b. Then raise affected generator to 90% - 95%

INSTRUCTOR NOTES

Obj. 2.

* This will allow the operator to raise OTSG level to 95% with better control of the RCS cooldown rate. The unaffected OTSG level should be raised first while the affected OTSG level should be prevented from boiling dry. The operator can control one (1) OTSG instead of trying to raise level in both OTSG's simultaneously.

c. If I/C thermocouple temperatures are not decreasing and there is no heat transfer to the OTSG's, then both OTSG levels must be raised to 95% simultaneously.

This is allowed per ATP Rule 1.5.

Step 7

Obj. 3

3. RCS pressure reduction should be accomplished by use of following and in this order.

a. Turn off PZR heater and start pressurizer spray

b. Reduce RCS pressure using pressurizer vent.

Last because PORV capacity is greater than required-more operator attention to depressurization is required

c. Last, if vent is not sufficient the PORV may be used.

4. Plant stabilization before cooldown

a. Previously the operator would initiate a

INSTRUCTOR NOTES

plant cooldown and then establish minimum subcooling margin. This previous experience shows that the RCS could not be depressurized fast enough to maintain a minimum subcooling margin. Therefore, emphasize the need to stabilize the plant and reach the minimum allowance subcooling margin. Plant cooldown should then be initiated.

b. 25° subcooling margin. Minimize subcooling margin means that primary to secondary differential pressure is also minimized, which reduces leakage and offsite doses, make them even more manageable.

Step 12

Obj. 6

NOTE: Continue steaming until: RCS less than 540°. This is required to maintain secondary press greater than 1000 PSI To prevent lifting M.S. Safeties.

5. O.T.S.G. Isolation Criteria

a. BWST Level less than 21'

Bases: 1) Sufficient level to flood both steam lines and put about 30,000 gallons of water into containment for piggy-back mode of core injection.

INSTRUCTOR NOTES

b. Off-Site Dose Projections of 50 mr/hr whole body or 250 mr/hr thyroid.

Step 15 & Note

6. If O.T.S.G. Isolation is required this will result in flooding the applicable M.S. Line.

a. Under emergency conditions this is acceptable without blocking/pinning of M.S. hangers.

Obj. 7

b. Consequence of above:

Engineering evaluation of the structural integrity of the M.S. lines must be performed prior to resuming normal operations.

c. Isolation of both OTSG requires going to HPI cooling using ATP 1210-9

Step 22

Obj. 8

Note: GPUNC evaluation showed that the DHR System has the capability to operate at 300°F. Normal DHR operation is 275°F.

7. Placing Decay Heat Removal in operation at 300° is acceptable if the consequences of losing forced flow are acceptable. (I/E No Hot Leg Steam Bubbles)

IX. SUMMARY

Review Objectives

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev.**
ATP 1210-6 SMALL BREAK LOCA		P

Objectives

A. State the condition that requires opening the PORV and the condition which allows reclosure of the PORV.

B. State the two conditions which allow securing the Emergency Feedwater System.

C. State the reason for the caution regarding ES component operation following ES Actuation.

D. Explain why it is preferable to makeup to the BWST rather than go on RB recirculation.

E. List the criteria for opening containment isolation valves that have been automatically closed, as stated in ATP 1210-10.

Responsibility		Signature	Title	Date
Origination		Charles Hustead	Sup. Non-licensed Op. Trng	1/11/84
Review/Concurrence		AB Shipman	U-1 Ops Eng	1/12/84
		M. J. Ross	Mgr PLT OPS	1/12/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-12-84
	Final	Bruce Leonard 1.0	Operator Training Manager	1-12-84

LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-6 SMALL BREAK LOCA

TRAINING SECTION: OPERATIONS

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/15/83						
2.0	P	12/15/83						
3.0	P	12/15/83						
4.0	P	12/15/83						
5.0	P	12/15/83						

Revision P
12/15/83

INSTRUCTOR NOTES

I. TITLE: ATP 1210-6 Small Break LOCA

II. LESSON OBJECTIVES:

A. State the condition that requires opening the PORV and the condition which allows reclosure of the PORV.

B. State the two conditions which allow securing the Emergency Feedwater System.

C. State the reason for the caution regarding ES component operation following ES Actuation.

D. Explain why it is preferable to makeup to the BWST rather than go on RB recirculation.

E. List the criteria for opening containment isolation valves that have been automatically closed, as stated in ATP 1210-10.

III. REFERENCES:

A. Current Revision of 1210-1, 6, 10

B. Babcock & Wilcox ATOG Part I & II

IV. MATERIAL REQUIRED:

A. Student Handout

B. ATP 1210-1, 6, 10

V. CLASSROOM OR AREA REQUIREMENTS:

A. Adequate for number of students

INSTRUCTOR NOTES

VI. TIME:

A. Hours

VII. INTRODUCTION:

A. Instructor's Name

B. Now that the student has had an opportunity to review this procedure we will study it in detail and discuss the entry, use, and exit from this portion of ATOG.

