ZION STATION
INDIVIDUAL PLANT EXAMINATION

INTERIM DEPLOYMENT TOOL

PREPARED BY: GEORGE KLOPP
SHANNON SHANEYFELT

PRA/HF GROUP
NUCLEAR ENGINEERING DEPARTMENT

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ABSTRACT

The Zion Interim Deployment Tool for the Individual Plant Examination (IPE) provides summary IPE results for use by station personnel in:

* Maintenance prioritization while at power (Section 2)
* Maintenance prioritization during an outage (Section 3)
* Modification prioritization (Section 3)
* Operator training prioritization (Section 3)

It also provides examples and cautions on the use of the information.

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1.0 INTRODUCTION

This section provides a summary of the Zion Interim Deployment Tool including limitations and cautions on its use.

1.1 Introduction

The Zion Station Individual Plant Evaluation (IPE) is a large, complex, technological undertaking. It will be useful in many areas of plant operations including maintenance, technical specification assessment, modification evaluation and risk optimization. However, the use of the IPE, as currently structured, requires a great deal of probabilistic risk assessment (PRA) experience and expertise. The IPE is not in a form that promotes use by plant engineers or other plant personnel.

In an effort to overcome this difficulty, this **interim deployment tool** has been developed to address some of the issues raised by the station and others regarding the use of PRA at Zion. The interim tool has limited uses and does not pretend to completely represent the results of the Zion IPE. Those limits are either self evident or are carefully spelled out as they pertain to sections of this tool. **If questions arise, the prudent course of action is to contact the Edison PRA group for clarification.**

Edison is actively pursuing the development of a much more comprehensive deployment tool which will provide a great deal more capability to the station while preserving a user friendly, format. Feedback on the effectiveness of this interim tool will aid in the design of the more comprehensive tool.

1.2 Limitations

It is crucial for users of the IPE, the interim deployment tool, or, eventually, the final deployment tool to understand the technical basis of the IPE and the limitations these impose on the use of the IPE or any product derived therefrom. The Zion IPE is based on plant configuration information which amounts to a late 1989 "snapshot" of the plant design, data and procedures. This does not invalidate the IPE in our view. It does mean that an update to the IPE as part of the "living PRA" process will be in order in the future. In the mean time, some care must be taken when applying the IPE to detailed assessments of plant alternatives.

More importantly, it is vital to recognize that the IPE, as with any PRA, is based on representations of the plant on an annual average or mean basis. One can derive, from the IPE, lists of functions and systems which are ranked in order of risk importance. Typically, any one of a number of such measures are employed by PRA practitioners in assessing PRA results. The Zion IPE "Top Events" Report in the IPE documentation is representative of such a list. These lists are useful to risk assessment personnel in evaluating the PRA results, searching for insights, and cross checking conclusions reached through other techniques. **Such lists are utterly inappropriate for use on a daily or weekly basis by station personnel in assigning priorities for maintenance or other activities.**

The reason behind this limitation is simple. The lists represented by the "Top Events" Report are annual average composites. They are not correct for the plant on any given day in any given configuration. For example, if the plant is in an LCO condition with the diesel generator supplying bus 147 out of service, the relative importance of AFW is raised because the potential success[1] of bleed and feed cooling is reduced. This perspective highlights the need to examine the "state" of the plant before making daily decisions on the relative importance of components or systems. Clearly, by contrast, the annual average representations (independent of current plant state) may be used to assist in decision making aimed at management of annual average risk.

Lastly, the IPE addresses internal events associated with the plant in the "at power" condition. It does not represent shutdown risk considerations at all nor does it consider external initiators.

1.3 Interim Tool

This interim tool for the Zion IPE addresses a limited number of plant "states" by considering a few key support system states as a basis for development. The tool considers those states which are most likely or most risk significant as defined by the top 110 accident sequences in the Zion IPE. Then, for each support state, the appropriate results are decomposed to reveal the most important systems and components and to comment, where appropriate, on key precautions to limit risk while in a given state. It also considers the relative risk importance of key systems and operator actions on an annual average basis.

The tool consists of two separate sections. The first section, the main portion of the tool provides a list of and definition of the support states considered in the interim tool and a discussion, for each support state of the risk significance and relative risk contributors associated with each support state. This section may be used directly to assess maintenance priorities while at power. It may also be key to assessing the risk significance of various other operating decisions while at power. A set of examples is provided to assist in understanding the use of this section.

The second section provides the "Top Events" Report from the IPE. This section should be used with extreme care. It is recommended that this section be employed primarily to assess priorities for maintenance and/or modification work

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[1] "Success" in the IPE is defined as preventing the hottest core node temperature from exceeding 1200° F for more than 30 minutes (the prevention of core damage in the IPE).

to be performed during plant outages where such work may affect the annual average reliability of components and systems having possible risk significance. Other proposed uses of this section should be discussed with the PRA group to insure the suitability of the application. Examples of the use of this section are included to assist in guiding the reader.

Because many factors influence decision making at Zion station, it should be noted that this tool only offers a perspective from PRA viewpoint and it is meant to supplement, not replace, the numerous other viewpoints (e.g. Technical Specifications, reliability, ALARA, etc.)

2.0 ASSESSING MAINTENANCE PRIORITIES WHILE AT POWER

This section provides a method for using the IPE results to assess maintenance priorities while at power including a discussion of the status of key support systems, front line system information, a step-by-step process, and examples to illustrate the use of this material.

2.1 Introduction

The information contained in this section may be used directly to assess maintenance priorities while at power. It may also be key to assessing the risk significance of various other operating decisions while at power.

The Zion IPE employed a "support state methodology" to model the key support systems and their impact on the safety systems that are required to respond to the various initiating events modelled in the IPE. Systems shared between the two units were modelled to ensure that the influence on both units was captured.

The following key support systems were modelled in the IPE:

* Electrical Power - DC
* Electrical Power - AC
* Engineered Safety Features Actuation System - ESFAS
* Safe Shutdown Sequencer
* Service Water - SW
* Component Cooling Water - CCW

The Zion IPE which was submitted to the NRC in April, 1992, considered over 200 support system states. Because the vast majority of these states represent degraded conditions which are not allowed in the Zion Technical Specifications, this interim deployment tool only uses a total of 2 support states (4 combinations of components) as defined on Table 1. If support system components not listed in Table 1 are unavailable, this tool cannot be employed for at power maintenance prioritization. Should there be any questions as to the applicability of the information contained in this section, please contact the PRA/HF Group in the Nuclear Engineering Department.

TABLE 1

PLANT SUPPORT STATES

UNAVAILABLE SUPPORT SYSTEM COMPONENT	SUPPORT STATE IDENTIFIER
NONE - ALL COMPONENTS AVAILABLE	1
ONE SERVICE WATER PUMP	1A
ONE COMPONENT COOLING WATER PUMP	1A
ONE SERVICE WATER **AND** ONE COMPONENT COOLING WATER PUMP	1A

It should be noted that the most risk significant of the key severe accident sequences occur while the plant is in Support State 1. We hasten to add that these results must be considered with care. Other states, potentially more risky once occasioned, may simply be masked in the existing data banks and/or may result from un-analyzed series of conditions. The Zion IPE does contain uncertainties.

The information contained in this section can be used for <u>at power</u> maintenance prioritization. If the plant is in a cold shutdown condition and extensive outage work is contemplated, the information contained in Section 3.0 should be employed. Although the nomenclature of this tool is for Zion Unit 1, the appropriate Unit 2 nomenclature should be used when applying the tool to Unit 2. All results apply equally to either unit.

The remainder of this section provides a discussion of the support states considered in this interim tool, a step-by-step application process, and examples of the use of the information.

2.2 Support State 1 - Discussion of Risk Significance and Relevant Risk Contributors

Support State 1 is defined as all support systems operational with all key support equipment functioning or operable. For this state, we have developed assessments of the:

a) risk importance of the top initiating events (Table 2),

b) risk importance of the most significant of the system failures in the key accident sequences (Table 3), and

c) risk importance of the most important system successes (Table 4).

In this latter case, we have simply identified the systems which did not fail for the success and Success with Accident Management (SAM)[2] sequences. This information provides valuable input on "what worked" and is an indication of the importance of systems which contributed to success.

Support State 1 is the numerically most important support state for Zion Station in that it contains over 99.8 percent of the frequency of support state occurrence.

It will readily be noted that the four important system failures shown in Table 3 are also found repeatedly as important successes in Table 4. This dual appearance reinforces the significance of those four systems for Support State 1.

TABLE 2

KEY ACCIDENT INITIATORS
SUPPORT STATE 1

INITIATOR	RELATIVE IMPORTANCE IN SUPPORT STATE 1
Steam Generator Tube Rupture	7.3
Large Loss of Coolant Accident	1.9
Medium Loss of Coolant Accident	0.6
Small Loss of Coolant Accident	0.2

[2] Success with Accident Management (SAM) sequences are those which are successful but require Accident Management intervention after the first 24 hours to prevent core damage.

TABLE 3

IMPORTANT SYSTEM FAILURES

SUPPORT STATE 1

SYSTEM	RELATIVE IMPORTANCE IN IPE
RWST Refill Systems per Zion EOP's	6.9
Residual Heat Removal System as ECCS Injection	1.5
Residual Heat Removal System as ECCS Recirculation	0.9
Centrifugal Charging Pumps as ECCS Injection	0.7

NOTE: The relative importance of the initiators and systems shown in Table 2 and 3 for Support State 1 includes consideration of the impact of the initiator on both core damage frequency and frequency of serious release. Both of these factors receive equal weight. The scale employed is one to ten with ten indicating the greatest risk contribution.

TABLE 4

IMPORTANT SYSTEM SUCCESSES

SUPPORT STATE 1

INITIATOR	FUNCTION	KEY SUCCESSFUL SYSTEMS
LARGE LOCA	Inventory Control	RHR as ECCS Injection; SI or C. Chg in same role
	Long Term Inventory Control	RHR as ECCS Recirc.; SI or C. Chg with RWST Refill
	Long Term Heat Removal	RCFC's or RHR Heat Exchanger
MEDIUM LOCA	Inventory Control	SI or C. Chg as ECCS Injection or RHR as ECCS Injection with AFW and SG PORV's to De-pressurize
	Long Term Inventory Control	RHR and SI/C. Chg as ECCS Inventory Recirc.; SI or C. Chg with RWST Refill
	Long Term Heat Removal	RCFC or RHR Heat Exchanger
SMALL LOCA (or ISLOCA) Rev. 1b, 11/25/92)	Inventory Control	SI or C. Chg as ECCS Injection or RHR as ECCS Injection with AFW and SG PORV's to De-pressurize
	RCS Heat Removal	AFW and SG PORV's or Turbine Bypass Valves
	Long Term Inventory Control	RHR and Normal Charging or RHR and/or C. Chg/SI as ECCS Recirc. or C. Chg/SI plus RWST Refill
	Long Term Heat Removal	RCFC's or RHR Heat Exchanger
STEAM GENERATOR TUBE RUPTURE	Inventory Control	C. Chg or SI as ECCS Injection
	RCS Heat Removal	AFW and SG PORV's or Turbine Bypass Valves
	Long Term Inventory Control	Normal Chg. or RHR and C. Chg/SI as ECCS Recirc. Control or C.Chg/SI and RWST Refill
	Long Term Heat Removal	RCFC or RHR Heat Exch. or AFW/PORV/stm dump

NOTE: The reference for this table is Table 4.1.4-1 in the Zion IPE submittal document. The detailed success criteria combinations for various initiating events are set forth for each of the key safety functions. That information is independent of the support state at any given time so care must be taken to insure that inappropriate use is not made of the information therein. Table 4 provides a distillation appropriate in that regard for Support State 1.

2.3 Support State 1A - Discussion of Risk Significance and Relevant Risk Contributors

As shown in Table 1, Support State 1A is defined as one in which one service water pump or one component cooling water pump or one service water pump and one component cooling water pump are unavailable. These conditions are allowed by the plant Technical Specifications. Support State 1A is not a significant risk contributor in the Zion IPE. In fact, it is so insignificant, that it is not listed as a contributor.

The behavior of the plant, in risk space, is nearly identical for Support State 1A and Support State 1. Therefore, the information provided for State 1 can be employed if the plant is in State 1A.

2.4 Application Process

This section provides a step-by-step process for application of this interim tool to "at power" maintenance prioritization.

STEP 1 - Verify that the plant is in Mode 1. If not, this section cannot be employed.

STEP 2 - Determine if the only support system components which are unavailable are those listed in Table 1. If not, this section cannot be employed.

STEP 3 - Determine if any other support systems are inoperable and thereby renders the ECCS systems, AFW, or RCFC's in an inoperable or degraded state. If so, this section cannot be employed.

STEP 4 - Determine if there is anything unusual at the plant indicating a precursor to a possible initiating event, such as:

- Steam Generator Tube Leakage (SGTR)
- Excessive or unusual RCS leakage (LOCA)
- High temperatures in the RHR System (Interfacing Systems LOCA)
- High System Demand, High winds or Thunderstorms, work in the switchyard (LOOP or DLOOP)

If one of these precursors exist, use the equipment prioritization information for the appropriate initiating event provided in Table 4. If a precursor to a LOOP or DLOOP exists, priority should be given to the Diesel Generators before any of the Table 4 equipment. If no precursors exist (Rev 1b, 11/25/92), proceed to STEP 5.

STEP 5 - Prioritize maintenance in accordance with the relative importance of the systems listed in Table 3. If the system of interest is not contained in Table 3, use the information contained in Table 4 (Rev. 1a, 10/30/92).

2.5 Application Examples for At Power Maintenance Prioritization

This section provides three examples for use of the Section 2 information to prioritize maintenance activities while at power.

2.5.1 Example A

Given: The plant is at full power with a minor steam generator tube leak on the 1B steam generator. All support systems are fully operational. There is a work request for replacement of a minor part on the "A" centrifugal charging pump on unit 1, which has the pump "inoperable" and a second work request for an RPS surveillance waiting to be processed. In the past, this particular RPS work has occasionally led to unit trips.

Question: What does the interim deployment tool suggest regarding this situation?

Response: First of all, note that all support systems are fully operational. This puts the plant in Support State 1. The charging pump is one of the primary tools for RWST refill and is important in two roles for this support state (i.e. See Tables 3 and 4).

Also, with a leaking tube, any transient which might severely stress the steam generator tube bundle, such as a trip, should be avoided. This is particularly true if key safeguards equipment is not available.

Reasonable courses of action would be to fix the pump prior to performing any surveillance and to add extra precautions to avoid a unit trip when the surveillance is performed. Alternatively, one might take the plant to a shutdown condition (depending on a variety of conditions) in an orderly manner, fix the pump, perform the surveillance and restart the plant.

2.5.2 Example B

Given: The 1A service water pump is OOS for maintenance. Surveillances have just disclosed that the 1B SI pump and the 1A RHR pump are "inoperable." The RHR pump will require 144 hours of maintenance time to restore to service. The SI pump will require 18 hours of maintenance time to restore to service. The plant does not have enough maintenance manpower to work on both at the same time. The tech spec LCO is 7 days for both SI and RHR systems.

Question: Which of the three pumps should be addressed first?

Response: The plant is in Support State 1A with one service water pump unavailable. The discussion for State 1A indicates that the plant behavior is judged to be nearly identical to that set forth for State 1. An examination of Table 3 for Support State 1 reveals that the RHR pumps play an important role but that the SI pumps do not appear to be anything like as risk significant. Table 4 also highlights the importance of RHR pumps while offering the charging pumps as alternatives for the SI pumps. Therefore, despite the shorter restoration time associated with the SI pumps, the RHR pumps should receive the higher priority.

2.5.3 Example C

Given: All support systems and equipment available and the plant at power. Work requests are on hand for a containment spray system pumping train and for a RCFC.

Question: Which should have the highest priority?

Response: A review of Table 4 reveals that the RCFCs act in an important role for long term heat removal. The containment spray system does not show up as an important success in this table. The RCFC should have a higher priority. [Note: Further review of the Zion IPE would reveal that the sprays have a limited beneficial role and may, as currently configured, contribute to risk given automatic actuation.]

2.5.4 Example D

Given: During full power operation, with no support systems out-of-service, two NWR's are being prioritized. One will adjust the circuits controlling an Auxiliary Feedwater Pump, the other is to investigate spurious alarms on the Rod Control Cabinets.

Question: Which should have the highest priority from a risk viewpoint?

Response: The plant is in support state 1. From Table 4 it can be seen that the AFW system plans an important role in SGTR's, Medium and Small LOCA's. The Rod Control Cabinet does not appear in Tables 2 through 4. Therefore, the Auxiliary Feedwater Pump NWR should be given priority.

2.5.5 Example E

Given: During full power operation with no support systems out-of-service, two NWR's are being prioritized. One is for the Main Feedwater system and the other is for the Instrument Air System.

Question: Which should have the highest priority from a risk viewpoint?

Response: The plant is in support state 1. From Tables 2 through 4 it can be seen that neither system has importance from a risk standpoint. Therefore, priority should be assigned based on other criteria.

3.0 MAINTENANCE/MODIFICATION PRIORITIZATION PRIOR TO RETURN TO POWER

This section provides the Zion IPE "Top Events" and "Initiating Events" Reports which can be used for maintenance and modification prioritization prior to return to power from an outage (i.e. outage work prioritization). Examples have been provided to assist in the understanding the use of this section.

The "Top Events" report provides the **annual average** top events from the IPE and has been broken out into equipment top events (Table 5) and operator top events (Table 6). The events listed in Tables 5 and 6 are the branches (nodes) on the Plant Response (or Event) Trees (PRT's). The Plant Response Trees are used to logically model the accident progression of each initiating event through successful mitigation or core damage and containment disposition. The events are the series of equipment which is activated or operator actions which are taken in response to an initiating event. A description of each of the "events" is provided in appendix A.

The core damage frequency (CDF) listed in Tables 5 and 6 is a cumulative total CDF of the occurrence of that event on core damage pathways across all initiating events. For example, ORT failure occurs in core damage pathways have a total CDF of 1.366E-6 (i.e. 34.15% of the total CDF of 4.00E-6).

The events listed in Table 5 may be useful for setting priorities for overhaul, maintenance or replacement of components used during power operation **while the plant is undergoing an outage.** Table 6 identifies those key operator actions which are most risk significant and which might benefit most from emphasis during annual training. In that role, this interim tool provides a prioritized list of those components, systems or operator functions which are likely to average highest in importance over the course of the coming year and which, therefore, are deserving of a high outage work priority.

CAUTION

The information contained in this section should be used with extreme care. It is recommended that this section be employed primarily to assess priorities for maintenance and/or modification work to be performed during plant outages where such work may affect the annual average reliability of components and systems having possible risk significance. Other proposed uses of this section should be discussed with the PRA group to insure the suitability of the application.

When prioritizing outage work, the relative ranking of the systems or components shown in Table 5 can be employed. The relative rank of components which are on the lower portion of the table is of less significance than those which are high on the list.

3.1 Application Examples for Outage Work Prioritization

3.1.1 Example A

Given: A plant outage is being planned. Key modification packages are being reviewed and efforts are being made to prioritize these and allocate available funding and personnel resources. Two of the modifications in question are;

A. a change to the low pressure injection (RHR) system which will decrease its unavailability by a factor of 5.

B. a change to engineered safety features actuation system which will decrease its unavailability by a factor of 20.

Question: Which of these modifications should receive priority attention from a risk perspective?

Response: Table 5 shows that the low pressure injection (LPI) system (Item #3) has a CDF contribution which is 18.57% of the total versus the ESF (Item #11) contribution of 2.85%. Therefore, the LPI CDF contribution is 6.52 times greater than the ESF contribution. The ESF unavailability decrease, however, is only a factor of 4 greater than the LPI modification. Therefore, more is to be gained by improving the low pressure injection system than by improving the engineered safety features actuation system. The change to RHR should be given priority.

3.1.2 Example B

Given: During a refueling outage, an effort is being made to assign priorities to work requests covering essential maintenance on the following systems/components needed for power operation;

A. auxiliary feedwater pumps
B. safety injection pumps
C. containment spray valves
D. service water pumps
E. main steam isolation valves

Question: How should these work requests be ranked so as to minimize annual average risk once the plant returns to power?

Response: Using the top events report, the work requests should be ranked as follows;

1. auxiliary feedwater pumps (Item #5)
2. service water pumps (Item #8)
3. containment spray valves (Item #9)
4. safety injection pumps (Item #17)
5. main steam isolation valves (Item #34)

TABLE 5
ZION IPE TOP EVENTS REPORT
(Equipment)

NODE NAME	DESCRIPTION	CORE DAMAGE FREQUENCY	PERCENT OF TOTAL CDF
1. RTK	EQUIPMENT TO REFILL RWST	1.337E-006	33.42%
2. BUS	4160V AC BUSES 147, 148, 149	9.128E-007	22.82%
3. LPI	LOW PRESSURE INJECTION	7.430E-007	18.57%
4. FC	REACTOR CONTAINMENT FAN COOLERS	5.243E-007	13.11%
5. AFW	AUXILIARY FEEDWATER SYSTEM	5.114E-007	12.78%
6. HPR	HIGH PRESSURE RECIRCULATION	4.559E-007	11.40%
7. LPR	LOW PRESSURE RECIRCULATION	3.604E-007	9.01%
8. SWS	SERVICE WATER SYSTEM	1.375E-007	3.44%
9. CSI	CONTAINMENT SPRAY SYSTEM	1.329E-007	3.32%
10. SAC	SAFEGUARDS ACTUATION 17, 18, 19	1.168E-007	2.92%
11. ESF	ENGINEERED SAFETY FEATURES ACTUATION	1.139E-007	2.85%
12. CCP	CENTRIFUGAL CHARGING PUMPS	1.115E-007	2.79%
13. CI	CONTAINMENT ISOLATION	1.062E-007	2.65%
14. HPI	HIGH PRESSURE INJECTION	9.939E-008	2.48%
15. DCB	125V DC BUSES 011-1, 111, 112	5.691E-008	1.42%
16. CCW	COMPONENT COOLING WATER SYSTEM	5.624E-008	1.41%
17. SIP	SAFETY INJECTION PUMPS	3.345E-008	0.84%
18. CB	CONDENSATE BOOSTER PUMPS	3.015E-008	0.75%
19. RHX	RHR HEAT EXCHANGER COOLING	2.692E-008	0.67%
20. RXT	REACTOR TRIP	1.404E-008	0.35%
21. SLO	CONSEQUENTIAL SEAL LOCA	1.183E-008	0.30%
22. AFT	TURBINE-DRIVEN AUXILIARY FEEDWAER PUMP	1.042E-008	0.26%
23. MF	FRAC OF TRAN MFW AVAIL UNTIL TT	6.377E-009	0.16%
24. AM	ATWS MITIGATING SYSTEM ACTUATION CIRCUIT	6.377E-009	0.16%
25. RE	RESTORE EQUIPMENT & SUPPORT SYSTEMS	3.932E-009	0.10%
26. AFI	CLOSE ALL FW/AFW VALVES TO RUPT SG	2.860E-009	0.07%
27. SEQ	SAFE SHUTDOWN SEQUENCERS 17, 18, 19	1.103E-009	0.03%
28. PRV	PRESSURIZER PORVS	5.109E-010	0.01%
28. DS	SECONDARY PRESSURE RELIEF	3.843E-010	0.01%
30 TT	TURBINE TRIP	3.695E-010	0.01%
31. PPR	PRIMARY PRESSURE RELIEF	1.993E-010	0.00%
32. TK	REFUELING WATER STORAGE TANK	1.567E-010	0.00%
33. ALT	ALTERNATE FEEDWATER	1.372E-010	0.00%
34. MSI	MAIN STEAM ISOLATION	1.199E-010	0.00%
34. DP	PRESSURIZER PORVS	7.382E-011	0.00%
36. TT2	TURBINE TRIP OR ALL MSIVS CLOSE	1.659E-011	0.00%
37. AC	CHARGING PUMP FLOW ALIGNMENTS	1.626E-011	0.00%
38. NC	NORMAL CHARGING	4.355E-012	0.00%
39. ACC	ACCUMULATORS	4.345E-012	0.00%
40. EC	FIREWATER TO OPERATING CHARGING PUMP	4.099E-012	0.00%
41. NRC	NORMAL RHR COOLING	2.437E-012	0.00%
42. MFW	MAIN FEEDWATER SYSTEM	1.451E-012	0.00%
43. SGI	SEC BREAK INSIDE CTMT ISO - MSIV + FWIV	1.183E-012	0.00%
44. BL	PRESSURIZER PORVS BLEEDING	4.930E-013	0.00%
45. CRI	CONTROL ROD INSERTION	2.870E-013	0.00%
46. NCP	PROBABILITY OF 2/2 CCP AVAIL	2.681E-013	0.00%
47. FB1	FEEDWATER ISOLATION (FOR BREAK OUTSIDE CONTAINMT)	8.406E-014	0.00%
48. VLV	CHARGING PUMP INJECTION VALVING	3.560E-014	0.00%
49. SW	EQUIPMENT TO RESTORE SW & ALIGN CCW	1.730E-014	0.00%
50. MSR	OPEN BREAKER OR TRIP MG SET OR INSERT	1.681E-014	0.00%
51. FB2	FEEDWATER ISOLATION (FOR BREAK INSIDE CONTAINMT)	4.608E-015	0.00%
52. EB	EMERGENCY BORATION	2.249E-016	0.00%
53. RCW	EQUIPMENT TO RESTORE CCW	2.620E-017	0.00%

Total plant core damage frequency = 4.001E-006 per year

TABLE 6

ZION IPE TOP EVENTS REPORT

(Operator Actions)

NODE NAME	DESCRIPTION	CORE DAMAGE FREQUENCY	PERCENT OF TOTAL CDF
1. ORT	OP ACTION - REFILL THE RWST	1.366E-006	34.15%
2. ORC	OP ACTION - ESTABLISH ECC RECIRCULATION	8.144E-007	20.36%
3. ODS	OP ACTION - SG DEPRESS FOR PRIM COOLING	6.785E-007	16.96%
4. OIR	OP ACTION - REDUCE INJECTION	4.770E-007	11.92%
5. ORE	OP ACTION - RESTORE EQUIP/SUPPORT SYSTEMS	1.699E-007	4.25%
6. OSI	OP ACTION - INITIATE SAFETY INJECTION	4.691E-008	1.17%
7. ORS	OP ACTION - RAPID SG DEPRESS FOR CB INJ	5.478E-009	0.14%
8. OIB	OP ACTION - ISOLATE RHR BREACH	4.532E-009	0.11%
9. ONC	OP ACTION - ESTABLISH NORMAL CHARGING	4.083E-009	0.10%
10. OTT	OP ACTION - TURBINE TRIP OR CLOSE MSIVS	2.474E-009	0.06%
11. ORF	OP ACTION - RESTORE CB &/OR MFW	1.916E-009	0.05%
12. OPR	OP ACTION - DEPRESS PRIM WITH PRZR PORVS	1.469E-009	0.04%
13. OHX	OP ACTION - ESTABLISH CCW TO RHR HX	1.369E-009	0.03%
14. OAF	OP ACTION - ISOLATE FEED TO RUPT SG	1.114E-009	0.03%
15. OOF	OP ACTION - OPEN AFW THROTTLE VALVES	7.853E-010	0.02%
16. OAI	OP ACTION - ISOLATE STEAM FROM RUPT SG	6.782E-011	0.00%
17. OSW	OP ACTION - RESTORE SW AND ALIGN CCW	4.939E-011	0.00%
18. ORI	OP ACTION - MANUAL CONTROL ROD INSERTION	1.731E-011	0.00%
19. OAC	OP ACTION - ALIGN CHARGING SUCTION	5.600E-012	0.00%
20. OFW	OP ACTION - START AUX FEEDWATER	4.897E-012	0.00%
21. ODP	OP ACTION - DEPRESS PRIM WITH PRZR PORVS	3.027E-012	0.00%
22. OEC	OP ACTION - FIREWATER TO CCP OIL COOLER	2.393E-012	0.00%
23. ONR	OP ACTION - ESTABLISH NORMAL RHR COOLING	1.198E-012	0.00%
24. OSC	OP ACTION - STOP CCW PUMPS	6.488E-013	0.00%
25. OSR	OP ACTION - CONTROL RODS TO CORE BOTTOM	3.229E-013	0.00%
26. OBL	OP ACTION - DEPRESS PRIM WITH PRZR PORVS	1.482E-013	0.00%
27. OCC	OP ACTION - RESTORE CCW	1.461E-013	0.00%
28. OEB	OP ACTION - EMERGENCY BORATION	3.446E-014	0.00%
29. OXR	OP ACTION - ECC RECIRC AFTER CORE DAMAGE	3.368E-015	0.00%

Total plant core damage frequency = 4.001E-006 per year

TABLE 7

ZION IPE INITIATING EVENTS REPORT

EVENT NAME	DESCRIPTION	CORE DAMAGE FREQUENCY	PERCENT OF TOTAL CDF
1. LLOCA	LARGE LOCA INITIATING EVENT	1.324E-006	33.09%
2. SGTR	STEAM GENERATOR TUBE RUPTURE INITIATING EVENT	1.152E-006	28.80%
3. DLOOP	DUAL UNIT LOSS OF OFFSITE POWER INITIATING EVENT	9.000E-007	22.50%
4. MLOCA	MEDIUM LOCA INITIATING EVENT	3.973E-007	9.93%
5. SLOCA	SMALL LOCA INITIATING EVENT	1.540E-007	3.85%
6. GTR	GENERAL TRANSIENT INITIATING EVENT	4.615E-008	1.15%
7. LOOP	LOSS OF OFFSITE POWER INITIATING EVENT	2.124E-008	0.53%
8. ISLOCA	INTERFACING SYSTEMS LOCA INITIATING EVENT	4.532E-009	0.11%
9. LDC	LOSS OF 125V DC BUS 111 INITIATING EVENT	7.209E-010	0.02%
10. FBIN	FEED BREAK INSIDE CONTAINMENT INITIATING EVENT	2.346E-010	0.01%
11. SBIN	STEAM BREAK INSIDE CONTAINMENT INITIATING EVENT	2.346E-010	0.01%
12. FBOUT	FEED BREAK OUTSIDE CONTAINMENT INITIATING EVENT	2.345E-010	0.01%
13. SBOUT	STEAM BREAK OUTSIDE CONTAINMENT INITIATING EVENT	2.344E-010	0.01%
14. LSW	LOSS OF SERVICE WATER INITIATING EVENT	5.126E-011	0.00%
15. LCCW	LOSS OF COMPONENT COOLING WATER INITIATING EVENT	4.687E-013	0.00%
	TOTAL	4.00E-006	100.00%

APPENDIX A

DESCRIPTION OF TOP EVENT NODES

The following information provides a description of the equipment and operator action top event nodes identified in Tables 5 and 6.

