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Vol. 18

Precursors To Potential Severe Core Damage Accidents: 1992 A Status Report

Appendices B, C, D, E, F, and G

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Oak Ridge National Laboratory

Prepared for
U.S. Nuclear Regulatory Commission

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NOTE

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LIST OF ACRONYMS

ADS	automatic depressurization system
AEOD	NRC Office for Analysis and Evaluation of Operational Data
AFW	auxiliary feedwater
AIT	augmented inspection team
ASP	accident sequence precursor (program)
ATWS	anticipated transient without scram
BWR	boiling-water reactor
BWST	borated water storage tank
CAR	containment air recirculation
CC	containment cooling
CCP	centrifugal charging pump
CCW	component cooling water
CRD	control rod drive
CSR	containment spray recirculation
CST	condensate storage tank
DG	diesel generator
DHR	decay heat removal
DSDG	dedicated shutdown diesel generator
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFW	emergency feedwater
EHC	electrohydraulic control
EOP	emergency operating procedures
EPS	emergency power system
ESF	engineered safety feature
FWCI	feedwater coolant injection
FSAR	final safety analysis report
GOI	general operating instruction
HHSI	high-head safety injection
HPCI	high-pressure coolant injection
HPCS	high-pressure core spray
HPI	high-pressure injection
HPR	high-pressure recirculation
IA	instrument air
IC	isolation condenser
IEEE	Institute of Electrical and Electronics Engineers
IIT	incident investigation team
INPO	Institute of Nuclear Power Operation
IPE	Individual Plant Examination
LER	licensee event report
LOCA	loss-of-coolant accident
LOFW	loss of main feedwater
LOOP	loss of offsite power
LPCI	low-pressure coolant injection
LPCS	low-pressure core spray

LPI	low-pressure injection
LPR	low-pressure recirculation
LPS	liquid poison system
LWR	light-water reactor
MDAFWP	motor-driven auxiliary feedwater pump
MDEFWP	motor-driven emergency feedwater pump
MFW	main feedwater
MOV	motor-operated valve
MSIV	main steam isolation valve
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
NSSS	nuclear steam supply system
PCB	power circuit breaker
PCS	power conversion system
PORV	pilot- or power-operated relief valve
PRA	probabilistic risk assessment
PWR	pressurized-water reactor
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RHRSW	residual heat removal service water
RPS	reactor protection system
RPV	reactor pressure vessel
RV	relief valve or reactor vessel
RWCU	reactor water cleanup
RWST	refueling water storage tank
RY	reactor year
SCSS	sequence coding and search system data base
SDC	shutdown cooling
SG	steam generator
SI	safety injection
SLB	steam-line break
SLC	standby liquid control
SP	suppression pool
SRO	senior reactor operator
SRV	safety relief valve
SSF	safe shutdown facility
SSGFW	standby steam generator feedwater
SSMP	safe shutdown makeup pump
STS	standard technical specifications
SW	service water
TBS	turbine bypass system
TDAFWP	turbine-driven auxiliary feedwater pump
TDEFWP	turbine-driven emergency feedwater pump
UFSAR	updated final safety analysis report

APPENDIX B: PRECURSORS

B. PRECURSORS

B.1 Accident Sequence Precursor Program Event Analyses for 1992

This report documents 1992 operational events selected as accident sequence precursors.

Licensee Event Reports (LERs) describing operational events at commercial nuclear power plants were reviewed for potential precursors if:

(1) the LER was identified as requiring review based on a computerized search of the Sequence Coding and Search System data base maintained at Oak Ridge National Laboratory, or

(2) the LER was identified as requiring review by the NRC Office for Analysis and Evaluation of Operational Data.

Details of the precursor review, analysis and documentation process are provided in Volume 17 of this report (*Precursors to Potential Severe Core Damage Accidents: 1992, A Status Report*, NUREG/CR-4674, Vols. 17 and 18).

B.2 Precursors Identified

Twenty-seven precursors were identified among the 1992 LERs reviewed at the Nuclear Operations Analysis Center. These precursors constitute the total precursors for 1992. Events were identified as precursors if they met one of the following precursor selection criteria, and the conditional core damage probability estimated for the event was at least 10^{-6}:

(1) the event involved the total failure of a system required to mitigate effects of a core damage initiator,

(2) the event involved the degradation of two or more systems required to mitigate effects of a core damage initiator,

(3) the event involved a core damage initiator such as a loss of offsite power or small-break loss-of-coolant accident, or

(4) the event involved a reactor trip or loss of feedwater with a degraded safety system.

The precursors identified are listed in Table B.1:

Table B.1. Index of Precursors

Docket/ LER No.	Description	Plant Name	Core damage probability	Page
219/92-005	Loss of Offsite Power Due to Forest Fire	Oyster Creek	7.1×10^{-5}	B-6
247/92-007	Reactor Trip and Auxiliary Feedwater Pump Problems	Indian Point 2	3.6×10^{-6}	B-11
250/92-S01 & 251/92-S01	LOOP Due to Hurricane Andrew	Turkey Point 3 & 4	1.6×10^{-4}	B-17
251/92-007	Main Feedwater Pump Trip with One Auxiliary Feedwater Pump Out of Service	Turkey Point 4	3.1×10^{-6}	B-35
254/92-004 & -002	Reactor Trip With HPCI and One Safety Relief Valve Unavailable	Quad Cities 1	6.9×10^{-6}	B-40
261/92-013, -014, & -018	Safety Injection Pump Out of Service	H. B. Robinson 2	3.5×10^{-5}	B-49
261/92-017, -013, & -018	Loss of Offsite Power	H. B. Robinson 2	2.1×10^{-4}	B-57
269/92-004 & -005	Reactor Trip with One Emergency Feedwater Train Inoperable	Oconee 1	4.0×10^{-6}	B-65
269/92-008	Both Keowee Emergency Power Hydro Units Unavailable	Oconee 1, 2, & 3	2.8×10^{-6}	B-71
269/92-018	Both Keowee Emergency Power Hydro Units Potentially Unavailable	Oconee 1, 2, & 3	3.2×10^{-5}	B-79
270/92-004, 269/92-011, -014, -016, -019, & 93-001	Loss of Offsite Power with Failed Emergency Power	Oconee 2	2.1×10^{-4}	B-88
285/92-023 & -028	Reactor Trip with Faulty Pressurizer Safety Valve	Fort Calhoun	2.5×10^{-4}	B-105
286/92-011	Multiple EDGs Inoperable	Indian Point 3	1.2×10^{-6}	B-113
301/92-003	Plugged Safety Injection Pump Suction	Point Beach 2	9.9×10^{-6}	B-118
302/92-001 & -002	Loss of Offsite Power with Inoperable Vital Bus Inverter	Crystal River 3	1.7×10^{-5}	B-126
327/92-027	Loss of Offsite Power	Sequoyah 1 & 2	1.8×10^{-4}	B-137
328/92-010	Emergency Diesel Generator and Residual Heat Removal Pump Inoperable	Sequoyah 2	1.9×10^{-6}	B-142
344/92-020	Reactor Trip and Auxiliary Feedwater Pump Failure To Start	Trojan	5.9×10^{-6}	B-148
374/92-012	Reactor Trip with Degraded Reactor Core Isolation Cooling	LaSalle 2	6.1×10^{-6}	B-153

Table B.1. Index of Precursors

Docket/ LER No.	Description	Plant Name	Core damage probability	Page
388/92-001	Reactor Trip with Emergency Diesel Generator and Vital Bus Unavailable	Susquehanna 2	6.6×10^{-6}	B-160
483/92-011	Loss of Main Control Board Annunciators	Callaway	1.3×10^{-5}	B-167

B.3 Event Documentation

Analysis documentation and precursor calculation sheets (if applicable) for each precursor are attached. The precursors are presented by event type and in docket/LER number order.

For each precursor, an event analysis sheet is included. This provides a description of the operational event, event-related plant design information, the assumptions and approach used to model the event, and analysis results. Two figures are normally included. The first figure compares the significance of the event from a core damage standpoint with other potential events at the same plant. The other potential events at the same plant are briefly described below:

<u>PWR & BWR</u>

Trip	• Trip with equipment operable.
LOOP	• Loss of offsite power. Includes plant-centered, grid-centered, severe weather and extreme severe weather-related initiators.
360h EP	• 360 h without emergency power sources (normally on-site emergency diesel generators).

<u>PWR</u>

LOFW + 1MTR AFW	• Transient with loss of main feedwater and one motor driven AFW (or EFW pump failed (turbine driven pump substituted if plant does not have any motor driven pumps).
360h w/o AFW	• 360 hours with all AFW (or EFW) pumps failed.

<u>BWR</u>

360 h w/o HPCI and RCIC	• 360 hours with HPCI and RCIC failed (not applicable for Type A BWRs).
LOFW and HPCI	• Transient with loss of main feedwater and HPCI (loss of main FW and loss of Isolation Condensor is run instead for Type A BWRs).

The second figure highlights the dominant core damage sequence associated with the event. A conditional core damage calculation is also provided.

B.4 LER Number 219/92-005

Event Description: Loss of Offsite Power Due to Forest Fire

Date of Event: May 3, 1992

Plant: Oyster Creek

B.4.1 Summary

Oyster Creek lost offsite power for 5 min when a forest fire near the plant caused the offsite transmission lines to fault. The two emergency diesel generators (EDGs) operated as designed. Although offsite power was restored in 5 min, the emergency buses were supplied from the EDGs for 17 h until reliability of the offsite power supply could be assured. The conditional core damage probability estimated for this event is 7.1×10^{-5}. The relative significance of this event compared to other postulated events at Oyster Creek is shown in Fig. B.1.

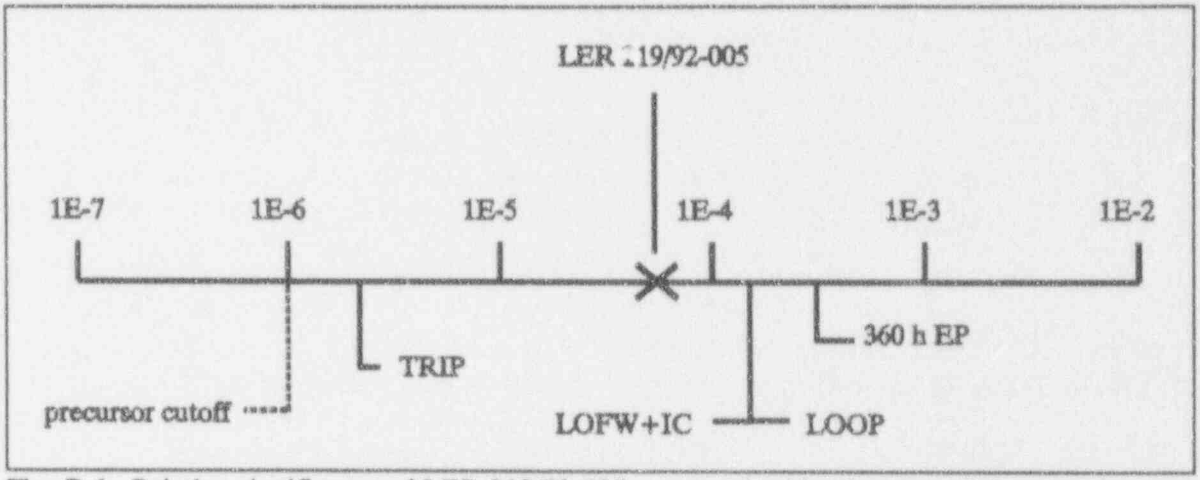

Fig. B.1. Relative significance of LER 219/92-005 compared with other potential events at Oyster Creek.

B.4.2 Event Description

On May 3, 1992, at 1310 hours, the control room at Oyster Creek was informed that a forest fire was burning to the west of the plant near the 230-kV offsite distribution lines. At 1326 hours, a full reactor scram occurred following the loss of the 230-kV lines. It is believed that the heavy smoke and heat from the fire ionized the air near the lines and caused the line to fault. The 34.5-kV supply was also lost and the result was a complete loss of offsite power (LOOP). The two EDGs started and loaded onto the two emergency buses (1C and 1D). However, control rod drive (CRD) pump A failed to start during the loading sequence because of high-resistance contacts in its time-delay relay. Offsite power was restored from the 34.5-kV system through the two startup transformers at 1331 hours, and the two nonemergency buses were reenergized. The plant staff questioned the reliability of the offsite supply due to the proximity of the fire to the station and the reduced number of offsite supply lines that were available. In addition, difficulties were encountered in transferring the emergency buses to offsite power. As a result, the emergency buses continued to be supplied from the two EDGs for another 17 h. By 0631 hours on May 4, 1992, the emergency buses were restored to their normal offsite supplies.

B.4.3 Additional Event-Related Information

Oyster Creek has three 230-kV supply lines and five 34.5-kV offsite lines. Two of the three 230-kV lines share double-circuit transmission towers. Normal operation is with two or three of the 230-kV lines and at least three of the 34.5-kV lines in service.

During startups and shutdowns, station power is supplied from the 34.5-kV system to the two startup transformers. During normal operation station power is supplied from the main generator through an auxiliary transformer and no loads are carried by the startup transformers. The two 4160-V emergency buses (1C and 1D) are normally supplied by the auxiliary transformer via the two nonemergency buses (1A and 1B). The EDGs associated with each emergency bus can supply power in case of a LOOP.

B.4.4 Modeling Assumptions

This event was modeled as a recoverable LOOP. To reflect the impact of the fire on the 230-kV lines and the extended time on the EDGs, nonrecovery probabilities for short-term and long-term ac power were developed by averaging the probabilities normally used for plant-centered and grid-related LOOPs. (See ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989). This calculation results in somewhat higher short-term and long-term nonrecovery probabilities when compared to the plant-centered LOOP model and gives credit for the startup transformers as a source of supply for the safeguards buses that was available but not utilized. The nominal LOOP includes the effects of extreme severe weather and severe weather induced LOOPs in addition to the plant-centered and grid-related LOOPs, with correspondingly higher nonrecovery probabilities. Therefore the core damage probability for this event is less than that for the nominal case.

The failure of the CRD pump to start during EDG loading was not addressed in the event model. This pump would have been manually started if required (operator action to start and align the CRD system is included in the branch model).

B.4.5 Analysis Results

The conditional probability of core damage estimated for this event is 7.1×10^{-5}. The dominant core damage sequence, highlighted on the following event tree in Fig. B.2, involves a LOOP with a postulated failure of emergency power and failure to restore ac power prior to battery depletion.

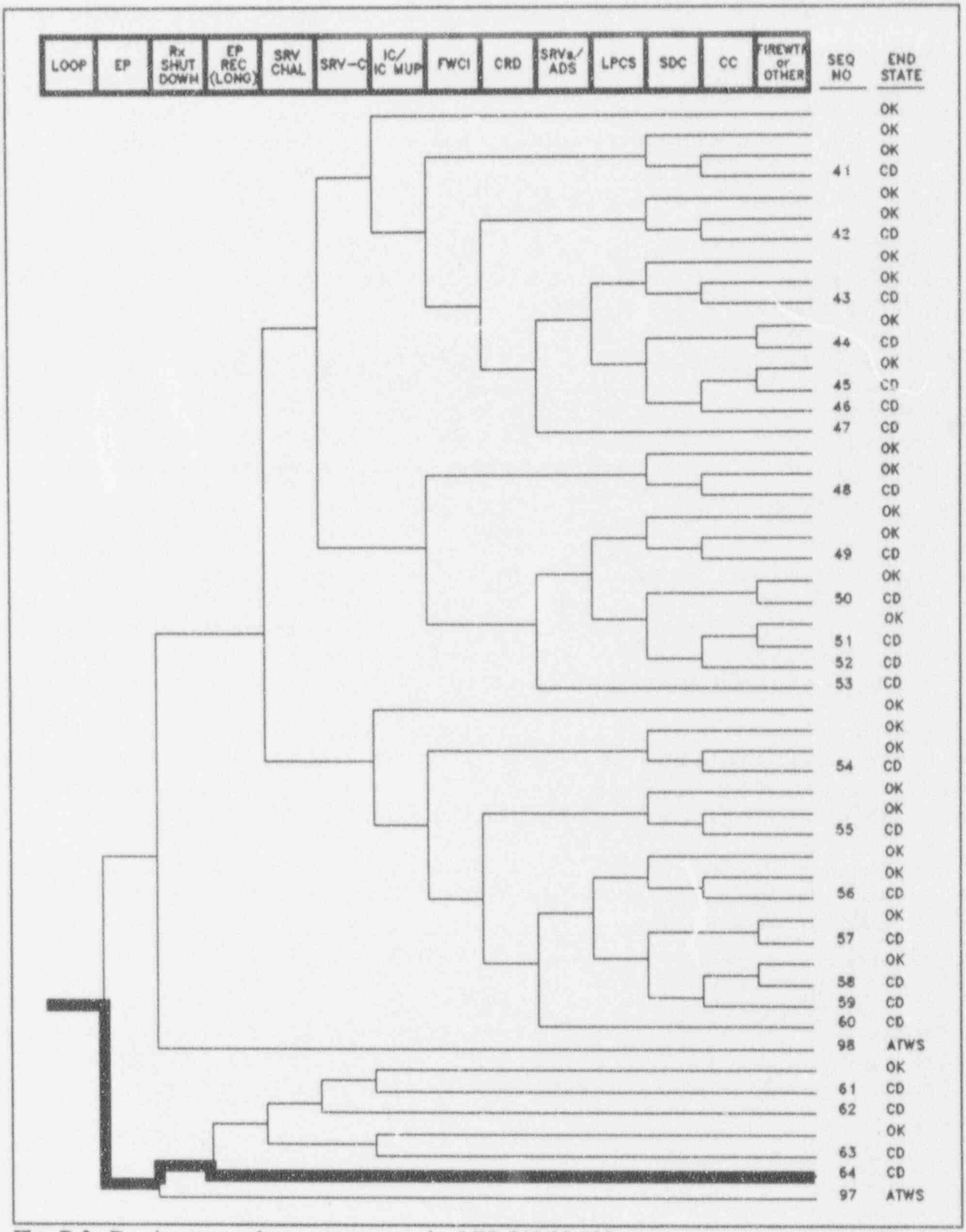

Fig. B.2. Dominant core damage sequences for LER 219/92-005.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 219/92-005
Event Description: LOOP Due to Forest Fire
Event Date: 05/03/92
Plant: Oyster Creek

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.9E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	7.1E-05
Total	7.1E-05
ATWS	
LOOP	1.2E-05
Total	1.2E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
64	LOOP emerg.power -rx.shutdown/ep EP.REC	CD	6.0E-05	3.1E-01
62	LOOP emerg.power -rx.shutdown/ep -EP.REC srv.chall/loop.-scram srv.close	CD	9.9E-06	3.1E-01
98	LOOP -emerg.power rx.shutdown	ATWS	1.2E-05	3.9E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
98	LOOP -emerg.power rx.shutdown	ATWS	1.2E-05	3.9E-01
62	LOOP emerg.power -rx.shutdown/ep -EP.REC srv.chall/loop.-scram srv.close	CD	9.9E-06	3.1E-01
64	LOOP emerg.power -rx.shutdown/ep EP.REC	CD	6.0E-05	3.1E-01

** non-recovery credit for edited case

SEQUENCE MODEL: C:\asppra\models\bwraseal.cmp
BRANCH MODEL: C:\asppra\models\oyster.sl1
PROBABILITY FILE: C:\asppra\models\bwr_csl1.pro

No Recovery Limit

Event Identifier: 219/92-005

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.6E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	3.6E-01 > 3.9E-01	
Branch Model: INITOR			
Initiator Freq:	1.6E-05		
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	1.2E-02	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
EP.REC	1.6E-01 > 6.8E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.6E-01 > 6.8E-02		
fw/pcs.trans	1.0E+00	1.0E+00	
fwci/fw.trans	2.9E-01	3.4E-01	
fwci/loop	1.0E+00	1.0E+00	
fwci/loca	1.0E-03	3.4E-01	
isol.cond	1.0E-03	1.0E+00	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
ipcs	3.0E-04	3.4E-01	
sdc	2.1E-02	3.4E-01	1.0E-03
cc/sdc	1.0E-03	1.0E+00	
firewater	1.0E+00	1.0E+00	2.0E-03

* branch model file
** forced

Event Identifier: 219/92-005

B.5 LER Number 247/92-007

Event Description: Reactor Trip and Auxiliary Feedwater Pump Problems

Date of Event: April 13, 1992

Plant: Indian Point 2

B.5.1 Summary

Indian Point 2 was operating at 100% power on April 13, 1992 when errors in returning a condenser hotwell to service after maintenance resulted in misleading hotwell level indication. Consequently, plant operators reduced hotwell level too far, resulting in insufficient suction supply to the condensate system and the main feedwater (MFW) pumps. When the MFW pumps began to experience symptoms associated with cavitation, operators recognized the problem and opened a condenser makeup valve in a 12 inch supply line from the condensate storage tank (CST). MFW pump suction was restored, but the plant tripped a short time later on high steam generator (SG) level. Both motor-driven auxiliary feedwater pumps (MDAFWPs) received auto-start signals; one started and tripped repeatedly and the other did not start. Investigation suggested that the auxiliary feedwater (AFW) pumps failed to successfully auto-start because of low pressure in their suction supply, which was provided from the same 12 inch header supplying the hotwell. The conditional core damage probability estimated for this event is 3.6×10^{-6}. The relative significance of this event compared to other potential events at Indian Point 2 is shown in Fig. B.3.

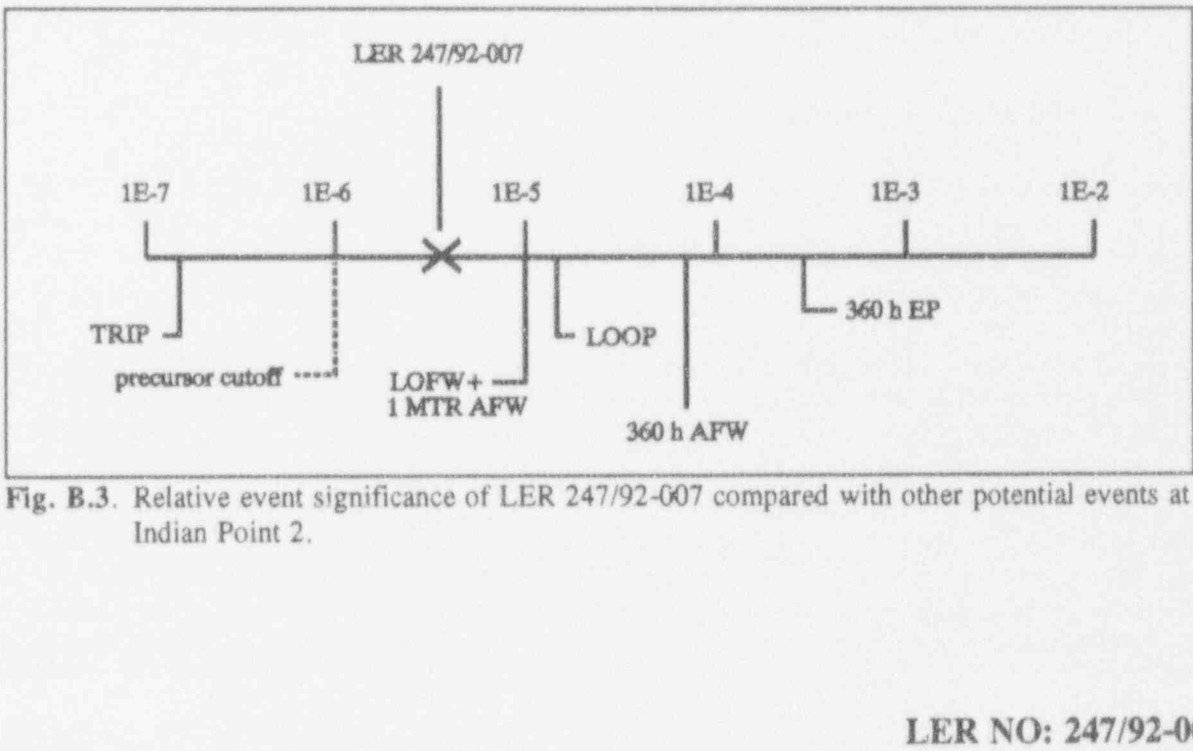

Fig. B.3. Relative event significance of LER 247/92-007 compared with other potential events at Indian Point 2.

B.5.2 Event Description

Indian Point 2 was operating at 100% power when the MFW pumps began experiencing high vibration levels, low suction pressures, and speed variations. As operators attempted to identify the cause, they stepped reactor power down to 25% in an effort to maintain SG levels. It was then recognized that a low hotwell level was causing insufficient condensate supply to the MFW pump suction header. Valve LCV-1128 was opened to refill the hotwell via a 12 inch line from the CST and MFW pump performance immediately began to improve. A short time later, high SG levels resulted in a reactor trip. MDAFWP 21 auto-started but immediately tripped. It subsequently restarted and tripped five additional times. Similar cycling was noted with control logic circuitry for the MFW pump 21 as well. MDAFWP 23 should have started but did not. The turbine-driven auxiliary feedwater pump (TDAFWP) was not demanded. A short time after the trip, LCV-1128 was closed and an attempt was made to manually start the MDAFWPs. This attempt was successful.

B.5.3 Additional Event-Related Information

Prior to the event, condenser hotwell 22B outlet valve CS-1-3 was isolated during tagout of the circulating water side of that condenser. Later, the tagout was lifted but CS-1-3 remained closed. This resulted in a false high level indication, and operators reduced hotwell makeup to compensate. Low hotwell level resulted, causing the condensate and feedwater system perturbations described. Operators opened LCV-1128 to quickly make up water to the condenser. This allowed the MFW system to promptly recover SG level; level in one SG increased sufficiently to result in a high SG level turbine and reactor trip. The normal suction supply for all AFW pumps at Indian Point is from the same line which was used to supply the hotwell. It is believed that the high flow rate to the condenser which existed during this event resulted in a low pressure in the AFW supply piping. In turn, it is thought that this caused AFW pump suction pressure switches to prevent successful auto-start of the pumps. It is unclear why cycling of the main feed pump control logic circuitry was observed.

B.5.4 Modeling Assumptions

Seventy-four seconds after the reactor trip, operators isolated the condensate makeup to the hotwell and apparently restored the AFW system to operability. Had they failed to do so, or delayed in doing so, it is possible that repeated start attempts could have resulted in damage to the AFW pumps. At Indian Point 2 a high SG level turbine trip and reactor trip result in a trip of the MFW pumps as well. It was reported that one MFW pump experienced control logic failures after the unit trip. The other feed pump was assumed to have tripped but recoverable. This event was modeled as a reactor trip with a recoverable loss of MFW and reduced availability of AFW. MDAFWP 21 started and tripped six times in approximately one minute. Multiple starts of a large electric motor within a short period of time may cause its circuit breaker to trip. Motor winding damage is also possible. While it is not known whether MDAFWP 21 experienced any motor winding damage during the event, the motor clearly operated in a manner inconsistent with good practices and it is possible that the manufacturer's recommended duty cycle was exceeded. Therefore, it is considered inappropriate to credit MDAFWP 21 as being fully available at its usual level of reliability during the balance of the event. In addition, operation of the TDAFWP at Indian Point requires manual intervention to align pump output to a steam generator.

It is believed that MDAFWP 23 did not auto-start during the event because of the low pressure experienced at its suction. Further, it is also believed that this condition would have cleared without operator intervention before the steam generator inventory was depleted. As there is no reason to question the pump's ability to perform its required function, MDAFWP 23 is credited as being fully available during the event. The AFW system model for this event consists therefore of one MDAFWP and one TDAFWP recoverable (or available with manual intervention) and one MDAFWP fully available.

Because cues existed to indicate the need to isolate LCV-1128, and because manual alignment of the TDAFWP was a proceduralized action, AFW recovery was assigned to ASP recovery class "R4" (Reference Vol. 17, Section A.1.3 of this report). This recovery class is appropriate when "the failure appeared recoverable in the required period from the control room and was considered routine or procedurally based." The nonrecovery likelihood for this class is 0.04.

In event of complete AFW failure, it may be possible at Indian Point to rapidly depressurize the plant secondary side to 400 psig and supply the steam generators with the condensate pumps. While limited information is available concerning the thermal hydraulics, reactor physics, human factors, and other issues related to this approach, an effort has been made to credit this strategy. As time to implement this strategy could be limited and operator burden could be significant, the nonrecovery for this event is assigned from class "R3", "The failure appeared recoverable in the required period from the control room, but recovery was not routine or involved substantial operator burden." Component failures are assumed to be negligible in comparison with the operator nonrecovery probability. The nonrecovery probability for this class, 0.12, was incorporated by adjusting the AFW nonrecovery probability.

B.5.5 Analysis Results

The conditional probability of core damage estimated for this event is 3.6×10^{-6}. The two dominant core damage sequences, highlighted on the following event tree in Fig. B.4, are associated with failures of MFW, AFW, and feed-and-bleed cooling. This event has been analyzed based on the information available in the referenced LER.

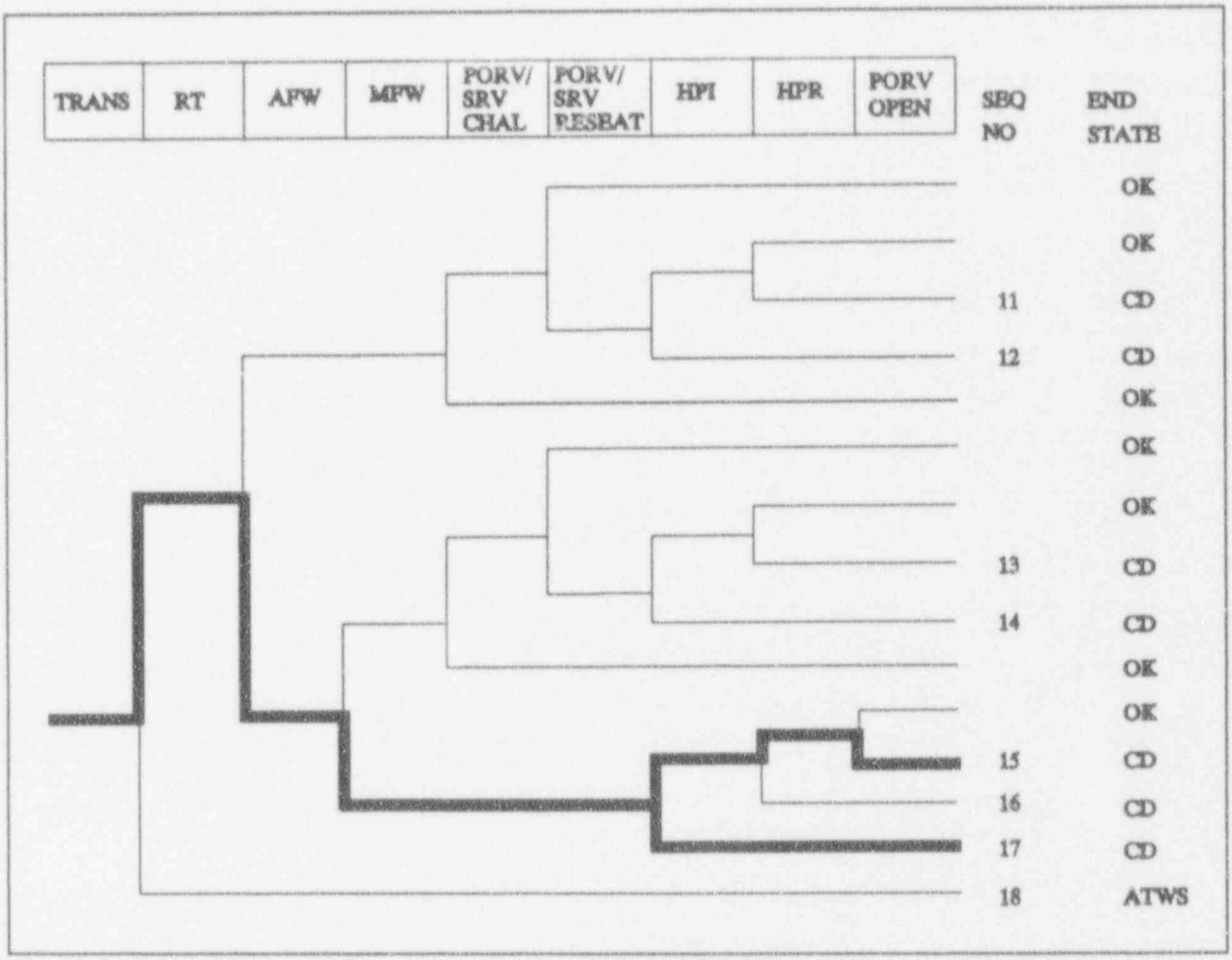

Fig. B.4. Dominant core damage sequences for LER 247/92-007

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 247/92-007
Event Description: Reactor trip and auxiliary feedwater pump problems
Event Date: April 13, 1992
Plant: Indian Point 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	3.6E-06
Total	3.6E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt AFW MFW -hpi(f/b) -hpr/-hpi porv.open	CD	1.7E-06	1.6E-03
17	trans -rt AFW MFW hpi(f/b)	CD	1.7E-06	1.4E-03
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	1.9E-07	1.6E-03
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt AFW MFW -hpi(f/b) -hpr/-hpi porv.open	CD	1.7E-06	1.6E-03
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	1.9E-07	1.6E-03
17	trans -rt AFW MFW hpi(f/b)	CD	1.7E-06	1.4E-03
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\models\pwrbseal.cmp
BRANCH MODEL: c:\asp\models\indpoint.sl1
PROBABILITY FILE: c:\asp\models\pwr_bsl1.pro

No Recovery Limit

Event Identifier: 247/92-007

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	4.6E-04	1.0E+00	
loop	3.1E-05	1.7E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	5.4E-04	8.0E-01	
AFW	3.8E-04 > 1.0E-01	2.6E-01 > 4.8E-03[1]	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02 > 1.0E+00		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02 > 1.0E+00		
Serial Component Prob:	2.8E-04		
afw/emerg.power	5.0E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > 1.0E+00		
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.1E-01	1.0E+00	
ep.rec(sl)	6.0E-01	1.0E+00	
ep.rec	5.6E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Notes:
1. SG depressurization credited by adjusting the AFW non-rec probability. See the modeling assumptions section for a description of this modification.

Event Identifier: 247/92-007

B.6 Identifier Number: 250/92-S01 and 251/92-S01

Event Description: Loss of Office Power Due to Hurricane Andrew

Date of Event: August 24, 1992

Plant: Turkey Point Units 3 and 4

B.6.1 Summary

On August 24, 1992, Hurricane Andrew, a Category 4 hurricane, struck the Turkey Point Electrical Generating Station with sustained winds of 145 mph. The storm caused a loss of offsite power (LOOP) which required the use of the emergency diesel generators (EDGs) for 6.5 d. Prior to the arrival of the storm, both units were shut down. The class I structures of the plant sustained essentially no damage. Damage to other equipment, including the offsite power supplies, offsite communications, on-site electrical distribution systems, fire protection system, and miscellaneous plant structures, complicated the recovery from the event. The conditional core damage associated with this event is 1.6×10^{-4} per unit. This event was of long duration and occurred while both units were shut down. The analysis of core damage risk from shutdown-related events has only recently begun in the nuclear industry. Issues that are important in estimating risk during shutdown, primarily human error and equipment repair over the long term, are not well understood. Because of this, core damage probability estimates developed for shutdown-related events, including this event, are not directly comparable to estimates developed for at-power events. Therefore, the relative significance of this event has not been compared to other postulated events using a relative significance graph.

B.6.2 Event Description

On Friday, August 21, 1993, site personnel began preparing for the potential arrival of Hurricane Andrew at Turkey Point. Preparations were guided by an Emergency Plan Implementing Procedure (EPIP). Most of the preparations consisted of removing equipment from outside areas, securing of equipment, and preparing for the storm surge. On Saturday, August 22, the operators completed simulator scenarios likely to occur during the hurricane. These included loss of instrument air, loss of residual heat removal (RHR), and loss of all ac power.

On Sunday, August 23, the National Hurricane Center issued a hurricane warning for the Turkey Point area. The utility declared an Unusual Event and began preparations for a Category 5 hurricane. At 1800 hours on August 23, a shutdown of Unit 3 began. The Unit 4 shutdown was started 2 h later at 2000 hours. The objective of the shutdowns was to place the units in Mode 4 (on RHR) prior to the onset of Hurricane winds. The units were placed in the shutdown (Mode 4) rather than cold shutdown (Mode 5) to retain the availability of the turbine driven auxiliary feedwater (AFW) pumps as an immediate backup for RHR cooling.

Operators were prepositioned in the EDG control centers for Units 3 and 4. Each of these are located in class I structures and are not accessible from other class I structures without going outside. As a result, personnel may not have been able to respond to abnormal EDG conditions during the storm unless they were prepositioned. By midnight, preparations were complete and all on-site personnel were located in class I structures.

The leading edge of the storm hit the Turkey Point site at about 0200 hours on Monday, August 24. Winds steadily increased from about 20 mph to 145 mph. At 0440 hours offsite power was lost to Unit 3. At 0522 hours, offsite power was lost to Unit 4. The EDGs automatically started and loaded for both units. Throughout the event, the plant remained in a stable condition. The plant vital areas were secure and were never jeopardized by the storm.

During the time period that offsite power was lost, the EDGs ran continuously to supply plant safety-related loads. An EDG tripped on two instances during this period. The "A" EDG for Unit 4 tripped during troubleshooting efforts to isolate a ground on the dc control power supply. The procedure was intended to be used when the bus was supplied by offsite power. The EDG was restarted after a few minutes and the procedure was revised. The "A" EDG for Unit 3 tripped 3.5 d after the storm. Troubleshooting to locate the cause of the trip was unsuccessful. The EDG was restarted 2.5 h later. No further problems were encountered.

By 0700 hours, the storm had passed and assessment of the damage began. During the storm offsite power had been lost. Restoration of offsite power took 4.5 d. The startup transformers for Units 3 and 4 were energized 6.5 d after the storm and the EDGs were shutdown. A second offsite line became available about one day later.

Two fossil plants, Units 1 and 2, are located adjacent to the two nuclear units (Units 3 and 4). Each fossil unit has a 400 foot reinforced concrete chimney. The chimneys were designed to withstand 150-mph winds. During the storm, the unit 1 stack sustained significant, visible damage. The Unit 2 stack, the closest to the nuclear units, suffered minor cracking but without any significant structural damage. The Unit 1 stack was subsequently demolished.

B.6.3 Additional Event-Related Information

The impact of Hurricane Andrew at Turkey Point is described in detail in a report jointly sponsored by the Institute of Nuclear Power Operations (INPO) and the Nuclear Regulatory Commission (NRC); NUREG-1474, *Effect of Hurricane Andrew on the Turkey Point Nuclear Generating Station from August 20-30, 1992*, March 1993.

B.6.4 Modeling Assumptions

The analysis addresses the potential to proceed to core damage for the conditions observed during the actual event: the hurricane-induced loss of offsite power (LOOP) occurred with both units shut down, depressurized below 350 psig, and on RHR cooling. Reactor coolant system (RCS) temperature was maintained between 200 and 350°F to facilitate prompt initiation of the turbine-driven AFW pumps for core cooling if RHR failed. All four EDGs auto-started and loaded following the LOOP. Any one of the four diesel generators and any one of the three AFW pumps was assumed capable of providing ac power and secondary-side makeup to both units. The event was initially modeled by NRC staff personnel. That analysis which used somewhat different assumptions is included as Attachment 1. Some of the conclusions from that assessment were utilized in this analysis.

An event tree model of the potential sequences to core damage during the 157 h that offsite power was unavailable is shown in Fig. B.5. Three core damage sequences are addressed:

- failure of RHR and AFW with emergency power available (both decay heat removal mechanisms unavailable);

- failure of emergency power (which fails RHR) with successful AFW and failure to recover ac power prior to core uncovery (AFW is assumed to fail following battery depletion and consequent loss of dc power if ac power is not recovered); and

- failure of emergency power (which fails RHR), failure of AFW, and failure to recover ac power.

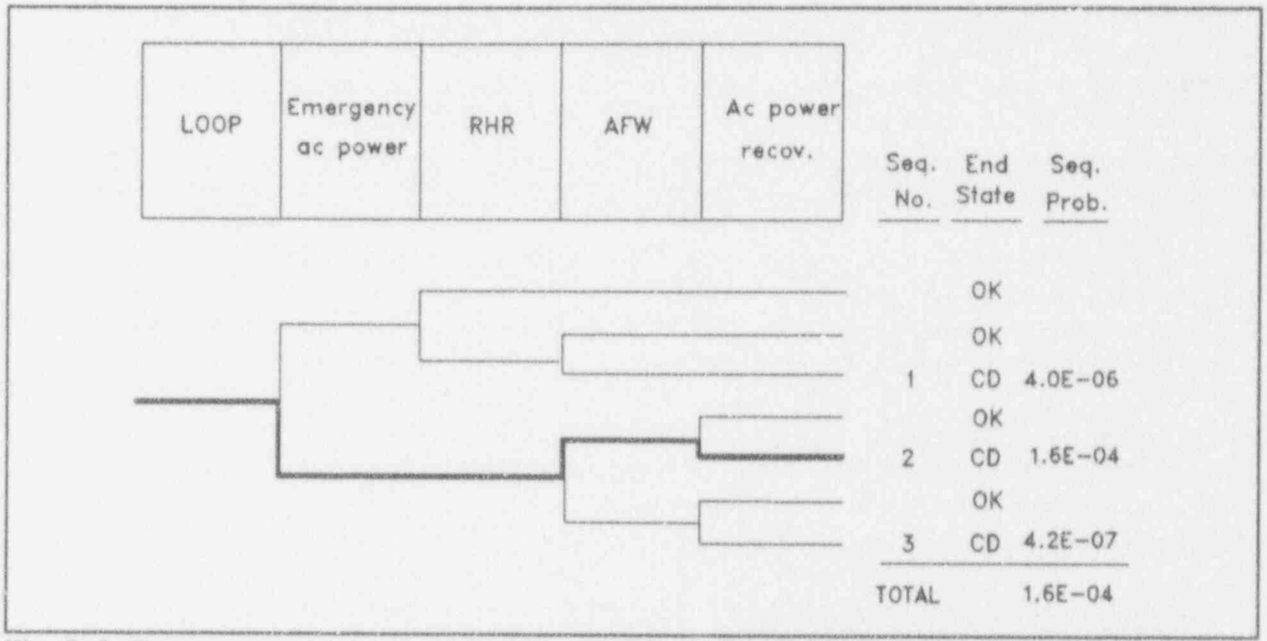

Fig. B.5. Event tree model for loss of offsite power at Turkey Point.

Development of conditional probabilities for the three sequences is described in the following paragraphs. Analysis assumptions which may result in over- or under-estimation of the conditional probability for the event are then discussed.

Sequence 1. Failure of RHR and AFW. RHR operated correctly during the event. However, because of the debris in the intake water at Turkey Point, the service water strainers required hourly cleaning. Errors during this process could have resulted in a loss of service water and a subsequent loss of RHR. If RHR was lost, the turbine-driven AFW pumps could have been used for core cooling. Failure of both RHR and AFW was estimated in the attached analysis to be approximately 4.0×10^{-7} over the 157-h period, assuming nominal RHR and AFW performance. Increasing the RHR system failure probability by an order of magnitude to account for the degraded service water system performance (caused by the excessive amount of debris in the intake water) results in a conditional probability estimate for the sequence of approximately 4.0×10^{-6}. This probability is low compared with the probability estimated for the second sequence. Therefore, although further mitigation strategies are potentially available to allow further time for RHR or AFW recovery (e.g., high-pressure injection (HPI) for feed and bleed), this sequence was not developed further.

Sequence 2. Failure of emergency AC power, AFW success, and failure to recover power before battery depletion and core uncovery. The analysis addressed the potential for emergency power failure caused by all four EDGs failing to start and all four EDGs failing to run. (The analysis described in Attachment A also considered the potential for emergency power failure caused by the postulated collapse of the Unit 2 (fossil plant) stack plus independent failures of the two remaining EDGs. Failure of emergency power due to this cause did not significantly contribute to the overall failure probability estimated in Attachment A and was not addressed herein.) If emergency power were to fail, it must be recovered before battery depletion, steam generator (SG) dryout, and RCS boil-off, to prevent core damage.

Time to core uncovery. Battery depletion was assumed to occur at 2 h, based on the data included in the Turkey Point FSAR. If the EDGs failed during the first day following the LOOP, secondary-side dryout and RCS boil-off to the point of core uncovery was estimated to occur ~10.5 h after battery depletion. The time to core uncovery was increased in proportion to the reduction in decay heat on subsequent days (loss of RCS inventory through the RCP seals and other leakage was assumed not to significantly affect these estimates).

EDG failure probability. The probability of an EDG failing to start (0.03) and failing to run (0.003/h) was estimated based on data included in NUREG/CR-4550, Vol. 1, Rev.1, *Analysis of Core Damage Frequency: Internal Events Methodology*, 1990. The value for failure to run is consistent with two EDG unavailabilities observed during the 6-d event.

The probability of all four EDGs failing to start was assumed to be dominated by common-cause effects. Utilizing the multiple Greek Letter (MGL) parameters included in NUREG/CR-5801, *Procedure for Analysis of Common Cause Failures in Probabilistic Safety Analysis*, 1993 ($\beta = 0.03$, $\gamma = 0.27$, and $\delta = 0.4$) results in an overall failure-to-start probability of 9.7×10^{-5}, without consideration of repair.

The probability of the four EDGs failing to run for the required period (157 h - time to core uncovery) was estimated by first calculating the probability that three of the four EDGs were failed and multiplying this value by the probability that the fourth EDG would fail and by the probability that none of the EDGs would be repaired before core uncovery.

Assuming EDG failure and repair are exponentially distributed, the unavailability of a single EDG at time t is $F(t) = [\lambda \times MTTR / (1 + \lambda \times MTTR)]\ [1 - \exp(-(\lambda + MTTR^{-1}) \times t]$ (see Martz and Waller, *Bayesian Reliability Analysis*, p. 154). In this equation, λ is the EDG failure rate and MTTR is the mean time to repair. The unavailability of the four combinations of three EDGs is therefore $4 \times [F(t)]^3$. The probability of the fourth EDG failing is $\lambda \times$ (157 h - time to core uncovery). The probability of not repairing any of the EDGs prior to core uncovery was estimated to be $[p(\text{single EDG not repaired before core uncovery})]^2$.[1]

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[1] p(no EDG recovered before core uncovery) was estimated in Attachment A as $p(\text{single EDG not repaired before core uncovery})^4$. This value is too small, because repair of the first three failed EDGs is addressed to a certain extent in $[F(t)]^3$. $p(\text{single EDG not repaired...})^1$ underestimates this value --

EDG Repair Probability. The spare parts and central receiving warehouses were severely damaged by the hurricane. Many of the spare parts that were in these warehouses were scattered and waterlogged. Some EDG spare parts were available -- the licensee noted in the telephone conversation with NRC and ORNL on November 30, 1993 that spare fuel filters were used during the 6-d period and that other spare parts had been identified after the storm. In an attempt to address the impact of the damaged warehouses, this analysis assumed that only one-half of repairs requiring spare parts could be accomplished with on-site spares and that the remainder of repairs required either the cannibalization of another failed unit or one of the non-safety-related black-start diesels (the bus used to provide power from these diesels to the safety-related buses was damaged during the hurricane) or the use of parts obtained from another site. The nominal probability of EDG non-repair as a function of time, shown in Table 1, was developed from data included in NUREG/CR-2989, *Reliability of Emergency AC Power Systems at Nuclear Power Plants*, 1983, plus supplemental data provided by a report author. This data was modified as follows to reflect the reduced availability of spare parts on-site:

a. EDG failures that could be recovered in 2 h or less were assumed not to require spare parts. Such repairs could be accomplished within their nominal repair times following the LOOP.

b. Repairs that required more than 2 h were assumed to require spare parts. Spare parts for half the potential repairs were assumed to be unavailable on-site. If these were obtained by cannibalizing another faulted EDG, repair times were increased by 50 percent (to disassemble the other EDG and obtain the part).

   If the spare parts were instead obtained from another site, the repair times were increased by 24 h. Repair personnel were assumed capable of choosing the most expeditious repair method -- the minimum of the two modified repair times was utilized. Note that a spare, truck-mounted EDG was brought on site after the second day. The estimated time to power a safety-related bus from this EDG is 24 h ame as the time estimated to obtain spare parts from another site. Because of this, the EDG was not specifically addressed in the analysis. Revised EDG repair probabilities as a function of time, based on these assumptions, are provided in Table 2 and is shown graphically for the first 30 h in Fig. 1.

c. During the first day following the LOOP, communications were non-existent to poor. Only repairs that did not require the shipment of spare parts from offsite were assumed possible in this period. The failure of four EDGs to start was assumed to be dominated by common-cause failures. Repairs that required cannibalized parts were not possible in this case, since similar parts were assumed failed on all four EDGs.

To address the variability in the time to core uncovery and EDG failure to run as a function of time since the start of the event, the conditional probability for sequence 2 was estimated for single-day increments throughout the 6-d period that offsite power was unavailable. The time to core uncovery, probability of

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repair of the three EDGs is assumed to continue after the fourth EDG fails (multiple EDG repair was assumed possible). p(no EDG repaired before core uncovery) was approximated by p(single EDG not repaired...)^3 in the analysis. This value recognizes some potential for repair of the first three EDGs, but is not overly optimistic.

not repairing an EDG before core uncovery, and MTTR wei : estimated as described earlier in this section. These estimates are given in Table B.2.

Table B.2. Estimates of parameters by 24 hour periods.

day (24 h increment)	time to core uncovery*	p(singie EDG not repaired)	MTTR
1	12.5 h	0.39 (0.86**)	48.4 h
2	14.7	0.32	42.2
3	17.9	0.27	42.2
4	20.2	0.26	42.2
5	22.7	0.24	42.2
6	24.7	0.22	42.2

*includes 2 h battery depletion time
**EDG common-cause failure to start

The probability of AFW success is about 1. This value was combined with the probability of AC power failure and the probability of not recovering AC power prior to core uncovery to estimate the conditional probability for sequence 2: p(AC power fails) × p(AFW success) × [p(EDGs fail to start) × p(failure to recover from failure to start prior to core uncovery) + p(EDGs fail to run for 157 h - core uncovery time) × p(failure to recover from failure to run prior to core uncovery)]. This calculation is shown in Table B.3.

Table B.3. Conditional core damage probability values for sequence 2

day (24 h increment)	p(AC power fails)	p(AFW success)	p(AC power not recovered)	p(cd)
start	9.7×10^{5}	~1	0.86	8.4×10^{5}
1	8.9×10^{4}	~1	0.15	1.3×10^{4}
2	9.6×10^{5}	~1	0.10	9.6×10^{6}
3	2.1×10^{4}	~1	0.073	1.5×10^{5}
4	2.9×10^{4}	~1	0.068	2.0×10^{5}
5	3.4×10^{4}	~1	0.058	2.0×10^{5}
6*	1.9×10^{4}	~1	0.048	9.1×10^{6}
			TOTAL:	1.6×10^{4}

*12.3 h

Sequence 3. Failure of emergency power and AFW, and failure to recover ac power before core uncovery. In this sequence, ac power must be recovered before SG dryout and RCS boil-off, about 2 h. The probability of this sequence can be estimated using the probabilities values described above, with an EDG non-repair probability at 2 h (0.84, from Fig. B.5). The probability of a non-recoverable failure-to-start or failure-to-run for the four EDGs in this case is 1.0×10^{-3}. Multiplying this value by the AFW failure probability estimated for Turkey Point in the ASP program (4.1×10^{-4})[1] results in a sequence conditional probability of 4.2×10^{-7}, not a significant contributor to the conditional probability estimated for the event.

Potential Sources of Over- and Under-estimation

A number of simplifying assumptions were made to facilitate the analysis. A precise estimate of the conditional probability associated with the event cannot be developed without the use of numeric methods, which are beyond the scope of ASP-type analyses. The assumptions and approach used in the analysis include the potential for over- and under-estimation. In many cases, the potential impact of these assumptions cannot be rigorously estimated. Principle contributors are discussed below.

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[1]The approach to system modeling used in the ASP program is described in Appendix A. For Turkey Point, the AFW system failure probability is assumed to be dominated by the common cause failure of the three turbine-driven AFW pumps and the failure to recover one pump in the short term: p(failure of the first pump) × p(common cause failure of second pump | first pump failed) × p(common cause failure of third pump | first two pumps failed) × p(failure to recover one pump) = 0.05 × 0.1 × 0.3 × 0.27.

EDG failure-to-start common cause probability. The analysis assumed that the four EDGs were subject to the same common-cause failure mechanisms. In actuality, two of the four EDGs were installed at a later date and are of a somewhat different design. These factors may reduce the significance of common cause failures during EDG start, and subsequently lower the combined failure-to-start probability for the four EDGs.

EDG failure-to-run probability. Most of the data associated with EDG failures to run was developed from short run durations (1 h to 24 h). EDGs are rarely run for greater than 24 h. Applying such data to the 157-h LOOP duration observed during the event may be conservative or non-conservative. However, the 0.003 failure rate used in the analysis is consistent with the two EDG trips observed during the 157-h period.

EDG failure-to-run common cause probability. The analysis did not address the potential for EDG common cause failures-to-run; all potential failures were assumed to be independent. Little data is available concerning EDG common-cause run time failures. Consideration of potential common cause failures would increase the conditional probability for the event.

The likelihood of EDG repair. The probability of failing to repair a faulted EDG was based on data included in NUREG/CR-2989. This data was modified to address the warehouse damage that occurred during the hurricane. The failure-to-repair distribution is quite skewed; the median repair time is approximately 8 h, while the MTTR is approximately 42 h. Thus, the probability of failing to repair an EDG is dominated by failures that would require long repair times. Prior to the arrival of Hurricane Andrew, personnel were stationed in both units' EDG control centers. This was to facilitate EDG recovery in the event of a failure. The control centers would not be accessible from other plant structures during the height of the storm. While this would increase the likelihood of short-term repair for failures that could be addressed without spare parts, access to the parts warehouse would be required for long-term repairs. Unfortunately, the hurricane severely damaged the Turkey Point parts warehouse. The damage to the parts warehouse reduced the likelihood of long-term repair.

The combined effect of these contributors to over- or under-estimating the core damage probability calculated for the event cannot be easily determined. For some contributors, such as common cause failure data, available information may not represent the actual plant design or the long run times required during the event. The effect of other contributors, such as the approach used to estimate the probability of multiple nonrecoverable EDG failures, could be better understood through more detailed modeling. However, the additional detail provided by such modeling is not expected to substantially impact the conditional probability estimated for the event.

B.6.5 Analysis Results

Combining the conditional probabilities for the three sequences described in Sect. B.6.4 results in an overall conditional probability estimate for the event of approximately 1.6×10^{-4}. This value is applicable to both units at Turkey Point (sequences 2 and 3 results in core damage at both units). The dominant core damage sequence is Sequence 2 on Fig. B.5, and involves a postulated failure of emergency power following the LOOP, successful AFW, and failure to recover emergency power prior to battery depletion and core uncovery.

Table B.4. Nominal probability of EDG non-repair

Time (h)	p(EDG repaired)
0.50	0.89
1.50	0.86
2.50	0.77
3.50	0.69
4.50	0.63
5.50	0.59
6.50	0.48
7.50	0.40
8.50	0.38
9.50	0.36
10.50	0.34
11.50	0.30
12.50	0.28
13.50	0.26

Time (h)	p(EDG repaired)
14.50	0.26
19.50	0.20
27.00	0.17
35.00	0.14
45.00	0.11
55.00	0.10
65.00	0.09
75.00	0.07
85.00	0.07
95.00	0.06
125.00	0.05
175.00	0.03
250.00	0.02
950.00	0.00

MTTR = 37.6

Table B.5. Probability of EDG non-repair utilized in the analysis

Time (h)	p(EDG repaired)
0.50	0.89
1.50	0.86
2.50	0.82
3.50	0.77
3.75	0.73
4.50	0.71
5.25	0.66
5.50	0.64
6.50	0.62
6.75	0.59
7.50	0.56
8.25	0.53
8.50	0.49
9.50	0.49
9.75	0.47
10.50	0.45
11.25	0.42
11.50	0.41
12.50	0.39
12.75	0.35
13.50	0.34
14.25	0.33
14.50	0.32
15.75	0.31
17.25	0.30
18.75	0.28
19.50	0.25
20.25	0.24
21.75	0.23
27.00	0.22
29.25	0.19
35.0	0.18
40.50	0.16
15.00	0.15
52.50	0.13
55.00	0.13
65.00	0.12
67.50	0.11
75.00	0.10
79.00	0.09
85.00	0.09
89.00	0.08
95.00	0.08
99.00	0.07
109.00	0.07
119.00	0.06
125.00	0.06
149.00	0.05
175.00	0.04
199.00	0.03
250.00	0.03
274.00	0.02
950.00	0.01
974.00	0.00

MTTR = 42.2

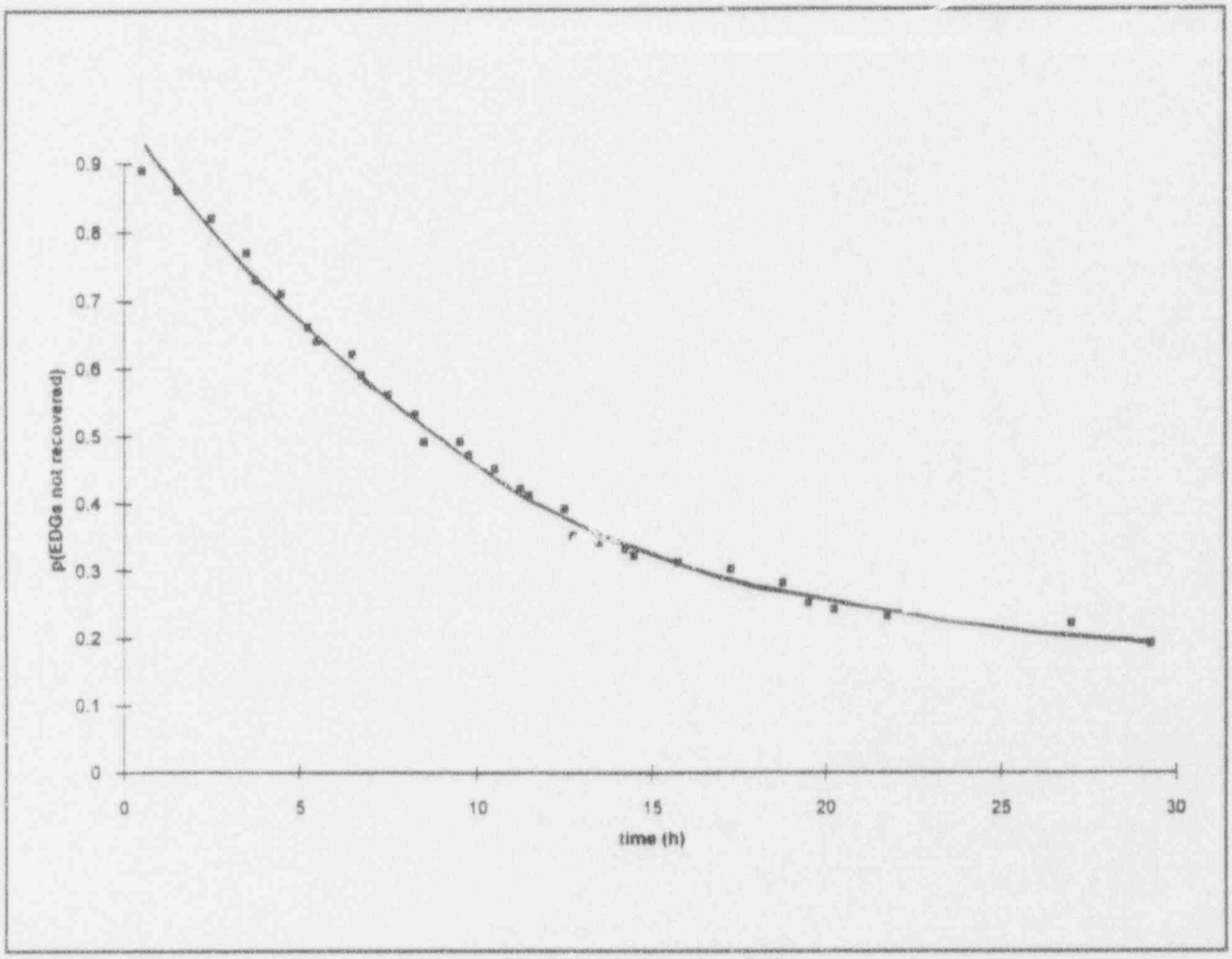

Fig. B.6. Probability of not repairing an EDG by time t (day 2-6)

Identifier NO: 250/92-S01 and 251/92-S01

Attachment 1 to 250/92-S01 and 251/92-S02

"Evaluation of the Risk Significance of the Impact of Hurricane Andrew on the Turkey Point Nuclear Power Plant"

By: S. Long, SPSB

IDENTIFIER NO: 250/92-S01 & 251/92-S01

EVALUATION OF THE RISK SIGNIFICANCE
OF THE IMPACT OF HURRICANE ANDREW
ON THE TURKEY POINT NUCLEAR POWER PLANT

S. Long, SPSB

INTRODUCTION

As Hurricane Andrew approached the Turkey Point Nuclear Power Plant in the early morning hours of August 24th, both units were shut down, cooled and depressurized below 350 psig, and placed on RHR cooling. Cooldown was intentionally stopped above 200°F and bubbles were maintained in the pressurizers to facilitate prompt initiation of (turbine-driven) auxiliary feedwater.

Storm damage to the switchyard and grid caused complete loss of offsite power, resulting in the automatic start and loading of all four emergency diesel generators. The five "black start" diesels located on site were covered with oil (from a damaged tank) and the "C" non-safety buses that could link these diesels to the safety buses were also damaged. Offsite power was not recovered for about 6 days.

Additional storm related damage of significance included:

- extensive cracking of the unit 1 stack, and minor cracking of the unit 2 stack (both are oil-fired units),
- extensive debris in the intake water, which necessitated cleaning the service water strainers every hour to prevent clogging,
- severe damage to the warehouses, which could have hampered recovery efforts if the emergency diesels required repair.
- loss of the station fire system, including damage to both raw water tanks and the fire header downstream of the fire pumps.

.The systems remaining operable for protection against core damage were:

- the four operating diesels, any one of which could power both units,
- two trains of RHR for each unit,
- the three operable turbine-driven AFW pumps, any one of which could provide secondary cooling to either unit so long as DC power remained available
- DC batteries, which are credited with capability for coping with 4 hours of station blackout and were being charged by the diesels.

Two sequences of additional equipment failures were considered for assessing the conditional core damage probability (CCDP) for this event:

1. Failures of all four emergency diesels creating a station blackout period exceeding at least six hours (to deplete the batteries, dry out the steam generators and boil down the RCS inventory sufficiently to expose the core), or

2. Failures of both RHR trains in one unit followed by failure of all three auxiliary feedwater trains.

CCDP CONTRIBUTION FROM DIESEL FAILURES

It was assumed for this analysis that the five non-safety "black start" diesels would not have been available if needed during this event.

Factors that are relevant, if not quantifiable, with respect to the probability of success for the onsite emergency power system include:

1. The diesels are cooled by radiators, and are thus not dependent on the service water system.
2. The fuel systems for the diesels are independent with the exception of the use of the same storage tank by EDGs 3A and 3B. (Fuel transfer systems, day tanks, etc. are provided separately for each diesel.)
3. EDGs 4A and 4B are physically located in a category 1 structure separate from the structure for EDGs 3A and 3B.
4. The severely damaged unit 1 (fossil-plant) stack is located where it could not have fallen on safety related equipment. However, the less severely damaged unit 2 stack could fall on either, but not both of the EDG buildings.

Three cases of EDG failure are considered below:

a. failure of all 4 EDGs to start,
b. concurrent failures of all EDGs while they are running,
c. collapse of the unit 2 smoke stack causing failure of 2 EDGs in combination with independent failure of the other 2 EDGs.

<u>Diesel failure to start:</u> Due to the potential for common cause failures, probabilistic risk assessment methods give reduced benefit to total system reliability for the addition of each similar train to a system. For early failures of the diesels at Turkey Point, the probabilities of failure to start, load or run for the first hour were taken from NUREG/CR-4550, Vol.1, Rev.1:

1st DG failure	= 0.03
failure of other 3 DGs given 1 failure	= 0.013

Failure to recover any one of the diesels was assumed = 0.6, giving a system failure-to-start estimate of about 2.3E-4.

Diesel failure to run: Because the diesels were required to run for long periods, it is also necessary to consider the probabilities of failures while running. Units 3 and 4 were on emergency diesel power for 154 hours and 157 hours, respectively. Generic data for failures while running ranges from 0.002/hour (NUREG-1150) to 0.003/hour (IREP). This results in failure probabilities of about 0.27 to 0.37 for each diesel during the extended run. The probability of multiple EDG failures is:

failures in 155 hours	failure rate 0.002/hour	failure rate 0.003/hour
0	0.29	0.16
1	0.42	0.37
2	0.23	0.33
3	0.06	0.13
4	0.005	0.02

The probability that no diesel would fail during this run is only about 0.29 to 0.16. It is more probable that there would be one DG failure, and almost as likely that two diesels would experience failures. In fact, EDG 3A was lost for 2 hours, 38 minutes due to a lockout on Thursday, August 27. Thus, the experience in this case is not inconsistent with the generic data.

The probability that all four EDGs would experience failures during this run duration is about 1E-2. However, as illustrated by the experience with EDG 3A, there is also a probability for recovery from each failure within a short period of time. Generic data for the mean time for recovery from failures is about 34 hours. (This is a very skewed probability distribution; the median time to recovery is only 8 hours.) In order to account properly for the CCDP due to DG failures while running, it is necessary to perform a time-dependent analysis that determines the probability that all four diesels would become inoperable at the same time for a period long enough to deplete the batteries (failing AFW), dry out the steam generators, and deplete the RCS inventory sufficiently to expose the core. The station batteries are rated at four hour capacity for coping with station blackout (SBO), and the time necessary to expose the core after AFW failure is estimated to be at least two hours at the beginning of the event. As the decay heat diminished over the duration of the LOSP condition, the time available for EDG repair significantly increased. However, it is difficult to capture these time-dependent complexities in the analysis, so several simplifying assumptions were made in order to produce an estimate of this portion of the CCDP.