VIII. PRESENTATION:

Instructor Notes	
Primarily used to cooldown with SBLOCA.	A. Review entry point to 1210-6 from ATP 1210-2 step #9 in follow-up actions
	B. Immediate Actions
	1. Review Action 1 thru 5
Objective #A	2. For step #5 review if/then
	C. Follow up Actions
	1. Review actions 1-27
	a. Must not allow RB level to get high enough to flood inst. (aprox. 6 feet)
Objective #B	2. For #21 review this criteria (emphasis)
Objective #C	3. Review "Caution" listed just before the #1 follow-up action.
Objective #D	4. Explain the preferance for maintaining HPI source from BWST vice Recirc of RB sump
	a. prevent bringing contaminated water into Aux. building

INSTRUCTOR NOTES

Objective #E

5. Review ATP 1210-10 Guide 2.4

   a. Emphasize that this includes MU-V-3, letdown isolation valve.

IX. SUMMARY:

A. Review objectives by questioning students

B. Review entry to 1210-6 from 1210-2

C. Ask for questions from students

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev.**
ATP 1210-7 LARGE BREAK LOCA		P

Objectives

A. State the emergency core cooling conditions which requires entrance in to this procedure.

B. State the reason for closing MS-VIA, B, C, and D as follow-up action.

C. State the action required if only one LPI pump is operating, and state the minimum required LPI flow in each line.

D. State how RCS cooldown rate would be controlled while on LPI or DHR, if DC-V2 and 65 are inaccessible or inoperable.

Responsibility		Signature	Title	Date
Origination		[illegible]	Sup. [illegible] Op. Trng	1/11/84
Review/Concurrence		HBShipman	U1 Ops Eng	1/12/84
		M. J. Ross	Mgr PLT OPS	1/12/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-12-84
	Final			

6210-ADM-12[illegible]1-1 (12/82)

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LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-7 LARGE BREAK LOCA

TRAINING SECTION: Operations

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						
5.0	P	12/29/83						

Revision P
12/29/83

INSTRUCTOR NOTES

I. TITLE: ATP 1210-7 Large Break LOCA

II. LESSON OBJECTIVES:

A. State the emergency core cooling conditions which requires entrance in to this procedure.

B. State the reason for closing MS-VIA, B, C, and D as follow-up action.

C. State the action required if only one LPI pump is operating, and state the minimum required LPI flow in each line.

D. State how RCS cooldown rate would be controlled while on LPI or DHR, if DC-V2 and 65 are inaccessible or inoperable.

III. REFERENCES:

A. Current revision of ATP 1210-7 Large Break LOCA

B. Babcock and Wilcox ATOG Part I & II

IV. MATERIAL REQUIRED:

A. Student Handouts

B. Current revision of ATP 1210-7 Large Break LOCA

V. CLASSROOM OR AREA REQUIREMENTS:

A. Sufficient room for number of students

VI. TIME:

A.

INSTRUCTOR NOTES

VII. INTRODUCTION:

A. The purpose of this ATP is to verify the ECCS has functioned properly during a Large Break LOCA as indicated by both core flood tanks level decreasing.

VIII. PRESENTATION:

A. Immediate actions

Enter procedure to cooldown with large Break LOCA

1. Review each verification to be made asking students for indications used.

B. Follow Up Actions

1. Review follow up actions and cautions
2. Closing of MS-V-1 A, B, C, and D establishes containment integrity if an OTSG tube leakage exists simultaneously with LOCA.
3. If only one LPI train is operating must open discharge cross-connect valves to assure minimum flow thru core if only operating train is also location of break. Must have 1000 gpm each leg to assure 1000 gpm to core.
4. If Decay heat closed cooling flow control valves cannot be used then manually throttle Decay Heat River Water valve on pump discharge

INSTRUCTOR NOTES

a. could take several minutes to see temperature change.

IX. SUMMARY:

A. Review Objectives

Training Content Record

Lesson Course Title		Number	
Lesson Plan Title ATP 1210-8 RCS SUPERHEATED		**Number**	**Rev.**

Objectives

1. Explain how to determine if the RCS is superheated.

2. Explain the reason for the limit of 25-100 psig above OTSG pressure associated with PORV operation.

3. Describe the conditions which allow use of the RCS vents; hot leg, PZR and head.

4. Give the purpose for the High Point Vents and explain why they connot be relied upon as a means of heat removal.

5. Give the conditions and restrictions associated with operation of all RB fans and problems associated with post accident fast speed operation of AH-E-1A/B/C.