1. Hardware, Align Charging Pumps (AC)

This node is the availability of equipment necessary to accomplish the valve alignments required by the operator actions of node OAC. A detailed description of AC is provided in the Miscellaneous System Notebook.

2. Accumulators (ACC)

This node is injection of the accumulators (ACC), a passive system designed to provide core cooling during the blowdown and reflood portions of the LOCA. When the RCS pressure drops below the nitrogen pressure in the accumulators (~650 psig), borated water in the accumulators is forced into the cold legs. For the consideration of the medium LOCA sequence, accumulators are required to prevent core damage if HPI and AFW or ODS/DS have failed, but ODP/DP is successful. A detailed description of ACC is provided in the ECCS notebook.

3. Isolation of Feedwater Flow to Ruptured SG (AFI)

This node includes the equipment to isolate feedwater flow to the ruptured SG. Specifically, this equipment includes the AFW flow regulating valves on the motor driven AFW pump line (FW0051, FW0053, FW0055, FW0057) and on the turbine driven AFW pump line (FW0050, FW0052, FW0054, FW0056). For feedwater to the SGs via the main feedwater pumps, the equipment includes the main feedwater flow regulating valve on each line (LCV-FW510, LCV- FW520, LCV-FW530, LCV-FW540) as well as the main feedwater bypass line flow regulating valve on each line (LCV-FW510A, LCV-FW520A, LCV-FW530A, LCV-FW540A). An evaluation of node AFI is given in the Auxiliary Feedwater Systems Notebook for auxiliary feedwater control and the Miscellaneous Systems Notebook for alternate feedwater control.

4. Auxiliary Feedwater - Turbine Driven (AFT)

This node represents the delivery of auxiliary feedwater to the steam generator(s). Since all AC power has been lost, only the turbine driven auxiliary feedwater pump is available. The automatic opening of the steam generator safety valves is also included in this node. At 4 hours, the time that the station batteries are postulated to be exhausted, all DC power will be lost and therefore all instrumentation will be lost. At this point, it is expected that the operator will leave the auxiliary feedwater control valves in the same position as just prior to the loss of DC power. Following this, as the generator fills , the operator will watch for water coming out of the relief valves and throttle auxiliary feedwater accordingly. A detailed description of AFW is provided in the Auxiliary Feedwater System Notebook.

5. Auxiliary Feedwater (AFW)

This node is auxiliary feedwater delivery to the steam generators with a motor driven auxiliary feedwater pump. The auxiliary feedwater system provides water to the steam generators to maintain steam generator level ensuring effective heat removal via the steam generators. Auxiliary feedwater is required to: 1) maintain RCS pressure below the shutoff head of the SI pumps, if charging pumps are not available, 2) cooldown and depressurize the reactor coolant system, and 3) prevent the EOPs from requiring the operators to initiate RCS bleed and feed cooling. The operation of the steam dumps or the automatic opening of the steam generator atmospheric relief and/or safety valves is also included in this node. A detailed description of AFW is provided in the Auxiliary Feedwater System Notebook.

6. Alternate Feedwater (ALT)

This node is alternate feedwater delivery to the steam generators with the main feedwater pumps. If auxiliary feedwater is not available, an alternate feedwater source is required to cooldown and depressurize the RCS. For the SGTR scenario, the main feedwater pump(s) can provide sufficient water to the steam generators in order to ensure steam generator heat removal capability. For injection with the main feedwater pump(s), this node represents the successful start and continued operation of the main feedwater pump(s) along with the operation of the associated valves required to realign the main feedwater pump(s) for injection to the steam generator(s). The main feedwater pump will be fed by the condensate booster pump(s); therefore successful injection with the main feedwater pump(s) also includes the successful start and continued operation of the condensate booster pumps along with the operation of the associated valves required for the condensate booster pumps to feed the main feedwater pump(s). However, no steam generator depressurization is necessary for injection with the main feedwater pump(s). A detailed description of ALT is provided in the Miscellaneous Systems Notebook.

7. ATWS Mitigation System Actuation Circuitry (AM)

The ATWS Mitigation System Actuation Circuitry (AMSAC) provides a means, diverse from the Reactor Protection System (RPS), for initiating turbine trip and auxiliary feedwater flow on conditions indicative of an ATWS. For power levels greater than 40%, if steam generator levels decrease to 6% narrow range, a diverse signal is sent to trip the main turbine and start the auxiliary feedwater pumps. The diverse signal improves the reliability of systems needed to ensure a secondary heat sink following an ATWS event. For most transient events, including a complete loss of main feedwater, turbine trip is initiated by the P-4 protective interlock, which requires the reactor trip breakers to be open. Because the breakers may fail to open on an ATWS event, a diverse means to trip the turbine is required. A diverse means to start the AFW pump is provided based on the unlikely event that the RPS failure was due to a failure in the SG level protection channel's power supply, comparator/bistable or logic relay.

8. RCS Bleed via Pressurizer PORV(s) (BL)

This node is the action of at least one pressurizer PORV to open and remain open upon demand. As part of this equipment, the associated block valve must also open (if not already) and remain open. A detailed description of BL is provided in the Miscellaneous Systems Notebook.

9. BUS

This node indicates the branching for the combinations of 4KV ESF buses that can be available to Unit 1 when offsite power is available.

10. Condensate Booster Pump (CB)

This node is alternate feedwater delivery to the steam generators with the condensate booster pumps, either acting as a booster pump to the main feedwater pumps or directly to a depressurized steam generator. If auxiliary feedwater is not available, an alternate feedwater source is required to cooldown and depressurize the reactor coolant system. The condensate booster pumps can provide sufficient water to the steam generators, via either alignment described above, to maintain steam generator level in order to ensure that heat removal via the steam generators is effective and prevent implementation of bleed and feed cooling. This node represents the operation of the condensate booster pumps (CBPs) and associated valves required for CBP injection to the steam generators for either alignment described above. The operation of the associated valves refers to the feedwater isolation MOVs and the feedwater regulating bypass valve manual isolation valves, and throttling the feedwater regulating bypass valves. A detailed description of CB is provided in the Miscellaneous Systems Notebook.

11. Component Cooling (CC)

This node indicates the availability of the CCW system.

12. Centrifugal Charging Pump (CCP)

This node is high-pressure injection via the charging pumps. Initiation of safety injection would immediately start the charging pumps which would deliver water to the reactor coolant system through the emergency core cooling system cold leg injection pipes. A charging pump is required for success. A detailed description of CCP is provided in the Emergency Core Cooling System Notebook.

13. Containment Isolation (CI)

This node represents containment isolation. Containment isolation is not required for success of either core or containment cooling. Failure of containment isolation, given core damage, will result in a release of fission products to the environment. A detailed description of containment isolation is given in the Containment Isolation Notebook.

14. Control Rod Insertion (CRI)

This node is the action of the control rods to insert in response to the operator action to insert the control rods. This adds negative reactivity to the core and reduces reactor power. As a result, the steam generators take longer to dry out and the reactor is at a lower power level when dryout occurs. This limits the peak RCS pressure reached for the ATWS event.

15. Containment Spray Injection (CSI)

This node is Containment Spray during the ECC injection mode (CSI). CSI rapidly reduces the pressure in the containment atmosphere temporarily. CSI also scrubs the atmosphere of radionuclides, reducing the severity of the release if CSI is operating after core damage occurs. CSI will not prevent core damage or containment failure. Operation of the containment spray system after core damage can also provide for draining the RWST water inventory to the containment. A detailed description of this system is provided in the Containment Spray Notebook.

16. Depressurize Reactor Coolant System (DP)

This node is action of the pressurizer PORV(s) to open, and remain open, upon demand. Reclosing of the pressurizer PORV(s) is not modeled in this node; failure to reclose results in a larger LOCA which also achieves the desired depressurization of the reactor coolant system. A detailed description of DP is provided in the Miscellaneous Systems Notebook.

17. DC BUSES (DCB)

This node indicates the branching for the combinations of DC buses that can be available to Unit 1.

18. Depressurize Steam Generators (DS)

This node is action of the atmospheric relief valves to open upon demand. As noted in the ODS discussion, the condenser steam dump valves would be isolated due to Phase B containment isolation; thus the atmospheric relief valves must be utilized. The opening of the atmospheric relief valves permits depressurization of the steam generators and removes heat from the RCS. A detailed description of DS is given in the Miscellaneous Systems Notebook.

19. Emergency Boration (EB)

This node addresses the equipment needed for injection of boric acid into the RCS. This node requires one of four emergency boration paths to be opened: 1) via the emergency boration valve (MOV-VC-8104), 2) via FCV-0110A and 0110B , 3) from the RWST through MOV-VC-112D and 112E, or 4) local opening of the manual emergency boration valve VC8439. All of the above methods require continued operation of a charging pump and opening of the charging flow control valve (FCV-121). Also the boric acid transfer pumps must operate in fast speed for those flow paths from the boric acid storage tank (methods 1,2 and 4 listed above). A detailed description of the equipment required for emergency boration is provided in the Emergency Core Cooling System Notebook.

20. Hardware, Emergency Charging Pump Cooling (EC)

This node is the availability of equipment necessary to establish emergency cooling to a charging pump. This equipment includes Fire Water supply as well as equipment located in the gang box outside the charging pump rooms (i.e., tools, hoses, fitting and quick disconnects). A detailed description of EC is provided in the Miscellaneous System Notebook.

21. ESF Trains Available (ESF)

This node indicates the branching for the combinations of ESFAS trains that can be available.

22. Feedline Break Isolation (FB1 & FB2)

This node is the action of the main feedline valves which automatically close to isolate the break following a feedline break either outside containment (FB1) or inside containment (FB2). The FW regulating/regulating bypass are closed automatically, and the main feedwater pumps are stopped, following the reactor trip signal. The FWIVs are all closed automatically by the safety injection signal. A detailed description of the valves required to close for nodes FB1 and FB2 is provided in the Feedline Break Success Criteria Notebook.

23. Reactor Containment Fan Coolers (FC)

This node is the RCFCs (FC) which provide cooling for the containment atmosphere and can prevent automatic spray actuation prior to reaching the refueling water storage tank low level alarm (the setpoint for switchover to emergency core coolant system recirculation). The Reactor Containment Fan Coolers Notebook provides a detailed description of this system.

24. High-Pressure Injection (HPI)

This node is high-pressure injection (HPI). The SI signal would immediately start the high-pressure pumps; two centrifugal charging pumps and two SI pumps. The high-pressure pumps would take suction from the RWST and inject subcooled, borated water to the RCS via the ECC cold leg injection pipes. The high-pressure pumps would also be used to inject subcooled, borated water during ECC recirculation for event sequences in which the RCS pressure is not reduced below the shutoff head of the RHR pumps. In the recirculation case, the high-pressure pumps take suction from the discharge of the RHR pumps. Finally, the high-pressure pumps could be used to continue injection of water from the RWST if ECC recirculation failed and the RWST were refilled. A detailed description of HPI is provided in the ECCS Notebook.

25. High-Pressure Recirculation (HPR)

This node is high-pressure recirculation with either the charging pumps or the safety injection pumps aligned to take suction from the residual heat removal pumps. This node includes the components required to operate in the high-pressure recirculation mode, including the low head pumps and related valves, associated with the operator action ORC (e.g., valves opening and closing to realign the high pressure pump suction from the refueling water storage tank to the residual heat removal pump discharge). HPR is required to maintain the plant in a long-term stable condition for event sequences with the reactor coolant system pressure above the residual heat removal pump shutoff head at the time of switchover to cold leg recirculation. A detailed description of HPR is given in the Emergency Core Coolant System Notebook.

26. Low-Pressure Injection (LPI)

This node is low-pressure injection (LPI) with the RHR pumps. LPI can maintain core integrity in the injection phase if the RCS can be depressurized to a point below the shutoff head of the RHR pumps. Failure of the RHR pumps during the ECC injection phase would result in immediate implementation of the RWST refill procedure via ECA-1.1 (EOP for 'Loss of Emergency Coolant Recirculation'). Failure of LPI at any time during the progression of the event results in failure of ECC recirculation (high- and low-pressure) as RHR pumps are required for recirculation. LPI is also considered on core damage sequences to address disposition of RWST inventory for the scenario in which containment spray fails. A detailed description of LPI is provided in the ECCS notebook.

27. Low-Pressure Recirculation (LPR)

This node is low-pressure recirculation with the RHR pumps (LPR) and includes the components required to start and/or operate (sump valves open, RWST suction valves closed, and RHR pumps restarted) in the low-pressure recirculation mode associated with the operator action ORC (or OXR). It is noted that for those event sequences in which the RCS pressure remains above the shutoff head of the RHR pumps, success of LPR is required to establish high-pressure recirculation (HPR). LPR is required to maintain the plant in a long-term stable condition. A detailed description of LPR is given in the ECCS notebook.

28. Main Feedwater Available (MF)

This node represents the fraction of anticipated transients for which main feedwater is available until after turbine trip. The most severe ATWS transient occurs on a loss of normal feedwater in conjunction with a failure of the main turbine to trip. If the turbine trips prior to loss of main feedwater, then main feedwater will be available for 50 seconds following turbine trip. The fraction of initiating events for which main feedwater is available until after turbine trip is determined in Appendix D of the ATWS Notebook.

29. Main Feedwater (MFW)

This node is alternate feedwater delivery to the steam generators with the main feedwater pumps. Use of the main feedwater pumps require the operation of the condensate booster pumps. If auxiliary feedwater is not available, an alternate feedwater source is required to cooldown and depressurize the reactor coolant system. The combination of main feedwater pumps and condensate booster pumps can provide sufficient water to the steam generators, without the need to depressurize the steam generators, to maintain steam generator level in order to ensure that heat removal via the steam generators is effective and prevent implementation of bleed and feed cooling. This node represents the operation of the main feedwater pumps (MFPs). The operation of condensate booster pumps and the valves required to align the main feedwater pumps to the steam generators following main feedwater trip are modeled in the previous node, (CB). A detailed description of alternate feedwater using the main feedwater pumps is provided in the Miscellaneous Systems Notebook.

30. Reactor Shutdown by Control Rods (MSR)

This node addresses the equipment used for shutdown of the reactor using control rods. Given failure of the automatic and manual reactor trip from the main control board, reactor trip can be accomplished by one of three means. First, locally opening the reactor trip breakers will interrupt reactor power to the RCCA drive mechanisms; thereby causing the control rods to drop into the core. Second, locally tripping the rod drive motor generator sets will discontinue the power supply to the control rods; thereby causing the control rods to drop into the core. Finally, continued insertion of the control rods can also be used to shutdown the reactor. It should be noted that interrupting power to the control rods is assumed to result in the control rods dropping into the core. Failure of a large number of control rods to fall into the core following power supply interruption would require a mechanical failure of several rod assemblies. Such a failure mode is not considered credible for Westinghouse reactor control cluster assemblies (RCCAs).

31. Isolation of Steam Flow from Ruptured SG (MSI)

This node includes the equipment to isolate steam flow from the ruptured SG. Specifically, this includes the MSIV on the ruptured steam generator. Isolation of the ruptured steam generator also includes isolation of other steam flow paths such as the turbine driven AFW pump steam supply line, etc. Success of this node may also be achieved by closing the MSIVs on the intact steam generators. This action effectively isolates the ruptured SG from the intact SGs since the steam dumps should stay closed. A detailed description of MSI is given in the Miscellaneous Systems Notebook.

32. Normal Charging (NC)

This node is the establishment of normal charging (NC) by realigning at least one charging pump from the ECCS injection mode to the normal charging mode. An evaluation of NC is provided in the ECCS Notebook.

33. Number of Charging Pumps (NCP)

This node is the availability of the centrifugal charging pumps (NCP). A charging pump is required to deliver RCP seal injection flow following a loss of CCW. In addition, the charging pumps provide inventory makeup and control capability. A detailed description of the charging pumps is provided in the Emergency Core Cooling System Notebook.

34. Normal RHR Cooling (NRC)

This node is normal RHR cooling with the RHR pumps (NRC) and includes the components required to start and/or operate (RHR isolation valves open, ECC valves closed, and RHR pumps restarted) in ES-1.2, Steps 19 through 27. An evaluation of NRC is given in the ECC System Notebook.

35. Operator Action to Align Charging Suction (OAC)

This node is a collection of operator actions per AOP-4.1 which are necessary to maintain a cool charging pump suction source. These actions are:

1) Align charging pump suction to the RWST. This action is directed by AOP-4.1 Appendix C step 5. This action realigns charging pump suction from the VCT to the RWST to provide a cool borated suction source for the charging pumps.

2) Isolate Letdown and RCP Seal Return Flow. This action is directed by AOP-4.1 Appendix C step 3. This action prevents heatup of the charging lines from RCS letdown and RCP seal return flow.

3) Align Charging pump miniflow to Hold-Up Tank. This action is directed by AOP-4.1 Appendix C step 7. This action directs charging pump miniflow to the holdup tank or Auxiliary Building Equipment Drain to prevent overheating of the charging pumps.

4) Start second charging pump (if required). This action is directed by AOP-4.1 Appendix C step 2. This action is only required if both charging pumps are initially available and a charging pump has been running without lube oil cooling for more than 90 minutes. This action allows additional time for establishing emergency lube oil cooling or CCW system startup.

The above operator actions have been modeled as a collective action for the purposes of simplifying plant response modeling. A detailed evaluation of the operator actions required for OAC is given in the Human Reliability Analysis Notebook.

36. Operator Action to Isolate Feedwater Flow to the Ruptured SG (OAF)

This node represents the operator action to terminate all feedwater flow to the ruptured steam generator. This action is necessary to prolong the time available to stop the primary to secondary break flow through the ruptured tube before steam generator overfill occurs. Operator guidance for feedwater isolation is given in Zion EOP E-3, Step 6. The detailed evaluation of operator action OAF is given in the Human Reliability Analysis Notebook.

37. Operator Action to Isolate Steam Flow from the Ruptured Steam Generator (OAI)

This node represents the operator action to diagnose a SGTR event, identify the steam generator with the ruptured tube, and to take the necessary steps to isolate this steam generator from the 3 intact steam generators. Indications of a SGTR event include pre-or post-trip SG level response as well as steamline and blowdown radiation indications. Isolation of the ruptured steam generator provides a pressure/temperature differential between this ruptured steam generator and the intact steam generators; such a differential is important in the subsequent actions during a SGTR event. Isolation requires closure of the ruptured SG MSIV and other potential leak paths (i.e., the steam supply line to the turbine driven AFW pump). If the MSIV for the ruptured SG can not be closed, the ruptured SG is isolated from the others by closure of the MSIVs on the intact SGs. Operator guidance for steam generator isolation is given in Zion EOP E-3, Step 4. The detailed evaluation of operator action OAI is given in the Human Reliability Analysis Notebook.

38. Operator Action to Initiate RCS Bleed (OBL)

This node is the operator action to initiate 'bleed and feed' via the opening of at least one pressurizer PORV. The actions considered at this node are dependent upon the event sequence path, as follows:

a) for all event sequences in which at least one charging pump is available but no feedwater injection to the steam generators is available (auxiliary feedwater or alternate supplies), this node models the operator actions to initiate bleed and feed cooling, per FR-H.1, Step 16 when the steam generator level reaches 24% of wide range indication and,

b) for all event sequences in which at least one SI pump is available but no charging pump and no auxiliary feedwater injection to the steam generators is available, this node models the operator actions to immediately initiate bleed and feed cooling per FR-H.1, Steps 4 and 16.

For scenario (a) above, the operators may initially transfer out of FR-H.1, but based on logic presented in Section 8 (and Appendix B), the operators will return to FR-H.1 to initiate bleed and feed cooling due to loss of level in all SGs and lack of AFW flow. The detailed evaluation of the operator actions OBL is given in the Human Reliability Analysis Notebook.

39. Operator Action To Restore CCW (OCC)

This node is the operator actions to restart the CCW system and to restore RCP seal cooling by reestablishing component cooling water to the RCP thermal barrier heat exchangers and charging pumps. These actions are identified in AOP-4.1 Appendix C steps 9 through 13. A detailed evaluation of the operator actions required to restore CCW is given in the Human Reliability Analysis Notebook.

40. Operator Action to Depressurize the Reactor Coolant System (ODP)

This node is the operator action to depressurize the RCS (ODP) in the event of failure of HPI in conjunction with failure of AFW or ODS/DS. The combination of HPI failure in conjunction with failure of AFW or ODS/DS will result in no high- or low-pressure ECCS injection and subsequently the core exit temperatures increase to 1200/F. The monitoring of the Critical Safety Functions would result in operator transition to FR-C.1 (FRG for 'Response to Inadequate Core Cooling'). This node models the operator action(s) to depressurize the RCS using the pressurizer PORV(s), per FR-C.1 / Step 19. This depressurization will allow the low pressure pumps to be used for injection prior to core damage; thus LPI must be available before ODP is considered in this case. (This sequence of events also requires successful injection of the accumulators). The detailed evaluation of the operator action ODP is given in the Human Reliability Analysis Notebook.

41. Operator Action to Depressurize the Steam Generators (ODS)

This node is the operator action to depressurize the steam generators in order to cooldown and depressurize the reactor coolant system. This node represents the initiation of a 100 degree per hour cooldown of the RCS by dumping steam from the steam generators. This action is done to enable ECCS injection and recirculation with the low pressure pumps. The operator instruction for this action comes from the Zion EOPs, Step 5 of ES-1.2 (EOP for 'Post-LOCA Cooldown and Depressurization'). Since Phase B isolation is expected due to high-high containment pressure by this time the condenser steam dump valves would not be available and the secondary depressurization must be accomplished with the atmospheric relief valves. The detailed evaluation of the operator action ODS is given in the Human Reliability Analysis Notebook.

42. Operator Actions to Emergency Borate (OEB)

This node addresses the remaining means to provide long term reactivity control. Long term reactivity control is required to ensure that only decay heat must be removed from the reactor. Specifically, this node represents the operator actions to shutdown the reactor by emergency boration as delineated in FR-S.1, Step 5. FR-S.1, Step 5 directs the operator to emergency borate via the emergency boration valve MOV-VC-8104. If emergency boration via this method cannot be established, then the operator is instructed to emergency borate either through the normal boration path, the RWST, or the manual emergency boration valve. The last method requires local operator action. A detailed evaluation of the operator actions to establish long term shutdown using emergency boration is described in the Human Reliability Analysis Notebook.

43. Operator Action to Restore Auxiliary Feedwater (OFW)

This node is the operator actions to manually initiate auxiliary feedwater to the steam generators following the restoration of AC power. This represents the operator action specified in ECA-0.1, Loss of All AC Power Recovery Without SI required, and ECA-0.2, Loss of All AC Power Recovery With SI Required, to start the auxiliary feedwater pumps as necessary to restore and maintain level in the steam generators. A detailed evaluation of the operator actions to initiate auxiliary feedwater is given in the Human Reliability Analysis Notebook.

44. Operator Action to Establish Heat Exchanger Cooling (OHX)

This node is the operator action to establish cooling to the residual heat removal heat exchangers by opening the component cooling water valves to the residual heat removal heat exchangers. The operators are instructed per EOPs to open the isolation valves long before switchover to recirculation begins. For event sequences in which the reactor coolant system remains above the shutoff head of the residual heat removal pumps for extended periods of time prior to switchover to recirculation, the component cooling water flow through the residual heat removal heat exchangers is required for residual heat removal pump cooling. Failure of this action for high pressure event sequences would result in damage to the pump and/or seals. For all event sequences which go to emergency core coolant system recirculation, failure of OHX would impact containment heat removal only if no reactor containment fan coolers are operating. Once ECC recirculation is established, failure of OHX would not result in core damage in the first 24 hours, even if no RCFC is operating. The detailed evaluation of the operator actions OHX is given in the Human Reliability Analysis Notebook.

45. Operator Action to Isolate RHR Breach (OIB)

This node models the operator actions of Step 2 of ECA-1.2, LOCA OUTSIDE CONTAINMENT, designed to isolate the "BROKEN" RHR trains. Specifically, these actions are to close the pump suction isolation valve for each affected RHR pump (1MOV-RH8700A and B) as well as the cross tie valves for the RHR trains. Success for this node is operator action to close both MOVRH8700A and B. Closure of the pump suction isolation valve for only one pump is not considered success. If leakage has developed in both pumps at the time the operator attempts to isolate the RHR pumps, then isolation of one pump by closure of the suction isolation valve (and cross tie valve) would reduce by half the maximum potential size of pump seal ISLOCA but would not fully isolate the ISLOCA. If only one RHR pump has developed a seal ISLOCA at the time of the operator action and this train is isolated then successful isolation can not be guaranteed since the seals in the unisolated pump would continue to be exposed to high temperature water at high pressure and could develop leakage at a later point in the event. The detailed evaluation of the operator actions OIB is given in the Human Reliability Analysis Notebook.

46. Operator Action to Reduce ECCS Injection (OIR)

This node represents the operator action to reduce the ECCS injection to no greater than one (1) high pressure injection pump (either 1 charging pump or 1 SI pump). For sequences in which the recovery actions of identification, isolation and RCS cooldown have been successful, the ECCS flow must be reduced as a necessary precursor to establishing normal charging. Normal charging (discussed later) is necessary for RCS inventory control and subsequent termination of the primary to secondary break flow (i.e., success end state). For sequences in which the charging pumps are not available or in which SG overfill occurs prior to ECCS reduction, the ECCS flow must be reduced to extend the time that the RWST will be available (i.e., SAM end state). [Recall that SG overfill is assumed to result in the consequential failure of a secondary safety valve to reclose, thereby necessitating continued ECCS injection.] Operator guidance to perform this ECCS reduction is provided in different procedures depending upon the specific path considered:

a) Zion EOP E-3, Steps 22 and 26 - ECCS flow is reduced to 1 charging pump following RCS cooldown and depressurization as a precursor to establishing RCS inventory control. Also, for cases in which charging pumps are not available or in which SG overfill has occurred, the ECCS pumps (typically 1 charging pump or 1 SI pump, as applicable) are restarted as necessary to maintain adequate RCS subcooling and pressurizer level.

b) Zion EOP ECA-3.3, Steps 11 and 14 - For the sequence in which there is no pressurizer pressure control (i.e., failure of ODP/DP), ECCS flow is reduced to 1 charging pump following RCS cooldown as a precursor to establishing RCS inventory control. Also, for cases in which charging pumps are not available or in which SG overfill has occurred, the ECCS pumps (typically 1 charging pump or 1 SI pump, as applicable) are restarted as necessary to maintain adequate RCS subcooling.

c) Zion EOP ECA-3.1, Steps 16, 20 and 21 - For the sequence in which steam flow from the ruptured SG cannot be isolated (i.e., failure of OAI/MSI), ECCS flow is reduced to 1 charging pump following RCS cooldown and depressurization as a precursor to establishing RCS inventory control. Also, for cases in which charging pumps are not available or in which SG overfill has occurred, the ECCS pumps (typically 1 charging pump or 1 SI pump, as applicable) are restarted as necessary to maintain adequate subcooling and pressurizer level.

d) Zion EOP ECA-3.2, Steps 11, 15 and 16 -For the sequence in which steam flow from the ruptured SG cannot be isolated (i.e., failure of OAI/MSI) in conjunction with high SG wide-range level or low RWST level, ECCS flow is reduced to 1 charging pump following RCS cooldown and depressurization as a precursor to establishing RCS inventory control. Also, for cases in which charging pumps are not available or in which SG overfill has occurred, the ECCS pumps (typically 1 charging pump or 1 SI pump, as applicable) are restarted as necessary to maintain adequate subcooling and pressurizer level.

