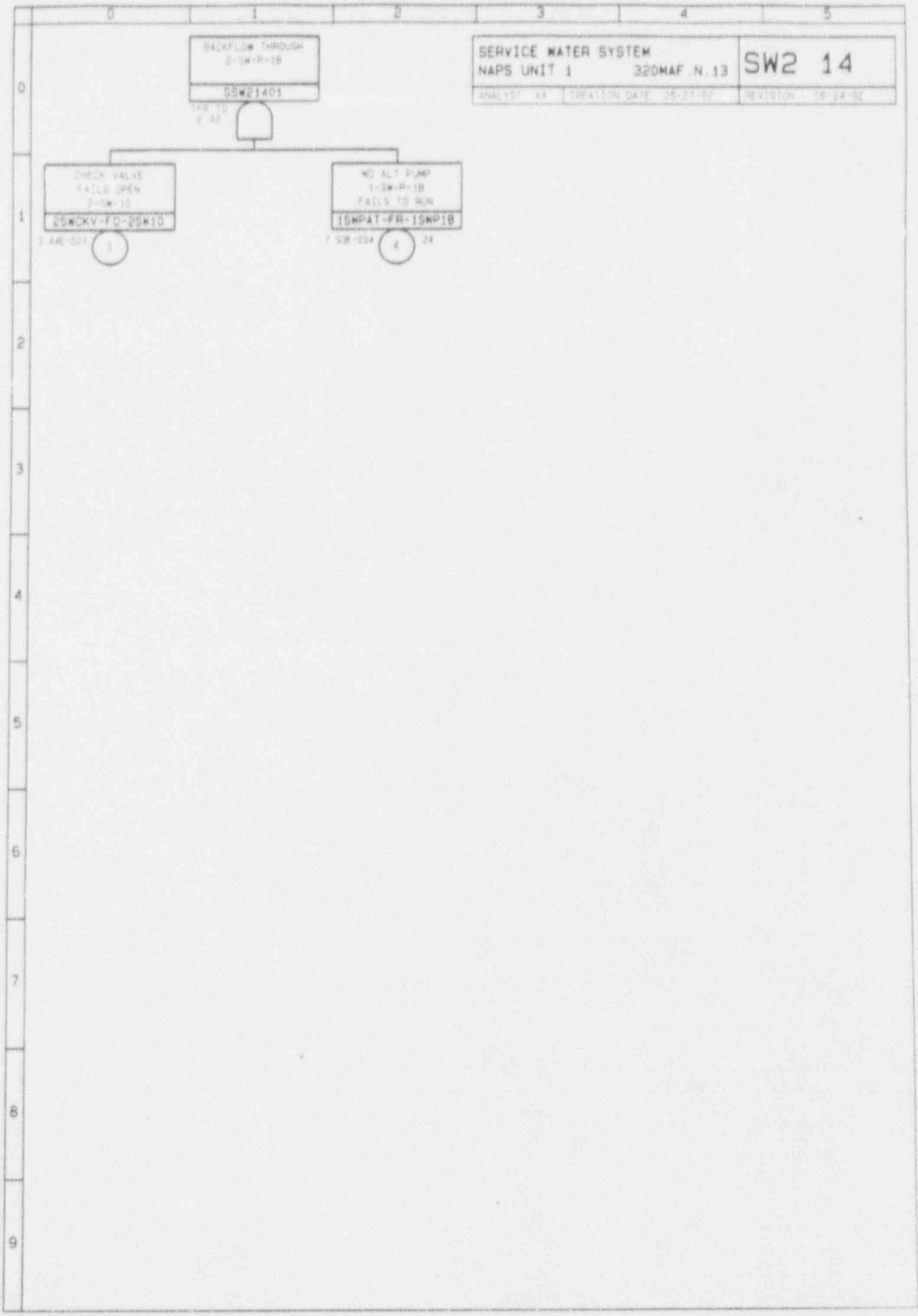

9209180041 920911
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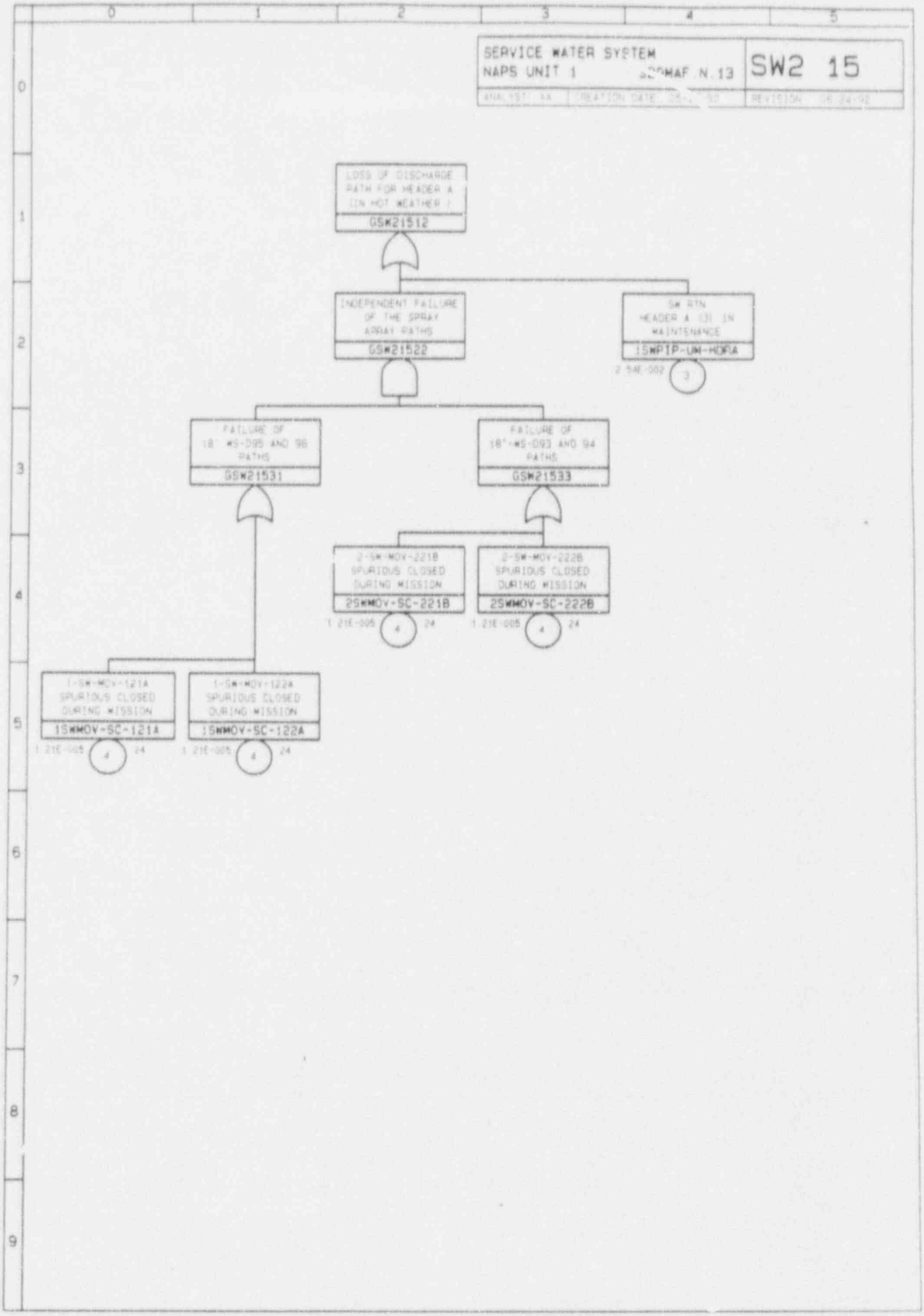
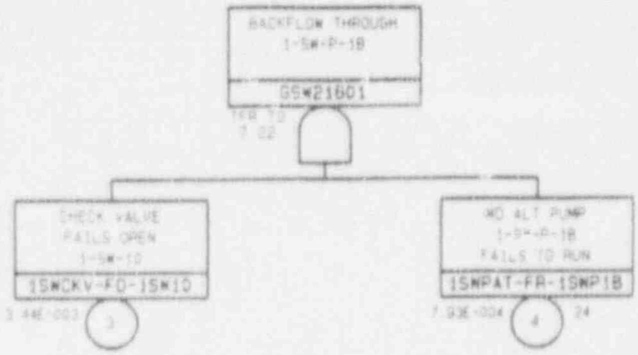
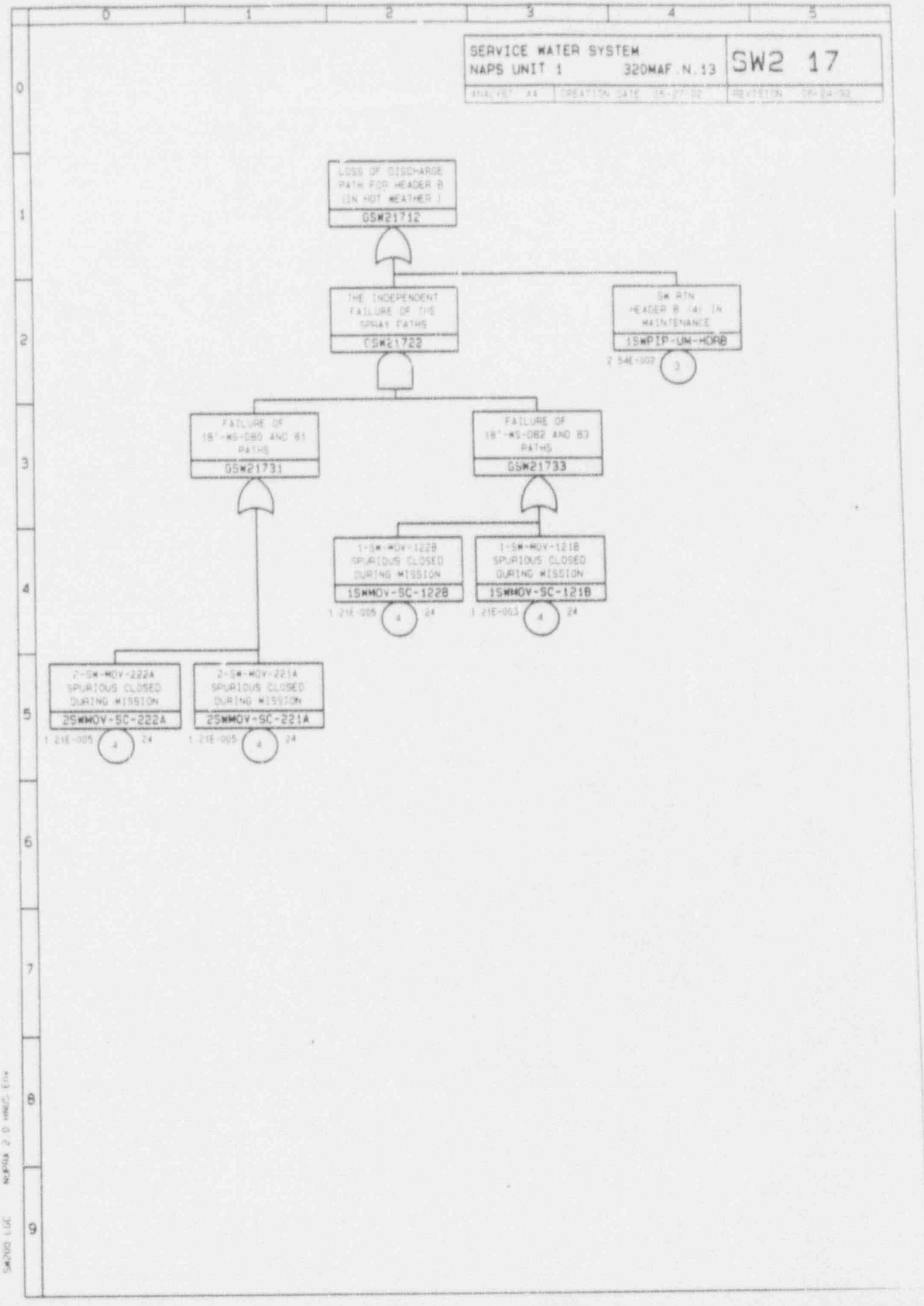
P PDR