The contribution to the CCDP from diesel failures while running was estimated with the formula

$$4 \times (\text{failure rate}) \times (\text{run time} - 6\ \text{hours}) \times (\text{failure rate} \times \text{mean time to repair})^3 \times (\text{nonrepair probability @ 6 hours})^4$$

This is the probability of the fourth diesel failing times the steady-state probability of three diesels being in the failed state times the probability that none of the four diesels will be recovered in 6 hours after this condition occurs. (Note that this analysis assumes no time-correlated common cause failures of the EDGs while they are running and that their repair probability is unaffected by the number of EDGs that are failed simultaneously.)

Because the reliability of diesels and their repair probabilities are poorly documented for periods exceeding 24 hours, calculations were performed to explore the sensitivity of this formula to its various parameters. For a failure rate of 0.003 per hour, a mean recovery time of 34 hours and a probability of nonrecovery within 6 hours of 0.6, the contribution to the CCDP is 2.5E-4. If the failure rate is assumed to be 0.002 per hour, the contribution would be 4.9E-5. If it is assumed that only one diesel can be repaired at a time, these numbers would increase by a factor of $1/(\text{nonrepair probability @ 6 hours})^3 = 4.6$. If the coping time was increased to allow repair within 20 hours, the probability of not recovering each diesel would decrease to 0.25, resulting in a decreased CCDP contribution by a factor of 33 (independent repair) to 2.4 (repair only one at a time). On the basis of these calculations, it was assumed that the contribution to CCDP from failures while running is about equal to the contribution from failures to start and load.

CONTRIBUTION OF POTENTIAL FOSSIL UNIT STACK COLLAPSE TO THE CCDP

The contribution of the potential unit 2 stack collapse to the CCDP is difficult to assess. If it fell on one of the structures housing two of the EDGs and caused both to fail, it would increase the failure to start probability to about 9E-4 and the failure while running probability to about 3E-2. Thus, in order to double the CCDP estimate presented above, the probability of the stack falling, hitting an EDG structure, and causing both EDGs to fail would have to be at least 1.7E-2.

Licensee and staff analyses indicate that failure of the unit 2 stack was not imminent. However, failure of the upper portion of the unit 1 stack may have been imminent. Discussion with Goutam Bagchi (ESGB) indicated that, having sustained the observed hurricane wind damage, credible values for the failure probability for the unit 1 stack were in the range of 0.5 to 0.9. Also, because nominal design and construction of these two stacks is presumably identical, this experience suggests a probability of about 0.5 that this hurricane could have damaged the unit 2 stack to the degree experienced by unit 1. Thus, the probability of the unit 2 stack falling may have been as high as (0.5-to-0.9 x 0.5), or 0.25 to 0.45.

It is unlikely that even the category 1 building housing EDGs 4A and 4B could withstand the impact of the stack. This makes the probable direction of fall very important. A telephone discussion with Mike Janus (one of the Resident Inspectors) gave some insights into the pattern of wind damage on-site. The wind blew nominally north-to-south before passage of the eye and approximately the opposite direction afterwards. The strongest winds occurred after passage of the eye. The elevated water tower and two elevated light towers which blew down all fell approximately northward. This indicates that the unit 2 stack, if it had been damaged and had fallen, would probably have fallen away from the diesel buildings rather than toward them. In addition, the stacks behavior during demolition indicated that it may have twisted to the east if

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it had fallen due to wind loading. Damage to other elevated light towers indicated generally northward leaning with a significant spread in direction. Therefore, under the conditions actually encountered in this storm, it seems unlikely that the unit 2 stack would have fallen in the direction of the EDGs. This is important, because the two EDG buildings occupy about one-fifth to one-tenth of the arc around the stack (depending on the interpretation of what constitutes a "hit"). Thus, if the direction of fall were assumed to be random, it would be the dominant risk contributor for this event. However, given the conditions observed, it appears that the potential stack failure does not make a significant contribution to the total CCDP.

It is logical to ask what is the conditional probability of a storm such as Andrew having a wind pattern that would cause the stack to fall toward the south. Although the necessary information is not available to answer that question precisely, it is useful to note some important factors. First, the hurricane would have to have a wind pattern that put the most intense winds on the leading side of the storm, so that they would blow southward. Second, the storm's forward speed would have to be such that winds would persist at the site for a sufficient time for the stack concrete to degrade and collapse before the wind changed direction. Although Andrew had neither of these attributes, they are not necessarily improbable for a class 4 hurricane.

In summary, the CCDP contribution from the unit 2 stack striking one of the EDG buildings, combined with independent failures of the other two EDGs, is not considered to be dominant for the conditions that actually occurred on site. However, it should be noted that collapse of the unit 2 stack could increase the total CCDP by an order of magnitude under other conditions that are perhaps equally probable for a class 4 hurricane.

Thus the total CCDP estimate for SBO sequences is estimated at about 5E-4, about half from failure to start and half from failure to run.

CONTRIBUTION FROM RHR PLUS AFW FAILURES TO CCDP

The RHR systems were initiated only a few hours before the storm arrived, and the service water system strainers required hourly cleaning after the storm's passage due to the debris that had been blown into the intake water. Had both trains of RHR failed on a unit, three trains of AFW were available to cool either reactor's steam generators. Thus, core damage would have required failure of two trains of RHR plus three trains of AFW. (It was assumed that the two motor-driven standby feedwater pumps would be unavailable because they receive power through the damaged C buses.)

Data developed by BNL for the probability of RHR failure at Surry indicates a system failure rate of only 7.3E-6 per hour. This gives a probability of 1.1E-3 that the system will fail in 157 hours. The current ASP models for Turkey Point provide an AFW system failure probability (with nonrecovery) of 4.1E-4 per demand. Thus, the probability that these two systems will cause core damage due to independent failures is only about 4E-7. The failure rate of the RHR system would have to be increased by about three orders of magnitude to make a significant contribution to the total CCDP.

Clearly, the contribution to the CCDP from this sequence of failures will be insignificant in comparison to those from potential EDG failures, unless the storm could cause common mode failures that would affect both RHR and AFW together.

OTHER CONTRIBUTORS TO THE CCDP

The Turkey Point IPE contains an analysis of risks due to hurricanes and the conclusion that storm surge is the only factor that contributes significantly. The mechanism is flooding of the safety bus switchgear when the surge exceeds the plant's flood protection elevation (20 feet). However, Hurricane Andrew did not produce a large surge. It was estimated at only 8 feet. As with the potential for the collapse of the unit 2 stack, no effort was made to calculate the conditional probability of a 20' storm surge, given a class 4 hurricane.

BENEFIT OF RECENT PLANT MODIFICATIONS

Recent modifications at the Turkey Point plant included the addition of EDGs 4A and 4B. Without these two additional sources of emergency AC power, the CCDP for this event would have been considerably higher. The formula used above to estimate the probability of a six-hour SBO with four EDGs would yield a value of about 3.3E-2 with only two EDGs (assuming a failure rate of 0.003/hour and independence of repair probabilities). Failure to start probability would be only about 9E-4 for two EDGs, on the basis of NUREG-1150 common cause factors. Thus, the addition of EDGs 4A and 4B appears to have reduced the CCDP associated with this event by a factor of about 70.

Addition of EDGs 4A and 4B also made the plant much more robust with respect to the CCDP contribution from the unit 2 stack, although that was not a significant factor for this particular event due to the direction of the strongest winds.

B.7 LER Number 251/92-007

Event Description: Main Feedwater Pump Trip with One Auxiliary Feedwater Pump Out of Service

Date of Event: September 29, 1992

Plant: Turkey Point 4

B.7.1 Summary

Turkey Point 4 was in startup at 2% power on September 29, 1992 when an operating main feedwater (MFW) pump tripped. This resulted in automatic actuation of the auxiliary feedwater (AFW) system. However, one AFW pump was out of service for post-maintenance testing. The remaining AFW pumps started and operated as designed. The conditional probability of subsequent core damage estimated for this event is 3.1×10^{-6}. The relative significance of the event compared to other postulated events at Turkey Point 4 is shown in Fig. B.7.

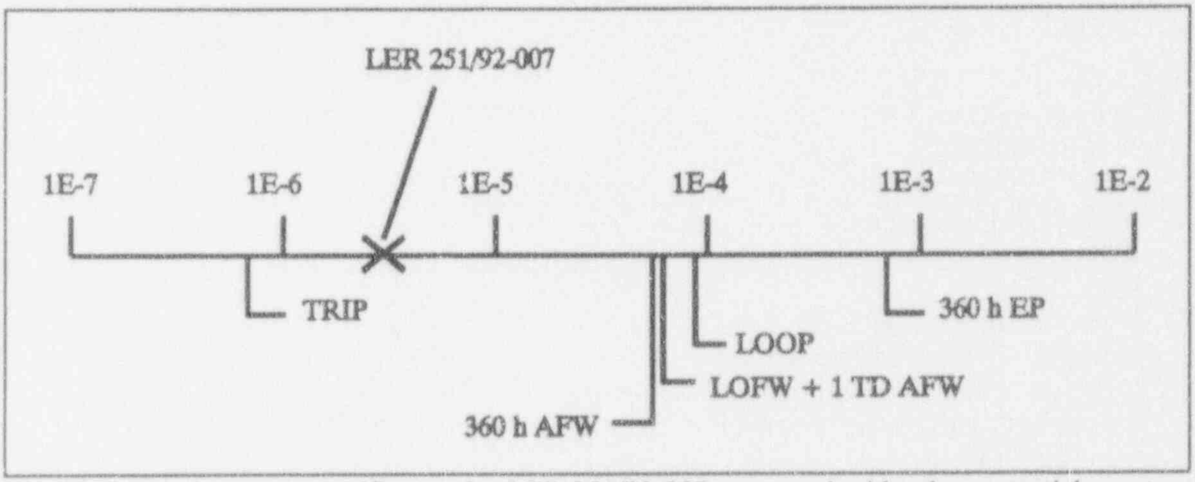


Fig. B.7. Relative event significance for LER 251/92-007 compared with other potential events at Turkey Point 4.

B.7.2 Event Description

On September 29, 1992, Turkey Point 4 was in startup at 2% power. During performance of a condensate polisher backwash evolution, the inlet valve on the 4D condensate polisher opened. This allowed the running 4A MFW pump suction pressure to be relieved through the 4D polisher vent valve to the backwash receiver tank. As a result, the 4A MFW pump suction decreased below the trip setpoint, and the pump tripped. The trip of the 4A MFW pump resulted in an automatic AFW start and isolation of the steam generator blowdown. The B AFW pump was out of service for post-maintenance testing at the time of the MFW pump trip. The A and C AFW pumps started as designed and provided feedwater flow to the steam generators. The reactor did not trip, since it was operating below the 10% power trip setpoint. Approximately 30 min after the trip of the MFW pump, the A motor-driven standby steam generator feedwater (SSGFW) pump was started, and the running AFW pumps were secured.

B.7.3 Additional Event-Related Information

The Turkey Point 4 AFW system consists of three 100% capacity steam-driven AFW pumps that are shared with Turkey Point 3. In addition, the plant has a standby steam generator feedwater system consisting of two 100% capacity motor-driven pumps. The AFW system is safety-related. Although the SSGFW system is not safety-related, it is provided power from multiple on-site and off-site power sources.

B.7.4 Modeling Assumptions

This event has been modeled as a nonrecoverable loss of feedwater with one turbine-driven AFW pump unavailable. The SSGFW system was included in the modeling of the MFW system. The MFW system failed and was not recoverable. Therefore, it has a failure probability of 1.0. The SSGFW system success requires one of the two pumps and realignment of one valve. An operator failure rate of 0.01 was assigned. Usually this operator failure rate is assigned to HPI feed-and-bleed since it is usually the first proceduralized response to a loss of MFW and AFW. However, for Turkey Point, the SSGFW system is placed into service prior to attempting feed and bleed. The probability assigned to the SSGFW system is as follows.

System Failure Probability	$= (\text{PMPA} \times \text{PMPB}) + \text{VLV1}$
	$= (0.01 \times 0.1) + 0.0004$
	$= 0.001$
Operator Failure Probability	$= 0.01$
Total System Failure Probability	$= 0.011$

Since the operators will attempt to use the SSGFW system prior to feed-and-bleed, the operator failure rate for initiating feed-and-bleed is increased. The failure rate used by the licensee in the Turkey Point PRA is 0.2. This value was also used in this analysis. This accounts for the time delay in attempting to use feed-and-bleed caused by attempting to use the SSGFW system first.

The event was conservatively analyzed with the assumption that it had occurred at power, although it actually occurred at low-power startup conditions when decay heat loads are lower.

B.7.5 Analysis Results

The conditional core damage probability for this event is estimated at 3.1×10^{-6}. The dominant core damage sequence, highlighted on the event tree shown in Fig. B.8, involves a reactor trip with unavailability of secondary side cooling and failure of feed and bleed.

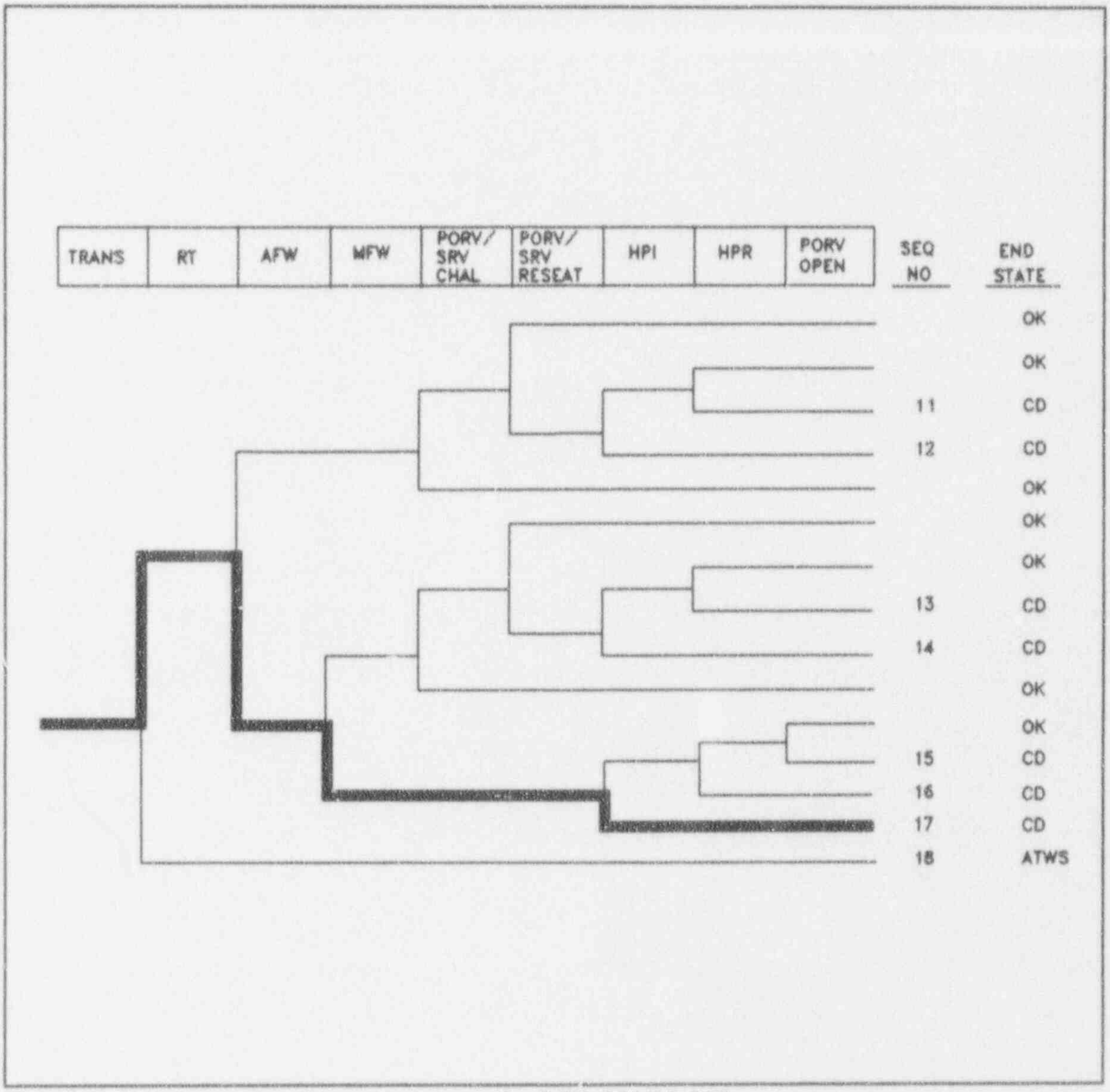


Fig. B.8. Dominant core damage sequence for LER 251/92-007.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 251/92-007
Event Description: MFW Pump Trip with one AFW pump OOS
Event Date: 09/29/92
Plant: Turkey Point 4

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	3.1E-06
Total	3.1E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
17	trans -rt AFW MFW HPI(F/B)	CD	3.0E-06	2.3E-01
15	trans -rt AFW MFW -HPI(F/B) -hpr/-hpi porv.open	CD	1.2E-07	2.7E-01
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt AFW MFW -HPI(F/B) -hpr/-hpi porv.open	CD	1.2E-07	2.7E-01
17	trans -rt AFW MFW HPI(F/B)	CD	3.0E-06	2.3E-01
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: s:\asp\prog\models\pwrbseal.cmp
BRANCH MODEL: s:\asp\prog\models\turkey.sl1
PROBABILITY FILE: s:\asp\prog\models\pwr_bsl1.pro

No Recovery Limit

Event Identifier: 251/92-007

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	1.7E-04	1.0E+00	
loop	6.7E-05	1.7E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
AFW	1.5E-03 > 5.0E-03	2.7E-01	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01 > Failed		
afw/emerg.power	1.5E-03	2.7E-01	
MFW	1.9E-01 > 1.1E-02[1] **	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.9E-01		
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.6E-01	1.0E+00	
ep.rec(sl)	6.2E-01	1.0E+00	
ep.rec	7.6E-02	1.0E+00	
HPI	1.0E-03	8.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
HPI(F/B)	1.0E-03	8.4E-01	1.0E-02 > 2.0E-01[2]
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

NOTES:

1 Value modified to incorporate the SSGFW system. See Modeling Assumptions section for a description of the modifications.

2 Value modified to account for use of SSGFW system prior to use of feed-and-bleed. See Modeling Assumptions section for a description of basis for this value.

Event Identifier: 251/92-007

B.8 LER Number 254/92-004 and 254/92-002

Event Description: Reactor Trip With HPCI and One Safety Relief Valve Unavailable

Date of Event: February 7, 1992

Plant: Quad Cities 1

B.8.1 Summary

Quad Cities 1 was at 100% power when a spurious Group 1 isolation signal resulted in main steam isolation valve (MSIV) closure and a reactor trip. One safety-relief valve (SRV) failed to open for pressure control. Feedwater (FW) was manually isolated and reactor core isolation cooling (RCIC) was used for makeup. High-pressure coolant injection (HPCI) was out of service for maintenance and unavailable during the event. The conditional probability of subsequent core damage estimated for the event is 6.9×10^{-6}. The relative significance of the event, compared to other postulated events at Quad Cities 1, is shown in Fig. B.9.

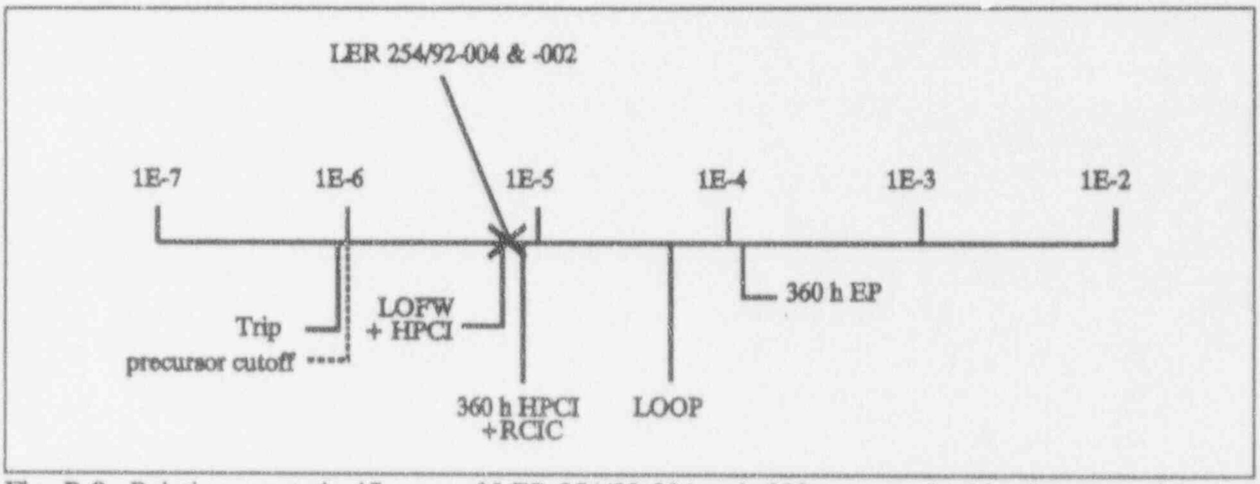


Fig. B.9. Relative event significance of LER 254/92-004 and -002 compared with other potential events at Qaud Cities 1.

B.8.2 Event Description

With the plant at 100% power on February 7, 1992, a spurious signal in the main steam line high flow circuitry resulted in the generation of a Group 1 isolation signal which closed the MSIVs. The reactor feed pumps did not auto-trip as expected at +48 inches, so FW was isolated by closing valves in the A feedwater line and manually tripping the B feedwater pump. The investigation following the event indicated that the failure-to-isolate was caused by calibration errors, and that FW would have isolated had reactor vessel (RV) level continued to increase. Level and pressure were controlled by manually initiating RCIC and manually opening the B safety-relief valve. Following the initial use of the B valve, an attempt was made to use the C valve; however, this valve failed to open.

On the day preceding this event (February 6, 1992, 10CFR50.72 Report No. 22754), while testing the remote HPCI trip function, HPCI stop valve H01-2317 had failed in the open position. HPCI had been declared inoperable, the stop valve had been isolated, and was disassembled at the time of the reactor trip (LER 254/92-002).

B.8.3 Additional Event-Related Information

In addition to HPCI and RCIC, Quad Cities can utilize a Safe Shutdown Makeup Pump (SSMP) to provide high pressure makeup in the event of a loss of feedwater (FW). The pump is motor driven and is capable of supplying 400 gpm at essentially all reactor pressures. The pump and associated valves can be operated from the control room. Utilization of the SSMP requires opening a test return valve, starting the pump, opening the injection valve, and closing the test return valve. The SSMP would be used if both HPCI and RCIC were to fail.

Four electromatic and one Target Rock relief valve are available for depressurization at Quad Cities 1. The test history for these valves is shown in Table B.6. Based on maintenance demands, and assuming for the purposes of this analysis that the results for the five valves can be grouped, a failure-to-open probability of 0.056 and a failure-to-close probability of 0.013 is estimated.

Table B.6. Quad Cities 1 Safety Relief Valve Demand History for LER 254/92-004

		Valve				
Date[a]	Type	A	B	C	D	E
020073	Initial Startup	s	s	s	s	s
080073	Routine	s	s	s	s	s
020074	Routine	s	s	s	s	s
070074	Post Maint	s	s	s	s	s
010075	Routine	s	s	s	s	s
070075	Routine	s	s	s	s	s
010376	Routine	s	s	s	s	s
050076	Post Maint	s	s	s	s	s
110776	Post Maint			s		s
032077	Routine	s	s	fto	s	s
051077	Post Maint	s	s	s	s	s
102977	Routine	s	s	s	s	s
111677	Scram		fto			
111677(?)	Post Maint		s		s	

Table B.6. Quad Cities 1 Safety Relief Valve Demand History for LER 254/92-004

		Valve				
Date[a]	Type	A	B	C	D	E
020578	Routine(?)		s	s	s	fto
021378	Post Maint					s
042478	Routine(?)	s	s	fto	s	s
042678	Post Maint			s		
102678	Routine	s	s	s	s	s
022779	Post Maint	s	s	s	s	s
051179	Routine	s	s	s	s	s
091479	Routine(?)	s	s	s	s	s
092079	Post Maint					s
122079	Routine(?)	s	s	s	s	s
051180	Routine	s	fto	s	s	s
051180(?)	Post Maint		s			
083180	?	s	ftc			
083180(?)	Post Maint	s	s	s	s	s
122080	Post Maint	s	s	s	s	s
030381	?	s	s	s	s	s
052281	?	s				
052581	Post Maint		s	s	s	s
112081	Routine	s	s	s	s	s
052882	Routine	s	s	s	s	s
122282	Post Maint	s	s	s	s	s
031183	?	s				
031583	?		s	s	s	s
092283	Routine	s	s	s	s	s
030584	Routine	s	s	s	s	fto
081784	Post Maint	s	s	s	s	s
021685	Routine	s	s	s	s	s
091385	Routine	s	s	s	s	s
010786	Post Maint	s	s	s	s	s
040586	Post Maint	s	fto	s	s	s
111686	?					s
030287	Routine	s	s	s	s	s
122387	Post Maint	s	s	s	s	s
122887	HPCI Inop	s	s	s	s	s
060088	Routine	s	s	s	s	s
120088	Routine	s	s	s	s	s
041789	?	s	s	s	ftc	

Table B.6. Quad Cities 1 Safety Relief Valve Demand History for LER 254/92-004

		Valve				
Date[2]	Type	A	B[1]	C	D	E
041889	Post Maint		s		s	s
090989	?	s	s	s	s	s
031390	Post Maint	s	s	s	s	s
081190	?	s	s	fto	s	s
081790	Post Maint			s		
042691	Post Maint	s	s	s	s	s
102791	Routine	s	fto	s	s	s
112491	Post Maint		s			s
020792	Scram		s	fto		
021992	Post Maint	s	s	s	s	s
Non post-maint fto		0	3	4	0	2
Non post-maint ftc		0	1	0	1	0
Non post-maint demands		32	34	32	31	31

p(fto) = 9/160 = 0.056

p(ftc) = 2/160 = 0.013

s: successful operation
fto: failed to open
ftc: failed to close

1. Taking credit for a stuck-open relief valve for ADS would be optimistic for situations in which the valve is partially open.

2. Only months and years were provided by the utility for dates indicated as MM00YY.

Based on the Quad Cities final safety analysis report (FSAR), operability of three of the five safety relief valves is required for automatic depressurization system (ADS) success. In the event of a stuck-open relief valve, two of the remaining four valves must operate. Thermal-hydraulic analyses performed in support of the Individual Plant Examination (IPE) indicate that RCIC or the SSMP, in addition to HPCI and FW, can provide sufficient makeup to prevent core damage in the event of a single stuck-open relief valve (the potential use of RCIC for this function has been confirmed at other plants).

B.8.4 Modeling Assumptions

The event has been modeled as a reactor trip with MSIV closure (loss of power conversion systems [PCS]). Because of the way that feedwater was isolated, it was assumed to be nominally available (the failure probability for FW was not modified in the analysis). HPCI was modeled as unavailable and nonrecoverable.

The probability of a stuck-open relief valve was estimated to be 0.013. At Quad Cities, normal practice appears to involve the manual opening of one relief valve to control pressure following a scram. Therefore, only one valve could fail to close during most transients.

The failure probability for ADS was estimated based on the single relief valve failure-to-open probability (0.056) discussed above and the common cause β-factors listed in NUREG/CR-4550, *Analysis of Core Damage Frequency: Internal Events Methodology*, Vol. 1, Rev. 1, January 1990, pp 6-13 and 6-14. These β-factors are 0.22 (two relief valves fail to open), 0.15 (three valves), and 0.12 (four valves). The three-out-of-five success criteria described above was utilized for ADS. This criteria is consistent with that utilized in the NUREG 1150 ananlysis of Peach Bottom (NUREG/CR-4550, *Analysis of Core Damage Frequency: Peach Bottom, Unit 2, Internal Events*, Vol. 4, Rev. 1, August 1989). For sequences in which three of five valves must operate for success (three of five valves must fail to fail ADS), the ADS failure probability is estimated as p(ADS) = p(independent failures) + p(dependent failures) + p(incorrect operator actions associated with depressurization) $\approx C(5,3) \times P_I^3 + P_I\beta_3 + p(opr) \approx 10 \times (0.056)^3 + (0.056) \times 0.15 + 0.01 \approx 0.020$.

For sequences in which two of four valves must open (sequences involving a stuck open relief valve, three of four valves must fail in order to fail ADS), $p(ADS) \approx C(4,3) \times P_I^3 + P_I\beta_3 + p(opr) \approx 4 \times (0.056)^3 + 0.056 \times 0.15 + 0.01 \approx 0.019$.

For this event, the C relief valve failed to open. The ADS failure probability is estimated to be

$p(ADS \mid 3 \text{ valves required and one failed}) \approx C(4,2) \times P_I^2 + P_I\beta_2 + p(opr) \approx 0.041$, and

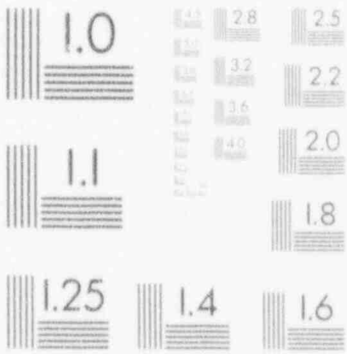
$p(ADS \mid 2 \text{ valves required and one failed}) \approx C(4,3) \times P_I^3 + P_I\beta_3 + p(opr) \approx 0.019$.

The calculations were performed using a branch probability for ADS of 0.041. Probabilities for sequences involving a stuck-open relief valve and ADS challenge were modified to reflect an ADS failure probability of 0.019.

The SSMP was considered the primary backup for HPCI and RCIC in the analysis. Since the pump can be operated from the control room, it was assumed that no effort would be made to recover RCIC before using the SSMP (HPCI was unavailable during the event). Two motor-operated valves plus the pump itself must be remote-manually operated for SSMP success. A failure probability of 0.04 was estimated, based on the nominal failure probabilities used in the ASP program (0.01 for pumps and motor-operated valves) and an assumed operator error probability of 0.01. This operator error probability is typically used for failure to utilize the CRD pumps for reactor pressure vessel makeup following HPCI and RCIC failure (see Appendix A, Sect. A.3.2, BWR Nonspecific Reactor Trip, and Table A.14). At Quad Cities, however, the operators are directed to use the CRD pumps only if HPCI, RCIC and the SSMP all fail. The probability assumed in the analysis for failure to use the CRD system following failure of HPCI, RCIC and the SSMP was 0.12 (see Appendix A, Sect. A.1).

2

IMAGE EVALUATION TEST TARGET (MT-3)



150mm

6″

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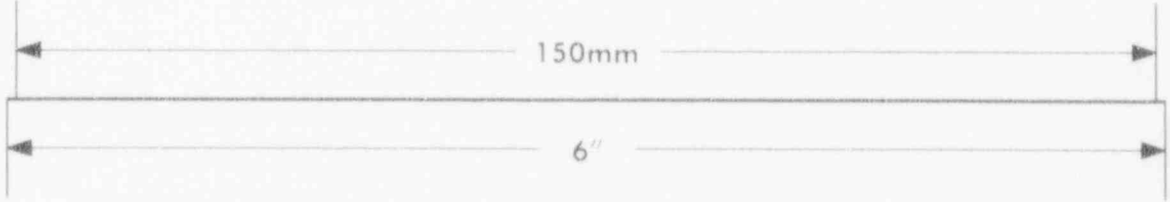
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

2

IMAGE EVALUATION TEST TARGET (MT-3)



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To address the potential use of RCIC or the SSMP to provide core cooling in the event of a single stuck-open relief valve, the conditional probabilities for sequences involving a stuck-open relief valve with FW and HPCI failure (sequences 23 - 28) were muliplied by

$$p(\text{2 or more RVs open} \mid \text{one RV open}) + p(\text{RCIC}) * P(\text{SSMP}).$$

Since only one RV is manually opened at Quad Cities for most transients, p(2 or more RVs open | one RV open) ~ 0. Sequences with successful relief valve closure and FW, HPCI and RCIC failure (sequences 14 - 20 and 32 - 38) were similarly modified to include failure of the SSMP by multiplying their failure probabilities by p(SSMP).

Modifications to the sequence conditional probabilities indicated on the Conditional Core Damage Probability Calculation sheets to reflect the above considerations follow:

Sequence	p(RCIC)	p(SSMP)	p(ADS)
14 - 20	included	0.04	
23 - 28	0.042	0.04	0.019
32 - 38	included	0.04	

For the dominant sequences shown on the calculation sheets, the above modifications result in the following revised co. . tional probabilities:

	calculation sheet probability	revised probability
sequence 28	5.2×10^{-5}	4.1×10^{-8}
sequence 20	2.1×10^{-5}	8.4×10^{-7}
sequence 11	4.9×10^{-6}	4.9×10^{-6}

The overall conditional probability estimated for the event is 6.9×10^{-6}.

B.8.5 Analysis Results

The estimated conditional probability calculated for this event is 6.9×10^{-6}. The dominant sequence associated with the event, shown on the event tree in Fig. B.10, involves failure of long-term core cooling following successful scram and failure of continu ' PCS operation, SRV challenge and successful reseat, and successful FW. Note that the core damage probabilities shown on the calculation sheets have been revised as described above.

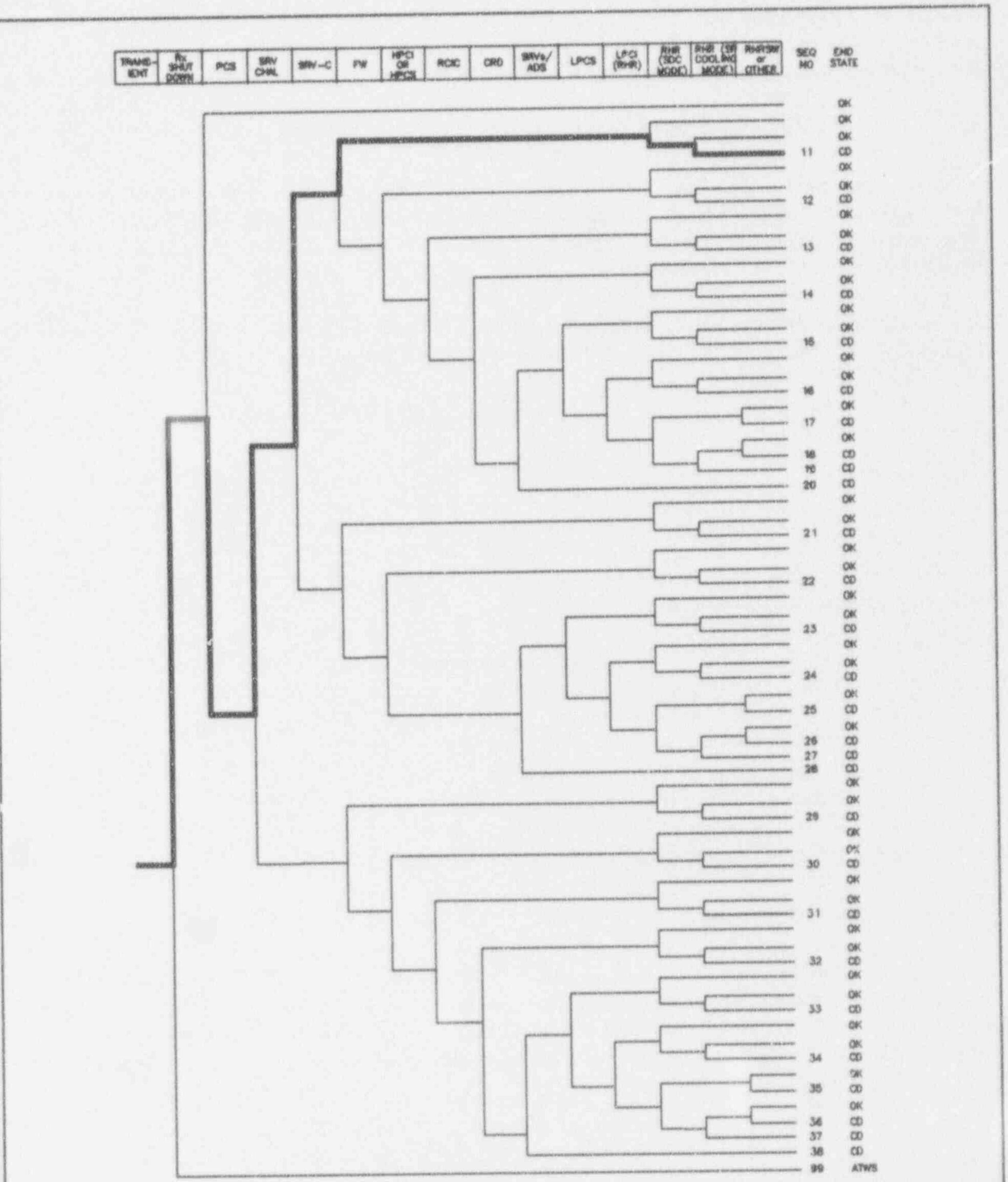

Fig. B.10. Dominant core damage sequence for LER 254/92-004.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 254/92-004
Event Description: Trip and FW isolation with HPCI and one SRV unavailable
Event Date: 02/07/92
Plant: Quad Cities 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	7.9E-05 (1)
Total	7.9E-05 (1)
ATWS	
TRANS	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram SRV.CLOSE fw/pcs.trans HPCI SRV.ADS	CD	5.2E-05[1]	3.4E-01
20	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -SRV.CLOSE fw/pcs.trans HPCI rcic CRD SRV.ADS	CD	2.1E-05[1]	2.4E-01
11	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -SRV.CLOSE -fw/pcs.trans rhr(sdc) rhr(spcool)/rhr(sdc)	CD	4.9E-06	1.1E-01
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
11	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -SRV.CLOSE -fw/pcs.trans rhr(sdc) rhr(spcool)/rhr(sdc)	CD	4.9E-06[1]	1.1E-01
20	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -SRV.CLOSE fw/pcs.trans HPCI rcic CRD SRV.ADS	CD	2.1E-05[1]	2.4E-01
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram SRV.CLOSE fw/pcs.trans HPCI SRV.ADS	CD	5.2E-05[1]	3.4E-01
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

Event Identifier: 254/92-004

SEQUENCE MODEL: c:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\quadcit1.sl1
PROBABILITY FILE: c:\asp\1989\bwr_csl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	1.4E-04	1.0E+00	
loop	1.6E-05	5.3E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Unavailable[2]		
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
SRV.CLOSE	1.0E-02 > 1.3E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-02 > 1.3E-02[3]		
emerg.power	2.9E-03	8.0E-01	
ep.rec	4.9E-02	1.0E+00	
fw/pcs.trans	2.9E-01	3.4E-01	
fw/pcs.loca	4.0E-02	3.4E-01	
HPCI	2.9E-02 > 1.0E+00	7.0E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.9E-02 > Unavailable[4]		
rcic	6.0E-02	7.0E-01	
CRD	1.0E-02 > 1.0E-02	1.0E+00	1.0E-02 > 1.2E-01[5]
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	1.0E-02		
SRV.ADS	3.7E-03 > 3.1E-02[3]	7.1E-01 > 1.0E+00[3]	1.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	3.7E-03 > 3.1E-02		
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Notes:
[1] See Modeling Assumptions for modifications to this sequence conditional probability value.
[2] The MSIVs were closed during the event; this resulted in PCS unavailability.
[3] See Modeling Assumptions for development of this probability value.
[4] The HPCI stop valve was disassembled during the event; this resulted in HPCI unavailability.
[5] The probability of failing to initiate CRD injection for core cooling was modified based on consideration of the SSMP in the analysis. See Modeling Assumptions.

Event Identifier: 254/92-004

B.9 LER Number 261/92-013, 261/92-014, and 261/92-018

Event Description: Safety Injection Pump Out of Service

Date of Event: June 18, 1992, through August 22, 1992

Plant: H. B. Robinson, Unit 2

B.9.1 Summary

Both safety injection (SI) pumps were out of service for 1.5 h on July 10, 1992, while H. B. Robinson was at 100% power. The "B" SI pump was rendered inoperable because plastic sheeting material obstructed the pump's recirculation line. The plastic material was believed to have been used during a design modification during the refueling outage that ended on June 18, 1992. The "A" pump was out of service for 1.5 h on July 10, 1992, because of a blown control power fuse in the pump's breaker closing circuit. On August 22, 1992, with the plant operating at 100% power, the plant experienced a total loss of offsite power (LOOP) (See LER 261/92-017). Following the LOOP, on August 24, 1992, the "B" SI pump recirculation line was again found to be obstructed with the plastic sheeting material from the outage modification.

The conditional core damage probability for the 1.5 h that both SI pumps were inoperable (LERs 261/92-013 and -014) is 6.2×10^{-8}. This is below the precursor cutoff value of 10^{-6}. Therefore, this event is not a precursor but is included here since this is when the extended inoperability of the "B" SI pump began. The conditional core damage probability for the time period when the "B" SI pump was inoperable (LERs 261/92-013 and -018) is 3.5×10^{-5}. The relative significance of this event compared to other postulated events at H. B. Robinson Unit 2 is shown in Fig. B.11.

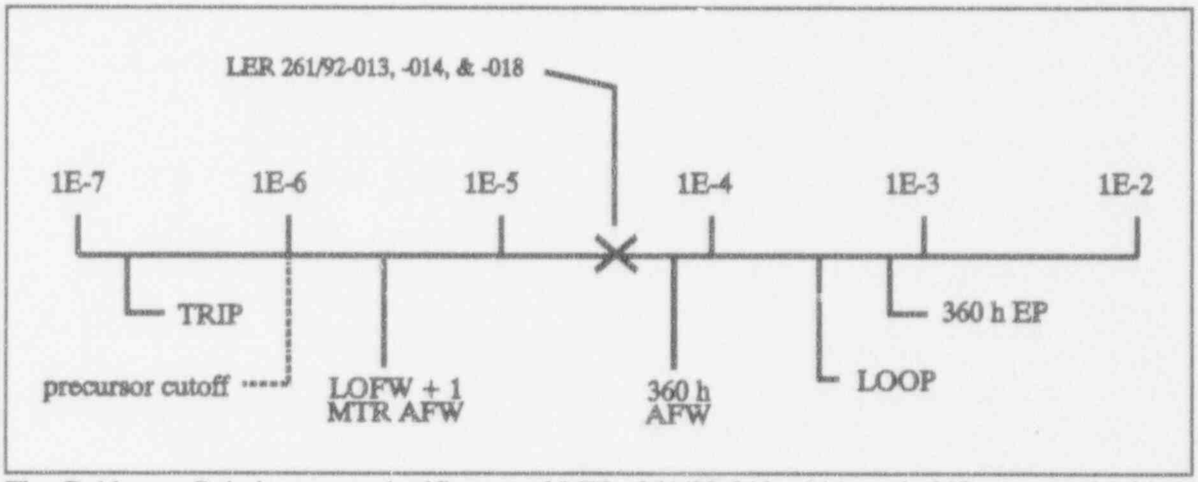

Fig. B.11. Relative event significance of LERs 261/92-013, -014, and -018 compared with other potential events at H. B. Robinson 2.

B.9.2 Event Description

On July 8, 1992, at 2307 hours, the "B" SI pump was declared out of service because of low flow on the pump's recirculation line. Plastic sheet material was found in the "B" SI pump minimum flow line. The plastic material was believed to be from a purge dam that had been fabricated for welding operations for a modification to the minimum flow line for the residual heat removal (RHR) system during the cycle 14 refueling outage. The refueling outage ended on June 18, 1992. It is believed the material was introduced as a result of breakage of one of the 9-in.-diameter purge dam pieces. A portion of the material was introduced into the RHR system, the refueling water storage tank (RWST), and SI and containment spray (CS) pump suction piping. The debris was removed through system flushing.

On July 9, 1992, at 1839 hours, with the plant still at 100% power, an attempt was made to start the "A" SI pump. During this attempt, one of the two control power fuses in the pump's breaker closing circuit blew. The fuses were replaced, and the pump was returned to service 1.5 h later, at 2009 hours on July 9, 1992. The fuse manufacturer concluded that the "fuse was progressively weakened by repeated breaker closures until it opened to clear the circuit."

At 2030 hours, on July 9, 1992, a plant shutdown to the hot shutdown condition was initiated because of the continued inoperability of the "B" SI pump. On July 12, 1992, at 0812 hours, the "B" SI pump was returned to service following repeated flushing of the SI system. Operability tests were also performed for the RHR and CS systems. The plant returned to service on July 12, 1992.

On August 22, 1992, with the plant at 100% power, a LOOP occurred at 1007 hours because of the loss of the startup transformer (see LER 261/92-017 in Appendix B). On August 24, 1992, following the LOOP and before plant restart, the "B" SI pump was tested and declared inoperable because of low flow in the recirculation line. The "A" SI pump was also declared inoperable because of reduced flow in its recirculation line. Investigation revealed that additional plastic sheeting, similar to the material found in the line on July 8, had partially blocked the "B" SI pump recirculation line. It was speculated by the licensee that a residual piece from the RHR system modification performed during the cycle 14 refueling outage that was initially too large to enter the recirculation line had been eroded by subsequent use of the SI pumps. The licensee had originally thought that the material was broken into very small pieces from the SI pump and the material would have easily entered the piping during previous flushing of the system. This was based on the fragments found in the SI pump recirculation line in July. No debris was found in the "A" pump recirculation line, and the flow was within the required limits. Therefore, the "A" line was considered to have been operable throughout the event.

B.9.3 Additional Event-Related Information

H. B. Robinson has two RHR pumps, which take suction from the RWST or the containment sump. The system can discharge to the reactor coolant system (RCS) cold legs or to the suction of the SI and CS system pumps. The RHR pump recirculation lines run back to the suction of the pumps.

The SI system uses two pumps that can take suction from the RWST or the RHR pump discharge. Each pump has a recirculation line to provide pump cooling. The recirculation lines return to the RWST. The RHR, SI, and CS pumps all share a common suction line from the RWST. The original SI system included three pumps; however, one of the pumps has been removed from service for an extended period of time.

B.9.4 Modeling Assumptions

These three licensee event reports (LERs) are analyzed together in two separate cases because of the unavailability of the "B" SI pump throughout the entire time period. The root cause of the "B" SI pump inoperability was the plastic sheeting material from the RHR system modification performed during the cycle 14 refueling outage.

The first case was modeled assuming that the two SI pumps were inoperable for 1.5 h. For the second case, it was assumed that the "B" SI pump was inoperable from the time the plant went critical following the completion of the plant outage on June 18, 1992, until the LOOP event occurred on August 22, 1992 (64.5 d).

The failure probability for the "A" SI pump was doubled for Case 2. This was to account for the increased likelihood of "A" pump failure due to recirculation line clogging. Following the failure of the "B" SI pump due to recirculation line plugging, all flow would be through the "A" pump. This increased flow potentially increases the likelihood of failure for the "A" pump from the same cause. For Case 1 the "A" pump was failed because of the fuse failure in the starting circuit.

The nonrecovery values for the high pressure injection (HPI) and high pressure injection for feed and bleed (HPI(F/B)) were modified for both cases. For Case 1, the HPI nonrecovery was decreased from 0.84 to 0.34. This is based on the assumption that sufficient time would be available to recover the "A" SI pump by locally closing the breaker. In the HPI(F/B) case, the nonrecovery was increased from 0.84 to 1.0, assuming that neither pump would be recoverable in the required time period. For Case 2, the nonrecovery values for both HPI and HPI(F/B) were set to 1.0. This based on the assumption that the dominant failure mechanism would be blockage of the recirculation line by the plastic material and that this would not be recoverable in the required time period.

The system failure probabilities for HPI were modified to include the use of low pressure injection (LPI) in lieu of a failed high pressure injection (HPI) system. This process involves the use of the secondary side to cooldown and depressurize the RCS to below the LPI system injection pressure. A failure probability of 0.12 was assigned to the cooldown process as this a proceduralized process performed under stress (see Appendix A, Sect. A.1). This operator failure is dominant and the equipment failure rates are insignificant. The system probabilities for HPI in both cases were modified to include this recovery process.

B.9.5 Analysis Results

The conditional core damage probability for the 1.5 h that both SI pumps were inoperable (Case 1, LERs 261/92-013 and -014) is 6.2×10^{-8}. This is below the precursor cutoff. Therefore, this event is not a precursor. The conditional core damage probability for the time period when the "B" SI pump was inoperable (Case 2, LERs 261/92-013 and -018) is 3.5×10^{-5}. The dominant core damage sequence for this precursor, shown in Fig. B.12, involves a postulated loss of coolant accident (LOCA) followed by a failure of HPI.

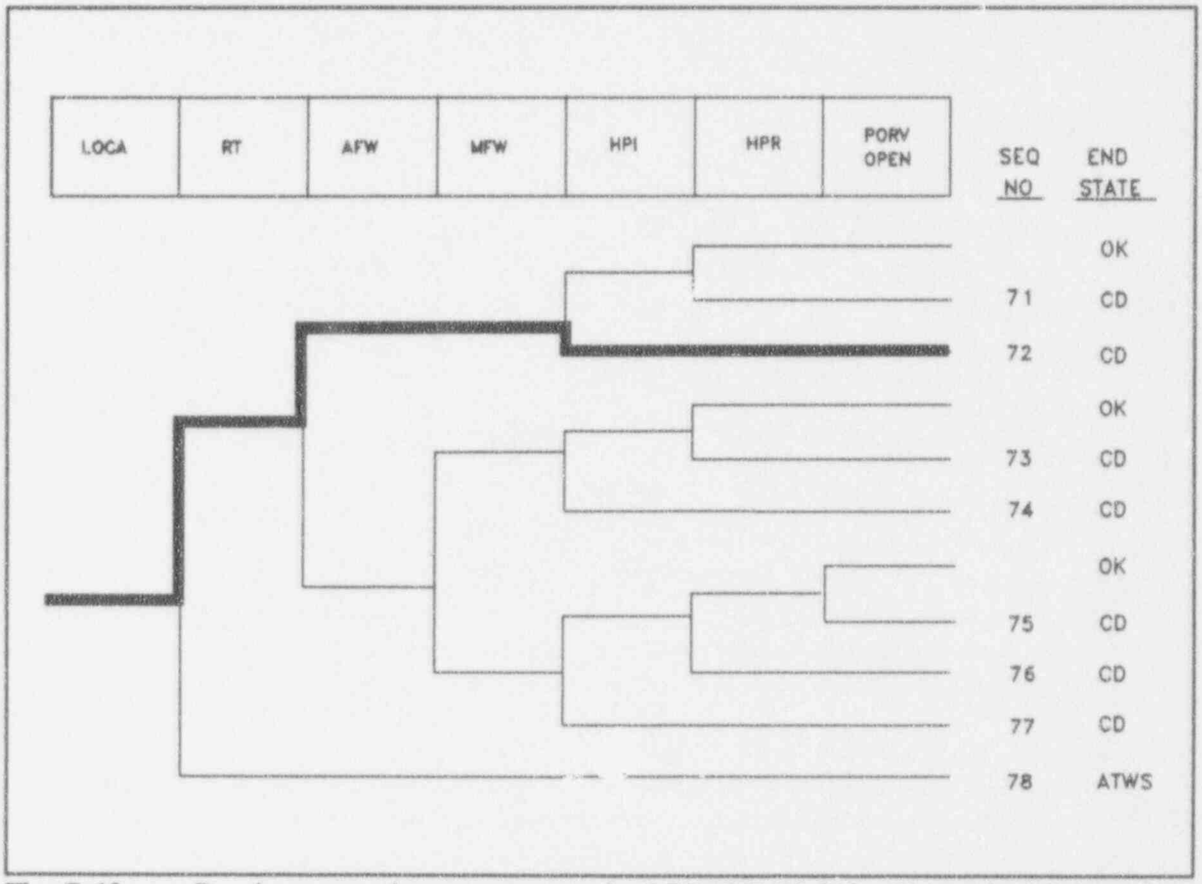

Fig. B.12. Dominant core damage sequence for LERs 261/92-013, -014, and -018 (case 2).

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 261/92-013, 014
Event Description: CASE 1: Both SI pumps inoperable for 1.5 hours
Event Date: 07/10/92
Plant: Robinson 2

UNAVAILABILITY, DURATION= 1.5

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.5E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOCA	6.2E-08
Total	6.2E-08
ATWS	
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
72	loca -rt -afw HPI	CD	6.2E-08	1.5E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
72	loca -rt -afw HPI	CD	6.2E-08	1.5E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asppra\special\pwrbseal.cmp
BRANCH MODEL: c:\asppra\special\robinson.sl2
PROBABILITY FILE: c:\asppra\special\pwr_bsl1.pro

Event Identifier: 261/92-013, -014

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.0E-04	1.0E+00	
loop	1.6E-05	5.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	1.0E-03
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.7E-01	1.0E+00	
ep.rec(sl)	5.7E-01	1.0E+00	
ep.rec	7.0E-02	1.0E+00	
HPI	1.0E-03 > 1.2E-01 **	8.4E-01 > 3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
HPI(F/B)	1.0E-03 > 1.0E+00	8.4E-01 > 1.0E+00	1.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	2.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Event Identifier: 261/92-013, -014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 261/92-013, 018
Event Description: CASE 2: "B" SI pump inoperable
Event Date: 06/18/92 - 08/22/92
Plant: Robinson 2

UNAVAILABILITY, DURATION= 1482

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.5E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOCA	3.5E-05
Total	3.5E-05
ATWS	
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	3.5E-05	4.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
72 loca -rt -afw HPI	CD	3.5E-05	4.3E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asppra\special\pwrbseal.cmp
BRANCH MODEL: c:\asppra\special\robinson.sl2
PROBABILITY FILE: c:\asppra\special\pwr_bsl1.pro

Event Identifier: 261/92-013, -018

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.0E-04	1.0E+00	
loop	1.6E-05	5.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	1.0E-03
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.7E-01	1.0E+00	
ep.rec(sl)	5.7E-01	1.0E+00	
ep.rec	7.0E-02	1.0E+00	
HPI	1.0E-03 > 2.4E-02 **	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > 2.0E-01		
HPI(F/B)	1.0E-03 > 2.0E-01	8.4E-01 > 1.0E+00	1.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > 2.0E-01		
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	2.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Event Identifier: 261/92-013, -018

B.10 LER Number 261/92-017, 261/92-013, and 261/92-018

Event Description: Loss of Offsite Power

Date of Event: August 22, 1992

Plant: H. B. Robinson, Unit 2

B.10.1 Summary

On August 22, 1992, with the plant operating at 100% power, the loss of the startup transformer resulted in loss of one of the two emergency buses and an instrument bus. Following a subsequent reactor/turbine trip, the transfer of the other emergency bus to offsite power failed and resulted in a total loss of offsite power (LOOP). Two days after the LOOP, on August 24, 1992, the "B" SI pump recirculation line was found to be obstructed with the plastic sheeting material. The plastic sheeting had been used during a design modification while in a refueling outage that ended on June 18, 1992. The conditional core damage probability for the LOOP event is 2.1×10^{-4}. The relative significance of this event compared to other postulated events at H. B. Robinson Unit 2 is shown in Fig. B.13.

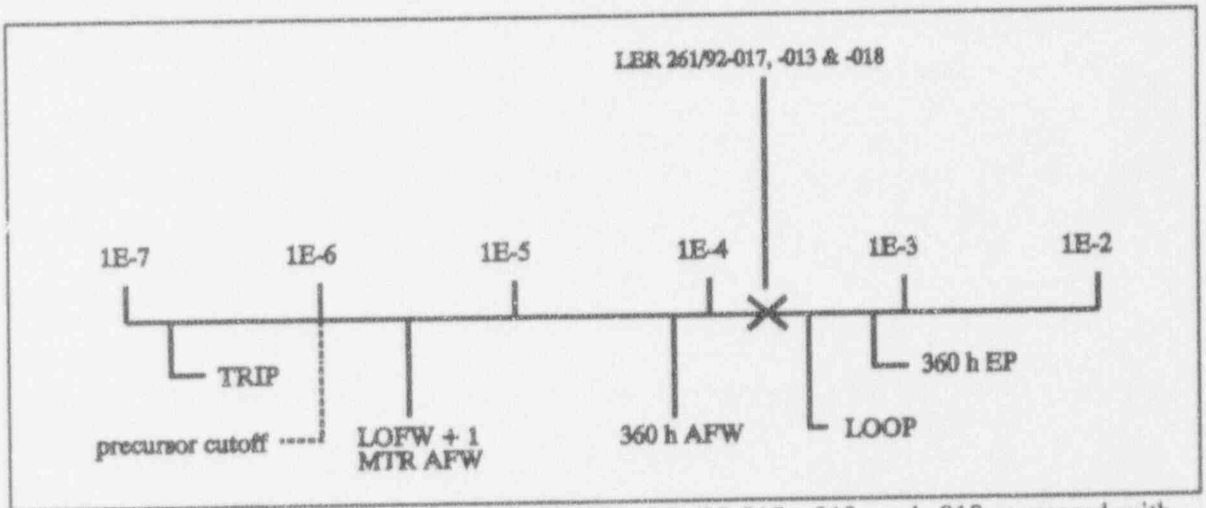

Fig. B.13. Relative event significance of LERs 261/92-017, -013, and -018 compared with other potential events at H. B. Robinson 2.

B.10.2 Event Description

On July 8, 1992, at 2307 hours, the "B" SI pump was declared out of service because of low flow on the pump's recirculation line. Plastic sheet material was found in the "B" SI pump minimum flow line. The plastic material was believed to be from a purge dam that had been fabricated for welding operations for a modification to the minimum flow line for the residual heat removal (RHR) system during the cycle

14 refueling outage. The refueling outage ended on June 18, 1992. It is believed the material was introduced as a result of breakage of one of the 9-in.-diameter purge dam pieces. A portion of the material was introduced into the RHR system, the refueling water storage tank (RWST), and SI and containment spray (CS) pump suction piping. The debris was removed through system flushing.

On August 22, 1992, with the plant at 100% power, a LOOP occurred at 1007 hours because of the loss of the startup transformer. The loss of the startup transformer caused a loss of emergency bus E-2 and instrument bus 4, and a turbine runback. The "B" emergency diesel generator (EDG) started and supplied emergency bus E-2. At 1009 hours, the turbine and reactor tripped on high steam generator level. At 1010 hours the auxiliary transformer tried to transfer its loads to the startup transformer but failed because the startup transformer was not operational. This resulted in a LOOP to the other emergency bus (E-1). The "A" EDG started and supplied emergency bus E-1. A manual SI was initiated at 1018 hours because the pressurizer level had fallen to less than 10% during the initial transient. At 1037 hours the manual SI was terminated. At 1103 hours natural circulation was verified, with RCS temperatures stabilized at 500°F. Repairs to the startup transformer were completed and normal power alignment restored to the emergency busses between 0014 and 0050 hours on August 23, 1992.

On August 24, 1992, following the LOOP and before plant restart, the "B" SI pump was tested and declared inoperable because of low flow in the recirculation line. The "A" SI pump was also declared inoperable because of reduced flow in its recirculation line. Investigation revealed that additional plastic sheeting, similar to the material found in the line on July 8, had partially blocked the "B" SI pump recirculation line. It was speculated by the utility that a residual piece from the RHR system modification performed during the cycle 14 refueling outage that was initially too large to enter the recirculation line had been eroded by subsequent use of the SI pumps. The utility had originally thought that the material was broken into very small pieces from the SI pump and the material would have easily entered the piping during previous flushing of the system. This was based on the fragments found in the SI pump recirculation line in July. No debris was found in the "A" pump recirculation line, and the flow was within the required limits. Therefore, the "A" line was considered to have been operable throughout the event.

B.10.3 Additional Event-Related Information

H. B. Robinson has two RHR pumps, which take suction from the RWST or the containment sump. The system can discharge to the reactor coolant system (RCS) cold legs or to the suction of the SI and CS system pumps. The RHR pump recirculation lines run back to the suction of the pumps.

The SI system uses two pumps that can take suction from the RWST or the RHR pump discharge. Each pump has a recirculation line to provide pump cooling. The recirculation lines return to the RWST. The RHR, SI, and CS pumps all share a common suction line from the RWST. The original SI system included three pumps; however, one of the pumps has been removed from service for an extended period of time.

During power operation the main generator supplies 4160-Vac buses 1 and 4 via the unit auxiliary transformer (UAT) (see Fig. B.14). Buses 2 and 5 are also supplied from the UAT via buses 1 and 4, respectively. Bus 3 is supplied from offsite power via the startup transformer (SUT). Emergency bus E-1 is supplied from the main generator via the UAT, bus 1 and bus 2. Emergency bus E-2 is supplied from offsite power via the SUT and bus 3. Upon loss of the main generator, the UAT transfers all loads to the SUT. If this transfer fails, the emergency buses are isolated from the nonsafety-related buses and the EDGs start and load onto the buses.

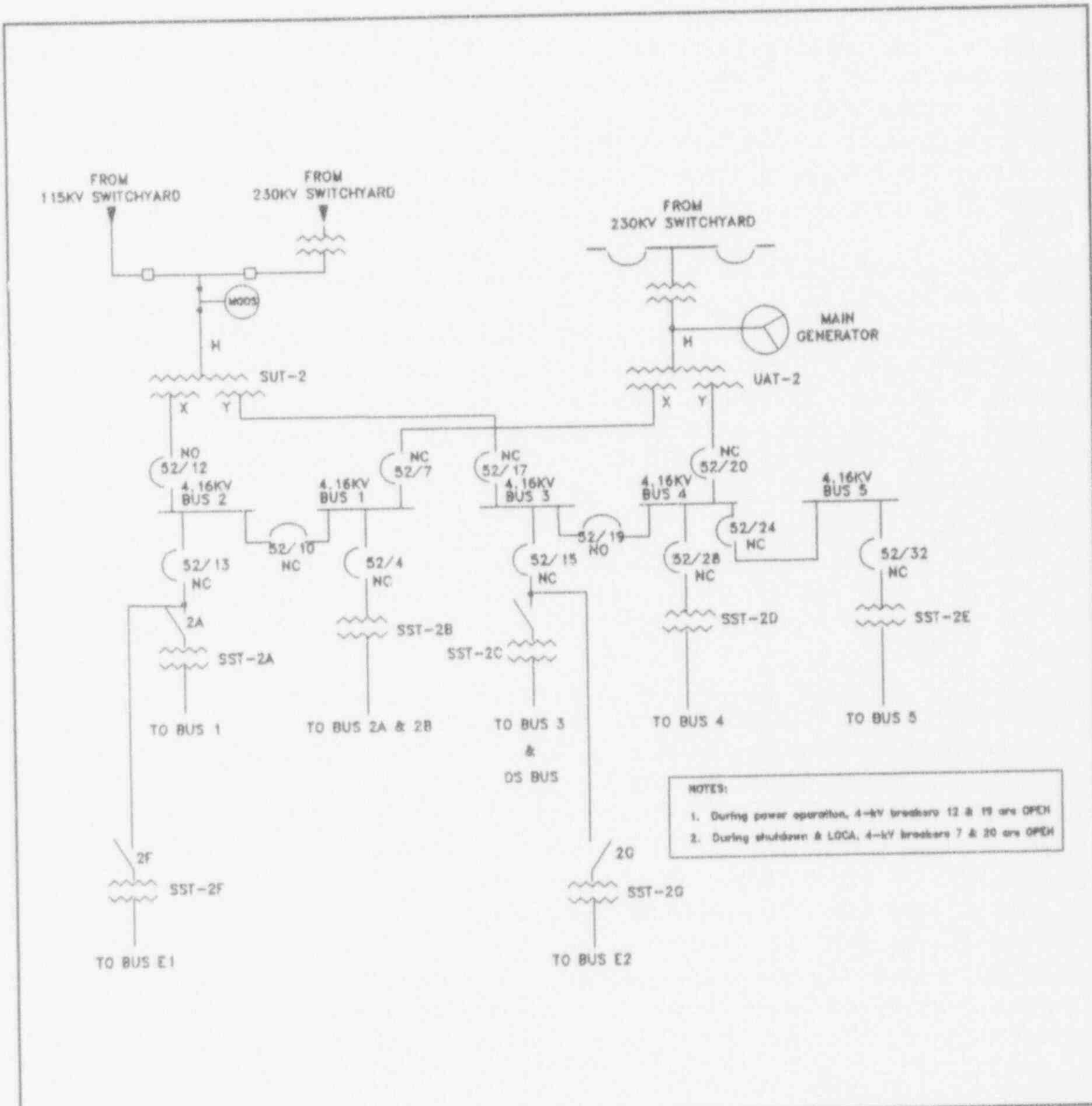

Fig. B.14. H.B. Robinson electrical distribution system.

The Dedicated Shutdown Diesel Generator (DSDG) is designed primarily to bring the plant to a hot shutdown condition in the event of a fire in the control room, cable spreading room and certain other areas of the plant. The DSDG supplies power to the "A" charging pump, "A" component cooling water pump, "D" service water pump, and MCC 5. MCC 5 in turn supplies power to two of the instrument busses via one of the battery chargers. This equipment is sufficient to prevent reactor coolant pump seal LOCAs and battery depletion if the diesel is aligned to the bus within one hour of the loss of all ac power.

B.10.4 Modeling Assumptions

The LOOP event was modeled as plant-centered. The probabilities for failure to recover ac power prior to battery depletion were set to 1.0 because of the extended period the plant was without offsite power (~14 hours). During this 14-h time period, about 3 h was spent investigating the failure of the startup transformer, 4.5 h was spent repairing the failed relay, and 6.5 h was spent attempting to restore power to specific loads (NRC Inspection Report 50-261/92-25). Therefore, off-site power could not have been quickly recovered during this period if problems were experienced with the on-site power supplies.