Responsibility		Signature	Title	Date
Origination		Charles Hartfield	Sup NLO Trng	1/2/84
Review/Concurrence		HB Simpman	U-1 Operations Eng	1/2/84
		M J. Ross	Mgr Plt OPS	1/2/84
		Lou Lanese	SAPC Engineer	1/5/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1/2/84
	Final	Bruce Leonard	Operator Training Manager	1/2/84

1.0

6210-ADM-[illegible]01-1 (12/82)

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Revision P
12/16/83

LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-8 RCS SUPERHEATED

TRAINING SECTION: OPERATOR TRAINING

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						
5.0	P	12/29/83						
6.0	P	12/29/83						
7.0	P	12/29/83						

Revision P
12/29/83

INSTRUCTOR NOTES

I. TITLE: ATP 1210-8 RCS SUPERHEATED

II. LESSON OBJECTIVES

1 Explain how to determine if the RCS is superheated.

2. Explain the reason for the limit of 25-100 psig above OTSG pressure associated with PORV operation.

3. Describe the conditions which allow use of the RCS vents; hot leg, PZR and head.

4. Give the purpose for the High Point Vents and explain why they connot be relied upon as a means of heat removal.

5. Give the conditions and restrictions associated with operation of all RB fans and problems associated with post accident fast speed operation of AH-E-1A/B/C.

III. REFERENCES

A. ATP 1210-8 RCS Superheated

IV. MATERIAL REQUIRED

A. Viewgraph Projector

B. Chalk Board and Chalk/White Board and Markers

C. Transparencies

V. CLASSROOM OR AREA REQUIREMENTS

A. Theater Style Arrangement

INSTRUCTOR NOTES

VI. TIME: 2 Hours

VII. INTRODUCTION

A. Name

B. Class Rule

C. Lesson presented to review steps outlined in ATP 1210-8 RCS Superheated and discussion supporting information.

D. Cover Objectives.

VIII. PRESENTATION

A. Review Steps 1 and 2. Emphasize how each step is verified.

1. Review Step 3

a. Explain why it is necessary to use secondary pressure as indication during cooldown.

2. Review Steps 4, 5 and 6.

B. Follow up Actions

1. Review Step One

2. Review Step Two

a. Detail what valid incore readings are

3. Review Step 3 highlighting

a. Determination of saturation conditions

b. Basis for curves 5 and 6

C. Incore Thermocouple greater than 1400^{o} but

INSTRUCTOR NOTES

less than 1800^{o}.

1. Review Step 4.1

   a. Detail conditions which could cause steam pressure to go below 150 psig as noted in caution.

2. Review Step 4.2

   a. Emphasize need to establish coupling

3. Review Step 4.3

   a. Detail location of vents and operation

   b. Why are vents used vice PORV at this point

   Remove gases from RCS while limiting inventory loss

   c. Vents relieve 3 lbm/sec each at 2500 psig which is insufficient for heat removal: ,5.4 MW at 1 hr with 38 MW decay heat level

   approx. gpm 2500 psig (to be provided)

4. Review Steps 4.4 and 4.5

5. Review Step 4.6

   a. Detail cooldown rate achieved by PORV

   b. Outline steps in Attachment 1 and actions needed to accomplish it.

6. Review Steps 4.6, 4.7 and 4.8

   a. Min. 25 psig above OTSG pressure maintains primary temperature above secondary temperature.

INSTRUCTOR NOTES

b. Max. 100 psig minimizes flowrate out the break while allowing for maximum flow from ECCS.

D. Incore Thermocouples greater than 1800°

1. Review Step 5.1

a. Detail RCP starting interlocks and how to defeat

b. Outline Attachment 2

2. Review Step 5.2

a. Outline actions necessary to accomplish depressurization

3. Review Step 5.3

a. Review PORV cooldown rate

b. Outline steps in Attachment 1 and actions needed to accomplish

4. Review Step 5.4

a. Detail location of vents and operation

b. Differentiate why PORV used first when incores are greater than 1800° vice vents

Decrease RCS prss. to increase flow in from HPI/LPI/CFT's and reduce RCS leakage

5. Review Step 5.5 and 5.6

a. Detail why RB fans started when greater than 1800° and not when less than 1800°

Start all RB fans to prevent H_2 pockets

6. Review note and basis for 3 percent

7. Review Steps 5.7 and 5.8

Post accident Hydrogen Purge System

INSTRUCTOR NOTES

a. Detail need to maintain pressure less than 150 psi

8. Review Step 5.9 and 5.10

a. Outline steps needed for LPI recirc

IX. SUMMARY

A. Emphasize need to establish cooldown rapidly.

B. Differentiate between sequence of PORV and vents in procedure.

C. Review exit points in procedure.

D. Review immediate actions.

E. Answer student questions.

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev.**
ATP 1210-9 HPI COOLING/RECOVERY FROM SOLID OPERATION		

Objectives

1. Explain the significance of the HPI flowrates listed on Enclosure 1 of the procedure.

2. Explain how Figure 1/1A of ATP 1210-10 are used in assuring the RCS pressure/temperature limits are complied with, while on HPI cooling.