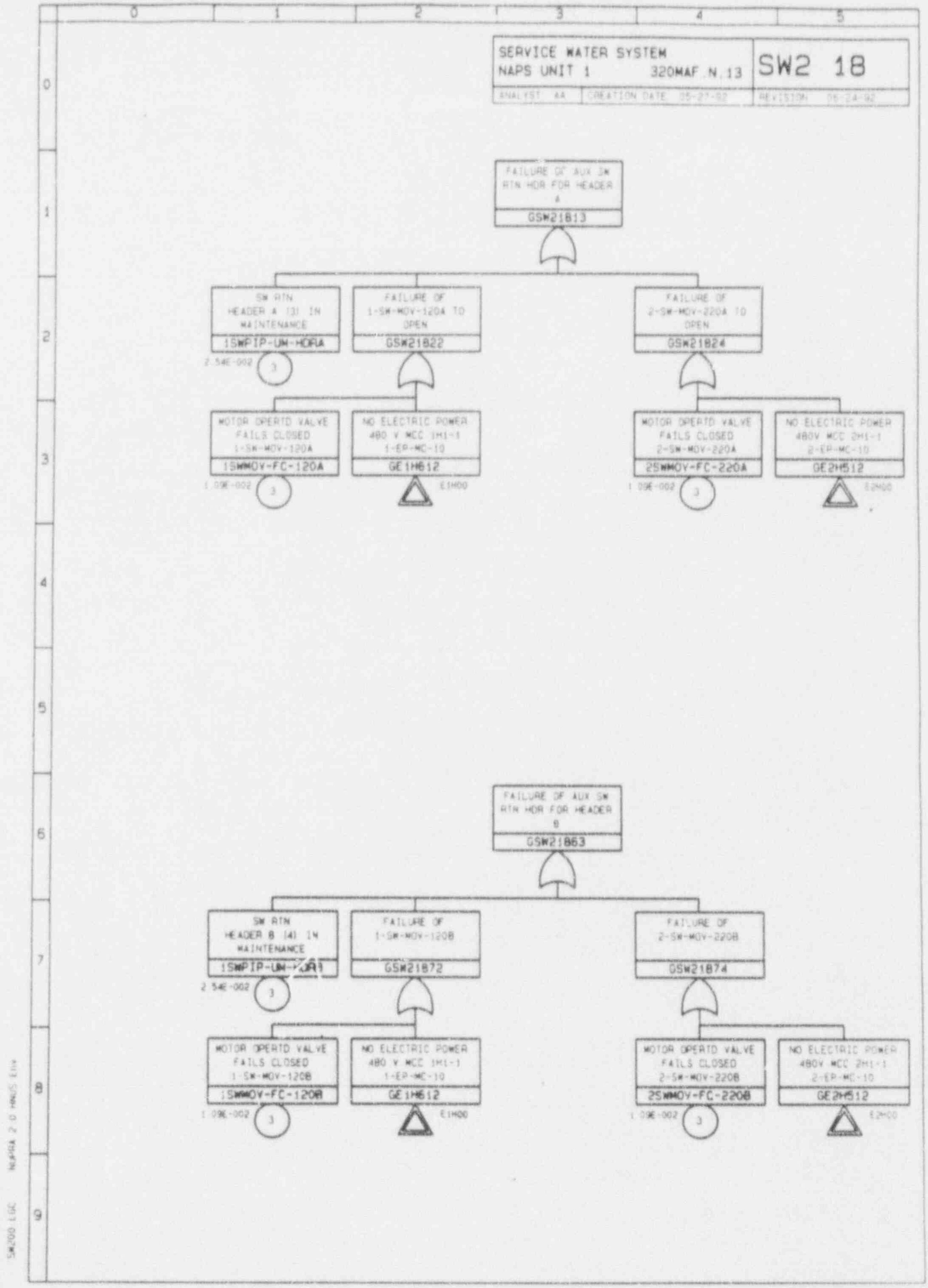

SERVICE WATER SYSTEM
NAPS UNIT 1
SW2 15
ANALYST: AA
REVISION 06-24-92
LOSS OF DISCHARGE PATH FOR HEADER A (IN HOT WEATHER)
GSW21512
INDEPENDENT FAILURE OF THE SPRAY ARRAY PATHS
GSW21522
SW RTN HEADER A (3) IN MAINTENANCE
1SWPIP-UM-HDRA
2.54E-002
3
FAILURE OF 18" WS-D95 AND 96 PATHS
GSW21531
FAILURE OF 18"-WS-D93 AND 94 PATHS
GSW21533
2-SW-MOV-221B SPURIOUS CLOSED DURING MISSION
2SWMOV-SC-221B
2-SW-MOV-222B SPURIOUS CLOSED DURING MISSION
2SWMOV-SC-222B
1-SW-MOV-121A SPURIOUS CLOSED DURING MISSION
1SWMOV-SC-121A
1-SW-MOV-122A SPURIOUS CLOSED DURING MISSION
1SWMOV-SC-122A
1.21E-005
4
24

SERVICE WATER SYSTEM
NAPS UNIT 1 320MAF.N.13

SW2 16




SERVICE WATER SYSTEM
NAPS UNIT 1 320MAF.N.13
SW2 17
LOSS OF DISCHARGE PATH FOR HEADER B (IN HOT WEATHER)
GSW21712
THE INDEPENDENT FAILURE OF THE SPRAY PATHS
GSW21722
SW RTN HEADER B (4) IN MAINTENANCE
1SWPIP-UM-HDRB
FAILURE OF 18"-WS-DB0 AND B1 PATHS
GSW21731
FAILURE OF 18"-WS-DB2 AND B3 PATHS
GSW21733
1-SW-MOV-122B SPURIOUS CLOSED DURING MISSION
1SWMOV-SC-122B
1-SW-MOV-121B SPURIOUS CLOSED DURING MISSION
1SWMOV-SC-121B
2-SW-MOV-222A SPURIOUS CLOSED DURING MISSION
2SWMOV-SC-222A
2-SW-MOV-221A SPURIOUS CLOSED DURING MISSION
2SWMOV-SC-221A



SERVICE WATER SYSTEM
NAPS UNIT 1 320MAF.N.13
SW2 18
ANALYST AA
CREATION DATE 05-27-92
REVISION 06-24-92
FAILURE OF AUX SW RTN HDR FOR HEADER A
GSW21813
SW RTN HEADER A (3) IN MAINTENANCE
1SWPIP-UM-HDRA
2.54E-002
3
FAILURE OF 1-SW-MOV-120A TO OPEN
GSW21822
FAILURE OF 2-SW-MOV-220A TO OPEN
GSW21824
MOTOR OPERTD VALVE FAILS CLOSED 1-SW-MOV-120A
1SWMOV-FC-120A
1.09E-002
NO ELECTRIC POWER 480 V MCC 1H1-1 1-EP-MC-10
GE1H612
E1H00
MOTOR OPERTD VALVE FAILS CLOSED 2-SW-MOV-220A
2SWMOV-FC-220A
1.09E-002
NO ELECTRIC POWER 480V MCC 2H1-1 2-EP-MC-10
GE2H512
E2H00
FAILURE OF AUX SW RTN HDR FOR HEADER B
GSW21863
SW RTN HEADER B (4) IN MAINTENANCE
2.54E-002
FAILURE OF 1-SW-MOV-120B
GSW21872
FAILURE OF 2-SW-MOV-220B
GSW21874
MOTOR OPERTD VALVE FAILS CLOSED 1-SW-MOV-120B
1SWMOV-FC-120B
1.09E-002
NO ELECTRIC POWER 480 V MCC 1H1-1 1-EP-MC-10
GE1H612
E1H00
MOTOR OPERTD VALVE FAILS CLOSED 2-SW-MOV-220B
2SWMOV-FC-220B
1.09E-002
NO ELECTRIC POWER 480V MCC 2H1-1 2-EP-MC-10
GE2H512
E2H00
SW200.LGC NEPRA 2.0 HNUS Env