The DSDG was modeled as shown in Fig. B.15. A DSDG event was added to the LOOP tree following the PORV/SRV RESEAT event for those sequences with emergency power failure (Sequences 46-49 and 51-54) (see Appendix A, Sect. A.3.1 for the original tree). If the PORV/SRV is challenged (up branch), reseats (up branch), and the DSDG is successfully loaded, RCP seal LOCA will be prevented and a battery charger will be operational. Therefore offsite power recovery and use of HPI and HPR are not required. As a result the end state for this sequence is OK. If the PORV/SRV is challenged (up branch), reseats (up branch), and the DSDG is not successfully loaded, the remainder of the original tree is applicable (sequences 46-49). If the PORV/SRV is challenged and fails to reseat, the loading of the DSDG does not prevent core damage since the equipment supplied by it cannot provide sufficient makeup in this situation. Therefore this sequence still goes to core damage. If the PORV/SRV is not challenged, successful loading of the DSDG leads to an OK end state since RCP seal cooling and a battery charger are restored. If the DSDG is not loaded, then the remainder of the original tree is applicable (sequences 51-54).

To compute the estimated CCDP values, the original computer model was not modified. Instead, the results of the computer program for sequences 46-49 and 51-54 were multiplied by the failure probability of the DSDG to be successfully loaded. The results of this hand calculation are shown on the calculational forms. The failure probability for loading the DSDG was set to 0.075. This consists of a 0.05 equipment failure probability and a 0.025 operator failure probability. The 0.05 equipment failure probability value is the typical value used for safeguards emergency DGs in ASP analyses. Data supplied by the licensee indicated that the non-safeguards DSDG experienced fewer failures to start, fewer run time failures and had higher availability than the safeguards diesels at Robinson. Therefore it is reasonable to use the same value as is normally used for safeguards DGs . This value is somewhat nonconservative in that common cause failures between the safeguards DGs and the DSDG are not

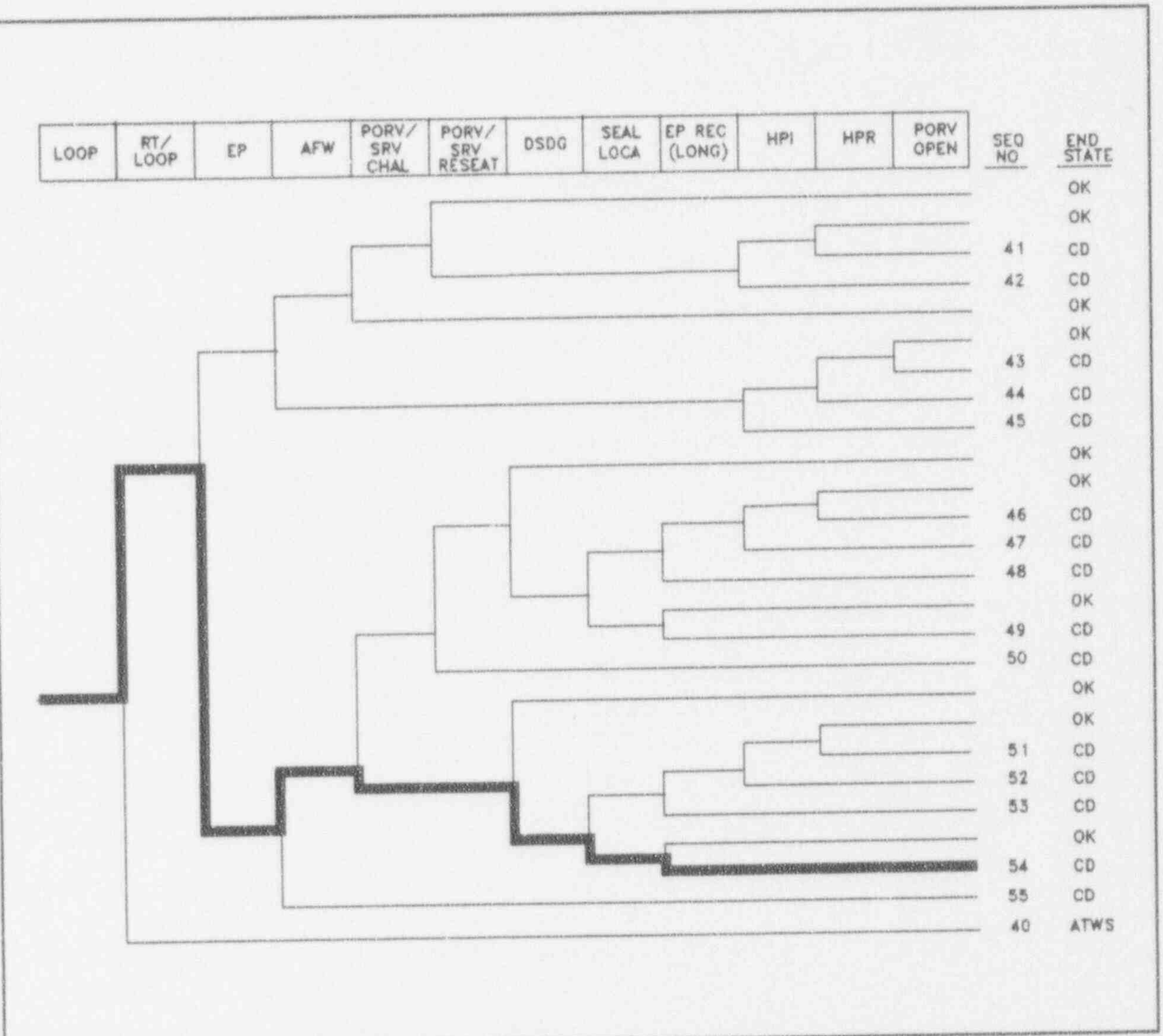

Fig. B.15. LOOP event tree for LERs 261/92-017, -013, and -018 including DSDG event and indicating the dominant core damage sequence.

included in this value. The operator failure probability was determined using time reliability correlations from *Human Reliability Analysis*, E.M. Dougherty, Jr. and J.R. Fragola, 1988, Wiley & Sons. Information from the licensee indicated that it would take approximately 30 min to complete the loading of the DSDG. The safegaurds battery lifetime is only 1 hour. Therefore the DSDG must be successfully loaded within this one hour time period. This leaves 30 min of available time (1 hr. - 30 min.) to begin the procedure and recover from errors. Using the recovery with hesitancy curve from Figure 11-4 of the previous reference, the operator failure probability is 0.025.

The procedure for the loading of the DSDG states that if limited manpower is available, recovery of the safeguards diesels should be postponed until the DSDG is successfully aligned. Since this particular event occurred on a Saturday morning, it was assumed that the recovery actions for the DSDG would be completed before recovery of the safeguards diesels would be pursued. Therefore, the nonrecovery value for the safeguards diesels was set to 1.0. Due to the extended period of time to recover offsite power ($\sim$14 hours), the long term nonrecovery probabilities for offsite electric power were set to 1.0.

The failure probability for the "A" SI pump was doubled. This was to account for the increased likelihood of "A" pump failure due to recirculation line clogging. Following the failure of the "B" SI pump due to recirculation line plugging, all flow would be through the "A" pump. This increased flow potentially increases the likelihood of failure for the "A" pump from the same cause.

The nonrecovery values for the high pressure injection (HPI) and high pressure injection for feed and bleed (HPI(F/B)) were also modified. The nonrecovery values for both HPI and HPI(F/B) were set to 1.0. This is based on the assumption that the dominant failure mechanism would be blockage of the recirculation line by the plastic material and that this would not be recoverable in the required time period.

B.10.5 Analysis Results

The conditional core damage probability for this event is 2.1×10^{-4}. The dominant core damage sequence for this event, shown in Fig. B.15, involves a postulated failure of emergency power, failure to load the DSDG, and failure to restore ac power prior to core uncovery.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 261/92-017, 013, 018
Event Description: LOOP with SI pump "B" inoperable
Event Date: 08/22/92
Plant: Robinson 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability (w/o DSDG)	Probability (w/ DSDG)
CD		
LOOP	2.9E-03	2.1E-04
Total	2.9E-03	2.1E-04
ATWS		
LOOP	0.0E+00	
Total	0.0E+00	

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
54[2]	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	2.1E-03	9.9E-01
53[2]	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	6.2E-04	9.9E-01
49[2]	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power -SEAL.LOCA EP.REC	CD	8.5E-05	9.9E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
49[2]	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power -SEAL.LOCA EP.REC	CD	8.5E-05	9.9E-01
53[2]	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	6.2E-04	9.9E-01
54[2]	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	2.1E-03	9.9E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asppra\special\pwrbseal.cmp
BRANCH MODEL: c:\asppra\special\robinson.sl2

Event Identifier: 261/92-017, 013, 018

PROBABILITY FILE: c:\asppra\special\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.0E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	5.3E-01 > 1.0E+00	
Branch Model: INITOR			
Initi?tor Freq:	1.6E-05		
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 2.9E-03	8.0E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02		
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	1.0E-03
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
SEAL.LOCA	2.7E-01 > 2.3E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.7E-01 > 2.3E-01		
EP.REC(SL)	5.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.7E-01 > 1.0E+00		
EP.REC	7.0E-02 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	7.0E-02 > 1.0E+00		
HPI	1.0E-03 > 2.0E-01	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > 2.0E-01		
HPI(F/B)	1.0E-03 > 2.0E-01	8.4E-01 > 1.0E+00	1.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > 2.0E-01		
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	2.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

NOTES:

1 Value obtained by performing hand caclulation. See Modeling Assumptions section for a description of how this value was obtained.

2 Sequences affected by DSDG. See Modeling Assumptions section for a description of this modification.

Event Identifier: 261/92-017, 013, 018

B.11 LER Number 269/92-004 and 269/92-005

Event Description: Reactor Trip with One Emergency Feedwater Train Inoperable

Date of Event: May 8, 1992

Plant: Oconee 1

B.11.1 Summary

On May 8, 1992, Oconee tripped from 14% power as a result of a pressure transient in the main feedwater (MFW) system. On May 27, 1992, it was discovered that one train of emergency feedwater had been inoperable at the time of the trip on May 8. The conditional core damage probability estimated for this event is 4.0×10^{-6}. The relative significance of this event compared to other postulated events at Oconee 1 is shown in Fig. B.16.

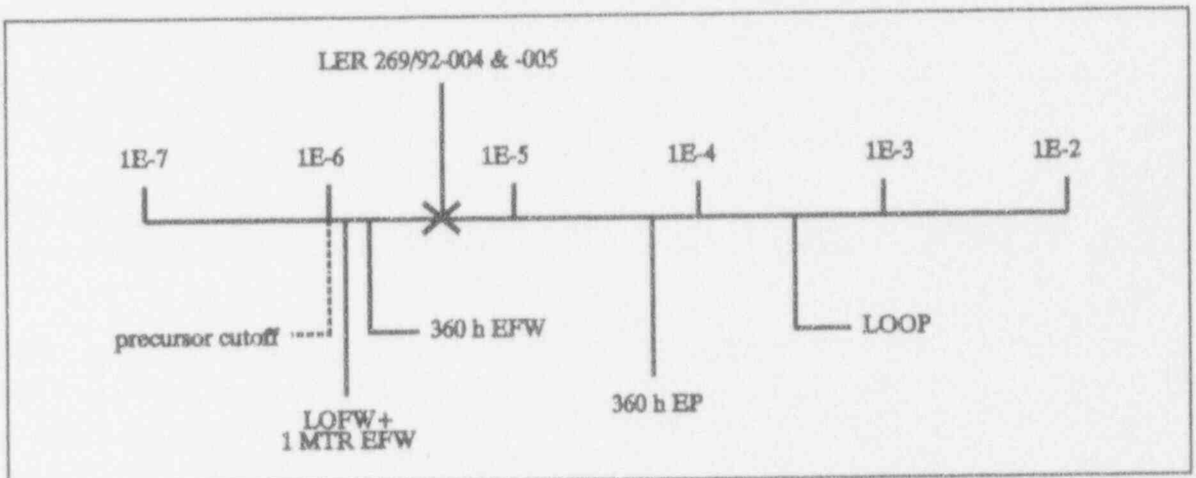

Fig. B.16. Relative event significance of LERs 269/92-004 and -005 compared with other potential events at Oconee 1.

B.11.2 Event Description

With Oconee 1 at 14% power, draining of the condenser hotwell was in progress during a plant startup on May 8, 1992. Because of the low power level, only one MFW pump (the 1B MFW pump) was required; the 1A MFW pump was idle. When the operator opened the condensate dump line (from the condensate system to the condensate storage tank) to drain the condenser, the decreased flow to the feedwater pumps caused a plant trip on low MFW pump discharge pressure. Following the trip, the emergency feedwater (EFW) system actuated, and the 1B MFW pump continued to run. After verifying that the 1B MFW pump was running, the operator manually shut down both the 1A and 1B EFW pumps.

The two motor-driven EFW pumps had run for 43 sec. The turbine-driven EFW pump did not start because the start signal was not present for greater than 15 sec. The remainder of the post-trip recovery was uneventful.

Between May 12 and May 24, 1992, the plant operated at 100% power. On May 24 the plant was shut down to repair a reactor coolant pump seal.

On May 27, 1992, with the plant in hot standby, the quarterly stroke test procedure was conducted on the A steam generator (SG) EFW control valve. The test revealed that the solenoid valve for enabling automatic control of the A SG EFW control valve had failed. A review of the post-trip data for the May 8, 1992, event revealed that the A EFW train had exhibited no flow during the event. The valve had last been successfully tested on September 22, 1991.

B.11.3 Additional Event-Related Information

The condensate pumps, condensate booster pumps, and MFW pumps are arranged in series to provide the SGs with water from the condenser hotwell and secondary side drains. The condensate dump line to the condensate storage tank branches off between the condensate booster pumps and the MFW pumps.

The EFW system consists of three pumps: two motor-driven and one turbine-driven. The pumps start on loss of the MFW pumps as indicated by low discharge pressure or loss of hydraulic oil pressure on both MFW pumps. If the start signal clears within 15 sec, the turbine-driven EFW pump will reset. The three pumps discharge into two lines, each of which is connected to a SG. The A SG EFW flow control valve automatically varies its position to bring the A SG level to a predetermined setpoint following a reactor trip. Failure of the automatic control portion of the system does not prevent manual control of the valve.

A standby shutdown facility (SSF) is located in a separate building on the Oconee site. This facility, which is not normally manned, is capable of providing limited RCS makeup, RCP seal cooling, and steam generator makeup. SSF systems consist of single trains and are therefore not single-failure-proof.

B.11.4 Modeling Assumptions

This event was modeled as a reactor trip with one of two EFW trains inoperable. The model normally utilizes pump status for input, and as a result, the existing EFW model is a 1 of 3 system. The EFW system failure probability was calculated using a one of two train success criteria since the component that failed is one of two EFW lines to the SGs. The first train was modeled as failed; the second with a failure probability of 0.1. This results in a system failure probability of 0.1. Consistent with other ASP analyses, the nonrecovery probability for EFW was not revised since the system was observed to be degraded and not failed. The use of the SSF as a alternate source of steam generator feedwater was included in the modeling. A combined operator and equipment failure probability of 0.2 was used for the SSF. This probability is consistent with values developed in the Oconee PRA (NSAC-60) and in the analysis of another event (see LER No. 270/92-004).

B.11.5 Analysis Results

The conditional probability of core damage estimated for this event is 4.0×10^{-6}. The dominant core damage sequence, highlighted on the event tree in Fig. B.17, involves a postulated failure of EFW and MFW, PORV challenge and reseat, failure of the SSF feedwater function, successful initial feed-and-bleed, and subsequent failure when recirculation is initiated.

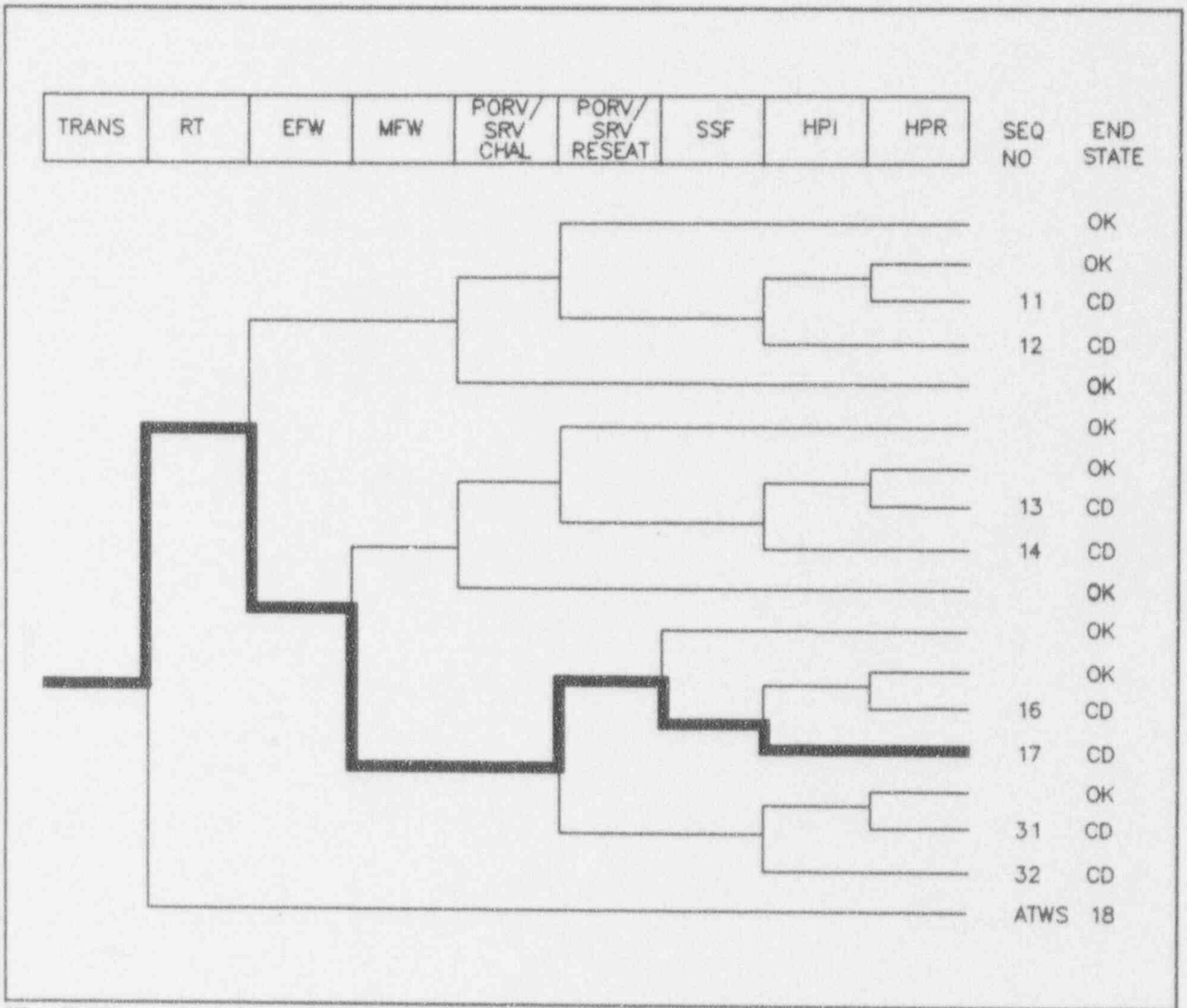

Fig. B.17. Dominant core damage sequence for LER 269/92-004 and -005.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 269/92-004, 005
Event Description: Trip with one train of EFW inoperable
Event Date: 05/08/92
Plant: Oconee 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	4.0E-06
Total	4.0E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
17	trans -rt AFW mfw -porv.or.srv.reseat ssf hpi(f/b)	CD	3.6E-06	7.4E-02
16	trans -rt AFW mfw -porv.or.srv.reseat ssf -hpi(f/b) hpr/-hpi	CD	4.0E-07	8.8E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
16	trans -rt AFW mfw -porv.or.srv.reseat ssf -hpi(f/b) hpr/-hpi	CD	4.0E-07	8.8E-02
17	trans -rt AFW mfw -porv.or.srv.reseat ssf hpi(f/b)	CD	3.6E-06	7.4E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asppra\models\oconseal.cmp
BRANCH MODEL: c:\asppra\models\oconee1.ssf
PROBABILITY FILE: c:\asppra\models\pwr_bsl1.pro

No Recovery Limit

Event Identifier: 269/92-004, 005

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	6.4E-05	1.0E+00	
loop(plant_cent)	1.3E-05	1.5E-01	
loop(grid)	1.6E-06	4.8E-01	
loop(weather)	1.1E-06	9.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power(plant_cent)	3.0E-04	8.0E-01	
emerg.power(grid)	2.5E-03	8.0E-01	
emerg.power(weather)	2.5E-03	8.0E-01	
AFW	3.8E-04 > 1.0E-01[1] **	2.6E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02		
Serial Component Prob:	2.8E-04		
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	8.0E-02	1.0E+00	
porv.or.srv.chall(loop)	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
ssf	2.0E-01	1.0E+00	
seal.loca(plant_cent)	0.0E+00	1.0E+00	
seal.loca(grid)	0.0E+00	1.0E+00	
seal.loca(weather)	0.0E+00	1.0E+00	
ep.rec(sl)(plant_cent)	0.0E+00	1.0E+00	
ep.rec(sl)(grid)	0.0E+00	1.0E+00	
ep.rec(sl)(weather)	0.0E+00	1.0E+00	
ep.rec(plant_cent)	2.3E-01	1.0E+00	
ep.rec(grid)	5.3E-02	1.0E+00	
ep.rec(weather)	8.6E-01	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03

* branch model file
** forced

Notes:
[1] This value reflects the failure of one train of EFW. See Modeling ASsumptions for a complete explanation.

Event Identifier: 269/92-004, 005

B.12 LER Number 269/92-008

Event Description: Both Keowee Emergency Power Hydro Units Unavailable

Date of Event: July 16, 1992

Plant: Oconee 1, 2, and 3

B.12.1 Summary

With all three Oconee units at 100% power and emergency power source Keowee 1 unavailable because of maintenance, a failed fuse was discovered in the control power circuit for an auxiliary power breaker on Keowee 2. This rendered Keowee 2 also unavailable. Both emergency power sources were unavailable for 34 h. The conditional core damage probability estimated for this event is 2.8×10^{-6}. The relative significance of this event compared to other postulated events at Oconee is shown in Fig. B.18.

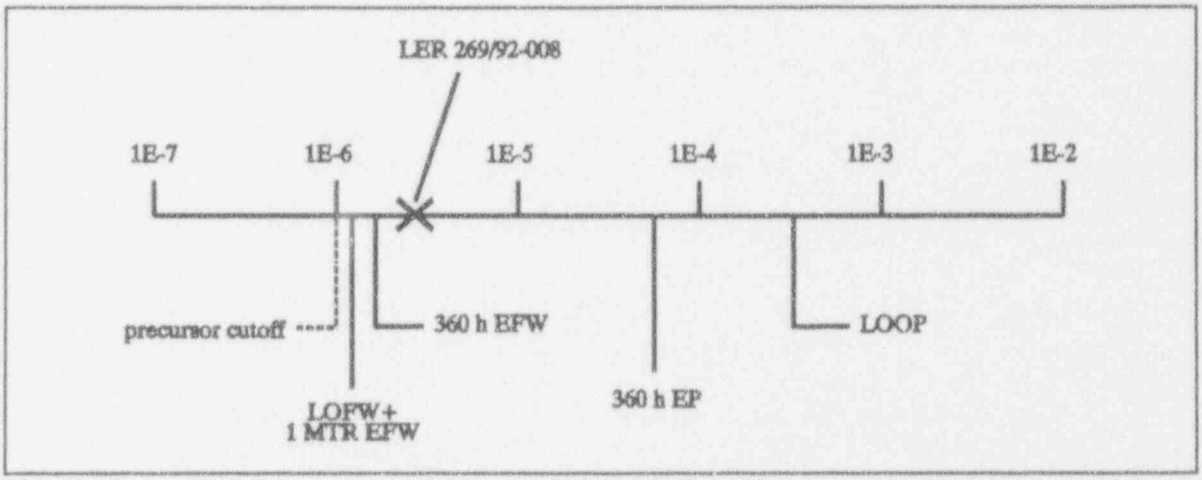

Fig. B.18. Relative event significance of LER 269/92-008 compared with other potential events at Oconee.

B.12.2 Event Description

On July 16, 1992, with all three Oconee units at 100% power, Keowee 1 was removed from service for maintenance at 1515 hours. Consistent with the Oconee Technical Specifications, Keowee 2 was aligned to the underground path.

At 1200 hours, the hydro operations specialist (HOS) at Keowee found the green (trip) control power indicator light for breaker ACB-8 (the alternate power source for Keowee 2 auxiliary loads) glowing less brightly than expected. At 1430 hours, the red (close) control power indicator light for ACB-8 was also found to be glowing, but not as brightly as the "trip" light. The HOS concluded that the problem with the lights was caused by dirty contacts and was not an operability concern, and therefore decided to wait to investigate the problem until Keowee 2 was taken out of service for maintenance (scheduled for the next day).

Due to modification delays, Keowee 1 remained out of service. On July 17, 1992, at 1200 hours, the HOS and other personnel began to investigate the cause of the lighted control power indicator lights. At about 1330 hours, it was determined that the fuse feeding the positive circuit in ACB-8 had blown. With the positive fuse blown, a bypass series circuit path illuminated both indicator lights. In addition, the negative fuse was found to be rated at 15 amperes, instead of the required 10 amperes. The HOS realized that an operability/limiting condition for operation concern existed and began to search for replacement fuses. Unsuccessful attempts were made to contact the Oconee Operations support manager and switchyard coordinator for assistance in resolving the operability issues related to the Keowee units.

At 1415 h, the HOS notified the Oconee 2 Unit supervisor that a blown fuse had been found in the positive circuit for ACB-8. The unit supervisor realized that this rendered Keowee 2 inoperable (with Keowee 2 aligned to the underground path, closure of ACB-8 is required to power Keowee 2 auxiliary loads). Since Keowee 1 was also out of service, the Oconee Technical Specifications required the standby buses to be energized from the Lee combustion turbines. At 1436 hours, Lee was notified that backup power was required.

The replacement fuses needed for ACB-8 were determined to be safety-related. When none could be located on-site, fuses from a spare breaker cabinet were used. These fuses appeared to be original equipment and were determined to be in good condition. After the fuses for ACB-8 were replaced, the breaker was tested and determined to be operable at 1509 hours.

At 1513 hours, Oconee Operations personnel were notified that Keowee 2 was operable. At 1528 hours, Lee notified Oconee that a gas turbine was in operation and that transformer CT-5 was energized. This was almost 2 h after Keowee 2 had been declared inoperable. The Lee operators had experienced trouble with the first gas turbine they had started, and a second turbine had to be started. The standby buses were never energized from the Lee gas turbine because Keowee 2 had been returned to service before Oconee received power from Lee.

B.12.3 Additional Event-Related Information

The Keowee Hydro Station, located approximately three-fourths of a mile east-northeast of the Oconee Nuclear Station, consists of two hydroelectric generators that generate at 13.8 kV. The two Keowee hydro units serve the dual functions of generating commercial power to the Duke Power system grid through the Oconee 230-kV switchyard and providing emergency power to the Oconee Station. When a Keowee unit is generating to the grid and an emergency start at Oconee occurs, it is separated from the 230-kV switchyard and continues to run in standby until needed. Upon loss of power from an Oconee generating unit and 230-kV switchyard, power is supplied from both Keowee units through two separate and independent paths. One path is a 4000-ft underground 13.8-kV cable feeder to transformer CT-4, which supplies power to the 4160-V standby buses. The underground power path is conne ted at all times to one hydro unit on a predetermined basis through locked-closed breakers. The underground power path and the associated transformer are sized to carry full engineered safeguards auxiliaries of one Oconee unit plus auxiliaries for safe shutdown of the other two units. If a Keowee unit is to provide power to an Oconee unit through the underground power path (required by Technical Specifications if one of the Keowee units is out of service), then due to the limited capacity of CT-4, loadshed of non-essential loads occurs. The second path from Keowee is a 230-kV transmission line through breakers ACB-1 or ACB-2, via the yellow bus, to the startup transformer of each Oconee unit.

Keowee auxiliary power is required for the ac hydraulic oil pumps, which are used to pressurize the air pre-loaded accumulators that provide hydraulic oil pressure to the governor which controls the position (depending on load) of the wicket gates on the Keowee water turbine. The length of time that the Keowee units can run without ac auxiliaries is limited by the changing load to which the governor must respond. The utility has indicated in several LERs that one hour is the expected maximum time period of Keowee operation without ac auxiliaries.

A standby shutdown facility (SSF) is located in a separate building on the Oconee site. This facility, which is not normally manned, is capable of providing limited high-pressure injection for reactor coolant system (RCS) makeup and reactor coolant pump (RCP) seal cooling [provided an RCP seal loss-of-coolant accident (LOCA) does not occur]. It can also supply limited steam generator makeup. The facility includes a separate diesel generator which can power SSF loads in the event of a station blackout. SSF systems consist of single trains and are therefore not single-failure-proof.

A more detailed description of the Oconee emergency power system is included in the precursor analysis for LER 270/92-004, *Loss of offsite power with failed emergency power*.

B.12.4 Modeling Assumptions

The event was modeled as a postulated LOOP during the 34 h that both Keowee units were unavailable. Potential sequences associated with the event are described in Appendix A, Sect. A.3.1, PWR Loss of Offsite Power. These sequences were modified to address the Oconee-specific SSF, as described later in this section, and shown on the event tree included with this analysis documentation. The plant response observed during the event impacted the following branch on the event tree:

Emergency Power. Consistent with the analysis for LER 270/92-004, *Loss of Offsite Power with Failed Emergency Power*, October 19, 1992, the Keowee hydro units were assumed to fail after approximately 37 min without auxiliary power; once the supply of hydraulic oil in the accumulator tanks, used for wicket gate positioning, was consumed. When the Keowee on-call technician arrived during the October 19, 1992 event, he was able to quickly reset the locked-out and tripped breakers and restore auxiliary power. However, hydraulic oil was almost depleted by the time he arrived.

The probability of the on-call technician failing to arrive on-site and recover auxiliary power to Keowee Hydro prior to the loss of hydraulic oil was estimated to be 0.64, as described under Modeling Assumptions for the precursor analysis for LER 270/92-004. Use of an on-call technician was assumed to be required except for the day shift, when adequate support was assumed available on-site to quickly correct the breaker problem and restore auxiliary power, if needed. This assumption results in a revised estimate for failing to recover Keowee of (16h/24h) × 0.64 = 0.43.

The Central Switchyard was also assumed available as an alternate source of power to the Standby Buses for plant-centered LOOPs. A probability of 0.12 (ASP nonrecovery class R3, see Appendix A, Sect. A.1) was assumed for failing to recover power from the Central Switchyard via transformer CT-5. This value was chosen because recovery appeared possible in the required time period from the control room. However, during a postulated LOOP with problems at Keowee, this recovery would be considered to be non-routine and burdened. During a postulated grid- or severe weather-related LOOP, the Central Switchyard was assumed to be unavailable. However, during a postulated grid-related LOOP, ac power was assumed to be recoverable in approximately 1 h using the Lee combustion turbines. A non-recovery probability of 0.12 was also assumed for this action, for the same reasons.

The frequency of LOOP and the probability of not recovering offsite power with a loss of emergency power at 37 min was estimated as described in Modeling Assumptions for LER 270/92-004, *Loss of Offsite Power with Failed Emergency Power*, October 19, 1992. The frequencies and probability values used in the calculations follow:

	LOOP Type		
	Plant-Centered	Grid-Related	Severe Weather-Related
LOOP frequency	1.3×10^{-5}/hr	1.6×10^{-6}/hr	1.1×10^{-6}/hr
P_{nrec} (LOOP)	0.15	0.48	0.93
P_{nrec} (emergency power)	0.43×0.12	0.43	0.43
P_{nrec} (ac power prior to battery depletion)	0.056	0.20×0.12	0.86

The use of the SSF as an alternate source of reactor coolant system (RCS) and steam generator (SG) makeup was also addressed in the analysis. This was done by identifying core damage sequences that could be recovered through the use of the SSF (sequences with failed SG makeup or RCP seal cooling and without loss of inventory), and modifying the event tree model described in Appendix A to include its consideration. The revised event tree for Oconee [illegible] included with this analysis. A combined operator and equipment failure probability of 0.2 was u[illegible] the SSF. This probability is consistent with values developed in the Oconee PRA (NSAC-60) and in licensee analyses of this event.

B.12.5 Analysis Results

The conditional core damage probability estimated for the event is 2.8×10^{-6}. This conditional probability is applicable to each of the three Oconee units. The dominant core damage sequence, highlighted on the event tree in Fig. B.19, involves a postulated severe weather-related LOOP with failed emergency power and failure to recover ac power before battery depletion.

The conditional probability estimate is strongly influenced by assumptions concerning the failure of Keowee upon loss of hydraulic oil and the likelihood of Keowee recovery.

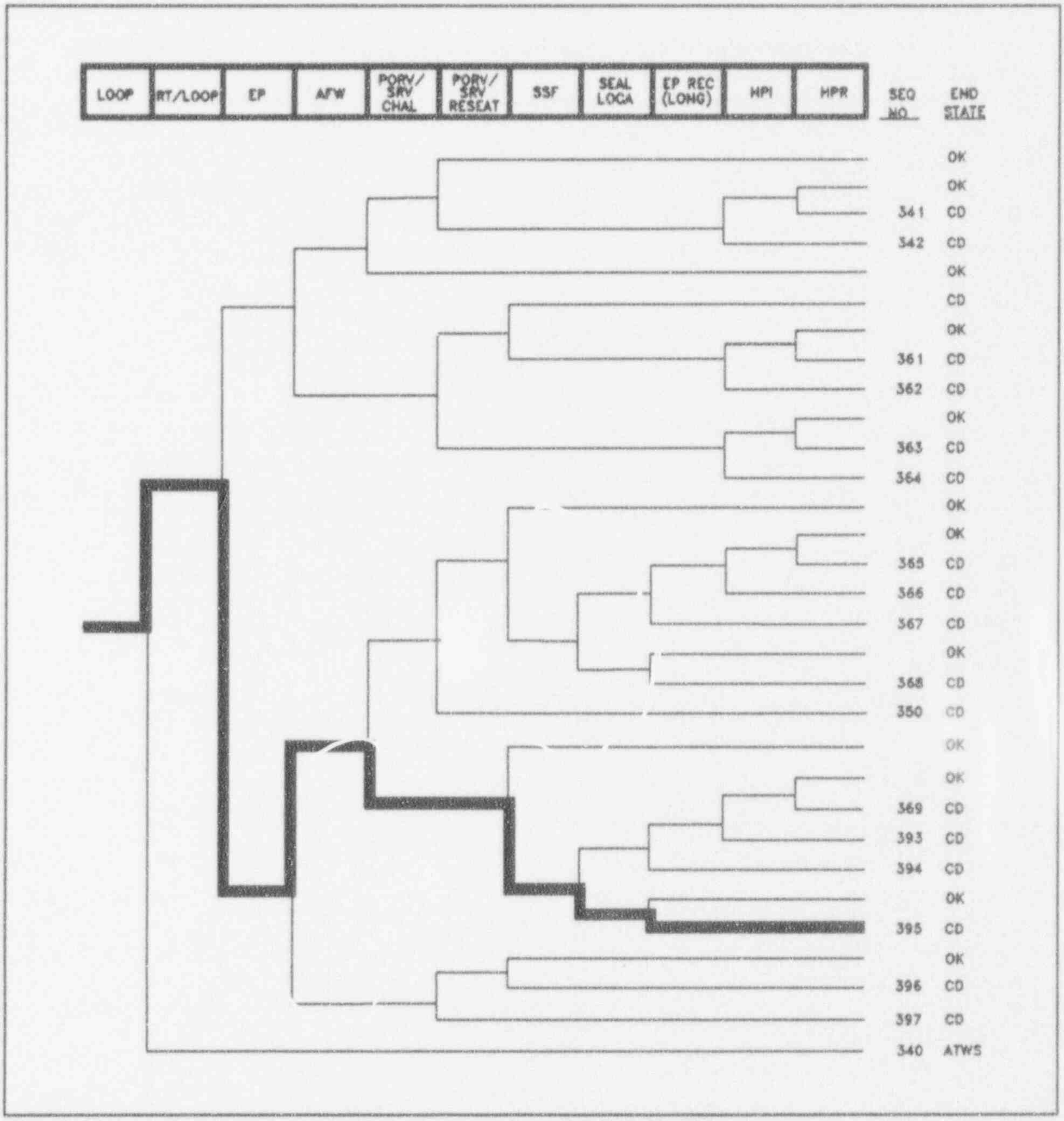

Fig. B.19. Dominant core damage sequence for LER 269/92-008.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 269/92-008
Event Description: Both Keowee hydro units unavailable
Event Date: 07/16/92
Plant: Oconee 1

UNAVAILABILITY, DURATION= 34 hours

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP(PLANT_CENT)	6.6E-05
LOOP(GRID)	2.7E-05
LOOP(WEATHER)	3.6E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP(PLANT_CENT)	5.1E-08
LOOP(GRID)	1.0E-07
LOOP(WEATHER)	2.7E-06
Total	2.8E-06
ATWS	
LOOP(PLANT_CENT)	0.0E+00
LOOP(GRID)	0.0E+00
LOOP(WEATHER)	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
395	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(weather) ep.rec(weather)	CD	2.4E-06	4.0E-01
368	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power porv.or srv.chall(loop) -porv.or.srv.reseat/emerg.power ssf -seal.loca(weather) ep.rec(weather)	CD	2.1E-07	4.0E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
368	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power porv.or.srv.chall(loop) -porv.or.srv.reseat/emerg.power ssf -seal.loca(weather) ep.rec(weather)	CD	2.1E-07	4.0E-01
395	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(weather) ep.rec(weather)	CD	2.4E-06	4.0E-01

** non-recovery credit for edited case

Event Identifier: 269/92-008

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asp\1989\oconseal.cmp
BRANCH MODEL: c:\asp\1989\oconee1.ssf
PROBABILITY FILE: c:\asp\1989\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	6.4E-05	1.0E+00	
loop(plant_cent)	1.3E-05	1.5E-01	
loop(grid)	1.6E-06	4.8E-01	
loop(weather)	1.1E-06	9.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER(PLANT_CENT)	3.0E-04 > 1.2E-01[1]	8.0E-01 > 4.3E-01[1]	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > Failed[2]		
Train 2 Cond Prob:	5.0E-02 > Failed[2]		
Train 3 Cond Prob:	1.2E-01		
EMERG.POWER(GRID)	2.5E-03 > 1.0E+00[1]	8.0E-01 > 4.3E-01[1]	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed[2]		
Train 2 Cond Prob:	5.0E-02 > Failed[2]		
EMERG.POWER(WEATHER)	2.5E-03 > 1.0E+00[1]	8.0E-01 > 4.3E-01[1]	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed[2]		
Train 2 Cond Prob:	5.0E-02 > Failed[2]		
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	8.0E-02	1.0E+00	
porv.or.srv.chall(loop)	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
ssf	2.0E-01	1.0E+00	
seal.loca(plant_cent)	0.0E+00	1.0E+00	
seal.loca(grid)	0.0E+00	1.0E+00	
seal.loca(weather)	0.0E+00	1.0E+00	
ep.rec(sl)(plant_cent)	0.0E+00	1.0E+00	
ep.rec(sl)(grid)	0.0E+00	1.0E+00	
ep.rec(sl)(weather)	0.0E+00	1.0E+00	

Event Identifier: 269/92-008

EP.REC(PLANT_CENT)	2.3E-01 > 5.6E-02[1]	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.3E-01 > 5.6E-02		
EP.REC(GRID)	5.3E-02 > 2.4E-02[1]	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.4E-01 > 2.0E-01		
Train 2 Cond Prob:	1.2E-01		
ep.rec(weather)	8.6E-01[1]	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03

* branch model file
** forced

Notes:

[1] See Modeling Assumptions for the development of this probability value.
[2] Both Keowee units assumed failed if auxiliary power not recovered.

Event Identifier: 269/92-008

B.13 LER Number 269/92-018

Event Description: Both Keowee Emergency Power Hydro Units Potentially Unavailable

Date of Event: December 2, 1992

Plant: Oconee 1, 2, and 3

B.13.1 Summary

With all three Oconee units at 100% power, both emergency power sources, Keowee Hydro Units 1 and 2 (Keowee 1 and 2), were determined to be inoperable. A modification to the antipump relays in the Westinghouse (type DB) breakers at Keowee did not consider the reduced control circuit dc voltage which would exist following a loss of offsite power (LOOP), when the battery chargers are not supplying the dc buses. During emergency start testing 6 d after completion of the modification (which simulated a LOOP) and in subsequent testing, certain Keowee breakers did not close when required. Both Keowee units were potentially unavailable for 15 d. The conditional core damage probability estimated for this event is 3.2×10^{-5}. This estimate is a bounding estimate that assumes all impacted breakers fail following an actual LOOP and may be conservative for the observed event. The relative significance of this event compared to other postulated events at Oconee is shown in Fig. B.20.

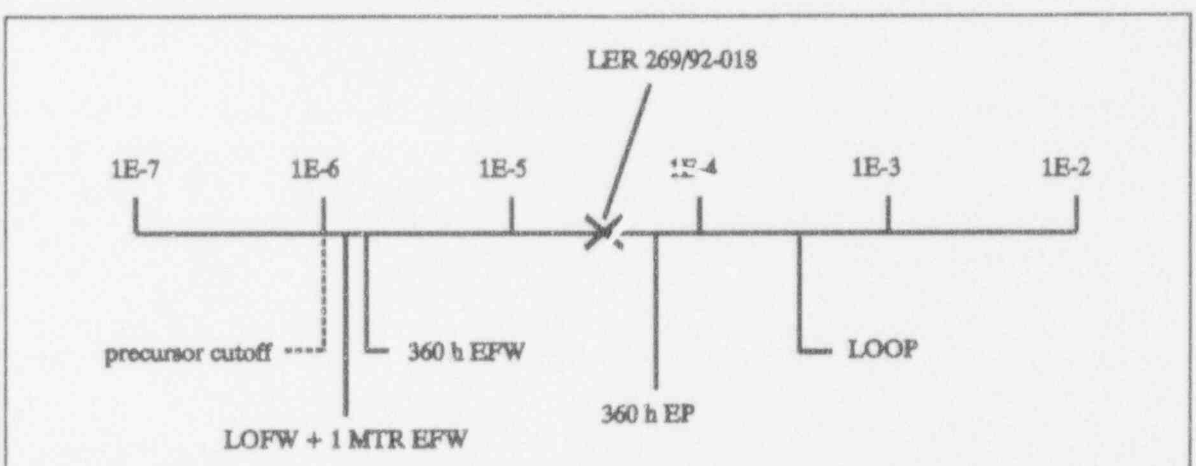

Fig. B.20. Relative event significance of LER 269/92-018 compared with other potential events at Oconee.

B.13.2 Event Description

On January 29, 1992, Keowee 2 failed to start during a routine attempt to supply power to the grid. The failure to start was caused by a mechanical failure of the "X" relay (antipump relay) in a Westinghouse (type DB) circuit breaker. Corrective actions included the replacement of the existing electromechanical antipump scheme with an electrical antipump scheme in a number of breakers. During the design review prior to the modification, Westinghouse expressed a concern that the closing coil could be damaged if it remained energized for too long a period of time. Because of this concern, each type-DB breaker was individually time-tested before and after the modification to ensure that the new antipump scheme would keep the closing coil energized for the same time as the old antipump scheme. The modification was completed for Keowee 1 on July 19, 1992, and for Keowee 2 on November 18, 1992.

On November 24, 1992, the annual Keowee emergency start test was performed for both units. This test differed from the postmodification testing described above in that a loss of auxiliary ac power was also simulated. With no output from the battery charger because of the unavailability of auxiliary ac power, dc voltage (supplied only by the battery) was lower than during the post-modification testing. During attempts to tie Keowee 2 to the overhead path (one of the two power paths from Keowee to Oconee), the Keowee 2 auxiliary power alternate feeder breaker (ACB-8) could not be closed after the normal feeder breaker (ACB-6) was opened. The auxiliaries for both units were placed in a dedicated alignment which would not require breaker operation during an emergency, pending further breaker testing. On December 1, 1992, voltage regulator problems required Keowee 1 to be shut down and declared inoperable. Testing later in the day demonstrated that the Keowee 1 auxiliary power alternate feeder breaker (ACB-7) failed to close at low dc voltages.

The standby buses were energized from a Lee gas turbine on December 2, 1992 around 1000 hours, and testing of the control circuitry for the type-DB circuit breakers was completed later that day at about 1605 hours. The testing indicated that the available dc voltage was inadequate to ensure closure of the breakers. Keowee 2 was declared inoperable.

The utility stated that, under reduced dc voltage situations, the closing mechanism moves more slowly and therefore has less momentum. This reduced momentum was inadequate to complete the breaker travel for the actual dc voltage. In addition to the auxiliary power breakers, the problem affected the field and field supply breakers, which made both units inoperable. The problem was corrected by increasing the time that the closing coils were energized.

Keowee 1 was restored to an operable status at 0835 hours on December 3, 1992, following the modification to increase the time that the type-DB breaker closing coils are energized. On December 4, 1992, modifications to increase the time that the Keowee 2 closing coils are energized were completed and Keowee 2 was returned to service just before midnight.

B.13.3 Additional Event-Related Information

The Keowee Station, located approximately 0.75 mile east-northeast of the Oconee Nuclear Station, it consists of two hydroelectric generators that generate at 13.8 kV. The two units serve the dual functions of generating commercial power to the Duke Power system grid through the Oconee 230-kV switchyard and providing emergency power to the Oconee Station. When a Keowee unit is generating to the grid and an emergency start occurs, it is separated from the 230-kV switchyard and continues to run in standby until needed. Upon loss of power from an Oconee generating unit and 230-kV switchyard, power is supplied from both Keowee units through two separate and independent paths. One path is a 4000-ft underground 13.8-kV cable feeder to transformer CT-4, which supplies power to the 4160-V standby buses. The underground power path is connected at all times to one hydro unit on a predetermined basis through locked-closed breakers. The underground power path and associated transformer are sized to carry full engineered safeguards auxiliaries of one Oconee unit plus auxiliaries for safe shutdown of the other two units. If a Keowee unit is to provide power to an Oconee unit through the underground power path (required by Technical Specifications if one of the Keowee units is out of service), then due to the limited capacity of CT-4, loadshed of non-essential loads occurs. The second path from Keowee is a 230-kV transmission line through breakers ACB-1 or ACB-2, via the yellow bus, to each Oconee unit's startup transformer.

Keowee auxiliary power is required for the ac hydraulic oil pumps, which are used to pressurize the air preloaded accumulators that provide hydraulic oil pressure to the governor which controls the position (depending on load) of the wicket gates on the Keowee water turbine. The length of time that the Keowee units can run without ac auxiliaries is limited by the changing load to which the governor must respond. The utility has indicated in several LERs that 1 h is the expected maximum time period of Keowee operation without ac auxiliaries.

A standby shutdown facility (SSF) is located in a separate building on the Oconee site. This facility, which is not normally manned, is capable of providing limited high-pressure injection for reactor coolant system (RCS) makeup and reactor coolant pump (RCP) seal cooling [provided an RCP seal loss-of-coolant accident (LOCA) does not occur]. It can also supply limited steam generator makeup. The facility includes a separate diesel generator which can power SSF loads in the event of a station blackout. SSF systems consist of single trains and are therefore not single-failure-proof.

A more detailed description of the Oconee emergency power system is included in the precursor analysis for LER 270/92-004, *Loss of Offsite Power with Failed Emergency Power*.

B.13.4 Modeling Assumptions

The event was modeled as a postulated LOOP from the time the Keowee units became unavailable (November 13, 1992) until the standby buses were energized from the Lee gas turbine (December 2, 1992), approximately 360 h. Since the breakers that failed were found in different tests (some breakers apparently worked correctly during some tests and not for others), it is not possible to conclude that all breakers would have failed to function during an actual LOOP. Because of this, a bounding analysis was performed, with the assumption that, given a LOOP, the Keowee auxiliary power and field breakers would have failed to function. Such an analysis may be conservative, but provides insight into the potential significance of the event.

Potential sequences associated with the event are described in Appendix A, Sect. A.3.1, PWR Loss of Offsite Power. These sequences were modified to address the Oconee-specific SSF, as described later in this section, and are shown on the event tree included with this analysis documentation. The plant response observed during the event impacted the following branch on the event tree:

Emergency Power. The Keowee hydro units were assumed to fail because of the postulated inoperability of the auxiliary power and field breakers, a result of reduced dc voltage following the LOOP.

Recovery from the event was assumed to be sufficiently complex that an on-call technician would have to be called to the site during off-hours. The probability of the on-call technician failing to arrive on-site and recover Keowee Hydro prior to the loss of wicket gate control was estimated to be 0.64, as described under Modeling Assumptions for the precursor analysis for LER 270/92-004. While procedures at Keowee had been revised after the LOOP, the method used to notify the on-call technician (a phone call) had not been changed. (Depending on the specifics of an event, the Keowee operator may be remotely instructed to close the breakers manually. The potential effectiveness of such an action was not addressed in this analysis.)

Use of an on-call technician was assumed to be required except for the day shift, when adequate support was assumed available on-site to quickly correct the breaker problem and recover Keowee, if needed. This assumption results in a revised estimate for failing to recover Keowee of (16h/24h) $\times$ 0.64 = 0.43.

The Central Switchyard was also assumed available as an alternate source of power to the Standby Buses for plant-centered LOOPs. A probability of 0.12 (ASP nonrecovery class R3, see Appendix A, section A.1) was assumed for failing to recover power from the Central Switchyard via transformer CT-5. This value was chosen because recovery appeared possible in the required time period from the control room. However, during a postulated LOOP with problems at Keowee, this recovery would be considered to be non-routine and burdened. During a postulated grid- or severe weather-related LOOP, the Central Switchyard was assumed to be unavailable. However, during a postulated grid-related LOOP, ac power was assumed to be recoverable in approximately 1 h using the Lee combustion turbines. A nonrecovery probability of 0.12 was also assumed for this action, for the same reasons.

The frequency of LOOP and the probability of not recovering offsite power was estimated as described in ORNL/NRC/LTR-89/11, *Revised LOOP and PWR Seal LOCA Models*, August 1989. The frequencies and probability values used in the calculations follow:

	LOOP Type		
	Plant-Centered	Grid-Related	Severe Weather-Related
LOOP frequency	1.3×10^{-5}/h	1.6×10^{-6}/h	1.1×10^{-6}/h
P_{nrec} (LOOP)	0.15	0.48	0.93
P_{nrec} (emergency power)	0.43 $\times$ 0.12	0.43	0.43
P_{nrec} (ac power prior to battery depletion)	0.23	0.44 $\times$ 0.12	0.86

The use of the SSF as an alternate source of reactor coolant system (RCS) and steam generator (SG) makeup was also addressed in the analysis. This was done by identifying core damage sequences that could be recovered through the use of the SSF (sequences with failed SG makeup or RCP seal cooling and without loss of inventory), and modifying the event tree model described in Appendix A to include its consideration. The revised event tree for Oconee is included with this analysis. A combined operator and equipment failure probability of 0.2 was used for the SSF. This probability is consistent with values developed in the Oconee PRA (NSAC-60) and in licensee analyses of this event.

B.13.5 Analysis Results

The conditional core damage probability estimated for the event is 3.2×10^{-5}. This conditional probability is applicable to each of the three Oconee units. The dominant core damage sequence, highlighted on the event tree in Fig. B.21, involves a postulated weather related LOOP with failure of emergency power, failure of the SSF, and failure to recover ac power before battery depletion. The conditional probability estimate is strongly influenced by assumptions concerning the potential for recovery of the Keowee units.

As described in Sect. B.13.4, this analysis is a bounding analysis that addresses the potential impact of multiple breaker inoperability over the entire exposure period. As such, this analysis may be conservative.

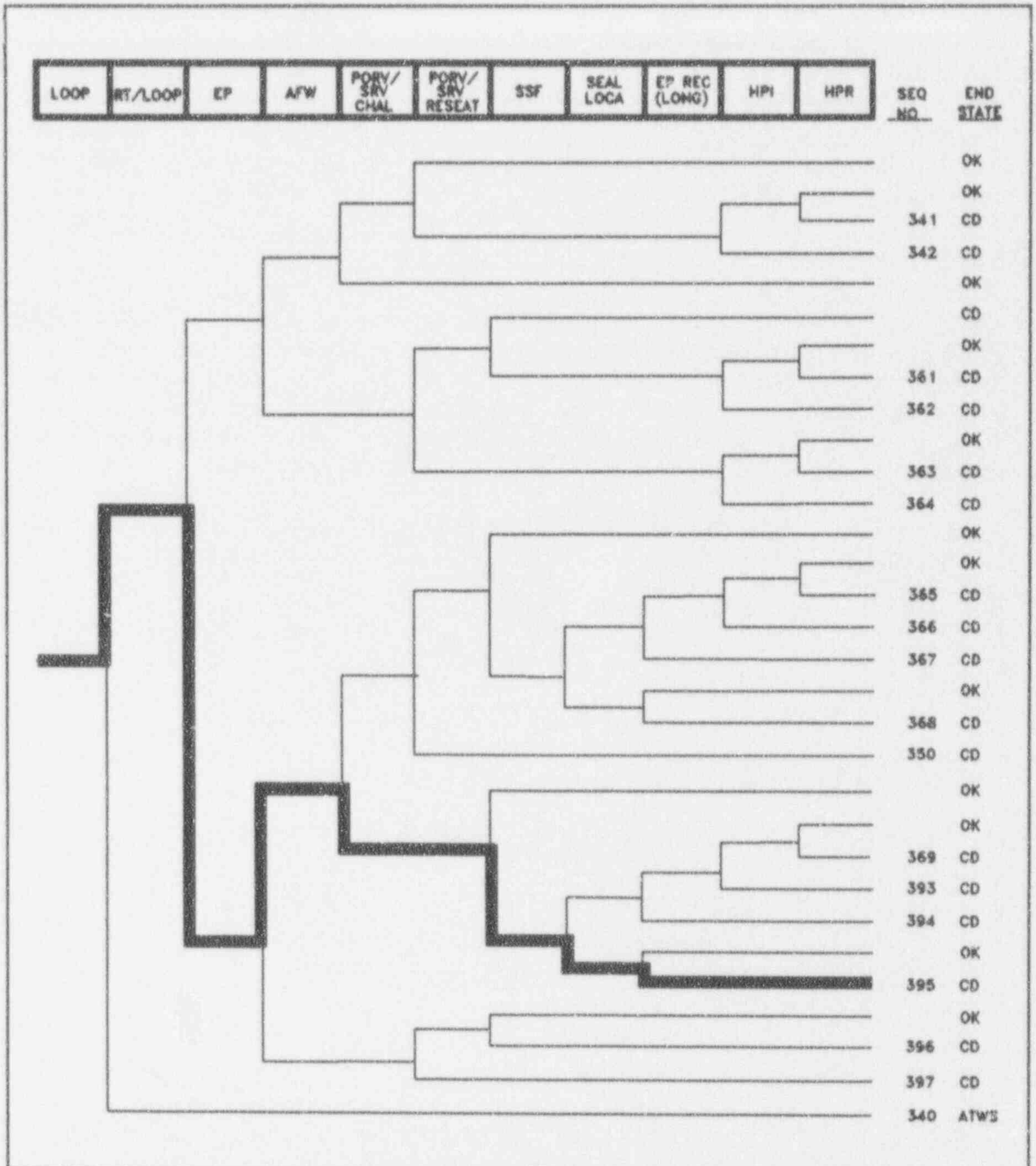

Fig. B.21. Dominant core damage sequences for LER 269/92-018.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 269/92-018
Event Description: Both Keowee hydro units potentially unavailable
Event Date: 12/02/92
Plant: Oconee 1

UNAVAILABILITY, DURATION= 360

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP(PLANT_CENT)	7.0E-04
LOOP(GRID)	2.8E-04
LOOP(WEATHER)	3.8E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP(PLANT_CENT)	1.8E-06
LOOP(GRID)	1.8E-06
LOOP(WEATHER)	2.8E-05
Total	3.2E-05
ATWS	
LOOP(PLANT_CENT)	0.0E+00
LOOP(GRID)	0.0E+00
LOOP(WEATHER)	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
395	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(weather) ep.rec(weather)	CD	2.5E-05	4.0E-01
368	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power porv.or.srv.chall(loop) -porv.or.srv.reseat/emerg.power ssf -seal.loca(weather) ep.rec(weather)	CD	2.2E-06	4.0E-01
195	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(plant_cent) ep.rec(plant_cent)	CD	1.5E-06	6.4E-02
295	loop(grid) -rt/loop EMERG.POWER(GRID) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(grid) ep.rec(grid)	CD	1.2E-06	2.0E-01

** non-recovery credit for edited case

Event Identifier: 269/92-018

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
195	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(plant_cent) ep.rec(plant_cent)	CD	1.5E-06	6.4E-02
295	loop(grid) -rt/loop EMERG.POWER(GRID) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(grid) ep.rec(grid)	CD	1.2E-06	2.0E-01
368	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power porv.or.srv.chall(loop) -porv.or.srv.reseat/emerg.power ssf -seal.loca(weather) ep.rec(weather)	CD	2.2E-06	4.0E-01
395	loop(weather) -rt/loop EMERG.POWER(WEATHER) -afw/emerg.power -porv.or.srv.chall(loop) ssf -seal.loca(weather) ep.rec(weather)	CD	2.5E-05	4.0E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asp\1989\oconseal.cmp
BRANCH MODEL: c:\asp\1989\oconee1.ssf
PROBABILITY FILE: c:\asp\1989\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	6.4E-05	1.0E+00	
loop(plant_cent)	1.3E-05	1.5E-01	
loop(grid)	1.6E-06	4.8E-01	
loop(weather)	1.1E-06	9.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER(PLANT_CENT)	3.0E-04 > 1.2E-01[1]	8.0E-01 > 4.3E-01[1]	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.0E-02 > Failed		
Train 3 Cond Prob:	1.2E-01		
EMERG.POWER(GRID)	2.5E-03 > 1.0E+00[1]	8.0E-01 > 4.3E-01[1]	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.0E-02 > Failed		
EMERG.POWER(WEATHER)	2.5E-03 > 1.0E+00[1]	8.0E-01 > 4.3E-01[1]	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.0E-02 > Failed		
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	8.0E-02	1.0E+00	

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porv.or.srv.chall(loop)	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
ssf	2.0E-01	1.0E+00	
seal.loca(plant_cent)	0.0E+00	1.0E+00	
seal.loca(grid)	0.0E+00	1.0E+00	
seal.loca(weather)	0.0E+00	1.0E+00	
ep.rec(sl)(plant_cent)	0.0E+00	1.0E+00	
ep.rec(sl)(grid)	0.0E+00	1.0E+00	
ep.rec(sl)(weather)	0.0E+00	1.0E+00	
ep.rec(plant_cent)	2.3E-01	1.0E+00	
ep.rec(grid)	5.3E-02	1.0E+00	
ep.rec(weather)	8.6E-01	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03

* branch model file
** forced

Notes:

[1] See Modeling Assumptions for the development of this probability value

Event Identifier: 269/92-018

B.14 LER Number 270/92-004, 269/92-011, 269/92-014, 269/92-016, 269/92-019, and 269/93-001

Event Description: Loss of Offsite Power With Failed Emergency Power

Date of Event: October 19, 1992

Plant: Oconee 2

B.14.1 Summary

Use of an inadequate procedure for switchyard battery replacement resulted in a lockout of the Oconee 230-kV switchyard, a reactor trip, and loss of offsite power (LOOP) at Unit 2, and unavailability of power to the startup transformers for Units 1 and 3. An operator error and two breaker failures at the Keowee Hydro Station, the emergency power source for the three Oconee units, caused a loss of all auxiliary power to both hydro units. Auxiliary power was recovered 0.5 h later, when an on-call technician arrived at Keowee. Problems were also experienced with the emergency feedwater (EFW) system, instrument air (IA) system, and the standby shutdown facility (SSF) during recovery from the event. The emergency power system, the turbine-driven EFW pump, and SSF are the primary features available to protect against core damage from a station blackout following a LOOP.

The conditional core damage probability estimated for this event is 2.1×10^{-4}. The relative significance of this event compared to other postulated events at Oconee is shown below in Fig. B.22.

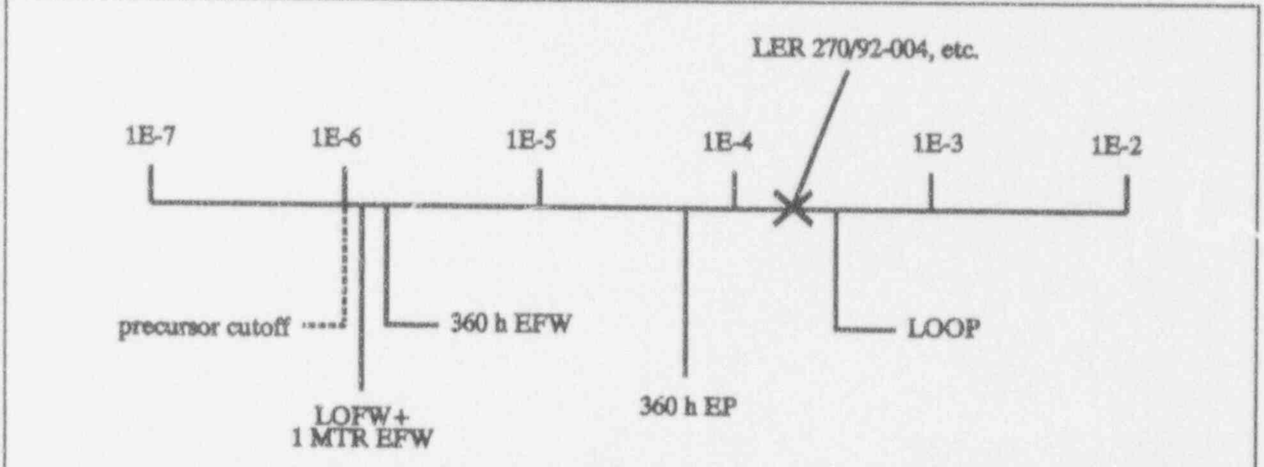

Fig. B.22. Relative event significance of LER 270/92-004, etc., compared with other potential events at Oconee.

B.14.2 Event Description

On October 19, 1992, Oconee 2 was operating at 100% power. Keowee Hydro Unit 1 (Keowee 1), one of the emergency power sources for the three Oconee units, was supplying power to the grid via the overhead power path (see Fig. B.23). Keowee 2 was shut down and was aligned to provide emergency power via the underground path. Replacement of the 230-kV switchyard batteries was in progress: battery SY-2 and charger SY-2 were disconnected, switchyard dc buses SY-DC-1 and SY-DC-2 were cross-tied, and charger SY-1 and battery SY-1 were powering both buses (see Fig. B.24).

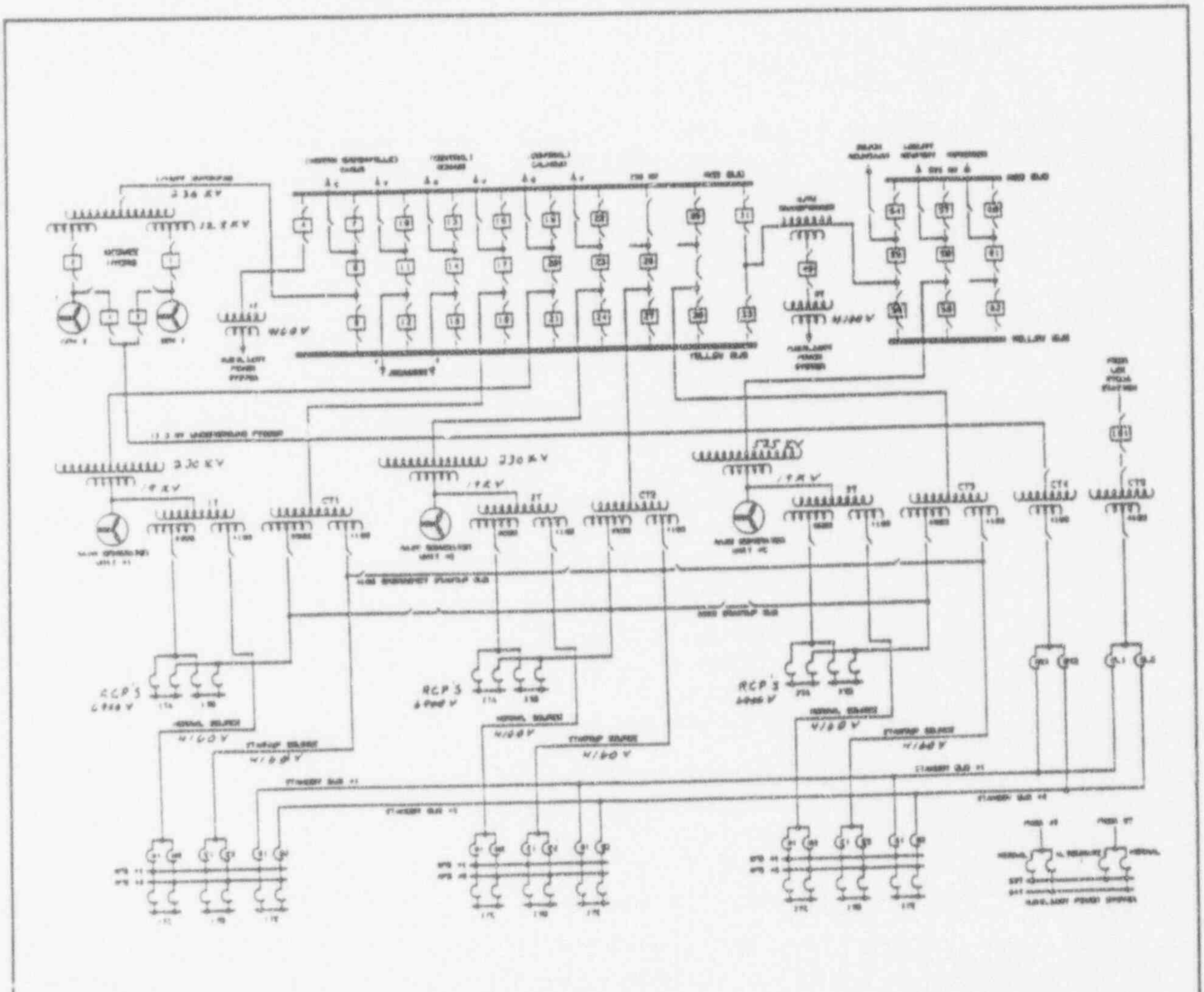

Fig. B.23 Emergency power distribution at Oconee
(Original figure was illegible.)