3. List, in order, the steps to be taken to make the transition from HPI cooling to OTSG heat removal mode of operation.

4. Describe the process of establishing a steam bubble in the pressurizer.

Responsibility		Signature	Title	Date
Origination		Chuck Hester	Sr. NO Trng	1/2/84
Review/Concurrence		H B Shipman	U-1 Operations Eng	1/2/84
		M J Ross	Mgr PLT OPS	1/2/84
		Lou Lanese	S/APC Engineer	1/5/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-2-84
	Final	Bruce Leonard	Operator Training Manager	1/2/84

1.0

6210-ADM-1[illegible]01-1 (12/82)

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LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-9 HPI COOLING/RECOVERY FROM SOLID OPERATION

TRAINING SECTION: OPERATOR TRAINING

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						

Revision P
12/29/83

INSTRUCTOR NOTES

I. TITLE: ATP 1210-9 HPI COOLING/RECOVERY FROM SOLID OPERATION

II. LESSON OBJECTIVES

A. Explain the significance of the HPI flowrates listed on Enclosure 1 of the procedure.

B. Explain how Figure 1/1A of ATP 1210-10 are used in assuring the RCS pressure/temperature limits are complied with, while on HPI cooling.

C. List, in order, the steps to be taken to make the transition from HPI cooling to OTSG heat removal mode of operation.

D. Describe the process of establishing a steam bubble in the pressurizer.

III. REFERENCES

A. Current revisions of ATP 1210-1, 9, 10

B. Babcock & Wilcox ATOG Part I and II

IV. MATERIAL REQUIRED

A. ATP's 1210-1 through 1210-10

V. CLASSROOM OR AREA REQUIREMENTS

A. Adequate for number of students

VI. TIME: Hours

VII. INTRODUCTION

A. Instructor's name

INSTRUCTOR NOTES

B. Now that the students have had an opportunity to review this procedure, we will study it in detail and determine how to enter, use and exit from this portion of ATOG.

VIII. PRESENTATION

A. Review entry point to 1210-9 from 1210-4

1. Could possibly be entering from 1210-5

B. Immediate Actions

1. Read thru all steps (1 and 2).

a. Emphasize need to carefully read if/then statements.

C. Follow Up Actions

1. Read thru all steps (1 - 12)

Objective #A

D. Explain the significance of the minimum HPI flowrates listed on Enclosure 1.

a. Remove DH

Objective #B

E. Explain how to use Figure 1/1A of ATP 1210-10 while on HPI cooling.

Objective #C

F. Review follow up action 9

1. Emphasize importance of transfer of heat removal paths.

Objective #D

9.1 Do not close RC-V-2: may need PORV for pressure relief

G. Describe the process of establishing a steam bubble in the pressurizer.

a. State caution on page 2 after 9.7.

IX. SUMMARY

A. Review entry to 1210-9.

B. Review objectives by questioning students.

C. Ask for questions from students.

Training Content Record

Lesson Course Title	Number	
Lesson Plan Title	**Number**	**Rev**
ATP 1210-10 RULES, GUIDES, GRAPHS		P

Objectives

A. Without the use of the procedure, be able to recite the rules contained in the procedure.

B. Using the procedure, give the plant conditions when each guide would be used.

C. Using the procedure, explain the bases for each guide and how to comply with each guide.

D. Explain the bases for the changes in philosophy regarding feeding a dry OTSG.

Responsibility		Signature	Title	Date
Origination		Charles Husted	Supv. NUC Trng	1/2/84
Review/Concurrence		H.B. Shipman	U-1 Operations Eng.	1/2/84
		M. J. Ross	Mgr PLT Ops	1/3/84
		Lou Yanese	SAPC Engineer	1/5/84
Approval	Objectives	Bruce Leonard	Operator Training Manager	1-2-84
	Final			

6210-ADM-3010.01-1 (12/82)

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LIST OF EFFECTIVE PAGES

LESSON PLAN TITLE: ATP 1210-10 RULES, GUIDES, GRAPHS

TRAINING SECTION: Operator Training

PAGE	REV.	DATE	PAGE	REV.	DATE	PAGE	REV.	DATE
1.0	P	12/29/83						
2.0	P	12/29/83						
3.0	P	12/29/83						
4.0	P	12/29/83						
5.0	P	12/29/83						