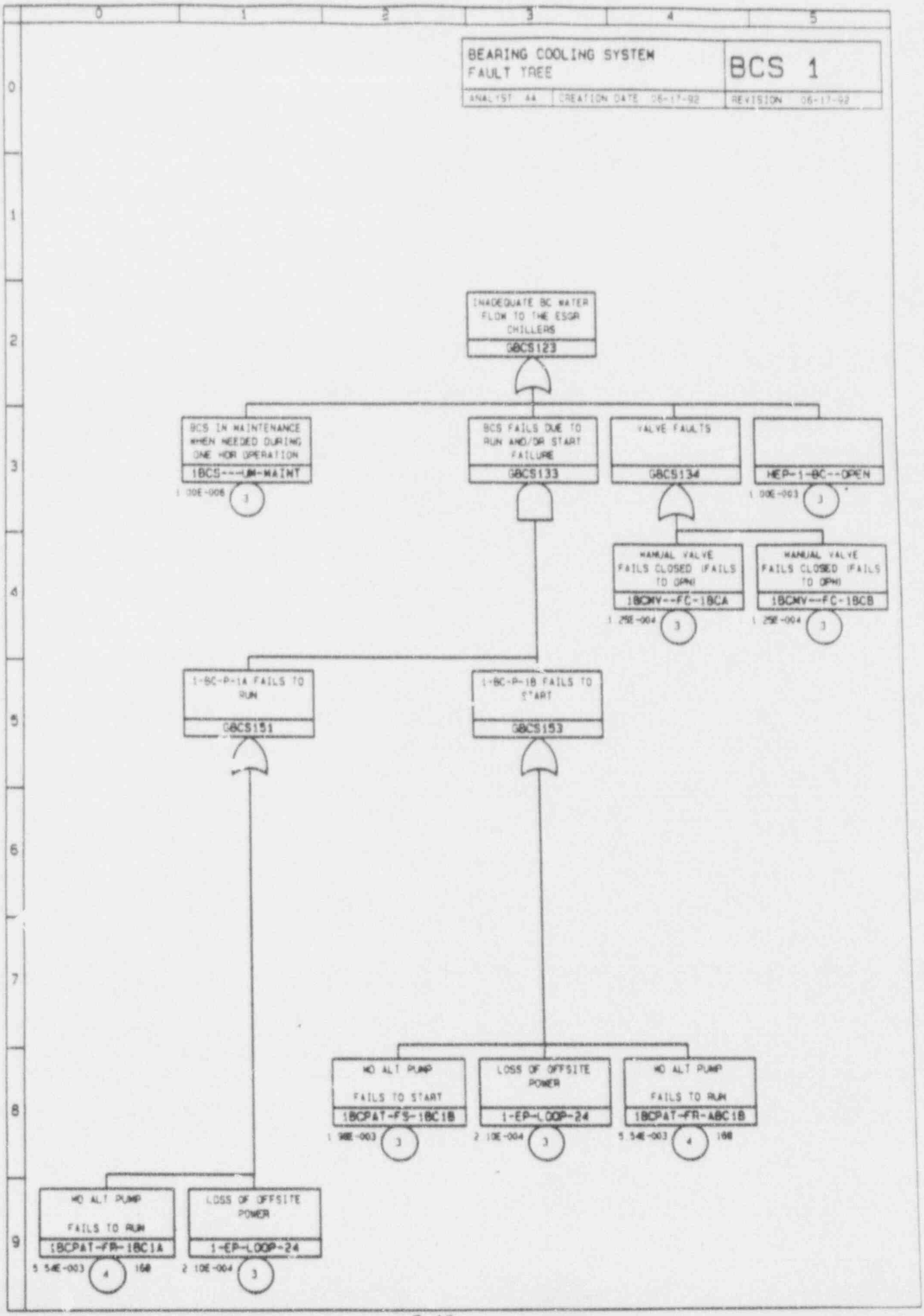
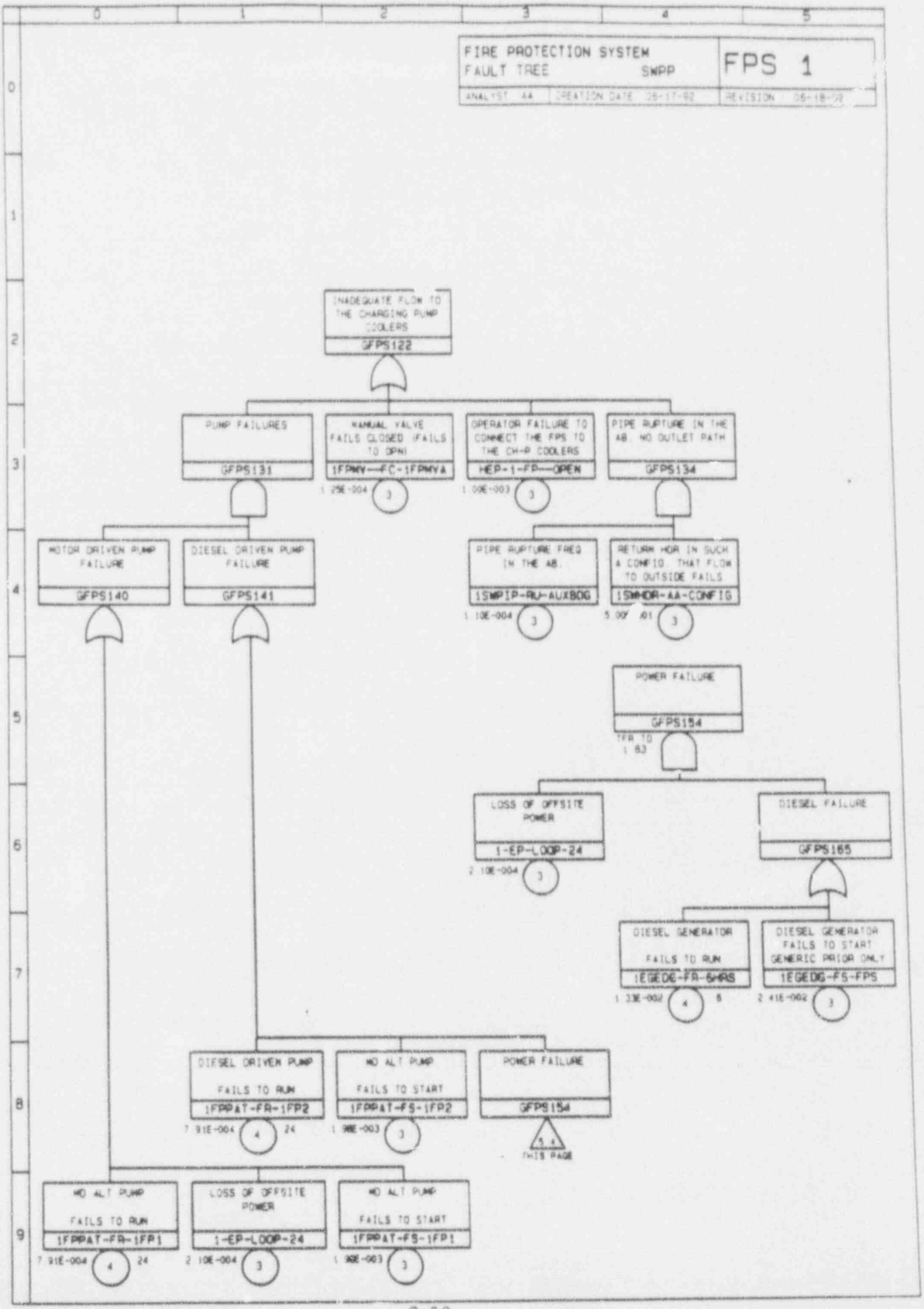


Figure C-7. Loss of BC System Fault Tree

Figure C-4 Loss of Fire Protection System Fault Tree



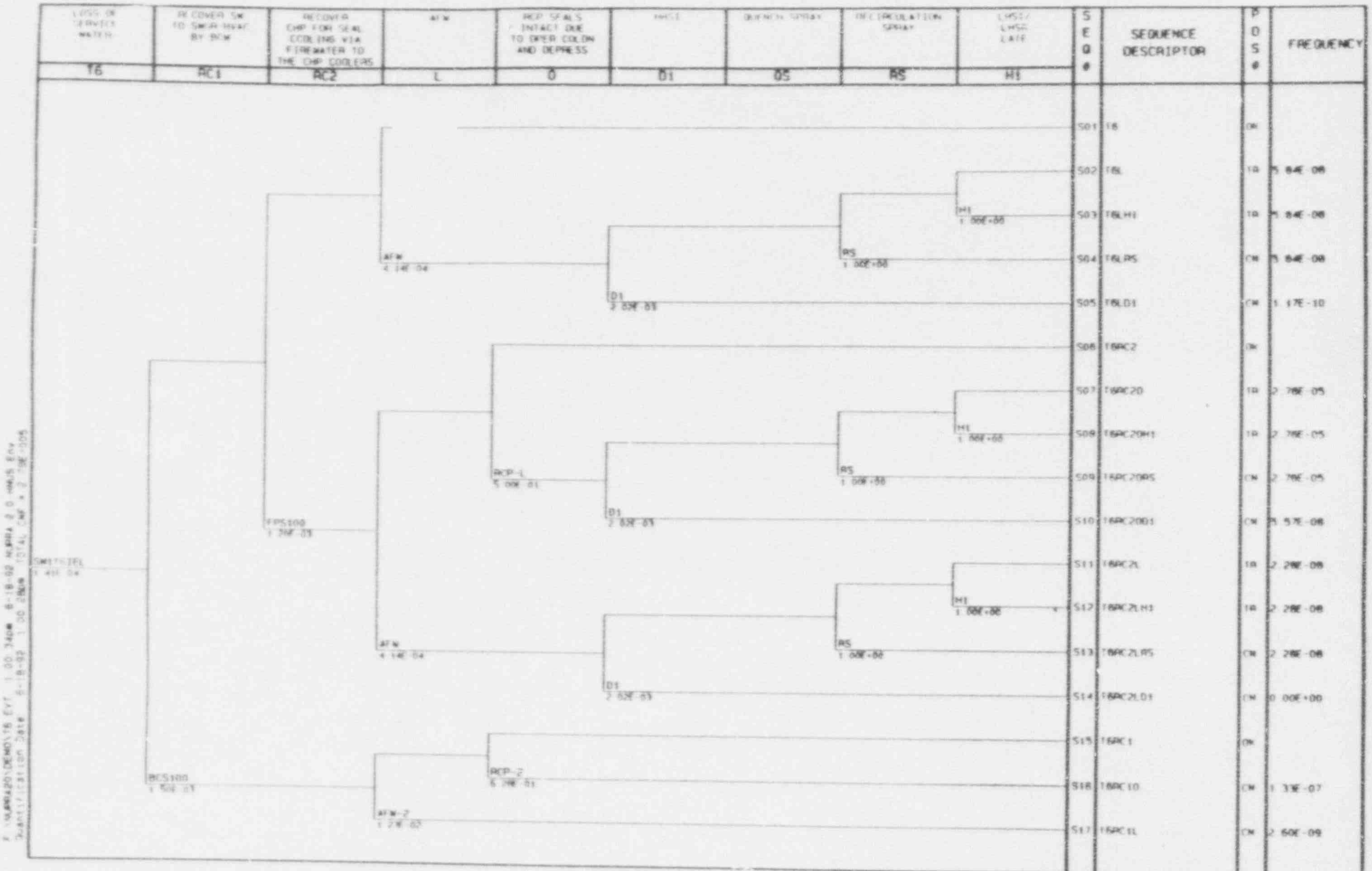


Figure C-5 Modified Loss of SW Initiating Event Tree

EVENT TREE FOR LOSS OF
SERVCIE WATER CAUSED BY
HEADER RUPTURE

NORTH ANNA JUNE 18, 1992

PROBABILISTIC RISK ASSESSMENT
FOR
NORTH ANNA POWER STATION
SERVICE WATER PRESERVATION PROJECT

PART 1
Supplemental Report

Prepared for
Virginia Electric Power Company

by
Amir Afzali

September 8, 1992

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ABSTRACT

This is a supplemental report to the Probabilistic Risk Assessment for Part 1 of the North Anna Power Station Service Water Preservation Project. Part one of this supplemental report represents the assessment of the change in failure probability of the unit 2 Air Conditioning system while its backup chiller is being supported by the Bearing Cooling (BC) system. Part 2 presents the justification for using the methodology (Log-Linear Model) which was utilized for quantification of the service water pipe rupture frequency.