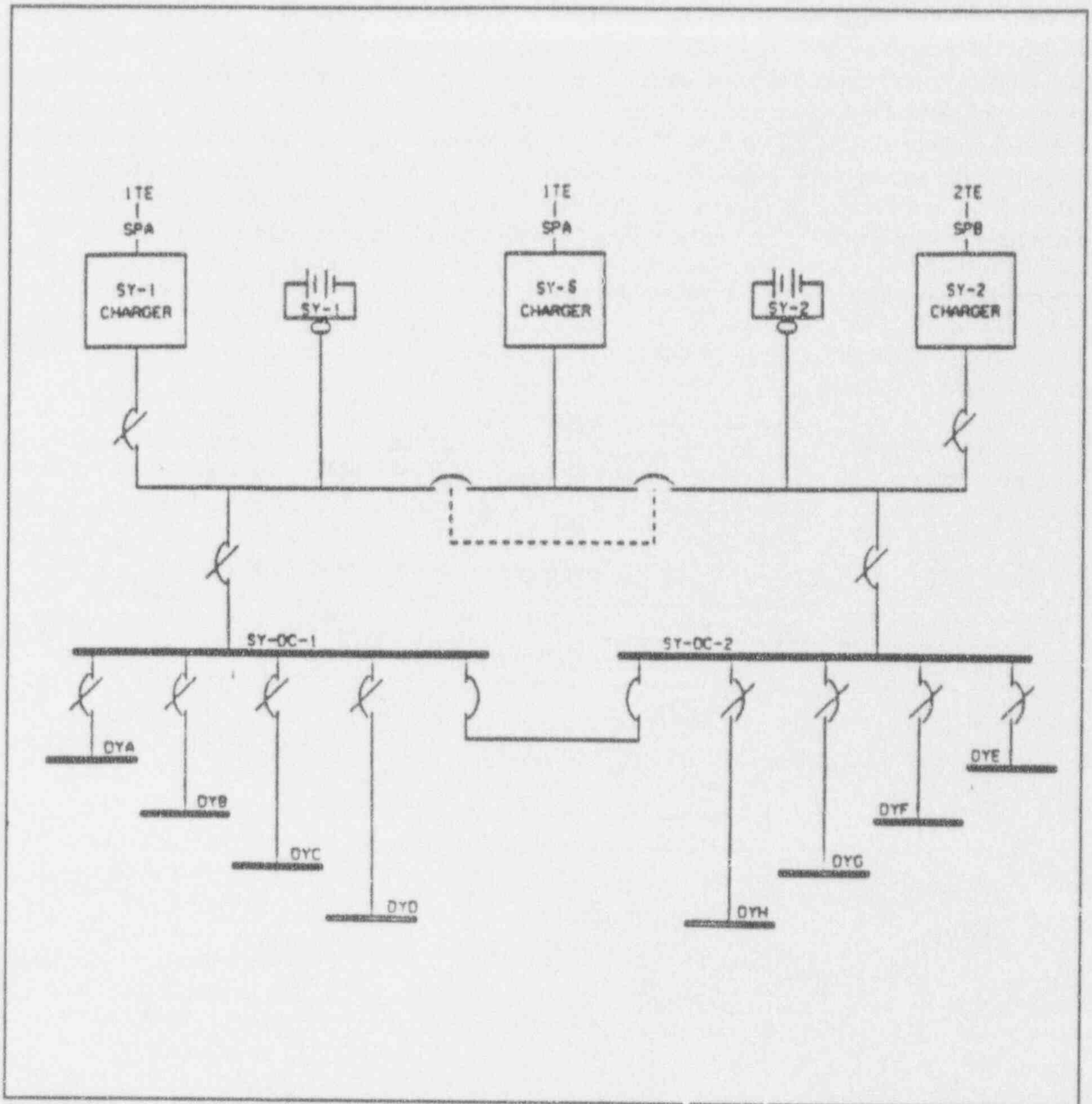

Fig. B.24. 230-kV switchyard dc power distribution at Oconee
(Original figure was illegible.)

A point had been reached during the battery replacement when charger SY-2 was to be reconnected to its bus and the two buses separated. This alignment was allowed by the battery replacement procedure. Once this was done, bus SY-DC-2 would be powered only by its charger. Battery SY-2, which was normally connected to the bus, would remain unconnected. This highly unusual alignment (which can subject a bus to large voltage fluctuations because of battery charger instability) had been used between October 6 and October 12, 1992, when battery SY-1 was replaced, without any complications. The Oconee 1 unit supervisor went to the switchyard relay house with several technicians to perform the procedural steps to reconnect the charger and separate the dc buses. He connected the charger to the bus and then, at 2121 hours, opened the tie breaker to separate the two switchyard dc buses. Within the next several seconds a switchyard lockout, Oconee 2 trip, Keowee 1 normal trip, and emergency start of both Keowee units occurred. The unit supervisor suspected that his actions had initiated the event and backed out of the procedure by reclosing the switchyard dc bus tie breakers and opening the breaker from the SY-2 charger.

The 230-kV switchyard lockout was a result of a voltage transient on switchyard dc bus SY-DC-2 caused by charger SY-2. Bus SY-DC-2 powered the breaker failure circuits for all of the 230-kV switchyard breakers. The breaker failure circuitry is designed to actuate an auxiliary relay (AR) and trip adjacent breakers after a time delay if a faulted breaker fails to trip. The breaker failure circuitry employed a zener diode as a surge protector in a design that caused current to flow through the breaker AR relay coil when the zener diode conducted (performed its protective function). The relays had been identified as being susceptible to spurious operation due to excessive voltages in 1980, but were never modified. The AR relay for power circuit breaker (PCB)-24 was the first to actuate on the yellow 230-kV bus. This relay tripped PCB-23 and initiated a yellow bus lockout, which tripped PCBs-9, 12, 15, 18, 21, 24, 27, and 30. A lockout also occurred on the red bus, and tripped PCBs-4, 7, 10, 13, 16, 19, 22, 26, and 28. PCBs-31 and 33 were tagged open to support maintenance and did not trip. All of the PCBs are shown in Fig. B.23.

Actuation of the AR relay in PCB-24 also caused an Oconee 2 generator transformer lockout, which resulted in a turbine and reactor trip. With PCBs-26 and 27 open and the reactor tripped, Oconee 2 had no source of offsite power available. The External Grid Protective System sensed the loss of voltage and frequency on the yellow and red buses (which indicated a LOOP) and generated a switchyard isolation signal. This signal tripped PCBs-8, 9 and 17, load-shed Keowee 1, and gave an emergency start signal to both Keowee units. Oconee 1 and 3 continued to operate, but with PCBs-17 and 26 open, neither unit would have had a source of offsite power if Keowee had tripped (manual recovery of offsite power would have been possible). Keowee 2 started on the switchyard isolation signal. Nonessential Oconee 2 loads were shed, and Oconee 2 main feeder buses were reenergized via transformer CT-4. This provided power to essential loads via the underground power path.

The Keowee operator was in the turbine room when the event began. When he returned to the Keowee control room, he observed multiple alarms but failed to observe an alarm indicating that an emergency start signal existed. He noted that Keowee 1 was operating with no load, concluded that the hydro unit might be in danger of failing, and manually opened output breaker ACB-1 (see Fig. B.25). When ACB-1 opened, Keowee auxiliary buses 1X and 2X attempted to transfer to their alternate power source, transformer CX (which is powered from Oconee 1 switchgear 1TC-4). Breaker ACB-7 failed to close,

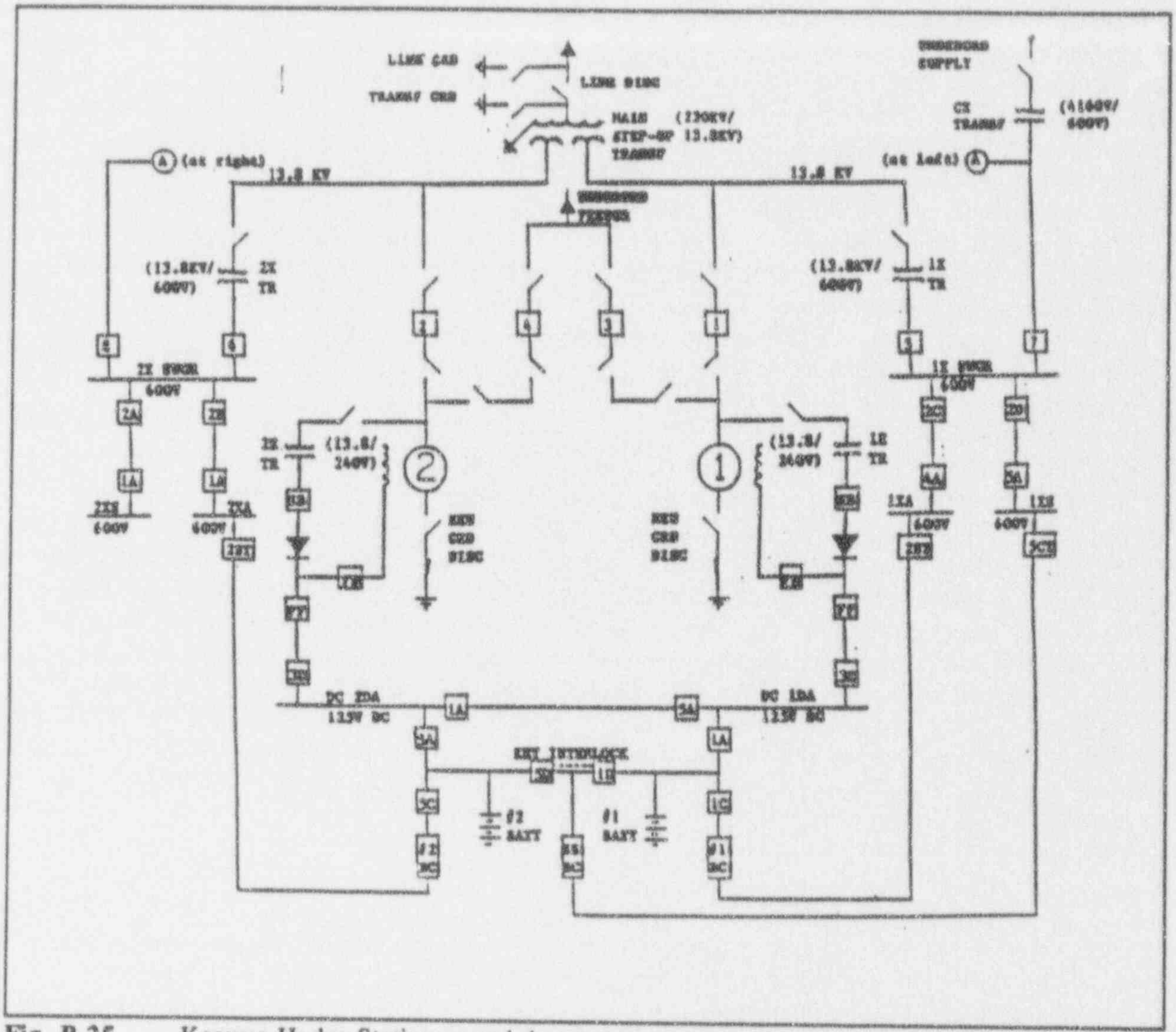

Fig. B.25. Keowee Hydro Station ac and dc systems
(Original figure was illegible.)

apparently because of the spurious actuation of a lockout relay following a series of repetitive breaker operations that occurred as load center 1X lost and regained power during the event. As a result, bus 1X remained deenergized. ACB-8 failed to close because of high resistance on a close permissive contact, which caused auxiliary bus 2X to remain deenergized. The loss of these two buses resulted in the loss of all auxiliary power to the Keowee units. The Keowee control room lights went off, the annunciator panels went dark, and the telephone connection to Oconee and the alarm typer were lost. At this point, the Keowee operator determined that Keowee 2 was running in the emergency mode. The Keowee units continued to operate with their control functions supplied by batteries.

The unavailability of Keowee auxiliary power prevented makeup to the hydraulic oil accumulator tanks. These accumulators provide the oil to operate the governor and wicket gates to control turbine speed and generator output. Keowee can operate up to about 1 h, depending upon load changes, without auxiliary power before governor and wicket gate control becomes unavailable.

The Oconee 2 turbine-driven EFW pump started automatically following the LOOP and reactor trip. Within a few seconds, EFW flow dropped to zero for 3 to 5 sec, and then returned to normal. The loss of flow resulted from water intrusion into the steam supply to the turbine. The water intrusion was caused by a faulty steam trap. As the turbine-driven pump picked up flow again, power was restored (Keowee 2 start and load), and both motor-driven EFW pumps started as well.

About 1 min after the LOOP, alarms were received at Oconee 1 and Oconee 2 indicating low pressure in the IA system. The Oconee primary IA compressor is powered from the switchyard and lost power when the red bus lockout occurred. The backup IA compressor powered from Unit 2 was load-shed and could not start automatically. While two other backup IA compressors (powered from Oconee 1) did start, they were unable to maintain IA pressure. A diesel-powered IA compressor was started locally at Oconee 3, and a loss of IA was averted. A loss of IA would have caused a loss of main feedwater control and loss of control rod drive mechanism cooling at Oconee 1 and would have resulted in a reactor trip at that unit. If that had occurred, offsite power would have been lost to Unit 1 also.

Several minutes after the loss of auxiliary power at Keowee, the Keowee operator contacted the Duke Power system dispatcher in Charlotte via a dedicated phone line, which was still in service. The dispatcher was requested to call the Keowee on-call technician to come to the site. The dispatcher was able to connect the Oconee control room to Keowee via the dispatcher phone line. The Keowee operator discussed the status of Keowee with the Oconee 2 unit supervisor, and the unit supervisor instructed him not to take any action involving Keowee 2, since it was supplying the Oconee 2 main feeder buses. It appears that the Keowee operator did not adequately describe the ramifications of the loss of auxiliary power. The Keowee operator then monitored the operation of the hydro units and awaited the arrival of the on-call technician. Meanwhile, because of problems at Keowee, the Oconee operations shift supervisor and the dispatcher decided to try to quickly restore the switchyard. The dispatcher had confirmed that there was no indication of faults or breaker actuations outside the switchyard, and it was decided to skip the lengthy checkout of equipment required by the Loss of Power Abnormal Procedure.

The on-call technician arrived in the Keowee control room at 2150 hours, about 30 min after the event had started. The most immediate problem was the restoration of auxiliary power so that hydraulic oil for wicket gate and governor control could be made up to the accumulators. The normal oil level in the accumulator sight-glass is 48 in.; when the on-call technician arrived, the level in both accumulators was 4 to 8 in.

Using the Charlotte dispatcher's phone, the Keowee on-call technician, the dispatcher, and the Oconee 2 unit supervisor decided to attempt to reset the Keowee main transformer lockout and also have personnel at the Lee Steam Station start a combustion turbine and establish a dedicated line from Lee to

Oconee.[1] The Keowee on-call technician reset the transformer lockout at 2158 hours. This allowed ACB-1 to close automatically, and this closure, in turn, allowed Keowee 1 (which had been running with no load) to energize the transformer. The normal supply breaker to the Keowee 2X load center (ACB-6) then closed, restoring auxiliary power to Keowee 2. Auxiliary power to Keowee 1 was restored 8 min later, after a local lockout at breaker ACB-7 was reset.

At 2200 hours, the Oconee 1 unit supervisor reset the red and yellow bus lockouts from the switchyard. The red bus was reenergized from offsite power at 2213 hours by closing PCB-10. By 2218 hours, power had been restored to the Unit 2 startup transformer from the red bus. Some difficulty was experienced with breaker operation because of the existing switchyard isolation signal, which had not been cleared. At 2221 hours, a dedicated line was available from a Lee combustion turbine. One result of the breaker operation associated with not clearing the switchyard isolation signal was the repowering of the yellow bus from Keowee 1. Because Keowee 1 was not synchronized to the grid, a decision was made to shut down Keowee 1 and repower the yellow bus from the red bus prior to restoring power to the Oconee 1 and Oconee 3 startup transformers.

The single emergency start signal to both Keowee units was reset, and Keowee 1 was shut down at 2251 hours. The yellow bus deenergized as expected, but Keowee 2 also tripped. The Keowee 2 trip was caused by the undervoltage condition on the yellow bus combined with the lack of an emergency start signal; system logic determined that Keowee 2 was generating to the grid with no output and tripped the unit (the system logic does not include Keowee supplying power via the underground feeder). The Keowee 2 trip deenergized the underground feeder, the standby buses, and the Oconee 2 main feeder buses. After a 31-sec delay, the standby breakers tripped open and the startup breakers closed to restore power to the main feeder buses. The deenergization of the main feeder buses generated a second Keowee emergency start signal. Keowee 1 started, but did not close onto the yellow bus since a switchyard isolation initiation signal was not generated because the red bus was still energized. This response was expected; however, Keowee 2 did not respond as expected. After the trip, it began to slow down. The emergency start signal initiated a restart prior to resetting a speed switch in the field breaker anti-pump circuit. The speed switch and anti-pump circuit prevented the field from energizing and therefore kept the generator from functioning.

At 0018 hours the next morning, October 20, 1992, both Keowee units were shut down. By 0024 hours, Keowee 2 had slowed down enough to reset the speed switch in the field flashing circuit, had been restarted, and had been realigned to transformer CT-4. At 0041 hours, PCB-8 was closed, and the yellow bus was reenergized from the red bus. The switchyard was restored to its normal alignment by 0057 hours, which also restored power to the startup transformers for Oconee 1 and 3.

It was subsequently determined that the Oconee SSF was degraded as a result of the event. SSF systems provide a backup supply of water to the steam generators and a backup source for reactor coolant pump (RCP) seal injection and reactor coolant makeup sufficient to maintain natural circulation cooling. Normal power to the SSF is fed from Oconee 2 and was lost following the LOOP. Oconee personnel

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[1]Both the dispatcher and the unit supervisor were aware of problems at Keowee 20 min earlier, during their first telephone call.

confirmed that the SSF diesel generator was not started to power SSF loads. The battery charger in the SSF was de-energized because of the Unit 2 LOOP and resulted in dc and 120-Vac loads being powered from the SSF battery. The potential problems with the SSF were discovered at 0125 hours, October 20, 1992, about 4 h after the event began. Power was restored to the SSF at 0415 hours. The utility stated that a spare battery was included in the SSF dc power system and could have been aligned if required.

Numerous equipment inspections, necessary repairs, and procedure modifications took place after the event. A Keowee abnormal procedure was developed to specify operator response following an emergency start. Before this event, no specific procedure existed for verifying or responding to an emergency start of the Keowee units. After the event, the Keowee Hydro Station organization was realigned to report to the Nuclear Generation Department. Previously, it had reported to the Hydro Department. In addition, an Oconee operator was assigned to Keowee to stress watchstanding.

A dedicated phone was installed between the Keowee and Oconee control rooms. Previously, a commercial phone line had been used. Protective logic was revised so that the Keowee units would no longer trip because of undervoltage on the main step-up transformer. A special test was performed to confirm (1) the proper response of Keowee Hydro to a simulated switchyard isolation signal when aligned to the grid and (2) the implementation of an Oconee "live" bus transfer procedure to repower loads from the switchyard. Generally, the Keowee units performed as expected during the test. However, the Oconee operators had difficulty controlling Keowee 1 while initially tying it to the grid and while paralleling the overhead path to the grid during system restoration after the test. In addition, the Keowee operator was unfamiliar with the response required to several annunciators that alarmed during the test.

B.14.3 Additional Event-Related Information

All three Oconee units have the same generating capacity (850 MWe net) and similar ac power systems (see Fig. B.23). Output from the Oconee 1 and 2 generators feed power to the 230-kV switchyard via step-up transformers T1 and T2. The output of the Oconee 3 generator feeds the 525-kV switchyard via step-up transformer T3. The 230-kV and the 525-kV switchyards are divided into two buses, designated as the red bus and the yellow bus. The switchyards are normally operated with both buses energized through a breaker-and-one-half scheme to the grid. The yellow bus in the 230-kV switchyard is identified as safety-related. The Keowee Hydro Station supplies power to the switchyard via an above-ground (overhead) path, and this overhead path is used to supply power to the yellow bus if the grid is lost.

The operating Oconee units normally provide power to their own auxiliary loads through auxiliary transformers 1T, 2T, and 3T. When the generator for a unit is unavailable, such as following a reactor trip or during outages, electric power is automatically supplied from the switchyard through its respective startup transformer, CT-1, CT-2, or CT-3. Although Oconee 3 feeds the 525-kV switchyard, the source of power for its startup transformer is through the 230-kV switchyard. The auxiliary power system for each Oconee unit is designed as a dual-train cascading bus system. There are two 4160-V main feeder buses, MFB1 and MFB2, each of which supplies power to three 4160-V load buses (TC, TD, and TE). Except for the reactor coolant pumps, all ac is fed from these three buses. The power to MFB1 and MFB2 is either supplied by the unit's auxiliary transformer through the N breakers or by the startup transformer through the E breakers. In addition, MFB1 and MFB2 for each Oconee unit can be energized from the two standby buses (SB1 and SB2) through the S breakers. SB1 and SB2 are common to all three Oconee units and can be energized automatically through transformer CT-4 or manually from CT-5. Transformer CT-5 can be supplied from the Lee Steam Station through a dedicated line or from the central substation.

The Keowee Hydro Station is located approximately three-fourths of a mile east-northeast of the Oconee Nuclear Station. It consists of two hydroelectric generators that generate at 13.8 kV. The two Keowee hydro units serve the dual functions of generating commercial power to the Duke Power system grid through the Oconee 230-kV switchyard and providing emergency power to the Oconee station. When a Keowee unit is generating to the grid and an emergency start occurs, it is separated from the 230-kV switchyard and continues to run in standby until needed. Upon loss of power from an Oconee generating unit and 230-kV switchyard, power is supplied from both Keowee units through two separate and independent paths. One path is a 4000-ft underground 13.8-kV cable feeder to transformer CT-4, which supplies power to the 4160-V standby buses though breakers SK1 and SK2. The underground power path is connected at all times to one hydro unit on a predetermined basis by having either ACB-3 or ACB-4 locked closed. The underground power path and associated transformer are sized to carry full engineered safeguards auxiliaries of one Oconee unit plus auxiliaries for safe shutdown of the other two units. If a Keowee unit is to provide power to an Oconee unit through the underground power path, due to the limited capacity of CT-4, loadshed of nonessential loads from the Oconee units MFBs occurs. The second path from Keowee is a 230-kV transmission line through ACB-1 or ACB-2, via the yellow Bus, to each Oconee unit's startup transformer.

Keowee auxiliary power (buses 1X and 2X) is required for the ac hydraulic oil pumps, which are used to pressurize the air preloaded accumulators that provide hydraulic oil pressure to the governor which controls the position (depending on load) of the wicket gates on the Keowee water turbine. The length of time that the Keowee units can run without ac auxiliaries is limited by the changing load to which the governor must respond. The utility has indicated in several LERs that 1 h is the expected maximum time period of Keowee operation without ac auxiliaries.

The normal Keowee configuration at the time of the event was to have either Keowee 1 or 2 available for generation to the grid using the overhead path (via ACB-1 for Keowee 1 or ACB-2 for Keowee 2). One unit was also aligned to supply the underground path with emergency power (either ACB-3 or ACB-4 closed). The design of the Keowee control circuitry was to provide emergency power to the underground power path from one unit for all emergency-start situations while providing power to the overhead path from the other unit only if offsite power was lost.

The Keowee auxiliary buses normally were powered from the overhead path through their respective 1X and 2X transformers, the Keowee main step-up transformer, and the 230-kV switchyard. Normal power was supplied to the 1X bus through ACB-5 and to the 2X bus through ACB-6. These two load centers also had an alternate power source from the CX transformer that receives power from Oconee 1 load center 1TC. Alternate power from the CX transformer for the 1X bus was provided via ACB-7, and alternate power for the 2X bus was provided via ACB-8. An automatic transfer scheme would quickly switch these buses to their alternate power supply upon loss of normal power. The transfer scheme was designed to be normal-seeking so that if normal power was restored for about 10 sec, the bus would switch back to the normal supply.

A standby shutdown facility (SSF) is located in a separate building on the Oconee site. This facility, which is not normally manned, is capable of providing limited high-pressure injection for reactor coolant system (RCS) makeup and reactor coolant pump (RCP) seal cooling [provided an RCP seal loss-of-coolant accident (LOCA) does not occur]. It can also supply limited steam generator makeup. The facility includes a separate diesel generator which can power SSF loads in the event of a station blackout. SSF systems consist of single trains and are therefore not single-failure-proof.

B.14.4 Modeling Assumptions

The event was modeled as a plant-centered LOOP with failed emergency power and (slightly) degraded EFW. Potential sequences associated with the event are described in Appendix A, sect. A.3.1, PWR LOOP. These sequences were modified to address the Oconee-specific SSF, as described later in this section, and shown on the event tree included with this analysis documentation. The plant response observed during the event impacted the following branches on the event tree:

Loss of Offsite Power. The LOOP was caused by the lockout of the 230-kV switchyard. Potential short-term (~30 min) recovery of offsite power was considered in the analysis (bus lockouts were reset 39 min after the LOOP and the switchyard was repowered 52 min after the LOOP). The probability of not recovering offsite power in the short term was estimated to be 0.15, as described in ORNL/NRC/LTR-89/11R1, *Revised LOOP Recovery and Seal LOCA Models*, October 1993.

Emergency Power. Although Keowee Hydro continued to supply power to Unit 2 after auxiliary power was lost, it was assumed in the analysis that the operable Keowee generator would have failed once the supply of hydraulic oil in the accumulator tanks, used for wicket gate positioning, was consumed. When the Keowee on-call technician arrived, he was able to quickly reset the locked-out and tripped breakers and restore auxiliary power. However, hydraulic oil was almost depleted by the time he arrived.

The probability of the on-call technician failing to arrive on-site and recover auxiliary power to Keowee Hydro prior to the loss of hydraulic oil was estimated to be 0.64. Since there is no published data available that could be used to estimate such a value, it was developed assuming the probability of repair (dominated by travel time in this case) was log-normally distributed with the observed arrival time (29 min) the most probable value (mode) of the distribution. The 95th percentile was assumed to be 1 h, based on a 1 h response requirement for on-call technicians in Keowee procedures. All time once the on-call technician arrived at Keowee was assumed to be required for restoration of the first hydro unit. Additionally, since hydraulic fluid was nearly depleted when the on-call technician arrived, the time at which the Keowee hydro units would fail was assumed to be the time required for recovery during this event (37 min). The actual Keowee time-to-failure given the loss of auxiliary power is poorly understood — the licensee has stated in several LERs that it could be as long as 1 h in some cases (this possibility is addressed in a sensitivity analysis).

The Central Switchyard was also available as an alternate source of power to the standby buses. A probability of 0.12 (ASP non-recovery class R3, see Appendix A, sect. A.1) was assumed for failing to recover power from the Central Switchyard via transformer CT-5. This value was chosen because recovery appeared possible in the required time period from the control room. However, because of the LOOP and the problems with Keowee, recovery was considered to be non-routine and burdened.

Auxiliary Feedwater. Flow from the Oconee 2 turbine-driven EFW pump dropped to zero for 3 to 5 sec shortly after the pump started. The utility stated that this was caused by water accumulation in the auxiliary steam line to the pump turbine, resulting from a faulty steam trap. While the pump remained operable during this event, greater amounts of water could have caused the pump to trip; therefore, the unavailability for the turbine-driven EFW pump in the ASP model for Oconee 2 was increased from 0.05 to 0.1 to reflect this.

Recovery of Electric Power in the Long term. The probability of not recovering offsite power prior to battery depletion and RCP seal LOCA, given that offsite power was not recovered in the short term and Keowee Hydro failed at 37 min, was estimated to be 0.056. This is the probability of not recovering offsite power at 1.6 h (the 37 min failure time for Keowee plus the 1 h Oconee battery depletion time) given it was not recovered at 0.5 h (nonrecovery at 0.5 h is addressed in the LOOP nonrecovery) for plant-centered LOOP class I1, as described in ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and Seal LOCA Models*, August 1989 (see Table B.7 for Weibull distribution parameters used for this estimate). The overall probability of not recovering offsite power through recovery of the Oconee switchyard or through the use of the Central switchyard via CT-5 was estimated to be 0.001.

Table B.7. Oconee Loss of Offsite Power Sensitivity Analyses

Assumption	Conditional Probability	Impact (factor)
Probability of failing to provide power from the central switchyard = 0.04 (instead of 0.12)	7.2×10^{-5}	0.34
Keowee successfully operates for 1 h (instead of 0.5 h). Estimated probability of nonrecovery of 0.05 (see Sect. B.14.4)	1.7×10^{-5}	0.08
Oconee 1 trips due to reduced instrument air (IA) pressure. Complications from the two-unit LOOP prevents recovery of Keowee; *p* (loss of IA) = 0.1 assumed	2.5×10^{-4}	1.19
No impact on pump reliability from water in turbine-driven EFW pump steam line (instead of doubling pump failure probability)	1.8×10^{-4}	0.86
Probability of SSF failure = 0.4 (instead of 0.2) because of the long-term unavailability of normal power	4.2×10^{-4}	2.0

The use of the SSF as an alternate source of reactor coolant system (RCS) and steam generator (SG) makeup was also addressed in the analysis. This was done by identifying core damage sequences that could be recovered through the use of the SSF (sequences with failed SG makeup or RCP seal cooling and without loss of inventory), and modifying the event tree model described in Appendix A to include its consideration. The revised event tree for Oconee is included with this analysis. A combined operator and equipment failure probability of 0.2 was used for the SSF. This probability is consistent with values developed in the Oconee PRA (NSAC-60) and in licensee analyses of this event.

The SSF was without power from Oconee 2 (its normal power source) for over 4 h following the LOOP, which resulted in loss of power to the SSF battery chargers. However, since no undervoltage alarms resulted from the unavailability of normal power, and because a spare battery was available in the SSF, the SSF failure probability was not modified in the base analysis (an increase in failure probability was considered in a sensitivity analysis).

The results of sensitivity analyses — that considered a greater likelihood of recovering ac power, the potential for Keowee operation for 1 h after loss of auxiliary power, the potential for trip of Oconee 1 due to a loss of instrument air initiated by the LOOP, nominal operation of the EFW system, and a increased failure probability for the SSF because of the long-term unavailablity of normal power - are described in the next section.

B.14.5 Analysis Results

The conditional core damage probability estimated for the event is 2.1×10^{-4}. The dominant core damage sequence, highlighted on the event tree in Fig. B.26, involves the observed LOOP with failure to recover emergency power, failure to utilize the SSF for RCS and SG makeup, and failure to recover ac power before battery depletion.

The conditional probability estimate is strongly influenced by assumptions concerning the impending failure of Keowee upon loss of hydraulic oil, the potential for recovery of Keowee once hydraulic oil is lost, and the availability of ac power via transformer CT-5.

Five sensitivity analyses were performed to determine the impact of selected assumptions on the core damage probability estimated for the event. The assumptions and resulting probability estimates are shown in Table B.7. As can be seen from these cases, more optimistic assumptions concerning the likelihood of recovering ac power using the central switchyard and longer Keowee operations without auxiliary power reduce the conditional probability by up to a factor of 12. This is to be expected, considering the dominant sequence. Assuming a possible Oconee 1 trip following a loss of IA increases the core damage probability by 19% to 2.5×10^{-4}. This value includes probabilities for Units 1 and 2. Assuming that the water in the EFW pump steam line had no impact on pump reliability reduces the estimated conditional probability by 14%. Increasing the SSF failure probability by a factor of two doubles the conditional probability. This is also to be expected considering the dominant sequences.

A LOOP caused by a similar actuation of breaker failure relays by dc voltage surges occurred at Vermont Yankee on April 23, 1991, during replacement of switchyard batteries (see *Precursors to Potential Severe*

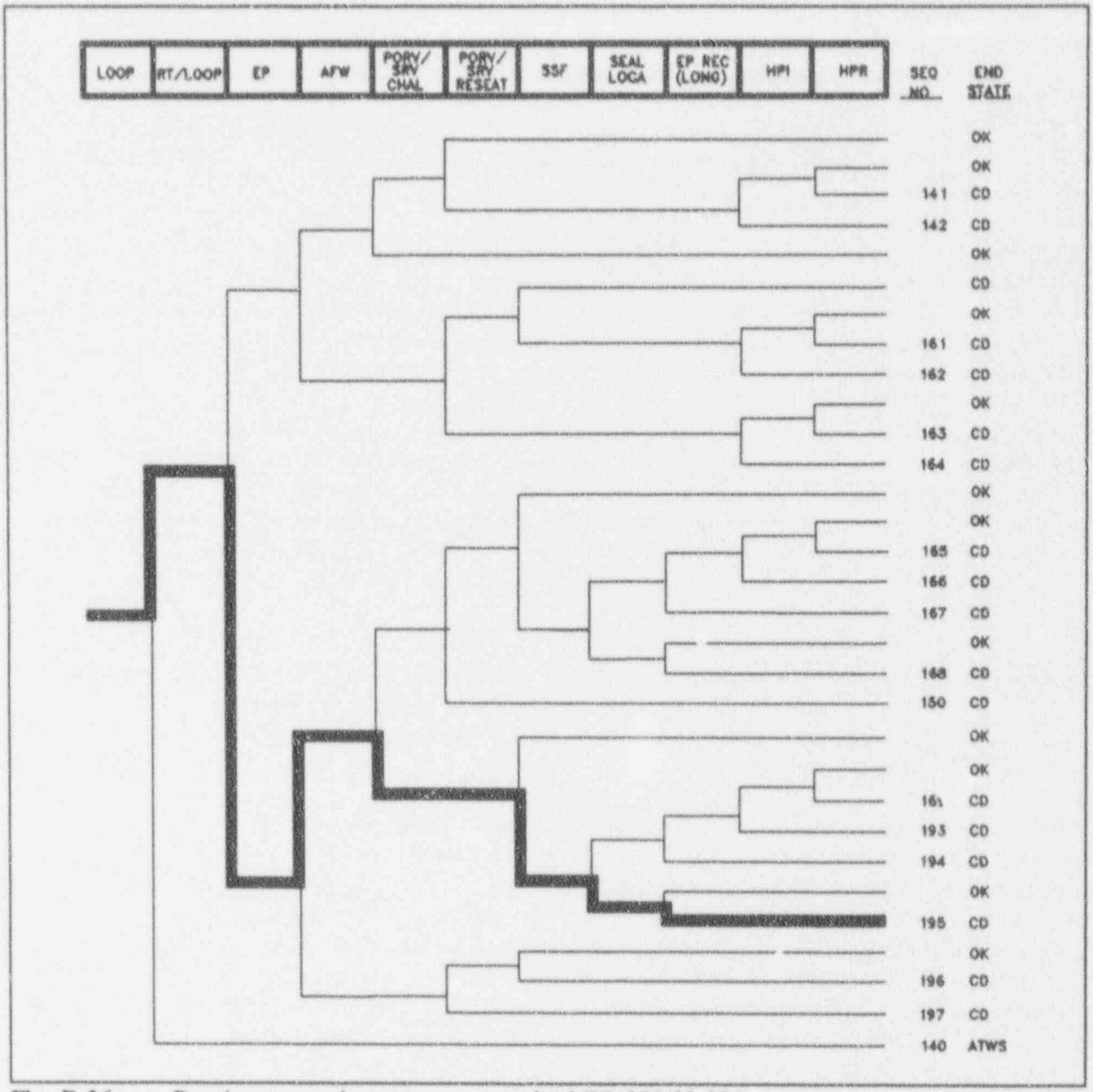


Fig. B.26. Dominant core damage sequences for LER 270/92-004

Core Damage Accidents: 1991, A Status Report, NUREG/CR-4674, Vol. 16). The LER reporting the Oconee LOOP noted that the Vermont Yankee event had been evaluated by the Duke Power Operating Experience Program (OEP). That evaluation had concluded that the relay models involved, while similar, were not exactly the same and that the zener diode involved did not exist in the equivalent circuit at Oconee. As a result, the OEP review of the Vermont Yankee event concluded that the equivalent portion of the same circuit at Oconee would not fail in the same way. The OEP review did not discover that a different circuit was subject to the same failure mode.

Additional information concerning this event and the post-event special test at Keowee is included in NRC Augmented Inspection Team (AIT) report no. 50-269/92-26, 50-270/92-26, and 50-287/92-26. A number of other LERs reported problems with Keowee during 1992 and early 1993. Two of these events describe periods in which both Keowee units were unavailable and are documented separately as precursors. Additionally, the following events were related to this event and also occurred at Keowee or Oconee:

269/91-012	Incorrect relief value setpoints resulted in inoperability of each Oconee unit SSF reactor coolant makeup system since initial installation in 1981.
269/92-011	Potential single failure could tie both Keowee units together out of phase.
269/92-014	Unavailability of Keowee 2 to supply power to the overhead path because of a failed relay.
269/92-016	Potential single failure (bus fault) could result in the unavailability of both Keowee units, due to the protective relaying that would occur while clearing the fault.
269/92-019	Potential single failure (bus fault) could lock out both Keowee units from the overhead path and also lock out the auxiliary power normal and alternate feeder breakers for both units.
269/93-001	Potential for a Keowee unit trip on overspeed if that unit was generating power to the grid and an emergency start signal was initiated.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 270/92-004
Event Description: Loss of offsite power with failed emergency power
Event Date: October 19, 1992
Plant: Oconee 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP(PLANT_CENT)	1.5E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP(PLANT_CENT)	2.1E-04
Total	2.1E-04
ATWS	
LOOP(PLANT_CENT)	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
195	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -AFW/EMERG.POWER -porv.or.srv.chall(loop) ssf -seal.loca(plant_cent) EP.REC(PLANT_CENT)	CD	1.1E-04	9.4E-02
196	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) AFW/EMERG.POWER -porv.or.srv.reseat/emerg.power ssf	CD	7.8E-05	3.3E-02
168	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -AFW/EMERG.POWER porv.or.srv.chall(loop) -porv.or.srv reseat/emerg.power ssf -seal.loca(plant_cent) EP.REC(PLANT_CENT)	CD	9.9E-06	9.4E-02
150	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -AFW/EMERG.POWER porv.or.srv.chall(loop) porv.or.srv.reseat/emerg.power	CD	8.9E-06	9.4E-02
197	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) AFW/EMERG.POWER porv.or.srv.reseat/emerg.power	CD	3.9E-06	3.3E-02

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
168	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -AFW/EMERG.POWER porv.or.srv.chall(loop) -porv.or.srv.reseat/emerg.power ssf -seal.loca(plant_cent) EP.REC(PLANT_CENT)	CD	9.9E-06	9.4E-02
150	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -AFW/EMERG.POWER porv.or.srv.chall(loop) porv.or.srv.reseat/emerg.power	CD	8.9E-06	9.4E-02

Event Identifier: 270/92-004

195	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) -AFW/EMERG.POWER -porv.or.srv.chall(loop) ssf -seal.loca(plant_cent) EP.REC (PLANT_CENT)	CD	1.1E-04	9.4E-02
196	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) AFW/EMERG.POWER -porv.or.srv.reseat/emerg.power ssf	CD	7.8E-05	3.3E-02
197	loop(plant_cent) -rt/loop EMERG.POWER(PLANT_CENT) AFW/EMERG.POWER porv.or.srv.reseat/emerg.power	CD	3.9E-06	3.3E-02

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\1989\oconseal.cmp
BRANCH MODEL: c:\asp\1989\oconee2.ssf
PROBABILITY FILE: c:\asp\1989\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.6E-04	1.0E+00	
loop(plant_cent)	1.3E-05	1.5E-01[1]	
loop(grid)	1.6E-06	4.8E-01	
loop(weather)	1.1E-06	9.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER(PLANT_CENT)	3.0E-04 > 1.2E-01	8.0E-01 > 6.4E-01[2]	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > Failed[3]		
Train 2 Cond Prob:	5.0E-02 > Failed[3]		
Train 3 Cond Prob:	1.2E-01		
emerg.power(grid)	2.5E-03	8.0E-01	
emerg.power(weather)	2.5E-03	8.0E-01	
AFW	3.8E-04 > 4.8E-04	2.6E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02 > 1.0E-01[4]		
Serial Component Prob:	2.8E-04		
AFW/EMERG.POWER	5.0E-02 > 1.0E-01	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.0E-02 > 1.0E-01[4]		
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	8.0E-02	1.0E+00	
porv.or.srv.chall(loop)	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
ssf	2.0E-01	1.0E+00	
seal.loca(plant_cent)	0.0E+00	1.0E+00	
seal.loca(grid)	0.0E+00	1.0E+00	
seal.loca(weather)	0.0E+00	1.0E+00	

Event Identifier: 270/92-004

ep.rec(sl)(plant_cent)	0.0E+00	1.0E+00	
ep.rec(sl)(grid)	0.0E+00	1.0E+00	
ep.rec(sl)(weather)	0.0E+00	1.0E+00	
EP.REC(PLANT_CENT)	2.3E-01 > 5.6E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.3E-01 > 5.6E-02[1]		
ep.rec(grid)	5.3E-02	1.0E+00	
ep.rec(weather)	8.6E-01	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03

* branch model file
** forced

Event Identifier: 270/92-004

Notes:

[1] See Modeling Assumptions for development of this non-recovery value.
[2] This non-recovery value addresses the potential for recovery of Keowee and the potential use of transformer CT5.
[3] Keowee 1 and 2 are assumed failed if auxiliary power is not recovered.
[4] The failure probability for the turbine-driven EFW pump was increased to address the potential for trip because of water in the steam line.

B.15 LER Number 285/92-023 and 285/92-028

Event Description: Reactor Trip with Faulty Pressurizer Safety Valve

Date of Event: July 3, 1992

Plant: Fort Calhoun

B.15.1 Summary

Fort Calhoun tripped from 100% power on July 3, 1992. The reactor tripped on high pressure following the closure of all turbine control valves. Two pressurizer power-operated relief valves and one pressurizer safety valve opened to relieve reactor coolant system (RCS) pressure. After an initial pressure decrease in the RCS, the safety valve opened again. When RCS pressure reached 1000 psia the valve closed but continued to leak. The conditional core damage probability estimated for this event is 2.5 × 10^{-4}. The relative significance of this event compared to other postulated events at Fort Calhoun is shown in Fig. B.27.

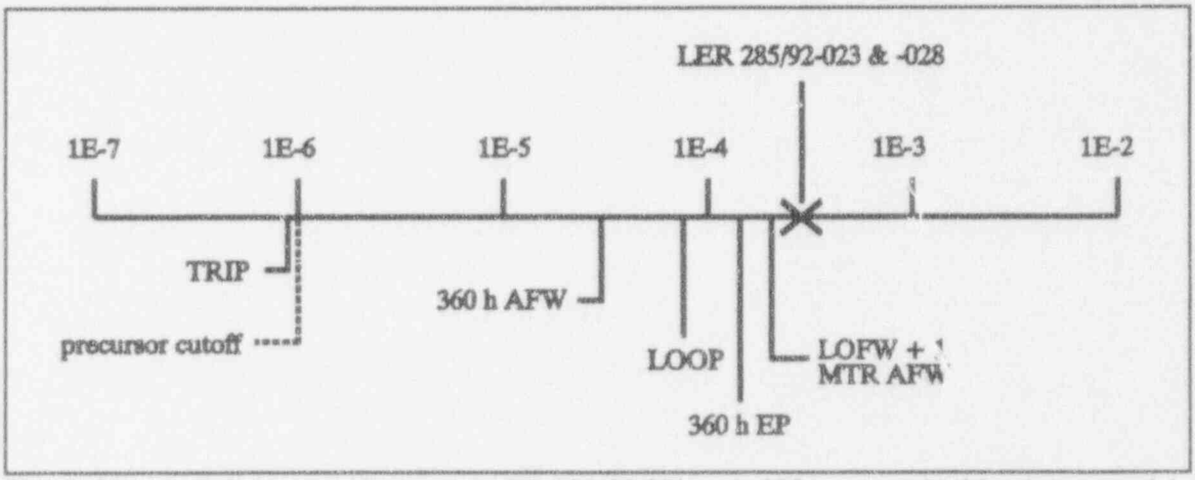


Fig. B.27. Relative significance of LER 285/92-023 and -028 compared with other potential events at Fort Calhoun.

B.15.2 Event Description

With Fort Calhoun at 100% power, nonsafety-related inverter no. 2 switched to its bypass mode three times on July 3, 1992. In the first two instances, the cause could not be determined and the inverter was returned to service. In the third instance, two circuit boards in the inverter were replaced before returning it to service at 2335 hours. However, one of the boards did not have the required jumper in place before installation. When the inverter was placed back in service, a voltage oscillation between 0 and 120-Vac was observed on the output of the inverter. The voltage oscillations caused the normal electrohydraulic control (EHC) system power supply to de-energize which caused four pressure transmitters powered by the EHC cabinet to also de-energize.

The four deenergized transmitters provide control signals to the turbine control valves. When power was lost to these transmitters, the control valves were sent a signal to close; however, closure of the control valves does not generate a turbine or reactor trip signal. With the control valves closed, a large mismatch developed between primary power production and secondary heat removal (steam dump has a 5% capacity when the turbine is not tripped). As a result, RCS pressure increased to about 2400 psia at which point a reactor trip occurred, both pressurizer power-operated relief valves (PORVs) opened, and one of the two pressurizer safety valves lifted. When RCS pressure decreased to 2350 psia, the PORVs reclosed; however, the safety valve remained open until RCS pressure decreased to 1745 psia. After the safety valve closed, RCS pressure increased for the next 8 min until it reached 1925 psia. At this point the safety valve opened again, and RCS pressure decreased rapidly. During this depressurization, safety injection (SI), emergency boration, containment isolation (CI), and containment ventilation isolation (CVI) were automatically actuated on low pressurizer pressure. The operator closed the PORV block valves in response to the loss of RCS pressure and the increasing pressure and temperature in the pressurizer quench tank; however, the safety valve still did not close. All four reactor coolant pumps (RCPs) were manually tripped as required when pressure dropped below 1350 psia. Throughout the remainder of the event, the SI flow was throttled to maintain 20°C subcooling. The rupture disk on the pressurizer quench tank actuated because of the sustained flow from the pressurizer safety valve. As a result, containment temperature, pressure, and radiation levels increased. RCS pressure decreased to ≈ 1000 psia, at which time the pressurizer safety valve finally closed but did not properly seat. This resulted in a continuous leak rate of approximately 200 gpm.

Following the shutdown of all RCPs, natural circulation was established at 0004 hours on July 4, 1992. By 1840 hours shutdown cooling was placed in service for cooldown to cold shutdown conditions. Approximately 21,500 gal of coolant was released though the pressurizer PORVs and safety valve during the event.

On August 22, 1992 with the plant operating at 100% power, the plant tripped following a partial closure of all the main turbine control valves. The partial closure was the result of a failure of an ac to dc power converter for two of the four pressure transmitters that provide control signals for the turbine control valve. These are the same transmitters that initiated the July 3 event. Due to the loss of turbine load, RCS pressure increased. The pressure increase was terminated when one of the pressurizer safety valves actuated 100 psi below its normal setpoint. This was the same pressurizer safety valve that lifted prematurely during the July 3, 1992 event. The reactor tripped when RCS pressure decreased to 1750 psia. RCS pressure stabilized at 1721 psia.

B.15.3 Additional Event-Related Information

Inverter no. 2 is a nonsafety-related inverter that supplies various nonsafety-related instrumentation and components in the plant. Among the loads supplied from this bus is the EHC power cabinet. All EHC components, except for the four transmitters that sense turbine pressures, receive backup power from the permanent magnet generator (PMG). The PMG is driven by the main turbine shaft. Normally inverter no. 2 converts 125-Vdc from battery bus 2, to 120-Vac to supply the instrument bus. However, the inverter is equipped with a 480-Vac/120-Vac transformer to allow the inverter to be bypassed. The inverter automatically switches to this bypass mode when a problem is detected with the inverter.

There are two pressurizer code safety valves on the pressurizer that are set to actuate at 2500 and 2545 (+/− 25) psia. Each valve has a blowdown of ≈ 20% and therefore would be expected to shut at ≈ 2000 psia. During the event on July 3, 1992 it appears that the safety valve lifted the first time at about 2430 psia, which is below its normal setpoint. It remained open until pressure decreased to 1745 psia, which is below its normal blowdown setpoint of 2000 psia. The valve reopened when pressure increased to 1925 psia and then reclosed at about 1000 psia. The safety valve did not reset properly following the second cycle. From post-event inspection of the valve, it was concluded that the valve setpoint had changed during the event because of valve chatter. Valve chattering occurs when a safety valve oscillates off its seat (i.e., opens and closes rapidly). During the time of the valve chatter, vibration and torque caused the adjusting bolt to turn and reduced the valve's setpoint. Thus the valve had a blowdown of > 20% each time it lifted and actuated. To minimize valve chattering, the valve's blowdown was increased in 1990 from 5% to about 20%. The valve chattering also caused damage to the valve disc and disc holder. This prevented the valve from properly seating after the second cycle and resulted in a leak rate of approximately 200 gpm through the valve.

The utility determined that the root cause of the premature opening of the pressurizer safety valve during the August 22, 1992 event was improper calibration. The valve's setpoint was found to be sensitive to the temperature of the valve body and bonnet. The valve was calibrated while it was below its normal operating temperature. This resulted in a lower setpoint than anticipated.

B.15.4 Modeling Assumptions

The July 3, 1992 event was modeled as small break loss-of-coolant accident (LOCA). It could also have been modeled as a challenged pressurizer safety valve with no recovery possible. The results of both calculations are the same. The existing event model was modified to include the potential for RCS cooldown and use of RHR following successful initiation of HPI. Once the unit is placed on RHR (with limited HPI for RCS makeup), the transfer to HPR can be avoided. To do this, the HPR event was replaced with the results of the event tree in Fig. B.28 for sequences where AFW or MFW were successful (sequences 71 and 73). The probabilities for the additional events are shown in Table B.8. The August 22, 1992 event was not modeled and does not contribute to the calculated conditional probability of core damage.

B.15.5 Analysis Results

The conditional probability of core damage estimated for the July 3, 1992 event is 2.5×10^{-4}. The dominant core damage sequence, highlighted on the event tree in Fig. B.29 involves a failure of the high-pressure injection system following the LOCA.

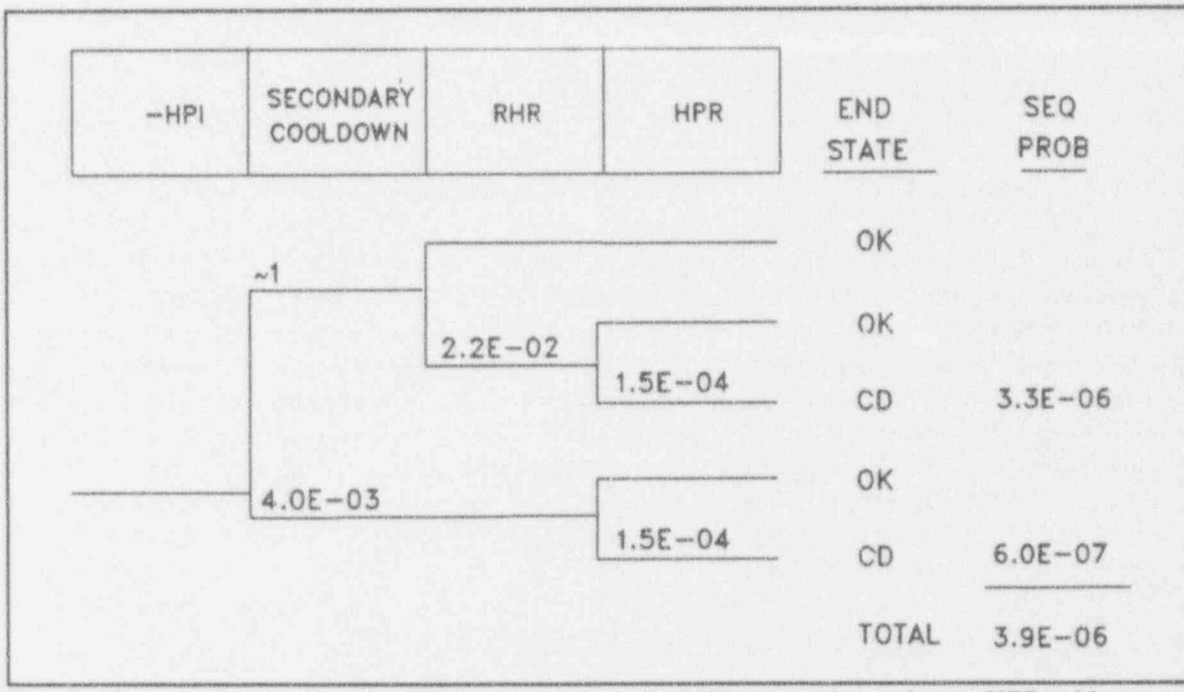


Fig. B.28. Modification for HPR event to include RHR as an alternative to HPR with successful HPI and secondary side cooling available.

Table B.8. Probability values used for modification of high-pressure recirculation event for 285/92-023 and -028.

Event	Model Probability	×	Non Recovery	+	Operator Action	=	Branch Probability
Secondary cooldown	3.0E-03*		1.0		1.0E-03		4.0E-03
RHR = VLV1 + VLV2 + (PMP1 × PMP2) + (VLV3 × VLV4 × VLV5 × VLV6) = 0.01 + 0.01 + (0.01 × 0.1) + (0.01 × 0.1 × 0.3 × 0.5) = 0.021	2.1E-02		1.0		1.0E-03		2.2E-02
HPR = VLV1 × VLV2 = 0.01 × 0.015 = 0.00015	1.5E-04		1.0				1.5E-04

*See NRR Daily Events Evaluation Manual, 1-275-03-336-01, January 31, 1992 (Preliminary).

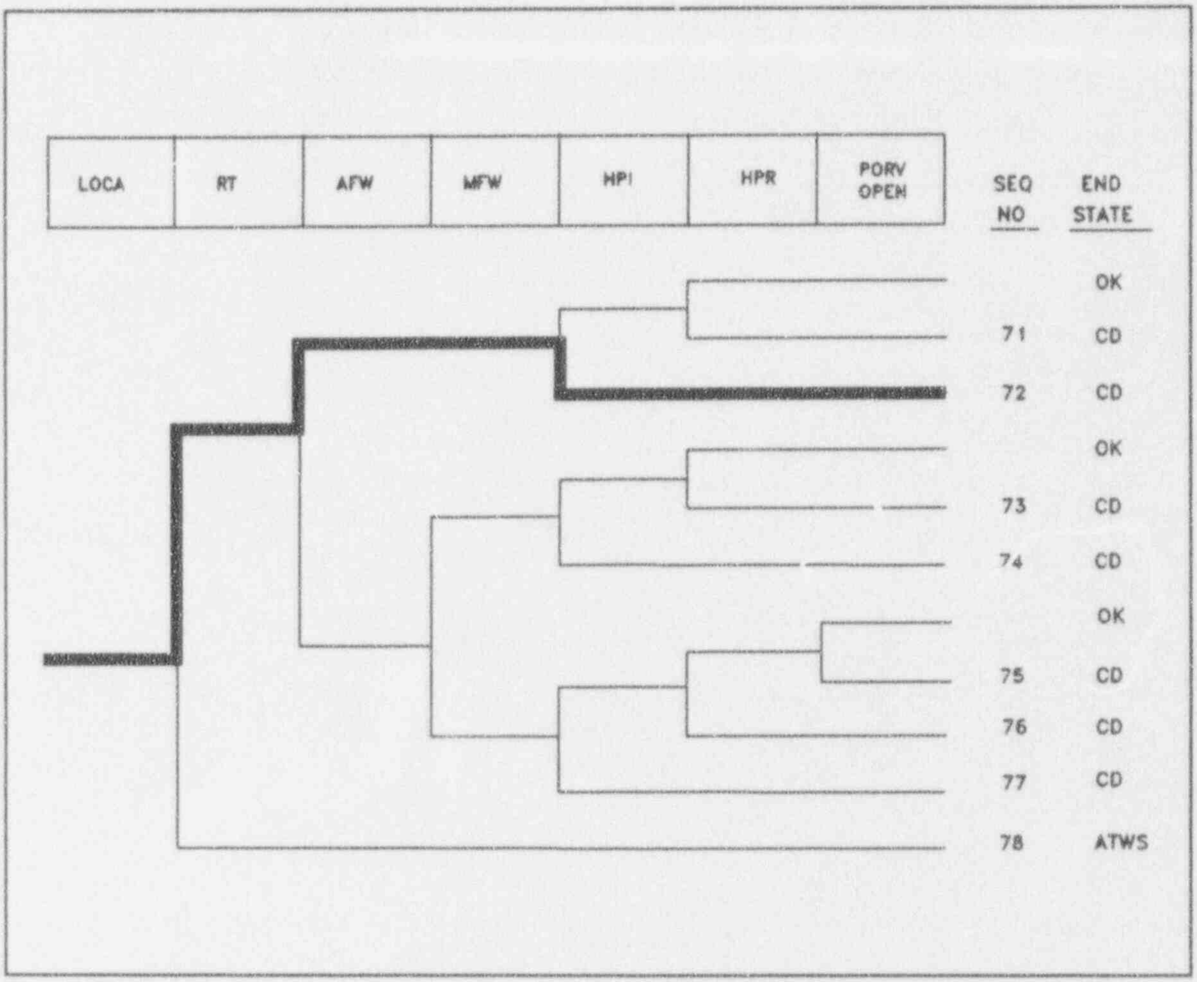


Fig. B.29. Dominant core damage sequence for LER 285/92-023.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 285/92-023
Event Description: Trip Followed by Stuck Open PRZR Safety Valve
Event Date: 07/03/92
Plant: Fort Calhoun

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOCA	2.5E-04
Total	2.5E-04
ATWS	
LOCA	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
72	LOCA -rt -afw hpi	CD	2.5E-04	8.4E-01
71	LOCA -rt -afw -hpi HPR/-HPI	CD	3.9E-06	1.0E+00
78	LOCA rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
71	LOCA -rt -afw -hpi HPR/-HPI	CD	2.1E-05	1.0E+00
72	LOCA -rt -afw hpi	CD	2.5E-04	8.4E-01
78	LOCA rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: s:\asp\prog\models\pwrgseal.cmp
BRANCH MODEL: s:\asp\prog\models\calhoun.sl2
PROBABILITY FILE: s:\asp\prog\models\pwr_prob.pro

No Recovery Limit

Event Identifier: 285/92-023

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	6.0E-05	1.0E+00	
loop	1.6E-05	5.3E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.0E+00	
Branch Model: INITOR			
Initiator Freq:	2.4E-06		
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	7.9E-03	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.9E-01	3.4E-01	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	4.6E-02	1.0E+00	
ep.rec(sl)	5.7E-01	1.0E+00	
ep.rec	1.4E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
porv.open	2.0E-02	1.0E+00	4.0E-04
HPR/-HPI	1.5E-04 > 3.9E-06 **[1]	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02		
csr	2.0E-03	3.4E-01	1.0E-03

* branch model file
** forced

Notes:
1. Probability was modified to account for the possible use of RHR as an alternative to HPR. See the modeling assumptions sectio for a description of this modification.

Event Identifier: 285/92-023

B.16 LER Number 286/92-011

Event Description: Multiple EDGs Inoperable

Date of Event: July 6, 1992

Plant: Indian Point 3

B.16.1 Summary

During surveillance testing of 480-V engineered safety feature (ESF) bus 5A, it was discovered that a wire was not connected correctly in the relay circuits required to auto-start emergency diesel generator (EDG) 33. During the time that EDG 33 was not available to perform its safety function, the other two EDGs were inoperable at various times. Two EDGs were simultaneously unavailable for a total of 3.5 d, reducing onsite ac power supplies below the minimum assumed in the Final Safety Analysis Report (FSAR). Even though this event occurred while the unit was shut down, other similar modifications and tests have been conducted while Indian Point was at power (e.g., see LER 286/90-005, p. B-184, Vol. 14 of NUREG/CR-4674) that have resulted in more than one EDG being inoperable at the same time. Therefore, with no written policy indicating otherwise, it is credible that an EDG could be discovered inoperable during power operations coincident with the removal of another EDG from service for maintenance testing, or modifications. Consistent with the ASP methodology, this event was therefore modeled as if it occurred at power. The conditional core damage probability estimated for this event is 1.2×10^{-6}. The relative significance of this event compared to other postulated events at Indian Point 3 is shown Fig. B.30.

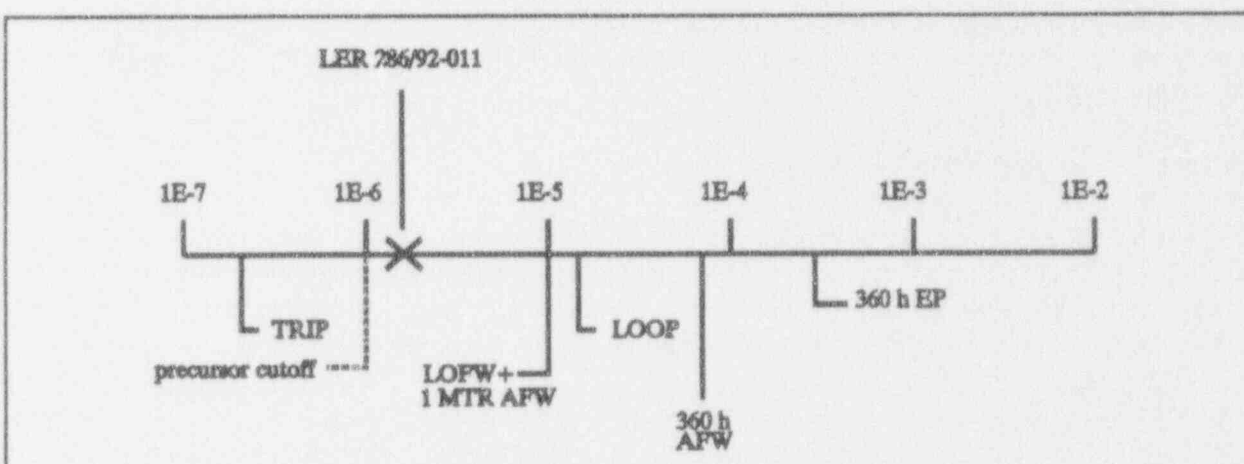


Fig. B.30. Relative event significance of LER 286/92-011 compared with other potential events at Indian Point 3.

B.16.2 Event Description

During surveillance testing while the unit was shut down, a loose wire was discovered in circuitry associated with the control relays for 480-V ESF bus 5A. The utility suspected that electricians working in the relay cabinet disturbed the wire during an unrelated modification. This loose wire would have prevented auto-start of the associated EDG 33. The condition was believed to have existed for about 2 weeks. During part of this time other EDGs were out of service. At least two EDGs were simultaneously out of service for a total of 3.5 d.

B.16.3 Additional Event-Related Information

There are four independent sources of emergency power available to Indian Point 3. They are the 138 kV and 345 kV ties from Buchanan and the two 13.8 kV feeders from Buchanan. In addition, there are three gas turbine generators, one located on the Indian Point site and the others connected to 13.8 kV feeders at Buchanan. Also, there are three EDGs which supply onsite emergency power.

B.16.4 Modeling Assumptions

This event was modeled as a postulated 84-h unavailability of two trains of emergency power with the plant at power. While the FSAR indicates that operation of two EDGs is required for emergency power success, other information suggests that one EDG may be sufficient. The ASP model assumes that one EDG is sufficient.

An additional onsite ac power supply, the Appendix R diesel generator, may also be aligned to feed the safety buses, however operators must manually perform a number of steps to connect it. The ASP program assumes an operator nonrecovery likelihood of 0.34 in such a circumstance. If it is assumed that the EDG can be aligned in the short term and that the likelihood of its failure is small compared with the operator nonrecovery term, then the Appendix R diesel can be credited by reducing the EP nonrecovery value by a factor of 0.34.

B.16.5 Analysis Results

The conditional probability of subsequent core damage estimated for the 84-h unavailability of two EDGs during steady-state power operation is 1.2×10^{-6}. The dominant core damage sequence, highlighted on the following event tree in Fig. B.31, involves a postulated LOOP with failure of emergency power, a subsequent reactor coolant pump seal LOCA, and failure to recover ac power prior to core uncovery.