Revision P
12/29/83

INSTRUCTOR NOTES

I. TITLE: ATP 1210-10 Rules, Guides, Graphs

II. LESSON OBJECTIVES:

A. Without the use of the procedure, be able to recite the rules contained in the procedure.

B. Using the procedure, give the plant conditions when each guide would be used.

C. Using the procedure, explain the bases for each guide and how to comply with each guide.

D. Explain the bases for the changes in philosophy regarding feeding a dry OTSG.

III. REFERENCES:

A. Current revision of ATP 1210-10 Rules, Guides, Graphs

B. Babcock and Wilcox ATOG Part I & II

IV. MATERIAL REQUIRED:

A. Current revision of ATP 1210-10 Rules, Guides, Graphs

V. CLASSROOM OR AREA REQUIREMENTS:

A. Suitable for size of class

VI. TIME:

A.

VII. INTRODUCTION:

A. This procedure was created to reduce the physical size of the procedures the operator would be required to read while responding to an emergency.

INSTRUCTOR NOTES

B. All the information contained in the rules section should be committed to memory and only a reminder needed in the ATP used to deal with the emergency. If you cannot remember the rules reference is made to ATP 1210-10 when the rule is being applied. Rules must be followed to assure core cooling.

C. Guides are to be read at the time they apply. Memorization is not required but an understanding is essential. Guides are procedure steps which are often repeated.

VIII. PRESENTATION:

ASK QUESTIONS

A. Rules

1. Review rules concentrating on when the rule is applied

B. Guides

Point out new step in HPI throttling to open MUP recirc valves when throttling below 400 gpm

Emphasize on Note after 2.6 that only months after trip or long shut down; (present plant conditions)

1. Review guides giving plant conditions when each is used.

2. Explain the purpose for each guide

3. Feeding a dry OTSG with MFW at a slow rate will not induce high tensil stresses on the tubes.

INSTRUCTOR NOTES

a. the concern for the tube sheet to shell weld is not as significant as tube to shell delta-T.

b. a slow rate will allow refill to 18" without undue stress and reduce tube to shell delta - T.

IX. SUMMARY:

A. Have several students recite a rule to ensure they know them.

B. Review objectives stressing required memorization of rules.

ATOG DRILL GUIDE

1. GENERAL DESCRIPTION OF DRILL:

   Reactor trip from 100 percent power caused by I & C error.

2. DRILL OBJECTIVES:

   A. Proper implementation of ATOG procedures.

   B. Proper utilization of rules and guides in ATP 1210-10 where applicable.

3. METHOD OF INITIATION:

4. SEQUENCE OF EXPECTED ACTIONS:

   A. Reactor trip.

   B. Turbine trip.

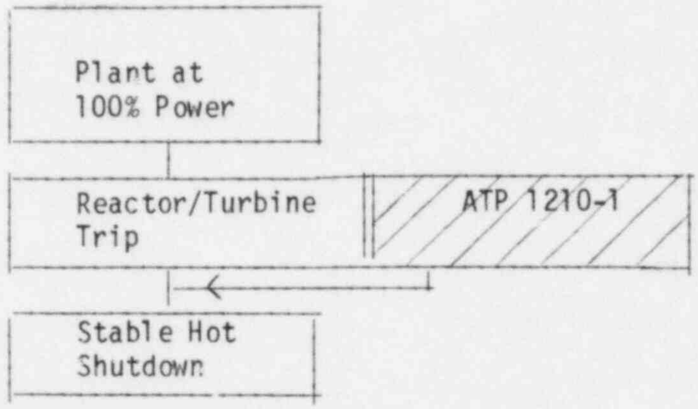
   C. Carry out 1210-1 Immediate Actions.

   D. Carry out 1210-1 Follow-up Actions.

   E. Attain Stable Hot Shutdown Conditions.

5. POINT OF TERMINATION:

   A. Reactor in stable hot shutdown.


Plant at
100% Power
Reactor/Turbine
Trip
ATP 1210-1
Stable Hot
Shutdown

DAY #1

Reactor Startup from 10^{-8} Amps towards Power Level Cutoff
CRD Exercising last 15 minutes of 2 hour time period
T.S. Drills for Day #1 @ 15 Minute Intervals — NON ATOG

Reactor Shutdown from HFP
- @19% Power - Turbine Trip w/o Reactor Trip — ATOG #3
- @10% Reactor Trip — ATOG #1

OTSG Tube Leak (30 GPM) @ HFP — ATOG #5

Security Intrusion @ HFP: — ATOG #2
- Loss of MU-P, Manual Rx Trip
- Turb. Hdr. Press. Fails Low @ Rx. Trip