The results of the analysis for Part One indicate that the most significant change in failure probability of the Unit 2 AC system is a result of the possibility of a design basis accident (DBE). The change in the Unit 2 AC system failure probability, during the period when the bearing cooling system is used for the Unit one chillers, will be in the range of 1.4E-6 to 6.8E-6.

The conclusion of Part 2 is that the Log-Linear Model is a conservative method and is appropriate for the condition of the North Anna Plant Service Water piping.

TABLE OF CONTENTS

PART 1

ASSESSMENT OF THE UNIT 2 AIR CONDITIONING SYSTEM RELIABILITY DURING COMPLETION OF SERVICE WATER PRESERVATION PROJECT

1.1 INTRODUCTION

This is an assessment of the reliability of the North Anna Power Station's (NAPS) Unit 2 Air Conditioning (AC) System during performance of the SWPP activities associated with replacement of service water piping to the Unit 1's components. The change in the reliability will be due to the change in the operational configuration of the backup chillers for the Unit 2 control room and emergency switchgear room (CR/ESGR) AC system. Unit 1 is not evaluated in this study, since this unit will not be in operation during the isolation of the SW supply to the unit's chillers.

The environmental qualification basis for the Unit 2 CR/ESGR AC chillers is the backup function provided by the Unit 1 chillers. The normal supply of water for the AC chillers is provided by the service water (SW) system. The SW system is a safety related system. Its components are seismically qualified and are supported by the emergency power supply. During performance of the service water preservation project (SWPP), the SW supply to the unit 1 chillers will be isolated and the Bearing Cooling (BC) system will be utilized to supply water to at least one of the unit 1 chillers. The BC system is not a safety related system and is not seismically qualified or supported by the emergency power supply. This change in the source of water to the Unit 1 chillers lessens the reliability of the Unit 1 chillers and therefore the backup chiller for the Unit 2 AC system. Virginia Power intends to submit to the NRC an exemption request from 10 CFR 50.49 for environmental qualification basis for the Unit 2 Control Room A/C chillers for the period while Unit 1 is shutdown and its AC chillers are being supported by the BC system. This reliability assessment of the consequence of this change in the configuration of the supply of water to the unit 1 chillers is performed to support the exemption request.

1.2 OBJECTIVES

The objective of this probabilistic assessment is to quantify the change in failure probability of the Unit 2's CR/ESGR AC system due to the change in the configuration of the backup system to the Unit 2 AC chillers.

1.3 SCOPE

The source of the harsh environmental stress for the Unit 2's chillers is the main steam line (MSL) rupture in the Unit 2 Turbine Building (TB). Steam released from the ruptured line can propagate to the Unit 2 Air Conditioning (AC) Room via a louvered wall interconnecting the Turbine Building and the AC room. The environmental qualification of the AC chillers is based on the availability of chillers in the other unit to provide chilled air. The major difference between the regular configuration of the AC system and the configuration of the AC system during the SWPP activities is the source of water supply to the Unit 1 AC system chillers. The following cases are analyzed to evaluate the stated objective of this study:

Case 1. A main steam line rupture in the Unit 2 Turbine Building is coincidental with failure of the BC system supply to the Unit 1 Chillers. This case is analyzed under the following set of accident scenarios:

> Accident Scenario 1- BC system fails to provide water to the Unit 1 chillers and before recovery of the BC system the Unit 2 AC chillers fail due to the MSL rupture in the Unit 2 Turbine Building (MSLRTB);
>
> Accident Scenario 2- A Loss of Off-Site Power (LOSP) event occurs and before recovery of off-site power, the Unit 2 AC chillers fail due to the MSLRTB;

Accident Scenario 3- The Unit 2 AC chillers fail due to the MSLRTB and before recovery of the Unit 2 chillers, the supply of water from the BC system to the Unit 1 chillers fails.

Case 2. A Design Basis Earthquake (DBE) resulting in the main steam line rupture in the Turbine Building and failure of the BC system. This case is analyzed under the following accident scenario:

Accident Scenario 4- A design basis seismic event occurs causing the main steam line rupture in the Turbine Building together with failure of the BC System.

It is important to note that this study does not consider failure of the Unit 2's AC system due to any other failure mechanism other than the harsh environmental conditions for the Unit's chillers caused by MSL rupture in the Unit 2 Turbine Building. Also, no evaluation of the effects of a design basis earthquake (DBE) on the failure probability of the plant's components and systems is included. The analysis assumes, in an event of a DBE, all components which are seismically qualified will remain unaffected and those not qualified will fail.

1.4 METHODOLOGY

The change in the failure probability of the Unit 2 CR/ESGR AC system induced by the change in the configuration of the backup system for the Unit 2 AC chillers is given by:

$$U_{AC}=\prod P_1$$

Where

U_{AC} is the change in failure probability of the Unit 2 AC during the performance of the SWPP and

P_i (i= 1, 2,...) is the probability of occurrence of an independent damage inducing event.

Evaluation of the P_i is carried out by:

1. Identification of the interdependencies, if any, between each postulated damage inducing event. That is, the consequence of occurrence of each postulated damage inducing event is evaluated to identify the systems/components potentially at risk.

2. Evaluation of the probability for occurrence of postulated damage inducing events associated with accident scenarios mentioned above.

The North Anna Power Station IPE [Virginia Power, 1992] data and models will be used to quantify all failure probabilities and the consequence evaluations.

1.5 RESULTS

This section reports the results of the analysis carried out to quantify the contribution of cases 1 and 2 to the change in failure probability. Details of the analysis is presented in Appendix A. The contribution from each case is shown in Table 1.1.

For Case 1, the change in failure probability of the unit 2 AC system during the construction period of concern will be negligible and no further evaluation of the consequence is considered necessary.

The corresponding change in failure probability for Case 2 has a wide range. The range is from 1.0E-6 for 90 days construction period and using EPRI seismic hazard curves to 6.8E-6 for 120 days construction period and using the LLNL seismic hazard curves. The reasons for this

variance in the failure probability include:

1. The range of postulated exposure times of the plant to the possibility of occurrence of a DBE event. This variance is induced as a result of uncertainty in the length of time required to complete the SWPP activities.

2. The differences in the numerical value for frequency of occurrence of a DBE, using the EPRI and LLNL seismic hazard curves.

As can be seen from Table 1.1, the second reason has much greater effect on the value of the failure probability.

The change in probability of failure for the unit 2 AC system is not equivalent to the change in core damage probability. There are several contingencies which would prevent core damage given failure of the AC system in the scenarios analyzed. For the case of the DBE, the core damage probability cannot be quantified without performing a seismic PRA of the plant. The change in AC failure probability can be considered a conservative upper-bound for the change in risk.

1.6 CONCLUSIONS

The result of this analysis indicate that for Case 1, the change in failure probability of the unit 2 AC system during the construction period of concern will be negligible and no further evaluation of the consequence is considered necessary.

The calculated change in failure probability for Case 2 has a wide range, depending on the length of the construction period and more importantly on the difference in the probability of occurrence of a DBE, obtainable from EPRI and LLNL seismic hazard curves.

This change in failure probability of the unit 2 AC system is not equivalent to the change in the Core Damage Probability (CDP). There are many accident mitigating systems and measures which can be utilized to prevent a core damage event even if the AC system is inoperable. However, even if the most conservative value for the change in failure probability of the unit 2 AC system (6.8E-6) is considered as the upper bound value for the change in CDP, the change is not significant.

Additionally, the results of the SWPP PRA indicate that, if the BC system is used as a source of water to the unit 2 AC system backup chillers, the change in the CDP, due to operation of the SW system in one header configuration, will be reduced from 5.1E-6 to 3.0E-6. This change in CDP is mainly due to providing an independent source of water to the chillers which in turn introduces defense against common cause failure of water supply to the chillers.

Considering the above factors, it can be concluded that providing the BC system to the unit 1 chillers while SW system to the chillers is isolated is an acceptable measure.

TABLE 1.1
Contribution of Study Cases To The Failure Probability of The Unit 2 AC System

CASE	ACCIDENT SCENARIO	U_{AC}
1	- BC System Failure - MSL Rupture before Recovery of BC - Failure to Isolate the MSL Rupture	1.8E-9 (2.5E-9)
	- LOSP - MSL Rupture - Failure to Isolate the MSL Rupture	2.9E-10 (3.8E-10)
	- MSL Rupture - Failure to isolate the MSL Rupture - LOSP	3.3E-11 (4.4E-11)
CASE 1 TOTAL		2.1E-9 (2.9E-9)
2	- DBE Event causing BC Failure LOSP MSL Rupture - Failure to Isolate the MSL Rupture	5.1E-6[a] (6.8E-6)[a] 1.0E-6[b] (1.4E-6)[b]

The change in failure probability values in parentheses assume a construction period of 120 days, others assume a construction period of 90 days.

a Using LLNL 85th Percentile Seismic Hazard Curve

b Using EPRI 85th Percentile Seismic Hazard Curve

PART 2

SW PIPE RUPTURE FREQUENCY

A PRA analysis was performed to determine the increase in core damage probability resulting from operating with one service water header out-of-service. The principal contributor to increased risk is the possibility of pipe rupture in the operating header.