The detailed evaluation of operator action OIR is provided in the Human Reliability Analysis Notebook.

47. Operator Action to Establish Normal Charging (ONC)

This node models the operator action to terminate operation of the ECCS injection pumps and realign the charging pumps to their normal, flow control, alignment (ONC). This is a pre- requisite for establishing normal RHR cooling. The operators are instructed, per ES-1.2 / Steps 12 to 17, to sequentially terminate operation of the charging and SI pumps following RCS cooldown and depressurization. If pressurizer level and RCS subcooling can be maintained with one charging pump injecting less than 50 gpm, this set of actions is successful and the operators are instructed to continue with attempts to establish normal RHR cooling. If this action fails, the operators must rely on ECCS recirculation for long term decay heat removal and RCS inventory control. A detailed evaluation of the ONC operator action is given in the Human Reliability Analysis Notebook.

48. Operator Action to Establish Normal RHR Cooling (ONR)

This node is the operator action to establish normal RHR cooling (ONR), as opposed to low pressure recirculation, following a small LOCA. This action involves aligning the RHR pumps to the reactor coolant system hot leg(s) and cold leg(s), according to ES-1.2, Steps 19 through 27. The detailed evaluation of the operator action ONR is given in the Human Reliability Analysis Notebook.

49. Operator Action to Open AFW MOVs (OOF)

This node represents the operator actions to open the normally throttled motor operated valves (MOVs) in the AFW line to each steam generator to increase AFW flow to the steam generators during an ATWS event. The MOVs must be opened to increase the heat removal capability of the secondary system to match or exceed core power generation. This node represents the operator actions directed in FR-S.1, Step 8. A detailed evaluation of the operator actions to open the AFW throttle valves is given in the Human Reliability Analysis Notebook.

50. Operator Action to Depressurize the Reactor Coolant System (OPR)

This node is the operator action to depressurize the reactor coolant system. The actions considered at this node are for all event sequences in which at least one charging pump is available but no feedwater injection to the steam generators is available (auxiliary feedwater and alternate supplies). This node models the operator actions to initiate reactor coolant system bleed and feed cooling, per FR-H.1/Step 16, using the pressurizer PORVs when the steam generator level reaches 24% of wide range indication.
The detailed evaluation of the operator actions OPR is given in the Human Reliability Analysis Notebook.

51. Operator Action to Establish ECCS Recirculation (ORC)

This node is the operator action to establish either high pressure or low pressure ECCS recirculation (ORC), as appropriate for the accident sequence. The EOPs instruct the operators to begin switchover to recirculation when the RWST low-level alarm is reached. This action includes aligning the ECC system for low pressure recirculation plus starting and stopping the RHR pumps, as directed by ES-1.3 (EOP for 'Transfer to Cold Leg Recirculation'). For accident sequences in which high-pressure recirculation is required, this node also includes those operator actions to isolate the high pressure pump suction (charging pumps and/or SI pumps) from the RWST and align the RHR pump discharge to the high pressure pump suction. The detailed evaluation of the operator action ORC is given in the Human Reliability Analysis Notebook.

52. Operator Action to Load Essential Equipment on to Energized ESF Buses (ORE)

This node represents the operator action to restore electrical power, support systems, load essential equipment back on to the energized ESF bus(es), and start the required equipment following the restoration of AC power. Early in ECA-0.0, Loss of All AC Power, if AC power is not available, essential equipment switches are placed in the pull-to-lock position which will prevent their automatic starting when power is restored. The required equipment are the charging pump, the RHR pump, the containment spray pump, the reactor containment fan coolers, the component cooling water pump, the service water pump, RCP seal injection cooling, and the auxiliary feedwater pump. If these actions fail, then it is assumed that these components fail to operate.

53. Operator action to Restore Feedwater (ORF)

This node is the operator actions to establish an alternate feedwater source to the steam generators if auxiliary feedwater fails. In all event sequences in which this node is addressed, it represents the operator actions specified in FR-H.1 (Reference 10.1), Step 3 to stop all reactor coolant pumps, and FR-H.1 (Reference 10.1), Step 9 and/or 22 to initiate flow from either the main feedwater pumps or the condensate booster pumps to at least one (1) steam generator. The operator actions in FR-H.1 (Reference 10.1), Step 9 and/or Step 22 include starting the condensate booster pumps and the main feedwater pumps, if available, and aligning the pumps for injection to the steam generator. The alignment for injection to the steam generators includes opening the feedwater isolation MOVs and the feedwater regulating bypass valve manual isolation valves and throttling the feedwater regulating bypass valves. A detailed evaluation of the operator actions to restore feed water is given in the Human Reliability Analysis Notebook.

54. Operator Action to Insert Control Rods (ORI)

This node represents the operator actions to manually insert the control rods to mitigate the RCS pressure transient in response to an ATWS event. This node represents the operator actions directed in FR-S.1, Step 1 upon the operator being unable to verify the symptoms of a reactor trip. A detailed evaluation of the operator actions to manually insert control rods is given in the Human Reliability Analysis Notebook.

55. Operator Action to Initiate Rapid Steam Generator Depressurization (ORS)

This node represents the operator actions to initiate a rapid steam generator depressurization to permit condensate booster pump injection directly to at least one steam generator or to depressurize the reactor coolant system. Either the condenser steam dump valves, if available, or the atmospheric relief valves can be used for the rapid steam generator depressurization. The detailed evaluation of the operator action to initiate rapid steam generator depressurization is given in the Human Reliability Analysis Notebook.

56. Operator Action to Refill the RWST (ORT)

This node represents the operator action to refill the refueling water storage tank. If high pressure recirculation fails, the operators are instructed to transfer to ECA-1.1: Loss of Emergency Coolant Recirculation (Reference 10.8). This procedure instructs the operator to start refilling the refueling water storage tank. The detailed evaluation of the operator action to refill the refueling water storage tank is given in the Human Reliability Analysis Notebook.

57. Operator Action to Stop CCW Pumps (OSC)

This node is the operator action per AOP-4.1, Loss of Component Cooling, to stop all CCW pumps and place in Pull-To- Lock. This action is taken to prevent damage to the CCW pumps from cavitation, allowing CCW restart when conditions have been restored. This action is only required for CCW events resulting from a loss of inventory or loss of heat removal. A loss of CCW resulting from a loss of flow does not require this action.

58. Operator Action to Initiate Safety Injection (OSI)

This node is the operator action to establish and maintain an emergency core coolant injection source for the reactor coolant system. This includes the action to manually initiate safety injection. A detailed evaluation of the operator actions to initiate safety injection is provided in the Human Reliability Analysis Notebook.

59. Operator Action to Shut Down the Reactor Using Control Rods (OSR)

This node addresses one of the means to provide long term reactivity control. Long term reactivity control is required to ensure that only decay heat must be removed from the reactor. Specifically, this node represents the operator actions required to ensure the reactor is shutdown with control rods. This can be accomplished by the operator performing one of the three following actions: 1) locally tripping the reactor trip breakers, 2) locally tripping the rod drive MG sets, or 3) continued manual insertion of the control rods. This node represents the operator actions directed in FR-S.1, Step 1. A detailed evaluation of the operator actions to establish long term shutdown using the control rods is described in the Human Reliability Analysis Notebook.

60. Operator Action To Restore SW/CCW (OSW)

This node is the operator actions to restart the Service Water and Component Cooling Water systems and to restore RCP seal cooling by reestablishing component cooling water to the RCP thermal barrier heat exchangers and charging pumps. Actions to restart the Service Water System are identified in AOP-4.2. The actions to restart the CCW system and reestablish CCW to the RCP thermal barrier heat exchangers and charging pumps are identified in AOP-4.1 Appendix C steps 9 through 13. A detailed evaluation of the operator actions required to restore SW and CCW is given in the Human Reliability Analysis Notebook.

61. Operator Action to Trip Turbine or Close MSIV's (OTT)

This node represents the operator actions to trip the main turbine or close the Main Steam Isolation Valves (MSIV's) in response to an ATWS event. This node represents the operator actions specified in FR-S.1, Step 2, including the "Response Not Obtained" Column for the event. FR-S.1, Step 2 directs the operator to manually trip the turbine if automatic turbine trip has not occurred. If the turbine will not trip, then FR-S.1, Step 2 further directs the operator to close all MSIV s and MSIV bypass valves. A detailed evaluation of the operator actions to trip the main turbine or close the MSIVs is given in the Human Reliability Analysis Notebook.

62. Operator Action to Establish Low-Pressure Recirculation After Core Damage (OXR)

This node is the operator action to establish ECCS recirculation after core damage, if ORC fails (OXR). Due to the failure to establish ECCS recirculation (ORC), the core exit thermocouple temperature would exceed 1200/F and the operators would enter FR-C.1. This procedure would instruct the operators to continue attempts to establish ECCS flow. The operators could continue attempts to establish recirculation even if core damage occurred. This action is considered in the plant response tree since establishing low-pressure recirculation flow after core damage will enhance containment heat removal, provided that the RHR heat exchanger(s) are available, and subsequently delay or prevent containment failure. The detailed evaluation of the operator action OXR is given in the Human Reliability Analysis Notebook.

63. Power Level Less Than 60%. (PL)

This node represents the fraction of anticipated transients that occur below an initial power level of 60%. Analyses presented in the Success Criteria Notebook show that for initial power levels below 60%, turbine trip is not required to prevent RCS pressures from exceeding 3200 psig, the ASME Stress Level C Criterion. The fraction of transient events initiated from power levels less than 60% is determined in Appendix D of the ATWS Notebook.

64. Primary Pressure Relief (PPR)

This node addresses the ability of the pressurizer power operated relief valves (PORVs) and safety valves to relieve RCS pressure during an ATWS event. The combination of pressurizer PORV's and safety valves required for successful mitigation of the transient is a function of control rod insertion and the value of the moderator temperature coefficient. A detailed description of the pressurizer PORVs and safety valves is provided in the Miscellaneous Systems Notebook. A detailed description of the impact of the value of the moderator temperature coefficient on the PPR node is provided in the ATWS Success Criteria Notebook.

65. Depressurize Reactor Coolant System (PRV)

This node is action of the pressurizer PORVs to open, and remain open, upon operator demand. Reclosing of the pressurizer PORVs is not modeled in this node. A detailed description of PRV is provided in the Miscellaneous Systems Notebook.

66. Hardware, Restore CCW (RCW)

This node is the availability of equipment necessary to restart the CCW system and restore cooling water to the RCP thermal barrier heat exchangers and centrifugal charging pumps. An evaluation of RCW is provided in the CCW System Notebook.

67. Essential Equipment is Loaded on to Energized ESF buses (RE)

This node represents the loading of the essential equipment and systems listed under node ORE. If this equipment and systems fail to load on to the ESF buses, then the components are assumed to not operate.

68. Heat Exchanger Cooling (RHX)

This node is the equipment for residual heat removal heat exchanger cooling and includes the component cooling water isolation valves to the residual heat removal heat exchanger. A detailed description of RHX is given in the Emergency Core Cooling System notebook.

69. Refilling the RWST (RTK)

This node is the refilling of the refueling water storage tank and includes the components required to refill the refueling water storage tank and continue the associated emergency core cooling systems injection. If the flow to refill the refueling water storage tank is sufficient to match the delivered flow from the operating pumps then the reactor core would remain covered and core damage would be averted for a prolonged time. A detailed description of the components required for refilling the refueling water storage tank is given in Appendix B, extracted from the Emergency Core Cooling System Notebook.

70. Reactor Trip (RXT)

This node represents either the reactor protection system or manual action by the operators in the control room to open the breakers allowing the control rods to fall into the core. Failure of this node is designated as an Anticipated Transient Without Scram (ATWS) and is continued in the ATWS plant response tree.

71. Safeguards Actuation 17, 18, 19 (SAC)

This node indicates the branching for the combinations of safeguards sequencers that can be available after a LOOP or DLOOP initiator.

72. Safe Shutdown Sequencers 17, 18, 19 (SEQ)

This node indicates the branching for the combinations of safe shutdown sequencers that can be available for all initiators other than LOOP or DLOOP.

73. Steam Generator Isolation (SGI)

This node is the isolation of the secondary side of the faulted SG following a steamline break inside containment in order to close off a direct release pathway from the containment (Reference 14). To isolate this containment release pathway the following lines of the faulted steam generator must be isolated: the main steamline, the main steamline bypass, main feedwater, auxiliary feedwater, steam generator blowdown, and the turbine driven AFW pump steam supply (if the faulted steam generator is one of the two which supplies steam to the turbine driven AFW pump).

74. Safety Injection Pumps (SIP)

This node is high-pressure injection via the safety injection pumps (SIP). The SI signal would immediately start the two safety injection pumps which would deliver water to the RCS via the ECC cold leg injection pipes. The safety injection pumps would also be used to inject subcooled, borated water during ECC recirculation for event sequences in which the RCS pressure is not reduced below the shutoff head of the RHR pumps. In this case, the safety injection pumps take suction from the discharge of the RHR pumps. The safety injection pumps could also be used to continue injection of water from the RWST if ECC recirculation is failed and the RWST is refilled. The SI pumps are not required for ECC injection if the charging pumps are successful. A detailed description of SIP is provided in the ECCS Notebook.

75. Consequential Small LOCA (SLO)

This node represents the likelihood of a loss of coolant accident (LOCA) caused by the failure of the reactor coolant pump (RCP) seals. The node accounts for r. .dom seal failures and seal failures caused by inadequate seal cooling. Seal failures due to inadequate seal cooling are determined based on support states in which there is no component cooling water or service water. Prolonged exposure of the #1 RCP seal could result in degradation of the seal material and eventual failure of the seal. Seal injection water from the charging pumps prevents hot RCS water from moving upward along the RCP shaft and contacting the #1 RCP seal. If seal injection is lost, then the hot RCS water is cooled by component cooling water (CCW) in the thermal barrier heat exchanger. If no CCW is available, then cooling via the thermal barrier heat exchanger will be lost. Additionally, CCW is required to provide charging pump cooling. Thus, a lack of CCW will eventually result in a loss of seal injection capability. Service water provides cooling for the CCW system; therefore, a loss of service water will eventually result in a loss of CCW and consequently a seal LOCA. Failure of this node results in transfer to the consequential small LOCA plant response tree. The consequential small LOCA tree is identical in structure to the small LOCA plant response tree which is discussed in detail in the small LOCA plant response tree notebook.

76. Equipment to Restore Service Water and Component Cooling (SW)

This node indicates the availability of the equipment needed to restore the SW and CCW systems.

77. Service Water System (SWS)

This node indicates the availability of the SW system.

78. Refueling Wate Storage Tank (TK)

This node is the refueling water storage tank. The refueling water storage tank provides the source of borated water necessary for both safety injection and containment spray following an initiating event. It is shown as a separate node because it is shared by several nodes in the plant response tree (i.e., HPI, CSI). The suction lines from the refueling water storage tank supply water to the following pumps:

- Two centrifugal charging pumps
- Two safety injection pumps
- Two residual heat removal pumps, and
- Three containment spray pumps.

If the refueling water storage tank fails, all emergency core cooling system (ECCS) injection fail and containment spray injection (CSI) fails; without secondary side heat removal capabilities (when applicable) the accident sequence results in core damage with no refueling water storage tank water in containment.

79. Turbine Trip (TT)

This node represents the tripping of the turbine, either automatically or manually. Steam flow to the turbine can also be stopped by closing the turbine control valves. Failure of this to occur will result in an event that is similar to a secondary side break downstream of the main steam isolation valves. Failure of this event will transfer to the secondary side break plant response tree.

80. Turbine Trip/MSIV Closure (TT2)

This node includes the interruption of steam to the main turbine by closure of the turbine stop valves, governor valves, or any combination thereof. This node also includes closure of all four MSIVs. The node is required to minimize short term secondary water inventory losses and thereby delay steam generator dryout and reduce the corresponding primary pressure spike. A detailed description of the trip of the turbine and closure of the MSIVs for ATWS pressure mitigation is provided in the Miscellaneous Systems Notebook.

81. Safety Injection Valves (VLV)

This node represents the valves in the ECCS line which must operate for successful initiation of bleed and feed cooling. An evaluation of this node is included in Emergency Core Cooling System Notebook.

APPENDIX B

EQUIPMENT TO REFILL RWST & ESTABLISH CHARGING FLOW FROM VCT

EQUIPMENT NAME

1. SPENT FUEL PIT PUMP 1SF-003
2. MOTOR OPERATED VALVE 1SI8801B
3. MOTOR OPERATED VALVE 1SI8801A
4. MOTOR OPERATED VALVE VC8106
5. MOTOR OPERATED VALVE VC8105
6. MOTOR OPERATED VALVE VC LCV112C
7. MOTOR OPERATED VALVE VC LCV112B
8. MOV VC LCV112E
9. MOV VC LCV112D
10. CHECK VALVE VC-8443
11. SPENT FUEL PUMP PIT RETURN BLOCK VALVE 1SF-8765
12. SPENT FUEL PIT FLOW TO RWST CHK VLV SF-8766
13. SPENT FUEL FLTR BLOCK VLV SF-8774
14. MANUAL ISOLATION VALVE SPENT FUEL PIT FLOW TO RWST SF-8788
15. MANUAL BLOCK VLV TO RWST SI-8931
16. RWST-U1 BLOCK VALVE (N.C.) 1SI-8927
17. RWST-U1 REFU. WTR PUR. PUMP BLOCK VALVE N.C. 1SF-8758
18. RWST-U2 BLOCK VALVE (N.C.) 2SI-8927
19. RWST-U2 REFU. WTR PUR. PUMP BLOCK VLV (N.C.) 2SF-8758
20. MANUAL VALVE VC-8281
21. MANUAL VALVE VC-8434
22. CHECK VALVE VC-8433
23. MANUAL VALVE VC-8432
24. VCT OUTLET CHECK VALVE VC-8440
25. MANUAL VALVE VC-8428
26. MANUAL VALVE VC-8416
27. AIR OPERATED VALVE VC-FCV-0110A
28. CHARGING PUMP 1A
29. FILTER IN EMERGENCY BORATION SYSTEM
30. AIR OPERATED VALVE VC-FCV-0111A
31. MAKE-UP ISOL. VALVE TO VCT (F.C.) FCV-VC-0110B
32. MAKE-UP ISOL. VALVE TO VCT (F.C.) FCV-VC-0111B
33. SPENT FUEL PIT PUMP SUCTION PIPING STRAINER (AT TANK)
34. SPENT FUEL PIT FILTER SF-006
35. SPENT FUEL PIT PUMP DISCHARGE CHECK VALVE SF-8793
36. 20 AMP FUSE FROM DC DISTRIB. PANEL 1CB37
37. 20 AMP FUSE FROM 1CB37 TO 1CB07
38. 20 AMP FUSE FROM DC DISTRIB. PANEL 1CB38
39. CIRCUIT BREAKER 1374B FROM 480V ESF BUS 137
40. CIRCUIT BREAKER 1494 FROM 4160V ESF BUS 149
41. CIRCUIT BREAKER 1474 FROM 4160V ESF BUS 147
42. CIRCUIT BREAKER 1395B FROM 480V ESF BUS 139
43. CIRCUIT BREAKER 1373A FROM 480V ESF BUS 137

44. 4160-480V TRANSFORMER 139
45. 4160-480V TRANSFORMER 137
46. FD BR. C1-2 FROM DC BUS 011-1 TO PANEL 1CB37
47. CIRCUIT BREAKER 2422
48. CIRCUIT BREAKER 2421
49. PRIMARY WATER PUMP OB
50. FD BREAKER E1-7 FROM DC BUS 111 TO 1CB38
51. CIRCUIT BREAKER 1443 FROM 480V BUS 144
52. FD. BREAKER 1341 TO BUS 134
53. FD. BREAKER 1442 TO BUS 144
54. B A TRANSFER PUMP 1B
55. B A TRANSFER PUMP 1A
56. PRIMARY WATER MAKE-UP PUMP 0A
57. PRIMARY WATER MAKE-UP PUMP 0B
58. CHECK VALVE VC-8429
59. 4160-480V TRANSFORMER 134
60. CHARGING PUMP FCV FCV-VC-121
61. SPENT FUEL PIT HEAT EXCHANGER INLET BLOCK VLV SF-8762A
62. SPENT FUEL PIT HEAT EXCHANGER OUTLET BLOCK VLV SF-8762B
63. FD BREAKER RFI-23 FROM DC BUS 112
64. FIRE PUMPS AND HOSES

6

NRC Information Request - Zion IPE Common Cause Failure Factors

Attachment A is an excerpt (pp. 82-87) from the Zion IPE Data Collection & Analysis Notebook discussing Common Cause Analysis. It includes an explanation of the process used and a discussion (p. 85) and rationale for using an average common cause grouping for components with no history of common cause failures.

Attachment B are the notes from the meeting held to review EPRI CCF data for applicability to Zion. It includes (Attachment 1) the rules used to categorize CC events and (Attachments 2 & 3, partial), as examples, the EPRI diesel generator common cause event descriptions and categorization.

The information from the meeting was consolidated onto LOTUS 1-2-3 spreadsheets. LOTUS was also used to calculate the CC factors. These spreadsheets are Reference 14 from Attachment A.

A copy of the three LOTUS files is provided on the enclosed disc.

The spreadsheet dealing with DG CCFs is printed out as Attachment C. Page C1 serves to show the layout of the entire file. The remaining pages of Att. C are legible "blow-ups" of each section of the file. They are identified by their location in the main spreadsheet (3A1 to 3C3).

The sections of the spreadsheet dealing with diesel generators are 3A2 (data) and 3C1 (CCF calculations).

The DG information is expanded as Attachment D.
Page D1 is the DG CC failure data retained from the EPRI event descriptions as applicable to Zion. Page D2 shows the calculations used to establish the DG MGL factors. Column BK shows the resulting beta factor value of 4.3E-3 that was of interest in Question F.E. 15 of the NRC's 12 / 22 / 92 information request.

Attachment A

4.3 Common Cause Analysis

Common cause failure (CCF) is used to describe events that are a subset of dependent events in which two or more components fail due to the same cause at the same time, or in a short interval, and that are a direct result of a shared cause. The common cause failure analysis evaluates and estimates the effects of these dependencies that impact the ability of a system to prevent and mitigate a severe accident.

To assure that the effects of common cause were properly accounted for in the Zion analysis, common cause failures were modeled at the basic event level and the Multiple Greek Letter (MGL) method was used for quantification. The Zion IPE used the MGL method and parametric factors, beta, gamma, and delta as defined in NUREG/CR-4780, Reference 13, "Procedures for Treating Common Cause Failure in Safety and Reliability Studies" as follows:

- BETA conditional probability ($Pr(x \geq 2 | x \geq 1)$) that the common cause of a component failure will be shared by one or more additional components

- GAMMA conditional probability ($Pr(x \geq 3 | x \geq 2)$) that the common cause of a component failure that is shared by one or more components will be shared by two or more components additional to the first

- DELTA conditional probability ($Pr(x \geq 4 | x \geq 3)$) that the common cause of a component failure that is shared by two or more components will be shared by three or more components additional to the first

The evaluation of Zion failure data indicated that there had been no common cause events at the Zion site applicable to current maintenance and operation practices. As a result, in order to more realistically model current experience at Zion, a Zion specific evaluation of CCF events was performed. Zion specific common cause (CC) factors were developed for components which had data available including:

- Auxiliary Feedwater Pumps
- Large AC Circuit Breakers
- Containment Building Spray Pumps
- Check valves
- Cooling Water Pumps, AFW and SW systems
- Diesel Generators
- High Head Pumps, SI and VC systems
- Residual Heat Removal Pumps
- Motor Operated Valves
- Reactor Trip Breakers
- Safety/Relief Valves
- HVAC Chillers

- HVAC Fans

A generic CCF database of common cause events was developed from EPRI NP-3967, "Classification and Analysis of Reactor Operating Experience Involving Dependent Events" (Reference 11) supplemented with events from the September 1990 EPRI draft report, "A Database of Common Cause Events for Risk and Reliability Evaluations" (Reference 12).

An expert judgement panel was established to review data from the generic CCF database for applicability to CECo plants. IPEP and CECo each provided two members to the panel, one representing the Zion and Dresden IPEs, respectively. The members from IPEP were common cause data specialists and the members from CECo were plant experts. One CECo plant expert had previously worked as a Zion SRO and was familiar with current plant practices and procedures as well as those in practice at the time of the events in the generic CCF database.

The CCF database was reviewed for events applicable to Zion. The expert judgement panel came to a consensus opinion on each common cause event's applicability to Zion. This applicability was based upon current Zion system configuration, and maintenance and operational practices. Events involving known common cause mechanisms addressed by specific programs in place at Zion were discarded from the Zion database as where common cause events which occurred due to specific system configurations not present at Zion. Events involving common cause mechanisms which have been addressed in general by maintenance or operational practices at the Zion site were assigned a lesser probability of occurrence at Zion based on judgement of the panel. The Zion specific MGL factors resulting from this analysis are included in table 15. The detailed analysis of the common cause events are provided in Reference 14.

An average common cause component group was quantified from a composite of all the common cause failures for all components in the database. Use of the factors calculated for this average common cause group was extended to components which have no history of common cause failure, but were judged by the analyst to have some potential for common cause failure. The common cause contribution was calculated using the average MGL factors for the following components:

- Air compressor

- Air operated, hydraulic operated, and manual, valves

- Electrical/electronic components such as: comparator, lead/lag amplifier, battery charger, limit switch, inverter, relay, switch, mechanical cam timer, power transformer, circuit breakers (other than large AC breaker which was specified directly in CCF database).

- Fan cooler

- Heat exchanger

- Motor driven and turbine driven pumps other than those specified directly in CCF database.

- Strainer filter

In general, the components included in the list were judged to be less complex than the components in the database and thought to have less potential for common cause failure mechanisms. Therefore, assignment of the average common cause factor is judged to be realistic.

TABLE 15

ZION SPECIFIC MGL COMMON CAUSE FACTORS.

CC COMP GROUP	4-COMPONENT SYSTEM BETA	GAMMA	DELTA	3-COMPONENT SYSTEM BETA	GAMMA	2-COMP SYSTEM BETA
AFW PUMPS	1.5E-02	7.8E-01	--b--	1.4E-02	2.8E-01	8.8E-03
LG AC CIRCUIT BRKX	6.6E-02	7.4E 01	5.3E-01	5.3E-02	5.5E-01	4.0E-02
CS PUMPS	--a--	--a--	--a--	--a--	--a--	7.2E-02
CHECK VALVES	8.7E-03	--b--	--b--	5.8E-03	--b--	2.9E-03
COOLING WTR PUMPS	1.6E-03	7.8E-01	5.7E-01	1.4E-03	6.0E-01	1.1E-03
DIESEL GENERATORS	--a--	--a--	--a--	7.5E-03	1.6E-01	4.3E-03
HIGH HEAD PUMPS	--a--	--a--	--a--	--a--	--a--	3.2E-02
HEAT REMOVAL PUMPS	--a--	--a--	--a--	--a--	--a--	2.1E-03
MOVs	1.7E-02	5.0E-01	6.8E-01	1.4E-02	4.7E-01	1.0E-02
RTB	--a--	--a--	--a--	--a--	--a--	3.8E-02
SAFETY/RELIEF VLVS	9.7E-02	6.6E-01	2.1E-01	8.6E-02	3.5E-01	5.8E-02
HVAC CHILLERS	--a--	--a--	--a--	3.1E-03	1.3E-01	1.7E-03
HVAC FANS	1.2E-02	1.0E+00	1.0E+00	1.2E-02	1.0E+00	1.2E-02
AVERAGE	2.0E-02	7.4E-01	5.3E-01	1.8E-02	5.5E-01	1.4E-02

NOTES:

a - FACTORS NOT CALCULATED FOR THIS SIZE SYSTEM.

b - VALUE OF FACTOR IS NOT CALCULATED. A VALUE EQUAL TO THE VALUE FOR THE AVERAGE OF ALL COMPONENT FAILURES ("AVG") GIVEN IN THIS TABLE ARE USED FOR THESE COMPONENTS.