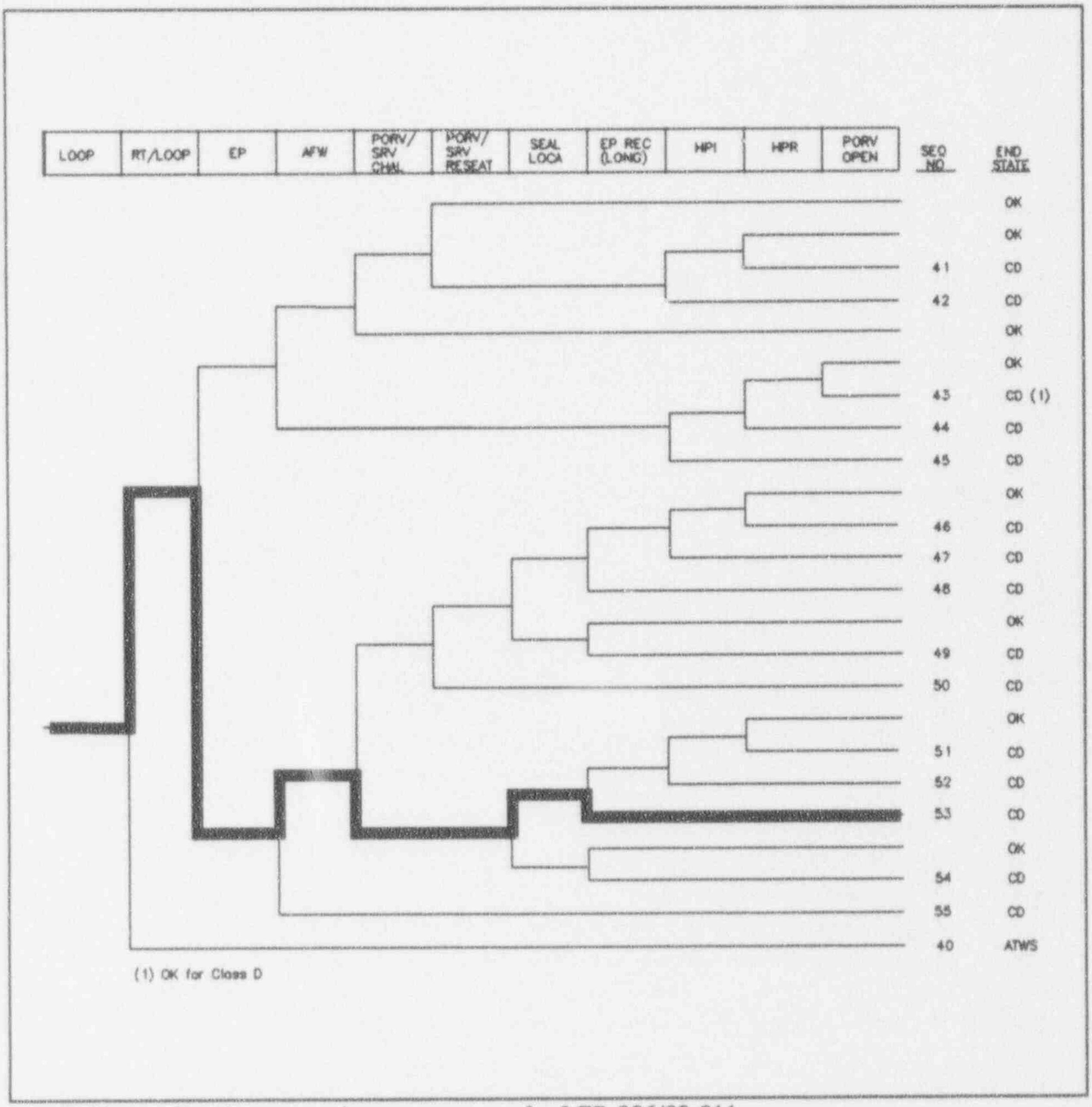


Fig. B.31. Dominant core damage sequence for LER 286/92-011

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 286/92-011
Event Description: Multiple EDGs Simultaneously Inoperable
Event Date: 7/6/92
Plant: Indian Point 3

UNAVAILABILITY, DURATION= 84

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.9E-02
LOOP	4.4E-04
LOCA	8.7E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	0.0E+00
LOOP	1.2E-06
LOCA	0.0E+00
Total	1.2E-06
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca ep.rec(sl)	CD	7.9E-07	4.5E-02
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - seal.loca ep.rec	CD	2.8E-07	4.5E-02
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	1.1E-07	1.6E-02
48	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power seal.loca ep.rec(sl)	CD	3.2E-08	4.5E-02

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
48	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power seal.loca ep.rec(sl)	CD	3.2E-08	4.5E-02
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca ep.rec(sl)	CD	7.9E-07	4.5E-02
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - seal.loca ep.rec	CD	2.8E-07	4.5E-02
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	1.1E-07	1.6E-02

** non-recovery credit for edited case

Event Identifier: 286/92-011

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asp\models\pwrbseal.cmp
BRANCH MODEL: c:\asp\models\indpoint.sl1
PROBABILITY FILE: c:\asp\models\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	4.6E-04	1.0E+00	
loop	3.1E-05	1.7E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	5.4E-04 > 5.7E-02	8.0E-01 > 2.7E-01[1]	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > 1.0E+00		
Train 2 Cond Prob:	5.7E-02		
Train 3 Cond Prob:	1.9E-01 > 1.0E+00		
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.1E-01	1.0E+00	
ep.rec(sl)	6.0E-01	1.0E+00	
ep.rec	5.6E-02	1.0E+00	
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Notes:
1. Appendix R EDG credited by adjusting the EP nonrecovery probability. See the modeling assumptions section for a description of this modification.

Event Identifier: 286/92-011

B.17 LER Number 301/92-003

Event Description: Plugged Safety Injection Pump Suction

Date of Event: September 18, 1992

Plant: Point Beach 2

B.17.1 Summary

Point Beach 2 was at 100% power on September 18, 1992 while performing the A train containment spray (CS) pump quarterly test. When the pump failed to pass the test, it was disassembled. A foam rubber plug, which had been installed in the RHR system 10 months earlier, was found in the suction line of the CS pump. This plug rendered the A train SI and RHR pumps inoperable for the 10 months it was installed. The conditional probability of subsequent core damage estimated for this event is 9.9×10^{-6}. The relative significance of the event compared to other postulated events at Point Beach 2 is shown in Fig. B.32.

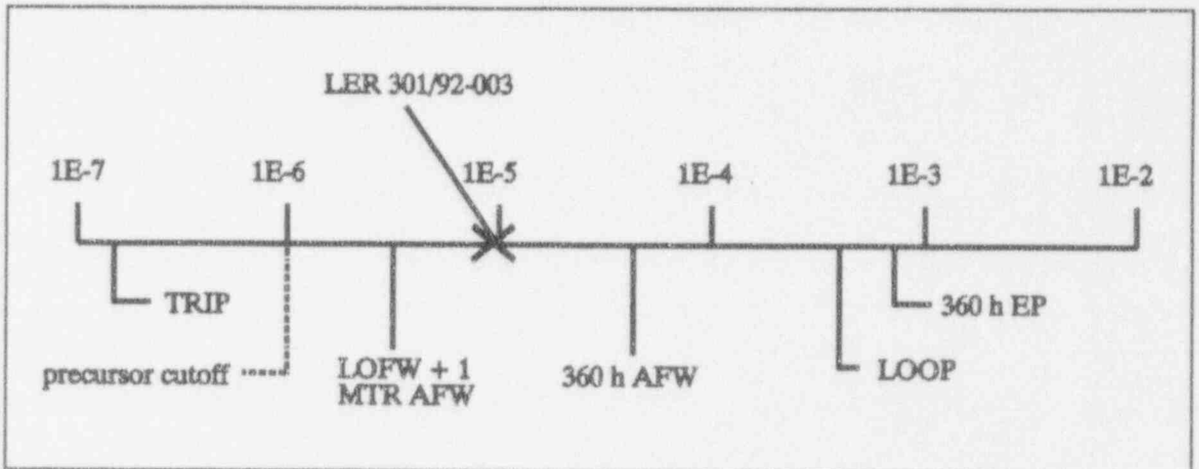


Fig. B.32. Relative significance of LER 301/92-003 compared with other potential events at Point Beach 2.

B.17.2 Event Description

On September 17, 1992, the CS system "Leakage Reductions and Preventive Maintenance Program Test" was conducted. This test requires each CS pump to be operated with its suction aligned to the discharge of its corresponding RHR pump. The RHR pump is operated with its suction aligned to the refueling water storage tank (RWST). After the test was completed, a significant difference was noted between the discharge pressures of the train A and train B CS pumps.

The following day, September 18, 1992, the quarterly test of the CS pumps was performed. This test, which consists of operating each CS pump with its suction aligned to the RWST and its discharge recirculating back to the RWST, was conducted while the plant was at 100% power. When the train A CS pump was started, an operator stationed at the pump noted that the pump suction pressure was oscillating. The pump was stopped and vented and then restarted. The pump discharge pressure was reading zero after the restart, so the pump was again stopped and vented. When the pump was started for a third time, the operator noted abnormal noises emanating from the pump. The train A CS pump was then secured. Upon disassembly of the pump, a foam rubber plug was found blocking the pump suction. The plug was removed, and the pump was reassembled. The pump subsequently tested satisfactorily.

The utility chartered an incident investigation team to attempt to determine the source of the foam rubber plug. Although the team could not conclusively ascertain the origin of the foam rubber plug, they determined that it was probably installed 10 months earlier as a temporary cleanliness barrier during modifications to the RHR system performed during the fall 1991 refueling outage. They also concluded that the most likely original location for the plug was in the portion of the common line between the train A RHR pump discharge to the train A CS pump and train A SI pump suction. In this location, the plug would not have affected any of the pumps in the initial injection mode but could have prevented both the A CS and the A SI pumps from operating in the long-term recirculation mode.

B.17.3 Additional Event-Related Information

The CS system provides a water spray to the containment atmosphere following a design basis accident. The system consists of two pumps which discharge to spray headers inside the containment building. The SI system provides high pressure, borated water to the reactor coolant system. Following initiation, the SI system's two pumps take suction from a concentrated boric acid storage tank (BAST). Following the depletion of the BAST, the system suction is automatically realigned to the refueling water storage tank (RWST). The residual heat removal (RHR) system functions as the low pressure safety injection system. Following actuation, it too takes suction from the RWST.

Following depletion of the RWST, these three systems are manually realigned. The RHR system is realigned to take suction from the containment sump, and discharge to the suction of the CS and SI pumps. The CS and SI systems are realigned to take suction from the RHR pump discharge (the CS system may not be required in the recirculation phase). Plant design prevents the CS and SI systems from taking suction directly from the containment sump. Therefore, plugging of the RHR discharge line could prevent the operation of the associated CS and SI pumps when the recirculation phase is initiated.

B.17.4 Modeling Assumptions

This event was analyzed because one train of both CS and SI were unavailable for operation in the recirculation mode for the 10 months of plant operation while the foam rubber plug was in the piping. The CS pump is not modeled in the current ASP model for Point Beach 2. Therefore, the impact of the foam rubber plug on the availability of the train A CS pump does not affect the estimation of the conditional core damage probability for this event, and only the availability of the train A SI pump is addressed by the current model.

The foam rubber plug was found to be blocking the impeller suction of the train A CS pump. The plug had evidently migrated there when the CS pump was run with its suction aligned to the RHR pump discharge on September 17, 1992. Prior to that time the plug was presumably in the common line between the train A RHR pump discharge to both the A CS and the A SI pumps. If the plug had remained in that location, it would have prevented both the A CS pump and the A SI pump from operating in the recirculation mode. If not, the SI pump would have been started in the recirculation mode before the CS pump during an actual event. Therefore, the plug would have migrated to the suction of the SI pump and caused it to fail. Therefore it was assumed that the presence of the foam rubber plug in the A RHR pump discharge to the A CS and A SI pump suctions was equivalent to an unavailability of the A SI pump in the recirculation mode. This was modeled as the unavailability of one train of high-pressure recirculation (HPR) for 10 months.

The use of RHR as an alternate to HPR when HPI is successful and secondary feed is available was included in the modeling for this event. To do this, HPR failure was set to 1.0 in the model and the output of the computer model was mutiplied by the results of the event tree in Fig. B.33 for sequences where HPR failed, and AFW or MFW were successful (sequences 71 and 73). The model was also modified to include LPI as an alternative to a failed HPI system when secondary feed is available. In this case, HPI failure was multiplied by the results of the event tree shown in Fig. B.34 for sequences where AFW or MFW were sucessful (sequences 71-74). This modification does not have a significant effect on the results. The probabilities for the additional events are shown in Table B.9.

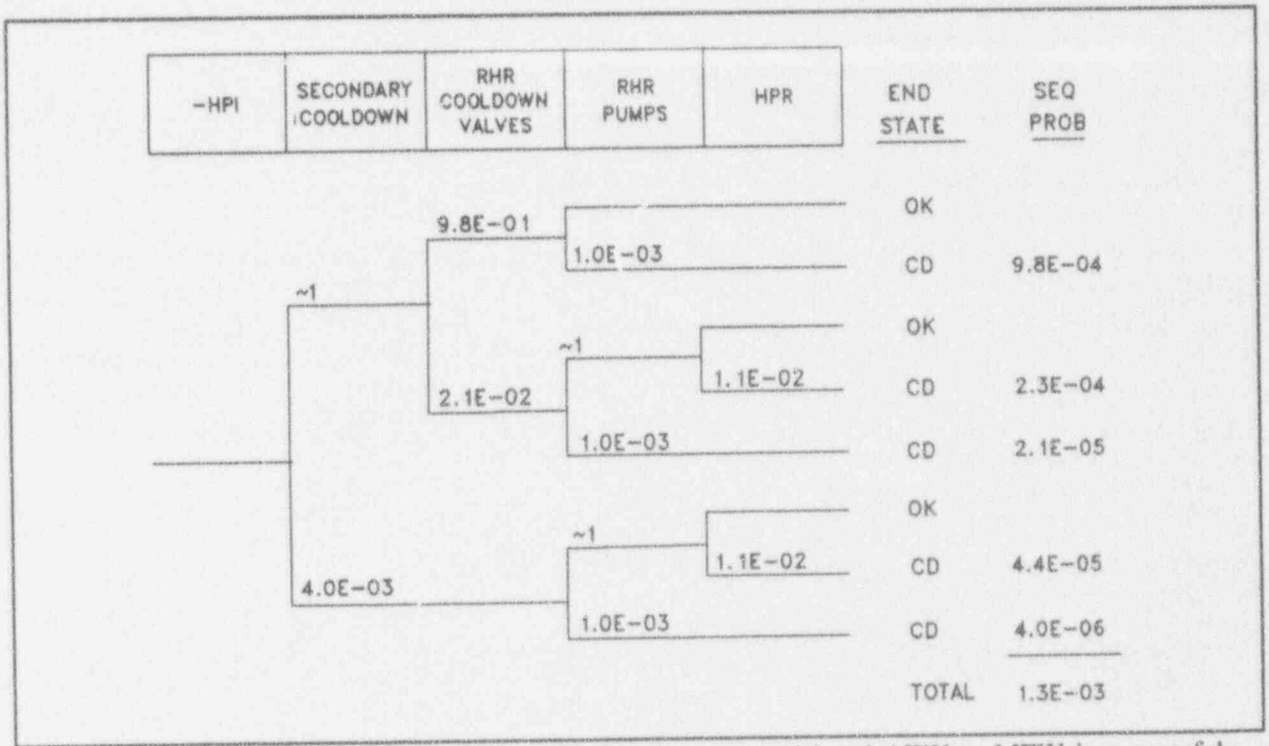


Fig. B.33. Modification to HPR event when HPI is successful and AFW or MFW is successful.

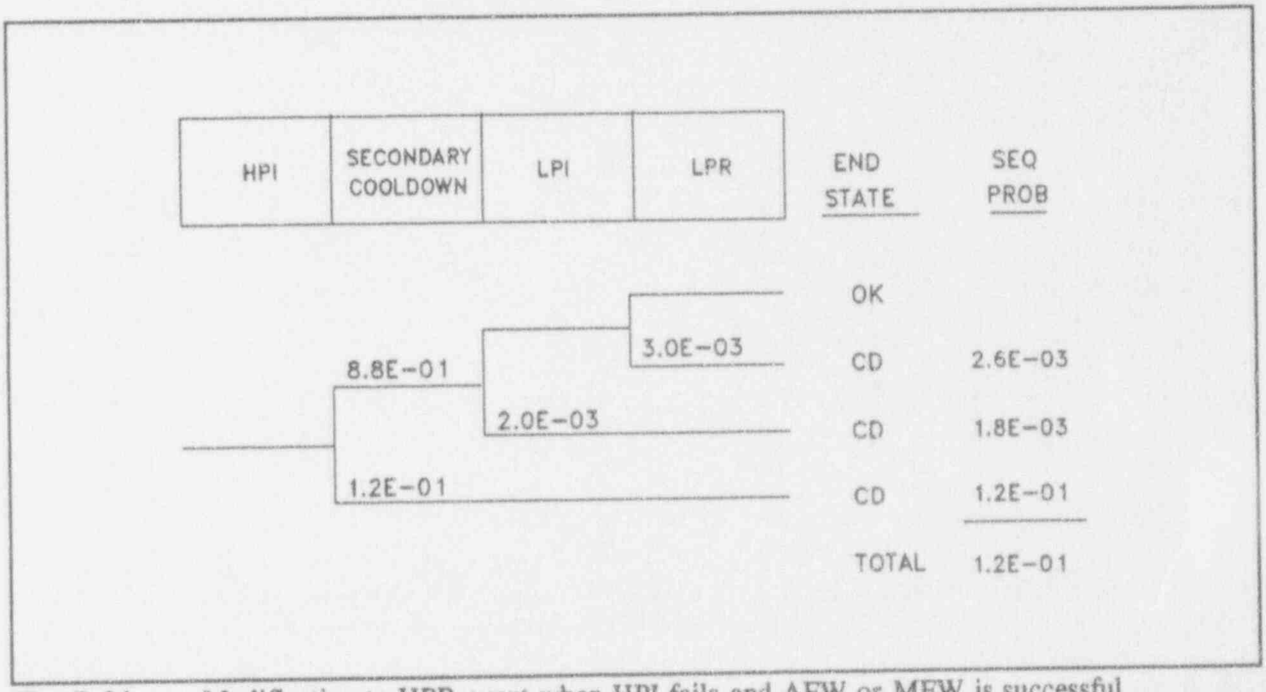


Fig. B.34. Modification to HPR event when HPI fails and AFW or MFW is successful.

Table B.9. Probability values used for modification of high-pressure recirculation event for 301/92-003.

Event	Model Probability	×	Non Recovery	+	Operator Action	=	Branch Probability
Secondary cooldown							
Following HPI Success	3.0E-03*		1.0		1.0E-03		4.0E-03
Following HPI Failure	3.0E-03*		1.0		1.2E-01		1.2E-01
RHR Cooldown Valves = VLV1 + VLV2 + (VLV3 × VLV4 × VLV56 × VLV6) = 0.01 + 0.01 + (0.01 × 0.015 × 0.3 × 0.5) = 0.02	2.0E-02		1.0		1.0E-03		2.1E-02
RHR Pumps	1.0E-03		1.0				1.0E-03
HPR = (VLV1 + PMP1) × (VLV2 + PMP2) = (0.01 + 0) × (0.015 + 1) = 0.01	1.0E-02		1.0		1.0E-03		1.1E-02
LPI = (PMPA + VLVA) + (PMPB + VLVB) = (0.01 + 0.01) × 0.1 = 0.002	2.0E-03		1.0				2.0E-03
LPR = (SUMPVLVA + RWSTVLVA) + (SUMPVLVB + RWSTVLVB) = (0.01 + 0.01) × 0.1 = 0.002	2.0E-03		1.0		1.0E-03		3.0E-03

*See NRR Daily Events Evaluation Manual, 1-275-03-336-01, January 31, 1992 (Preliminary).

B.17.5 Analysis Results

The estimated conditional core damage probability associated with this event is 9.9×10^{-6}. The dominant core-damage sequence, highlighted on the event tree in Fig. B.35, involves a postulated loss-of-coolant accident (LOCA) with successful auxiliary feedwater and high-pressure injection and failure of high-pressure recirculation.

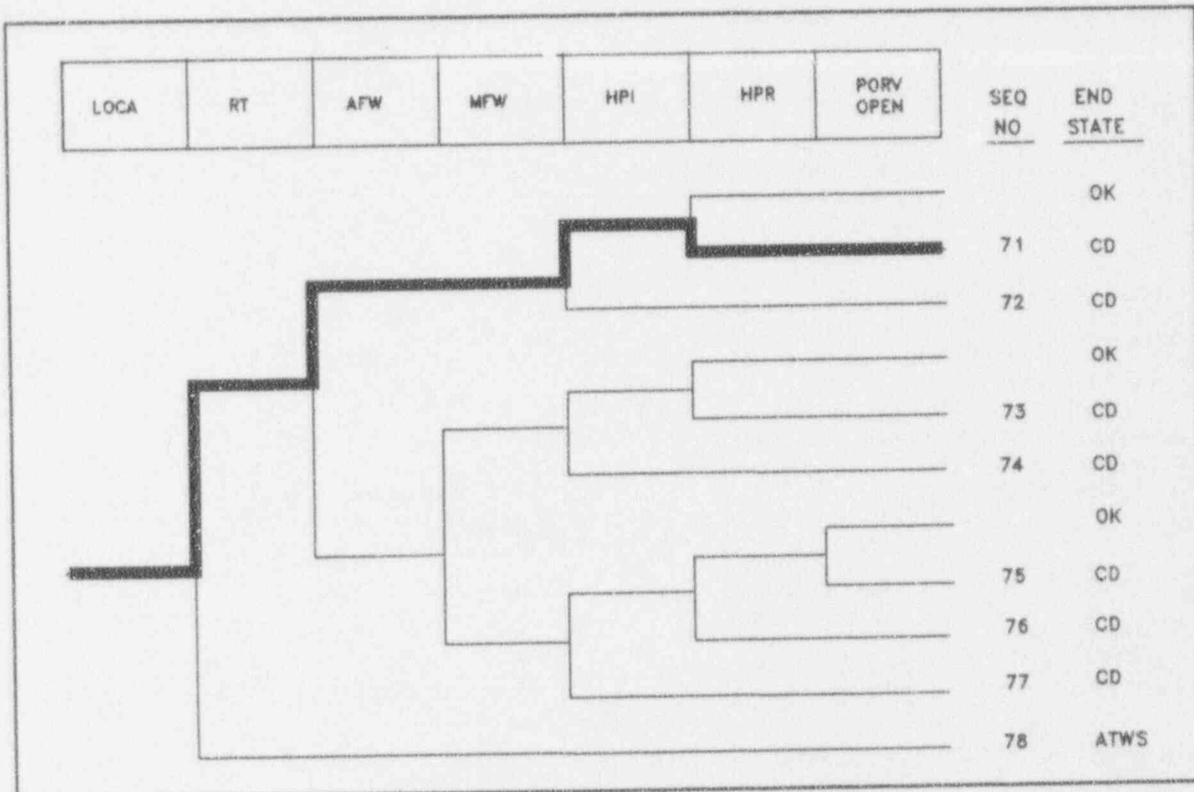


Fig. B.35. Dominant core damage sequence for LER 301/92-003.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 301/92-010
Event Description: Foam Rubber Plug in RHR discharge line
Event Date: 09/18/92
Plant: Point Beach 2

UNAVAILABILITY, DURATION= 7488

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	7.7E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability (w/o modifications)	Probability (w/modifications)
CD		
LOCA	7.6E-03	9.9E-06[1]
Total	7.6E-03	9.9E-06
ATWS		
LOCA	0.0E+00	
Total	0.0E+00	

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

Sequence	End State	Prob	N Rec**
71 loca -rt -afw -HPI HPR/-HPI	CD	7.6E-03	4.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

Sequence	End State	Prob	N Rec**
71 loca -rt -afw -HPI HPR/-HPI	CD	7.6E-03	4.3E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

Event Identifier: 301/92-010

SEQUENCE MODEL: s:\asp\prog\models\pwrbseal.cmp
BRANCH MODEL: s:\asp\prog\models\ptbeach2.sl2
PROBABILITY FILE: s:\asp\prog\models\pwr_prob.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.0E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	1.0E-03
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	0.0E+00	1.0E+00	
ep.rec(sl)	0.0E+00	1.0E+00	
ep.rec	4.5E-01	1.0E+00	
HPI	1.0E-03 > 1.0E-04[2]**	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
hpi(f/b)	1.0E-03	8.4E-01	1.0E-02
HPR/-HPI	1.5E-04 > 1.0E+00 **	1.0E+00	1.0E-03 > 1.0E+00
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Failed		
porv.open	2.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Notes:

[1] Includes use of RHR cooldown (see -HPI event tree). Probability = 7.6E-03 × 1.3E-03 = 9.9E-06.
[2] Includes use of LPI and LPR for failed HPR (see HPI event tree). Probability = 1.0E-03 × 8.4E-01 × 1.2E-01 = 1.0E-04.

Event Identifier: 301/92-010

B.18 LER Number 302/92-001 and 302/92-002

Event Description: Loss of Offsite Power with Inoperable Vital Bus Inverter

Date of Event: March 27, 1992

Plant: Crystal River, Unit 3

B.18.1 Summary

Maintenance work on a vital bus inverter resulted in the loss of the inverter, loss of offsite power (LOOP) to the two safeguards busses, and a plant trip. Following the start of the emergency diesel generators (EDGs), an existing leak in the 3B EDG jacket cooling system increased. After partial restoration of offsite power to the safeguards busses, the 3B EDG was declared inoperable because of the jacket system leakage. The conditional core damage probability for this event is estimated to be 1.7×10^{-5}. The relative significance of this event compared to other postulated events at Crystal River, Unit 3, is shown in Fig. B.36.

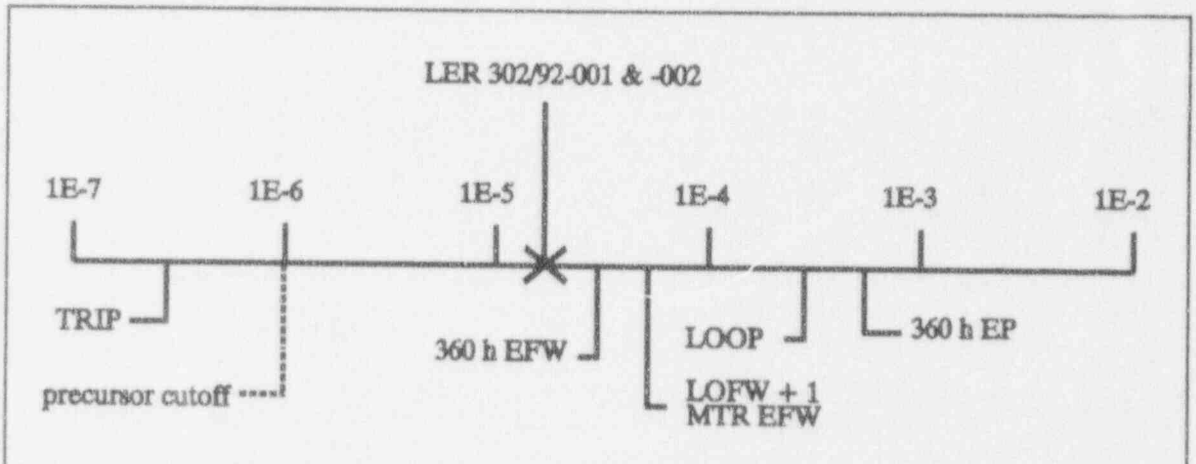


Fig. B.36. Relative event significance of LER 302/92-001 and 302/92-002 compared with other potential events at Crystal River 3.

B.18.2 Event Description

Maintenance was in progress on the C vital bus inverter (see Fig. B.37). The inverter was removed from service, and the C vital bus was being powered by the 480-Vac/120-Vac regulating transformer. When the inverter was repowered from the dc bus at 1308 hours as part of the troubleshooting effort, incomplete isolation of the inverter from the 480-Vac supply resulted in ac voltage swings on the 125-Vdc bus. The voltage swings caused the relays for the Offsite Power Transformer (OPT) to actuate, resulting in the opening of the OPT supply breakers (4900 and 4902). As a result, offsite power to the safeguards busses (ES-3A and ES-3B) was lost. This caused the C vital bus to lose power because the inverter was

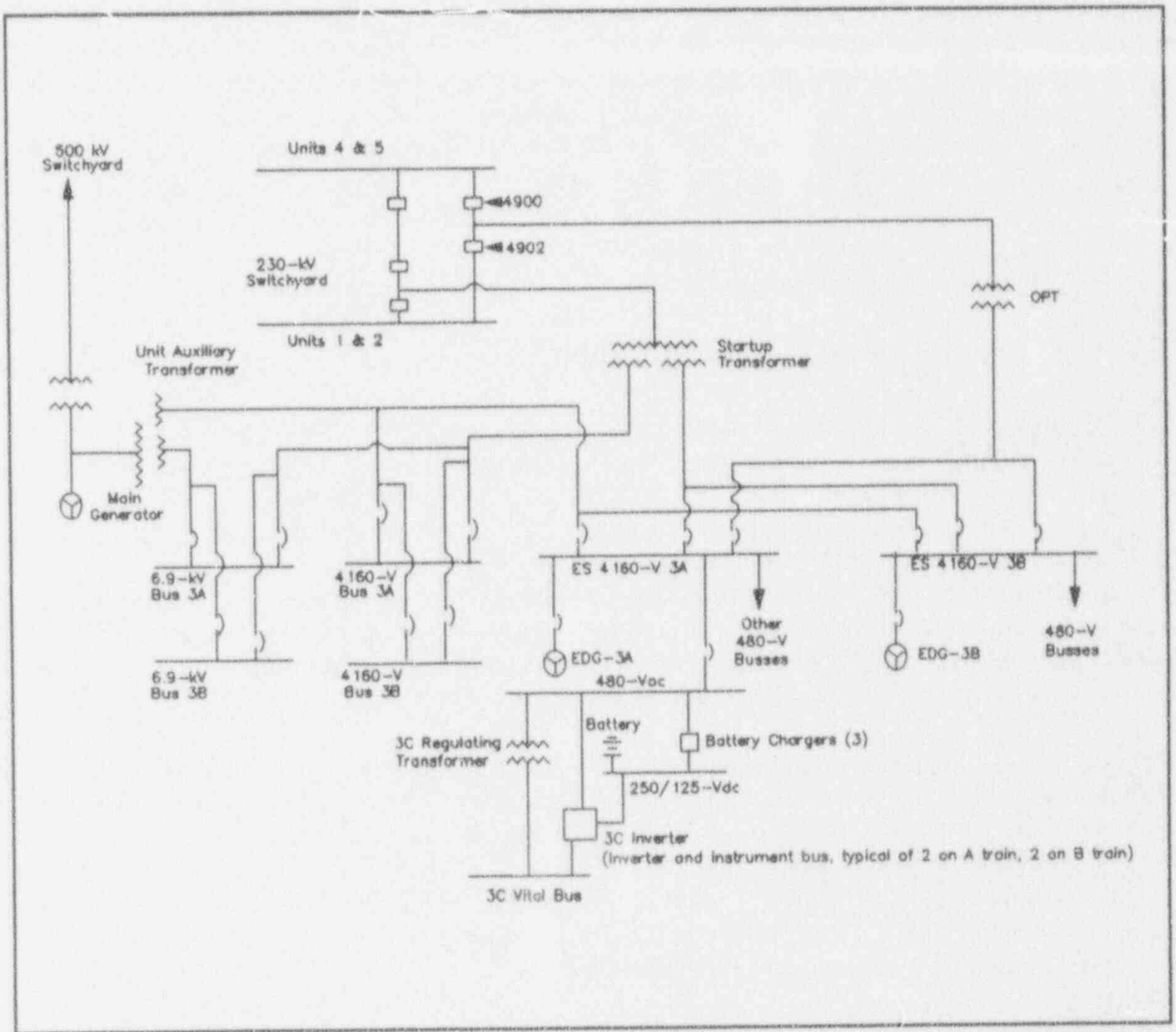


Fig. B.37. Electrical distribution system for Crystal River 3

out of service. Both EDGs started and loaded as expected. The reactor tripped (rods inserted) because of loss of power to the control rod drive (CRD) motors. The reactor coolant pumps did not trip because nonsafeguards busses 3A and 3B were unaffected, and the turbine did not trip because a reactor trip setpoint had not been reached yet. When the operator pushed the manual reactor trip button, the CRD motor breakers and the turbine both tripped.

Post trip reactor coolant system (RCS) temperature was lower than expected because of the temporary mismatch between primary heat production and secondary heat removal. The reactor was effectively tripped when all the control rods were inserted and resulted in a sharp decrease in primary heat production. The turbine remained on-line for a brief period after the rods were inserted and was drawing 100% steam flow during this time. This resulted in more heat removal following the trip than would be normal. As a result, post-trip RCS temperature was lower than expected.

A leak of 1 gph was present on the 3B EDG jacket water-cooling system pump seal prior to the transient. Following the starting and loading of the EDG the leakage from the pump seal increased to 2 – 3 gpm. With the EDG running, it was difficult to maintain jacket cooling water inventory through manual makeup. At this point the operability of the EDG was questioned by the licensee. At 1538 hours, the 4160-V bus ES-3B was repowered from the OPT. Following shutdown of the 3B EDG, the leakage decreased but remained above pretrip levels. At 1918 hours, the 4160-V bus ES-3A was repowered from the OPT. At 2330 hours, 7 h and 52 min after it was shut down, the 3B EDG was declared out of service as a result of the jacket system leakage. With the 3B EDG and the C vital bus inverter both out of service, Technical Specifications required the plant to proceed to cold shutdown.

B.18.3 Additional Event-Related Information

The in-plant ac distribution system consists of six ac busses: two 6900-V nonsafeguards busses (3A and 3B) that supply the reactor coolant pumps, two nonsafeguards 4160-V busses (3A and 3B), and two safeguards 4160-V busses (ES-3A and ES-3B). Busses ES-3A and ES-3B normally receive power from the OPT. The startup and auxiliary transformers will not close in on the safeguards busses following a loss of the OPT; however, they can be aligned manually to the busses. On loss of the feed from the OPT, the EDGs automatically supply power to the safeguards busses. Although it is not explicitly stated in the Licensee Event Report (LER), two alternate sources of power (the startup and auxiliary transformers) were apparently available throughout the event because the four nonsafeguards busses remained energized by offsite power throughout the event.

The vital ac and dc distribution system consists of two 250-/125-Vdc busses and four vital 120-Vac busses (3A, 3B, 3C, and 3D). Normally the dc busses are supplied by the battery chargers, but a backup supply is available from the safeguards batteries. The 125-Vdc system provides primary control power to the OPT feeder breakers. Normally, the vital dc busses are supplied by their associated 480-V bus via an inverter. On loss of the 480-V input, the inverter automatically transfers to the 125-Vdc input. If the inverter is out of service (e.g., as it was during the troubleshooting of the C inverter), the bus can be powered from the 480-V bus via a regulating transformer.

B.18.4 Modeling Assumptions

The event was modeled as a plant centered LOOP. Two bounding cases were initially run: one with the B EDG and its associated equipment operable throughout the event (case 1) and another with the B EDG and its associated equipment inoperable throughout the event (case 2). These two cases determine the upper and lower bounds of the estimated core damage probability. For these cases, the probabilities for LOOP nonrecovery (short term), failure to recover ac power prior to battery depletion, and reactor coolant pump seal LOCAs were revised to reflect values associated with a plant-centered LOOP (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989).

A point estimate calculation was then performed assuming that the "B" EDG would not have been able to function beyond 2.5 h. The event tree was modified to include the failure of the "B" EDG 2.5 h into the event. The modified tree is shown in Fig. B.38. The following sections describe the basis for the event tree probabilities.

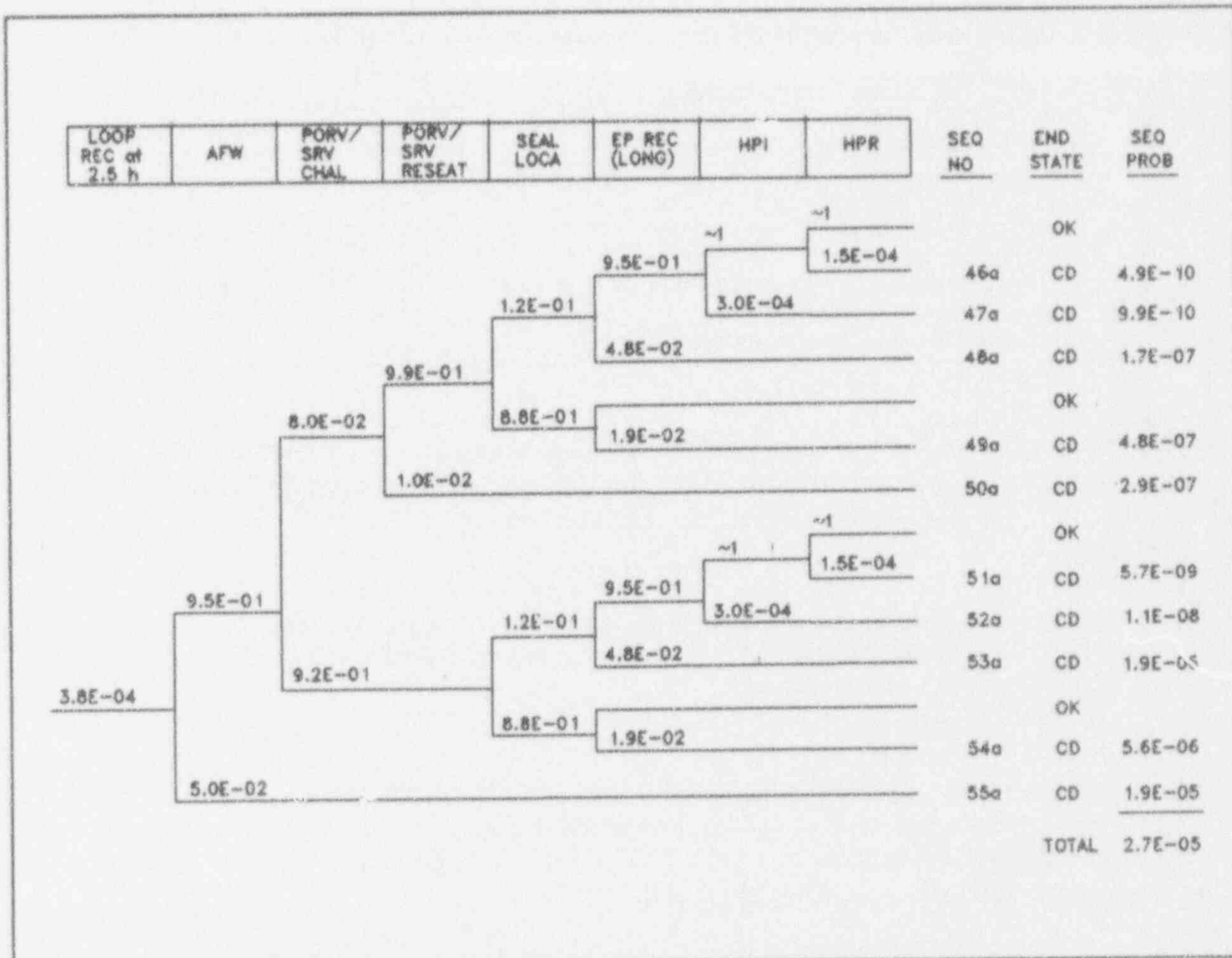


Fig. B.38. Modification to event tree to account for failure of EDG "B" at 2.5 hours.

AC Power Recovery Values

The probabilities for ac nonrecovery were estimated using a Weibull-based distribution (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989). This distribution is based on data from NUREG-1032, *Evaluation of Station Blackout Accidents at Nuclear Power Plants*. In this case, the frequency of a LOOP of duration greater than time t is given by:

$$\lambda(t) = 0.0707\ e^{-3.3136t^{0.7837}}$$

where t is in hours. Table B.10 provides values from this equation for times of interest in this event.

LOOP Recovery at 0.5 h. The ac power recovery for the first 0.5 h of the event is included in the LOOP nonrecovery value. From Table B.10, this value is 0.146 which is approximately equal to 0.15.

Table B.10. Probabilities for nonrecovery of emergency power for 302/92-001 and -002.

Time (in hours)	Description	p(nonrecovery of ac)
0.5	Recovery to this time addressed in LOOP frequency	1.46E--01
2.5	EDG "B" failure	1.12E−03
4.0	Core uncovery given seal LOCA	5.43E−05
4.5	Core damage given battery depletion	2.10E−05

LOOP Recovery at 2.5 h. It was assumed that the "B" EDG would not operate beyond 2.5 h. Therefore, the probability of failure of emergency power at 2.5 h is the probability that the "A" EDG has failed and offsite power recovery has not been successful. This is given by:

= p(ac power not recovered at 2.5 h) × p(DG A failed to start and run)
= p(ac power not recovered at 2.5 h | ac power not recovered at 0.5 h) × p(DG A failed to start and run)
= (1.12E-03 / 1.46E-01) × 0.05 = 3.8E-04

LOOP Recovery at 4.0 h. It is assumed that seal failure will occur 1.0 h after seal cooling is lost (1.0 h after emergency power is lost) and core uncovery will occur 0.5 h after the seal LOCA. If power is lost at 2.5 h, then core uncovery will occur at 4.0 h (2.5 + 1.0 + 0.5) given a seal LOCA. The probability of not recovering offsite power at 4.0 h is given by:

= p(ac power not recovered at 4.0 h | ac power not recovered at 2.5 h)
= 5.43E-05 / 1.12E-03 = 4.8E-02

LOOP Recovery at 4.5 h. If a seal failure does not occur, then core damage will occur when battery depletion occurs. The battery lifetime, as stated in the Crystal River Final Safety Analysis Report (FSAR), is 2.0 h. Therefore core damage will occur at 4.5 h (2.0 + 2.5). The probability of not recovering offsite power at 4.5 h is given by:

= p(ac power not recovered at 4.5 h | ac power not recovered at 2.5 h)
= 2.10E-05 / 1.12E-03 = 1.9E-02

Seal LOCA probability

The seal LOCA is assumed to occur 1.0 h after the loss of seal cooling with a probability of 0.12 (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models,* August 1989). This is the minimum time period for failure and the maximum failure probability given in the reference document.

PORV/SRV Reseat

Assume that power for the PORV block valve is unavailable. The resulting failure to reseat probability is 0.01.

Other Values

The remaining values are the same as those typically used for Crystal River 3. These values are also found in the computer model calculations.

PORV/SRV Challenge Rate	8.0E-02
HPI (Given Offsite Power Recovery)	3.0E-04
HPR (Given HPI success and Offsite Power Recovery)	1.5E-04

Sequence Probabilities

The total conditional core damage probability for the sequences in the event tree in Fig. B.38 is found by multiplying the total value of the tree by the conditional events as follows:

$$= \quad p(\text{LOOP}) \times p(\text{-RT/LOOP}) \times p(\text{-EP}) \times p(\text{total for tree in Fig. B.38})$$
$$= \quad 0.15 \times (1.0 - 0.0) \times (1.0 - 2.3\text{E-03}) \times (2.7\text{E-05}) = 4.1\text{E-06}$$

The sequences where EP fails, sequences 46 – 55, are unaffected by the modification made to the original event tree. Therefore, values for these branches can be read directly from the output of the existing ASP model for case 1. For those sequences where EP succeeds throughout the event (initially and after 2.5 h), sequences 41 – 45, the results of the ASP model for case 1 are multiplied by the probability of success for EP at 2.5 h. This value is $1.0 - 3.8 \times 10^{-4} = 0.9996$. This is close enough to 1.0 that these values can also be read directly from the output of case 1.

Therefore, the conditional core damage probability for this event is obtained by adding the results of case 1 to the results of the tree as just calculated.

B.18.5 Analysis Results

The conditional core damage probability for this event is estimated to be 1.7×10^{-5}. Two cases were run to examine the sensitivity of the results to the operability of the 3B EDG. Case 1 assumes that the 3B train of equipment is not degraded and is operable throughout the event and results in a value of 1.3×10^{-5}. Case 2 assumes that the 3B train of equipment is inoperable throughout the event and results in a value of 2.6×10^{-4}. The dominant core damage sequence, highlighted on the event tree in Fig. B.39, involves a reactor trip, a postulated failure of on-site emergency power, and a postulated failure of auxiliary feedwater.

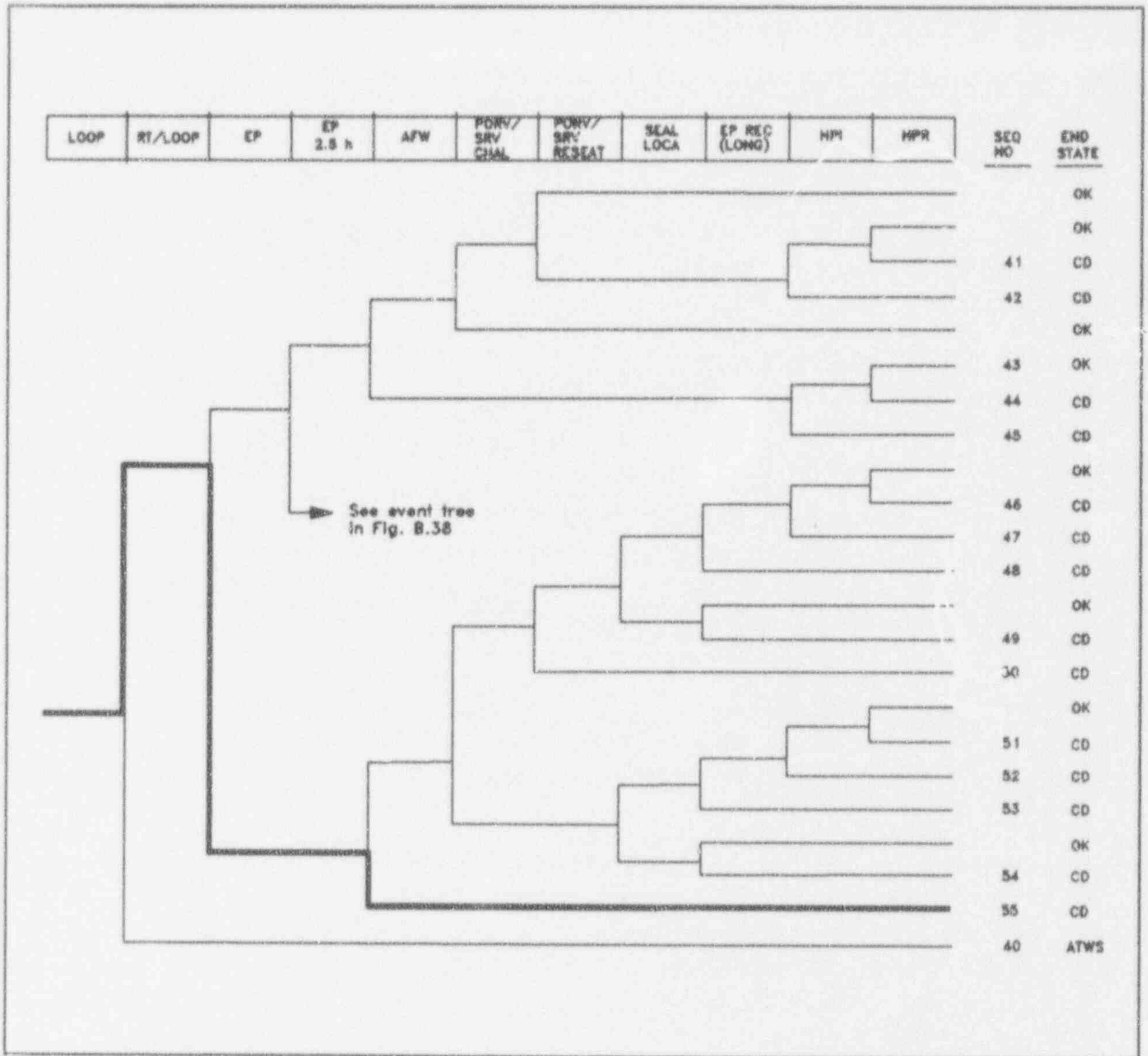


Fig. B.39. Dominant core damage sequences for LER 302/92-001 and 302/92-002

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 302/92-001
Event Description: LOOP from loss of vital bus (EDG B & Assoc Equip Operable) (Case 1 - Lower Bound)
Event Date: 03/27/92
Plant: Crystal River 3

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.5E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	1.3E-05[1]
Total	1.3E-05[1]
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	5.8E-06	4.1E-02
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	4.9E-06	1.2E-01
53	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	1.3E-06	1.2E-01
45	LOOP -rt/loop -emerg.power afw hpi(f/b)	CD	5.1E-07	3.3E-02
49	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power -SEAL.LOCA EP.REC	CD	4.2E-07	1.2E-01
50	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall porv.or.srv.reseat/emerg.power	CD	2.7E-07	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
45	LOOP -rt/loop -emerg.power afw hpi(f/b)	CD	5.1E-07	3.3E-02
49	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power -SEAL.LOCA EP.REC	CD	4.2E-07	1.2E-01
50	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall porv.or.srv.reseat/emerg.power	CD	2.7E-07	1.2E-01
53	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	1.3E-06	1.2E-01
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	4.9E-06	1.2E-01
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	5.8E-06	4.1E-02

** non-recovery credit for edited case

Event Identifier: 302/92-001

SEQUENCE MODEL: c:\asppra\models\pwrdseal.cmp
BRANCH MODEL: c:\asppra\models\crystal3.sl1
PROBABILITY FILE: c:\asppra\models\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	3.9E-04	1.0E+00	
LOOP	1.8E-05 > 1.8E-05	3.3E-01 > 1.5E-01	
Branch Model: INITOR			
Initiator Freq:	1.8E-05		
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
SEAL.LOCA	6.0E-02 > 1.5E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.0E-02 > 1.5E-02		
EP.REC(SL)	7.6E-01 > 2.8E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	7.6E-01 > 2.8E-01		
EP.REC	3.1E-01 > 1.6E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	3.1E-01 > 1.6E-02		
hpi	3.0E-04	8.4E-01	
hpi(f/b)	3.0E-04	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03

* branch model file
** forced

Notes:
[1]This value was modified to obtain the point estimate for the event. See Modeling Assumptions section for a description of the modifications made.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 302/92-001
Event Description: LOOP from loss of vital equip bus (EDG B & Assoc Equip OOS) **(CASE 2 - Upper Bound)**
Event Date: 03/27/92
Plant: Crystal River 3

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.5E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.6E-04
Total	2.6E-04
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
55	LOOP -rt/loop EMERG.POWER afw/emerg.power	CD	1.2E-04	4.1E-02
54	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	9.7E-05	1.2E-01
53	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	2.6E-05	1.2E-01
49	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power -SEAL.LOCA EP.REC	CD	8.4E-06	1.2E-01
50	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall porv.or.srv.reseat/emerg.power	CD	5.4E-06	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
49	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power -SEAL.LOCA EP.REC	CD	8.4E-06	1.2E-01
50	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall porv.or.srv.reseat/emerg.power	CD	5.4E-06	1.2E-01
53	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	2.6E-05	1.2E-01
54	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	9.7E-05	1.2E-01
55	LOOP -rt/loop EMERG.POWER afw/emerg.power	CD	1.2E-04	4.1E-02

** non-recovery credit for edited case

Event Identifier: 302/92-001

SEQUENCE MODEL: c:\asppra\models\pwrdseal.cmp
BRANCH MODEL: c:\asppra\models\crystal3.sl1
PROBABILITY FILE: c:\asppra\models\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	3.9E-04	1.0E+00	
LOOP	1.8E-05 > 1.8E-05	3.3E-01 > 1.5E-01	
Branch Model: INITOR			
Initiator Freq:	1.8E-05		
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 5.7E-02	8.0E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02		
afw	1.3E-03	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	2.0E-01	3.4E-01	
porv.or.srv.chall	8.0E-02	1.0E+00	
porv.or.srv.reseat	1.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	1.0E-02	1.0E+00	
SEAL.LOCA	6.0E-02 > 1.5E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.0E-02 > 1.5E-02		
EP.REC(SL)	7.6E-01 > 2.8E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	7.6E-01 > 2.8E-01		
EP.REC	3.1E-01 > 1.6E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	3.1E-01 > 1.6E-02		
HPI	3.0E-04 > 1.0E-03	8.4E-01	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
HPI(F/B)	3.0E-04 > 1.0E-03	8.4E-01	1.0E-02
Branch Model: 1.OF.3+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
HPR/-HPI	1.5E-04 > 1.0E-02	1.0E+00	1.0E-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		

* branch model file
** forced

Event Identifier: 302/92-001

B.19 LER Number 327/92-027

Event Description: Loss of Offsite Power

Date of Event: December 31, 1992

Plant: Sequoyah 1 & 2

B.19.1 Summary

Shortly after a switchyard tie breaker was installed, it faulted and caused an undervoltage condition in the switchyard. This resulted in the tripping of both units from 100% power after both unit's reactor coolant pumps (RCPs) tripped on undervoltage. Because of the momentary undervoltage condition on the safeguards buses, the emergency diesel generators started and loaded. The conditional core damage probability estimated for this event is 1.8×10^{-4} per unit. The relative significance of this event compared to other postulated events at Sequoyah is shown in Fig. B.40.

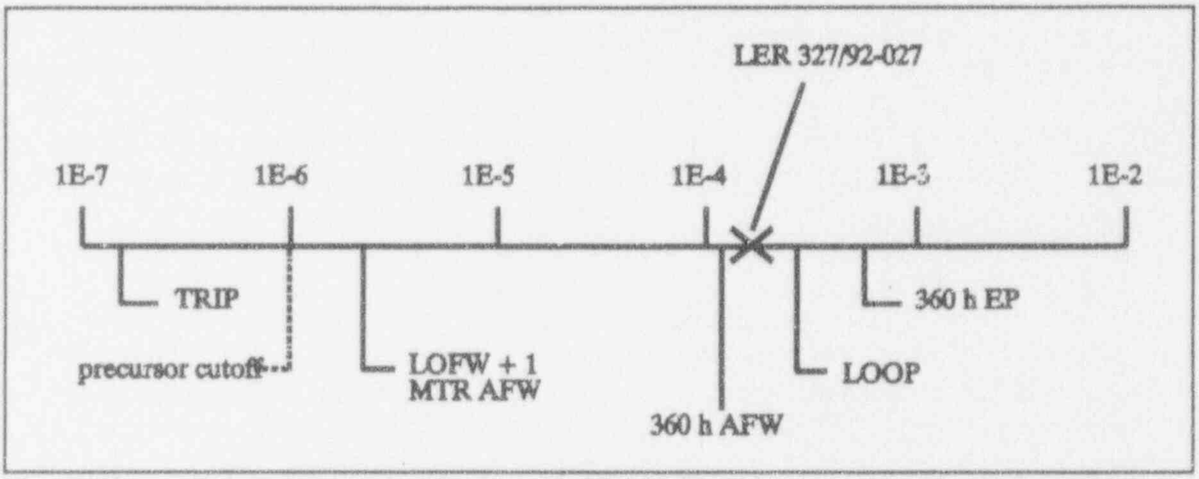


Fig. B.40. Relative event significance of LER 327/92-027 compared with other potential events at Sequoyah 1 & 2.

B.19.2 Event Description

On December 31, 1992, with both units at 100% power, work was progressing on the installation of a 500-kV/161-kV switchyard inter-tie breaker (see figure in LER 327/92-027). For testing purposes, the primary relay protection for the breaker was disabled. At 2148 hours, 11 min after the breaker was placed in service, both units tripped following the loss of the RCPs from an undervoltage signal. The undervoltage was caused by an internal fault in the inter-tie breaker that resulted in decreased voltage throughout the entire switchyard. After the switchyard fault was cleared (in 88 cycles), offsite power was available to the station.

Following the plant trips and the clearing of the switchyard fault, loads automatically transferred as designed from the unit station service transformers to the common station service transformers. However, because of the undervoltage sensed on the shutdown (safeguards) buses, the emergency diesel generators started and loaded. At 2313 hours the safeguards buses were realigned to offsite power. By 0013 hours on January 1, 1993, both units were stabilized in hot shutdown.

Due to limited staffing levels, the unit 2 recovery progressed with only one senior reactor operator (SRO) and one reactor operator (RO). During the recovery process, cooling to the RCP seals was placed in a degraded condition. For a period of 20 seconds, all charging pumps and thermal barrier booster pumps (TBBPs) were stopped. The charging pumps provide RCP seal injection while the TBBPs boost component cooling water (CCW) pressure to the RCP thermal barriers. During this 20 second time period, the CCW pumps continued to run and supplied approximately 70% of normal CCW flow to the RCP seals. This was sufficient flow to assure long term seal cooling.

B.19.3 Additional Event-Related Information

The Sequoyah switchyard consists of a 500-kV section and a 161-kV section. Unit 1 is directly connected to the 500-kV switchyard and unit 2 is directly connected to the 161-kV portion of the yard. The two sections are joined by the inter-tie transformer. Power circuit breaker (PCB) 5058 connects one of the 500-kV buses to the inter-tie transformer. During startup and shutdown, power to both units is supplied by the 161-kV system via the common station service transformers. Normally, primary relaying will isolate PCB 5058 in 3.5 cycles. Since PCB 5058 was removed from service, the undervoltage relays on the RCP trip actuated instead (in 17.5 cycles). Also, the undervoltage relays on the safeguards busses actuated (in 30 cycles) before the secondary relaying could isolate the fault (normally, in 88 cycles).

B.19.4 Modeling Assumptions

Since the LOOP was caused by a substation fault, this event was modeled as a plant-centered LOOP. Probabilities for LOOP nonrecovery (short term), failure to recover ac power prior to battery depletion, and RCP seal LOCA probabilities were revised to reflect values associated with a plant-centered LOOP (see ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989). The event was modeled for a single unit. The event sequence was essentially the same for both units.

B.19.5 Analysis Results

The conditional probability of core damage estimated for this event is 1.8×10^{-4} per unit. The dominant core damage sequence, highlighted on the event tree in Fig. B.41, involves failure of emergency power restoration resulting in an RCP seal LOCA.

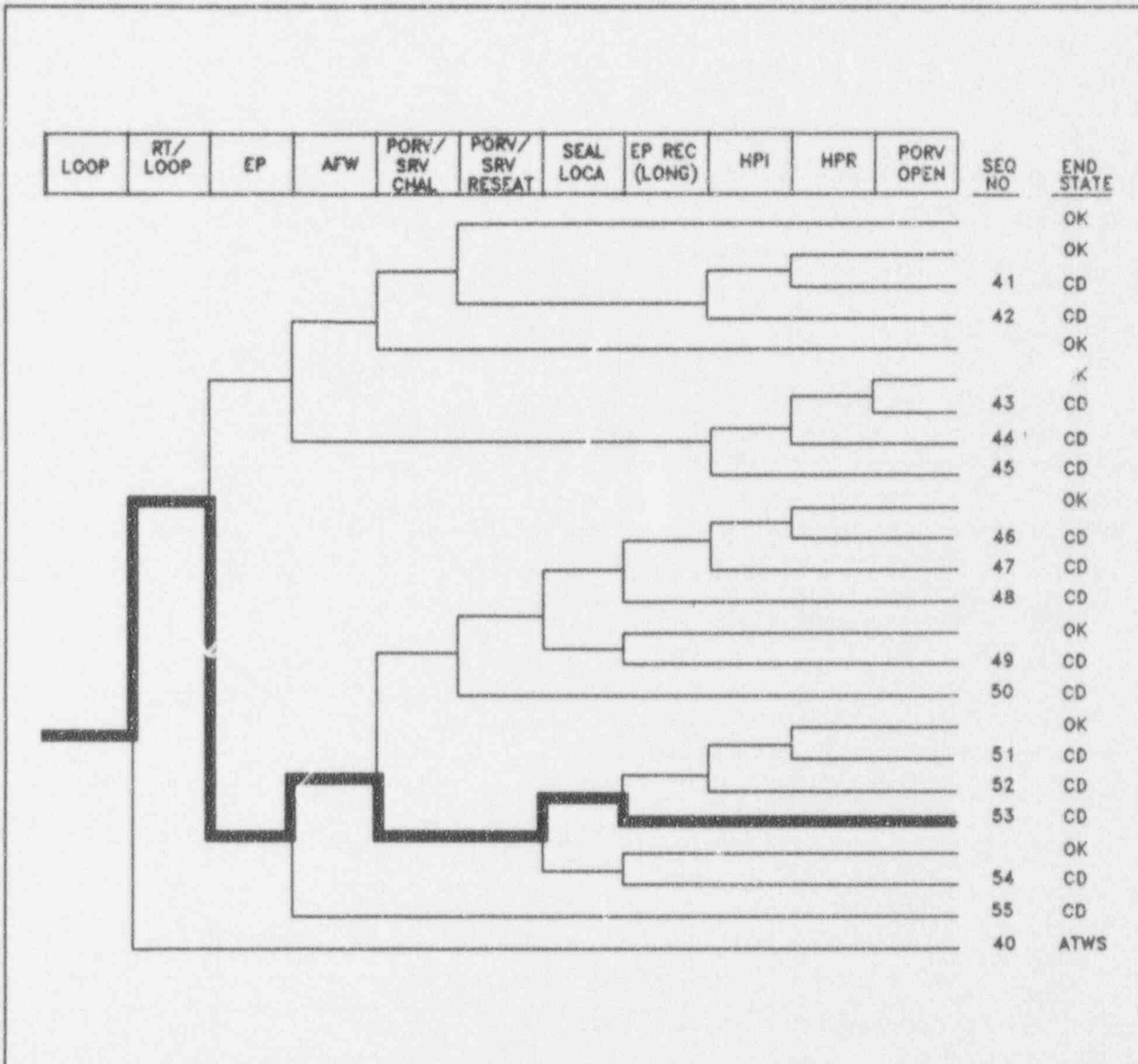


Fig. B.41. Dominant core damage sequence for LER 327/92-027.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 327/92-027
Event Description: Loss of Offsite Power
Event Date: 12/31/92
Plant: Sequoyah 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	5.0E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	1.8E-04
Total	1.8E-04
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
53	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	1.2E-04	4.0E-01
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	3.6E-05	4.0E-01
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	1.9E-05	1.4E-01
48	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power SEAL.LOCA EP.REC(SL)	CD	4.8E-06	4.0E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
48	LOOP -rt/loop emerg.power -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power SEAL.LOCA EP.REC(SL)	CD	4.8E-06	4.0E-01
53	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall SEAL.LOCA EP.REC(SL)	CD	1.2E-04	4.0E-01
54	LOOP -rt/loop emerg.power -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	3.6E-05	4.0E-01
55	LOOP -rt/loop emerg.power afw/emerg.power	CD	1.9E-05	1.4E-01

** non-recovery credit for edited case

SEQUENCE MODEL: C:\asppra\models\pwrbseal.cmp
BRANCH MODEL: C:\asppra\models\sequoyah.sl1
PROBABILITY FILE: C:\asppra\models\pwr_bsl1.pro

Event Identifier: 327/92-027

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	7.7E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	5.3E-01 > 5.0E-01	
Branch Model: INITOR			
Initiator Freq:	1.6E-05		
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
SEAL.LOCA	2.7E-01 > 2.3E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.7E-01 > 2.3E-01		
EP.REC(SL)	5.7E-01 > 4.8E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.7E-01 > 4.8E-01		
EP.REC	7.0E-02 > 4.3E-02	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	7.0E-02 > 4.3E-02		
hpi	1.0E-03	8.4E-01	
hpi(f/b)	1.0E-03	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Event Identifier: 327/92-027

B.20 LER Number 328/92-010

Event Description: Emergency Diesel Generator and Residual Heat Removal Pump Inoperable

Date of Event: July 17, 1992

Plant: Sequoyah Nuclear Plant, Unit 2

B.20.1 Summary

During performance of a surveillance procedure on the 2B-B Residual Heat Removal (RHR) pump, it was found that the miniflow control valve continuously cycled open and closed when it should have remained opened. While the 2B-B RHR pump was inoperable, the 2A-A emergency diesel generator (EDG) wa: inoperable for 17 h and the 2A-A centrifugal charging pump was inoperable for 6 h. The conditional core damage probability estimated for this event is 1.9×10^{-6}. The relative significance of this event compared to other postulated events at Sequoyah, Unit 2 is shown in Fig. B.42.

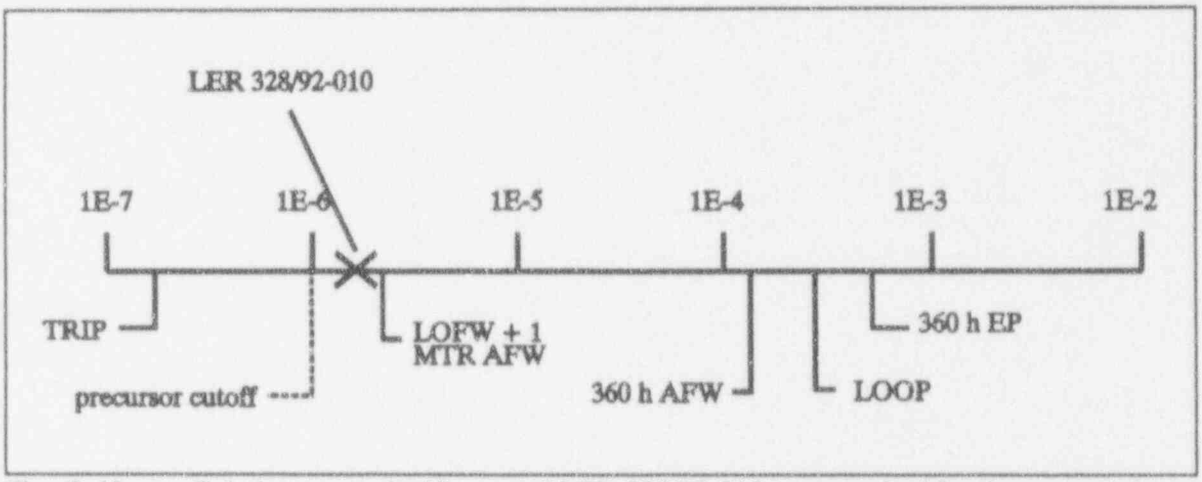


Fig. B.42. Relative event significance of LER 328/92-010 compared with other potential events at Sequoyah 2.

B.20.2 Event Description

On July 17, 1992, with the unit at 100% power, a quarterly surveillance procedure on the 2B-B RHR pump was conducted. During the test, it was discovered that the pump's miniflow line motor control valve was continuously cycling open and closed when it should have remained open.

Further investigation revealed that the valve had been miswired on July 1, 1992, during performance of the flow switch quarterly preventive maintenance procedure. Between July 1, 1992 and July 17, 1992, there were 10 instances where Train A safety equipment had been out of service. Only two of these instances were of a significant duration; EDG 2A-A was out of service for 17 h, and centrifugal charging pump (CCP) 2A-A was out of service for 6 h.

The wiring for the other RHR trains was verified to be correct.

B.20.3 Additional Event-Related Information

The Sequoyah Units have miniflow lines for each of the RHR pumps. This flow path consists of the pump, a flow sensor, the RHR heat exchanger, and a recirculation line that returns to the pump suction. The recirculation line contains a motor-operated flow control valve that varies its position, based on the pump discharge flow signal, to maintain total pump flow between 500 and 1500 gal/min. Manual control and indication of the valve's position is available in the control room.

During an accident, the pump would be aligned for reactor coolant system (RCS) injection. However, the pump would be in the recirculation mode until RCS pressure drops below the pump deadhead pressure, or the RHR system is realigned to the safety injection pump suction during the recirculation phase.

The recirculation valve does not have any thermal overloads and may fail after 15 min of continuous operation. With the valve closed and RCS pressure greater than the RHR pump deadhead pressure, insufficient flow through the pump could damage the pump because of overheating. With the valve fully open, flow to the RCS would be insufficient to ensure accident mitigation under large break LOCA conditions. Because the valve continuously cycled opened and closed, the actual time to failure of the RHR pump is more difficult to predict.