The frequency of non-isolatable rupture of the Service Water (SW) piping was quantified using a piping rupture frequency model which was developed for the internal flooding analysis of the Surry Power Station [Virginia Power, 1991]. This pipe rupture frequency model is a system specific model based on the observed rupture events in the US Nuclear Power Plants with an estimated 1463 plant years experience. This model is identified as the Log-Linear Model.

Another approach which has been used in other studies to calculate piping rupture frequency is Wash-1400 data [NRC, 1975]. To calculate rupture frequency using Wash-1400 data, the median pipe rupture frequency reported for a piping section (Table III 4-1) can be utilized.

Pipe rupture probability can also be evaluated from empirical correlations derived by Thomas, [Thomas, 1981] which takes into account the following effects:

1. Historical failure data
2. Pipe and weld geometric factors
3. Penalty factor for plant-age
4. Penalty factor for weld material

In short, this model contains parameters which addresses the pipe characteristics including the pipe thickness.

A comparison of the rupture frequencies which can be obtained from the above mentioned models was carried out using the evaluation of the rupture frequency for the 10-inch diameter

SW piping upstream of the isolation MOV for the return header from the SW supply to the Component Cooling Water (CCW) Fuel Pit Cooler. This piping section has been identified as the major contributor to the loss of service water initiating event during one header operation. The calculations and justifications for Thomas Correlations and WASH-1400, are presented in Appendix B.

Table 2-1

Comparison of Service Water Pipe Rupture Frequency Using Alternative Methods

	Model	Rupture Frequency Events/Year
1.	Log-Linear Model	1.1E-5
2.	WASH-1400 Model[a]	9.5E-6
3.	Thomas Correlation[b]	5.1E-6

a. The median rupture rate for piping sections with diameter greater than 3" was used
b. Plant specific data, including the piping inspection data from a January 1992 inspection were used

A comparison of the pipe rupture frequency values derived using each of these methods is presented in Table 2.1.

The results indicate the Log-Linear model provides a conservative estimate. Although it does not explicitly address the piping characteristics, it does not under estimate the rupture frequency. The values obtained from this log-linear model were used in the PRA analysis to ensure conservatism as well as to provide consistency with the IPE data. Since these data are obtained from actual SW operating experience and have been shown to be more conservative than data obtained by alternative calculations, they are appropriate for use in the PRA analysis.

REFERENCES

1. Virginia Electric Power Company, 1992, Probabilistic Risk Assessment, North Anna Nuclear Power Station Units 1 and 2 for the Individual Plant Examination, Richmond, Virginia, (To be published).

2. Virginia Power Electric Power Company, 1992, Probabilistic Risk Assessment, Surry Nuclear Power Station Units 1 and 2 for the Individual Plant Examination, Richmond, Virginia, August.

3. Nuclear Regulatory Commission, 1975, WASH-1400, NUREG-75/014, Reactor Safety Study: An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants, USNRC, October.

4. Thomas, H.M., 1981, Pipe and Vessel Failure Probability, Reliability Engineering, Volume 2, pps 83-124.

APPENDIX A
QUANTIFICATION OF FAILURE SCENARIOS

APPENDIX A

Quantification of Failure Scenarios

This appendix presents the detail calculation of the change in failure probability of the Unit 2 AC system for the postulated accident scenarios. The construction activities associated with this phase of the SWPP is considered to be ompleted within 90 days. However, due to unforeseen circumstances the construction activities may continue for up to 120 days. The analysis for both construction durations are performed. The numerical values presented in parentheses are for 120 days exposure time.

A.1. Accident 1 Failure Scenario

The change in failure probability of the Unit 2 AC system, U_{AC}, is obtained by performing the following analysis:

1. Identification of the interdependency, if any, between the BC system failure event, MSL rupture failure event, and valve closure failure event.

2. Quantification of the probability of BC system failure in 90 (120) days (ie. the period of time that BC system will be supporting the Unit 1 chillers), P_1;

3. Quantification of the probability of Main Steam Line Rupture in the Unit 2 Turbine Building after occurrence of the event outlined in number one and before recovery from such an event, P_2. In this analysis, it is assumed that the BC system can be recovered within 30 days after its failure.

4. Q'antification of the probability of failure to isolate the ruptured header from the main steam valve house, P_3;

The result of item one analysis is shown in Table A-1. No interdependency between the postulated failure scenarios is noted. Thus the change in failure probability of Unit 2 CR\ESGR cooling is given by:

$$U_{AC}^1 = P_1 * P_2 * P_3$$

where

U_{AC}^1 = Contribution of the accident 1 failure scenario to the change in failure probability of the Uni. 2 AC system.

P_1 is quantified by construction of a fault tree model(See Figure A-1) for the failure of the BC

system. The model is constructed based on the simplified flow diagram of the BC system supply to the Unit 1 chillers shown in Figure A-2 and under the following assumptions:

1. 1-BC-P-1A is the running pump
2. 1-BC-P-1B is the standby pump
3. Failure data for motor driven alternating pump as described in appendix C of the North Anna IPE is applicable to these pumps
4. Failure of the normally open manual valves to spuriously close is not considered as significant
5. Probability of BC pipe rupture is conservatively assumed as 5.0E-5 for the 90 days time period
6. The standby BC system's pump will be taken out for maintenance approximately for 45 (60) days, during the 90 (120) days time period

P_2 is calculated by multiplying the frequency of the main steam line break, quantified in the NAPS IPE as the mean frequency of initiating event A, by 30/365, where 30 days is conservatively assumed to be the mean time to repair the BC system. However not all the main steam lines are located in the Turbine Building. In this analysis, it is assumed that approximately 75 percent of the lines are in the Turbine Building. Thus the probability of main steam line rupture is given by:

$$P_2 = [\text{Frequency of "A"}] * [30/365] * 0.75$$

From Appendix B of NAPS IPE, mean frequency of "A" is 5.0E-4; thus

$$P_2 = 5.0E\text{-}4 * [30/365] * 0.75 = 3.1E\text{-}5$$

P_3 is quantified by the construction of a simple fault tree, as shown in Figure A-3. This fault tree is constructed based on a simplified main steam line diagram as shown in Figure A-4. A MSL rupture in the Turbine Building can be isolated by closure of the main steam Trip Valves

(TV) (MS-TV-101A,B,C) which are seismically qualified and are located in the Main Steam Valve House (MSVH). These valves can be closed manually or automatically. Per NAPS steam system training manual (NCRDOP-23-NA, page 18-19) a main line trip valve shuts when any of the following conditions exist:

1. either the train A or B pushbuttons on the Safeguards Panels is depressed,
2. intermediate high-high containment pressure (17.8 psig on two of three channels),
3. either train A or B safety injection signal on high steam line flow coincident with low-low T_{avg} or low steam line rupture,
4. Control Room App. R isolation switch in EMERGENCY CLOSE, or
5. Emergency Switchgear Room App. R isolation switch in EMERGENCY CLOSE.

In this analysis condition 3 above is taken credit for initiation of the automatic isolation. Additionally MSL rupture can be isolated by closure of the motorized non-return check valves (NRV) which are also located in the MSVH. The assumptions used in the construction and quantification of the fault tree include:

1. Failure of any one of the three TVs or NRVs to close is considered as the failure to isolate the MSL rupture in the Turbine Building.

2. Probability of the failure of the actuation signal is the same as that evaluated for the probability of "NO TRIP SIGNAL TO MAIN STEAM TRIP VALVE" in the NAPS IPE steam generator fault tree model (Page 3, gate SG1344);

3. Probability of the operator failure to isolate the main steam line before significant steam is released in the Turbine Building is assumed to be 0.1. This assumption is made since deterministic evaluation of the time available to the operator to isolate the main steam line rupture, before chillers are damaged, is not available presently. However, the following existing emergency procedures are applicable:

   1-E-0, "REACTOR TRIP OR SAFETY INJECTION, REV 9, 12-14-91,

1-E-3, "STEAM GENERATOR TUBE RUPTURE, REV 4, 12-27-89".

4. Probability of loss of power to the NRVs is not modeled since review of the IPE model for 480 V buses (eg review of EP1, page 9, gate 12) indicate that probability of random failure of the bus (excluding LOSP which will be addressed separately) is insignificant compared with the operator failure probability value (0.1) assumed in here.

Thus from quantification of the fault tree shown in Figure A-3, the probability of failure to isolate is $P_3 = 1.17E\text{-}3$.

Therefore the change in the failure probability of the CR\ESGR cooling for 90 days project duration is given by:

$$U_{HV}^1 = P_1 * P_2 * P_3 = 4.99E\text{-}2 * 3.1E\text{-}5 * 1.17E\text{-}3$$

$$U_{HV}^1 = 1.8E\text{-}9$$

and for 120 days project duration is $U_{HV}^1 = 2.5E\text{-}9$.

This change in failure probability of the CR\ESGR cooling is considered negligible and this scenario is not considered any further.

A.2. Accident 2 Failure Scenario

The change in failure probability of the Unit 2 AC system for this scenario is obtained by performing the following analysis:

1. Identification of the interdependency, if any, between the BC system failure event, MSL rupture failure event, and valve closure failure event.

2. Quantification of the Loss of Off-Site Power (LOSP) probability, P_4, in a 90 (120) day time period. In this analysis it is assumed that the LOSP will result in failure of the BC system.

3. Quantification of the probability, P_5, of MSL rupture before recovery of LOSP. In conventional PRAs the time to recover from a LOSP event is 6 hours. In this analysis, it is conservatively assumed that OFF-Site Power and therefore BC system will be recovered in 24 hours. Additionally, very conservatively it is assumed that Unit 2 is not affected by the LOSP event. That is Unit 2 is not tripped.

4. Quantification of the probability, P_6, of failure to isolate the main steam line rupture in the Turbine Building.

Thus

$$U_{AC}^2 = P_4 * P_5 * P_6$$

P_4 is given by multiplying the annual frequency of LOSP event, as reported in the NAPS IPE, by the time period of interest, which in this failure scenario is 90 days. Thus

$$P_4 = 1.14E\text{-}1 * [90/365] = 2.8E\text{-}2\ (3.7E\text{-}2)$$

where 1.1E-1 is the annual frequency of LOSP event (from Figure 3.1.3-1 of the NAPS IPE).