DAY #2

Reactor Shutdown from HFP to Hot Shutdown (in 1 Hour) Rod Exercising @ HFP Power Reduction to 50% due to CW Tube Leak Day #2 T.S. Drills	NON ATOG
Total LOFW from HFP with Loss of SCM	ATOG #6
RCS Leak requiring Plant S/D . Leads to Small Break LOCA . Stuck Rod on Reactor Trip	ATOG #7
RCS Leak Req'g Plant S/D from HFP . Leads to Large Break LOCA	ATOG #8

DAY #3

Reactor Trip from HFP	
. TBV Setpoint Bias Shift Failure	ATOG #9
Reactor Trip from 50% Power	
. With OTSG Overfeed	
. With OTSG Tube Rupture (50 GPM)	ATOG #10
Total LOFW @ 40% Power	
. W/O Loss of SCM	ATOG #11
Steam Line Break @ HFP	
. B OTSG	ATOG #12

DAY #4

Steam Line Break (A OTSG)
- With overfeed to A OTSG leads to PTS Event — ATOG #4

Blackout from HFP with LOFW
- Leads to PORV Cooling, Solid Gas, recovery — ATOG #13

Total LOFW & HPI Leading to RCS Superheat
- Per Safety/PORV Sticks Open — ATOG #14

DAY #5

OTSG Tube Rupture (100 GPM) ATOG #15

Operational Examination

DATES

COURSE

NAME

ATOG TRAINING PROGRAM

MANAGEMENT EVALUATION CHECK LIST

B&W Simulator Training

When evaluating the effectiveness of the simulator experience, each reviewer should identify program strengths and weaknesses and make recommendations for improvement. The following items are suggested, but should not be used in any way to restrict the observations or comments of the reviewers.

1. Does the instructor have documented learning objectives for each exercise?

2. How does the instructional staff ensure that trainees participate in the regulatory required transients?

3. Were the operators provided an opportunity to request particular transients or events be simulated?

4. Do the instructors provide effective evaluations of trainee performance against some standard?

5. What is the process used by instructors to evaluate individual and team performance on plant operations and transient scenarios?

6. Are the operating team assignments clearly identified and does the group communicate effectively?

7. Are the trainees given clear instructions on the difference between the simulator and TMI control room/plant features?

8. Are TMI procedures and technical specifications used, and are trainees reinforced in the importance of compliance with procedures and operating limits?

9. Are exercises conducted in a manner that requires the operator to diagnose and predict the response of the plant under specific considered or planned actions or inactions?

10. Did the instructor create a stressful environment to observe how the operator performs under stress?

11. Were the trainees required to role-play actions and/or communications with out-of-control-room activities required during similar evolutions at TMI?

12. Are logs kept and used in post-transient analysis discussions?

13. During simulated abnormal plant transients, are trainees required to identify any E-Plan responses and notifications during any of the transients which exceed E-Plan action levels?

14. Does the instructor stress the methodology of analysis?

15. Are all team members given a review and analysis of each transient in a manner which assures that each person understands the impact of their individual actions?

16. Are parameters vs. time plots available for review and analysis of plant transients? If so, are they used effectively?

17. When concerns or problems with TMI plant procedures are identified, how is it documented and GPUN notified? List the items identified during this course.

18. When problems with either simulator hardware, software, or operating procedures are identified, what system exists to assure that immediate and/or long term action is taken to ensure a review and incorporation of any needed changes? List the items identified during this course.

19. Is there a documented mechanism available to solicit the students' comments, ideas, thoughts, and recommendations associated with both the specific training/certification session attended and the overall program? Is there a mechanism available to notify GPUN of the comments?

20. What mechanisms exist to evaluate and document the students' performance (both strengths and weaknesses)? How is this information transmitted to GPUN?

Other Comments and Observations

ATOG Training Program

STUDENT COURSE CRITIQUE

Name ______________________ Section/Position ______________________

Course Title ______________________ Date ______________ Location ______________

Your constructive criticism will be used to provide the feedback required to more effectively develop and evaluate training and education programs. Please make your comments on the following points detailed so that appropriate action may be taken.

. Program							COMMENTS
a. Content	Excellent	Very Good	Good	Fair	Poor		
b. Pace			Fast	OK	Slow		
c. Level			High	OK	Low		
d. Visual aids			Good	OK	Poor	N/A	
e. Course handouts			Good	OK	Poor	N/A	
f. Demonstration			Good	OK	Poor	N/A	
g. Did exams test the objectives?			Yes	No			
h. Instructor(s) preparation			Good	OK	Poor		
i. Your opportunity to interact with speakers			Good	OK	Poor		
j. Your opportunity to interact with participants			Good	OK	Poor		
Overall evaluation	Excellent	Very Good	Good	OK	Poor		

. a. Which topic(s) did you find was/were of greatest value to you?

b. Which topic(s) did you find was/were of least value to you?

c. Which topic(s) should be extended?

d. Were objectives covered in class?

e. Additional Comments

(Use other side for additional comments)

This training course should be continued:

Highly recommended ______________;Recommended ______________;Not Recommended ______________

ATOG Training Program

Student Course Critique

1. Do you feel there are any topics that should be included in the program that were not, or could be included in future requal training?