The two CCPs fulfill part of the emergency core cooling system (ECCS) function. The discharge pressure of the pumps (2670 psig) is greater than normal RCS pressure. The two high pressure safety injection (HPSI) system pumps have a discharge pressure of 1650 psig. All four pumps are used during initial injection and during long term recirculation cooling. During the recirculation mode, the 1A-A RHR pump supplies the 1A-A safety injection (SI) pump and both CCPs. The 1B-B RHR pump supplies only the 1B-B SI pump.

B.20.4 Modeling Assumptions

The event was modeled as a potential LOOP assuming the 2B-B RHR train and the 2A-A EDG were inoperable for 17 h. Equipment associated with the train 2A-A EDG (2A-A AFW pump, 2A-A SI pump, 2A-A RHR pump) is rendered inoperable due to loss of electrical power. Both trains of high-pressure recirculation were inoperable because both trains of RHR were inoperable.

The current Accident Sequence Precursor (ASP) models do not account for the separate high head CCPs and intermediate head systems (SI) that Sequoyah uses for the ECCS function. Inoperability of one train of RHR and one train of charging is not normally analyzed in the ASP program. Therefore the 6-hour CCP train/RHR train inoperability was not considered a precursor, and, as a result, was not analyzed. For the 17 h RHR train/EDG inoperability, the HPI system model was modified to incorporate the CCPs. The modification was performed as follows.

p(HPI system) = [p(HPI train 1) × p(HPI train 2)] × [p(CCP train 1) × p(CCP train 2) + p(CCP valves)]

= [0.01 × 1.0] × [0.01 × 1.0 + 0.0011]
= 1.11×10^{-4}

p(CCP valves) = 4 × [vlv1 × (vlv2 + BETA v)]

= 4 × [0.003 × (0.003 + 0.088)]

= 0.001092

B.20.5 Analysis Results

The conditional probability of core damage estimated for this event is 1.9×10^{-6}. The dominant sequence, highlighted on the event tree in Fig. B.43, involves a postulated LOOP with failure of on-site emergency power, and failure to recover offsite power prior to a RCP seal LOCA.

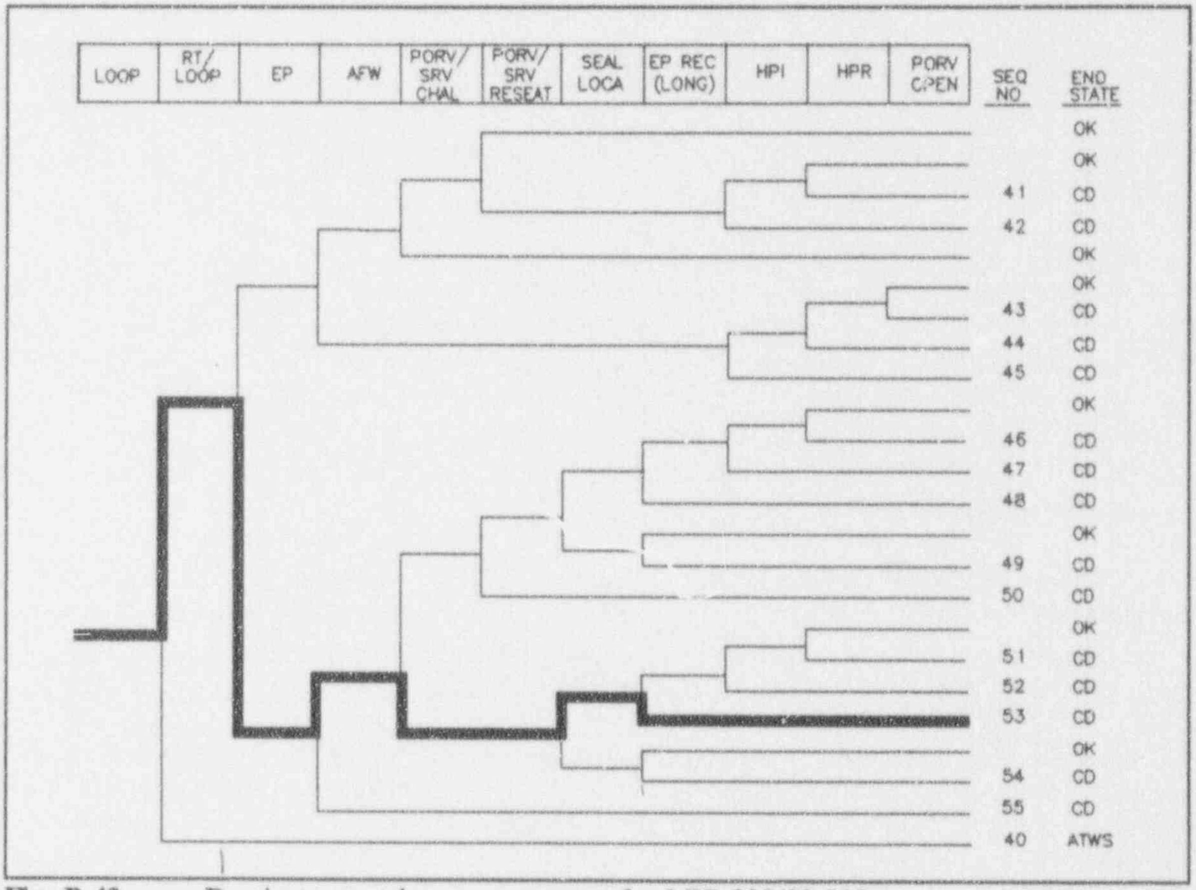


Fig. B.43. Dominant core damage sequences for LER 328/92-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 328/92-010
Event Description: 1A-A EDG Unavail & 1B-B RHR Unavail (LOOP Only)
Event Date: 07/17/92
Plant: Sequoyah 2

UNAVAILABILITY, DURATION= 17 h

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.5E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	1.9E-06
Total	1.9E-06
ATWS	
LOOP	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca ep.rec(sl)	CD	8.0E-07	4.2E-01
51	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	6.4E-07	4.2E-01
54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	2.7E-07	4.2E-01
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	9.4E-08	1.4E-01
44	loop -rt/loop -EMERG.POWER AFW -HPI(F/B) HPR/-HPI	CD	4.6E-08	1.4E-01
48	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca ep.rec(sl)	CD	3.3E-08	4.2E-01
46	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	2.6E-08	4.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
44	loop -rt/loop -EMERG.POWER AFW -HPI(F/B) HPR/-HPI	CD	4.6E-08	1.4E-01
46	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	2.6E-08	4.2E-01
48	loop -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power seal.loca ep.rec(sl)	CD	3.3E-08	4.2E-01
51	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca -ep.rec(sl) -HPI HPR/-HPI	CD	6.4E-07	4.2E-01
53	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall seal.loca ep.rec(sl)	CD	8.0E-07	4.2E-01

Event Identifier: 328/92-010

54	loop -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -seal.loca ep.rec	CD	2.7E-07	4.2E-01
55	loop -rt/loop EMERG.POWER afw/emerg.power	CD	9.4E-08	1.4E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asppra\models\pwrbseal.cmp
BRANCH MODEL: c:\asppra\models\sequoyah.sl1
PROBABILITY FILE: c:\asppra\models\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	7.7E-04	1.0E+00	
loop	1.6E-05	5.3E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 5.0E-02	8.0E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
AFW	3.8E-04 > 1.3E-03	2.6E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	5.0E-02		
Serial Component Prob:	2.8E-04		
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.7E-01	1.0E+00	
ep.rec(sl)	5.7E-01	1.0E+00	
ep.rec	7.0E-02	1.0E+00	
HPI	1.0E-03 > 1.1E-04 **	8.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
HPI(F/B)	1.0E-03 > 1.1E-04 **	8.4E-01	1.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		

Event Identifier: 328/92-010

HPR/-HPI	1.5E-04 > 1.0E+00	1.0E+00	1.0E-03
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Notes:

1. Probabilities were modified to incorporate CCPs. See the modeling assumptions section for a description of this modification.

Event Identifier: 328/92-010

B.21 LER Number 344/92-020

Event Description: Reactor Trip and Turbine-Driven Auxiliary Feedwater Pump Failure To Start

Date of Event: July 22, 1992

Plant: Trojan

B.21.1 Summary

Trojan was operating at 100% power on July 22, 1992 when erratic controller performance on one main feedwater (MFW) pump and controller failure on the other MFW pump resulted in a reactor trip on low-low steam generator (SG) level. The controller for the auxiliary feedwater (AFW) pump turbine also failed, rendering one of two safety-grade AFW pumps inoperable. The conditional core damage probability estimated for this event is 5.9×10^{-6}. The relative significance of this event compared to other postulated events at Trojan is shown in Fig. B.44

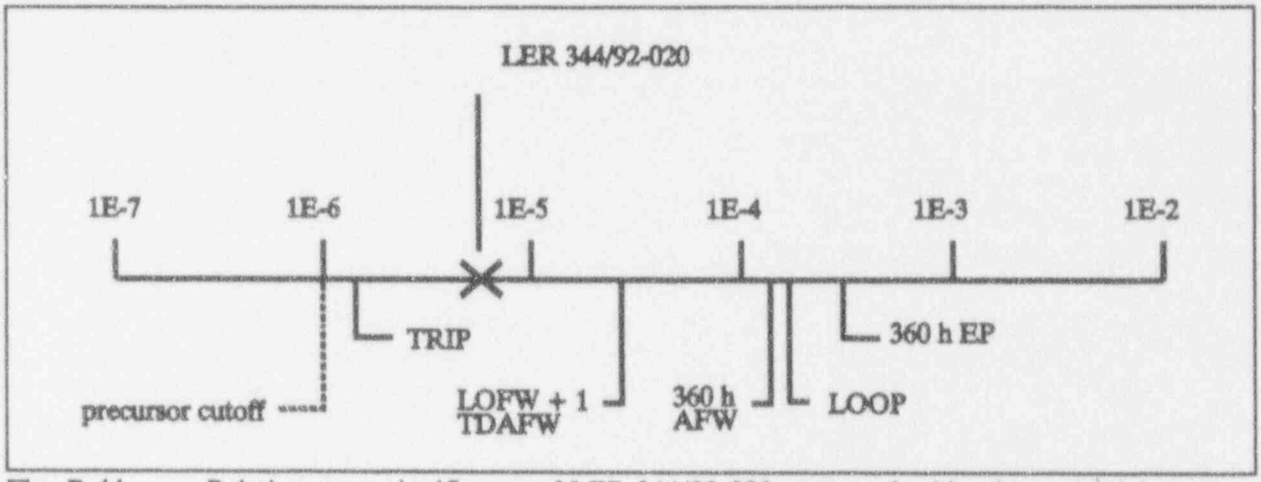


Fig. B.44. Relative event significance of LER 344/92-020 compared with other potential events at Trojan.

B.21.2 Event Description

Approximately two weeks prior to the plant trip, operators noted that the automatic controller for the A MFW pump was oscillating and placed the controller in manual. About two days prior to the plant trip, operators observed that the B MFW pump was supplying 20,500 gpm while the A MFW pump was supplying 10,000 gpm. While attempting to balance flows between the pumps, they experienced difficulty with the B pump controller and placed that controller in manual as well. On July 22, 1992 Trojan was operating at 100% power, while troubleshooting the B MFW pump control circuitry the pump suddenly slowed to minimum speed. Operators tripped the pump, initiating a turbine runback, but the reactor tripped a short time later on low-low SG level. The turbine-driven A AFW pump auto-started but tripped on overspeed. Subsequent attempts to restart the pump were unsuccessful. The diesel-driven B AFW pump started correctly and provided cooling water to the SGs.

The cause of the A MFW pump controller failure was diagnosed as a defective electronic component in the controller module. The B MFW pump controller failed because of a misadjusted power supply. The A AFW pump failed because a defective ramp generator signal converter permitted the pump to overspeed and trip on each start attempt.

B.21.3 Additional Event-Related Information

Trojan is equipped with two 100% capacity safety-related AFW pumps, each capable of supplying 880 gpm to any of the four SGs. One pump is powered by a steam turbine, and the other is powered by a diesel engine. A third, nonsafety-related electric-motor-driven pump is available for use during plant startups and shutdowns. This pump is operable from the control room and could have been used to provide flow to the SGs if both safety-related AFW pumps had failed.

B.21.4 Modeling Assumptions

This event was modeled as a reactor trip with loss of feedwater and one AFW pump unavailable. Since the A MFW pump was locally operable, a nonrecovery probability of 0.34 (This is ASP recovery class R2, see section A.1.3 of this report for more information.) was assumed for the MFW system. The non-safety related AFW pump also was assumed capable of providing SG cooling following a manual start. One AFW pump was modeled as being failed; however, for calculational convenience, only the two pumps which remained operable are depicted in the model.

An additional method for plant cooldown exists at Trojan which is not directly incorporated into the ASP model. Trojan Emergency Operating Procedures (EOPs) include steps to reduce the main steam pressure using the main steam line PORVs and supply the SGs with the condensate pumps after having attempted primary side feed-and-bleed operations. However, limited information has been obtained regarding the plant thermal hydraulics and the reactor physics associated with this evolution. Also, operator performance during this process is difficult to assess since the operators are required to perform actions outside the control room to accomplish this cooldown. Therefore, implementation of this strategy could involve time constraints and substantial operator burden. Nevertheless, since the EOPs exist and training is conducted on those EOPs it was determined that this was a viable alternative. However, since this method is not currently incorporated in the ASP model for Trojan, its impact was calculated by adjusting the AFW non-recovery probability from 0.34 to 0.12.

B.21.5 Analysis Results

The conditional probability of subsequent core damage estimated for this event is 5.9×10^{-6}. The dominant core damage sequences, highlighted on the following event tree in Fig. B.45, involve failure of all sources of SG makeup and failure of feed-and-bleed cooling.

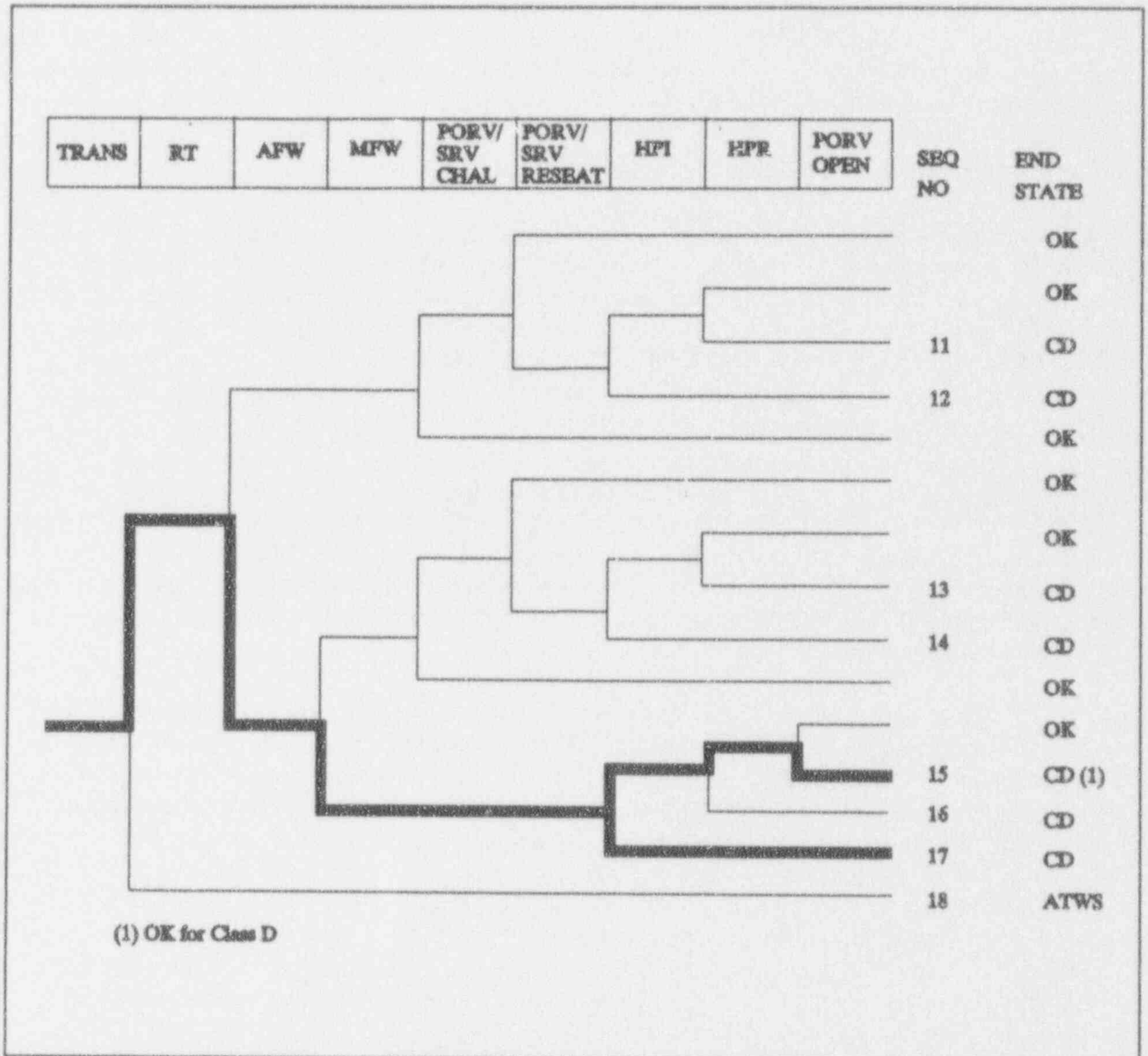


Fig. B.45. Dominant core damage sequences for LER 344/92-020

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 344/92-020
Event Description: Reactor Trip and AFW Pump Failure to Start
Event Date: 7/22/92
Plant: Trojan

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	5.9E-06
Total	5.9E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
17	trans -rt AFW MFW hpi(f/b)	CD	2.9E-06	3.4E-02
15	trans -rt AFW MFW -hpi(f/b) -hpr/-hpi porv.open	CD	2.7E-06	4.1E-02
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	3.0E-07	4.1E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
15	trans -rt AFW MFW -hpi(f/b) -hpr/-hpi porv.open	CD	2.7E-06	4.1E-02
16	trans -rt AFW MFW -hpi(f/b) hpr/-hpi	CD	3.0E-07	4.1E-02
17	trans -rt AFW MFW hpi(f/b)	CD	2.9E-06	3.4E-02
18	trans rt	ATWS	3.4E-05	1.2E-01

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\models\pwrbseal.cmp
BRANCH MODEL: c:\asp\models\trojan.sl1
PROBABILITY FILE: c:\asp\models\pwr_bsl1.pro

No Recovery Limit

Event Identifier: 344/92-020

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	5.6E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
AFW	2.5E-03 > 6.5E-03	3.4E-01 > 1.2E-01[1]	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.0E-02 > 1.3E-01		
afw/emerg.power	2.5E-03	3.4E-01	
MFW	1.0E+00 > 1.0E+00	7.0E-02 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E+00		
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	2.3E-01	1.0E+00	
ep.rec(sl)	5.9E-01	1.0E+00	
ep.rec	6.1E-02	1.0E+00	
hpi	1.0E-03	8.4E-01	
hpi(f/b)	1.0E-03	8.4E-01	1.0E-02
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Notes:

1. Secondary side depressurization and cooldown credited by adjusting the AFW nonrecovery probability. See modeling assumptions section for a description of this modification.

Event Identifier: 344/92-020

B.22 LER Number 374/92-012

Event Description: Reactor Trip With Degraded Reactor Core Isolation Cooling

Date of Event: August 27, 1992

Plant: LaSalle 2

B.22.1 Summary

The reactor scrammed from 80% power because of a main turbine trip. The main turbine tripped due to a thrust bearing failure indication. The reactor core isolation cooling system (RCIC) auto-started, and the motor-driven feed pump (MDFP) was started in preparation for tripping the turbine-driven feed pumps (TDFPs). However, when the TDFPs failed to trip, the reactor water level rose, resulting in a trip of the MDFP and RCIC. In an attempt to prevent flooding of the steam lines, the outboard main steam isolation valves (MSIVs) were manually closed, resulting in a TDFP shutdown. Later, the operators experienced difficulty in starting RCIC for reactor pressure control. Water that had accumulated in the steam line passed through the pump turbine and into the exhaust header. Flashing of that water to steam prevented RCIC startup due to high exhaust pressure trip signals. The conditional probability of subsequent core damage estimated for the event is 6.1×10^{-6}. The relative significance of the event compared to other postulated events at LaSalle 2 is shown in Fig. B.46.

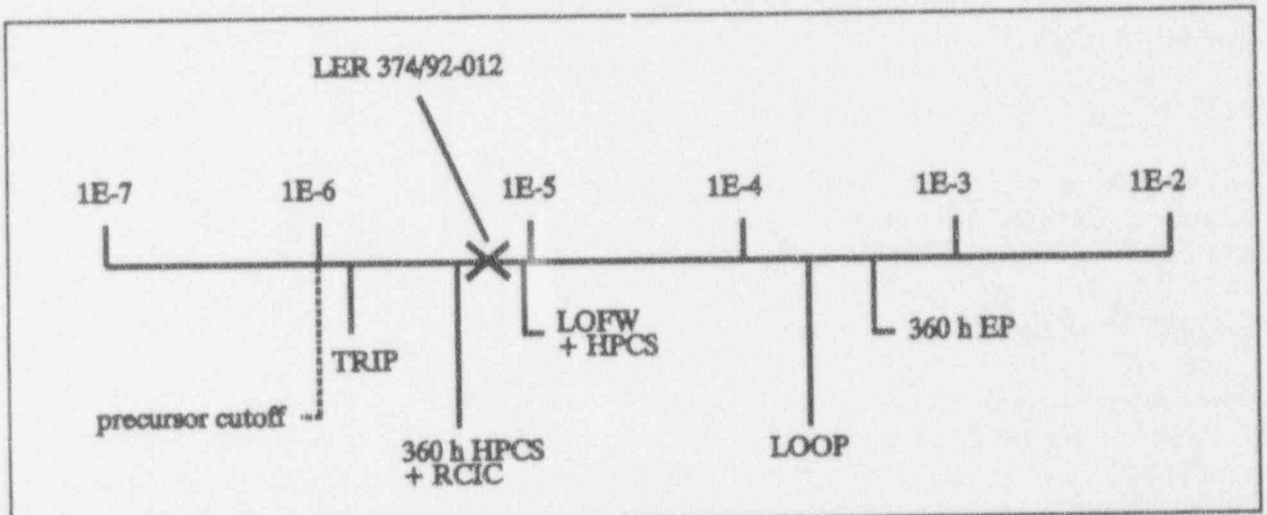


Fig. B.46. Relative event significance of LER 374/92-012 compared with other potential events at La Salle.

B.22.2 Event Description

On August 27, 1992, while reactor power was being reduced to 80%, LaSalle 2 scrammed because of a spurious thrust-bearing wear detector turbine trip signal. The spurious signal was caused by a shift in the trip setpoint due to manufacturer error. Within seconds, RCIC auto-started on a spurious low reactor water level signal caused by pressure oscillations induced by closure of the turbine stop valves.

The MDFP was successfully started to control water level; however, the TDFPs then failed to trip because of oil contamination and blockage in the turbine oil system (both TDFPs failed to trip on high vessel level and after multiple attempts from the control room and locally at the pump). The increasing water level in the reactor eventually resulted in a trip of RCIC and the MDFP. The MISVs were manually closed 3 min into the event when the 73-in administrative limit was reached; to prevent flooding outboard of the MISVs. However, the RCIC steam line is inboard of the MSIVs and the transient water level rose to 130 in. which is 22 in. above the bottom of the main steam lines. Closure of the MSIVs resulted in a trip of the TDFPs and loss of the main condenser as a heat sink. The safety relief valves (SRVs) were then required for control of reactor pressure. Although the SRVs were used successfully for this function, corrosion-caused instrumentation failures prevented direct confirmation of closure of two SRVs.

Attempts were made to use RCIC for reactor pressure control. Two start-up attempts failed as a result of high-exhaust-pressure trips. The cause was water accumulation in the steam lines which passed into the exhaust header via the pump turbine. There, flashing of water to steam resulted in pressure peaks which triggered the RCIC trips. The RCIC steam line drains had operated as designed, but the time available for water drainage was insufficient. The third attempt to start the RCIC (approximately 5 min after the first trip) was successful.

B.22.3 Additional Event-Related Information

LaSalle is equipped with high pressure core spray (HPCS) and RCIC, either of which can provide adequate reactor vessel makeup following a loss of feedwater (LOFW) or a loss of inventory from a stuck open relief valve. In addition, the MDFP can be used for reactor vessel makeup.

B.22.4 Modeling Assumptions

The event was modeled as a LOFW with failed RCIC. Potential sequences associated with the event are described in Appendix A, section A.3.2, BWR Nonspecific Reactor Trip, and shown on the event tree included with this analysis documentation. The plant response observed during the event impacted the following branches on the event tree:

- TRANSIENT (reactor trip occurs). The reactor tripped because of main turbine stop-valve closure.

- Power conversion system provides core cooling. The MSIVs were manually closed during the event in an attempt to prevent flooding of the main steam lines. This resulted in unavailability of the PCS.

- Feedwater provides reactor pressure vessel (RPV) makeup. The turbine-driven feedwater pumps shut down when the MSIVs were closed. The motor-driven feedwater pump tripped on high RPV water level. The motor-driven pump was assumed to be recoverable with a non-recovery probability of 0.12 (ASP non-recovery class R3, see Appendix A, sect. A.1). This value was chosen because the tripped pump appeared recoverable in the required period from the control room, but, because of the main steam line flooding and the problems with the turbine-driven feedwater and RCIC pumps, recovery was considered to be non-routine and burdened.

- RCIC provides reactor pressure vessel makeup. RCIC tripped twice on high exhaust pressure because of water accumulation in the steam lines. RCIC was assumed to be recoverable with a non-recovery probability of 0.12 (ASP non-recovery class R3), for the same reasons as FW. This non-recovery probabilty for RCIC may be conservative, since the steam line drain valves operated as intended and the third RCIC startup attempt was successful.

The current ASP event trees for LaSalle do not model the potential use of RCIC to provide RPV makeup in the event of a single stuck-open SRV. The use of RCIC for this purpose was included in the NUREG-1150 PRAs and utility-sponsored IPEs. To address this, the conditional probabilities for applicable sequences (sequences 25, 26 and 28) were reduced by the probability of failing to successfully use RCIC for this purpose. This is the probability that either RCIC fails, two or more SRVs fail to close given one or more fail to close, or long-term core cooling fails given RCIC is successful and only one SRV fails open. Since long-term core cooling is reliable, this probability can be approximated by

$$p(\text{RCIC}) + p(\text{2 or more valves fail open} \mid \text{1 or more valves fail open}).$$

The failure probability for RCIC during this event was estimated above as 0.12. A value of 0.027 was estimated for p(2 or more valves fail open | 1 or more valves fail open), based on an estimated probability for two or more SRVs stuck open of 0.0015 (see NUREG/CR-4550, Vol. 1, Rev. 1, Analysis of Core Damage Frequency: Internal events Methodology, january 1990, p. 6-10) and an estimated probability of one or more SRVs stuck open of 0.056 (developed as described in Appendix A, sect. A.4).

The probability multiplier used to adjust sequences 25, 26 and 28 to account for the potential use of RCIC to mitigate the effects of a single stuck-open SRV is therefore 0.12 [p(RCIC)] + 0.027 [p(2 or more SRVs fail open | 1 or more SRVs fail open)] = 0.15. The conditional probability for sequence 28 (the only dominant sequence of the three sequences – 25, 26, and 28) was manually revised from 5.8×10^{-7} to 8.7×10^{-8} to reflect this. This reduces the core damage probability estimated for the event from 6.6×10^{-6} indicated on the calculational sheets to 6.1×10^{-6}.

B.22.5 Analysis Results

The estimated conditional core damage probability associated with the event is 6.1×10^{-6}. This probability was calculated by reducing the core damage probability shown in the calculations (6.6×10^{-6}) by the change in sequence 28 (from 5.8×10^{-7} to 8.7×10^{-8}, a factor of 0.15) as discussed in the last paragraph in the modeling assumptions section. This has been reduced from the value shown on the calculational sheets to reflect the potential use of RCIC to mitigate a single stuck open relief valve, as discussed in the modeling assumptions section. The dominant core-damage sequence, highlighted on the event tree in Fig. B.47, involves an effective LOFW with successful reactor vessel makeup and failure to remove decay heat in the long term. Note that failure of RCIC does not contribute to the dominant sequences associated with the event.

This analysis addressed the potential loss of core cooling caused by failures of systems associated with transient mitigation. If the MISVs had not been closed, failure of the main steam line could have resulted. The potential for core damage from this sequence was not addressed in this analysis due to the difficulty in estimating the required steam line failure probabilities.

Additional information concerning this event is included in Augmented Inspection Team report 50-374/92020(DRS).

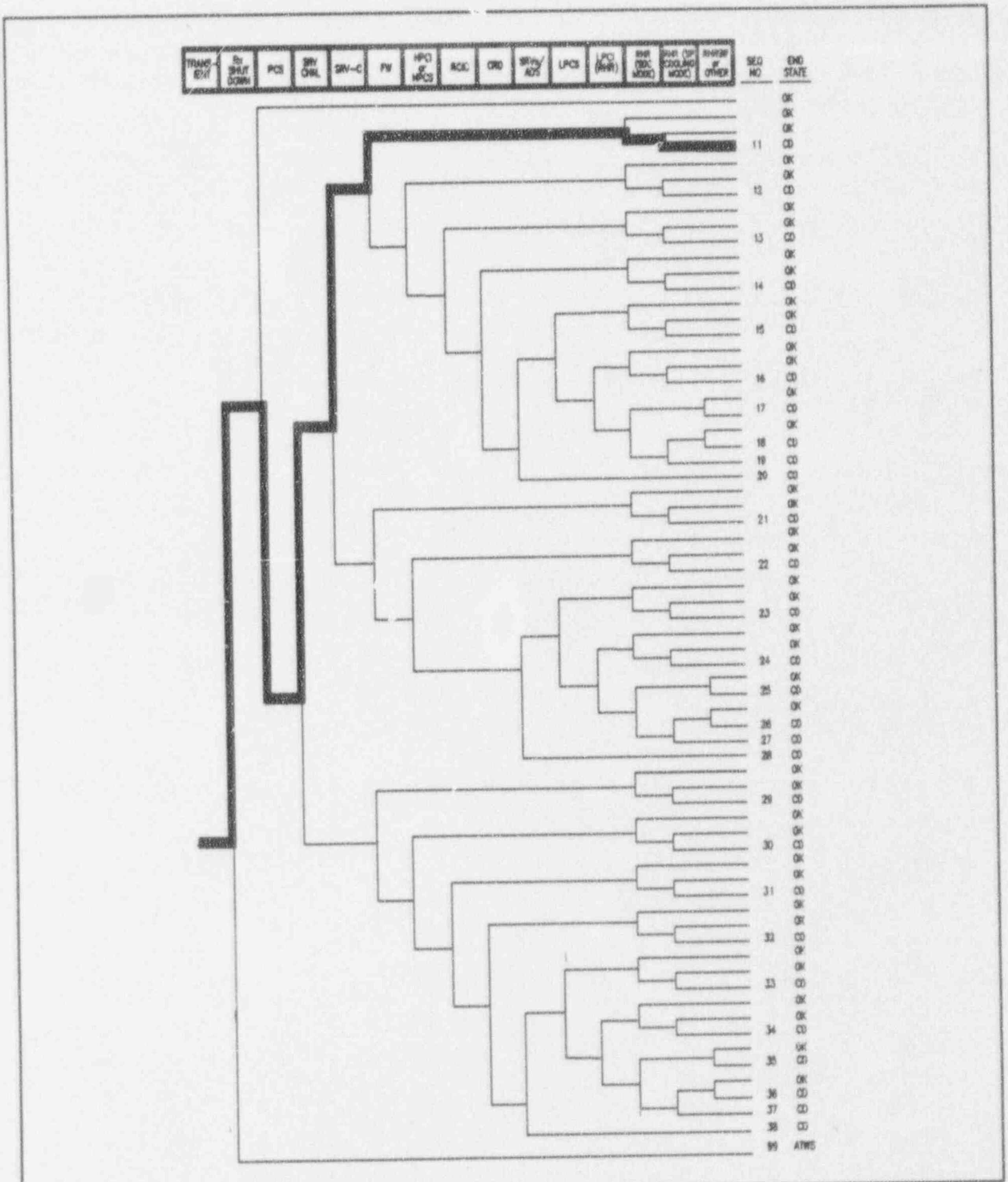


Fig. B.47. Dominant core damage sequences for LER 374/92-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 374/92-012
Event Description: Reactor trip and vessel overfill with degraded RCIC
Event Date: 08/27/92
Plant: LaSalle 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	6.6E-06[1]
Total	6.6E-06[1]
ATWS	
TRANS	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
11	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close -FW/PCS.TRANS rhr(sdc) rhr(spcool)/rhr(sdc)	CD	5.0E-06	1.0E-01
12	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS -hpci rhr(sdc) rhr(spcool)/rhr(sdc)	CD	6.7E-07	1.4E-02
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS hpci srv.ads	CD	5.8E-07[1]	2.9E-02
21	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close -FW/PCS.TRANS rhr(sdc) rhr(spcool)/rhr(sdc)	CD	3.0E-07	1.0E-01
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
11	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close -FW/PCS.TRANS rhr(sdc) rhr(spcool)/rhr(sdc)	CD	5.0E-06	1.0E-01
12	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS -hpci rhr(sdc) rhr(spcool)/rhr(sdc)	CD	6.7E-07	1.4E-02
21	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close -FW/PCS.TRANS rhr(sdc) rhr(spcool)/rhr(sdc)	CD	3.0E-07	1.0E-01
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS hpci srv.ads	CD	5.8E-07[1]	2.9E-02
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

Event Identifier: 374/92-012

SEQUENCE MODEL: c:\asp\1989\bwrcseal.cmp
BRANCH MODEL: c:\asp\1989\lasalle.sl1
PROBABILITY FILE: c:\asp\1989\bwr_csl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	7.4E-05	1.0E+00	
loop	1.6E-05	5.3E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Unavailable		
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	5.6E-02	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
ep.rec	1.7E-01	1.0E+00	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Unavailable		
FW/PCS.LOCA	1.0E+00 > 1.0E+00	3.4E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E+00		
hpci	2.0E-02	3.4E-01	
RCIC	6.0E-02 > 1.0E+00	7.0E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.0E-02 > Failed		
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	2.0E-02	3.4E-01	
lpci(rhr)/lpcs	6.0E-04	7.1E-01	
rhr(sdc)	2.3E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file

Event Identifier: 374/92-012

Notes:

[1]See Modeling Assumptions for a discussion of changes made to this probability value.

B.23 LER Number 388/92-001

Event Description: Reactor Trip with Emergency Diesel Generator and Vital Bus Unavailable

Date of Event: March 18, 1992

Plant: Susquehanna 2

B.23.1 Summary

Susquehanna 2 was operating at 100% power on March 18, 1992 when emergency diesel generator (EDG) B failed during surveillance testing, preparations were begun to align the spare diesel, EDG E, in its place. During the course of these preparations, ESF bus C suddenly isolated. Since this isolated the containment instrument gas supply required for control of the main steam isolation valves (MSIVs), the reactor was manually scrammed in anticipation of an automatic scram on MSIV closure. The conditional core damage probabilty estimated for this event is 6.6×10^{-6}. The relative significance of this event to other postulated events at Susquehanna is shown in Fig. B.48.

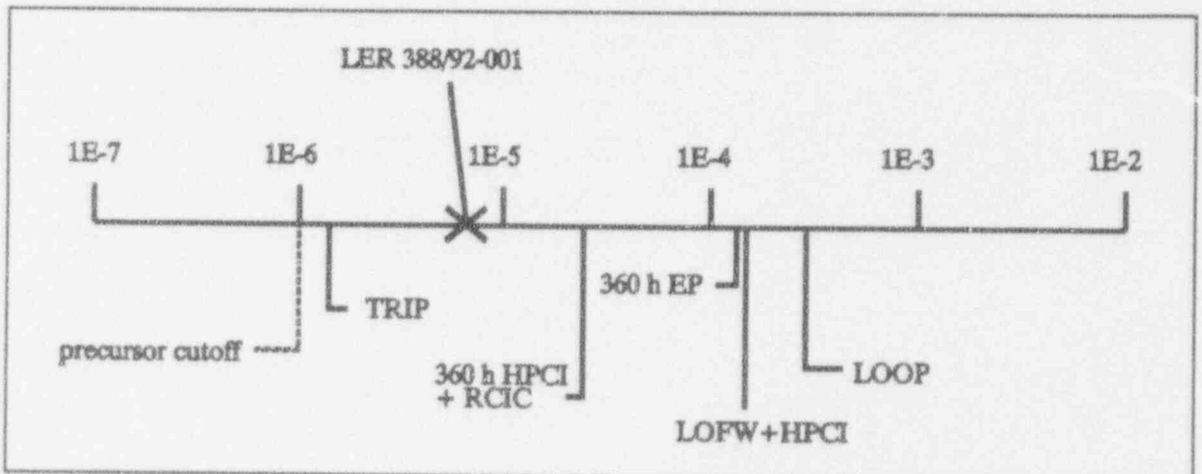


Fig. B.48. Relative event significance of LER 388/92-001 compared with other potential events at Susquehanna 2.

B.23.2 Event Description

Susquehanna Unit 2 was operating at 100% power on March 18, 1992, and EDG B was being run for its monthly surveillance test. During this test, the EDG tripped on loss of field, apparently due to failure of a diode in its field rectifier circuitry. EDG B was declared inoperable and procedures were begun to align the spare, EDG E, in its place. These procedures required operators to check all protective relay "targets" (actuation indicators) on the 4kV ESF buses and to reset the targets as necessary. When an operator found a bus differential relay target dropped on ESF bus 2C and attempted to reset it, the bus tripped and locked out.

This resulted in unavailablity of normal and emergency power to a number of loads including a core spray (CS) pump, a residual heat removal (RHR) pump, and several drywell coolers. In addition, several containment isolations occurred, including the containment instrument gas (CIG) system. As the CIG system is required for MSIV control, plant operators manually scrammed the reactor in anticipation of an automatic scram on MSIV closure.

B.23.3 Additional Event-Related Information

Susquehanna's emergency power system consists of four EDGs (A, B, C, and D) and one spare EDG (E) that are shared by two plants. EDG E is capable of being substituted for any of the other EDGs without violating the independence of the redundant safety-related load groups.

ESF bus 2C supplies the following loads: one of four core spray pumps, one of four core spray pump room coolers, one of four residual heat removal (RHR) pumps, one of four RHR room coolers, seven of 14 drywell coolers, one of two instrument air compressors, one of two reactor building chillers, one of two reactor core isolation cooling (RCIC) room coolers, both standby liquid control heaters, one of two standby liquid control injection pumps, one of three battery chargers, one of four containment hydrogen recombiners, and the main condenser vacuum pump.

B.23.4 Modeling Assumptions

This event was modeled as a scram with one train of CS and RHR/LPCI unavailable. This is slightly conservative. The turbine-driven main feedwater pumps and power conversion systems are unavailable following the expected MSIV closure.

RCIC was assumed to be capable of supplying adequate makeup for sequences involving a single stuck-open relief valve. (The BWR nonspecific reactor trip event tree was modified to reflect this -- see Fig. B.49). This probability was estimated as:

p(RCIC) + p(2 or more valves fail open | 1 or more valves fail open)

The ASP RCIC assumed failure rate is 0.06. A value of 0.027 was estimated for p(2 or more valves fail open | 1 or more valves fail open), based on an estimated probability for two or more SRVs stuck open of 0.0015 (see NUREG/CR-4550, Vol. 1, Rev. 1, *Analysis of Core Damage Frequency: Internal Events Methodology*, January 1990, p.6-10) and an estimated probability of one or more SRVs stuck open of 0.056 (developed as described in Appendix A. Sect. A.4). The probability of RCIC/SRV is then 0.06 + 0.027 = 0.09.

It was noted that, during this event, one EDG was unavailable and the distribution bus associated with another was unavailable, leaving only two EDG/bus pairs available to immediately supply power in event of a loss of offsite power (LOOP). The Susquehanna FSAR indicates that three EDGs are required for

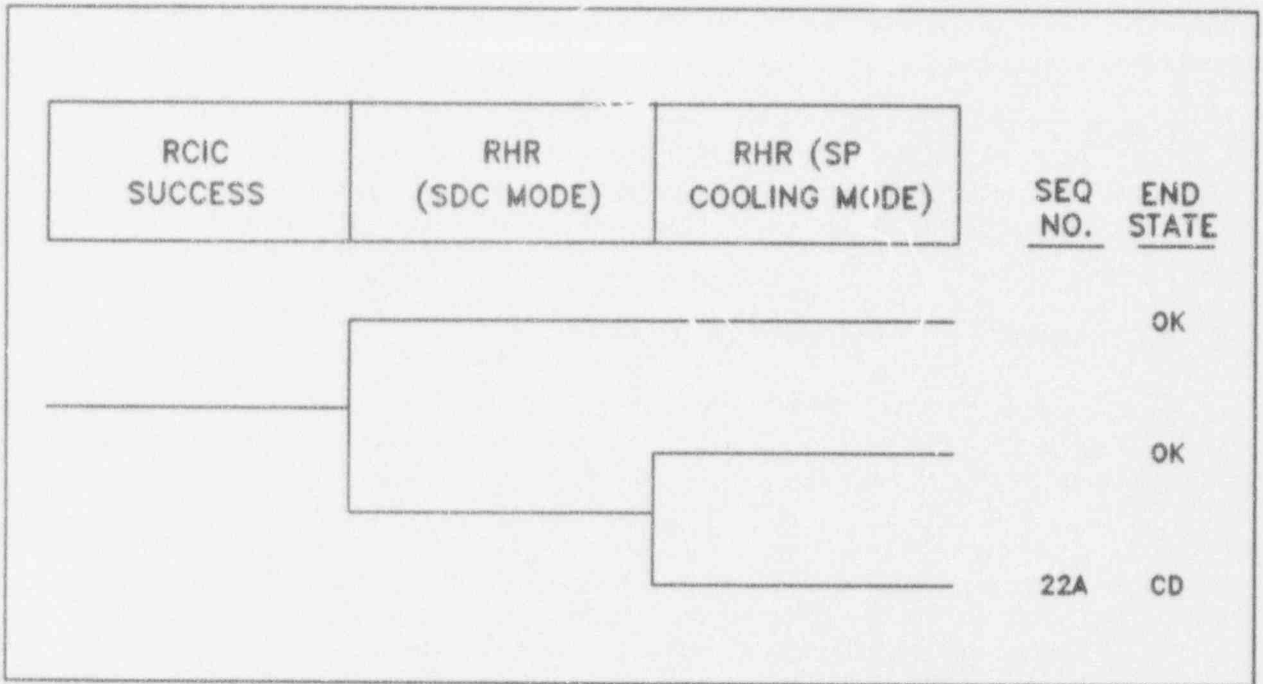


Fig. B.49. Modification to event tree when power conversion, feedwater, and HPCI systems are unavailable and an SRV has opened but failed to close.

safe plant shutdown under accident conditions. It is possible that two EDGs would be sufficient for ordinary plant shutdown during a LOOP. The spare EDG was always available for tie in which requires less than 2 h. This LOOP condition was modeled for a duration of 2 h. The core damage probability that resulted was less than 1.0×10^{-6}. Therefore, these LOOP concerns were not included in this analysis.

Available information indicates that the RHR outboard suction isolation valve is dc powered and the RHR inboard isolation valve is powered by division 1 ac. Therefore, the loss of bus C would not render the RHR shutdown cooling valves inoperable. The continued availability of ESF bus A from normal ac or emergency power (EDG A) would allow operation of the inboard isolation valve and thus would ensure availability of RHR sutdown cooling.

B.23.5 Analysis Results

The conditional probability of core damage for this event is estimated to be 6.6×10^{-6}. The dominant core damage sequence for this event, shown in Fig. B.50, involves scram with feedwater and power conversion systems unavailable, SRV operation and successful closure, HPCI success and failure of RHR shutdown cooling and suppression pool cooling modes.

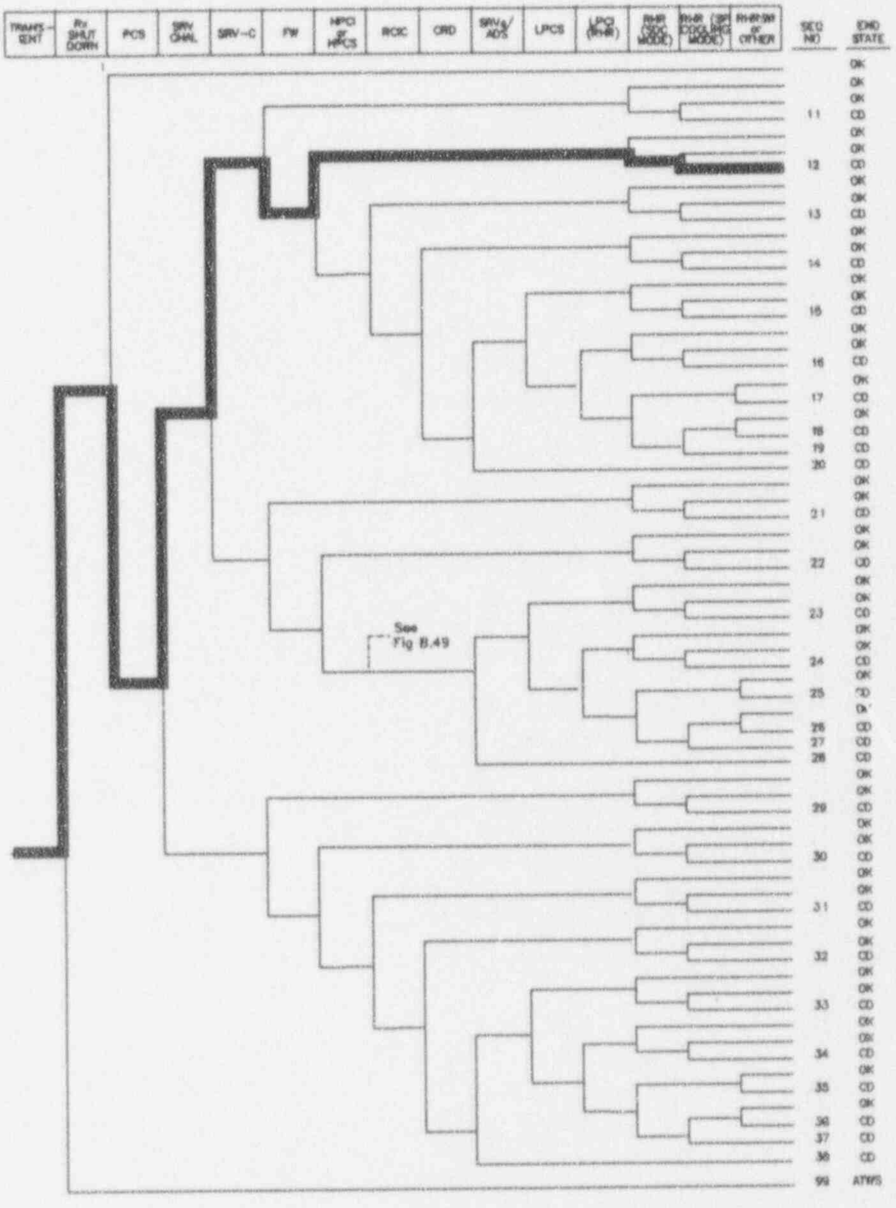


Fig. B.50. Dominant core damage sequence for LER 388/92-001.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 388/92-001
Event Description: Scram with EDG B and ESF bus C unavailable
Event Date: 3/18/92
Plant: Susquehanna 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS 1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	6.6E-06
Total	6.6E-06
ATWS	
TRANS	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
12	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	5.6E-06	1.1E-01
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS hpci rcic srv.ads	CD	3.9E-07	3.5E-01
22	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	2.1E-07	1.1E-01
20	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS hpci rcic crd srv.ads	CD	2.1E-07	3.5E-01
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
12	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	5.6E-06	1.1E-01
20	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram -srv.close FW/PCS.TRANS hpci rcic crd srv.ads	CD	2.1E-07	3.5E-01
22	trans -rx.shutdown PCS/TRANS srv.chall trans.-scram srv.close FW/PCS.TRANS -hpci RHR(SDC) rhr(spcool)/rhr(sdc)	CD	2.1E-07	1.1E-01
28	trans -rx.shutdown PCS/TRANS srv.chall/trans.-scram srv.close FW/PCS.TRANS hpci rcic srv.ads	CD	3.9E-07	3.5E-01
99	trans rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\models\susquhn2.cmp
BRANCH MODEL: c:\asp\models\susquhan.sl1
PROBABILITY FILE: c:\asp\models\bwr_sus1.pro

Event Identifier: 388/92-001

No Recovery Limit
BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	1.6E-04	1.0E+00	
loop	1.6E-05	2.4E-01	
loca	3.3E-06	5.0E-01	
rx.shutdown/ep	3.5E-04	1.0E+00	
rx.shutdown	3.0E-05	1.0E+00	
PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > 1.0E+00(1)		
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	3.6E-02	1.0E+00	
EMERG.POWER	1.4E-03 > 2.8E-01	8.0E-01	
Branch Model: 2.OF.4			
Train 1 Cond Prob:	5.0E-02 > 1.0E+00(3)		
Train 2 Cond Prob:	5.7E-02 > 1.0E+00(3)		
Train 3 Cond Prob:	1.9E-01		
Train 4 Cond Prob:	5.0E-01		
ep.rec	1.6E-01	1.0E+00	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 1.0E+00(1)	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > 1.0E+00		
FW/PCS.LOCA	1.0E+00 > 1.0E+00	3.4E-01 > 1.0E+00(1)	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E+00		
hpci	2.9E-02	7.0E-01	
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
LPCS	3.0E-03 > 3.0E-02	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	3.0E-02		
Train 2 Cond Prob:	1.0E-01 > 1.0E+00(2)		
LPCI(RHR)/LPCS	1.0E-03 > 1.0E-02	7.1E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > 1.0E+00(2)		
RHR(SDC)	2.1E-02 > 2.3E-02	3.4E-01	1.0E-03
Branch Model: 1.OF.2+ser+opr			
Train 1 Cond Prob:	3.0E-03		
Train 2 Cond Prob:	3.0E-01 > 1.0E+00(2)		
Serial Component Prob:	2.0E-02		

Event Identifier: 388/92-001

rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Notes:
1. This event began with MSIV isolation, and, since the plant has turbine driven MFW pumps, this means the turbine driven MFW are unavailable; therefore, the nonrecovery factor goes to 1.
2. The unavailability of normal ac power or emergency power to bus 2c causes the unavailability of one train of LPCS, LPCI, and SDC.
3. This failure probability was adjusted due to EDG B being declared inoperable and power to bus 2c was unavailable.

Event Identifier: 388/92-001

B.24 LER Number 483/92-011

Event Description: Loss of Main Control Board Annunciators

Date of Event: October 17, 1992

Plant: Callaway

B.24.1 Summary

Callaway was at 100% power on October 17, 1992. At 0100 hours a replacement power supply for the annunicator system was being placed into service. Failure of this power supply had caused 198 main control board (MCB) annunciator windows to fail and caused 76 to light. During this replacement process, a short circuit caused logic power supply fuses to blow, lighting 371 of 683 MCB annunciator windows and thus causing the annunciator system to fail. Blown fuses in the four field contact power supplies were found and replaced about 1 h later. The operators assumed that this fuse replacement would return the annunciator system to normal operation, although anomalous behavior was still being observed. Actually, 164 annunciator windows remained inoperable. The remaining failed fuses were found and replaced, and the annunciator system was tested and confirmed operable at 1937 hours. The conditional core damage probability estimated for this event is 1.3×10^{-5}. This estimate may be conservative; the analysis was performed using screening human error probabilities (HEPs) and with limited information concerning the activities that were in progress at the time of the event. The relative significance of this event compared to other postulated events at Callaway is shown in Fig. B.51.

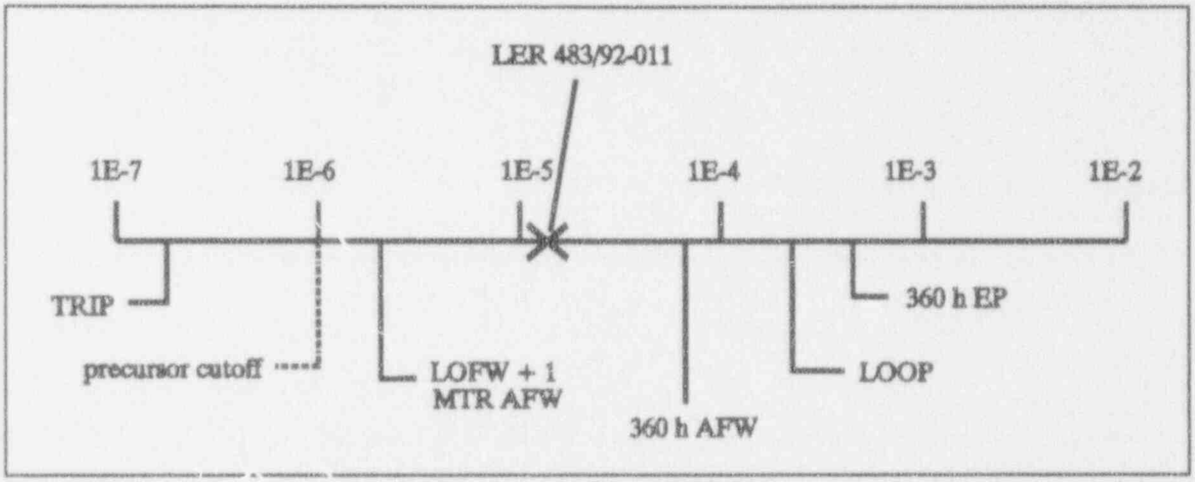


Fig. B.51. Relative event significance of LER 483/92-011 compared with other potential events at Callaway.

B.24.2 Event Description

On October 16, 1992, at 1840 hours, with Callaway at 100% power, an annunciator field contact power supply failed because of an internal transformer short. The power supply failure caused 76 MCB annunciator windows to illuminate (a total of 198 MCB annunciator windows failed). On October 17, 1992, at 0058 hours, the failed power supply was replaced, and all applicable annunciator windows were cleared. At 0100 hours, during restoration from the power supply replacement, a short circuit occurred, and fuses in four field contact power supplies blew. This resulted in the loss of the entire MCB annunciator system. Three hundred seventy-one annunciator windows were illuminated. Numerous plant computer alarms were also affected. By 0156 hours the blown fuses had been replaced and power had been restored to the MCB annunciator system. Upon restoration of power, the illuminated annunciators cleared and the critical problems with the system were considered corrected. The operations crew performed lamp tests on all the annunciator panels, which they assumed verified the operability of the system.

Although anomalous annunciator system operation was still being observed, the problems were considered minor, and plant personnel determined the problems could be analyzed by the morning shift. During the morning shift, unexpected annunciator system operation continued to be observed, and additional troubleshooting began. At 1300 hours, a bad logic power supply was found and replaced. At about 1630 hours, instrumentation and control technicians determined that five additional logic power supply fuses had been blown, apparently at the same time that the field power supply fuses blew. These fuses were replaced by 1800 hours, and testing to confirm annunciator operability was completed by 1937 hours. Following the replacement of the field power supply fuses at 0156 hours (when the annunciator system was believed to be operable), 164 annunciator windows had remained inoperable.

Lack of knowledge of the annunciator system on the part of plant personnel resulted in an inadequate assessment of the event, failure to declare an Alert when the system failed, and failure to terminate plant activities which could have resulted in unnecessary challenges to plant systems (for example, a 345-kV line tagout, and turbine stop valve surveillance testing).

B.24.3 Additional Event-Related Information

The Callaway annunciator system is designed to monitor 1400 alarm points using field contacts, which either open or close in response to the alarm point. Operators in the control room are then alerted to the alarm by illuminated annunciator windows and audible alarms. Individual alarm points grouped on a system basis also feed the plant computer and the alarm printer.

The system has four power supplies connected to a 125-Vdc station battery to power the 1400 field alarm contacts. These power supplies have common (parallel-connected) inputs and outputs, and each power supply input and output is protected by a 1 ampere "slow-blow" (delayed opening) fuse. There are also 14 logic power supplies that receive their input power from one of the two 125-Vdc station battery systems, one of which is common to the field contact power supplies discussed above. The logic power supplies provide five different voltages to the system. Each power supply has a protective fuse associated with its voltage. None of the fuses (78 total) have local indication or indicating lights to monitor their operability. The arrangement of the power supplies is shown in Fig. B.52.

Annunciators that were inoperable prior to 0100 hours on October 17, 1992 (when one power supply was failed), are shown in Fig. B.53. Annunciators that were inoperable following the fuse replacement at 0156 hours are shown in Fig. B.54.

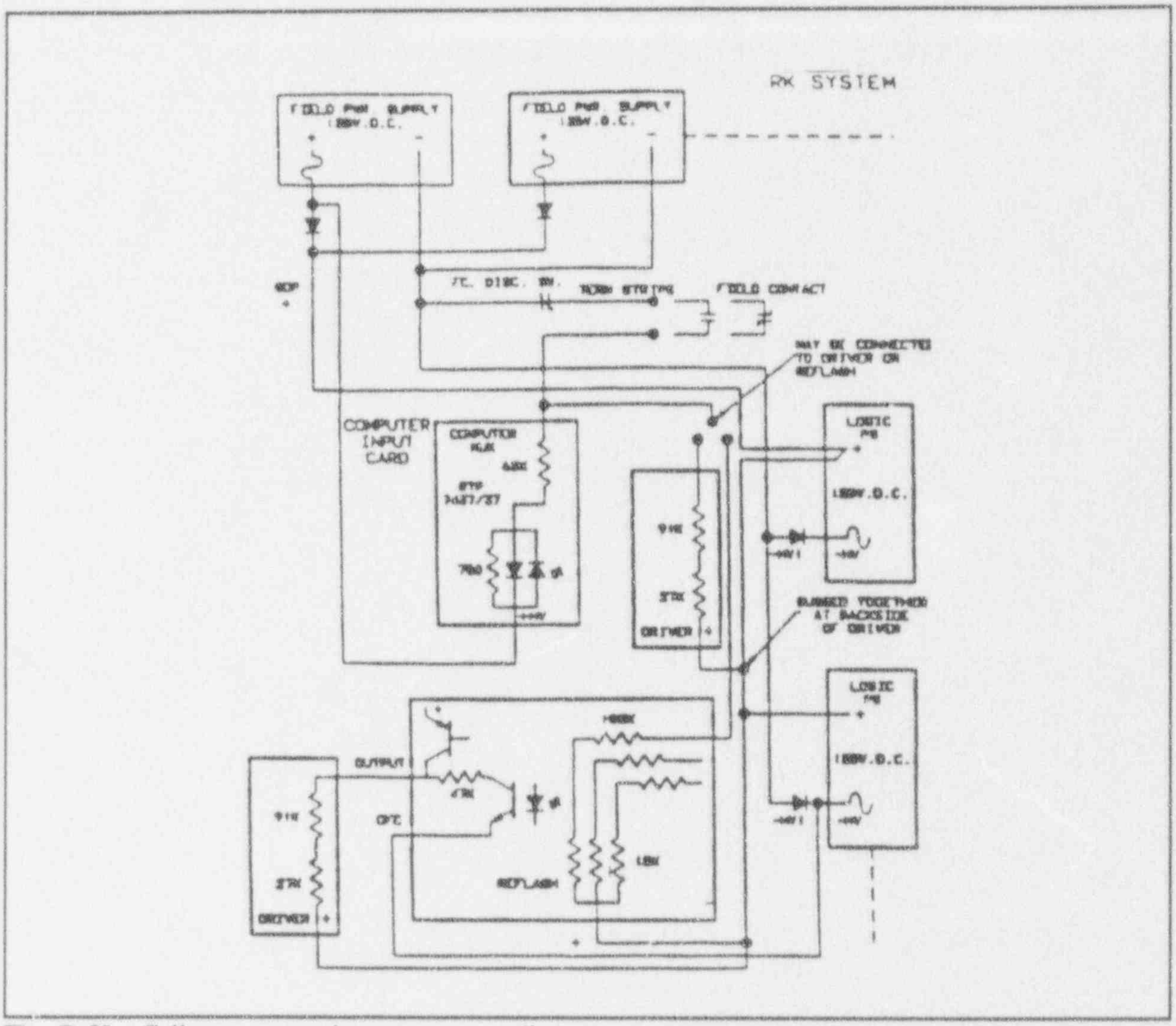


Fig. B.52. Callaway annunciator power supplies.
(Original figure was illegible.)

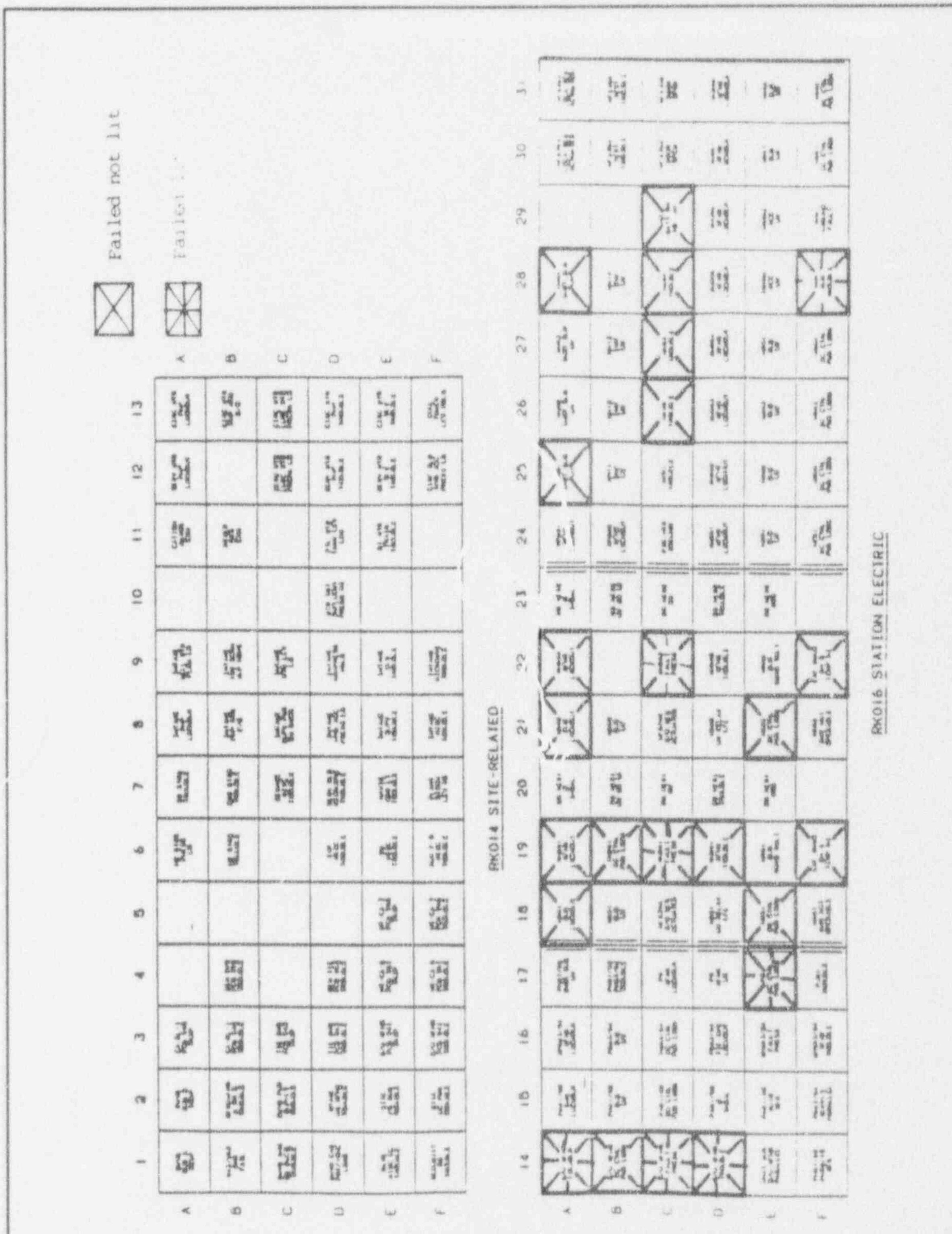


Fig. B.53. Failed annunciators prior to 0100 hours on October 17, 1992.
(Original figure was illegible.)