Also probability of the MSL rupture is quantified as described for failure scenario one but the exposure time is only one day (24 hours). Thus,

$$P_5 = [\text{Frequency of "A"}] * [1/365] * 0.75$$

$$P_5 = 5.0E\text{-}4 * [1/365] * 0.75 = 1.0E\text{-}6$$

Finally, from Table A-1 it is noted that the loss of off-site power will fail the source of power to the motorized NRVs but will not affect the main steam TVs, re-quantification of the isolation fault tree (Figure A-3), given that failure of the NRV branch is 1, gives:

$$P_6 = 1.03E\text{-}2$$

Therefore, the change in failure probability of the Unit 2 AC system for 90 days construction period is given by:

$$U_{AC}^2 = 2.8E\text{-}2 * 1.0E\text{-}6 * 1.03E\text{-}2 = 2.9E\text{-}10$$

and for 120 days construction period is:

$$U_{AC}^2 = 3.8E\text{-}10$$

Again, the change in failure probability of the Unit 2 AC system for this scenario is considered to be too small to merit further analysis.

A.3. Accident 3 Failure Scenario

The change in failure probability of the Unit 2 AC system for this accident scenario is obtained by performing the following analysis:

1. Identification of the interdepe..dency, if any, between the BC system failure event, MSL rupture failure event, and valve closure failure event.

2. Quantification of the probability, P_7, of MSL rupture in a 90 (120) day time period. This probability can be obtained using the same approach as described for accident 1 failure scenario.

2. Quantification of the LOSP probability, P_8, after the MSL rupture event in the Unit 2 Turbine Building. Since after a MSL rupture the unit will be tripped, using the conventional PRA approach, the exposure time for the LOSP event is considered to be 1 day (24 hours)

3. Quantification of the probability, P_9, of failure to isolate the main steam line rupture in the Turbine Building.

Therefore:

$$U_{AC}^3 = P_7 * P_8 * P_9$$

and

P_7 = 5.0E-4 * [90/365] * 0.75 = 9.2E-5 (1.2E-4)

P_8 = 1.14E-1 * [1/365] = 3.1E-4

P_9 = 1.17E-3 (assuming LOSP does not occur simultaneously with MSL rupture).

U_{AC}^3 = 3.1E-4 * 9.2E-5 * 1.17E-3 = 3.3E-11 (4.4E-11)

Again the probability of this plant damage state is considered too small to merit further consideration.

A.4. Accident 4 Failure Scenario

Review of Table A-1 indicates that this is the most sever accident scenario considered in this analysis, since occurrence of a design basis earthquake (DBE) is assumed to cause rupture of the main steam line in the Unit 2 Turbine Building, failure of the Bearing Cooling system (neither the MS piping in the Turbine Building nor the BC system is seismically qualified) and LOSP. However, all other seismically qualified systems are assumed not to be degraded as a result of a DBE. Additionally no other significant damage is assumed to be induced by a DBE. These assumptions are made because no probabilistic evaluation of a seismic event at the NAPS has been performed up to date and performance of such an evaluation is out of the scop of this study. To quantify the change in failure probability of the Unit 2 AC system for this accident scenario, the following analysis are performed:

1. Quantification of the probability, P_{10}, of a DBE in a 90 (120) day time period.
2. Quantification of the probability, P_{11}, of failure to isolate the main steam line rupture in the Turbine Building.

P_{10} is obtained by multiplying the annual frequency of a DBE by [90/365]. Using the 85th percentile curves from both LLNL and EPRI seismic hazard curves (per recommendation of the Generic Letter 88-20, Supplement 4), the annual frequency of DBE (0.18g) is 2.0E-3 to 4.0E-4. Thus the change in failure probability of the Unit 2 AC system is given

$$U_{AC}^4 = P_{10} * P_{11} = [2.0E\text{-}3] * [90/365] * 1.03E\text{-}2$$

where 1.03E-2 is the probability of the failure to isolate, given that the DBE has lead to LOSP and failure of the main steam line NRVs. The value of the P_{11} reported here also assumes that the DBE has not degraded the relays that send the auto trip signals, the mechanical integrity of the TVs and put additional stress on the operator. Thus

$$U_{AC}^4 = 5.1E\text{-}6\ (6.8E\text{-}6)$$

If 4.0E-4 is used as the frequency of a DBE, then

$$U_{AC}^4 = 1.0E\text{-}6\ (1.4E\text{-}6)$$

Table A-1

Interdependency Matrix Between Consequence of Failure Events

ACCIDENT SCENARIO	POSTULATED FAILURE EVENT	POTENTIALLY DAMAGED COMPONENTS OR SYSTEMS
1	U1 BC SYSTEM	U1 CHILLERS
	MSL RUPTURE + ISOLATION CAPABILITY	U2 MAIN FW PUMPS U2 CONDENSATE PUMPS U2 CW CONDENSER MOVs
2 AND 3	LOPS	BC SYSTEM MSL ISOLATION NRVs
	MSL RUPTURE + ISOLATION CAPABILITY	U2 MAIN FW PUMPS U2 CONDENSATE PUMPS U2 CW CONDENSER MOVs
4	DESIGN BASIS EARTHQUAKE	BC SYSTEM LOSP MSL RUPTURE MSL ISOLATION NRVs

U1= Unit 1

U2= Unit 2

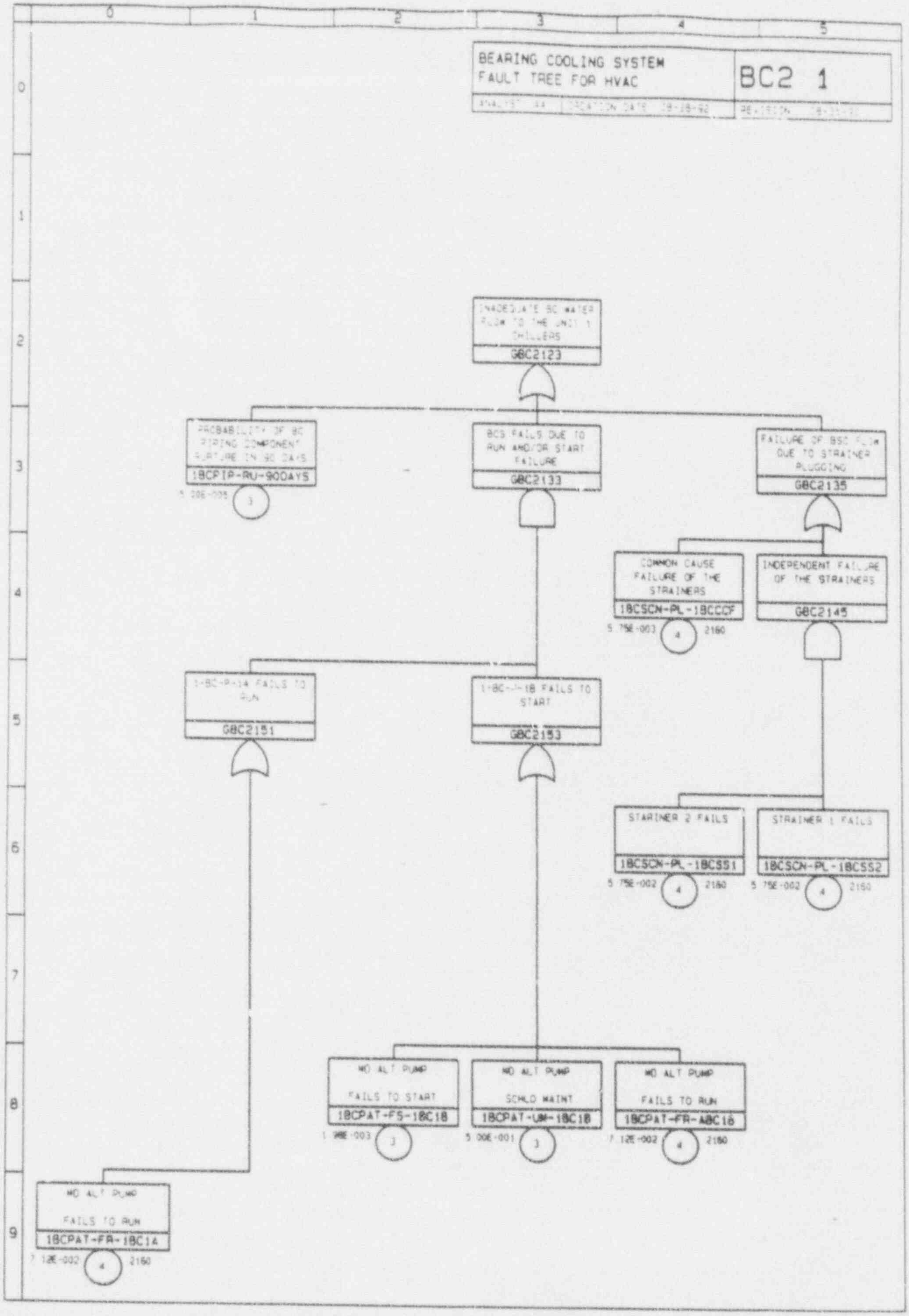

Figure A-1 BC System Fault Tree Model

NUPRA 2.0 FILE : BCS200.FTP   Page 1
Minimum Cut Set Solution for fault tree BCS200 , Serial no.= 3   HNUS Env
Performed : 15:50   31 AUG 1992
Cut Set Equation produced is : BCS200.EQN

BEARING COOLING SYSTEM FAULT TREE FOR HVAC

Top event: GBC2123
Top event unavailability (r.ev. appr)= 4.99E-02 (mission time 90 days)
Cutoff value used = 1.00E-10
Number of Boolean Indicated Cut Sets = 6
Number of MCS listed = 6
MINIMAL CUT SETS SORTED BY UNAVAILABILITY

1.	3.56E-02	1BCPAT-UM-1BC1B	1BCPAT-FR-1BC1A
2.	5.75E-03	1BCSCN-PL-1BCCCF	
3.	5.07E-03	1BCPAT-FR-ABC1B	1BCPAT-FR-1BC1A
4.	3.31E-03	1BCSCN-PL-1BCSS1	1BCSCN-PL-1BCSS2
5.	1.41E-04	1BCPAT-FR-1BC1A	1BCPAT-FS-1BC1B
6.	5.00E-05	1BCPIP-RU-90DAYS	