Same as Submittal Table 4.4.3-1

5.0 REFERENCES

1. "Zion Probabilistic Safety Study," Commonwealth Edison Company, 1981.

2. "Data Collection and Analysis Guideline," CECo IPE/Accident Management Program, Rev. 0, October 1989.

3. "Probabilistic Safety Analysis Procedures Guide," NUREG/CR-2815, Volume 1, Rev. 1, August 1985.

4. "Analysis of Core Damage Frequency From Internal Events: Methodology Guidelines," NUREG/CR-4550, Volume 1, September 1987.

5. "RPS/ESFAS Systems Report," CECo IPE/Accident Management Program, Rev. 0, March 1992.

6. "Containment Spray System Notebook," CECo IPE/Accident Management Program, Rev. 0, February 1992.

7. WCAP-10271, "TOPS", "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and Supplements 2 and 3, Westinghouse Proprietary Class 2.

8. IEEE Std 500-1984 "Guide to the Collection and Presentation of Electrical, Electronic, Sensing Component and Mechanical Equipment Reliability Data for Nuclear-Power Generating Stations", Sensing, December 1983.

9. Wash-1400, NUREG 75/014, "Reactor Safety Study; An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants", October 1975.

10. NUREG/CR-2728 "Interim Reliability Evaluation Program Procedures Guide" January 1983.

11. EPRI NP-3967, "Classification and Analysis of Reactor Operating Experience Involving Dependent Events", EPRI, February 1985.

12. September 1990 EPRI draft report, "A Database of Common Cause Events for Risk and Reliability Evaluations", EPRI, September 1990.

13. NUREG/CR-4780, "Procedures for Treating Common Cause Failures in Safety and Reliability Studies", January 1989.

14. Anderson, R., CN-PRRA-91-118-RI, Common Cause Factors for Zion and Dresden IPEs, Westinghouse, March 1992.

The LOTUS spreadsheets

Attachment B

NS-RMOI-PRRA-91-209
FROM : R.G. Anderson, W-RMOI, Product Risk Analysis
PHONE : 412-374-6224
DATE : May 23, 1991
SUBJECT: Trip Report: Commonwealth Edison Common Cause Failure Data Categorization, May 16-17, 1991

TO :	M.Loftus,	w/ attachments 2 and 3
	X.Polanski,	w/ attachments 2 and 3
	L.Soth,	w/o attachments 2 and 3
	L.Raney,	w/o attachments 2 and 3
	J.Trainer,	w/o attachments 2 and 3
cc :	G.Klopp,	w/o attachments 2 and 3
	K.Vavrek,	w/o attachments 2 and 3
	D.Sharp,	w/o attachments 2 and 3
	N.J.Liparulo,	w/o attachments 2 and 3
	N.Closky,	w/o attachments 2 and 3
	R.G.Brown,	w/o attachments 2 and 3
	E.Krantz,	w/ attachments 2 and 3

A meeting was held with the Commonwealth Edison PRA group in Downers Grove, Illinois to provide the rationale and categorization for common cause events to use in CECo IPEs for Zion and Dresden. The following persons were part of the team assembled for that purpose:

Larry Soth, Commonwealth Edison PRA Group
Lee Raney, Commonwealth Edison PRA Group
Jack Trainer, IPEP
Rick Anderson, IPEP

The purpose of the team meeting is to reach consensus on the common cause events reported in the EPRI database, consisting of EPRI NP-3967 and a recent EPRI draft document dated September 1990, with respect to the following:

1. Is the event a common cause event? (see Attachment A)

2. Does the event apply to the Zion plant?, Dresden plant? (see Attachment A)

The process for implementing the action plan which was established by personnel from CECo, Tenera and Westinghouse, is provided in Attachment 1, Table A1-1. As part of step 2, the team members became familiar with the Westinghouse Common Cause Guidebook, NUREG 4780, NUREG 5460, and the EPRI database (EPRI NP-3967 and unpublished draft report dated September 1990).

Each unique event was reviewed from the EPRI database. The results of that review are provided in Table 1. The "marked-up" pages from EPRI NP-3967 and the unpublished EPRI draft report dated September 1990 are included in Attachments 2 and 3, respectively. These pages provide the rationale upon which a decision was made regarding the applicability of each event to CECo plants, Zion, or Dresden.

In addition to the Process and Rules defined in Attachment 1, the following procedure was used in the team review process.

1) Each event from the September 1990 EPRI draft was reviewed for applicability. The rationale and categorization for each event was written on the event description. These are provided in Attachment 3.

2) The rationale and categorization for events in common with events in EPRI NP-3967 were marked on applicable pages from EPRI NP-3967, Attachment 2.

3) The other events not included in the September 1990 EPRI draft but designated applicable to common cause modeling in EPRI-3967 were then reviewed. The rationale and categorization for each event was written on the event description, Attachment 2.

Several CECo specific items had major impact in the review process these were:

- CECo Check Valve Directive, NO Directive NOD-TS9, Rev.0, May 15, 1989.
- CECo Guidelines for Motor-Operated Valve (MOV) Testing, Maintenance, and Evaluation, NO Directive NOD-MA.1, Rev.2, September 1990.
- Post Maintenance Testing of components after maintenance activities.
- Independent review of valving alignment per procedure after maintenance activities.
- Diesel Generator emergency start permissives which exclude many "out-of-tolerance" permissives responsible for many DG failures.

It should be noted that in general the rules stated in Attachment 1 were used as guidelines and not strict rules due to the uniqueness of each common cause event. One example of this is rule 1a, stated in attachment 1, which states that the common cause events must "happen" at the same time. The team generally used a "within 24 hour" call on most events. In some situations this time was extended to cover components not checked immediately following an event. This may be somewhat unrealistic since current practice requires a check of of components within a common cause group once a failure is found. In addition, "happen" was interpreted to mean an actual failure or potential failure following an actual failure to be counted as a common cause event.

The remainder of the evaluation is to be documented in a Calcnote and Common Cause Notebook. It was decided that the impact vectors for each event would not be evaluated by the team. Instead the Common Cause analyst will judge each event's impact vector for consistency with the description and the other events in the common cause grouping.

LOTUS FILES

Richard J Anderson

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed.

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
RTB	1RTB -01	2RTB -01	Conn. Yankee	(December 1981)	N	C
RTB	1RTB -02	2RTB -02	Oconee 1	(February 1979)	N	C
RTB	1RTB -03	2RTB -03	St. Lucie	(November 1980)	N	C
RTB	1RTB -04	2RTB -04	Salem 1	(February 1983)	A	C
RTB	1RTB -05	2RTB -05	San Onofre 2	(March 1983)	N	2
RTB	1RTB -06		San Onofre 3	(March 1983)	N	2
RTB	1RTB -07		McGuire 2	(March 1983)	A	C
RTB	1RTB -08		Calvert Cliffs	(March 1983)	N	C
RTB	1RTB -09		Calvert Cliffs	(March 1983)	N	C
RTB	1RTB -10	2RTB -06	McGuire 1	(March 1983)	N	C
RTB	1RTB -11		Maine Yankee	(March 1983)	N	C
RTB	1RTB -12		McGuire 2	(March 1983)	N	C
RTB	1RTB -13		Oconee 1	(January 1973)	N	C
RTB	1RTB -14		Oconee 2	(January 1973)	N	C
RTB	1RTB -15		Oconee 3	(January 1973)	N	C
RTB	1RTB -16		Summer	(April 1983)	N	C
DG	1DG -01		Oyster Creek	(September 1973)	N	C
DG	1DG -02	1DG -04	Hadam Neck	(April 1968)	N	C
DG	1DG -03		Fort Calhoun	(July 1973)	N	C
DG	1DG -04		Brunswick 1	(January1977)	N	C
DG	1DG -05	2DG -13	Brunswick 1	(January1977)	N	C
DG	1DG -06	2DG -09	Salem	(July 1977)	N	C
DG	1DG -07	2DG -06	Yankee Rowe	(August 1977)	N	C
DG	1DG -08	2DG -03	Zion	(July 1974)	N	C
DG	1DG -09		Crystal River	(June 1979)	N	C
DG	1DG -10		Dresden 2	(September 1974	N	C
DG	1DG -11		Dresden 2	(September 1974	N	C
DG	1DG -12	DG -08	Dresden 3	(May 1973)	N	C
DG	1DG -13		Dresden 3	(May 1973)	N	C
DG	1DG -14		Peach Bottom 2,	(June 1977)	N	C

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
DG	1DG -15	2DG -10	Millstone 2	(May 1977)	N	C
DG	1DG -16	2DG -12	Quad Cities	(May 1977)	N	C
DG	1DG -17	2DG -01	Peach Bottom 2	(February 1978)	N	C
DG	1DG -18		Farley 1	(September 1977	N	C
DG	1DG -19	2DG -05	Cook 1	(December 1977)	N	C
DG	1DG -20		Millstone	(March 1975)	N	C
DG	1DG -21	2DG -07	Arkansas-1 1	(August 1979)	N	C
DG	1DG -22		North Anna 2	(February 1981)	N	C
DG	1DG -23		TMI Unit 1	(April 1974)	N	C
DG	1DG -24	2DG -02	Browns Ferry 1	(January 1980)	N	C
DG	1DG -25		Browns Ferry 1,	(May,June 1981)	N	C
DG		2DG -11	TMI-1	(March 1978)	N	
DG		2DG -14	Dresden 2,3	(September 1973)	N	
MOV	1MV -01	2MV -22	Cook 2	(January 1979)	A	C
MOV	1MV -02	2MV -02	Turkey Point 3	(April 1979)	N	C
MOV	1MV -02	2MV -07	Turkey Point 3	(April 1979)	A	
MOV	1MV -03	2MV -03	Arkansas One 1	(April 1980)	N	C
MOV	1MV -03	2MV -08	Arkansas One 1	(April 1980)	A	
MOV	1MV -04	2MV -19	Palisades	(June 1971)	A	C
MOV	1MV -05		Ginna	(1972)	N	4
MOV	1MV -06	2MV -05	Oconee 2	(October 1975)	A	C
MOV	1MV -07	2MV -18	Trojan	(October 1976)	N	C
MOV	1MV -08	2MV -06	Zion 2	(December 1976)	N	4
MOV	1MV -09	2MV -20	North Anna	(August 1978)	N	C
MOV	1MV -10		Maine Yankee	(January 1982)	N	4
MOV	1MV -11	2MV -17	Kewaunee	(September 1975)	N	C
MOV	1MV -12	2MV -04	Zion 2	(October 1975)	N	C
MOV	1MV -13		Maine Yankee	(February 1975)	N	C
MOV	1MV -14		Salem 1	(January 1977)	N	2

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
MOV	1MV -15	2MV -10	Arkansas One 2	(September 1978)	N	2
MOV	1MV -16	2MV -01	Arkansas One 1	(August 1981)	N	C
MOV	1MV -17		Oconee 1	(November 1975)	N	C
MOV	1MV -18		Oconee 2	(December 1975)	N	C
MOV	1MV -19	2MV -21	Rancho Seco	(November 1976)	N	C
MOV	1MV -20		Prairie Island	(1971)	N	2
MOV	1MV -21		Zion 1	(September 1972	N	2
MOV	1MV -22		Prairie Island	(1974)	N	2
MOV	1MV -23		Prairie Island	(1974)	N	2
MOV	1MV -24		Oconee 1	(October 1973)	N	2
MOV	1MV -25		Maine Yankee	(June 1975)	N	2
MOV	1MV -26		Ginna	(June 1975)	N	2
MOV	1MV -27		Cook 1	(November 1977)	N	C
MOV	1MV -28	2MV -16	Davis Besse	(December 1977)	N	2
MOV	1MV -29		Davis Besse	(December 1977)	N	2
MOV	1MV -30		Trojan	(January 1976)	N	2
MOV	1MV -31		Indian Point 2	(May 1978)	N	2
MOV	1MV -32		Maine Yankee	(August 1978)	N	2
MOV	1MV -33		Arkansas One 1	(May 1979)	N	2
MOV	1MV -34		Farley 1	(September 1979)	N	2
MOV	1MV -35		Oconee 2	(June 1979)	N	C
MOV	1MV -36		Oconee 2	(December 1979)	N	C
MOV	1MV -37		Salem 2	(July 1980)	N	2
MOV	1MV -38		Surry 2	(December 1980)	N	2
MOV	1MV -39		Cook 1	(March 1981)	N	C
MOV	1MV -40	2MV -23	Monticello	(July 1972)	A	C
MOV	1MV -41	2MV -24	Browns Ferry 2	(December 1979)	N	C
MOV	1MV -42		Millstone 1	(January 1971)	N	2
MOV	1MV -43		Browns Ferry 3	(May 1975)	N	2
MOV	1MV -44	2MV -25	Robinson 2	(January 1981)	N	C

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
MOV	1MV -45	2MV -26	Surry 2	(July 1981)	N	C
MOV	1MV -46		Monticello	(March 1971)	N	2
MOV	1MV -47		Millstone 1	(February 1980)	N	4
MOV	1MV -48		Browns Ferry 1	(1973)	N	2
MOV	1MV -49	2MV -27	Dresden 2	(August 1973)	N	C
MOV	1MV -50		Arnold	(February 1974)	N	2
MOV	1MV -51	2MV -13	Vermont Yankee	(February 1976)	N	1
MOV	1MV -52	2MV -14	Browns Ferry 2	(December 1974)	A	C
MOV	1MV -53	2MV -15	Pilgrim	(September 1974)	N	C
MOV	1MV -54		Brunswick 2	(1975)	N	2
MOV	1MV -55		Cooper	(May 1974)	N	2
MOV	1MV -56		Peach Bottom 2	(May 1975)	N	4
MOV	1MV -57		Peach Bottom 2	(June 1982)	N	4
MOV	1MV -58		Vermont Yankee	(May 1976)	N	C
MOV	1MV -59	2MV -28	Dresden 3	(September 1975)	N	C
MOV	1MV -60	2MV -29	Browns Ferry 1	(September 1974	N	C
MOV	1MV -61		Millstone 1	(March 1978)	N	4
MOV	1MV -62	2MV -30	Hatch 2	(September 1978)	N	C
MOV	1MV -63		Millstone 1	(June 1979)	N	4
MOV	1MV -64		Pilgrim	(July 1979)	N	C
MOV	1MV -65	2MV -32	Hatch 2	(May 1980)	N	C
MOV	1MV -66	2MV -33	Hatch 2	(May 1982)	N	C
MOV	1MV -67	2MV -38	Dresden 2	(October 1973)	N	C
MOV	1MV -68		Browns Ferry 2	(August 1974)	N	2
MOV	1MV -69		Fitzpatrick	(January 1975)	N	2
MOV	1MV -70		Arnold	(March 1976)	N	C
MOV	1MV -71		Peach Bottom 2	(June 1973)	N	2
MOV	1MV -72	2MV -34	Dreseden 2	(May 1975)	N	C
MOV	1MV -73	2MV -39	Cooper	(October 1980)	N	C
MOV	1MV -74	2MV -35	Vermont Yankee	(September 1976)	N	C

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
MOV	1MV -75	2MV -36	Dresden 2	(August 1973)	N	C
MOV	1MV -76		Dresden 1	(October 1978)	N	C
MOV	1MV -77		Peach Bottom 3	(March 1983)	N	4
MOV	1MV -78		Peach Bottom 3	(March 1983)	N	4
MOV	1MV -79		Grand Gulf 1,2	(June 1981)	N	2
MOV	1MV -80		Pilgrim	(October 1981)	N	C
MOV	1MV -81		Susquehanna 1	(July 1981)	N	2
MOV	1MV -82		Monticello	(October 1978)	N	4
MOV	1MV -83		Brunswick 1	(November 1976)	N	2
MOV	1MV -84		Millstone 1	(May 1971)	N	C
MOV	1MV -85	2MV -37	Pilgrim	(April 1973)	N	C
MOV		2MV -09	Oconee 2	(October 1975)	N	
MOV		2MV -12	Maine Yankee	(February 1975)	N	
MOV		2MV -31	Pilgrim	(July 1977)	N	
SRV	1PSRV-01		Palisades	(1972)	N	4
SRV	1PSRV-02		Yankee Rowe	(November 1972)	N	4
SRV	1PSRV-03		Indian Point 2	(1973)	N	4
SRV	1PSRV-04		Fort Calhoun	(November 1976)	N	4
SRV	1PSRV-05		Surry 1	(November 1976)	N	4
SRV	1PSRV-06		Palisades	(October 1979)	N	4
SRV	1PSRV-07		Farley 1	(October 1979)	N	2
SRV	1PSRV-08		North Anna 1	(March 1981)	N	1
SRV	1PSRV-09		Yankee Rowe	(June 1981)	N	4
SRV	1PSRV-10		Oconee 1,2,3	(October 1982)	N	4
SRV	1PSRV-11		San Onofre 1	(February 1972)	N	4
SRV	1PSRV-12		Rancho Seco	(May 1978)	N	4
SRV	1PSRV-13		Davis Besse 1	(December 1977)	N	4
SRV	1PSRV-14		Davis Besse 1	(December 1978)	N	4
SRV	1PSRV-15		Davis Besse 1	(December 1978)	N	4

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
SRV	1PSRV-16		Davis Besse 1	(March 1979)	N	4
SRV	1PSRV-17		Davis Besse 1	(February 1979)	N	4
SRV	1PSRV-18		Davis Besse 1	(May 1981)	N	4
SRV	1PSRV-19		Palisades	(January 1978)	N	4
SRV	1PSRV-20		Palisades	(October 1981)	N	4
SRV	1PSRV-21		Surry 2	(November 1981)	N	4
SRV	1BSRV-01		Oyster Creek 1	(December 1970)	N	4
SRV	1BSRV-02	2EMRV-01	Nine Mile Point	(May 1972)	N	C
SRV	1BSRV-03		Oyster Creek 1	(June 1972)	N	4
SRV	1BSRV-04		Dresden 3	(May 1972)	N	4
SRV	1BSRV-05		Dresden 2	(April 1972)	N	4
SRV	1BSRV-06		Peach Bottom 2	(November 1973)	N	2
SRV	1BSRV-07		Cooper	(July 1974)	N	2
SRV	1BSRV-08		Peach Bottom	(November 1974)	A	C
SRV	1BSRV-09		Browns Ferry 2	(Nov,Dec 1974)	N	2
SRV	1BSRV-10		Monticello	(November 1974)	A	C
SRV	1BSRV-11		Cooper	(December 1974)	N	2
SRV	1BSRV-12		Brunswick 2	(May 1975)	N	2
SRV	1BSRV-13		Dresden 2	(May 1975)	A	C
SRV	1BSRV-14		Browns Ferry 1	(February 1975)	N	2
SRV	1BSRV-15	2EMRV-05	Dresden 2	(June 1975)	N	C
SRV	1BSRV-16		Cooper	(October 1975)	N	4
SRV	1BSRV-17		Brunswick 2	(July 1975)	A	C
SRV	1BSRV-18		Vermont Yankee	(July 1976)	A	C
SRV	1BSRV-19		Quad Cities 2	(November 1976)	A	C
SRV	1BSRV-20	2EMRV-06	Quad Cities 1	(November 1976)	A	C
SRV	1BSRV-21		Pilgrim 1	(May 1977)	N	C
SRV	1BSRV-22	2EMRV-07	Arnold	(March 1977)	A	C
SRV	1BSRV-23		Hatch 1	(October 1977)	N	4
SRV	1BSRV-24		Arnold	(March 1976)	N	C

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
SRV	1BSRV-25		Browns Ferry 3	(August 1978)	A	C
SRV	1BSRV-26		Peach Bottom 2	(November 1976)	N	C
SRV	1BSRV-27		PeachBottom 2	(January 1977)	N	4
SRV	1BSRV-28		Hatch 2	(May 1979)	N	3
SRV	1BSRV-29		Pilgrim	(November 1981)	N	4
SRV	1BSRV-30		Arnold	(March 1980)	N	4
SRV	1BSRV-31		Browns Ferry 2	(February 1978)	A	C
SRV	1BSRV-32	2EMRV-09	Hatch 2	(November 1980)	N	4
SRV	1BSRV-33		Hatch 1	(April 1981)	N	4
SRV	1BSRV-34		Hatch 2	(February 1979)	N	4
SRV	1BSRV-35		Pilgrim 1	(March 1982)	N	2
SRV		2EMRV-03	Quad Cities 2	(Oct, Dec 1980)	N	
SRV		2EMRV-04	Oyster Creek	(November 1984)	A	
SRV		2EMRV-04	Oyster Creek	(November 1984)	A	
SRV		2EMRV-02	Dresden 2	(May, June 1975)	N	
SRV		2EMRV-11	Oyster Creek	(December 1975)	N	
SRV		2EMRV-08	Quad Cities 1,2	(March 1979)	A	
SRV		2EMRV-09	Oyster Creek 1	(January 1980)	N	
SRV		2EMRV-10	Dresden 1	(May 1970)	N	
HHP	1HHP -01		Millstone 2	(March 1975)	N	2
HHP	1HHP -02	2HHP -01	Salem 1	(November 1979)	N	C
HHP	1HHP -03		Beaver Valley 1	(December 1976)	N	2
HHP	1HHP -04		North Anna 1	(July 1978)	A	C
HHP	1HHP -05	2HHP -02	Point Beach	(September 1978)	N	C
HHP	1HHP -06		St. Lucie 1	(February 1977)	N	C
HHP	1HHP -07	2HHP -03	Arkansas One 1	(January 1982)	N	C
HHP	1HHP -08	2HHP -04	North Anna 1	(April 1979)	N	C
HHP	1HHP -09	2HHP -06	Robinson 2	(July 1973)	N	C
HHP	1HHP -10	2HHP -05	Robinson 2	(November 1977)	N	C

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
HRP	1HRP -01		Crystal River	(December 1976)	N	2
HRP	1HRP -02		Farley 1	(July 1977)	N	2
HRP	1HRP -03		Turkey Point 3,	(1973)	N	2
HRP	1HRP -04		North Anna 1	(November 1976)	N	2
HRP	1HRP -05		Arkansas-1 2	(1978)	N	2
HRP	1HRP -06	2HRP -01	Beaver Valley 1	(January 1978)	N	C
HRP	1HRP -07		Beaver Valley 1	(January 1984)	N	1
HRP	1HRP -08		Beaver Valley 1	(September 1978	N	3
HRP	1HRP -09		Calvert Cliffs	(October 1978)	N	3
HRP	1HRP -10		Beaver Valley 1	(January 1980)	N	3
HRP	1HRP -11		Beaver Valley 1	(April 1980)	N	3
HRP	1HRP -12		Millstone 2	(March 1979)	N	1
HRP	1HRP -13	2HRP -05	Peach Bottom 2	(April 1978)	N	C
HRP	1HRP -14	2HRP -06	Brunswick 1	(April 1979)	N-Z;A-D	C
HRP	1HRP -15	2HRP -02	Monticello	(December 1972)	A	C
HRP	1HRP -16	2HRP -03	Browns Ferry 1	(September 1974	N	C
HRP	1HRP -17	2HRP -07	Brunswick 2	(April 1979)	A	1
HRP	1HRP -18		Dresden 2	(July 1970)	N	3
HRP		2HRP -01	Beaver Valley 1	(January 1981)	N	
CSP	1CSP -01	2CSP -01	Robinson 2	(October 1978)	N	C
CSP	1CSP -02		Oconee 1	(May1973)	N	2
CSP	1CSP -03	2CSP -02	Oconee 2	(January 1975)	N	1
CSP	1CSP -04	2CSP -03	Davis Besse	(January 1978)	N	1
CSP	1CSP -05	2CSP -04	Cook 2	(May 1978)	N	1
CSP	1CSP -06	2CSP -05	Farley	(September 1978)	N	1
CSP	1CSP -07	2CSP -06	Robinson 2	(November 1977)	N	1
CSP	1CSP -08		Sequoyah 2	(August 1981)	N	1
CSP	1CSP -09	2CSP -07	Kewaunee	(Oct-Dec 1977)	A	C

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
AFW	1AFWP-01	2AFWP-02	Ginna	(December 1973)	N	1
AFW	1AFWP-02		Zion 2	(February 1974)	N	1
AFW	1AFWP-03	2AFWP-01	Kewaunee	(November 1975)	N	C
AFW	1AFWP-04	2AFWP-03	Turkey Point 3	(May 1974)	N	C
AFW	1AFWP-05	2AFWP-04	Turkey Point 3	(May 1974)	N	C
AFW	1AFWP-06		Point Beach 1,2	(April 1974)	N	C
AFW	1AFWP-07		Zion 2	(September 1981	A	C
AFW	1AFWP-08	2AFWP-05	Zion 2	(September 1981	N	C
AFW	1AFWP-09		Zion 2	(November 1979)	N	1
AFW	1AFWP-10		Zion 2	(December 1979)	N	1
AFW	1AFWP-11		Turkey Point 4	(June 1973)	N	2
AFW	1AFWP-12	2AFWP-08	Arkansas One 2	(April 1980)	N	C
AFW		2AFWP-06	Zion 1,2	(November 1981)	N	
AFW		2AFWP-07	Zion 2	(December 1981)	N	
CWP	1SCWP-01		Salem 1	(September 1976)	N	2
CWP	1SCWP-02	2SCWP-02	Beaver Valley 1	(October 1976)	N	2
CWP	1SCWP-03	2SCWP-01	Farley 1	(December 1978)	N	C
CWP	1SCWP-04		Arkansas-1 1	(1979)	N	2
CWP	1SCWP-05	2SCWP-07	TMI Unit 1	(August 1978)	N	1
CWP	1SCWP-06		Oconee 1,2,3	(July 1981)	N	1
CWP	1SCWP-07		FitzPatrick	(July 1980)	N	1
CWP	1SCWP-08		Peach Bottom	(October 1973)	N	2
CWP	1SCWP-09		Pilgrim	(May 1974)	N	C
CWP	1SCWP-10	2SCWP-05	Pilgrim	(December 1974)	N	4
CWP	1SCWP-11	2SCWP-04	Pilgrim 1	(December 1975)	N	4
CWP	1SCWP-12		Hatch 1	(August 1979)	A	C
CWP	1SCWP-13		Hatch 1	(September 1981	N	4
CWP	1SCWP-14	2SCWP-08	Oyster Creek	(November 1978)	N	C

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
CWP	1SCWP-15		Fort Calhoun	(July 1973)	N	2
CWP		2SCWP-03	Palisades	(July 1982)	N	
CWP		2SCWP-09	Beaver Valley 1	(July 1982)	N	
CWP		2SCWP-06	Pilgrim	(May 1974)	N	
HPRC		2HPRC-01	Brunswick 1	(July 1982)	N	
HPRC		2HPRC-02	Browns Ferry 1	(April 1980)	N	
HPRC		2HPRC-03	Brunswick 2	(September 1980)	N	
HPRC		2HPRC-04	Brunswick 2	(Brunswick 2)	N	
CHIL		2CHIL-01	Calvert Cliffs	(Jul, Sep 1980)	N	
FAN		2FAN -01	(LATER)	(LATER)	N	
FAN		2FAN -02	"	"	N	
FAN		2FAN -03	"	"	N	
FAN		2FAN -04	"	"	N	
FAN		2FAN -05	"	"	N	
FAN		2FAN -06	"	"	N	
FAN		2FAN -07	"	"	N	
FAN		2FAN -08	"	"	N	
FAN		2FAN -09	"	"	N	
FAN		2FAN -10	"	"	N	
FAN		2FAN -11	"	"	N	
FAN		2FAN -12	"	"	N	
FAN		2FAN -13	"	"	N	
FAN		2FAN -14	"	"	N	
FAN		2FAN -15	"	"	N	
FAN		2FAN -16	"	"	N	
FAN		2FAN -17	"	"	N	
SLRV		2SLRV-01	(LATER)	(LATER)	N	

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

CC GROUP	ASSIGNED EVENT IDENTIFIER Ref. 1	Ref. 2	PLANT	DATE	APPLICABILITY OF CC EVENTS CECo	Ref.1
TARGET ROCK VALVES NOT CONSIDERED DUE TO NO CC AT D&Z						
CV		2CV -01	(LATER)	(LATER)	N	
CV		2CV -02	"	"	N	
CV		2CV -03	"	"	N	
CV		2CV -04	"	"	A	
CV		2CV -05	"	"	N	
CV		2CV -06	"	"	N	
CV		2CV -07	"	"	N	
CV		2CV -08	"	"	N	
				"		
BR		BR -01	(LATER)	(LATER)	N	
BR		BR -02	"	"	N	
BR		BR -03	"	"	N	
BR		BR -04	"	"	N	
BR		BR -05	"	"	N	
BR		BR -06	"	"	A	
BR		BR -07	"	"	N	
BR		BR -08	"	"	A	
BR		BR -09	"	"	N	
BR		BR -10	"	"	N	
BR		BR -11	"	"	N	
BR		BR -12	"	"	N	
BR		BR -13	"	"	N	
BR		BR -14	"	"	N	

Table 1. Summary of Team Decisions Specific to CECo Plants on Common Cause Events Reviewed. (Continued)

NOTES:

Ref. 1 - EPRI NP-3967, June 1985.