2. Are there any procedures which you feel should be emphasized more during simulator or classroom training?

3. Do you feel you could handle a plant transient using the ATOG procedures or that more procedure training is needed?

4. Did the classroom session adequately prepare you to utilize the procedures on the simulator?

5. Are there any unanswered technical questions resulting from the training program? If there are, please write them down.

ATTACHMENT 6

TMI-1 ABNORMAL TRANSIENT PROCEDURES (ATPs) VALIDATION/VERIFICATION PROGRAM

I. Objectives

The objectives of the ATP validation/verification program are:
(1) To verify that the plant procedures are technically equivalent to the plant specific guides of the TMI-1 ATOG program.

(2) To verify that the procedures are (a) usable in the control room environment, (b) understandable by TMI-1 operators, and (c) that they can be performed with minimum shift staffing of the control room.

To accomplish the first objective, the technical content of the procedures was verified by comparison of the plant procedures with the plant specific guidelines. The second objective was accomplished through (1) procedure reviews, (2) comparison of the procedures with the writers guide, (3) simulator exercises, and (4) control room walk throughs.

II. Technical Validation

Over the past two years, the GPUN TMI-1 ATOG Implementing Committee has worked with B&W to prepare the TMI-1 Generic ATOG guidelines. The generic guidelines were converted to TMI-1 plant specific guidelines by the ATOG Implementing Committee. Interaction between the members of the Committee and B&W helped to ensure that the technical content of the guidelines would be reflected in the plant procedures. As an independent check, a separate review was performed to compare the TMI-1 plant specific guidelines with the procedures used in the operator simulator training in January, 1984. Of the comments generated through this review, any comments affecting plant safety or core coolability were incorporated into the procedures prior to training. Additional comments will be resolved and may result in future revisions to the procedures.

III. Procedure Reviews

During the development of the TMI-1 ATOG guidelines, various reviews were performed by the TMI-1 ATOG Implementing Committee and others in the operations, plant engineering, and Technical Functions groups. In addition, the draft ATPs received further specific reviews concurrent with preparation of the training materials and simulator exercises. These reviews covered technical accuracy, completeness, usability, format, wording, level of detail, vocabulary usage, and sentence structure and were performed by Plant Operations, Plant Engineering, Plant Analysis, Safety Analysis and Plant Control, Human Factors and Systems Engineering groups. These reviews resulted in several revisions prior to the approval of the procedures in January, 1984.

IV. Operating Team Reviews

The ATOG Implementing Committee included four individuals who either hold or have held licenses to operate TMI-1 including one Control Room Operator (CRO) who is currently assigned to an operating crew. These individuals provided the operator's perspective during the procedure development and review process.

Draft procedures were also reviewed by members of the operating crews who were not assigned to the ATOG Committee. A majority of the operators including control room operators, shift foremen and shift supervisors reviewed the procedures and provided comments to the committee. During the simulator validation in December, each procedure was discussed after it was exercised to determine if there were comments from any members of the operating crews on technical content, format, or wording.

V. Simulator Exercises

The ATPs were exercised during the week of December 12, 1983 at the B&W Simulator in Lynchburg, Va. The crew which participated in the evaluation included licensed CROs, a Shift Technical Advisor and a Shift Supervisor. These exercises were observed by members of the ATOG Committee and a Human Factors specialist who directed the conduct of the scenarios and sought feedback from the operators as they were exercising the procedures on the simulator.

The list of scenarios used during the simulator session are included in Enclosure 1 to this attachment along with the ATPs that were used and evaluated for each scenario. The scenarios, selected to support operator training, were reviewed by the evaluators as follows:

(1) All the ATPs were exercised;
(2) Each procedure was tested to ensure it guided the operator in establishing the correct priorities using the symptoms approach;
(3) Both single and multiple events were used with multiple failures occurring concurrently and sequentially;
(4) Some random scenarios were selected which were event orientated to test the symptom based approach; and
(5) Interfaces between the ATPs and the other plant procedures were tested.

Comments from the operators and evaluators during the exercises and critiques resulted in certain changes to the procedures. At the conclusion of the simulator session, the evaluators determined that the procedures were usable even with the minimum control room shift staffing and agreed that all portions of the procedures had been adequately exercised.