NUPRA 2.0 FILE : BCS2002.FTP
Minimum Cut Set Solution for fault tree BCS200 , Serial no.= 4
HNUS Env
Performed : 16:09 31 AUG 1992
Cut Set Equation produced is : BCS2002.EQN

BEARING COOLING SYSTEM FAULT TREE FOR HVAC

Top event: GBC2123
Top event unavailability (r.ev. appr)= 7.02E-02 (mission Time 120 days)
Cutoff value used = 1.00E-10
Number of Boolean Indicated Cut Sets = 6
Number of MCS listed = 6
MINIMAL CUT SETS SORTED BY UNAVAILABILITY

1.	4.74E-02	1BCPAT-UM-1BC1B	1BCPAT-FR-1BC1A
2.	9.01E-03	1BCPAT-FR-ABC1B	1BCPAT-FR-1BC1A
3.	7.67E-03	1BCSCN-PL-1BCCCF	
4.	5.88E-03	1BCSCN-PL-1BCSS1	1BCSCN-PL-1BCSS2
5.	1.88E-04	1BCPAT-FR-1BC1A	1BCPAT-FS-1BC1B
6.	5.00E-05	1BCPIP-RU-90DAYS	

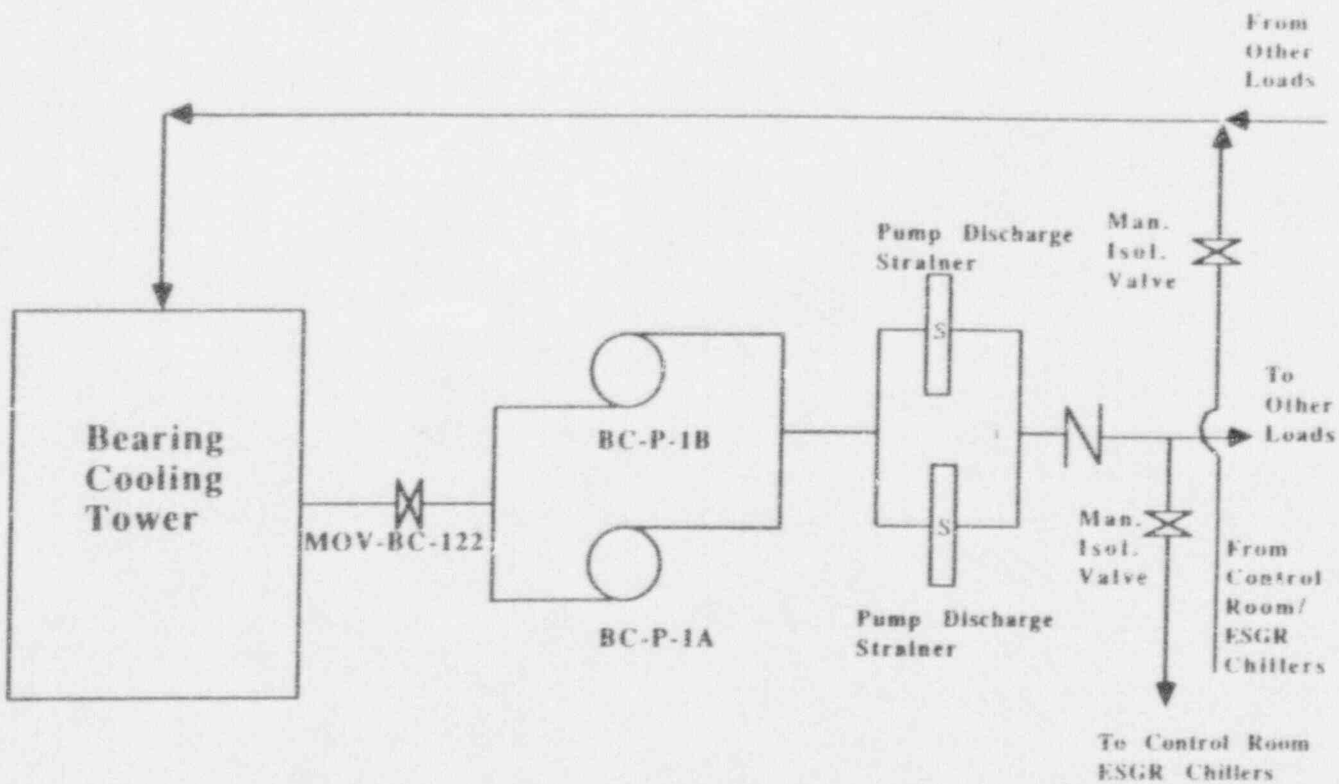

Figure A-2: Simpilified Flow Diagram of The Bearing Cooling Supply To The Control Roo a Emergency Switchgear Room Chillers

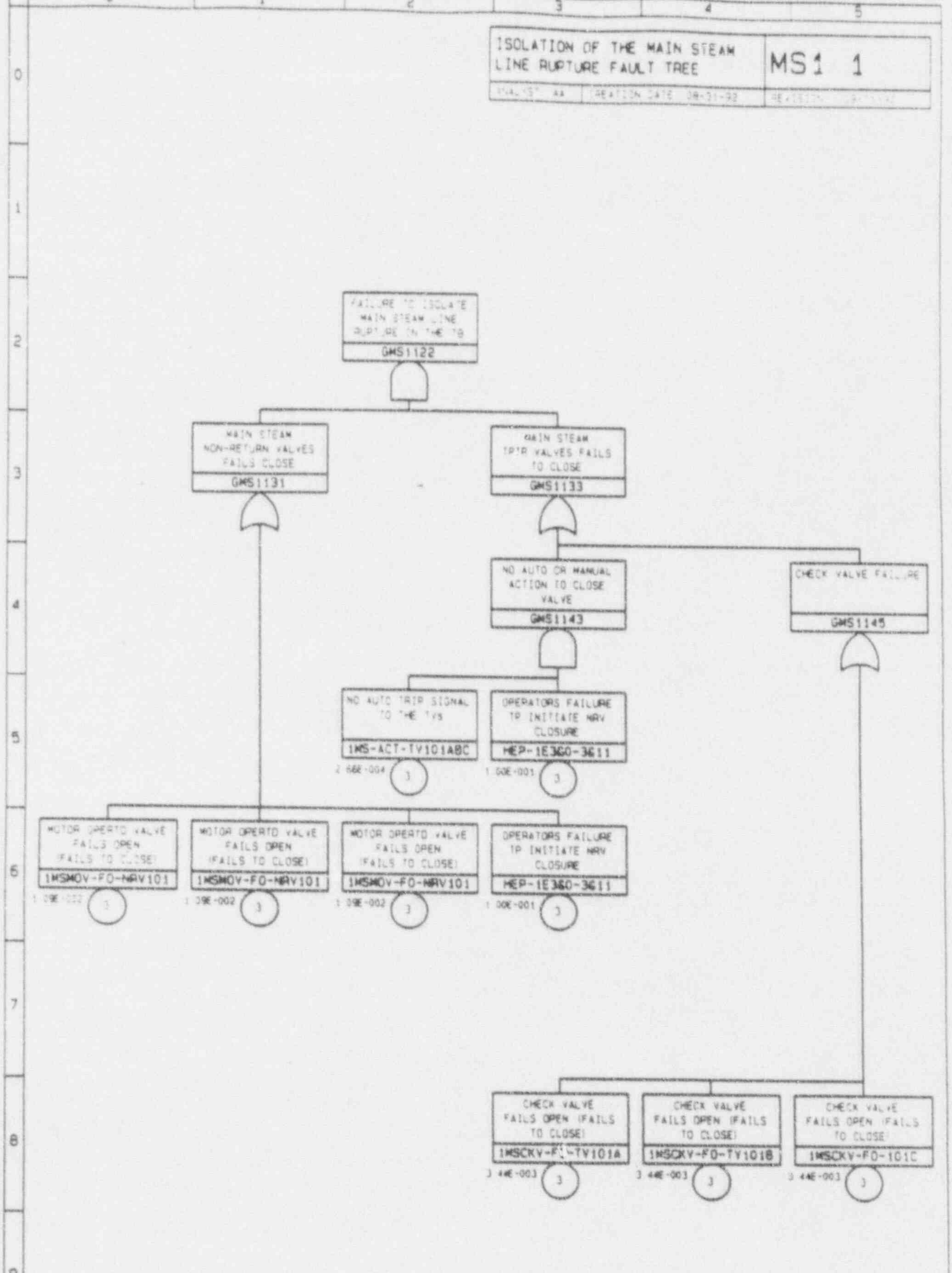

Figure A-3 Isolation of the Main Stream Line Rupture Fault Tree

NUPRA 2.0 FILE : MS100.FTP HNUS Env

Minimum Cut Set Solution for fault tree MS100 , Serial no.= 3

Performed : 16:50 31 AUG 1992

Cut Set Equation produced is : MS100.EQN

ISOLATION OF THE MAIN STEAM LINE RUPTURE FAULT TREE

Top event: GMS1122

Top event unavailability (r.ev. appr)= 1.17E-03

Cutoff value used = 1.00E-10

Number of Boolean Indicated Cut Sets = 8

Number of MCS listed = 7

MINIMAL CUT SETS SORTED BY UNAVAILABILITY

1.	3.44E-04	1MSCKV-FO-TV101A	HEP-1E3&0-3&11
2.	3.44E-04	HEP-1E3&0-3&11	1MSCKV-FO-TV101B
3.	3.44E-04	HEP-1E3&0-3&11	1MSCKV-FO-101C
4.	3.75E-05	1MSCKV-FO-TV101A	1MSMOV-FO-NRV101
5.	3.75E-05	1MSMOV-FO-NRV101	1MSCKV-FO-TV101B
6.	3.75E-05	1MSMOV-FO-NRV101	1MSCKV-FO-101C
7.	2.66E-05	1MS-ACT-TV101ABC	HEP-1E3&0-3&11

NUPRA 2.0 FILE : MS1133.FTP HNUS Env
Minimum Cut Set Solution for fault tree MS100 , Serial no.= 3
Performed : 3:00 1 SEP 1992
Cut Set Equation produced is : MS1133.EQN

ISOLATION OF THE MAIN STEAM LINE RUPTURE FAULT TREE

Top event: GMS1133
Top event unavailability (r.ev. appr)= 1.03E-02 (Prob of Failure to Isolate given LOSP)
Cutoff value used = 1.00E-10
Number of Boolean Indicated Cut Sets = 4
Number of MCS listed = 4
MINIMAL CUT SETS SORTED BY UNAVAILABILITY