Ref. 2 - EPRI draft document dated September 1990.

Applicability of CC Events-CECo - Assigned applicability of common cause events to CECo Plants. Joint decision of team meeting May 16-17, 1991.

- A - Applicable for common cause considerations at CECo Plants.
- N - Not applicable for common cause considerations at CECo Plants.

Applicability of CC Events-Ref.1 - Assigned screening category assigned to common cause events in EPRI NP-3967.

- C - Common cause events applicable to parametric modeling.
- 1 - Events modeled explicitly in systems analysis.
- 2 - Events occurring prior to commercial operation detected as a result of start-up testing.
- 3 - Events occurring during shutdown conditions that cannot occur during power operation.
- 4 - Events involving failures or potential failures that do not have a significant impact in analyses for PRA applications.

Attachment 1

Process and Rules used in Development of Rationale and Categorization of Common Cause Events to Use in Determination of MGL factors for CECo IPEs for Zion and Dresden.

Table A1-1 Action Plan for Addressing Common Cause Methodology
(based upon 4/22/91 meeting)

1. Use MGL method to quantify all fault trees.

2 Review EPRI database:

   a. review recent updated EPRI database and/or EPRI NP-3967 and review the events in the EPRI database in conjunction with those events identified by IPEP for new Zion database

   b. review each entry in database to ensure correct interpretations of common cause events

   c. identify those events which can not occur at Zion

   d. adjust MGL's based upon a.,b., and c., recognizing that adjustments due to c. are difficult since there is no knowledge for single component failures

3. Document well

   a. the decisions in #2 above

   b. that this is the best data available

   c. the strengths and weaknesses of this common cause analysis

4. Quantify the fault trees and PRT's

   a. with and without common cause as appropriate for each support state

   b. to determine if the insights or conclusions are truly any different

5. a. "Re-visit" common cause for all plants in the future when failure data is available for other plants and a large CECo-only database exists

   b. Recommend that IPEP generate a common cause database using all IPEP project data

6. Revise data collection/analysis for future plants

   a. emphasize common cause

   b. query system engineers for common cause actual events and potential occurences

Table 2 Recommended Process for Performing item's 2 & 3

1. Form team: 1 person from each group - W/TENERA/CECo PWR/CECo BWR

2. Team Preparation:

    a. Read appropriate NUREG's - 4780, 5460

    b. Read W RMOI guidebook #2

3. Each individual to evaluate entries in EPRI and plant-specific databases using general rules (see below)

4. Meeting to develop joint position on each entry

5. Each individual to evaluate entries in updated EPRI database and/or EPRI NP-3967 using plant-specific rules (see below)

    Note: This activity may be performed in conjunction with #3 above

6. Meeting to develop joint position on each entry for Zion, then Dresden

    Note: This activity may be performed in conjunction with #4 above

7. Adjust MGL's as appropriate

8. Document in Common Cause notebook

Rules

1. General

    a. Events must "happen" at same time to keep event in database
    b. Existence of same cause must be clear to keep event in database
    c. Off-tolerance conditions to be discarded from database (not a failure in CECo's judgement)
    d. Failures that are very easily recoverable to be discarded from database

2. Plant-specific

    a. For those events that have similar equipment in CECo plant to be kept in database
    b. For those events where a "defense mechanism exists" to be discarded from database

:hment 2

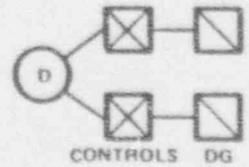
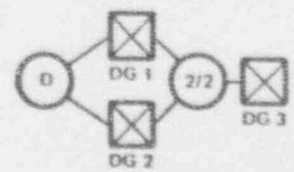
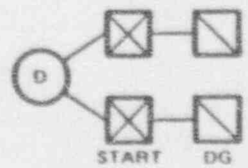
Selected "marked-up" pages of common cause event descriptions from EPRI NP-3967 with rationale and categorization from May 16-17, 1991 CECo-IPE meeting.

Table 3- 4	Reactor Trip Breakers
Table 3- 7	Diesel Generators
Table 3-10	Motor Operated Valves
Table 3-13	PWR Safety Valves / Relief Valves
Table 3-16	BWR Safety Valves / Relief Valves
Table 3-19	High Head Pumps
Table 3-22	RHR Pumps
Table 3-25	Containment Spray Pumps
Table 3-28	AFW Pumps
Table 3-31	SW and CCW Pumps

Table 3-7

EVENT DESCRIPTION AND CAUSE-EFFECT DIAGRAM FOR
BRANCHED ROOT-CAUSED EVENTS INVOLVING
DIESEL GENERATORS

Sheet 1 of 9

Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]
DG-1 Oyster Creek (September 1973)	Power	Two diesel generators failed to start due to circuit logic design error.		C
DG-2 Hadam Neck (April 1968)	Power	Two diesel generators failed to run; the third tripped on overload.		C
DG-3 Fort Calhoun (July 1973)	Prior to Initial Criticality	Two diesel generators failed to start due to moisture in air start circuit.		~~C~~ 2

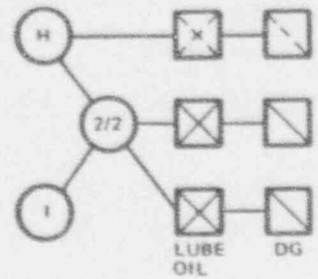
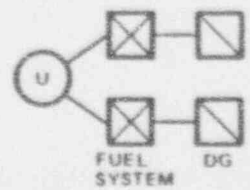
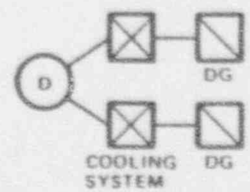
elim
mature plant

Elim

elim
mature plant

[a]Screening categories are described in notes on Sheet 9.

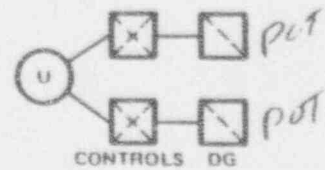
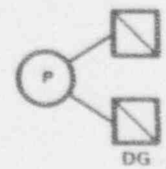
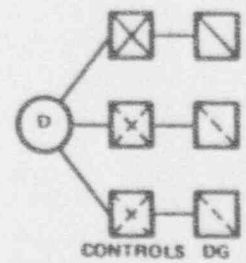
Table 3-7 (continued)

Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]	
DG-4 Brunswick 1 (January 1977) DG-5	32% Power	Two diesel generators failed to start and a third unit incipient failure due to lube oil pump switch.		C	elim NOTCECO contng.
DG-6 Salem (July 1977)	Power	Two diesel generators failed to start due to binding fuel rack.		C	Keep
DG-7 Yankee Rowe (August 1977)	Refueling	Two diesel generators failed to run due to plugged radiator.		C	Keep

[a]Screening categories are described in notes on Sheet 9.

Table 3-7 (continued)

Sheet 3 of 9

Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]
DG-8 Zion (July 1974)	74% Power	Two diesel generators degraded start due to loose screws on electrical terminal of voltage adjuster.		C
DG-9 Crystal River (June 1979)	Refueling	Two diesel generators failed to run due to procedure inadequacy. FTR		C
DG-10 Dresden 2 (September 1974) DG-11	Power	One diesel generator failed to start and two units incipient failure due to design error in circuit.		C

Elim indep events

elim

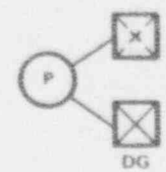
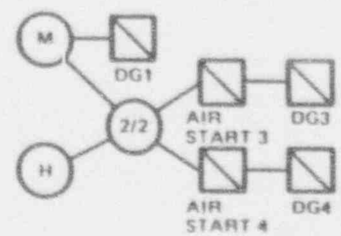
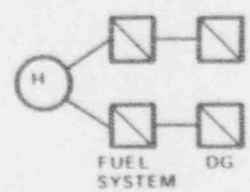
include mature plt. procd.

elim

mature plant

[a]Screening categories are described in notes on Sheet 9.

Table 3-7 (continued)

Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]
DG-12 Dresden 3 (May 1973) DG 13	Power	One diesel generator failed to start and one diesel generator incipient failure due to wrong procedure.		C
DG-14 Peach Bottom 2 and 3 (June 1977)	Shutdown and 100% Power	Three diesel generators inoperable; operator "jury-rigged" crosstie in air start circuit.		C
DG-15 Millstone 2 (May 1977)	Power	Two diesel generators failed to run due to fuel lines being valved out by operator.		C

elim
POST MAINT TEST

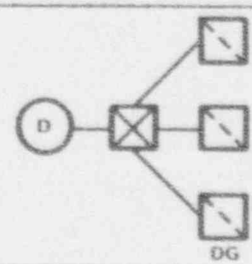
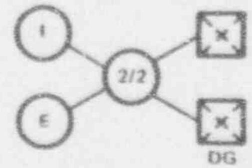
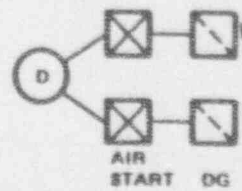
elim
NOT practice at CECO

elim
due not applic

[a]Screening categories are described in notes on Sheet 9.

Table 3-7 (continued)

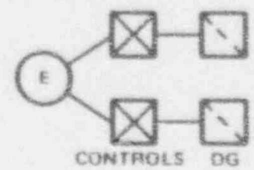
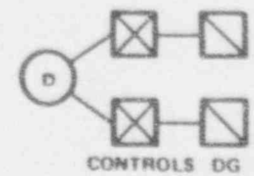
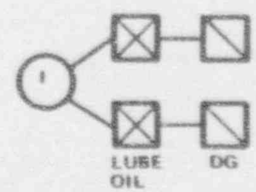
Sheet 5 of 9

Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]	
DG-16 Quad Cities (May 197[illegible]) 3 date error	Power	Three diesel generators degraded due to error in component cooling valve lineup. degraded.		C ✓	keep low impact
DG-17 Peach Bottom 2 (February 1978)	1% Power	Two diesel generators degraded because of water in lube oil.		C	elim single per 9/90 draft
DG-18 Farley 1 (September 1977)	30% Power	Two diesel generators degraded due to dirt in air start circuit.		C	elim no failure

[a]Screening categories are described in notes on Sheet 9.

Table 3-7 (continued)

Sheet 6 of 9

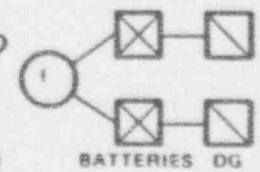
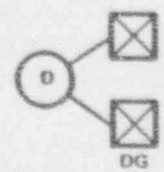
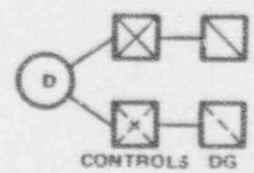
Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]
DG19 Cook 1 (December 1977)	100% Power	Two diesel generators inoperable due to spurious trip signals received because of extreme cold weather.		C
DG-20 Millstone (March 1975)	Power	Two diesel generators failed to run due to wiring error.		C
DG-21 Arkansas One 1 (August 1979)	100% Power	Two diesel generators failed to run (2 weeks apart) due to water in lube oil.		C

elim
warm Rooms

elim
post fail Test would uncover

[a]Screening categories are described in notes on Sheet 9.

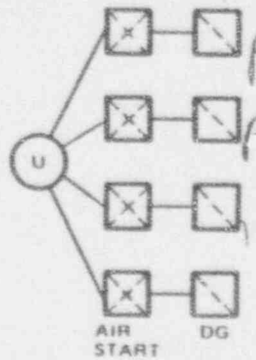
Table 3-7 (continued)

Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]	
DG-22 North Anna 2 (February 1981)	100% Pc	Two diesel generators inoperable due to battery problems. o NO STARTING BATTERIES o LOSS OF DC covered elsewhere o NOT ENOUGH INFO		C	ELIM
DG-23 Three Mile Island Unit 1 (April 1974)	Power	Two diesel generators failed to run due to design deficiency. LACK of INFO		C	elim mature plant.
DG-24 Browns Ferry 1 (January 1980)	Refueling	One diesel generator failed to run due to wrong material used in spider coupling. The spider on another unit was also found to be defective.		C	Keep

[a]Screening categories are described in notes on Sheet 9.

Table 3-7 (continued)

Sheet 8 of 9

Plant (date)	Status	Event Description	Cause-Effect Diagram	Screening Category[a]
DG-25 Browns Ferry 1 and 3 (May and June 1981)	Refueling	One of two redundant air start motors in each of four units failed to deliver rated rpm due to broken valve. ALL potentials NO FAILURES		C

elim

no real failure

[a]Screening categories are described in notes on Sheet 9.

Table 3-7 (continued)

Notes:

1. 1 ≡ events that are modeled explicitly in systems analysis. These include events caused by failure of support systems, cascade failures due to system configuration, and certain types of operator actions.

2. 2 ≡ events occurring prior to commercial operation detected as a result of startup testing.

3. 3 ≡ events occurring during shutdown conditions that cannot occur during power operation.

4. 4 ≡ events involving failures or potential failures that do not have a significant impact in analyses for PRA applications (e.g., component setpoint slightly outside of the technical specification limits).

5. C ≡ common cause events applicable to parametric modeling.

Attachment 3

Selected "marked-up" pages (3-5 to 3-206) of common cause event descriptions from September 1990 draft EPRI report with rationale and categorization from May 16-17, 1991 CECo-IPE meeting.

DG ONLY 3-6 to 3-15

3.4 DIESEL GENERATOR EVENTS

3.4.1 Component Boundaries

Diesel generators include the following:

- Diesel Engine
- Electrical Generator
- Air Start System, If Applicable
- Starter Motor, If Applicable
- Diesel Radiator/Cooler
- Air Inlet Filter
- Shaft Driven Fuel Oil or Fuel Oil Booster Pumps
- Diesel Exhaust System

Diesel generators do not include the following:

- Diesel Generator Load Sequencers
- Diesel Fuel Oil Transfer System
- Cooling Water Valves
- Diesel Generator Output Breaker, Output Bus
- Protection System Actuation Relays
- Diesel Room Cooling

3.4.2 Data Sheets

Following are the data sheets for the diesel generator.

COMPONENT: DIESEL GENERATOR

2DG-1

EVENT NUMBER: 1

PLANT: Peach Bottom 2

DATE: February 1978

REFERENCE: BWR XI.A.208

PLANT STATUS: 1% Power

DESCRIPTION:

One diesel tripped on high crankcase pressure during a test. Oil from a drum contaminated with water had been added to the makeup head tank. The oil in the remaining diesels showed no signs of water. Oil drums were stored outdoors and the contaminated drum had a leaking plug in the top of the drum.

elim
no cc

FAILURE MODE: Fail To Run

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels

POPULATION: 4

IMPACT:

P1: 1.000

P2: 0.000

P3: 0.000

P4: 0.000

singles

NOTES:

None

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG-2

PLANT: Browns Ferry 1

DATE: January 1980

REFERENCE: BWR XI.A.289

PLANT STATUS: Refueling

DESCRIPTION:

Speed control on one diesel was lost due to deterioration and failure of the spider coupling. The spider coupling on one other diesel was found to be defective. No significant deterioration was found in other couplings. The couplings were replaced on all diesels and an annual inspection was instigated.

keep

FAILURE MODE: Fail To Run

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels

POPULATION: 8

IMPACT:

P1: 0.930

P2: 0.070

P3: 0.000

P4: 0.000

NOTES: Some probability is given to the hypothesis that the other diesel with a defective coupling would have failed in the same way, if tested.

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG-3

PLANT: Zion 1

DATE: July 1974

REFERENCE: PWR XI.A.57

PLANT STATUS: 74% Power

DESCRIPTION:

Diesel 1B failed to respond to manual voltage control during a test. Diesel 1A was started and tripped off at about 50 % load. A loose terminal screw was found on the DG 1B voltage adjuster. DG 1A had a loose screw on the reverse power relay, and low lube oil pressure caused by plugged filters. A subsequent failure of 1B to respond to voltage control led to the discovery of a voltage control switch with dirty contacts. A third failure of 1B was due to failure of a relay in the voltage regulator.

elim independent causes

FAILURE MODE: Fail To Run

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels

POPULATION: 3

IMPACT:

P1: 1.970

P2: 0.017

P3: 0.000

P4: 0.000

assumes 2 events

NOTES: Some probability is given to the hypothesis that this is a common cause failure of two diesels. ✓

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG-4

PLANT: Connecticut Yankee

DATE: April 1968

REFERENCE: PWR XVI.C.9

PLANT STATUS: Full Power

DESCRIPTION: Diesel 1C tripped and was restarted. About four minutes later, two diesels tripped and a few seconds after that, the third diesel tripped. From tests done later, it was concluded that the diesels had tripped on reverse power. Circuitry had been added to allow a charging pump to be powered from the diesels, even though the diesels were not designed for the additional load. The diesels were modified such that on an auto-start signal, the diesel governors would go full open, while after a manual start the governors went to the no load state. A manually started diesel would not load with other diesels that were carrying load, due to the mismatch in governor settings and would eventually trip off on reverse power. Procedures were changed to include manual operation of the governor following a manual start.

elim bo on applic

Zion & dus procedure

FAILURE MODE: Fail To Run

SHOCK TYPE: Nonlethal

APPLICATION: Applicable only for plants with parallel configuration.

POPULATION: 3

IMPACT:

P1: 0.000

P2: 0.000

P3: 1.000

P4: 0.000

NOTES: The three diesels were restarted and loaded onto the bus within minutes.

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG-5

PLANT: D.C. Cook

DATE: December 1977, January 1978

REFERENCE: PWR XI.A.217

PLANT STATUS: 100 % Power

Elim. Rooms level

DESCRIPTION:

Spurious overspeed trip signals were received while the diesels were in standby. The cause was extremely cold temperatures in the diesel rooms. Snow was standing on the diesel control cabinets. On 17 Dec., 2 Jan. and 7 Jan., the emergency diesel for the motor-driven aux. feedwater pump tripped on overspeed. In each instance, the diesel was restarted and operated properly.

FAILURE MODE: ~~Fail To Run~~ FtS 1st attempt.

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to plants which might experience extremely cold weather conditions.

POPULATION: 2

IMPACT:

P1: 0.010

P2: 0.070

P3: 0.000

P4: 0.000

NOTES:

There is uncertainty about whether the diesels would have failed if demanded.

COMPONENT: DIESEL GENERATOR

2DG

EVENT NUMBER: 6

PLANT: Yankee Rowe

DATE: August 1977

REFERENCE: PWR XI.A.339

PLANT STATUS: Refueling

DESCRIPTION:

Two diesel generators gave high cooling water temperature alarms during a test. The temperature was still increasing after about 30 minutes. DG #1 had 67 % of its 120 radiator tubes plugged with sludge and DG #3 had 72 % of its tubes plugged. A design change was recommended by the manufacturer.

leave. sludge

Zion / HX water: wat

FAILURE MODE: Fail To Run

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels

POPULATION: 3

IMPACT:

P1: 0.000

P2: 0.900

P3: 0.100

P4: 0.000

NOTES: There is uncertainty about the condition of the DG #2 radiator tubes. Some probability is given to the hypothesis that the #2 diesel generator was in a similar condition and would have overheated if started.

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 206-7

PLANT: Arkansas 1

DATE: August 1979

REFERENCE: PWR XI.A.337

PLANT STATUS: 100% Power

DESCRIPTION:

One diesel tripped on high crankcase pressure during a test, due to water in the lube oil from a leaking lube oil cooler. Two weeks later, the other diesel failed for the same reason. The lube oil coolers were replaced on both diesels.

elim ~~long prod~~

2 weeks later

FAILURE MODE: Fail To Run

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels

POPULATION: 2

IMPACT:

P1: 0.000

P2: 1.000

P3: 0.000

P4: 0.000

NOTES:

None

COMPONENT: DIESEL GENERATOR

2DG

EVENT NUMBER: 8

PLANT: Dresden 2 and 3

DATE: May 1973

REFERENCE: BWR XVI.C.32

PLANT STATUS: Unit 2 Power and Unit 3 Shutdown

DESCRIPTION: Two diesels, one on Unit 3 and the swing diesel for Units 2 and 3 tripped on high temperature during a test. The cooling water flow lineup was incorrect due to an unclear procedure for reversing cooling flow during a maintenance outage. The procedure was revised to state the correct valve lineup explicitly.

FAILURE MODE: Fail To Start

SHOCK TYPE: Nonlethal

APPLICATION: Applicable if errors following maintenance are not specifically modeled or if post-maintenance testing is not done. (see Note)

POPULATION: 5

IMPACT:

P1: 0.000

P2: 1.000

P3: 0.000

P4: 0.000

NOTES: These failures were detected by operability test. This event is very plant specific; it depends on the valving during DG maintenance and plant post-maintenance testing philosophy. It is not applicable at all if post-maintenance tests are done. During power operation it is very unlikely that cooling water flow would be reversed, but may be done on a swing diesel.

elim

procedure error

HIGH TEMP - RIP NOT ACTIVE ON EM STA[illegible]

POST maint test?

COMPONENT: DIESEL GENERATOR

2DG

EVENT NUMBER: 9

PLANT: Salem 1

DATE: July 1977

REFERENCE: NUREG/CR-1362 March 1980

Keep

PLANT STATUS: Hot Standby

DESCRIPTION:

Two diesel generators tripped on overcrank due to binding fuel rack linkage. The third diesel operated satisfactorily after lube and cleaning. Three diesel generators were inoperable for about 4.5 hours.

FAILURE MODE: Fail To Start

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels

POPULATION: 3

IMPACT:

P1: 0.000

P2: 0.890

P3: 0.110

P4: 0.000

NOTES:

There is uncertainty about whether the third diesel would have also failed if started; it is clearly a failure of at least two diesels.

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG 10

PLANT: Millstone 2

DATE: May 1977

REFERENCE: NUREG/CR-1362 March 1980

PLANT STATUS: Power

DESCRIPTION:

Two diesel generators failed to run due to the fuel lines being valved out. PLG opinion is that these valves were closed for fuel-filling operation and then left misaligned.

FAILURE MODE: Fail To Start

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels except those that have a day tank large enough for 24 hours of operation.

POPULATION: 2

IMPACT:

P1: 0.000

P2: 1.000

P3: 0.000

P4: 0.000

NOTES: This failure is not dependent on run time, so it is assessed as a failure to start on demand. The diesel will fail when the day tank empties, for any demand to start.

elim.

Independent look

Day tank level alar

procedure not applic

COMPONENT:	DIESEL GENERATOR
EVENT NUMBER:	2DG- 11
PLANT:	Three Mile Island 1
DATE:	March 1978
REFERENCE:	PWR XI.A.230
PLANT STATUS:	Refueling
DESCRIPTION:	Two diesels failed to start during a test, due to faulty lube oil pressure switches. The switches had failed to operate before the cranking timer ran out. The switches were to be replaced.
FAILURE MODE:	Fail To Start
SHOCK TYPE:	Nonlethal
APPLICATION:	Applicable only if switches are not bypassed by emergency start signal.
POPULATION:	2
IMPACT:	
P1:	0.000
P2:	1.000
P3:	0.000
P4:	0.000
NOTES:	None

elim; they are ?

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG-12

PLANT: Quad Cities 1 and 2

DATE: May 1973

REFERENCE: BWR XI.A.29

PLANT STATUS: Unit 1 Shutdown and Unit 2 Power

Keep

DESCRIPTION: One diesel failed to start during a test. The cause was the welding together of relay contacts that resulted in the depressurization of the starting air accumulators. The contacts for the other two diesels showed signs of arcing. It was believed that this failure was due to the circuit design and not a component failure. A circuit modification was reviewed.

FAILURE MODE: Fail To Start

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels with air-start

POPULATION: 3

IMPACT:

P1: 0.983

P2: 0.000

P3: 0.017

P4: 0.000

use this vector

NOTES: Some probability is given to the hypothesis that the other two diesels would have failed to start for the same reason, if demanded.

elim

LO heaters

Bypass em start

slowstart

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG-13

PLANT: Brunswick 1

DATE: January 1977

REFERENCE: BWR XI.A.159

PLANT STATUS: 32% Power

DESCRIPTION: During a loss of offsite power test, DG 3 and DG 4 tripped after starting. Lockout switches were reset and the DGs operated properly. During a later test, DG 2, DG 3 and DG 4 tripped after starting. The cause was found to be low lube oil pressure switches that had not cleared during the 30 second time delay due to low lube oil temperature.

LOW LO TEMP

where are 310E'D diesels?

FAILURE MODE: Fail To Start

SHOCK TYPE: Nonlethal

APPLICATION: Applicable to all diesels

POPULATION: 4

IMPACT:

P1: 0.000

P2: 0.900

P3: 0.100

P4: 0.000

NOTES: There is some uncertainty about whether this is a common cause failure of two diesels or three diesels, since the third diesel, DG 2, did not fail in the first test. Some plants may have a bypass of DG trips if an emergency start signal is present.

Bypass of TRIPS?

COMPONENT: DIESEL GENERATOR

EVENT NUMBER: 2DG-14

PLANT: Dresden 2 & 3

DATE: September 1972

REFERENCE: PWR XI.A.25

PLANT STATUS: Unit 3 Cold Shutdown, Unit 2 350 MW

DESCRIPTION: One diesel auto-started when a bus was deenergized for transformer maintenance. Operators moved the control switch from the 'auto' position to the 'stop' position and back to the 'auto' position to reset diesel protective trips that are bypassed during an auto start. About six minutes later, the diesel tripped. A slow responding relay caused the timed engine shutdown sequence to commence when the switch was moved to the 'stop' position. The shutdown sequence had priority over the auto start signal. An examination of a second diesel revealed that it too was susceptible to the same problem. The time delay relays were replaced, correcting the problem.

elim;

screen out 4 not sig to PRA

FAILURE MODE: Fail To Start (Restart)

SHOCK TYPE: Nonlethal

APPLICATION: Applicable only to restart after manual shutdown.

VERY LOW prob. that

POPULATION: 3

IMPACT:

P1: 0.000

P2: 1.000

P3: 0.000

P4: 0.000

still same?

NOTES: Applicable to diesels with similar shutdown/auto-start logic.

FILE
DISC, 3 FORMAT

ZCCROPWR.WK1

ATTachment C

3A1

3B1

3A2

3B2

3C1

DG data

DG calcs.