In January, members of the ATOG Committee tested the proposed crew training plan through additional simulator sessions. Comments from that session were documented in consideration of further procedure modification. During the training sessions which follow, operators will be encouraged to comment on all aspects of the procedures and their comments will be evaluated by Operations management.

VI. Writers Guide Validation of Procedures

The abnormal transient procedures were compared with the Writers Guide by members of the ATOG committee to verify that the procedure conformed to the rules delineated in the guide. A separate review was performed by Human Factors personnel as a separate and independent validation of the procedure format.

VII. Control Room Walkthroughs

Since the simulator sessions adequately exercised all portions of the procedures so as to validate procedure usability, control room walkthroughs were performed only to validate the correlation with control room hardware. Prior to initial approval of the procedures, a member of the ATOG Committee reviewed the procedures in the control room and where a parameter or a control action was referenced, verified that an instrument/control was available. Subsequent to this review, a team consisting of a Human Factor specialist, a licensed Control Room Operator and a Shift Foreman reviewed the procedures step by step in the control room. At each step they evaluated whether an instrument or control was required and if it existed. This review further evaluated whether the control/instrument was usable, readable and that the scale units and markings were compatable with the procedure.

Walkthroughs on these procedures will also be conducted for validation of the control room as a part of the Control Room Design Review (CRDR) using the tasks defined by the EOPs. These walkthroughs will be conducted in the control room to validate that the changes made as a result of the previously completed CRDR are valid for the tasks defined by the EOPs. A description of the program was submitted to the NRC on January 16, 1984.

VIII. Future Procedure Changes

Administrative procedure 1043 controls the review and approval of changes to emergency operating procedures. The required process assures that procedures receive review and validation based on the extent of the change to the procedure. The change is reviewed by operations management for technical content, operability requirements, effect on safety, and also to determine training requirements. Procedural changes are also reviewed by operating

crews. All changes to ATPs must be written in accordance with the Writers Guide which is implemented as a plant administrative procedure. A review of all procedures is required to be performed by the Technical Functions Division. This review includes a technical review and a human factors review in order to provide input as to the extent of validation required depending on the scope of the change. This process is designed to maintain the original technical validity and usability of the ATPs.

ENCLOSURE 1

SIMULATOR SCENARIOS USED FOR ATP VALIDATION

Transient	Procedures Used*
Loss of RCPs due to grid upset resulting in reactor trip	ATP-1 Reactor trip EP-1202-14 Loss of RCP's OP-1102-16 Natural Circ.
Loss of Feedwater causing reactor trip.	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-9 HPI Cooling
Loss of Offsite Power	ATP-1 Reactor Trip
Loss of One Feedwater pump causing reactor trip and stuck open PORV	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-4 Lack of Heat Transfer ATP-6 Small Break LOCA ATP-9 HPI Cooling
Dropped Rod	EP-1202-8 CRD Malfunctions
Loss of Coolant .44 ft^2 with both HPI trains available	ATP-1 Reactor Trip ATP-7 Large Break LOCA
Rod Ejection	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-4 Lack of Heat Transfer ATP-6 Small Break LOCA ATP-9 HPI Cooling
Repressurization LOCA 1-3/8" Break	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-4 Lack of Heat Transfer ATP-6 Small Break LOCA
Small Break LOCA from 100%	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-4 Lack of Heat Transfer ATP-6 Small Break LOCA
Small Steam Leak - Stuck Open Safety Valve	ATP-1 Reactor Trip ATP-3 Excessive Cooling
Small Break LOCA with one HPI Train .01 to .02 Ft^2	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-4 Lack of Heat Transfer ATP-6 Small Break LOCA ATP-9 HPI Cooling

Reactor Trip with loss of Main Feedwater One EFW available after a delay PORV stuck open, loss of all HPI due to fire.	ATP-1 Reactor Trip ATP-4 Lack of Heat Transfer ATP-8 RCS Superheated
Normal Reactor Trip - no failures	ATP-1 Reactor Trip
ICS Failure, Loss of RCP while decreasing power which caused reactor trip - One feedwater valve failed after trip.	ATP-1 Reactor Trip ATP-3 Excessive Cooling
Tube rupture 8-10 gpm initially increasing to 100 gpm, no aux. boiler, lost MU pump	ATP-1 Reactor Trip ATP-5 OTSG Tube Leak/Rupture
Steam Leak in Reactor Building with reactor tirp ("A" SG level inst line break)	ATP-1 Reactor Trip EP-1203-24 Steam Leak
Reactor Trip without Turbine Trip	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-3 Excessive Cooling
Loss of B MU Pump with RCP Seal Leakage	ATP-1 Reactor Trip ATP-2 Loss of Subcooling ATP-6 Small Break LOCA

*ATP-10 Rules and Guidelines was used whenever appropriate during the sessions.