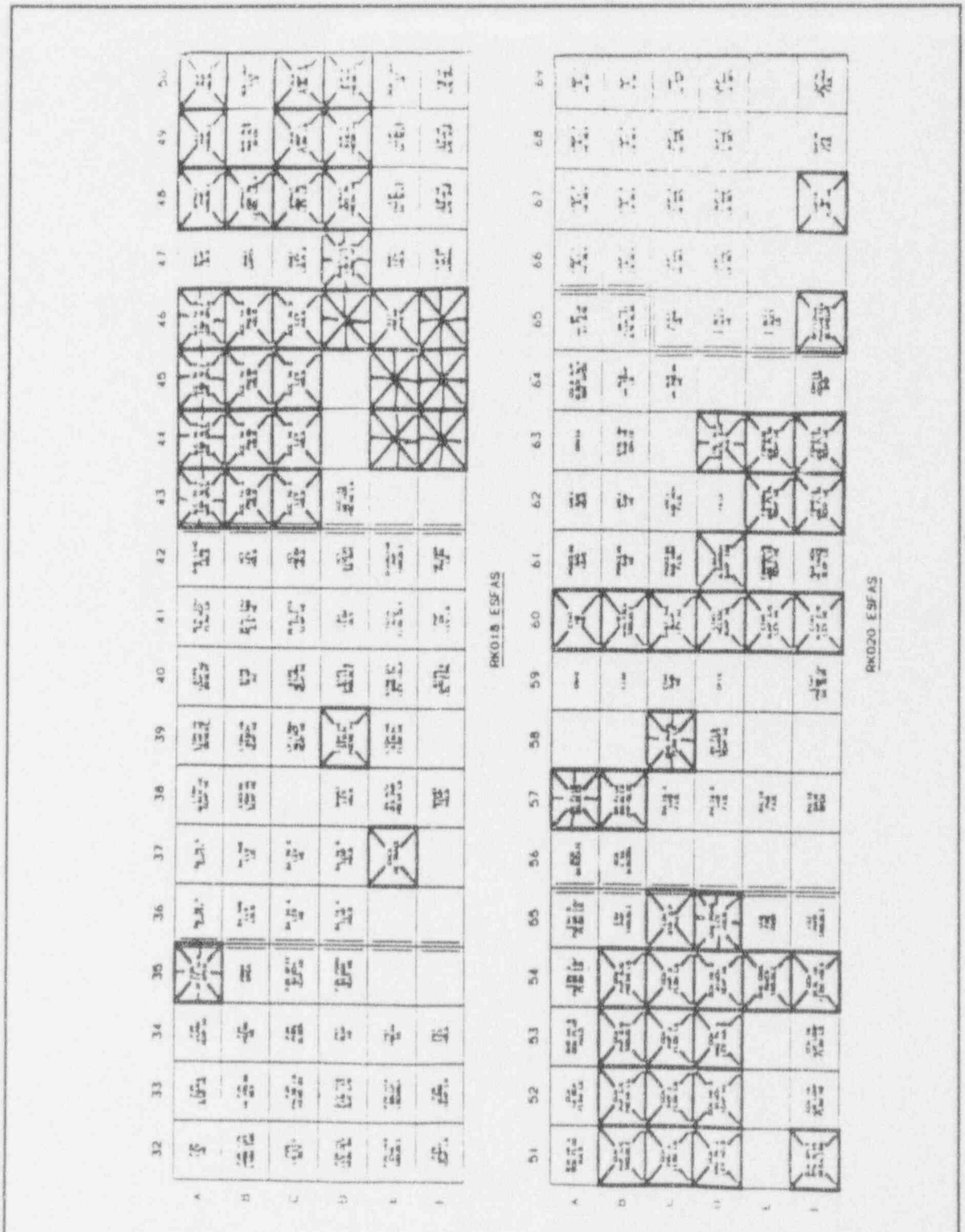


Fig. B.53. Failed annunciators prior to 0100 hours on October 17, 1992 (cont.).
(Original figure was illegible.)

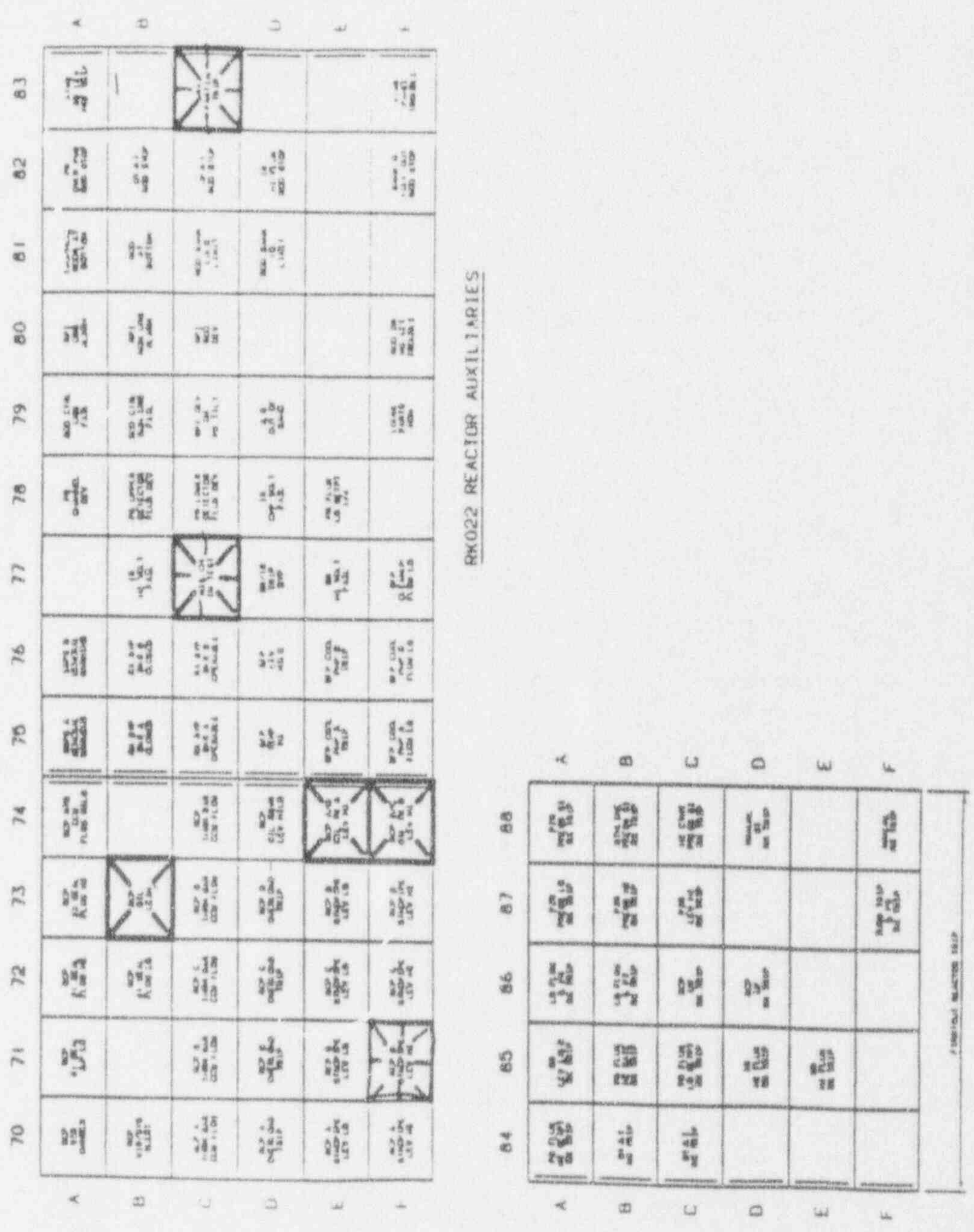


Fig. B.53. Failed annunciators prior to 0100 hours on October 17, 1992 (cont.).
(Original figure was illegible.)

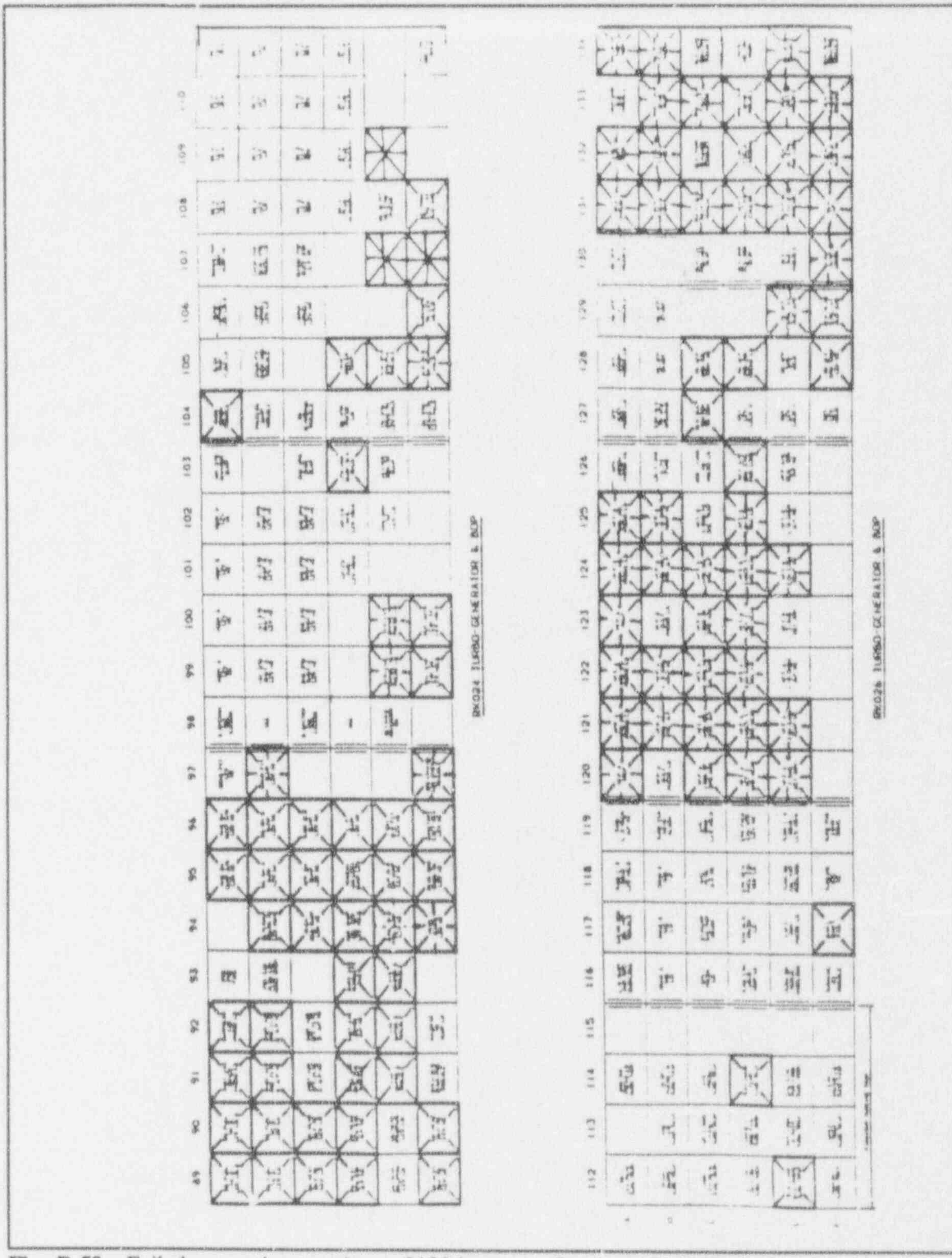


Fig. B.53. Failed annunciators prior to 0100 hours on October 17, 1992 (cont.).
(Original figure was illegible.)

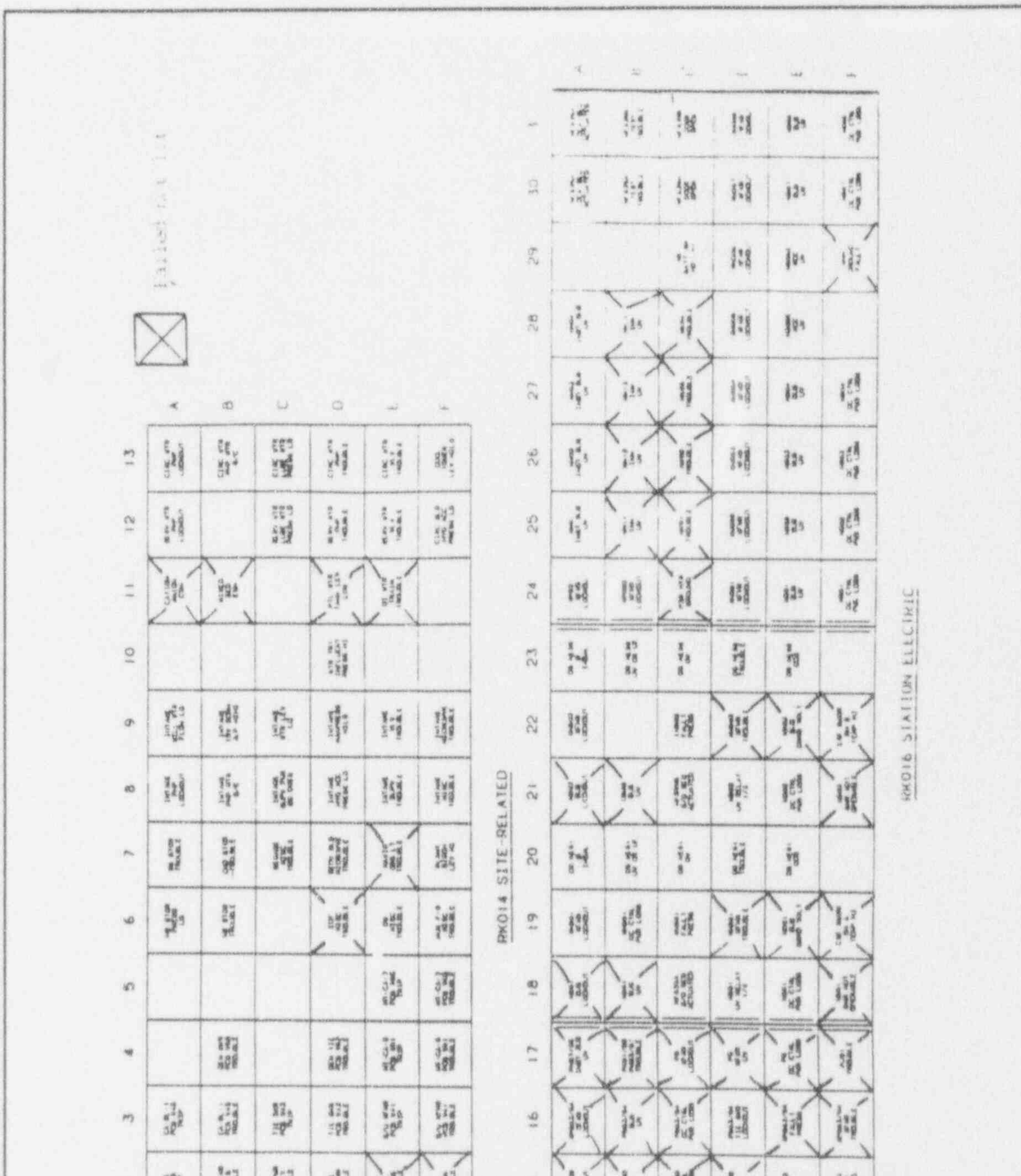


Fig. B.54. Failed annunciators after 0156 hours on October 17, 1992.
(Original figure was illegible.)

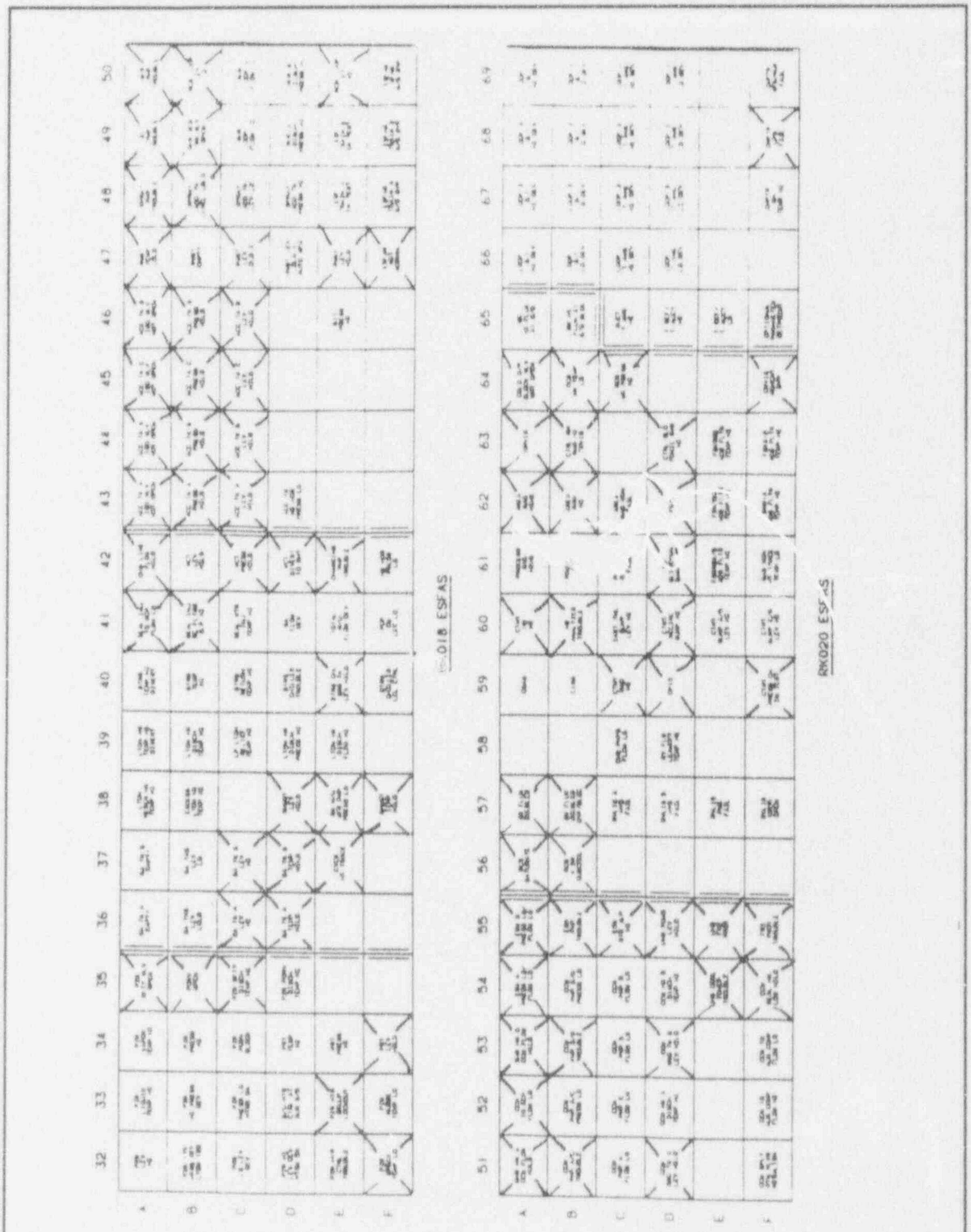


Fig. B.54. Failed annunciators after 0156 hours on October 17, 1992 (cont.).
(Original figure was illegible.)

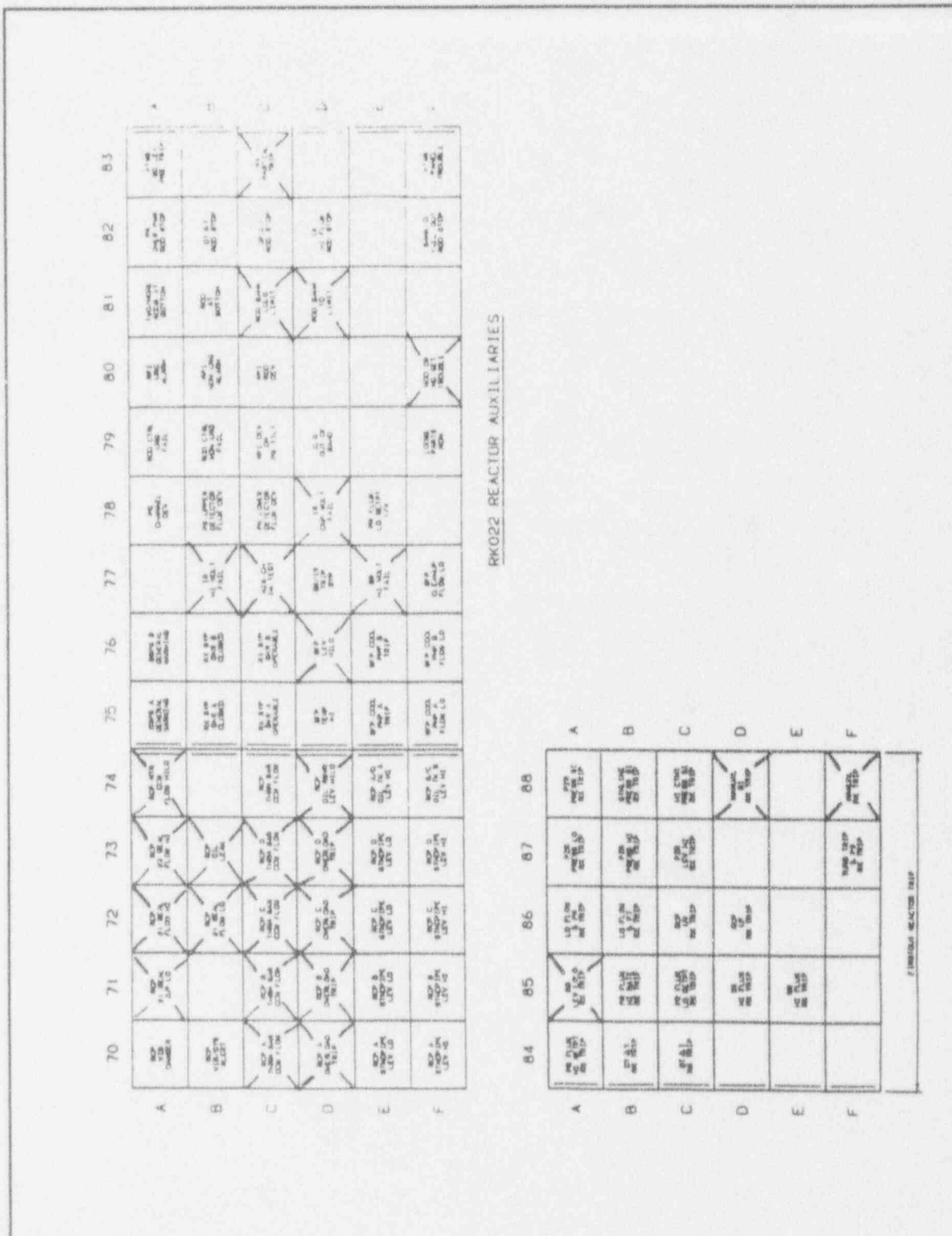


Fig. B.54. Failed annunciators after 0156 hours on October 17, 1992 (cont.).
(Original figure was illegible.)

LER NO: 483/92-011

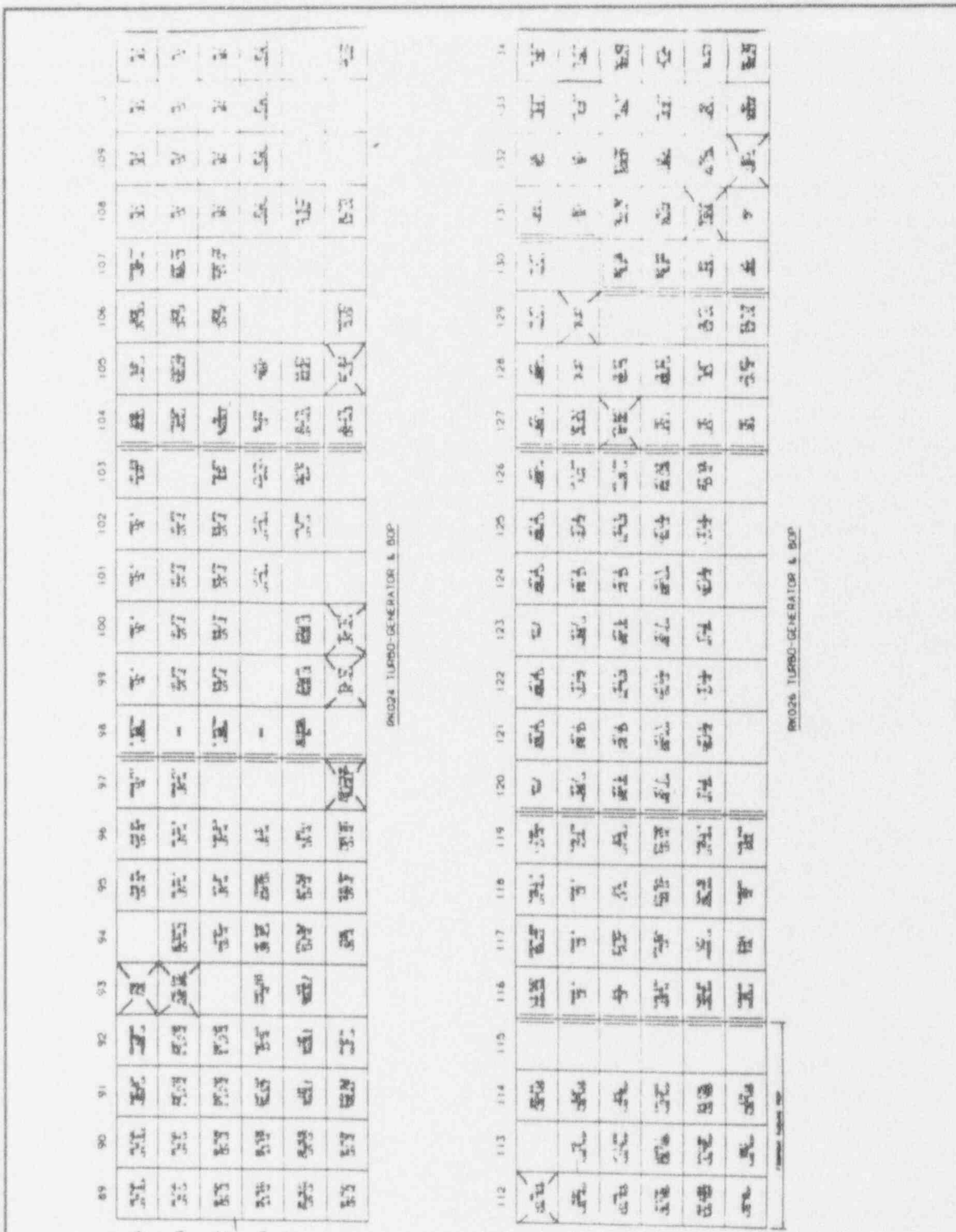


Fig. B.54. Failed annunciators after 0156 hours on October 17, 1992 (cont.).
(Original figure was illegible.)

B.24.4 Modeling Assumptions

The event was modeled considering three potential initiators. These were a potential reactor trip, a loss of offsite power (LOOP), and a small-break loss-of-coolant accident (LOCA) during the 18.5-h period starting at 0100 hours on October 17, 1992, when multiple power-supply fuses were blown. Before making any modeling assumptions, the loss of information normally available to the operators and plant operations in progress during the event were reviewed. Based on this review, the following parameters were revised: 1) the frequency of initiating events, 2) the probability of the operator failing to initiate manually actuated systems, and 3) the probability of not recovering initially failed systems. The revisions and their basis are indicated in the "Branch Frequencies/Probabilities" section and notes of the calculation sheets included with this analysis. Changes are shown to the right of the " > " symbols.

The key to this event was that after the initial annunciator repairs, a significant number of alarms remained unavailable, unlit, and this condition was unknown to the operators. The effect was that the operators continued with normal operations (e.g., rad waste processing, turbine valve testing and switchyard breaker testing); had they known that the annunciators were unavailable, the activities would have been suspended until the annunciators were repaired. In addition to the normal plant model that accounts for equipment faults, the ASP model was adjusted to include errors in performing the on-going tasks that could trigger initiating events, or leave a system in an unavailable state. Also, it was assumed that the operator responses to a variety of event sequences would be degraded because of the lack of annunciators. Thus, adjustments to the ASP model include primarily effects of the event rather than the causes of the annunciator tile unavailability. For example, unlit annunciators that might cue operators to prematurely secure HPI are PZR SFTY VLV OPEN (A35), PORV OPEN (B35), PZR SFTY DISCH TEMP HI (C35), CHG LINE FLOW HILO (A42), CHARGING PMP TROUBLE (E42), ACC TK A LEV HILO (A43), SI PMP TROUBLE (A49), RCS SATURATE (A56), and RCS < 50 SUBCOOL (B56).

The modifications to the base risk model addressed the 136 annunciators that were out for the duration of the event. The basis for changes to the data depend on the activities that were in progress during the event period, not the event duration. The on-going task error probabilities were averaged over the event duration to estimate changes to frequencies. Thus, changing the duration of the event would have little effect on the frequency of the initiating events or changes to the recovery actions. If other activities are on-going, such as turbine valve testing, breaker tag outs in the switchyard, normal I&C testing, etc., the crews attention may be focused on completing the testing and surveillance tasks, including communication with plant technicians. Hence, greater reliance is placed on the audible alarms associated with the annunciators. The assumption was made that diverse instrumentation was available to the operators. It was also assumed that alarmed annunciators provide positive detection capability during multiple task operations, and that crews give highest priority to the annunciator systems, and second priority to the plant computer controlled systems which, until recently, have been sources of lower information reliability.

B.24.5 Analysis Results

The conditional core damage probability estimated for this event is 1.3×10^{-5}. There were three dominant core damage sequences, they are each highlighted on the event trees in Fig. B.55, Fig. B.56, and Fig. B.57. The first sequence involves a postulated LOOP with a non-recoverable loss of emergency power, a reactor coolant pump seal LOCA, and failure to recover ac power prior to core unrecovery. The other two sequences had somewhat lower core damage probabilities. The second sequence involves a failure to initiate high-pressure recirculation following a postulated small-break LOCA with trip, AFW, and HPI success. The third sequence also involves the failure of high-pressure recirculation, but, in this instance, it follows a postulated transient-induced LOCA. This analysis used screening human error probabilities and limited information concerning the activities that were in progress at the time of the event. As such, the analysis is potentially conservative.

Additional information concerning this event is included in Augmented Inspection Team Report 50-483/92018 (DRP), *Callaway Loss of Annunciators Event*, October 16 – 19, 1992.

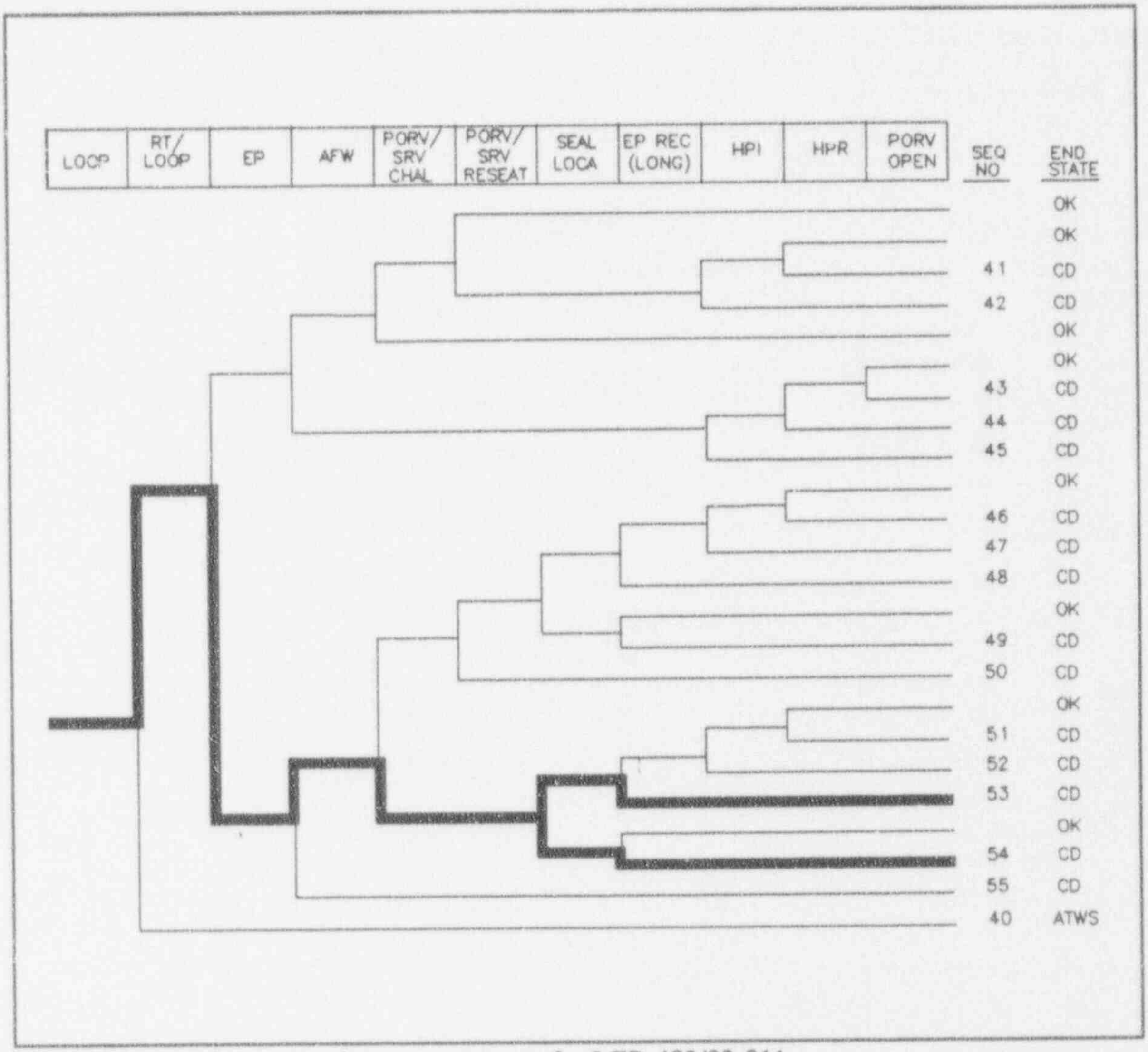


Fig. B.55. Dominant core damage sequences for LER 483/92-011.

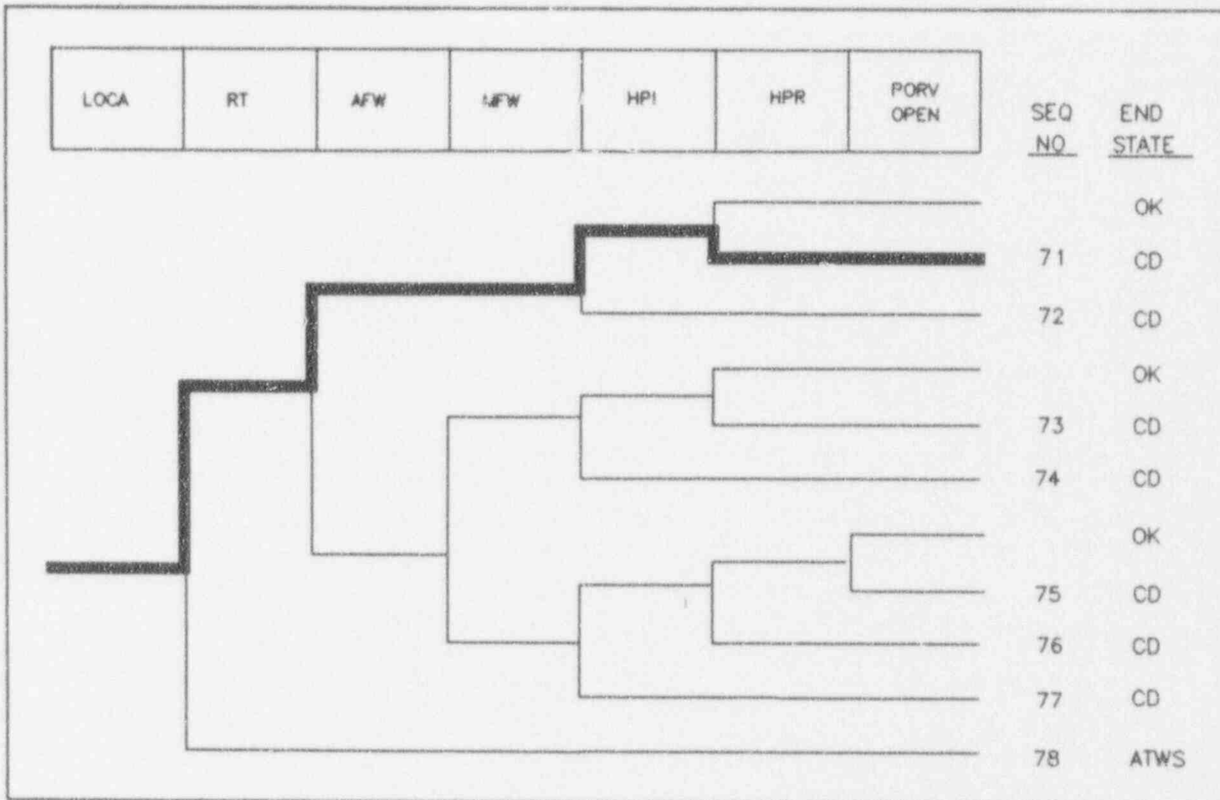


Fig. B.56. Dominant core damage sequences for LER 483/92-011 (cont.).

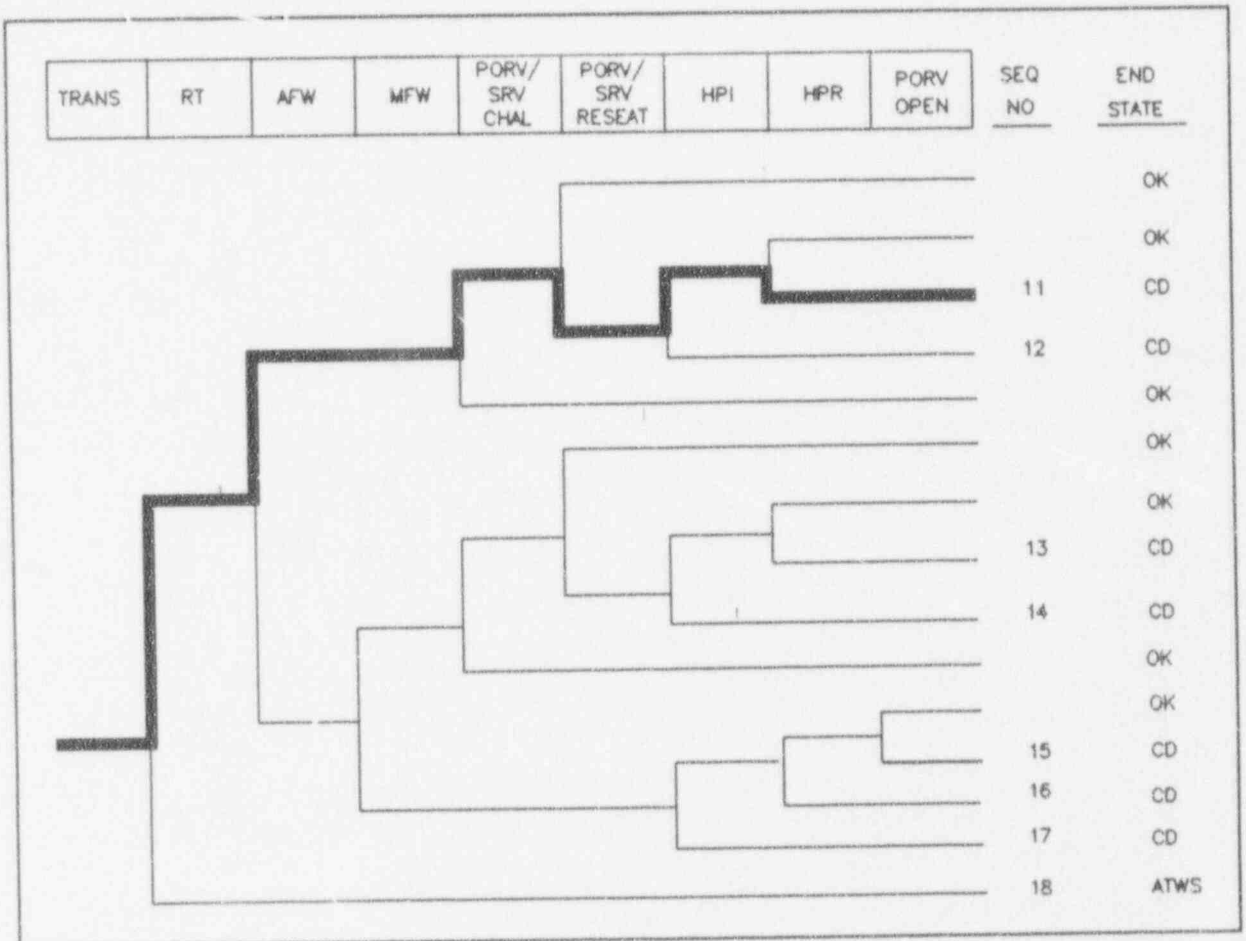


Fig. B.57. Dominant core damage sequences for LER 483/92-011 (cont.).

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 483/92-011
Event Description: Loss of main control board annunciators
Event Date: 10/17/92
Plant: Callaway 1

UNAVAILABILITY, DURATION= 18.5

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	7.6E-02
LOOP	4.8E-03
LOCA	3.3E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	3.1E-06
LOOP	6.6E-06
LOCA	3.5E-06
Total	1.3E-05
ATWS	
TRANS	2.2E-06
LOOP	0.0E+00
LOCA	4.8E-10
Total	2.2E-06

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
53	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA ep.rec(sl)	CD	4.0E-06	5.2E-01
71	LOCA -rt -AFW -HPI HPR/-HPI	CD	3.3E-06	7.5E-01
11	TRANS -rt -AFW porv.or.srv.chall PORV.OR.SRV.RESEAT -HPI HPR/-HPI	CD	2.4E-06	4.2E-01
54	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall -SEAL.LOCA EP.REC	CD	1.4E-06	5.2E-01
51	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA -ep.rec(sl) -HPI HPR/-HPI	CD	3.0E-07	5.2E-01
55	LOOP -rt/loop EMERG.POWER afw/emerg.power	CD	2.3E-07	1.8E-01
72	LOCA -rt -AFW HPI	CD	2.1E-07	6.3E-01
16	TRANS -rt AFW MFW -HPI(F/B) HPR/-HPI	CD	1.9E-07	6.6E-02
48	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall -porv.or.srv.reseat/emerg.power SEAL.LOCA ep.rec(sl)	CD	1.7E-07	5.2E-01
12	TRANS -rt -AFW porv.or.srv.chall PORV.OR.SRV.RESEAT HPI	CD	1.6E-07	3.5E-01
41	LOOP -rt/loop -EMERG.POWER -AFW porv.or.srv.chall PORV.OR.SRV.RESEAT -HPI HPR/-HPI	CD	1.6E-07	2.2E-01
17	TRANS -rt AFW MFW HPI(F/B)	CD	1.4E-07	5.5E-02
18	TRANS rt	ATWS	2.2E-06	1.2E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
11	TRANS -rt -AFW porv.or.srv.chall PORV.OR.SRV.RESEAT -HPI HPR/ -HPI	CD	2.4E-06	4.2E-01
12	TRANS -rt -AFW porv.or.srv.chall PORV.OR.SRV.RESEAT HPI	CD	1.6E-07	3.5E-01
16	TRANS -rt AFW MFW -HPI(F/B) HPR/-HPI	CD	1.9E-07	6.6E-02
17	TRANS -rt AFW MFW HPI(F/B)	CD	1.4E-07	5.5E-02
18	TRANS rt	ATWS	2.2E-06	1.2E-01
41	LOOP -rt/loop -EMERG.POWER -AFW porv.or.srv.chall PORV.OR.SRV. RESEAT -HPI HPR/-HPI	CD	1.6E-07	2.2E-01
48	LOOP -rt/loop EMERG.POWER -afw/emerg.power porv.or.srv.chall - porv.or.srv.reseat/emerg.power SEAL.LOCA ep.rec(sl)	CD	1.7E-07	5.2E-01
51	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA -ep.rec(sl) -HPI HPR/-HPI	CD	3.0E-07	5.2E-01
53	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall SEAL.LOCA ep.rec(sl)	CD	4.0E-06	5.2E-01
54	LOOP -rt/loop EMERG.POWER -afw/emerg.power -porv.or.srv.chall - SEAL.LOCA EP.REC	CD	1.4E-06	5.2E-01
55	LOOP -rt/loop EMERG.POWER afw/emerg.power	CD	2.3E-07	1.8E-01
71	LOCA -rt -AFW -HPI HPR/-HPI	CD	3.3E-06	7.5E-01
72	LOCA -rt -AFW HPI	CD	2.1E-07	6.3E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asp\1989\pwrbseal.cmp
BRANCH MODEL: c:\asp\1989\callwy.sl1
PROBABILITY FILE: c:\asp\1989\pwr_bsl1.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	3.5E-04 > 4.1E-03	1.0E+00	
Branch Model: INITOR			
Initiator Freq:	3.5E-04 > 4.1E-03[1]		
LOOP	1.6E-05 > 4.9E-04	5.3E-	
Branch Model: INITOR			
Initiator Freq:	1.6E-05 > 4.9E-04[2]		
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 7.5E-01[3]	
Branch Model: INITOR			
Initiator Freq:	2.4E-06		
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 2.9E-03	8.0E-01 > 1.0E+00[4]	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02		
AFW	3.8E-04 > 3.8E-04	2.6E-01 > 3.0E-01[5]	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02		
Serial Component Prob:	2.8E-04		

afw/emerg.power	5.0E-02	3.4E-01	
MFW	1.0E+00 > 1.0E+00	7.0E-02 > 2.2E-01[6]	1.0E-03 > 3.0E-02[7]
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	1.0E+00		
porv.or.srv.chall	4.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	2.0E-02 > 2.0E-02	1.1E-02 > 4.2E-01[8]	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-02		
porv.or.srv.rese[illegible]/emerg.power	2.0E-02	1.0E+00	
SEAL.LOCA	2.7E-01 > 5.5E-01	1.0E+00	
Branch [illegible]OF.1			
Train 1 [illegible]b:	2.7E-01 > 5.5E-01[9]		
ep.rec(sl)	5.8E-01	1.0E+00	
EP.REC	2.5E-02 > 2.5E-01	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.5E-02 > 2.5E-01[10]		
H[illegible]I	1.0E-03 > 8.0E-03	8.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	[illegible]E-02 > 8.0E-02[11]		
Train 2 Cond Prob:	[illegible]E-01		
HPI(F/B)	[illegible]E-03 > 1.0E-03	8.4E-01	1.0E-02 > 7.0E-02[12]
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
HPR/-HPI	1.5E-04 > 1.5E-04	1.0E+00	1.0E-03 > 1.0E-01[13]
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02		
PORV.OPEN	2.0E-02 > 2.0E-02	1.0E+00	4.0E-04 > 5.0E-02[14]
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	2.0E-02		

* branch model file
** forced

Notes:

Probability adjustments were based on:

1 turbine stop valve testing and other activities in progress
2 345 kV tagout in progress
3 delay in blocking postulated stuck-open PORV and controlling other postulated losses of inventory
4 delay in restoration from a postulated loss of emergency power following a LOOP
5 delay in recovering postulated failures that could normally be easily recovered in control room
6 delay in recovering from a postulated loss of condensate/MFW
7 screening HEP (little impact on analysis)
8 primarily delay in blocking a postulated stuck-open PORV
9 delay in recovering from a postulated RCP seal LOCA
10 delay in long term recovery of AC power following a postulated LOOP
11 reduced ability to properly control HPI after initiation
12 primarily delay in initiating feed and bleed following a postulated loss of secondary-side cooling
13 potential omission errors plus delay in initiation of sump recirculation following a postulated LOCA
14 potential omission errors plus delay in initiation of feed and bleed following a loss of secondary side cooling

APPENDIX C: CONTAINMENT-RELATED EVENTS

C. CONTAINMENT-RELATED EVENTS

Five reactor plant operational events for 1992 which were selected as containment-related events are documented in this section. These events involve unavailability of containment function, containment isolation, containment cooling, containment spray, or post-accident hydrogen control. These events are not probabilistically ranked, since containment models have not been developed. The five events are identified in Table C.1.

For each event, a summary, a description, and any additional event-related information is provided. Copies of the LERs associated with these events are provided in Appendix F.

Table C.1. Index of Containment-Related Events

C.1 LER Number 213/92-014

Event Description: Containment Air Recirculation Fan Coolers Inoperable Due to Silt Buildup

Date of Event: June 8, 1992

Plant: Haddam Neck

C.1.1 Summary

Haddam Neck was operating at 99% power when the differential pressure across the service water filters supplying the containment air recirculation (CAR) system was found to exceed the maximum allowable level after approximately 2 min of filter operation. The CAR system is required to be operable for 30 min post-accident to ensure acceptable containment pressures and temperatures. The high fouling rate was caused by silt in the intake water.

C.1.2 Event Description

With the plant at 99% power, a routine monthly check of the service water filters on June 8, 1992 indicated that the rate of debris accumulation caused the differential pressure across the filter to reach the maximum allowable level in approximately 2 min. On June 10, 1992, an expedited evaluation of the filter design basis was completed. The results indicated that the CAR system, which is fed by filtered service water, is required to be operable for 30 min post-accident to ensure acceptable containment pressures and temperatures. Over the next few days high silt levels in the river caused the filter to reach the maximum allowable level for fouling in 25 min to 2 h. When the fouling rate failed to meet the design basis, a dedicated operator was stationed at a bypass valve to ensure a maximum opening response time of 10 min. At the time of the event, the river water was at 70°F.

C.1.3 Additional Event-Related Information

The service water system provides cooling water, directly or indirectly, to all components requiring external cooling water supply, except the main condenser, under normal and abnormal conditions. The service water system is divided into two trains and takes suction from the Connecticut River.

Two service water filters are part of the CAR fan cooling system, which is required for post-LOCA containment pressure reduction following a design-basis accident. Normally, one filter is in service and the other is in standby. The switchover to the standby filter is done manually after the allowable pressure drop is exceeded as identified by operator surveillance and/or activation of a low-flow alarm. The units have a continuous backflush to extend the time between filter plugging. A motor-operated valve (MOV) with remote operation allows the filters to be bypassed. During power operations, all four CAR coolers are required to be in service.

During normal operations, the flow rate of the system is insensitive to plugging of the filters, and therefore the low-flow alarm function does not always activate when the plugging limit is reached. However, during post-accident conditions, the water is heated above saturation temperature at atmospheric pressure. As a result, the flow rate is sensitive to the filter plugging rate since pressurization of the line is necessary to prevent flashing under these conditions.

Analysis has shown that no cooling for the 10 min it takes to open the valve would not result in exceeding current containment and environmental qualification limits. This analysis assumed a river temperature of 90°F.

C.1.4 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

C.2 LER Number 275/92-009

Event Description:	Dose Limits Potentially Exceeded From Chemical and Volume Control System Valve Leak
Date of Event:	June 22, 1992
Plant:	Diablo Canyon 1

C.2.1 Summary

A manual valve on the emergency boration flow line to the volume control tank was leaking at 0.5 gpm to the Auxiliary Building atmosphere. This valve is in an area that does not have charcoal filtering of the ventilation system exhaust. After a loss-of-coolant accident (LOCA), leakage would be expected to increase to 9.0 gpm. Leakage in excess of 0.1 gpm during the recirculation phase of a LOCA could cause releases above the 10 CFR 100 limits.

C.2.2 Event Description

With the plant at 100% power, a manual valve on the emergency boration flow line to the volume control tank was leaking through the diaphragm at 0.5 gpm to the Auxiliary Building atmosphere. The absence of boric acid crystals indicated that the valve had not leaked for an extended period of time. The valve bonnet retaining nuts were determined to be "finger-tight," and retorquing the nuts stopped the leakage. The utility believed that thermally induced degradation of the diaphragm resulted in diaphragm extrusion and a breach of the system boundary. The valve was to be disassembled for inspection during the next refueling outage.

C.2.3 Additional Event-Related Information

The leaking valve is a manually operated diaphragm valve. This valve functions as an isolation valve for the emergency boration path and as such remains in the open position except during maintenance. During the recirculation phase of a LOCA it becomes part of the reactor coolant flow path pressure boundary. It is postulated that under post-LOCA conditions, the increased system pressure would increase the leakage to approximately 9.0 gpm.

This valve is located in the boric acid blender room. Ventilation in this room exhausts to the plant vent without passing through charcoal filters. The maximum permissible leakage from all sources that are part of the post-LOCA recirculation loop is 0.10 gpm where the ventilation exhaust is not filtered through charcoal filters.

Therefore, leakage of 9.0 gpm through this one valve could result in the control room and exclusion area boundary doses exceeding the 10 CFR 100 limits during the recirculation phase of recovery from a design basis LOCA. An analysis that was conducted using the "expected case" LOCA assumptions (no fuel damage) indicated that the doses would be significantly less than the 10 CFR 100 limits.

C.2.4 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

C.3 LER Number 304/92-002

Event Description: Containment Inadvertently Sprayed and Shutdown Cooling Lost

Date of Event: May 13, 1992

Plant: Zion 2

C.3.1 Summary

While performing a surveillance test to verify operability of residual heat removal (RHR) and containment spray (CS) system valves, operators inadvertently aligned the RHR system to spray containment. The RHR system, in service to provide shutdown cooling, pumped approximately 5500 gal from the reactor coolant system (RCS) to the containment before operators isolated the path to the CS system.

C.3.2 Event Description

At the time of the event, Zion 2 was in the 37th day of an outage. The RCS was being maintained at 390 psig and 180°F, using the RHR system. Presumably, RHR train B was in service, since the suction to RHR pump A was isolated for a time during the event.

At approximately 0100 hours, the unit operator began performance of periodic surveillance test PT-2B-ST, "Verification of Containment Recirculation Sump Valve Stroke and ECCS Continuity." He closed valve 2MOV-RH8700A, which isolated the A RHR pump from the refueling water storage tank and RHR letdown supplies. He then opened valve 2MOV-CS00049, the train A RHR supply to the CS system. Because either train of RHR can supply CS through this valve and because one train of RHR was in service, RCS inventory was diverted to spray headers in the containment.

At 0114 hours, multiple alarms and indications were received in the control room, and operators noted that pressurizer level and pressure both indicated zero, implying a loss of reactor coolant inventory. At about 0117 hours, operators shut down reactor coolant pump 2B, secured letdown flow, and increased charging flow. It was noted at 1025 hours that containment pressure had increased to 17 in. (of water), and containment humidity had risen to 70%. Reactor in-core thermocouple temperatures were also rising, and RHR flow had increased. At 0130 hours, operators made a containment entry and realized that containment spray had been initiated.

The precise time at which the A RHR supply to the CS system was closed was not noted in the LER, but it was stated that the valve was closed during performance of the steps in surveillance test PT-2B-ST, and that it was subsequently realized that opening this valve allowed diversion of RHR pump discharge to the CS system. Approximately 5500 gal were diverted and RCS in-core thermocouple temperatures rose from 180°F to 198°F as a result of the interruption to RHR flow. By 0145 hours, pressurizer level and pressure were observed to be recovering. By 0210 hours, RCS temperature had been reduced to 157°F.

C.3.3 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

C.4 LER Number 328/92-007

Event Description: Both Containment Spray Pumps' Suction Valves Found Closed

Date of Event: May 8, 1992

Plant: Sequoyah 2

C.4.1 Summary

With the plant in startup after a refueling outage, the refueling water storage tank (RWST) suction isolation valves for both containment spray system (CSS) pumps were found closed. The valves were reopened. With both valves closed, both trains of CSS were effectively inoperable.

C.4.2 Event Description

On May 8, 1992, with the unit in hot stand-by starting up from a refueling outage, both CSS pump suction valves were found closed. As a result, Technical Specifications (TS) Limiting Condition for Operation (LCO) 3.0.3 was immediately entered, the valves were opened, and the LCO was exited. Investigation revealed that the valves had been closed on May 3 after test activities requiring CSS operation had been completed. Closure of the valves prevented maintenance activities from draining the RWST to the containment sump. The operators did not control the closing of the valves using the licensee's configuration control process. Instead, they depended on the mode change procedures and alignment checklists to identify the valves and their mis-positioned status prior to leaving refueling shutdown. In the next 5 d, the valve alignment checklists for CSS trains A and B were completed, shift turnover checklists that identified the valves as closed were completed, a vessel injection required for verifying CSS alignment for TS was completed, the A train CSS pump was run to recirculate the RWST, and the general operating instruction (GOI) master checklist for the emergency core cooling system (ECCS) was completed. The incorrect positioning of the valves was not identified and corrected during any of these activities. On May 7, 1992, the plant entered cold shutdown. On May 8, 1992, the refueling coordinator senior reactor operator (SRO) identified the mispositioning of the valves as part of a routine control board review.

C.4.3 Additional Event-Related Information

Sequoyah 2 is a Westinghouse four-loop nuclear steam supply system (NSSS) design with an ice condenser containment. The design basis of the CSS is to ensure that the containment pressure does not exceed the containment design pressure or the maximum temperature limit following a loss of coolant accident (LOCA) or a main steam line rupture inside containment. The CSS, normally in standby mode, is designed to operate automatically during any design basis event that results in a high containment pressure signal. The CSS sprays subcooled borated water into the upper containment atmosphere. Spray is supplied through two spray ring headers. Initially, the CSS and ice condenser function simultaneously to remove heat from the containment atmosphere. After the ice is depleted, the CSS and residual heat removal (RHR) spray provide the only active means of containment cooling.

The CSS valves that were left closed were FCV 72-21 and 72-22. These are the motor-operated valves (MOVs) in the suction line to the RWST. These valves are intended to be open when the CSS is required to be operable. They are interlocked with the containment sump suction valves such that both the containment sump and RWST suction isolation valves cannot both be open at the same time. However, the valves do not receive an open signal on a CSS start signal. Therefore, after the CSS starts on a high containment pressure signal, the operator would have very little time to open the valves before both CSS pumps failed due to a loss of suction.

The operators had depended on the equipment alignment checklists in the GOI to identify the correct position of the valves prior to changing modes. In fact, the GOI ECCS master checklist was completed prior to leaving refueling shutdown and entering cold shutdown. However, it was discovered that these two valves were not included in the GOI checklist. Therefore, there was no effective way to ensure that the mispositioning of the valves would be identified.

C.4.4 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

C.5 LER Number 354/92-006

Event Description: Loss of Primary Containment Integrity

Date of Event: May 26, 1992

Plant: Hope Creek

C.5.1 Summary

Primary containment integrity was lost at Hope Creek on May 26, 1992 and the plant was shut down as a result of excessive leakage through the suppression chamber to drywell vacuum breakers.

C.5.2 Event Description

Hope Creek Generating Station was at 100% power. During surveillance testing of the drywell to pressure suppression chamber bypass area, leakage past the area above acceptable limits was indicated. With the plant at power, the actual path of the leakage could not be determined. Based on the results of the test, the suppression chamber was declared inoperable, and as a result, the primary containment was also declared inoperable. A reactor shut-down was commenced when a second leak-rate test obtained results comparable to the initial test. A manual scram was initiated when the plant was at approximately 20% power, and all plant systems and components operated as expected.

After the unit was shut down and the drywell was purged, the suppression chamber was entered in order to determine the location of the leakage. Suppression chamber to drywell vacuum breakers F, G, and H were found to be leaking. Replacement of the vacuum breaker seal terminated the leakage through vacuum breaker G, but not that through vacuum breakers F and H. Disassembly of the vacuum breakers showed that the alignment pins for the hinge arm were sheared. Maintenance personnel replaced the pins, adjusted the pallet to attain proper seating of the seal, and reinstalled the vacuum breakers; however, both breakers still leaked. The seal bolting was readjusted, and a satisfactory seal was finally obtained.

C.5.3 Additional Event Related Information

Hope Creek is a boiling water reactor (BWR) with a Mark 4 pressure suppression containment. The drywell to pressure suppression chamber bypass area test is used to determine the overall bypass area that would allow drywell atmosphere to flow directly to the pressure suppression atmosphere without passing through the pressure suppression pool.

C.5.4 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

APPENDIX D: 'INTERESTING' EVENTS

D. 'INTERESTING' EVENTS

Ten reactor plant operational events for 1992 which were selected as 'interesting' events are documented in this section. These events are not normally precursor events as defined by the Accident Sequence Precursor (ASP) Program but typically they have enough unusual characteristics to warrant their inclusion in the report. The ten events are identified in Table D.1.

A summary, event description, and any additional event-related information is provided for each event. Copies of the applicable LERs and/or AIT reports for these events are contained in Appendix F. Also, two events (LERs 266/92-101 and 306/92-002) have been included that were previously analyzed as potential precursors in the draft report. However, based on additional information received from comments on the draft report, these events were reanalyzed. The reanalysis indicated that the conditional core damage probability for both these events was below the precursor cut-off value of 1.0×10^{-6}. As a result, the events were removed from the precursor list, but they were still considered to be "interesting" and are therefore included in this appendix.

Table D.1. Index of 'Interesting' Events

Docket/ LER No.	Description	Plant Name	Page
155/92-002	Liquid Poison Relief Valve Unavailable	Big Rock Point	D-4
220/92-005	Loss of Ultimate Heat Sink	Nine Mile Point 1	D-5
254/92-006, 237/92-002	Failed Control Room Annunicators	Quad Cities 1 & Dresden 2	D-7
266/92-010	Safety Injection System Unavailable During Testing	Point Beach 1 & 2	D-9
298/92-002	Reactor Vessel Water Level 1 Setpoint Set Nonconservatively	Cooper	D-16
306/92-002	Loss of Shutdown Cooling During Reactor Coolant System Draindown	Prairie Island 2	D-18
311/92-017	Unrecognized Loss of Annunicators	Salem 2	D-50
443/92-002	Incorrect RHR Flow Rate in Technical Specifications	Seabrook	D-52
AIT 530/92-019	Loss of Plant Annunciators	Palo Verde 3	D-54

D.1 LER Number 155/92-002

Event Description: Liquid Poison Relief Valve Unavailable

Date of Event: January 9, 1992

Plant: Big Rock Point

D.1.1 Summary

While testing the Liquid Poison System (LPS) during plant shutdown, it was determined that the system relief valve lifted at about 1575 psig, instead of at the design value of 2000 psig. Had the system been demanded to mitigate an anticipated transient without scram (ATWS) event during the previous operating cycle, it is unclear whether it would have performed as required.

D.1.2 Event Description

When demanded during an ATWS event, the Big Rock Point LPS aligns bottled nitrogen at approximately 1945 psig to pressurize a tank of sodium pentaborate solution. Explosive squib valves are then opened to align the tank to the reactor via a line that takes suction from the tank bottom, rises above the tank, and drops about 30 ft to the reactor vessel. The nitrogen overpressure forces some of the liquid from the tank up into the discharge line and to the reactor vessel. At the same time, explosive squib valves open to align a one-way vent path from the steam drum back to the tank. After a few gallons of sodium pentaborate are transferred, the pressure in the tank equalizes with the pressure in the reactor, and the balance of the fluid is transferred via a siphoning action.

As with any potentially pressurized system, a relief valve was provided to protect the LPS from overpressurization. This valve was intended to lift at about 2000 psig to protect the LPS tank and associated piping. During testing, however, it began relieving at pressures as low as 1575 psig. A utility review undertaken after this discovery determined that the LPS could have functioned correctly during ATWS events involving maximum reactor pressures of 1500 psig or less.

Analyses referenced in the Big Rock Point Updated Final Safety Analysis Report (UFSAR) indicate that a number of ATWS scenarios involve maximum primary pressures below 1500 psig, and the LPS should have been operational for these. ATWS events involving main steam isolation valve (MSIV) closure or turbine trip with bypass unavailable, however, could result in reactor pressures as high as 1670 psig. It seems unlikely that the LPS would have been successful in injecting under these circumstances.

D.1.3 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

D.2 LER Number 220/92-005

Event Description: Loss of Ultimate Heat Sink

Date of Event: February 21, 1992

Plant: Nine Mile Point 1

D.2.1 Summary

Nine Mile Point 1 was inadvertently isolated from its ultimate heat sink when all of the gates that supply lake water to the plant's screen house bay were closed. The loss of the heat sink occurred with the plant shut down during testing of the control system for one of the screen house bay gates. Normal water level was restored to the screen house bay in about 6 min, following the opening of two of the screen house bay gates.

D.2.2 Event Description

On February 10, 1992, work was conducted to restore the open push button for the D screen house bay gate (see Figs. 2 and 3 of augmented inspection team [AIT] Report No. 50-220/92-80 which is in Appendix F). During the repairs, workers discovered an undocumented jumper that bypassed the mechanical tension overload protection switch from the drive motor circuit. On February 11, 1992, a deficiency event report was generated to determine what actions should be taken with regard to the jumper. On February 12, 1992, the jumper was removed before the resolution of the deficiency event report. Later that day, the station shift supervisor ordered the jumper reinstalled when he was informed that the gate might not close during reverse flow operation. Testing of the gate during reverse flow operation with the jumper removed was postponed until the plant was in a shut-down condition.

On February 21, 1992, the plant was in a shut-down, depressurized condition, with a reactor coolant system (RCS) temperature of 143°F. Using a special procedure, the circulating water system was placed in reverse flow operation. Following removal of the electrical jumper, the D gate was closed at 0829 hours. An attempt to reopen the gate was unsuccessful. This resulted in the isolation of the plant's ultimate heat sink. At this time, two circulating water pumps (125,000 gpm each) and one service water pump (20,000 gpm) were operating. This caused screen house bay level to drop rapidly.

Immediately following the closure of the D gate (at 0829 hours), low-water level alarms for the screen house bay activated in the control room. Control room operators ordered the immediate reopening of D gate. This was accomplished by holding a jumper across the tension overload switch while holding in the "UP" push button. The B gate was also ordered open. Between 0830 hours and 0835 hours, both B and D gates were being opened (it takes about 5 min for a gate to fully open). At 0832 hours the running service water pump cavitated and was shut down by the operators. The operators tried to start emergency service water pump number 11 as required by procedure, but secured it because of low discharge pressure. The operators also secured one of the two circulating water pumps to reduce the rate of water removal from the screen house bay.

At 0835 hours the water level of the screen house bay returned to normal. The two emergency service water pumps were started at 0838 hours, and one of the service water pumps was started at 0844 hours. At 0845 hours, both emergency service water pumps were secured, and other equipment was restored to normal shut-down operation. During the event, the screen house bay level was below the minimum level for safe operation for 6 min.

The only observed system change was a 2°F increase in the temperature of the reactor building closed loop cooling system.

As a result, the NRC dispatched an AIT to the site to review the causes and safety implications associated with this event.

D.2.3 Additional Event-Related Information

Nine Mile Point 1 uses five gates to control the flow of water into and out of the screen house bay. Under normal conditions, gates A, B, and C are open, and gates D and E are closed. This allows water to flow into the screen house bay through gates A and B to the suction of the pumps in the screen house. Discharge flow from the condenser flows out of the discharge channel and through gate C. To temper cold water, gate E can be partially opened to heat the incoming water with warmer discharge water. To de-ice the intake structure in the winter, the flow through the tunnels can be reversed by closing gates A, B, and C and opening gates D and E. In this configuration, water is drawn in from the discharge tunnel and discharged through the intake tunnel. This will de-ice the intake structure by pumping warmer discharge water out through it. This alignment is used infrequently, but can be used during at-power operation. It should be noted that this test was delayed by the licensee to ensure that it was performed when the plant was shut down.

The screen house bay provides a water supply for 19 safety- and non-safety-related pumps, including the circulating water pumps, the service water pumps, the emergency service water pumps, and the fire pumps. The screen house bay level instrumentation is not safety-related and provides no control function. An alarm is provided in the control room for low water level in the screen house bay; however, it actuates 18 in. below the design setpoint for the screen house bay level.