3A3

3C2

3B3

3A4

3A5

3A6

3B4

3C3

WORKSHEET FOR CECO COMMON CAUSE. POINT ESTIMATES FOR MGL FACTORS ZCC.WK1

ORIG SYS S N001 N002 N003 N004 F_MAP RHO

MAPPING UP CASES FOR VERIFICATION OF CELL FORMULAS														
CASE11														
	2	0.000	0.500	0.500		*2to3	0.5	2	0.000	1.000	0.000	0.000	1.000	*2to3
	2	0.000	0.250	0.500	0.250	*2to4	0.5	2	0.000	1.000	0.000	0.000	1.000	*2to4
CASE12														
	2	0.375	0.500	0.250		*2to3	0.5	2	0.500	0.500			1.000	*2to3
	2	0.250	0.438	0.375	0.125	*2to4	0.5	2	0.500	0.500			1.000	*2to4
CASE13														
	3	0.167	0.375	0.375	0.125	*3to4	0.5	3	0.250	0.500	0.250		1.000	*3to4
CASE5														
	2	1.350	0.100	0.000		*2to3	0.1	2	1.000	0.000	0.000	0.000	1.000	*2to3
	2	1.620	0.225	0.010	0.000	*2to4	0.1	2	1.000	0.000	0.000	0.000	1.000	*2to4
CASE6														
	2	0.675	0.500	0.050		*2to3	0.1	2	0.500	0.500			1.000	*2to3
	2	0.810	0.518	0.095	0.005	*2to4	0.1	2	0.500	0.500			1.000	*2to4
CASE7														
	3	0.300	0.475	0.275	0.025	*3to4	0.1	3	0.250	0.500	0.250		1.000	*3to4
MAPPING DOWN CASES FOR VERIFICATION OF CELL FORMULAS														
CASE1														
	4	0.000	0.000	1.000		*4to3		4	0.000	0.000	0.000	1.000	1.000	*4to3
	4	0.000	1.000			*4to2		4	0.000	0.000	0.000	1.000	1.000	*4to2
CASE2														
	4	0.000	0.750	0.250		*4to3		4	0.000	0.000	1.000	0.000	1.000	*4to3
	4	0.500	0.500			*4to2		4	0.000	0.000	1.000	0.000	1.000	*4to2
CASE3														
	4	0.500	0.500	0.000		*4to3		4	0.000	1.000	0.000	0.000	1.000	*4to3
	4	0.667	0.167			*4to2		4	0.000	1.000	0.000	0.000	1.000	*4to2
CASE4														
	4	0.750	0.000	0.000		*4to3		4	1.000	0.000	0.000	0.000	1.000	*4to3
	4	0.500	0.000			*4to2		4	1.000	0.000	0.000	0.000	1.000	*4to2
CASE 6														
	3	0.000	1.000			*3to2		3	0.000	0.000	1.000			
CASE 7														
	3	0.667	0.333			*3to2		3	0.000	1.000	0.000			
CASE 8														
	3	0.667	0.000			*3to2		3	1.000	0.000	0.000			

3A1

WORKSHEET FOR CECO COMMON CAUSE. POINT ESTIMATES FOR MGL FACTORS ZCC.WK1

ORIG SYS S	N001	N002	N003	N004	F_MAP	RHO	MAP	TYPE	ID_R1	ID_R2	APPLIC. Z	D	S	SIZE	N000	N001	N002	N003	N004	RHO	PLANT	DATE	STATUS	T	FAIL
3	0.000	0.300	0.7[illegible]	0.000	*3to4	0.7	3->4	AFW	1AFWP-07		A	A	C	3	0.000	0.000	1.000	0.000	0.000	0.7	Zion 2	September 1981	Shutdown		
4*	0.000	0.300	0.7 0	0.000		B&P	SUM	AFW																	
2	0.000	0.100	0.900		*2to3	0.9	2->3	BR	N/A	2BR -06	A	A		2	0.000	0.000	1.000	0.000	0.000	0.9	Cooper	August 1984			
2	0.000	0.100	0.900		*2to3	0.9	2->3	BR		2BR -08	A	A		2	0.000	0.000	1.000	0.000	0.000	0.9	Cooper	January 1976			
3*	0.000	0.200	1.800			B&P	SUM	BR																	
2	0.000	1.000	0.000	0.000	*NONE		NONE	CSP	1CSP -09	2CSP -07	A	A	C	2	0.000	0.000	1.000	0.000	0.000	0.9	Kewaunee	Oct-Dec 1977	100% Power		
2*	0.000	1.000	0.000	0.000		B&P	SUM	CSP																	
4	0.900	0.100	0.000	0.000	*NONE		NONE	CV		2CV -04	A	A		4	0.000	0.900	0.100	0.000	0.000	0.5	Crystal River	April 1980			
4*	0.900	0.100	0.000	0.000		B&P	SUM	CV																	
4*	0.040	0.020	0.020	0.020	*NONE		NONE	CWP	1SCWP-12		A	A	C		0.900	0.040	0.020	0.020	0.020	0.7	Hatch 1	August 1979	Cold Shutdown		
4*	0.040	0.020	0.020	0.020		B&P	SUM	CWP																	
3	0.000	0.890	0.110	0.000	*NONE		NONE	DG	1DG -06	2DG -09	A	A	C	3	0.000	0.000	0.890	0.110	0.000	0.7	Salem	July 1977	Power		
3	0.000	0.900	0.100	0.000	*NONE		NONE	DG	1DG -07	2DG -06	A	A	C	3	0.000	0.u00	0.900	0.100	0.000	0.7	Yankee Rowe	August 1977	Refueling		
3	0.000	0.000	0.017	0.000	*NONE		NONE	DG	1DG -16	2DG -12	A	A	C	3	0.983	0.000	0.000	0.017	0.000	0.7	Quad Cities	May 1977	Power		
8	0.733	0.035	0.000		*4to3	0.5	4->3	DG	1DG -24	2DG -02	A	A	C	8	0.000	0.930	0.070	0.000	0.000	0.5	Browns Ferry 1	January 1980	Refueling		
3*	0.733	1.825	0.227	0.000		B&P	SUM	DG																	

3AL

2*	0.000	1.000	0.000	0.000	*NONE		NONE	HHP	1HHP -04		A	A	C		0.000	0.000	1.000	0.000	0.000	0.5 North Anna 1	July 1978	92% Power
2*	0.000	1.000	0.000	0.000		B&P	SUM	HHP														

4	0.003	0.060			*4to2	0.5	4->2	HRP	1HRP -14	2HRP -06	N	A	C	4						0.5 Brunswick I	April 1979	30%Power
2	0.997	0.003	0.000	0.000	*NONE		NONE	HRP	1HRP -15	2HRP -02	A	A	C	2	0.000	0.997	0.003	0.000	0.000	0.7 Monticello	December 1972	Refueling
2	0.000	0.000	0.000	0.000	*NONE		NONE	HRP	1HRP -16	2HRP -03	N	A	C	2						0.9 Browns Ferry 1	September 1974	Cold Shutdown
4	0.498	0.043			*4to2	0.7	4->2	HRP	1HRP -17	2HRP -07	A	A	1	4	0.000	0.900	0.050	0.030	0.020	0.7 Brunswick 2	April 1979	Refueling
2*	1.495	0.046	0.000	0.000		PWR	SUM	HRP														

4	0.667	0.167			*4to2	0.5	4->2	HRP	1HRP -14	2HRP -06	N	A	C	4	0.000	0.000	1.000	0.000	0.000	0.5 Brunswick I	April 1979	30%Power
2	0.997	0.003	0.000	0.000	*NONE		NONE	HRP	1HRP -15	2HRP -02	A	A	C	2	0.000	0.997	0.003	0.000	0.000	0.7 Monticello	December 1972	Refueling
2	0.000	1.000	0.000	0.000	*NONE		NONE	HRP	1HRP -16	2HRP -03	N	A	C	2	0.000	0.000	1.000	0.000	0.000	0.9 Browns Ferry 1	September 1974	Cold Shutdown
4	0.498	0.043			*4to2	0.7	4->2	HRP	1HRP -17	2HRP -07	A	A	1	4	0.000	0.900	0.050	0.030	0.020	0.7 Brunswick 2	April 1979	Refueling
2*	2.162	1.213	0.000	0.000		BWR	SUM	HRP														

12	0.900	0.050	0.050	0.000	*NONE		NONE	MOV	1MV -01	2MV -22	A	A	C	12	0.000	0.900	0.050	0.050	0.000	0.5 Cook 2	January 1979	2% Power
3	0.000	0.110	0.110	0.000	*3to4	0.5	3->4	MOV	1MV -02	2MV -07	A	A		3	0.780	0.000	0.220	0.000	0.000	0.5 Turkey Point 3	April 1979	
10	0.900	0.100	0.000	0.000	*NONE		NONE	MOV	1MV -03	2MV -08	A	A		10	0.000	0.900	0.100	0.000	0.000	0.5 Arkansas One 1	April 1980	
4	0.900	0.000	0.000	0.100	*NONE		NONE	MOV	1MV -04	2MV -19	A	A	C	4	0.000	0.900	0.000	0.000	0.100	0.7 Palisades	June 1971	After Fuel Loading
9	0.711	0.186	0.070	0.003	*NONE		NONE	MOV	1MV -06	2MV -05	A	A	C	9	0.000	0.711	0.186	0.070	0.003	0.5 Oconee 2	October 1975	Cold Shutdown
25	0.900	0.050	0.030	0.020	*NONE		NONE	MOV	1MV -40	2MV -23	A	A	C	25	0.000	0.900	0.050	0.030	0.020	0.5 Monticello	July 1972	Cold Shutdown
4	0.900	0.000	0.000	0.100	*NONE		NONE	MOV	1MV -52	2MV -14	A	A	C	4	0.000	0.900	0.000	0.000	0.100	0.7 Browns Ferry 2	December 1974	Shutdown
81	0.000	1.000	0.000	0.000	*NONE		NONE	MOV	1MV -65	2MV -32	A	A	C	81	0.000	0.000	1.000	0.000	0.000	0.5 Hatch 2	May 1980	Startup
3	0.600	0.500	0.050	0.000	*3to4	0.5	3->4	MOV	1MV -66	2MV -33	A	A	C	3	0.000	0.900	0.100	0.000	0.000	0.5 Hatch 2	May 1982	99% Power
2	0.000	0.010	0.180	0.810	*2to4	0.9	2->4	MOV	1MV -72	2MV -34	A	A	C	2	0.000	0.000	1.000	0.000	0.000	0.9 Dresden 2	May 1975	Refueling
2	0.081	0.241	0.222	0.025	*2to4	0.7	2->4	MOV	1MV -73	2MV -39	A	A	C	2	0.500	0.450	0.050	0.000	0.000	0.7 Cooper	October 1980	98% Power
13	0.000	1.000	0.000	0.000	*NONE		NONE	MOV	1MV -75	2MV -36	A	A	C	13	0.000	0.000	1.000	0.000	0.000	0.5 Dresden 2	August 1973	Power
	0.450	0.050	0.000	0.000	*NONE		NONE	MOV	1MV -80		A	A	C		0.500	0.450	0.050	0.000	0.000	0.5 Pilgrim	October 1981	Refueling
	0.900	0.000	0.000	0.100	*NONE		NONE	MOV	1MV -84		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Millstone 1	May 1971	Power
4	0.900	0.100	0.000	0.000	*NONE		NONE	MOV	1MV -85	2MV -37	A	A	C	4	0.000	0.900	0.100	0.000	0.000	0.5 Pilgrim	April 1973	Power
4*	8.142	3.397	0.712	1.158		B&P	SUM	MOV														

2	0.000	1.000	0.000	0.000	*NONE		NONE	RTB	1RTB -04	2RTB -04	A	A	C	2	0.000	0.000	1.000	0.000	0.000	0.9 Salem 1	February 1983	Startup
	0.000	0.100	0.000	0.000	*NONE		NONE	RTB	1RTB -07		A	A	C		0.900	0.000	0.100	0.000	0.000	0.7 McGuire 2	March 1983	Shutdown
2*	0.000	1.100	0.000	0.000		B&P	SUM	RTB														

2	0.650	0.100	0.000	0.000	*NONE		NONE	SLRV		2SLRV-01	N	A		2	0.250	0.650	0.100	0.000	0.000	0.7		
4*	0.650	0.100	0.000	0.000		BWR	SUM	SLRV														

3A3

5	0.000	1.000	0.000	0.000	*NONE		NONE SRV		2EMRV-04	A	A		5	0.000	0.000	1.000	0.000	0.000	0.5 Oyster Creek	November 1984		B
5	1.000	0.000	0.000	0.000	*NONE		NONE SRV		2EMRV-04	A	A		5	0.000	1.000	0.000	0.000	0.000	0.5 Oyster Creek	November 1984		B
10	1.000	0.000	0.000	0.000	*NONE		NONE SRV		2EMRV-08	A	A		10	0.000	1.000	0.000	0.000	0.000	0.5 Quad Cities 1,2	March 1979		B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-08		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Peach Bottom	November 1974	100% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-10		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Monticello	November 1974	81% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-13		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Dresden 2	May 1975	Startup	B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-17		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Brunswick 2	July 1975	20% Power	B
	0.000	0.000	1.000	0.000	*NONE		NONE SRV	1BSRV-18		A	A	C		0.000	0.000	0.000	1.000	0.000	0.5 Vermont Yankee	July 1976	Shutdown	B
	0.000	1.000	0.000	0.000	*NONE		NONE SRV	1BSRV-19		A	A	C		0.000	0.000	1.000	0.000	0.000	0.5 Quad Cities 2	November 1976	20% Power	B
10	0.000	0.000	0.000	1.000	*NONE		NONE SRV	1BSRV-20	2EMRV-06	A	A	C	10	0.000	0.000	0.000	0.000	1.000	0.9 Quad Cities 1	November 1976	77% Power	B
6	0.800	0.000	0.000	0.200	*NONE		NONE SRV	1BSRV-22	2EMRV-07	A	A	C	6	0.000	0.800	0.000	0.000	0.200	0.7 Arnold	March 1977	Shutdown	B
	0.000	0.000	1.000	0.000	*NONE		NONE SRV	1BSRV-25		A	A	C		0.000	0.000	0.000	1.000	0.000	0.5 Browns Ferry 3	August 1978	89% Power	B
	0.000	1.000	0.000	0.000	*NONE		NONE SRV	1BSRV-31		A	A	C		0.000	0.000	1.000	0.000	0.000	0.5 Browns Ferry 2	February 1978	Power	B
4*	6.400	3.000	2.000	1.600		BWR	SUM SRV															

5	0.000	1.000	0.000	0.000	*NONE		NONE SRV		2EMRV-04	A	A		5	0.000	0.000	1.000	0.000	0.000	0.5 Oyster Creek	November 1984		B
5	1.000	0.000	0.000	0.000	*NONE		NONE SRV		2EMRV-04	A	A		5	0.000	1.000	0.000	0.000	0.000	0.5 Oyster Creek	November 1984		B
10	1.000	0.000	0.000	0.000	*NONE		NONE SRV		2EMRV-08	A	A		10	0.000	1.000	0.000	0.000	0.000	0.5 Quad Cities 1,2	March 1979		B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-08		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Peach Bottom	November 1974	100% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-10		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Monticello	November 1974	81% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-13		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Dresden 2	May 1975	Startup	B
	0.900	0.000	0.000	0.100	*NONE		NONE SRV	1BSRV-17		A	A	C		0.000	0.900	0.000	0.000	0.100	0.7 Brunswick 2	July 1975	20% Power	B
	0.000	0.000	1.000	0.000	*NONE		NONE SRV	1BSRV-18		A	A	C		0.000	0.000	0.000	1.000	0.000	0.5 Vermont Yankee	July 1976	Shutdown	B
	0.000	1.000	0.000	0.000	*NONE		NONE SRV	1BSRV-19		A	A	C		0.000	0.000	1.000	0.000	0.000	0.5 Quad Cities 2	November 1976	20% Power	B
10	0.000	0.000	0.000	1.000	*NONE		NONE SRV	1BSRV-20	2EMRV-06	A	A	C	10	0.000	0.000	0.000	0.000	1.000	0.9 Quad Cities 1	November 1976	77% Power	B
6	0.800	0.000	0.000	0.200	*NONE		NONE SRV	1BSRV-22	2EMRV-07	A	A	C	6	0.000	0.800	0.000	0.000	0.200	0.7 Arnold	March 1977	Shutdown	B
	0.000	0.000	1.000	0.000	*NONE		NONE SRV	1BSRV-25		A	A	C		0.000	0.000	0.000	1.000	0.000	0.5 Browns Ferry 3	August 1978	89% Power	B
	0.000	1.000	0.000	0.000	*NONE		NONE SRV	1BSRV-31		A	A	C		0.000	0.000	1.000	0.000	0.000	0.5 Browns Ferry 2	February 1978	Power	B
4*	6.400	3.000	2.000	1.600		PWR	SUM SRV															

5	0.000	1.000	0.000	0.000	*NONE		NONE SRV		2EMRV-04	A	A		5	0.000	0.000	1.000	0.000	0.000	0.5 Oyster Creek	November 1984		B
5	1.000	0.000	0.000	0.000	*NONE		NONE SRV		2EMRV-04	A	A		5	0.000	1.000	0.000	0.000	0.000	0.5 Oyster Creek	November 1984		B
10	1.000	0.000	0.000	0.000	*NONE		NONE SRV		2EMRV-08	A	A		10	0.000	1.000	0.000	0.000	0.000	0.5 Quad Cities 1,2	March 1979		B
10	0.000	0.000	0.000	1.000	*NONE		NONE SRV	1BSRV-20	2EMRV-06	A	A	C	10	0.000	0.000	0.000	0.000	1.000	0.9 Quad Cities 1	November 1976	77% Power	B
6	0.800	0.000	0.000	0.200	*NONE		NONE SRV	1BSRV-22	2EMRV-07	A	A	C	6	0.000	0.800	0.000	0.000	0.200	0.7 Arnold	March 1977	Shutdown	B
4*	2.800	1.000	0.000	1.200		BWR	SUM EMRV															

3A 4

	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-08	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Peach Bottom	November 1974	100% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-10	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Monticello	November 1974	81% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-13	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Dresden 2	May 1975	Startup	B
	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-17	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Brunswick 2	July 1975	20% Power	B
	0.000	0.000	1.000	0.000	*NONE		NONE	SRV	1BSRV-18	A	A	C	0.000	0.000	0.000	1.000	0.000	0.5 Vermont Yankee	July 1976	Shutdown	B
	0.000	1.000	0.000	0.000	*NONE		NONE	SRV	1BSRV-19	A	A	C	0.000	0.000	1.000	0.000	0.000	0.5 Quad Cities 2	November 1976	20% Power	B
	0.000	0.000	1.000	0.000	*NONE		NONE	SRV	1BSRV-25	A	A	C	0.000	0.000	0.000	1.000	0.000	0.5 Browns Ferry 3	August 1978	89% Power	B
	0.000	1.000	0.000	0.000	*NONE		NONE	SRV	1BSRV-31	A	A	C	0.000	0.000	1.000	0.000	0.000	0.5 Browns Ferry 2	February 1978	Power	B
4*	3.600	2.000	2.000	0.400		BWR	SUM	SRV (EMRV OMITTED)													

	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-08	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Peach Bottom	November 1974	100% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-10	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Monticello	November 1974	81% Power	B
	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-13	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Dresden 2	May 1975	Startup	B
	0.900	0.000	0.000	0.100	*NONE		NONE	SRV	1BSRV-17	A	A	C	0.000	0.900	0.000	0.000	0.100	0.7 Brunswick 2	July 1975	20% Power	B
	0.000	0.000	1.000	0.000	*NONE		NONE	SRV	1BSRV-18	A	A	C	0.000	0.000	0.000	1.000	0.000	0.5 Vermont Yankee	July 1976	Shutdown	B
	0.000	1.000	0.000	0.000	*NONE		NONE	SRV	1BSRV-19	A	A	C	0.000	0.000	1.000	0.000	0.000	0.5 Quad Cities 2	November 1976	20% Power	B
	0.000	0.000	1.000	0.000	*NONE		NONE	SRV	1BSRV-25	A	A	C	0.000	0.000	0.000	1.000	0.000	0.5 Browns Ferry 3	August 1978	89% Power	B
	0.000	1.000	0.000	0.000	*NONE		NONE	SRV	1BSRV-31	A	A	C	0.000	0.000	1.000	0.000	0.000	0.5 Browns Ferry 2	February 1978	Power	B
4*	3.600	2.000	2.000	0.400		PWR	SUM	SRV (EMRV OMITTED)													

0	0.068	0.050	0.005		*2to3	0.5	NONE	CHIL	2CHIL-01	P	P	2	0.000	0.090	0.010	0.000	0.000	Calvert Cliffs	Jul,Sep 1980		
3	0.068	0.050	0.005	0.000		B&P	SUM	CHIL													

4	0.900	0.000	0.000	0.100	*NONE			FAN	2FAN-07	P	P		0.000	0.900	0.000	0.000	0.100	Quad Cities 1	February 1978		
4*	0.900	0.000	0.000	0.100		B&P	SUM	FAN													

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AFWP		2AFWPSIN	SINGLE FAILURES			50
AFWP	1AFWPSIN		SINGLE FAILURES			178.7
BR		2BR SIN	SINGLE FAILURES			97
BR	1BR SIN		SINGLE FAILURES		N	
CHIL		2CHILSIN	SINGLE FAILURES			37
CHIL	1CHILSIN		SINGLE FAILURES		N	
CSP		2CSP SIN	SINGLE FAILURES			29
CSP	1CSP SIN		SINGLE FAILURES			25.7
CV		2CV SIN	SINGLE FAILURES			22
CV	1CV SIN		SINGLE FAILURES		N	
CWP		2CWP SIN	SINGLE FAILURES			126
CWP	1CWP SIN		SINGLE FAILURES			115.8
DG		2DG SIN	SINGLE FAILURES			574
DG	1DG SIN		SINGLE FAILURES			574.2
EMRV		2EMRVSIN	SINGLE FAILURES			19
EMRV	1EMRVSIN		SINGLE FAILURES		N	
FAN		2FAN SIN	SINGLE FAILURES			33
FAN	1FAN SIN		SINGLE FAILURES		N	
HHP		2HHP SIN	SINGLE FAILURES			75
HHP	1HHP SIN		SINGLE FAILURES			60.8
HPRC		2HPRCSIN	SINGLE FAILURES	B		69
HPRC	1HPRCSIN		SINGLE FAILURES	B	N	
HRP		2HRP SIN	SINGLE FAILURES			64
HRP	1HRP SIN		SINGLE FAILURES			42.7
MOV		2MOV SIN	SINGLE FAILURES			788
MOV	1MOV SIN		SINGLE FAILURES			784.4
RTB		2RTB SIN	SINGLE FAILURES			53
RTB	1RTB SIN		SINGLE FAILURES			55.1
SLRV		2SLRVSIN	SINGLE FAILURES	B		17
SLRV	1SLRVSIN		SINGLE FAILURES	B	N	
SRVB		2BSRVSIN	SINGLE FAILURES	B	N	
SRVB	1BSRVSIN		SINGLE FAILURES	B		109.9
SRVP		2PSRVSIN	SINGLE FAILURES	P	N	
SRVP	1PSRVSIN		SINGLE FAILURES	P		12.9

3A6

WORKSHEET FOR CONVERTING IMPACT VECTORS TO MGL FACTORS FOR 4, 3, 2 COMP SYSTEMS
MAPP ING

NOTES:

*	Adjusted factor for 1-component failures represents addition of single component failure contribution to the impact vector.
**	Fraction represents the following for the single component failure data: (System Size Mapped From)/(System Size Mapped To).
*****	These components use Beta factor from NUREG-3967 for all system sizes and the value calculated for "all" for gamma and delta.
+	Impact vector from CN-PRRA-90-153-R0.
++	All single componet failures for systems on which common cause data is based.
--a--	MGL factors not calculated for this system size.

	COMP VECT INFO	SYS SIZE	SINGLE FAIL's	MAPPING VECTOR FR/TO	MAPPING SINGLE FR/TO	MUL	N001	IMPACT VECTOR N001*	N002	N003	N004	NUMBER OF FAILURES K(N1)	K(N2)	K(N3)	K(N4)	SUM(KN)	FOUR BETA	COMP. GAMMA	SYS DELTA	3-COMP BETA	SYS GAMMA	2-C SYS BETA
178.7	AFW	+	178.7				0.000		0.300	0.700	0.000											
	SUM	4	178.7		NONE	1	0.000	178.700	0.300	0.700	0.000	178.700	0.600	2.100	0.000	181.400	1.49E-02	7.78E-01	5.26E-01			
	PWR	3		MAPPEDFROM 4-COMP SYSTEM				134.175	0.675	0.175		134.175	1.350	0.525	—	136.050				1.38E-02	2.80E-01	
	4"	2		MAPPEDFROM 4-COMP SYSTEM				89.900	0.400			89.900	0.800	—	—	90.700						8.82E-03
97	BR	+	97				0.000		0.200	1.800	0.000											
	SUM																					
	B&P	3	97	4/3	NONE	1	0.000	97.000	0.200	1.800		97.000	0.400	5.400	0.000	102.800				5.64E-02	9.31E-01	
	3"	2		MAPPEDFROM 3-COMP SYSTEM				64.800	1.867			64.800	3.733	—	—	68.533						5.45E-02
25.7 2	CSP	+	25.7				0.000		1.000	0.000	0.000											
	SUM	2	25.7	4/2	NONE	1	0.000	25.700	1.000			25.700	2.000	0.000	0.000	27.700						
	B&P																					
	2"																					7.22E-02
22	CV	+	22				0.900		0.100	0.000	0.000											
	SUM	4	22		NONE	1	0.900	22.900	0.100	0.000	0.000	22.900	0.200	0.000	0.000	23.100	8.86E-03	7.37E-01	5.26E-01			
	PWR	3		MAPPEDFROM 4-COMP SYSTEM				17.225	0.050	0.000		17.225	0.100	0.000	—	17.325				6.77E-03	5.52E-01	
	4"	2		MAPPEDFROM 4-COMP SYSTEM				11.517	0.017			11.517	0.033	—	—	11.550						2.89E-03
115.8	CWP	+	115.8				0.040		0.020	0.020	0.020											
	SUM	4	115.8		NONE	1	0.040	115.840	0.020	0.020	0.020	115.840	0.040	0.060	0.080	116.020	1.55E-03	7.78E-01	5.71E-01			
	PWR	3		MAPPEDFROM 4-COMP SYSTEM				86.890	0.025	0.025		86.890	0.050	0.075	—	87.015				1.44E-03	6.00E-01	
	4"	2		MAPPEDFROM 4-COMP SYSTEM				57.943	0.033			57.943	0.067	—	—	58.010						1.15E-03

DG calcs

	COMP VECT INFO	SYS SIZE	SINGLE FAIL's	MAPPING VECTOR FR/TO	MAPPING SINGLE FR/TO	MUL	N001	IMPACT VECTOR N001*	N002	N003	N004	NUMBER OF FAILURES K(N1)	K(N2)	K(N3)	K(N4)	SUM(KN)	FOUR BETA	COMP. GAMMA	SYS DELTA	3-COMP BETA	SYS GAMMA	2-C SYS BETA
574.2 3	DG	+	574.2				0.733		1.825	0.227	0.000											
	SUM																					
	B&P	3	574.2	4/3	NONE	1	0.733	574.933	1.825	0.227		574.933	3.650	0.681	0.000	579.264				7.48E-03	1.57E-01	
	3"	2		MAPPEDFROM 3-COMP SYSTEM				384.505	0.835			384.505	1.671	—	—	386.176						4.33E-03
60.8 2	HHP	+	60.8				0.000		1.000	0.000	0.000											
	SUM	2	60.8	4/2	NONE	1	0.000	60.800	1.000			60.800	2.000	0.000	0.000	62.800						
	B&P																					
	2"																					3.16E-02

	COMP VECT INFO	SYS SIZE	SINGLE FAIL's	MAPPING VECTOR FR/TO	MAPPING SINGLE FR/TO	MUL	N001	IMPACT VECTOR N001*	N002	N003	N004	NUMBER OF FAILUPES K(N1)	K(N2)	K(N3)	K(N4)	SUM(KN)	FOUR BETA	COMP. GAMMA	SYS DELTA	3-COMP BETA	SYS GAMMA	2-C SYS BETA
42.7 2	HRP	+	42.7				1.495		0.046	0.000	0.000											
	SUM	2	42.7	4/2	NONE	1	1.495	44.195	0.046			44.195	0.093	0.000	0.000	44.288						
	PWR																					
	2"																					2.09E-03

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	COMP VECT INFO	SYS SIZE	SINGLE FAIL's	MAPPING VECTOR FR/TO	MAPPING SINGLE FR/TO	MUL	N001	IMPACT N001*	VECTOR N002	N003	N004	NUMBER OF FAILURES K(N1)	K(N2)	K(N3)	K(N4)	SUM(KN)	FOUR COMP. BETA	GAMMA	SYS DELTA	3-COMP BETA	SYS GAMMA	2-C SYS BETA
784.4	. MOV	+	784.4				8.142		3.397	0.712	1.158											
	. SUM	4	784.4		NONE	1	8.142	792.542	3.397	0.712	1.158	792.542	6.794	2.135	4.630	806.100	1.68E-02	4.99E-01	6.84E-01			
	. B&P	3	MAPPEDFROM 4-COMP SYSTEM					596.105	2.232	1.335		596.105	4.464	4.006	---	604.575				1.40E-02	4.73E-01	
	. 4"	2	MAPPEDFROM 4-COMP SYSTEM					398.891	2.079			398.891	4.159	---	---	403.050						1.03E-02
55.1 2	RTB	+	55.1				0.000		1.100	0.000	0.000											
	. SUM	2	55.1	4/2	NONE	1	0.000	55.100	1.100			55.100	2.200	0.000	0.000	57.300						
	. B&P																					
	. 2"																					3.84E-02