1.	3.44E-03	1MSCKV-FO-TV101B
2.	3.44E-03	1MSCKV-FO-TV101A
3.	3.44E-03	1MSCKV-FO-101C
4.	2.66E-05	1MS-ACT-TV101ABC HEP-1E3&0-3&11

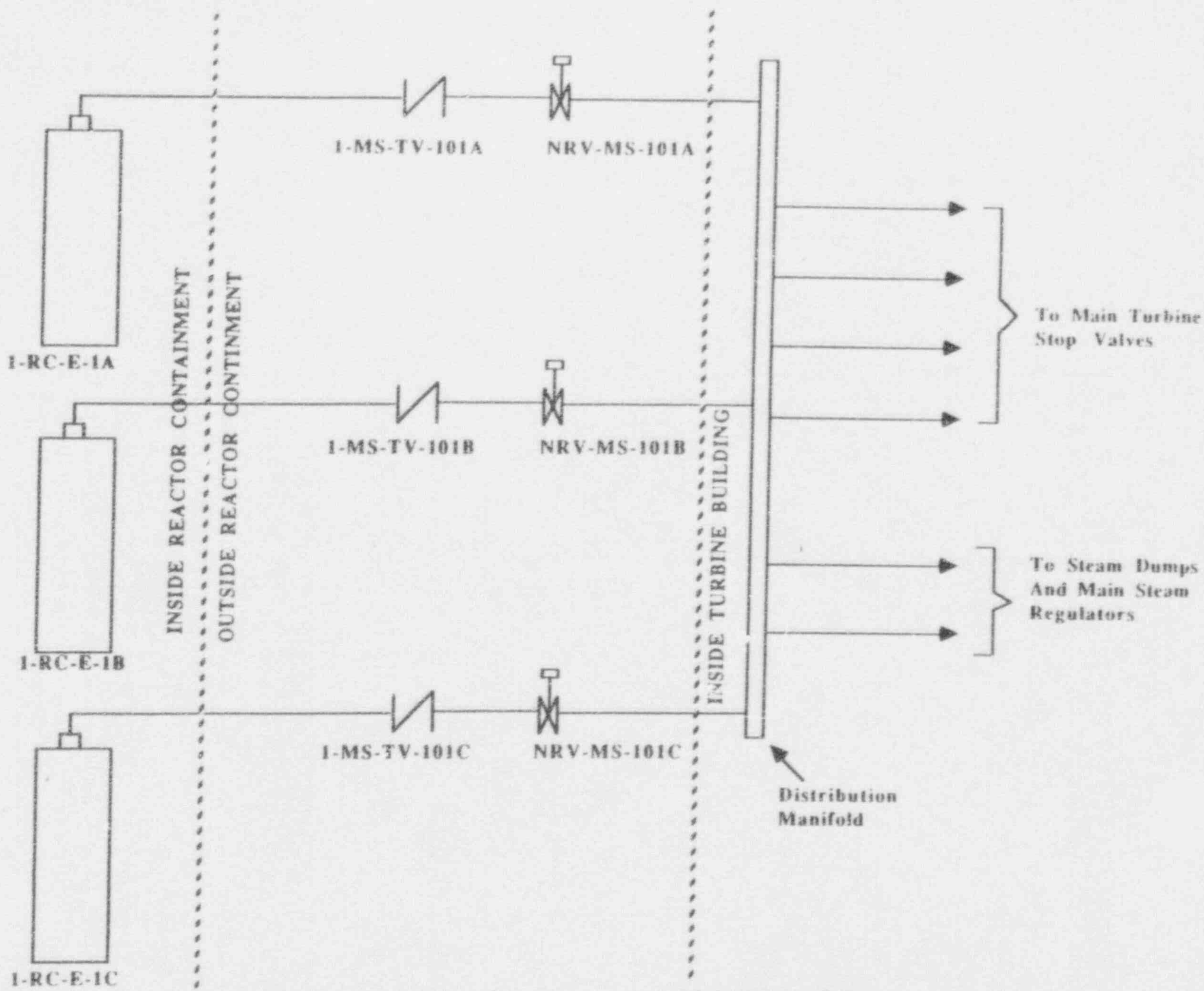

Figure A-4 Simpilified Diagarm of The Main Steam Lines

APPENDIX B
PIPE RUPTURE FREQUENCY QUANTIFICATION

APPENDIX B

PIPE RUPTURE FREQUENCY QUANTIFICATION

B.1. Frequency of SW Piping Rupture Using Thomas Correlation

The Thomas Correlation (Published in 1981) can be used for prediction of pipe rupture frequencies. This methodology was used in the Oconee Study [NSAC, 1984] and is an empirical correlation based on actual service failure statistics. In this methodology the actual pipe thickness can be used to predict failure frequency.

The general approach for evaluating failure frequency was similar to that adopted in the Indian Point Safety Study (1982).

1. Compare the generic data on pipe failure mechanisms with the North Anna Power Station SW attributes to assess the relative frequency failure at NAPS.

2. Determine frequency of pipe ruptures in the SW system using Thomas Correlation and correct for specific attributes of NAPS SW System.

B.1.1 SW Piping Rupture

The data upon which the Thomas Correlation is derived comes predominantly from high pressure systems where the ratio of design pressure to system working pressure is about 1.1 to 1.5. The ratio of the North Anna SW design pressure, 25 psig, to operating pressure of the return header pipe (the major contributors of T6 1E) is considerably higher. This higher ratio is a measure of additional safety margin for general causes of failure.

A representative list (extracted from Thomas, 1981) of pipe failure causes and their relative contributions (fraction of failures by each cause) is:

	Percent Generic Leaks
Manufacture and Fabrication	21.4
Material Selection	28.8
Fatigue - Vibration	4.3
- Low Cycle	7.8
Expansion/Flexibility	2.7
Corrosion/Erosion	24.6
Mal Operation	2.1
Thermal/Mechanical Shock	1.3
Miscellaneous	7.0
	100.0

The SW system at North Anna is examined below against possible causes of failure in order to justify a frequency reduction factor for:

Manufacture, Fabrication and Material Selection Errors - The SW system at North Anna has been in operation as long as the plant has been in commercial operation (approximately 15 years) and all major components are several years old. These types of causes are generally revealed early in the life and should have already been detected at North Anna if they exist. However, errors may still occur during repair work. The reduction in failure frequency is judged to be at least 90%.

Fatigue The SW Systems operate at low temperature and do not experience wide temperature fluctuation and is therefore not susceptible to thermal fatigue. However, conservatively, no reduction in failure frequency is taken credit for.

Expansion and Flexibility Such problems may arise due to design not adequately considering and allowing for pipe expansion and flexing caused by changes in temperature, pressure or other types of loads. It is likely that such problems in the design would have already been revealed and the failure frequency is judged to be at least 95% for these categories.

Corrosion/Erosion The SW lines have been or are being inspected and repaired in response to corrosion problems. However, as a conservative measure this factor has not been reduced.

Mal Operations The potential for maintenance/operational errors leading to the system being left open prior to reflooding or inadvertently opened prior to isolation is separately addressed in the internal flooding analysis of North Anna Power Station. The opportunity for mal operation of the system leading to internal stresses which caused a component failure is negligible. However conservatively, this parameter is not reduced.

Thermal and Mechanical Shock The SW system does not experience wide temperature fluctuations and thus the potential for thermal shock is negligible. The only internal mechanism for exerting mechanical shock would be water hammer. The reduction in failure frequency is at least 50% due to these categories.

Miscellaneous The contribution from this category has not been reduced.

Table B-1
Revised Frequency Calculation

	1	2	3
Pipe Failure Cause	% Generic Leaks Applicable to North Anna (After Applying Above)	PC/PL	PC of Generic Leaks Applicable to North Anna
Manufacture and Fabrication	2.14	0.08	.017
Material Selected	2.88	0.03	0.086
Fatigue -Vibration	2.15	.20	0.43
-Low Cycle	7.8	0.03	0.234
Expansion and Flexibility	0.14	0.10	0.14
Corrosion/ Erosion	24.6	0.02	0.49
Mal Operation	2.1	0.02	0.945
Thermal and Mechanical Shock	0.65	0.20	0.13
Miscellaneous	7	0.04	0.28
Total	**51.61**		**3.2**

The revised frequency contribution from each category is shown in Table B-1, Column 1.Also shown in the above table (Column 2) are the ratios of ruptures to leaks (PC/PL) for each type of failure mechanism. These ratios are based on information provided in Table 3 of Thomas, 1981. Column 3 is simply multiplication of Column 1 and Column 2 and shows the frequency of rupture due to various mechanisms as a percentage of the leak frequency determined from generic data. Overall this percentage is 3.2% (i.e., a ratio of .0032)

The frequency of pipe and valve rupture can be calculated using the Thomas Correlation as

discussed above. An evaluation of SW piping upstream of the isolated MOV for the return header from the SW supply to the CCW Fuel Pit Cooler is given as an example. Rupturing this piping section in the major contributor to the loss of SW initiating event while in one header operation.

Frequency of leakage (uncorrected)

$$F = P_1 \left[\frac{D_p L_p}{t_p^2} + nA \frac{D_w L_w}{t_w^2} \right]$$

Dp = OD = 10.75" diameter

Lp = Length = 120"

tp = pipe thickness = 0.283" includes corrosion (Measured January 1992)

A = penalty factor for weld ~ 50

Lw = weld length ~ 1.75 x tw

tw = weld thickness tw ~ tp

Pl = 1×10^{-8} yr $^{-1}$ (leak rate)

Dw = weld diameter Dw = Dp

n = number of welds = 4

$$F = 1\times10^{-8} \times \left(\frac{10.75 \times 120}{0.08} + (50 \times 4)\,\frac{10.75 \times 0.50}{0.08}\right)$$

$$F = 2.94\ E\text{-}4/yr$$

Multiplying this leak frequency by the North Anna specific rupture to leak ratio 0.0032 developed above gives a pipe rupture frequency of 9.5E-6.

B.2. Frequency of SW Piping Rupture Using WASH-1400 Data

Assuming 4 discontinuallies (i.e., 4 piping sections) and using probability of rupture as 1.0E-10 (Table III 4-1 of WASH-1400), then:

$$F = 4\ (1.0E\text{-}10)(365)(24) = 3.5E\text{-}6$$