	INFO	SIZE	FAIL's	MAPPING FR/TO	FR/TO	MUL	N001	N001*	N002	N003	N004	K(N1)	K(N2)	K(N3)	K(N4)	SUM(KN)	BETA	GAMMA	DELTA	BETA	GAMMA	BETA
103.8	. SRV (E!	+	103.8				3.600		2.000	2.000	0.400											
	OMIT EMRV	4	103.8		NONE	1	3.600	107.400	2.000	2.000	0.400	107.400	4.000	6.000	1.600	119.000	9.75E-02	6.55E-01	2.11E-01			
	. PWR	3	MAPPEDFROM 4-COMP SYSTEM					81.550	2.500	0.900		81.550	5.000	2.700	---	89.250				8.63E-02	3.51E-01	
	. 4"	2	MAPPEDFROM 4-COMP SYSTEM					56.033	1.733			56.033	3.467	---	---	59.500						5.83E-02
37	CHIL	+	37				0.068		0.050	0.005	0.000											
	. SUM																					
	. B&P	3	37 4/3		NONE	1	0.068	37.068	0.050	0.005		37.068	0.100	0.015	0.000	37.183				3.09E-03	1.30E-01	
	3	2	MAPPEDFROM 3-COMP SYSTEM					24.745	0.022			24.745	0.043	---	---	24.788 -						1.75E-03
33	. FAN	+	33				0.900		0.000	0.000	0.100											
	. SUM	4	33		NONE	1	0.900	33.900	0.000	0.000	0.100	33.900	0.000	0.000	0.400	34.300	1.17E-02	1.00E+00	1.00E+00			
	. B&P	3	MAPPEDFROM 4-COMP SYSTEM					25.425	0.000	0.100		25.425	0.000	0.300	---	25.725				1.17E-02	1.00E+00	
	. 4"	2	MAPPEDFROM 4-COMP SYSTEM					16.950	0.100			16.950	0.200	---	---	17.150						1.17E-02
	ALL	+	2671				14.759		7.296	6.470	5.377											
	SUM	4	2671		NONE	1	14.759	2685.759	7.296	6.470	5.377	2685.759	14.593	19.411	21.507	2741.270	[illegible]	[illegible]	5.26E-01			
	PWR	3	MAPPEDFROM 4-COMP SYSTEM					2017.967	8.501	6.994		2017.967	17.002	20.983	---	2065.953				1.85E-02	5.52E-01	
	4"	2	MAPPEDFROM 4-COMP SYSTEM					1350.979	9.828			1350.979	19.656	---	---	1370.635						1.43E-02

CC COMP GROUP	FOUR COMPO NENT SYSTEM BETA	GAMMA	DELTA		FACTOR*	THREE COMPONENT SYSTEM BETA	GAMMA		FACTOR*	TWO COMPONENT SYSTEM BETA		FACTOR*
AFW												
	1.5E-02	7.8E-[illegible]	5.3E-01									
	[illegible]	7.8E-01	5.3E-01	2/4	1.1E-03	1.4E-02	2.8E-01					
	1.5E-02	7.8E-01	5.3E-01	3/4	1.8E-03	1.4E-02	2.8E-01	2/3	5.0E-03	8.8E-03		
	1.5E-02	7.8E-01	5.3E-01	4/4	6.1E-03	1.4E-02	2.8E-01	3/3	3.9E-03	8.8E-03	2/2	8.8E-03
BR												
	--a--	0.0E+00	0.0E+00									
	0.0E+00	0.0E+00	0.0E+00			5.6E-02	9.3E-01					
	0.0E+00	0.0E+00	0.0E+00			5.6E-02	9.3E-01	2/3	1.9E-03	5.4E-02		
	0.0E+00	0.0E+00	0.0E+00			5.6E-02	9.3E-01	3/3	5.3E-02	5.4E-02	2/2	5.4E-02
CSP												
	--a--	0.0E+00	0.0E+00									
	0.0E+00	0.0E+00	0.0E+00			0.0E+00	0.0E+00					
	0.0E+00	0.0E+00	0.0E+00			0.0E+00	0.0E+00			7.2E-02		
	0.0E+00	0.0E+00	0.0E+00			0.0E+00	0.0E+00			7.2E-02	2/2	7.2E-02
CV												
	8.7E-03	7.4E-01	5.3E-01									
	8.7E-03	7.4E-01	5.3E-01	2/4	7.6E-04	5.8E-03	5.5E-01					
	8.7E-03	7.4E-01	5.3E-01	3/4	1.0E-03	5.8E-03	5.5E-01	2/3	1.3E-03	2.9E-03		
	8.7E-03	7.4E-01	5.3E-01	4/4	3.4E-03	5.8E-03	5.5E-01	3/3	3.2E-03	2.9E-03	2/2	2.9E-03
CWP												
	1.6E-03	7.8E-01	5.7E-01									
	1.6E-03	7.8E-01	5.7E-01	2/4	1.1E-04	1.4E-03	6.0E-01					
	1.6E-03	7.8E-01	5.7E-01	3/4	1.7E-04	1.4E-03	6.0E-01	2/3	2.9E-04	1.1E-03		
	1.6E-03	7.8E-01	5.7E-01	4/4	6.9E-04	1.4E-03	6.0E-01	3/3	8.6E-04	1.1E-03	2/2	1.1E-03

CC COMP GROUP	FOUR COMPO NENT SYSTEM BETA	GAMMA	DELTA		THREE COMPONENT SYSTEM BETA	GAMMA		FACTOR	TWO COMPONENT SYSTEM BETA		FACTOR
DG											
	--a--	0.0E+00	0.0E+00								
	0.0E+00	0.0E+00	0.0E+00		7.5E-03	1.6E-01					
	0.0E+00	0.0E+00	0.0E+00		7.5E-03	1.6E-01	2/3	3.2E-03	4.3E-03		
	0.0E+00	0.0E+00	0.0E+00		7.5E-03	1.6E-01	3/3	1.2E-03	4.3E-03	2/2	4.3E-03
HHP											
	--a--	0.0E+00	0.0E+00								
	0.0E+00	0.0E+00	0.0E+00		0.0E+00	0.0E+00					
	0.0E+00	0.0E+00	0.0E+00		0.0E+00	0.0E+00			3.2E-02		
	0.0E+00	0.0E+00	0.0E+00		0.0E+00	0.0E+00			3.2E-02	2/2	3.2E-02

CC COMP GROUP	FOUR COMPO NENT SYSTEM BETA	GAMMA	DELTA		THREE COMPONENT SYSTEM BETA	GAMMA		FACTOR	TWO COMPONENT SYSTEM BETA		FACTOR
HRP											
	--a--	0.0E+00	0.0E+00								
	0.0E+00	0.0E+00	0.0E+00		0.0E+00	0.0E+00					
	0.0E+00	0.0E+00	0.0E+00		0.0E+00	0.0E+00			2.1E-03		
	0.0E+00	0.0E+00	0.0E+00		0.0E+00	0.0E+00			2.1E-03	2/2	2.1E-03

CC COMP GROUP	FOUR COMPONENT SYSTEM BETA	GAMMA	DELTA			THREE COMPONENT SYSTEM BETA	GAMMA		FACTOR	TWO COMPONENT SYSTEM BETA		FACTOR
MOV												
	1.7E-02	5.0E-01	6.8E-01									
B&P	1.7E-02	5.0E-01	6.8E-01	2/4	2.8E-03	1.4E-02	4.7E-01					
	1.7E-02	5.0E-01	6.8E-01	3/4	8.8E-04	1.4E-02	4.7E-01	2/3	3.7E-03	1.0E-02		
	1.7E-02	5.0E-01	6.8E-01	4/4	5.7E-03	1.4E-02	4.7E-01	3/3	6.6E-03	1.0E-02	2/2	1.0E-02
RTB												
	--a--	0.0E+00	0.0E+00									
B&P	0.0E+00	0.0E+00	0.0E+00			0.0E+00	0.0E+00					
	0.0E+00	0.0E+00	0.0E+00			0.0E+00	0.0E+00			3.8E-02		
	0.0E+00	0.0E+00	0.0E+00			0.0E+00	0.0E+00			3.8E-02	2/2	3.8E-02

GROUP	BETA	GAMMA	DELTA			BETA	GAMMA		FACTOR	BETA		FACTOR
SRV (EMRV OMITTED)												
	9.7E-02	6.6E-01	2.1E-01									
PWR	9.7E-02	6.6E-01	2.1E-01	2/4	1.1E-02	8.6E-02	3.5E-01					
	9.7E-02	6.6E-01	2.1E-01	3/4	1.7E-02	8.6E-02	3.5E-01	2/3	2.8E-02	5.8E-02		
	9.7E-02	6.6E-01	2.1E-01	4/4	1.3E-02	8.6E-02	3.5E-01	3/3	3.0E-02	5.8E-02	2/2	5.8E-02
CHIL												
	--a--	0.0E+00	0.0E+00									
B&P	0.0E+00	0.0E+00	0.0E+00			3.1E-03	1.3E-01					
	0.0E+00	0.0E+00	0.0E+00			3.1E-03	1.3E-01	2/3	1.3E-03	1.7E-03		
	0.0E+00	0.0E+00	0.0E+00			3.1E-03	1.3E-01	3/3	4.0E-04	1.7E-03	2/2	1.7E-03
FAN												
	1.2E-02	1.0E+00	1.0E+00									
B&P	1.2E-02	1.0E+00	1.0E+00	2/4	0.0E+00	1.2E-02	1.0E+00					
	1.2E-02	1.0E+00	1.0E+00	3/4	0.0E+00	1.2E-02	1.0E+00	2/3	0.0E+00	1.2E-02		
	1.2E-02	1.0E+00	1.0E+00	4/4	1.2E-02	1.2E-02	1.0E+00	3/3	1.2E-02	1.2E-02	2/2	1.2E-02
ALL												
	2.0E-02	7.4E-01	5.3E-01									
PWR	2.0E-02	7.4E-01	5.3E-01	2/4	1.8E-03	1.8E-02	5.5E-01					
	2.0E-02	7.4E-01	5.3E-01	3/4	2.4E-03	1.8E-02	5.5E-01	2/3	4.1E-03	1.4E-02		
	2.0E-02	7.4E-01	5.3E-01	4/4	7.8E-03	1.8E-02	5.5E-01	3/3	1.0E-02	1.4E-02	2/2	1.4E-02

A	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
40																													
41	WORKSHEET FOR CECO COMMON CAUSE. POINT ESTIMATES FOR MGL FACTORS ZCC WK1																												
42		ORIG SYS S			N001	N002	N003	N004		F_MAP	RHO		MAP	TYPE	ID_R1	ID_R2	APPLIC.		S	SIZE	N000	N001	N002	N003	N004	RHO	PLANT	DATE	STATUS
43																	Z	D											

A	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC
81																													
82																													
83			3		0.000	0.890	0.110	0.000		*NONE			NONE	DG	1DG -06	2DG -09	A	A	C	3	0.000	0.000	0.890	0.110	0.000	0.7	Salem	July 1977	Power
84			3		0.000	0.900	0.100	0.000		*NONE			NONE	DG	1DG -07	2DG -06	A	A	C	3	0.000	0.000	0.900	0.100	0.000	0.7	Yankee Rowe	August 1977	Refueling
85			3		0.000	0.000	0.017	0.000		*NONE			NONE	DG	1DG -16	2DG -12	A	A	C	3	0.983	0.000	0.000	0.017	0.000	0.7	Quad Cities	May 1977	Power
86			8		0.733	0.025	0.000			*4to3	0.5		4->3	DG	1DG -24	2DG -02	A	A	C	8	0.000	0.930	0.070	0.000	0.000	0.5	Browns Ferry 1	January 1980	Refueling
87			3*		0.733	1.825	0.227	0.000			B&P		SUM	DG															
88																													

Attachment D

File ZCCROPWR.WK1

Diesel Generator CC Failure Data applicable to Zion based on review of EPRI NP-3967 and 9/90 draft EPRI Report.

Column C,T: System Size
Columns EFGH,UVWXY: Impact Vectors from references
Cells 87EFGH: Sum of Columns EFGH

A	AM	AN	AO	AP	AQ	AR	AS	AT	AU	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ	BK	BO
82					MAPP	ING																				
83		COMP			-----	-----				IMPACT	VECTOR			NUMBER	OF	FAILURES				FOUR	COMP.	SYS	3-COMP	SYS	2-C SYS	CC
84		VECT	SYS	SINGLE	VECTOR	SINGLE				-----	-----	-----	-----	-----	-----	-----	-----	-----		-----	-----	-----	-----	-----	-----	COMP
85		INFO	SIZE	FAIL's	FR/TO	FR/TO	MUL		N001	N001*	N002	N003	N004	K(N1)	K(N2)	K(N3)	K(N4)	SUM(KN)		BETA	GAMMA	DELTA	BETA	GAMMA	BETA	GROUP
86																										
87	3	DG	+	574.2					0.733		1.825	0.227	0.000													DG
88		SUM																								
89		B&P	3	574.2	4/3	NONE	1		0.733	574.933	1.825	0.227		574.933	3.650	0.881	0.000	579.264					7.48E-03	1.57E-01		
90		3*	2	MAPPED	FROM 3-	COMP SYSTEM				384.505	0.835			384.505	1.671	---	---	386.176							4.33E-03	
91																										
92																										

File ZCCROPWR.WK1

Diesel Generator MGL Factor Calculation

Cell AP87,89: Single Failures
Cells AU, AW, AX, AY: Sum of Impact Vectors from Data Cells 87E,F,G,H
Cell AV89: [(AP89 x AS89) + AU89]
Cell AV90: [(2/3 x AV89) +(2/3 x AW89)]
Column AZ = Column AV
Column BA = 2 x Column AW
Column BB = 3 x Column AX
Cell BD89: Sum AZ89 to BC89
Cell BD90: Sum AZ90 to BC90

Column BI: (Sum BA89 to BC89)/BD89

Column BJ: (Sum BB89 to BC89)/(Sum BA89 to BC89)

Column BK (Sum BA90 to BC90)/BD90

(8)

ZION IPE SECOND STAGE REVIEW: DEVELOPMENT OF SUCCESS CRITERIA
****

The NRC expressed interest in further information on the development of realistic success criteria for the Zion IPE. The discussion which follows relates the history of that process and describes the development of those criteria.

During the initial phases of planning the Edison IPE program, Edison elected to develop the "plant response tree" approach as opposed to employing classical event trees for the front and back end work. This decision was based on several considerations:

1. It was recognized that there exist strong interactions between the behavior of the primary system and of the containment. This is particularly true for the BWR plants. Edison had experience in using the classical modelling approach and was not satisfied that good modelling of these interactions was obtainable with the requisite confidence level even for its PWR plants with large, dry containments. The situation for BWR plants was judged to be even more difficult.

2. Edison, in a desire to be responsive to NRC guidance on modelling operator behavior, wanted a means to explicitly model the response of the control room staff to the new, symptom based EOPs in a way that would reflect the "symptoms" that staff would actually observe at any given point in an accident.

3. Edison, after some exploratory work with the MAAP code, knew that realistic refinement of success criteria was possible and that these criteria were very much time dependent.

The PRT structures, which evolved for Zion from these considerations, were constructed in an iterative process which involved determining the initial plant response to an initiating event, determining the minimum successful levels of system performance which prevented severe core damage at that point in time, establishing control room staff responses to that situation and associated system responses, again examining minimum acceptable levels of system performance as a function of time, and so on through each set of top events or nodes. A number of iterations were needed before the tree structure and success criteria were finalized for each PRT. Westinghouse was responsible for building the PRT's with careful review performed by Edison personnel experienced in Zion operations and design. Edison performed the MAAP code runs to investigate the timing of events and the minimal levels of successful system response. Westinghouse performed the review of that work.

The success criteria evolved using the MAAP code depended of avoiding severe core damage as defined for PRA applications, not classical licensing applications. In this context, Edison set the core peak nodal temperature limit to 1200 degrees F and allowed the evaluated temperature to exceed that value (for success) only if the analyses showed that the peak temperature decreased to much lower levels very quickly. Such a decrease indicated that decay removal was effected and that metal-water reactions were fully arrested.

Containment success criteria runs were much simpler, involving the heat removal functions of the fan coolers, sprays and RHR heat exchangers. Again, the MAAP code was employed to determine minimal successful system responses as a function of time for various sequences. Various combinations of systems responses were investigated where the PRT structure or investigation led to some interest. Containment capacity was investigated and found to be quite high, 147 psia. The plant response to various phenomenological issues was investigated in a series of separate evaluation papers along with consideration of relevant uncertainties. Only those issues found to be significant were included in the MAAP code evaluations.

In conclusion, the Zion IPE represents the most exhaustive investigation of success criteria performed to date and the most realistic. It couples careful consideration of EOP/operator responses, realistic thermal-hydraulic analyses, and realistic system responses all as a function of time into the event.

James T. Hawley
October 7, 1993

NRC Information Request - Zion IPE

Basis for Assigning the SAM Designator to SGTR Sequences

The technical basis for designating some SGTR (Steam Generator Tube Rupture) sequence endstates as SAM (Success with Accident Management) is a series of detailed calculations using the TREAT and MAAP codes. Attachments 1 and 2 document this technical basis.

Attachment 1 (pp. 0-42) is the Westinghouse Proprietary Class II Calc Note (CN-COA-92-106-R0) that formally documents the basis for assigning the SAM endstate designator to SGTR sequences. Attachment 1 consists of conservative hand-calcs and plots of key variables from supporting TREAT cases. Attachment 2 (pp. 0-11) consists of excerpts from a Westinghouse transmittal (DFH-91-015) related to determining SGTR success criteria that is cited as a reference in Attachment 1.

The approach taken in Attachment 1 is to conservatively determine an estimate of the time until the onset of core damage after a SGTR initiator occurs, assuming the operating staff follows the EOPs, but no recirc is possible and refilling the RWST does not occur. The time until core damage is estimated as the sum of the time to deplete the RWST plus the time to core damage after RPV injection due to RWST depletion. The latter time interval estimate is obtained from a MAAP run as 12 hr (see Case 11 plots in Attachment 2). The former time interval is estimated as the sum of three shorter time intervals: the time to overfill the ruptured steam generator plus the time to equilibrate ECCS and SGTR flows plus the time to deplete the remaining RWST inventory assuming the equilibrated ECCS flow persists indefinitely. These three time intervals are determined from TREAT runs as follows:

- The time to overfill the ruptured steam generator is estimated by dividing the mass required to fill the ruptured steam generator (see TREAT plots on pp. 35,36 of Attachment 1) by the average ECCS mass flow rate (see Case 9 plots in Attachment 2). Since the average ECCS mass flow rate used is for full ECCS injection, the resulting time to overfill the ruptured steam generator is the shortest possible and is taken to be 1 hr.

- The time to equilibrate ECCS and SGTR flows is estimated by using the TREAT code. Three possible cases are considered relating to the operational staff reducing ECCS injection per the EOPs. Case 1 assumes that ECCS flow is reduced to 2 SI pumps when the ruptured steam generator is overfilled and the ruptured steam generator safety valves stick fully open. The time interval to reach the equilibrium flow condition in this case is shown on the TREAT plots on pp. 32 and 33 of Attachment 1). Case 2 assumes that ECCS flow is reduced to 1 SI pump when the ruptured steam generator is overfilled and the ruptured steam generator safety valves stick 50% open. The time interval to reach the equilibrium flow condition in this case is shown on the TREAT plots on pp. 19 and 20 of Attachment 1). Case 3 assumes that ECCS flow is reduced to 1 SI pump when the ruptured steam generator is overfilled and the ruptured steam generator safety valves stick 25% open. The time interval to reach the equilibrium flow condition in this case is shown on the TREAT plots on pp. 25 and 26 of Attachment 1). All three cases determine a time to equilibrate ECCS and SGTR flows of about 2 hr.

- The time to deplete the remaining RWST volume is determined as follows. First, the volume remaining in the RWST when the ECCS and SGTR flows have equilibrated is determined by subtracting the volume injected by the ECCS pumps during the preceding two time periods from the initial RWST volume. This remaining water volume is then divided by the equilibrium flow rate from the TREAT plot (see plots on p. 33 for Case 1, on p. 20 for Case 2, and p. 26 for Case 3). Case 1 determines the time to deplete the remaining RWST volume as about 8 hr, while Cases 2 and 3 determine this time interval to be about 11 hr.

Given the preceding time intervals, Attachment 1 estimates the overall time to core damage for the three cases as follows:

- Case 1: 1 hr + 2 hr + 8 hr + 12 hr = 23 hr --> Core Damage

- Case 2: 1 hr + 2 hr + 11 hr + 12 hr = 26 hr --> Success with Accident Management

- Case 3: 1 hr + 2 hr + 11 hr + 12 hr = 26 hr --> Success with Accident Management

These estimates of core damage timing are considered to be conservatively early for the following reasons:

- Assuming maximum ECCS injection results in the earliest possible overfilling of a ruptured steam generator;

- Assuming ECCS injection flow is reduced when the ruptured steam generator is overfilled results in the largest possible depletion of RWST inventory prior to ECCS and SGTR flow equilibration;

- Assuming that ECCS injection flow is reduced to that of 1 SI pump rather than 1 Charging pump results in the largest equilibration flow and the shortest time to deplete the RWST inventory after ECCS and SGTR equilibration has occurred.

ATTACHMENT 1

CALC-NOTE NO. CN-COA-92-106-R0

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ATTACHMENT 2

EXCERPTS FROM DFH-91-015

Page 0 of 11

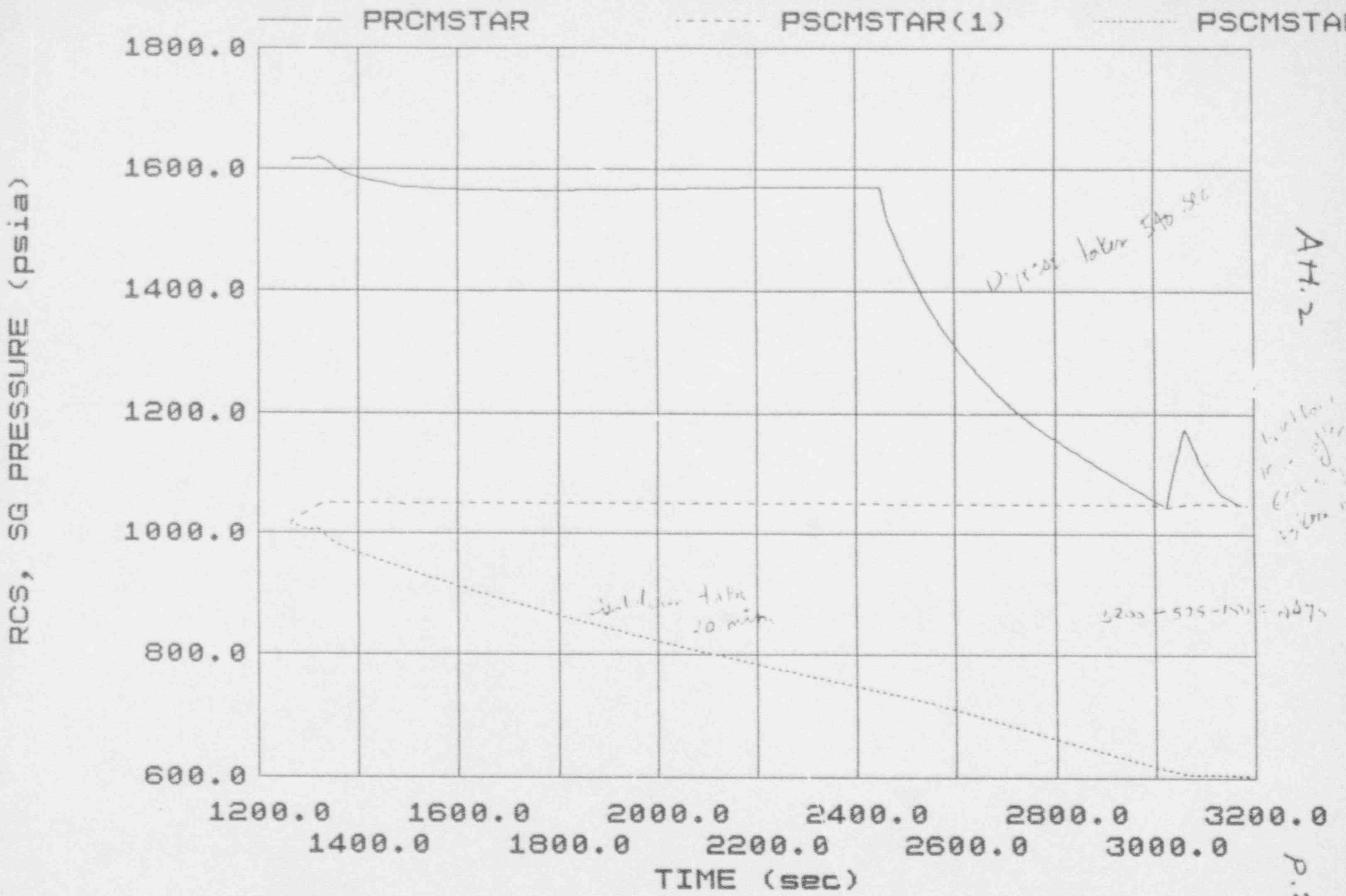
Att. 2, p. 1/11

CASE 9: ZION SGTR, ECCS & AFW ON, BEGIN OP ACTS @ 100% LEVEL, 1 ARV FOR RCS COOLDOWN, PRESSURE CONTROL AVAILABLE (ZTRE3.PLT)

This case was completed to track the progress of the E-3 operator actions and to develop the timing for the success criteria. Among the data excerpted from this case was timing, RCS cooldown rate w/ 1 ARV, RCS depressurization rate, time to terminate break flow after ECCS reduction. See addendum to Case 9 for details.

615
82

Att. 2

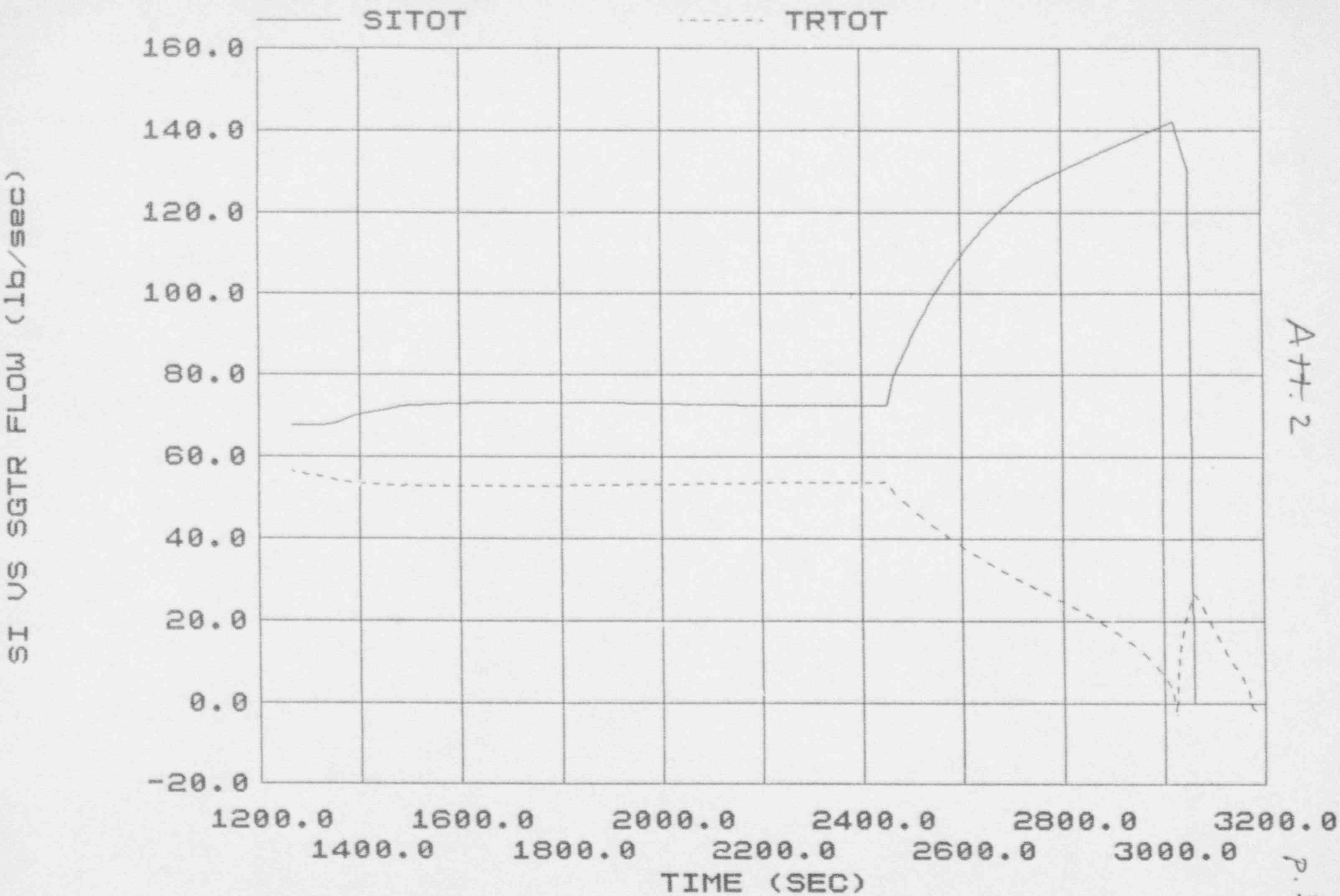


ZION SGTR: 1 ARV FOR COOLDOWN, OP ACTS @ 100% LVL

p. 3/11

10

Att. 2



ZION SGTR: 1 ARV FOR COOLDOWN, OP ACTS @ 100% LVL

p. 3/11.

CASE 11: ZION SGTR, NO ECCS, AFW ON, NO OPERATOR ACTIONS (ZSGTR_TEST_3A)

This case was a MAAP analysis to determine the time to core uncovery for a case with no ECCS, success of AFW and no operator actions. This case also was used to determine timing in which the RCS drains to top of tube sheet (break location), and following this (i.e., break uncovered) the time to core uncovery following all steam break flow.

```
1                  / 0=INTERACTIVE, 1=BATCH, 2=BATCH WITH SENSITIVITY OPTION
ZSGTR TEST 3A*
TUBE RUPTURE*
NO ECCS
1                  / 0=USE PARAMETER DEFAULTS, 1=USE SUPPLIED PARAMETER FILE
25                 / PARAMETER FILE I/O NUMBER
0                  / 0=NO PARAMETER FILE LIST,   1=LIST PARAMETER FILE
1                  / 0=NO LOCAL PARAMETER CHANGE, 1=LOCAL PARAMETER CHANGE(S)
13,39,5            / 13-STM GEN ,   39-BRK LOC       ,  COLD SIDE
13,40,4.0E-03      / 13-STM GEN,    40-BRK AREA      ,  1 TUBE = .775 IN ID
13,41,5.000E-01    / 13-STM GEN ,   41-BRK LOC       ,  TUBE SHEET + .5 FT
6,18, 0.000E+00    /  6-ENG SFGR,  18-NHPI           ,  1.000
6,19, 0.000E+00    /  6-ENG SFGR,  19-NLPI           ,  0.000
6,43, 0.000E+00    /  6-ENG SFGR,  43-NCHP           ,  1.000
6,21, 3460.        /  6-ENG SFGR,  21-ZHDHPI(1)     , 1515 PSIA
6,22, 692.         /  6-ENG SFGR,  22-ZHDHPI(2)     ,  315 PSIA
6,23, 427.         /
6,24, 231.         /
6,25,  0.         /
6,26,  0.          / 6-ENG SFGR, 26-WVHPI(1)       ,    0 GPM
6,27, 700.         /
6,28, 752.         /
6,29, 4109.        /
6,30, 6352.        /
6,45, 6000.        / 6-ENG SFGR, 45-ZHDCHP(1)      , SHUTOFF
6,46, 2307.        /
6,47, 1384.        /
6,48, 461.         /
6,49,  0.         /
6,50,   0.         / 6-ENG SFGR, 50-WVCHP(1)       , 0 GPM
6,51, 636.         /
6,52, 717.         /
6,53, 790.         /
6,54, 824.         /
6,13, 0            / 6-ENG SFGR, 13-NFN            ,
6,88, 3.000E+00    /  6-ENG SFGR,  88-NCSP          ,  3.000
6,159, 1.0500E+02/  6-ENG SFGR, 159-WVAFW(1)      ,  105       GPM
25,0,0            /ADD A PLOT FILE
PLOTFIL 77     / SGTR WATER AND GAS FLOWS
WWSB,WGSB
END
0,0,0.0000E+00     / NO MORE LOCAL PARAMETER CHANGE(S)
0                  / 0=INITIAL MAAP RUN, 1=RESTART MAAP RUN
0.0000E+00         / PROBLEM START TIME, HRS
25.000              / PROBLEM END TIME, HRS
25.000              / OUTPUT AND RESTART FILE INTERVAL, HRS,  INITIATOR(S) FOLLOW
209                / PS BREAK(S) FAILED
1                  / TRUE
238                / BYPASS CONTAINMENT
1                  / YES
0                  / NO (MORE) INITIATOR(S), INTERVENTION CONDITION(S) FOLLOW
11                 / INTERVENE ON: TRCHOT
1500              /  1500 DEG F
0                  / NO MORE INTERVENTIONS, OPERATOR ACTIONS FOLLOW
0                   / NO ACTIONS; STOP
12                / INTERVENE ON ELAPSED TIME
1                  / 1 HOUR
0                 / STOP
```

7 hrs after an steam line flow until core uncovery

5-10-81

So -

Lose ECCS: 5 hrs to drain to break location

+7 hrs to core uncovery

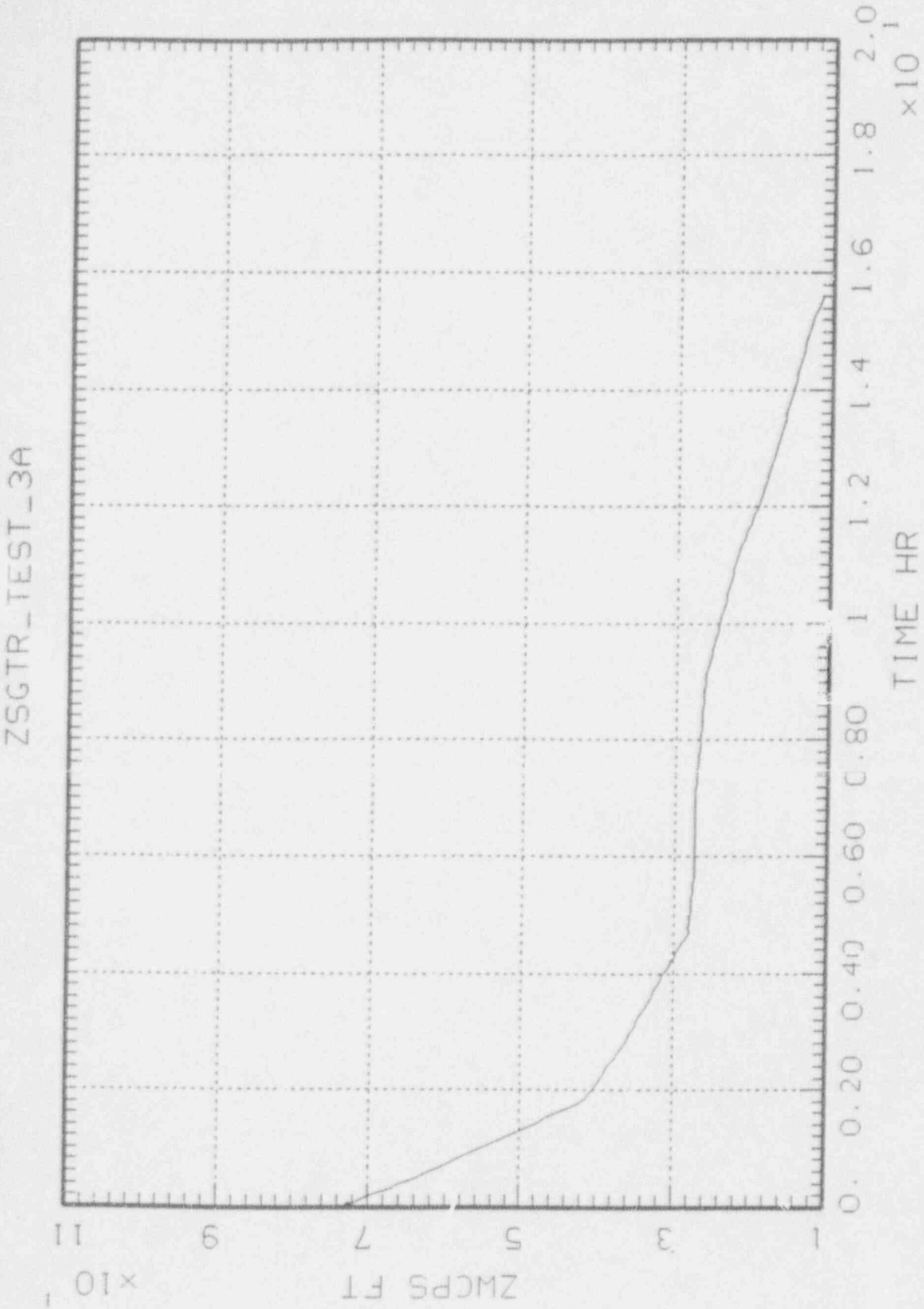
12 hrs.

Att. 2

p. 5/11

Att. 2

p. 6/11



ZSGTR_TEST_3A
TIME HR
×10^1
0. 0.20 0.40 0.60 0.80 1 1.2 1.4 1.6 1.8 2.0
ZWCPS FT
×10^1
1 3 5 7 9 11

$^{101}_{510}$

Att. 2

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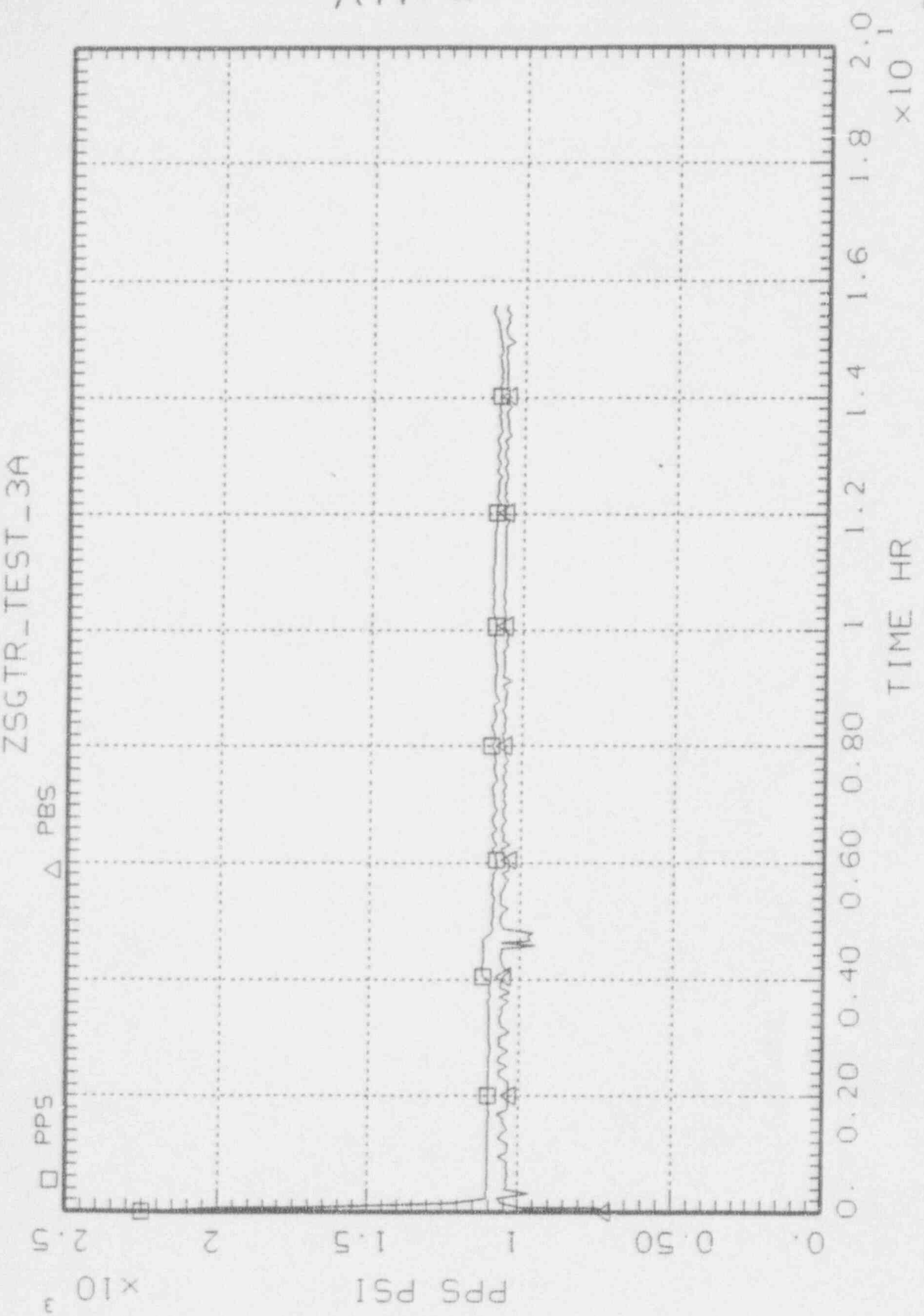
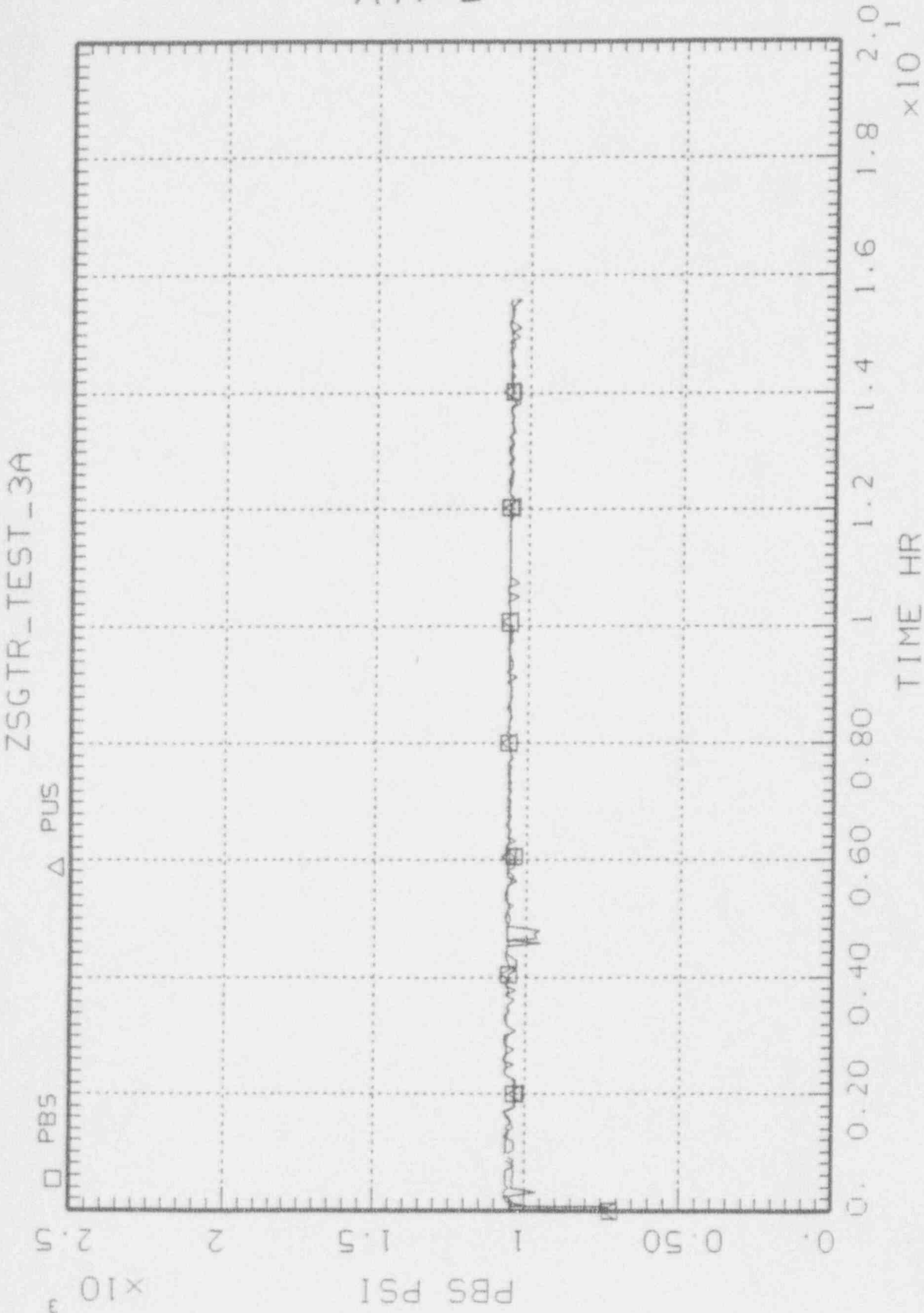


Att. 2

p. 8/11


ZSGTR_TEST_3A
PBS
PUS
TIME HR
PBS PSI
×10^1
×10^3
0. 0.20 0.40 0.60 0.80 1 1.2 1.4 1.6 1.8 2.0
0. 0.50 1 1.5 2 2.5

Att. 2

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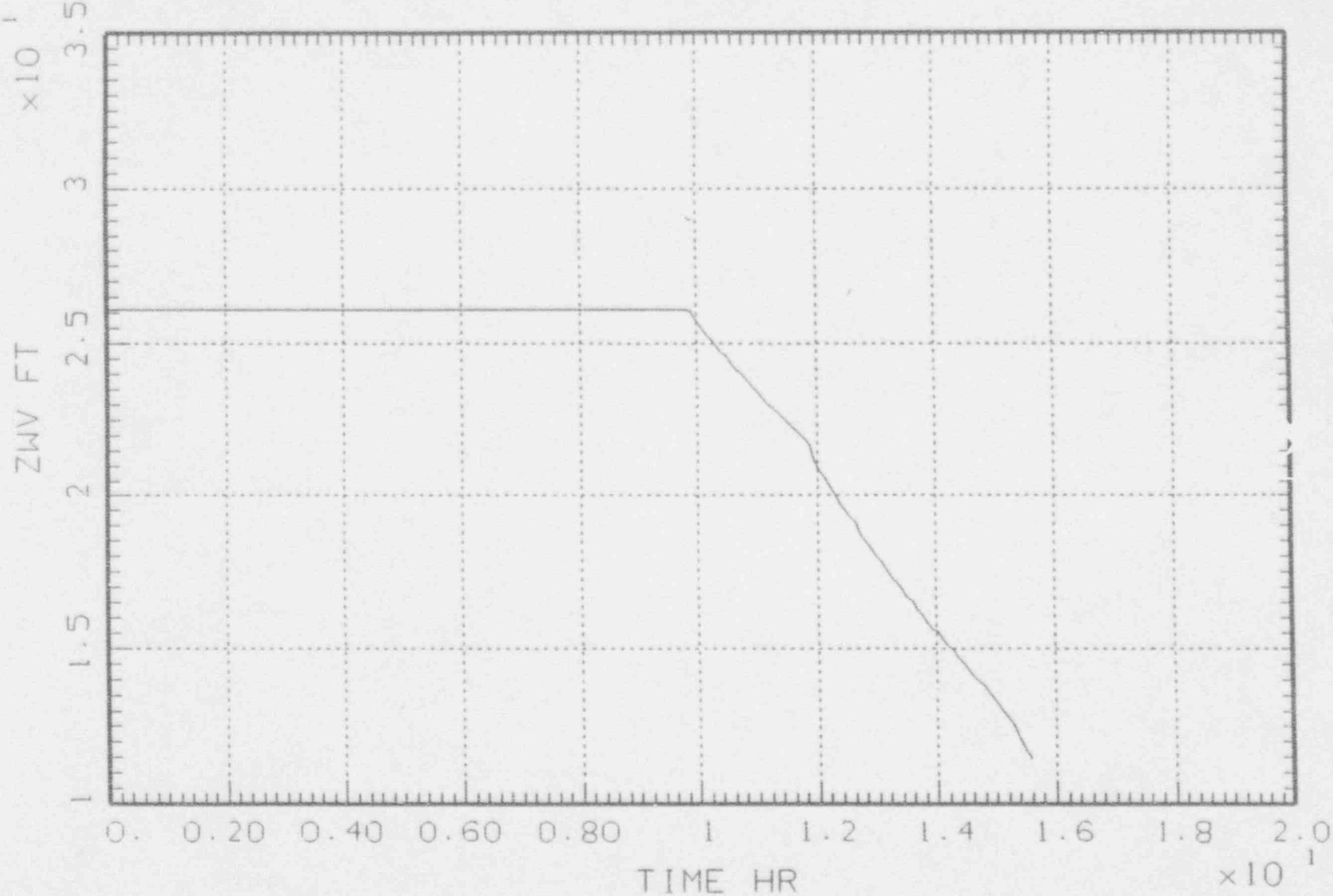
ZSGTR_TEST_3A



Att. 2

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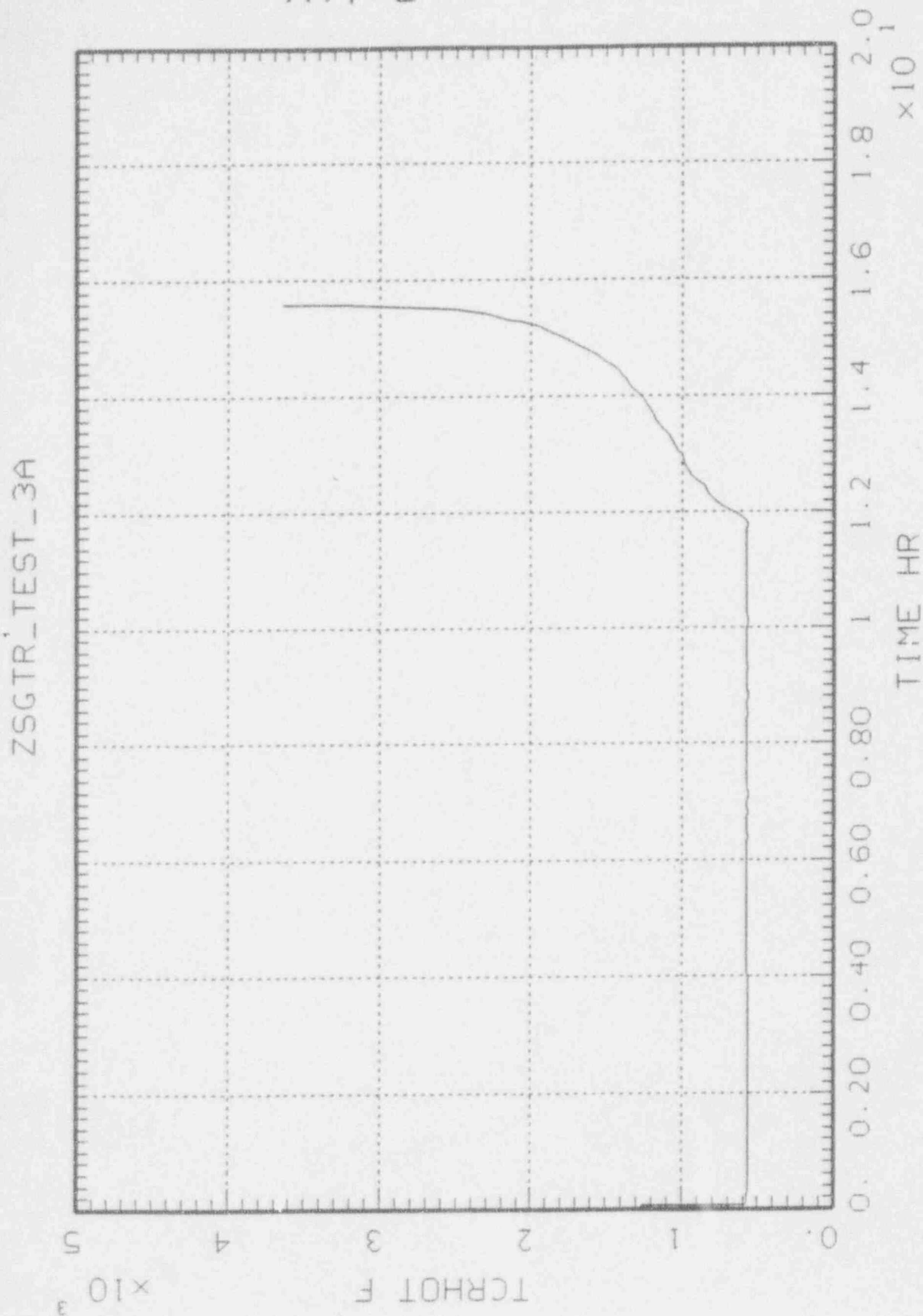

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Att. 2

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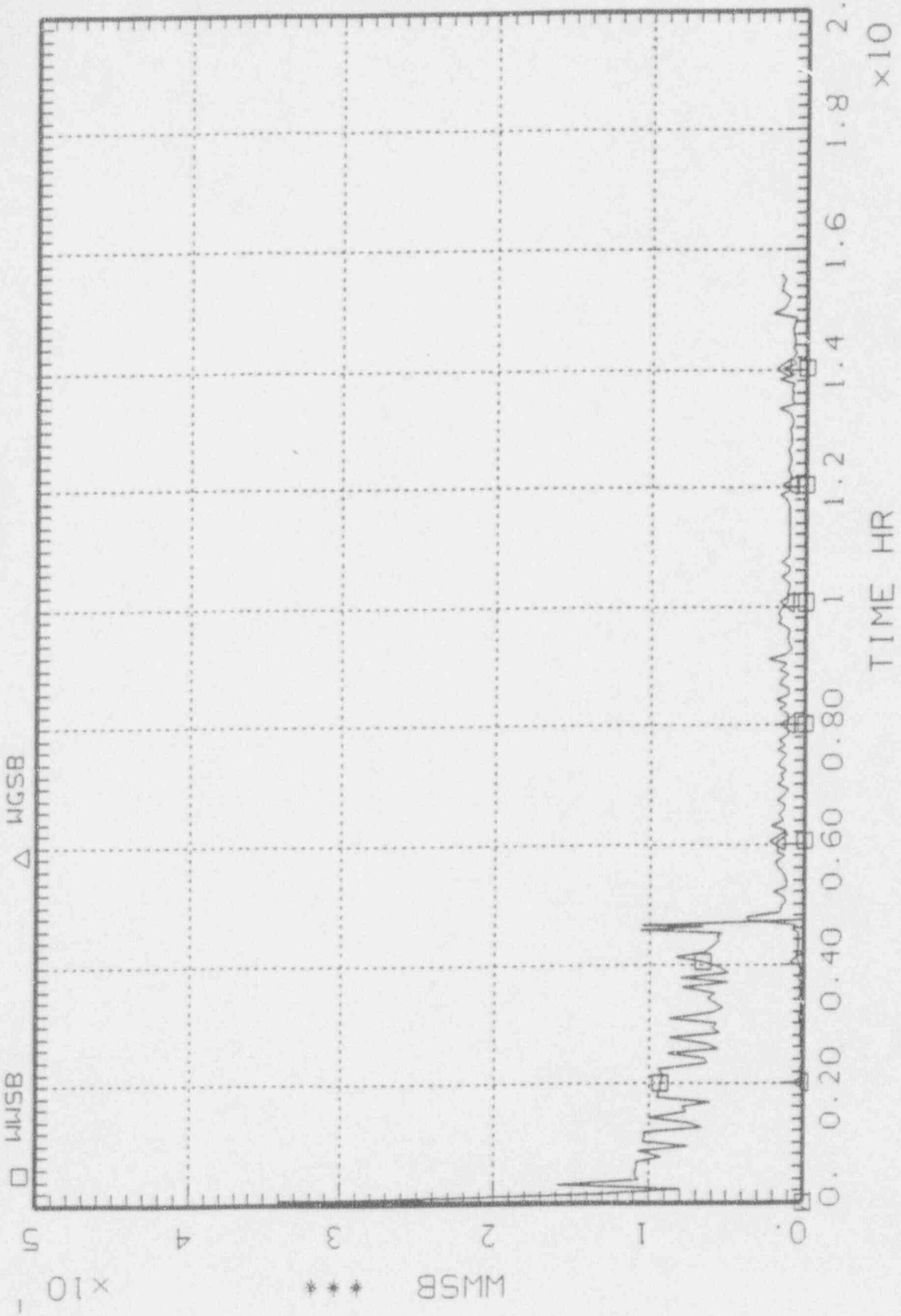

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