D.2.4 Modeling Assumptions

This event was not modeled as an accident sequence precursor. Had this event occurred coincident with a loss of offsite power, the emergency diesel generators (EDGs), the core spray system, and containment spray systems would have been rendered inoperable. However, the licensee was conducting a special test procedure and had prepositioned personnel to respond if the test did not proceed as expected. In addition, the test was delayed so that it would be conducted with the plant shut down. The AIT concluded that "the consequences of this event were minimal because the reactor core and the reactor coolant were unaffected by this event, no equipment was damaged and no radiation was released."

D.3 LER Number 254/92-006 and 237/92-022

Event Description: Failed Control Room Annunciators

Date of Event: February 14, April 4, and July 1, 1992

Plant: Quad Cities 1, Dresden 2, Dresden 3

D.3.1 Summary

At Quad Cities Unit 1, a lightning strike caused a power surge that resulted in a loss of the control room annunciators for 0.5 h. The plant was shut down at the time of the event.

At Dresden Unit 2, with the plant at 76% power, momentary losses of power to some of the main control room annunciators occurred over a 6-h period.

At Dresden Unit 3, several brief losses of all control room annunciators occurred intermittently over a period of 1.5 h.

D.3.2 Event Description

On February 14, 1992, at 2235 hours, while Quad Cities Unit 1 was shut down, a lightning strike in or near the main switchyard caused the unit to experience a power surge. The surge caused temporary failure of a main power fuse for the annunciator control panel 901-34 and also blew a fuse in panel 901-34 which is associated with the circuitry for control room annunciator panel 901-6. A continuity check on the fuses for panel 901-34 revealed that the fuses had not blown. When the fuse block was reinstalled at 2256 hours (with the original fuses still in place), all annunciator power except power to panel 901-6 was restored. At 2308 hours, a blown fuse associated with panel 901-6 was found and replaced, restoring power to the 901-6 annunciators. The main power fuse was later checked again and found to be degraded to the point where physical movement of the fuse affected the continuity. This explains why the fuse initially failed, but then functioned again when the fuse block was reinstalled.

On July 1, 1992, with Dresden Unit 2 at 76% power, the unit experienced intermittent failures of the annunciator system. Investigation revealed that a copper link (copper tubing) was not making sufficient contact. The link was installed in a fuse holder that feeds −125 Vdc to all annunciators in Unit 2. The original plant design did not include a fuse in this circuit. The fuse and holder were installed during annunciator system modifications in January 1990. The fuse was replaced with a copper link when the fuse blew and caused a failure of the annunciator system at Unit 3. The copper tubing was smaller than a standard link type, causing it to be subject to movement from vibration. Maintenance personnel were working in the cabinet containing the copper link when the event occurred. Because of this event, the copper link was replaced with a jumper in Units 2 and 3.

On April 4, 1992, Dresden Unit 3 lost all its control room annunciators while the plant was in a refueling outage. Over a 1.5-h period, the plant experienced several brief failures of the annunciator system before the system was repaired. The cause of the failures was a loose wire connector on a fuse block within an annunciator cabinet (PNO-III-92-17).

D.3.3 Modeling Assumptions

These events were not modeled as accident sequence precursors.

D.4 LER Number 266/92-010

Event Description: Safety Injection System Unavailable During Testing

Date of Event: December 8, 1992

Plant: Point Beach 1 and 2

D.4.1 Summary

Quarterly valve stroke tests were found to isolate the minimum flow recirculation line common to each unit's two safety injection (SI) pumps. If the pumps were demanded when the recirculation line was isolated, pump failure would occur quickly for high reactor coolant system (RCS) pressure conditions. The conditional core damage probability estimated for this event is 1.7×10^{-7}. This probability is applicable to both units. This estimate is below the minimum level defined for precursors; however, the event is interesting enough to warrant its inclusion in the report. The relative significance of this event compared to other postulated events at Point Beach is shown in Fig. D.1.

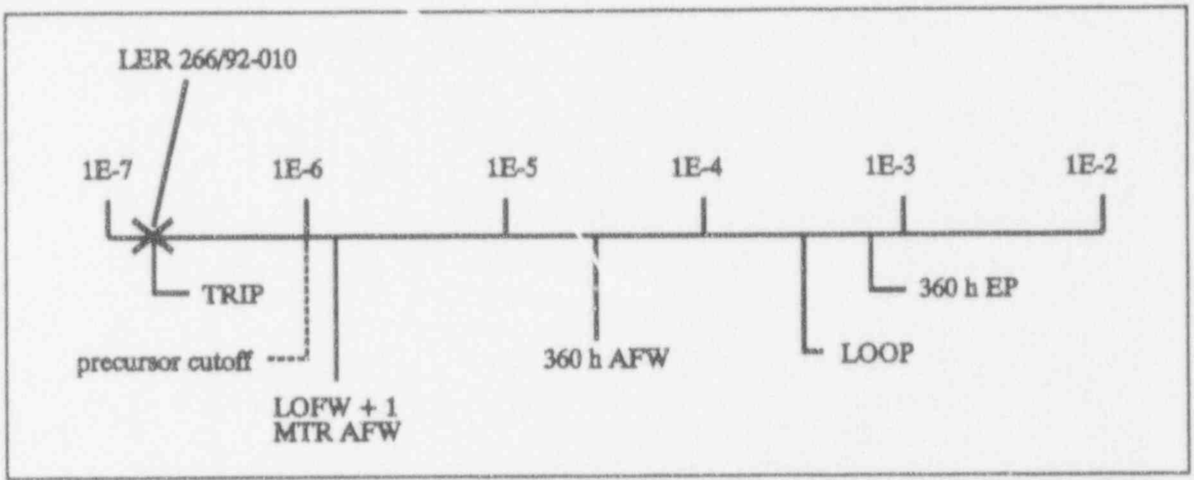


Fig. D.1. Relative event significance of LER 266/92-010 compared with other potential events at Point Beach.

D.4.2 Event Description

Point Beach Units 1 and 2 were at 100% and 95% power, respectively, on December 8, 1992. The utility discovered that Inservice Tests IT-40, *Safety Injection Valves (Quarterly), Unit 1*, and IT-45, *Safety Injection Valves (Quarterly), Unit 2*, isolated each unit's respective SI pump common minimum flow recirculation line by closing valves 897A and 897B. The utility stated that operation of the SI pumps at high RCS pressure conditions with the minimum recirculation line isolated would result in pump degradation after one minute.

A review of station logs indicated that the time required to complete IT-40 and IT-45 is on the order of two hours; however, the recirculation line is not isolated for the full duration of the test. The best estimate of the time the valves are actually closed is 10 to 20 min per test.

D.4.3 Additional Event-Related Information

An orificed minimum flow bypass line is provided at the discharge of each SI pump to recirculate flow to the refueling water storage tank (RWST) through a common header, or minimum flow recirculation line, in the event that the SI pumps are run while the RCS pressure is above the pumps' shutoff head. These bypass lines also permit the performance of periodic surveillance tests required by the Technical Specifications to demonstrate pump operability. The recirculation line is provided with series air-operated isolation valves 897A and 897B, which are closed to prevent the transfer of containment sump inventory to the RWST during the recirculation phase following a loss-of-coolant accident (LOCA). Because valves 897A and 897B fail closed, they are normally gagged open to prevent closure on a loss of instrument air. If the SI pumps are operated without a flow path, the pumps will overheat and quickly deteriorate.

Valves 897A and 897B are interlocked with the containment sump isolation valves. These valves are normally closed except during the recirculation phase following a LOCA. The interlock ensures the sump isolation valves cannot be opened until valve 897A or 897B is closed.

D.4.4 Modeling Assumptions

The event was modeled as an unavailability of high-pressure injection (HPI) and feed and bleed for a 1.33 h period (assuming 20 min per test) within a 1-yr observation period (the interval between precursor reports). All small-break LOCAs were assumed to slowly depressurize, such that RCS pressure would remain above the shutoff head of the SI pumps long enough to fail the pumps. Because of the short time period before SI pump degradation and expected failure, no recovery was assumed possible.

The existing model was revised to address two issues associated with the potential use of RCS cooldown and depressurization in providing core cooling success following a small-break LOCA:

(1) given HPI success, primary cooldown and initiation of RHR with continued use of HPI at reduced flowrates, instead of the use of high pressure recirculation (HPR), and

(2) given HPI failure, rapid depressurization and the use of low pressure injection (LPI) and low pressure recirculation (LPR).

The existing ASP model assumes HPR is required for core cooling success following successful HPI. The existing model also assumes that core damage occurs following a nonrecoverable failure of HPI.

To address these issues, LOCA-related sequences involving HPI success and AFW or MFW success (transient sequences 11 and 13, LOOP sequence 41, and small-break LOCA sequences 71 and 73 – see Appendix A, Sect. A.3.1) were modified to include the branches in Fig. D.2.

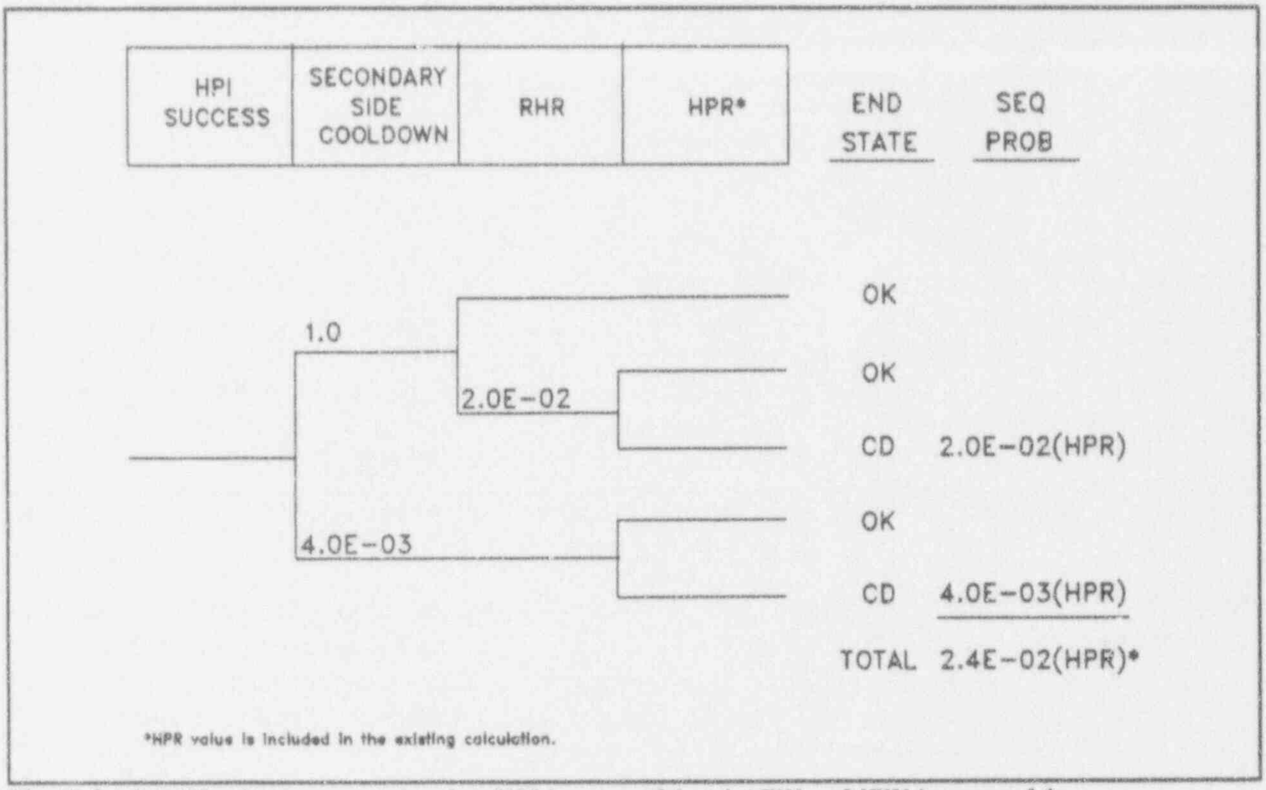


Fig. D.2. Modification to event tree when HPI is successful and AFW or MFW is successful.

The conditional probability for the additional branches is:

p(-sec side cool) × p(RHR) × p(HPR) + p(sec side cool) × p(HPR), or

[p(-sec side cool) × p(RHR) + p(sec side cool)] × p(HPR).

The probability of failure of secondary side cooldown was assumed to be 4.0×10^{-3}, including an operator error probability of 1.0×10^{-3} (see Appendix A, Table A.14). The RHR failure probability (2.0×10^{-2}) was assumed to be dominated by failures of the two series RCS drop valves (the ASP program uses a nominal failure probability of 0.01 for pumps and motor-operated valves).

The conditional probabilities for sequences 11, 13, 41, 71, and 73 were multiplied by the following to reflect the additional branches:

p(-sec side cool) × p(RHR) + p(sec side cool) = 2.4×10^{-2},

since p(HPR) is addressed in the existing model. Since none of these sequences are dominant, this modification does not affect the conditional core damage value for this event.

LOCA-related sequences involving HPI failure (sequences 12, 14, 42, 72 and 74) were also modified to include the branches in Fig. D.3.

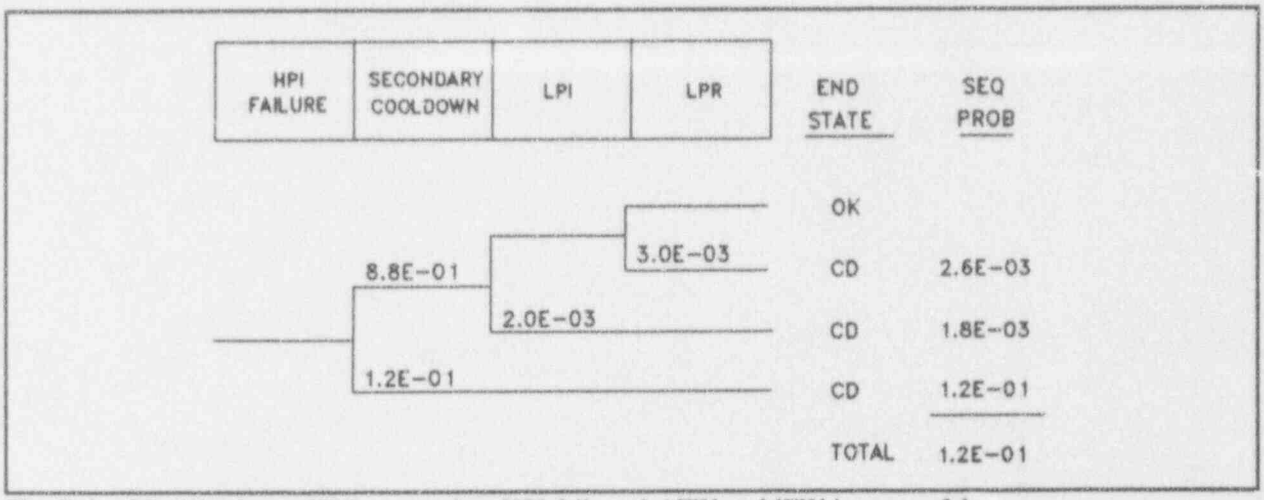


Fig. D.3. Modification to HPR event when HPI fails and AFW or MFW is successful.

In this case, the probability of failing to initiate rapid secondary side depressurization was estimated to be 0.12 (ASP recovery class R3 - see Appendix A, Sect. A.1). An equipment failure probability of 3×10^{-3} results in a probability of failing to complete secondary side depressurization of 1.23×10^{-1}. LPI success requires the opening of the motor-operated injection valve and the start of the LPI (RHR) pump in one of the two redundant trains. A failure probability of 2.0×10^{-3} was estimated for LPI, again assuming a nominal failure probability of 0.01 for pumps and motor-operated valves, and a common-cause (beta factor) of 0.1. LPR success requires the opening of the containment sump isolation valves (2 per train) to allow recirculation of water spilled into the containment sump from the break back to the RCS, using the LPI pumps. LPR failure is dominated by failure of the sump isolation valves to open. Therefore, the LPR failure probability is 3.0×10^{-3} (including 1.0×10^{-3} for failure to initiate recirculation). The combined failure probability for the three branches (secondary side depressurization, LPI and LPR) is 1.2×10^{-1}. The conditional probabilities for sequences 12, 14, 42, 72, and 74 estimated using the existing ASP models were multiplied by this value to address the potential use of LPI and LPR to provide core cooling in the event of HPI failure with AFW or MFW success. Since the conditional probability for sequence 72 is more than two orders of magnitude greater than the conditional probability for each of the other sequences, sequence 72 is the only significant sequence.

D.4.5 Analysis Results

The conditional core damage probability estimated for the event is 1.7×10^{-7}. This is the result of the probability estimated using the existing ASP model (1.4×10^{-6}) times the value for the additional relevant mitigation factors (1.2×10^{1}). The dominant core damage sequence, highlighted on the event tree in Fig. D.4, involves a potential small-break LOCA with failure of HPI, and failure to depressurize the secondary side to permit the use of LPI and LPR. As noted above, the minimum flow recirculation valves are not closed for the entire 2-h quarterly test period, and therefore this analysis is somewhat conservative.

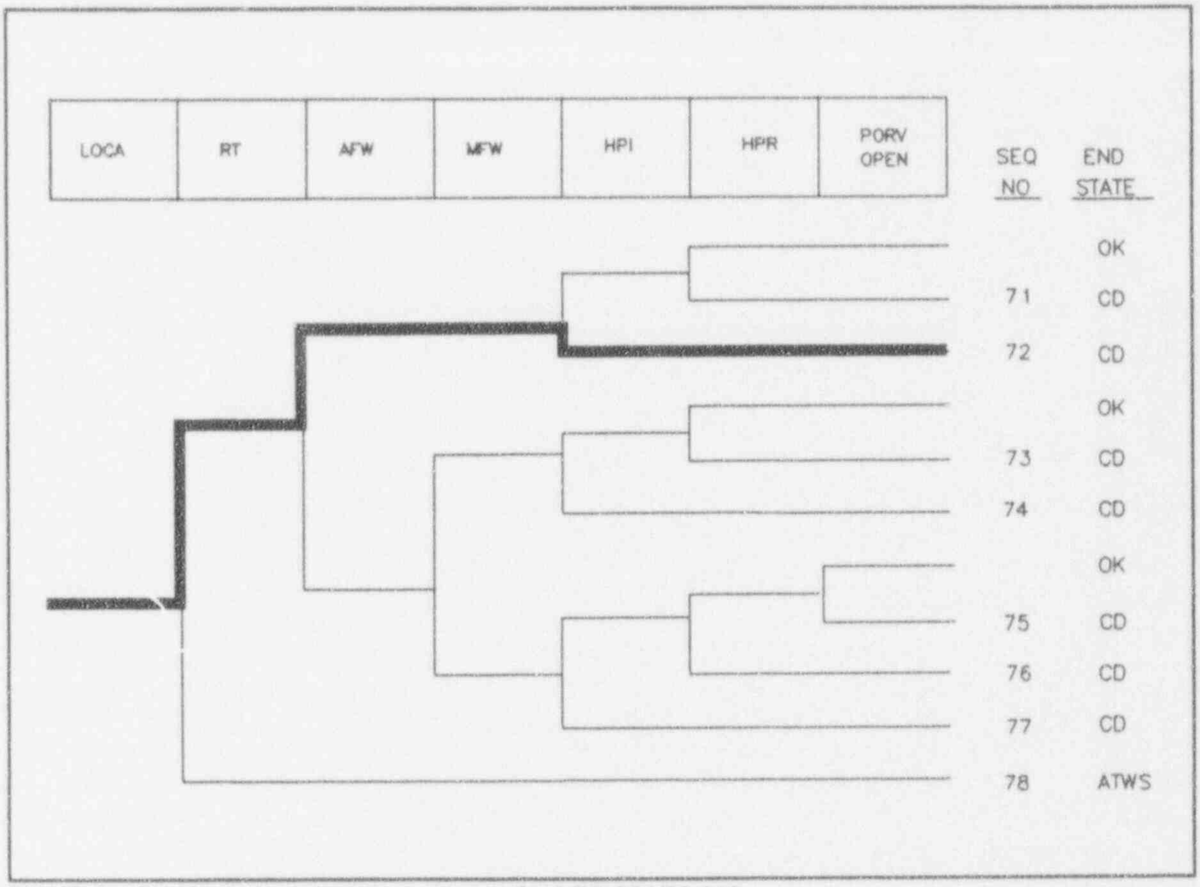


Fig. D.4. Dominant core damage sequences for LER 266/92-010.

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 266/92-010
Event Description: Safety injection system unavailable during testing
Event Date: 12/8/92
Plant: Point Beach 2

UNAVAILABILITY, DURATION= 1.333

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	2.6E-04
LOOP	7.8E-06
LOCA	1.4E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	4.1E-09
LOOP	8.2E-10
LOCA	1.4E-06[1]
Total	1.4E-06[1]
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
72	loca -rt -afw HPI	CD	1.4E-06[1]	4.3E-01

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
72	loca -rt -afw HPI	CD	1.4E-06[1]	4.3E-01

** non-recovery credit for edited case

Note: For unavailabilities, conditional probability values are differential values which reflect the added risk due to failures associated with an event. Parenthetical values indicate a reduction in risk compared to a similar period without the existing failures.

SEQUENCE MODEL: s:\asp\prog\models\pwrbseal.cmp
BRANCH MODEL: s:\asp\prog\models\ptbeach2.sl1
PROBABILITY FILE: s:\asp\prog\models\pwr_bsl1.pro

Event Identifier: 266/92-010

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.0E-04	1.0E+00	
loop	1.6E-05	3.6E-01	
loca	2.4E-06	4.3E-01	
rt	2.8E-04	1.2E-01	
rt/loop	0.0E+00	1.0E+00	
emerg.power	2.9E-03	8.0E-01	
afw	3.8E-04	2.6E-01	
afw/emerg.power	5.0E-02	3.4E-01	
mfw	1.0E+00	7.0E-02	
porv.or.srv.chall	4.0E-02	1.0E+00	
porv.or.srv.reseat	2.0E-02	1.1E-02	
porv.or.srv.reseat/emerg.power	2.0E-02	1.0E+00	
seal.loca	0.0E+00	1.0E+00	
ep.rec(sl)	0.0E+00	1.0E+00	
ep.rec	4.5E-01	1.0E+00	
HPI	1.0E-03 > 1.0E+00	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
HPI(F/B)	1.0E-03 > 1.0E+00	8.4E-01 > 1.0E+00	1.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
hpr/-hpi	1.5E-04	1.0E+00	1.0E-03
porv.open	1.0E-02	1.0E+00	4.0E-04

* branch model file
** forced

Note:

[1] This conditional probability was revised to reflect additional mitigation strategies. See Modeling Assumptions.

Event Identifier: 266/92-010

D.5 LER Number 298/92-002

Event Description: Reactor Vessel Water Level 1 Setpoint Set Nonconservatively

Date of Event: February 3, 1992

Plant: Cooper Nuclear Station

D.5.1 Summary

As a result of a General Electric (GE) information letter, a check on the reactor water level 1 setpoint was conducted. It was discovered that the four transmitters which initiate the residual heat removal (RHR) system in the low pressure coolant injection (LPCI) mode, the core spray (CS) system, the automatic depressurization system (ADS), and the standby emergency diesel generators (EDGs) had nonconservative actuation setpoints. Under certain conditions, their setpoints would not be reached because of an increase in drywell temperature. This condition had existed for a period of approximately 10 years.

D.5.2 Event Description

On January 20, 1992, an advance copy of supplement 2 to the GE service information letter (SIL) was received by the licensee. It notified boiling water reactor owners that a previous SIL (299), entitled "High Drywell Temperature Effect on Reactor Vessel Water Level Instrumentation" and issued in 1979, had been misinterpreted by at least one utility. As a result of this supplementary notification, the licensee reevaluated the reactor water level 1 setpoint calculations.

The review revealed that a calculation performed in 1981 had resulted in a nonconservative actuation setpoint for four level transmitters (NBI-LIS-72 A,B,C, and D). In 1981, the Technical Specifications required setpoint was changed to ≥ -145.5 in. and the transmitters were set at -118.5 in. Under certain accident conditions, the four channels of reactor level will indicate -114 in. when the level falls below the level of the lower sensor tap. As a result, the level 1 setpoint of -118.5 in. would not be reached. These transmitters actuate the RHR system in the LPCI mode, the CS system, the ADS, and the standby EDGs.

Under small-break loss-of-coolant accident (LOCA) conditions, drywell temperatures, and therefore reference leg temperatures, would be raised beyond the ranges for which the level instruments are calibrated. The time constant for the reference legs has been calculated at 20 to 30 min.

During the evaluation of the level 1 setpoint, another question was raised concerning a modification that occurred in 1983. This modification changed the Group 1 and Group 7 primary containment isolation setpoints (PCIS) for four level transmitters. The setpoints were changed from a required reactor level setpoint of ≥ -37 in. (Level 2) to ≥ -145.5 in. However, the instrument inaccuracy caused by reference leg heating was not accounted for in the setpoint change calculations. As a result, the nominal setpoint of -138.0 in. could be below the required level of ≥ -145.5 in. under the accident conditions described above.

D.5.3 Additional Event-Related Information

LPCI, CS, and the EDGs are also actuated by high drywell pressure signals. Under the accident conditions specified, the high drywell pressure signal will be reached before the reactor vessel low water level 1 setpoint is reached. The emergency operating procedures require the manual override of the ADS system under accident conditions. PCIS groups 1 and 7 would have to be manually actuated. In addition, wide-range reactor vessel level indicators are available to the operators to manually actuate the systems. Therefore, this scenario results in a loss of redundancy of initiation signals for the systems noted and a failure of the automatic actuation signals for PCIS groups 1 and 7.

D.5.4 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

D.6 LER Number 306/92-002

Event Description: Loss of Shutdown Cooling During Reactor Coolant System Draindown

Date of Event: February 20, 1992

Plant: Prairie Island 2

D.6.1 Summary

While draining the reactor coolant system (RCS) to mid-loop to install steam generator (SG) nozzle dams, problems with RCS level indication resulted in excessive inventory reduction. The operating residual heat removal (RHR) pump was tripped after vortexing occurred. Reactor vessel inventory was restored using both charging pumps and the second RHR pump aligned to the refueling water storage tank (RWST). RHR flow was restored about 20 minutes after the RHR pump was tripped. During this period of time, core outlet temperature (highest reading core exit thermocouple) increased ~80°F to 221.5°F.

The conditional probability of subsequent core damage estimated for the event is 6.3×10^{-7}. This estimate is below the minimum level defined for precrusors; however, the event is interesting enough to warrant its inclusion in the report. The calculated probability is strongly influenced by estimates of the likelihood of failing to recover failed systems (primarily RHR) over long time periods. These estimates involve substantial uncertainty, and hence the overall core damage probability estimated for the event also involves substantial uncertainty.

D.6.2 Event Description

Prairie Island 2 was shut down at 2254 hours on February 18, 1992 for a 20 d refueling outage. At 1704 hours on February 20, 1992, RCS drain down to mid-loop was begun to install SG nozzle dams. RCS temperature was 135°F. The 22 RHR pump was in service. All offsite and onsite power sources and all emergency core cooling system (ECCS) pumps were available, and one SG was functional.

Approximately 2 1/2 hours after draindown began, problems were suspected with the control room electronic level indication. This level indication was provided via two emergency response computer system (ERCS) level transmitters. The RCS drain down continued while attempts were made to diagnose the level indication problem.

Shortly after 2300 hours, the ERCS came on scale indicating low level. Four minutes later, RHR low flow alarms were received, and five minutes after that the drain down was secured and the operating RHR pump was stopped because of vortexing.

Both charging pumps were subsequently started. The ERCS indicated level was ~8 inches below the reactor coolant loop nozzle centerline. At 2320 hours, indicated RCS temperature reached 190°F and the Emergency Operating Procedure (EOP) for core cooling following a loss of RHR flow was entered. At 2326 hours, the suction of the 21 RHR pump was aligned to the RWST and that pump was started. Reactor vessel level was increased to the vessel flange. At that point, the 21 RHR pump was secured, realigned for shutdown cooling, and restarted. The highest local RCS temperature indicated during the event was 221.5°F (core exit thermocouple). However, this was at a time when RHR flow did not exist, and is not an accurate indication of coolant temperature in the vessel, which was subsequently estimated to be ~160°F.

A more detailed chronology of this event is provided in Table D.2.

Table D.2. Sequence of Events for LER 306/92-002.

February 20, 1992	
5:04PM	Commenced RCS drain down.
7:35PM	(approx.) Suspected problem with ERCS. Instruments had not come on scale as anticipated. Drain down continued while attempts were made to diagnose problem.
11:01PM	ERCS came on scale indicating low level.
11:03PM	Operators noted ERCS display.
11:05PM	RHR flow alarms received.
11:10PM	Drain down secured.
11:11PM	Stopped 22 RHR pump due to vortexing.
11:12PM	Entered AOP for loss of coolant at reduced inventory.
11:13PM	Started 21 charging pump.
11:15PM	ERCS indicated RCS level approximately 8 inches below nozzle centerline.
11:19PM	Started 22 charging pump.
11:20PM	RCS temperature 190° F.
11:25PM	RCS temperature 200° F.
11:26PM	Aligned RHR suction to RWST and started 21 RHR pump.
11:27PM	Core exit thermocouple indicated 221.5° F., highest trended temperature reached during event.
11:29PM	RCS level returned to vessel flange, 21 RHR pump secured.
11:32PM	RHR aligned for shutdown cooling and 21 RHR pump re-started.
11:35PM	Stopped charging pumps
February 21, 1992	
12:01AM	RCS sample drawn. No fuel damage indicated.
12:25AM	Unusual event declared and exited.
1:26AM	NRC notified via ENS.

D.6.3 Additional Event-Related Information

The Prairie Island RHR system consists of two trains, each containing an RHR pump, heat exchanger, and an air-operated flow control valve. The trains can be cross-connected upstream of the heat exchangers and downstream of the flow control valves. A separate line containing an additional air-operated valve runs from the centers of the cross-connect lines and allows the heat exchangers to be bypassed for temperature control. The RHR pump suction is fed from two sets of series valves from each RCS loop. These valves are interlocked to close if RCS pressure increases above 600 psig and, if closed, cannot be opened until RCS pressure is reduced to 425 psig.

The procedure for core cooling following loss of RHR flow, E-4, (included as Attachment 1), addresses situations when the RCS is and is not intact. For situations when the RCS is intact (as it was during this event), the procedure initially requires secondary-side heat removal to be established and the containment to be evacuated of non-essential personnel. Once this is accomplished, the operators are instructed to increase RCS inventory to one foot below the reactor vessel flange using an RHR, safety injection (SI), or charging pump aligned to the RWST. At this point, the operators are instructed to continue efforts to restore RHR and maintain vessel level. If the RCS is not intact, containment closure is initited and vessel level is increased as previously described. If the SG primary manways are not installed, the operators are instructed to start the fan cooling units for containment heat removal. In this case, if vessel makeup cannot be provided using the RHR, SI or charging pumps, gravity feed from the RWST is specified.

Procedure E-4 also provides a curve of makeup required for core cooling as a function of time after shutdown and background information for each step in the procedure. With regard to the use of the SGs, the background information notes that, once the RCS reaches saturation, steam will condense in the SG tubes, which will reduce the pressurization rate of the RCS. The steps in procedure E-4 used during this event are annotated in Attachment 2.

D.6.4 Modeling Assumptions

The event tree model developed for this event is shown in Fig. D.5. This model is based on procedure E-4 (Attachment 1) and includes use of the SGs for core cooling. If the RCS is open to containment (not intact), then RCS makeup from the RWST using an RHR or SI pump will provide core cooling success. If the RCS is intact (as it was during this event), then recovery of shutdown cooling or the use of the SGs with the long term recovery of RHR is assumed to provide core cooling success.

Branch probabilities were estimated as follows:

a. RCS open. During this event, the RCS was intact. A branch probability of 1.0 was utilized.

b. SGs provide core cooling. During this event, two motor-driven auxiliary feedwater (AFW) pumps (one from each unit) and both SGs were initially available (one SG had been dedicated for decay heat removal). A failure probability of 6.8×10^{-4} was estimated, based on nominal failure probabilities and on-recovery likelihoods used in the ASP program (0.01 for pumps and motor- or air-operated valves, 0.1 for beta-factor, and 0.34 for nonrecovery, unless other data exists).

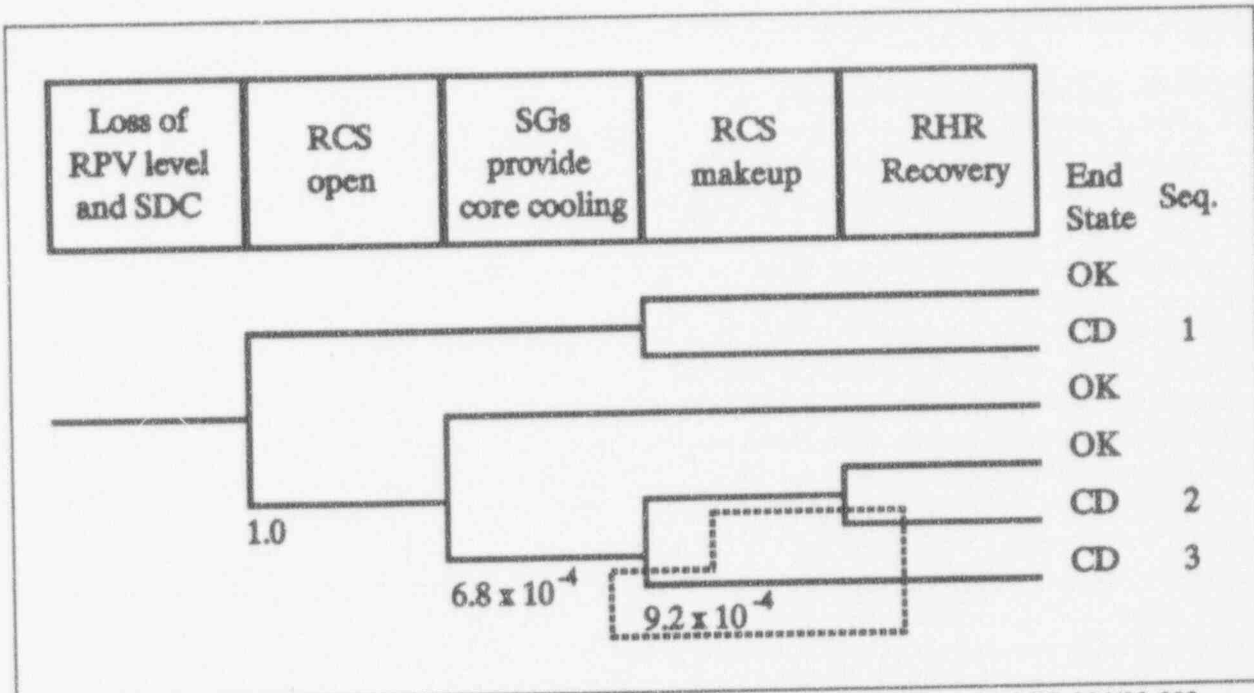


Fig. D.5. Event tree for loss of shutdown cooling with branch probabilities indicated for LER 306/92-002

c. RCS makeup. Success for this branch is provided by realigning the standby RHR pump to take suction from the RWST and starting that pump, or starting one of two SI pumps.

d. RHR recovery. Success for this branch is provided by realigning the RHR pump used for RCS makeup or by venting and restarting the RHR pump which was initially lost.

Branches involving RCS makeup and RHR recovery are coupled, since failure of the RHR pumps impacts both. To estimate the combined probability for sequences 2 and 3, given the SGs fail to provide core cooling [p(RCS makeup fails) + p(failure to restore RHR)], it was assumed that only RHR pump 21 could be used to recover vessel level via the RHR system, (RHR pump 22 had been stopped because of vortexing).

The probability of RCS makeup failure is therefore:

> [p(failure of RHR pump 21 or associated valves)] × [p(failure of SI pump A or associated valve) × p(failure of SI pump B or associated valve)]

The probability of failing to recover shutdown cooling is

> p(failure of RHR pump 21 or associated valves) × p(failure to recover RHR pump 22)

The combined probability for the two branches, after some rearrangement, is

p(failure of RHR pump 21) × p(SI) +
p(failure of RHR pump 21 associated valves) × p(SI) +
p(failure of RHR pump 21) × p(failure to recover RHR pump 22) +
p(failure of RHR pump 21 associated valves) × p(failure to recover RHR pump 22),

where p(SI) is the failure to provide makeup using the SI or charging pumps.

Based on the approach described in item b above, p(SI) is estimated at 6.8×10^{-4}, p(failure of RHR pump 21) at 0.01, and p(failure of RHR pump 21 associated valves) at 0.02. The probability of failing to recover RHR pump 22 before core uncovery (greater than 200 min after the loss of shutdown cooling, based on the increase in average RPV temperatures observed during the event) was estimated to be 0.03, based on the distribution of recovery durations for losses of RHR events attributed to inadequate RCS level included in E. Jordan memorandum, *Loss of Decay Heat Removal Function at Pressurized Water Reactors with Partially Drained Reactor Coolant Systems*, May 18, 1987 (the increased industry attention to shutdown cooling following the 1990 event at Vogtle may make this data somewhat conservative).

Combining these numeric values results in an estimate for failure of RCS makeup or failure to recover shutdown cooling of 9.2×10^{-4}. The overall probability estimated for sequences 2 and 3 is therefore $(1.0) \times (6.8 \times 10^{-4}) \times (9.2 \times 10^{-4}) = 6.3 \times 10^{-7}$.

D.6.5 Analysis Results

The event tree model for this event, including branch probabilities described above, is shown in Fig. D.5. The estimated conditional core damage probability for the event is 6.3×10^{-7}. The dominant sequence involves the loss of RPV level and SDC with failure to provide core cooling using the SGs and the RHR pumps. The calculated probability is strongly influenced by estimates of failing to recover failed systems (primarily RHR) over long time periods. These estimates involve substantial uncertainty, and hence the overall core damage probability estimated for the event also involves substantial uncertainty.

Attachment 1 to 306/92-002

Procedure E-4, "Core Cooling Following Loss of RHR Flow," Rev.2

UNIT 2

CORE COOLING FOLLOWING LOSS OF RHR FLOW

APPROVED BY: [illegible] DATE: [illegible]

CORE COOLING FOLLOWING LOSS OF RHR FLOW

A. PURPOSE:

This procedure provides actions to perform core cooling functions upon loss of RHR flow and a subsequent failure to recover RHR flow in a timely fashion. Methods in these procedures only provide interim cooling until RHR flow is restored.

B. ENTRY CONDITIONS:

1. 190°F or greater as indicated on two core exit thermocouples while in a reduced inventory condition.

2. RHR flow has not been restored via RCS makeup and venting of the RHR pump suction.

3. RHR pumping capability has been lost and cannot be restored in a timely fashion.

C. ATTACHMENTS:

ATTACHMENT H: Approximate Makeup Flow to Maintain RCS Inventory
ATTACHMENT I: Containment Closure Procedure

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

Caution *Attempts to restore RHR flow SHALL be performed in parallel with this procedure.*

NOTE *The conditions of the plant during this procedure may involve the Emergency Plan. A recommendation should be made to the Shift Supervisor to consider classification per F3-2.*

1	Check All Steam Generator Primary Manways - INSTALLED-(D2, Table-2)	Go to Step 19.
2	Verify RCS - INTACT	Go to Step 4
3	Go to Step 14	
4	Initiate Containment Closure Per 2E-4, ATTACHMENT I	
5	Isolate Tygon Tube: a. Close instrument block drain valve on refueling canal level transmitter LT-24128	

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

Caution *If aligning RHR to refill RCS, then valve alignments should be performed on only one train.*

6	Increase RCS Inventory Using RWST Supply to RHR Pump:	
	a. Open RWST supply to RHR pump suction to fill RCS: • Train A MV-32187 -OR- • Train B MV-32188	a. Go to Step 7.
	b. Open RHR to reactor vessel nozzle valve: • Train A MV-32167 -OR- • Train B MV-32168	b. Go to Step 7.
	c. Start associated RHR pump to refill RCS to one foot below reactor vessel flange (728'6")	c. Go to Step 7.
	d. Stop RHR pump	
	e. Go to Step 9	

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
7	Increase RCS Inventory Using SI Pump:	
	a. Open SI vessel injection valves: • MV-32170 -OR- • MV-32172	a. Go to Step 8.
	b. Start designated SI pump	b. Go to Step 8.
	c. Refill RCS to one foot below reactor vessel flange (728'6")	c. Go to Step 8.
	d. Stop SI pump	
	e. Go to Step 9	
8	Increase RCS Inventory Using Charging System	Go to Step 14.
	a. Verify two charging pumps running	a. Start charging pumps as necessary.
	b. Maximize charging flow	
	c. Verfiy RCS level increasing	c. Go to Step 14.
9	Provide Makeup To RCS As Necessary To Maintain Level One Foot Below Reactor Vessel Flange (728'6")	
10	Evacuate Containment Of Non-essential Personnel	

Number:	Title:	Revision number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
11	Continue To Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation	
12	RHR Flow - RESTORED	Continue attempts to restore RHR flow AND Return to Step 9.
13	Go To Step 35	
14	Establish Secondary Heat Sink In At Least One SG:	
	a. Feed SG(s) using AFW to maintain 70% wide range level	a. IF SG recirculation rig attached, THEN feed SG per D27.16.
	b. Place SG PORV controller(s) in "MANUAL"	
	c. Open SG PORV(s)	c. Locally open SG PORV(s). IF SG PORV(s) can NOT be locally opened, THEN establish SGB to remove decay heat.
15	Evacuate Containment Of Non-essential Personnel	
16	Continue To Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation	
17	RHR Flow - RESTORED	Continue attempts to restore RHR flow AND Return to Step 6.

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
18	Go To Step 36	
19	Initiate Containment Closure Per 2E-4, ATTACHMENT I	
20	Evacuate Containment Of Non-essential Personnel	
21	Continue To Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation	
22	Initiate Containment Cooling: • Start all available FCUs • Maximize water flow through available FCUs	IF personnel are in containment, THEN containment temperature should be monitored.
23	Check SG Nozzle Dams - ALL INSTALLED	Go to Step 30.

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

Caution *If aligning RHR to refill RCS, then valve alignments should be performed on only one train.*

24	Increase RCS Inventory Using RWST Supply to RHR Pump:	
	a. Open RWST supply to RHR pump suction to fill RCS: • Train A MV-32187 -OR- • Train B MV-32188	a. Go to Step 25.
	b. Open RHR to reactor vessel nozzle valve: • Train A MV-32167 -OR- • Train B MV-32168	b. Go to Step 25.
	c. Start associated RHR pump to refill RCS to one foot below reactor vessel flange (728'6")	c. Go to Step 25.
	d. Stop RHR pump	
	e. Go to Step 27	

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
25	Increase RCS Inventory Using SI Pump:	
	a. Open SI vessel injection valves: • MV-32170 -OR- • MV-32172	a. Go to Step 26.
	b. Start designated SI pump	b. Go to Step 26.
	c. Refill RCS to one foot below reactor vessel flange (728'6")	c. Go to Step 26.
	d. Stop SI pump	
	e. Go to Step 25	
26	Increase RCS Inventory Using Charging System	Go to Step 30.
	a. Verify two charging pumps running	a. Start charging pumps as necessary.
	b. Maximize charging flow	
	c. Verfiy RCS level increasing	c. Go to Step 30.
27	Provide Makeup To RCS As Necessary To Maintain Level One Foot Below Reactor Vessel Flange (728'6")	
28	RHR Flow - RESTORED	Continue attempts to restore RHR flow <u>AND</u> Return to Step 27.
29	Go To Step 36	

Number:	Title:	Revision number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	NOTE *The following steps may initiate charging flow at a rate slightly greater than the core boil off rate. See Attachment H.*	
30	Check incore Thermocouples - LESS THAN 200°F	Makeup from RWST using charging pump(s). Adjust charging flow rate as necessary to maintain RCS inventory - See ATTACHMENT H. <u>IF</u> charging pump makeup <u>NOT</u> available, <u>THEN</u> makeup using gravity feed from RWST via RHR pump. Continue with Step 31.
	NOTE *Restoration of RHR flow from this condition may result in a rapid level decrease as voids collapse in the RCS due to cooling in the RHR heat exchanger.*	
31	RHR Flow - RESTORED	Continue attempts to restore RHR flow <u>AND</u> Return to Step 30.
32	Throttle RHR Flow To 500 gpm	
33	Check incore T/Cs - LESS THAN 195°F	Do not isolate charging until incore T/Cs are less than 195°F.
34	Fill RCS To 3/4 Loop Level (723'11.75")	
35	RCS Level - AT 3/4 LOOP LEVEL a. Stop filling	Go to Step 34. When RCS at 3/4 loop level perform step 35a
36	Increase RHR Flow To 1000 gpm	

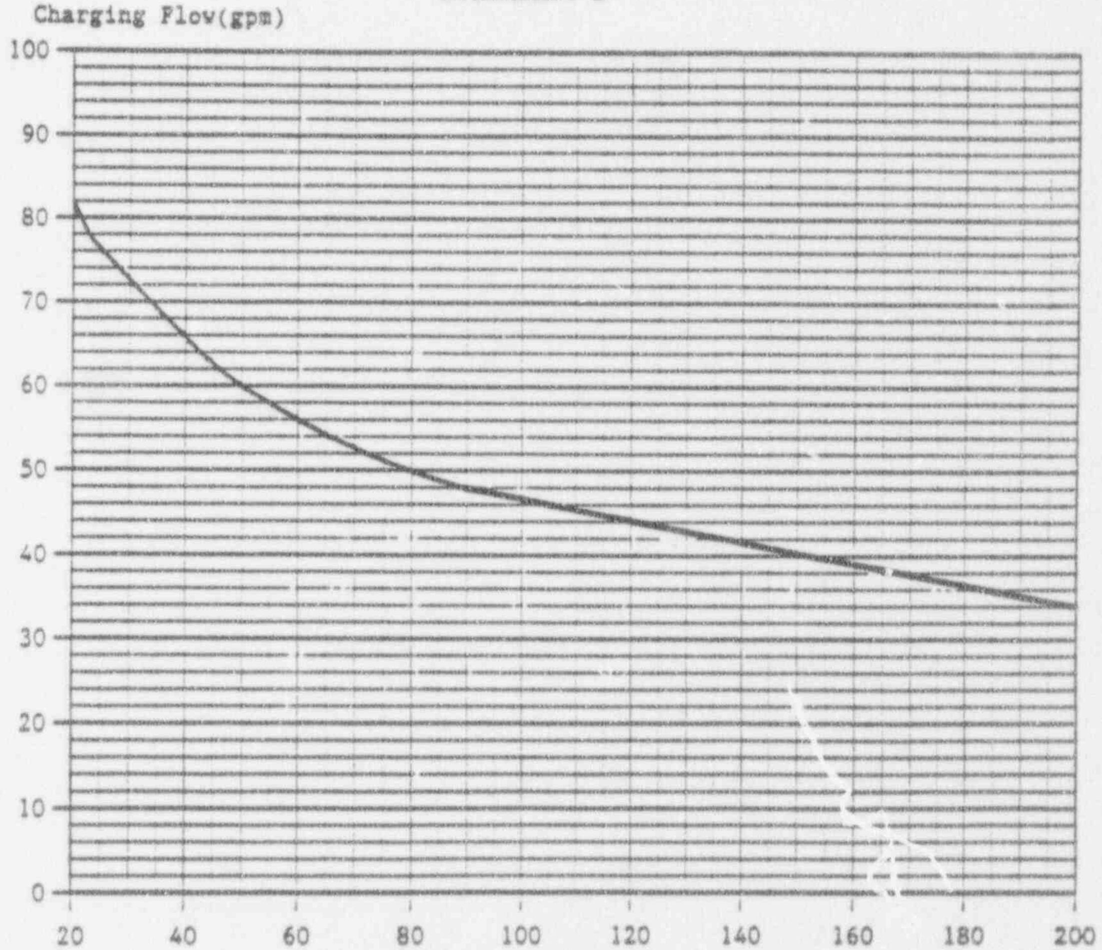
Number:	Title:	Revision number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
37	Evaluate Long Term Plant Status a. Maintain RHR in-service b. Maintain constant RCS level c. Consult plant engineering staff	

-END-

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

ATTACHMENT H



APPROXIMATE MAKEUP FLOW
TO MAINTAIN RCS INVENTORY

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

ATTACHMENT I
CONTAINMENT CLOSURE PROCEDURE

This section provides the guidance necessary to close up the containment should RHR be lost.

PROCEDURE:

STEP 1. Notify the Maintenance Supervisor on shift that RHR has been lost. Instruct maintenance to close penetrations that are logged open on Figure D2-5.

STEP 2. Manually initiate Containment Isolation Train A and Train B.

STEP 3. Verify the Containment Isolation Monitor lights are lit with exceptions.

STEP 4. Evaluate and rectify any unanticipated exceptions on the Containment Isolation Panel. An appropriate solution would be to close alternate isolation valves in the penetration. Systems that are pressurized to greater than 40 psig are acceptable and do not require isolation.

BACKGROUND INFORMATION FOR

E-4, CORE COOLING FOLLOWING LOSS OF RHR FLOW

SUMMARY FOR E-4

When operating in a reduced inventory condition, a loss of RHR flow can result in a rapid increase in RCS temperature due to decay heat generation in the core. If RHR flow is not restored in a timely fashion, this condition could lead to core damage if adequate water inventory were not maintained. This procedure assures the maintenance of adequate inventory to keep the core covered should a sustained loss of RHR flow be experienced.

BASIS FOR ACTIONS IN E-4

Caution Step 1

While this procedure assures adequate water inventory, the ultimate goal is to restore RHR flow as soon as possible.

Note Step 1

A complete loss of RHR capability through forced or natural circulation requires an ALERT per F3, condition 12.

Step 1

If all steam generator primary manways are installed, the RCS can be filled to one foot below the reactor vessel flange.

Step 2 and 3

If reactor coolant system is intact, a secondary heat sink will remove decay heat.

Step 4

Containment closure prevents the release of radioactivity should the reactor coolant temperature reach saturation and begin to boil.

Step 5

Since a heatup of the RCS could cause a pressurization of the system, the tygon hose level indicator must be isolated to prevent inventory loss.

Caution Step 6

Train separation of the RHR system may exist depending on plant condition.

Step 6

If RHR flow was lost due to low inventory in the RCS, this method of restoring inventory is not only the fastest, but also reestablishes RHR pump suction requirements to facilitate the regaining of RHR flow.

Step 7

If RHR pumps are unavailable, the dedicated SI pump can be used to inject directly into the vessel.

Step 8

Two charging pumps are required to assure that the injection flow exceeds the amount of inventory boiloff once the temperature reaches saturation. See Attachment H.

Step 9

Maintenance of this total inventory would assure adequate heat removal from the core should boiling occur.

Step 10

Should boiling occur, radioactivity will be released to containment through RCS vent paths.

Step 11

Radiation levels and temperature should be closely monitored and appropriate precautions taken by any personnel required inside containment.

Step 12 and 13

Once RHR flow has been restored, through continuing attempts, the need for increasing RCS inventory may no longer exist.

Step 14

When saturation is reached in the RCS, steam will condense in the steam generator tubes thereby reducing the pressurization rate of the RCS.

Step 15

Should boiling occur, radioactivity will be released to containment through RCS vent paths.

Step 16

Radiation levels and temperature should be closely monitored and appropriate precautions taken by any personnel required inside containment.

Step 17 and 18

Once RHR flow has been restored, through continuing attempts, the need for increasing RCS inventory may no longer exist.

Step 19

Containment closure prevents the release of radioactivity should the reactor coolant temperature reach saturation and begin to boil.

Step 20

Should boiling occur, radioactivity will be released to containment through RCS vent paths.

Step 21

Radiation levels and temperature should be closely monitored and appropriate precautions taken by any personnel required inside containment.

Step 22

When the RCS temperature reaches saturation, the boiloff into the containment atmosphere will require the containment cooling system to remove the decay heat.

Step 23

If the nozzle dams are installed, the RCS inventory can be increased to one foot below the reactor vessel flange. If the nozzle dams are not installed, raising the water level will result in reactor coolant overflowing the primary manway openings into containment.

Caution Step 24

Train separation of the RHR system may exist depending on plant condition.

Step 24

If RHR flow was lost due to low inventory in the RCS, this method of restoring inventory is not only the fastest, but also reestablishes RHR pump suction requirements to facilitate the regaining of RHR flow.

Step 25

If RHR pumps are unavailable, the dedicated SI pump can be used to inject directly into the vessel.

Step 26

Two charging pumps are required to assure that the injection flow exceeds the amount of inventory boiloff once the temperature reaches saturation. See Attachment H.

Step 27

Maintenance of this total inventory would insure adequate heat removal from the core should boiling occur.

Step 28 and 29

Once RHR flow has been restored, through continuing attempts, the need for increasing RCS inventory may no longer exist.

Note Step 30

Charging flow is initiated at desired flow to assure the water inventory is sufficient to match the core boiloff rate. Excessive flow may cause coolant to overflow through the SG primary manways.

Step 30

The 200°F limit assures the average coolant temperature remains below saturation with instrument error factored in.

Note Step 31

Collapsing of voids in the RCS when RHR flow is restored will cause a decrease in the level indication.

Step 31 and 32

Once RHR flow is restored, flow should be limited since the void collapse in the RCS could cause the subsuquent loss of RHR pump suction as level decreases.

Step 33

Charging should not be stopped until all voids have been collapsed and level is an accurate reflection of RCS inventory.

Step 34 and 35

The 3/4 loop level assures the RHR pump suction is maintained but is below the primary manway overflow level.

Step 36

Once RHR flow is restored, flow is increased to cool the RCS to the desired temperature.

Step 37

An evaluation is required to assess and core damage that may have occurred, to revise procedures and/or repair equipment to prevent recurrence of the loss of RHR flow.

Attachment 2 to 306/92-002

Steps in Procedure E-4 Relevant to the February 20, 1992 Loss of RHR

Number:	Title:	Revision number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
2320 Caution	*Attempts to restore RHR flow SHALL be performed in parallel with this procedure.*	
NOTE	*The conditions of the plant during this procedure may involve the Emergency Plan. A recommendation should be made to the Shift Supervisor to consider classification per F3-2.*	
1	Check All Steam Generator Primary Manways - INSTALLED-(D2, Table-2)	Go to Step 19.
2	Verify RCS - INTACT	Go to Step 4
3	Go to Step 14 → TO STEP 14	
4	Initiate Containment Closure Per 2E-4, ATTACHMENT I	
5	Isolate Tygon Tube: a. Close instrument block drain valve on refueling canal level transmitter LT-24128	

Number:	Title:	Revision number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
11	Continue To Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation	
12	RHR Flow - RESTORED	Continue attempts to restore RHR flow AND Return to Step 9.
13	Go To Step 35	
FROM STEP 3 → 14	Establish Secondary Heat Sink In At Least One SG:	
	a. Feed SG(s) using AFW to maintain 70% wide range level	a. IF SG recirculation rig attached, THEN feed SG per D27.16.
	b. Place SG PORV controller(s) in "MANUAL"	
	c. Open SG PORV(s)	c. Locally open SG PORV(s). IF SG PORV(s) can NOT be locally opened, THEN establish SGB to remove decay heat.
15	Evacuate Containment Of Non-essential Personnel	
16	Continue To Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation	
17	RHR Flow - RESTORED →	Continue attempts to restore RHR flow AND Return to Step 6. → STEP 6

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED

Caution *If aligning RHR to refill RCS, then valve alignments should be performed on only one train.*

From step 17

6 Increase RCS Inventory Using RWST Supply to RHR Pump:

a. Open RWST supply to RHR pump suction to fill RCS: — a. Go to Step 7.

- Train A MV-32187

-OR-

- Train B MV-32188

b. Open RHR to reactor vessel nozzle valve: — b. Go to Step 7.

- Train A MV-32167

-OR-

- Train B MV-32168

2326 c. Start associated RHR pump to refill RCS to one foot below reactor vessel flange (728'6") — c. Go to Step 7.

2329 d. Stop RHR pump

e. Go to Step 9

To step 9

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
7	Increase RCS Inventory Using SI Pump:	
	a. Open SI vessel injection valves: • MV-32170 -OR- • MV-32172	a. Go to Step 8.
	b. Start designated SI pump	b. Go to Step 8.
	c. Refill RCS to one foot below reactor vessel flange (728'6")	c. Go to Step 8.
	d. Stop SI pump	
	e. Go to Step 9	
8	Increase RCS Inventory Using Charging System	Go to Step 14.
	a. Verify two charging pumps running	a. Start charging pumps as necessary.
	b. Maximize charging flow	
	c. Verfiy RCS level increasing	c. Go to Step 14.
From step 6 → 9	Provide Makeup To RCS As Necessary To Maintain Level One Foot Below Reactor Vessel Flange (728'6")	
10	Evacuate Containment Of Non-essential Personnel	

LER NO: 306/92-002

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
11	Continue To Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation	
12	RHR Flow - RESTORED	Continue attempts to restore RHR flow <u>AND</u> Return to Step 9.
13	Go To Step 35 TO STEP 35	
14	Establish Secondary Heat Sink In At Least One SG:	
	a. Feed SG(s) using AFW to maintain 70% wide range level	a. <u>IF</u> SG recirculation rig attached, <u>THEN</u> feed SG per D27.16.
	b. Place SG PORV controller(s) in "MANUAL"	
	c. Open SG PORV(s)	c. Locally open SG PORV(s). <u>IF</u> SG PORV(s) can <u>NOT</u> be locally opened, <u>THEN</u> establish SGB to remove decay heat.
15	Evacuate Containment Of Non-essential Personnel	
16	Continue To Monitor Containment Conditions To Determine Necessity For Total Containment Evacuation	
17	RHR Flow - RESTORED	Continue attempts to restore RHR flow <u>AND</u> Return to Step 6.

LER NO: 306/92-002

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
	NOTE *The following steps may initiate charging flow at a rate slightly greater than the core boil off rate. See Attachment H.*	
30	Check Incore Thermocouples - LESS THAN 200°F	Makeup from RWST using charging pump(s). Adjust charging flow rate as necessary to maintain RCS inventory - See ATTACHMENT H. <u>IF</u> charging pump makeup <u>NOT</u> available, <u>THEN</u> makeup using gravity feed from RWST via RHR pump. Continue with Step 31.
	NOTE *Restoration of RHR flow from this condition may result in a rapid level decrease as voids collapse in the RCS due to cooling in the RHR heat exchanger.*	
31	RHR Flow - RESTORED	Continue attempts to restore RHR flow <u>AND</u> Return to Step 30.
32	Throttle RHR Flow To 500 gpm	
33	Check Incore T/Cs - LESS THAN 195°F	Do not isolate charging until incore T/Cs are less than 195°F.
34	Fill RCS To 3/4 Loop Level (723'11.75")	
FROM STEP 13 → 35	RCS Level - AT 3/4 LOOP LEVEL	Go to Step 34.
	a. Stop filling	When RCS at 3/4 loop level perform step 35a
36	Increase RHR Flow To 1000 gpm	

Number:	Title:	Revision Number:
2E-4	CORE COOLING FOLLOWING LOSS OF RHR FLOW	REV. 2

STEP	ACTION/EXPECTED RESPONSE	RESPONSE NOT OBTAINED
37	Evaluate Long Term Plant Status a. Maintain RHR in-service b. Maintain constant RCS level c. Consult plant engineering staff	

-END-

LER NO: 306/92-002

D.7 LER Number 311/92-017

Event Description: Unrecognized Loss of Annunciators

Date of Event: December 13, 1992

Plant: Salem 2

D.7.1 Summary

At 2122 hours on December 13, 1992, operators at Salem 2 observed that the control room overhead annunciator system was not functioning. It had been inoperable since 1946 hours because of operator error. The system was returned to service at 2123 hours. The plant remained at 100% power throughout the event.

D.7.2 Event Description

Salem 2 was at 100% power on December 13, 1992, and operators had used the annunciator system's remote configuration work station (RCWS) to obtain information on spare annunciator A-45, which had alarmed three times earlier in the day. At 1946 hours the operator entered "Ctrl-L" twice on the RCWS keyboard. This rendered the overhead annunciator lights inoperable but allowed the RCWS to continue functioning. The only indication of the annunciator system's failure was that the annunciator system cathode-ray tube (CRT) display clock stopped updating. Between 1946 and 2122 hours, there were three opportunities to discover the problem with the annunciator system. In one case, a radiation monitor alarmed, but the associated "RMS TRBL" annunciator did not actuate. In the other two cases, the alarm typer typed out an alarm, but the associated annunciator failed to actuate. At 2122 hours, following the third failure, an operator noted that the overhead annunciator system was not functioning. The operator reset the system at 2123 hours, and four annunciators immediately actuated.

The NRC formed an augmented inspection team (AIT) in response to this event. The team found that "there were no safety consequences due to the loss of the overhead annunciator system. However, the undetected loss of the overhead annunciator system could delay operator response or increase the likelihood of errors while responding to abnormal plant conditions."

D.7.3 Additional Event-Related Information

The annunciator systems for both Salem units were replaced during the first half of 1992. The new systems consist of a microprocessor-based annunciator system, a RCWS, a control room CRT, 480 annunciator tiles, and two sequential event recorders (SERs). One SER is the primary, and the other is the hot standby recorder.

Investigation revealed that the main controller will stop sending events to all devices connected to the system when (1) the RCWS is in the terminal emulation condition, (2) the system's switches are in a given configuration, and (3) specific keystrokes are entered into the RCWS. While attempting to obtain information on the A-45 alarm, the operator inadvertently typed "Ctrl-L" twice instead of the desired "Alt-L". These keystrokes and the system configuration emulated the password-protected software used to modify the system software. This put the system in a "waiting for keyboard input" condition. The system halted, but did not switch over to the backup processor, since the primary processor was behaving as expected. The system gave no indication to the operator that it had halted other than the failure of the CRT clock to update. The "Overhead Annunciators Operation" procedure directed the operators to verify the correct annunciator system switch positions before using the RCWS.

The annunciator system vendor indicated that Kewaunee, Sequoyah, Three Mile Island, and Susquehanna have similar annuciator systems.

D.7.4 Modeling Assumptions

This event was not modeled as an Accident Sequence Precursor.

D.8 LER Number 443/92-002

Event Description: Incorrect RHR Flow Rate in Technical Specifications

Date of Event: February 12,1992

Plant: Seabrook

D.8.1 Summary

An inconsistency was discovered between the test procedure acceptance criterion for residual heat removal (RHR) injection flow of 4350 gpm and the technical specifications value of 2828 gpm. Subsequent investigation showed that the proper technical specification value should be 3868.4 gpm. The possibility existed for the RHR system to be modified such that the proper technical specification acceptance criterion would not be met. However, no such modifications were made, and the flow rate remained above the required limits at all times.

D.8.2 Event Description

During a routine review of the RHR cold shutdown testing procedure, an inconsistency was noted between the test procedure acceptance criteria for RHR injection flow of 4350 gpm and the technical specification value of 2828 gpm. Upon further investigation, it was determined that the acceptance criterion for flow through three of the four RHR injection lines should be 2828 gpm, and for flow through all four lines, the acceptance criterion should be 3868.4 gpm. Therefore, the technical specification value should have been 3868.4 gpm. The system was originally designed and tested against an acceptance criterion of 3868.4 gpm. As a result, the system flow rate should be acceptable provided no flow-altering modifications were made to the system.

However, check valves had been installed in the suction lines to the RHR pumps in 1989. Post-modification testing, conducted with the pumps throttled, indicated a flow rate of 4012 gpm for train A and 3776 gpm for train B. Testing conducted during the 1991 outage indicated flow rates of 5013 gpm for train A and 4696 gpm for train B. The 1991 testing was conducted with the reactor vessel head off and was not performed pursuant to the technical specification surveillance requirement. However, the flow rates obtained using both trains exceeded 3868 gpm. This verified that operability concerns or design basis limits did not exist.

The RHR system was not rendered inoperable as a result of the technical specification error. However, the potential existed for a modification to be made to both trains of RHR which would have rendered it incapable of performing its emergency core cooling system (ECCS) function.

D.8.3 Additional Event-Related Information

The original draft technical specification, based on revision 3 of the Westinghouse Standard Technical Specifications (STS), contained an acceptance value for three-loop-injection operation of 2828 gpm. The acceptance value for four-loop-injection operation was to be provided at a later date. Subsequent drafts of the technical specification were in the STS revision 4 format, and the flow for four-loop injection was incorrectly listed as 2828 gpm. This error was carried through further revisions of the technical specification, including the version issued with the plant's operating license.

D.8.4 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

D.9 AIT Number 530/92-019

Event Description: Loss of Plant Annunciators

Date of Event: May 4, 1992

Plant: Palo Verde 3

D.9.1 Summary

On May 4, 1992, Palo Verde 3 was operating at 100% power when an electrician inadvertently shorted a 24-Vdc annunciator system lead to a 480-Vac power bus. The ensuing fault caused the immediate failure of non-safety-related control room annunciators and the eventual failure of the plant monitoring computer systems. Load was reduced to 70% to ensure compliance with core thermal limit requirements, and six additional operators were stationed in the control room to monitor plant instrumentation in lieu of annunciators. After approximately 2.5 d of repair, 95% of the annunciators were considered to be functional, and a plant shutdown was commenced. The plant was tripped from 20% power to complete the shutdown on the following day.

D.9.2 Event Description

While Palo Verde 3 was operating at 100% power, a utility electrician, who was performing maintenance work on 480-Vac turbine building load center 3E-NGN-L18, temporarily disconnected an electrical lead associated with the 24-Vdc plant annunciator system. This lead accidentally contacted the load center 480-Vac power bus, resulting in failure of the plant annunciator system and degradation of the plant computer core operating limit supervisory system. In addition, the main generator voltage regulator shifted from ac (automatic) control mode to dc (manual) mode.

After the short circuit the annunciator window status was as follows:

Section	Status
BO1	All windows lit and inoperable
BO2	Operable
BO3	Operable
BO4	All windows dark and inoperable
BO5A	All windows lit and inoperable
BO5B	All windows lit, then became dark and inoperable
BO6	All windows lit brightly, then became dark and inoperable
BO7	All windows lit, then became dark and inoperable

Initially, plant operators were able to view incoming alarms on the plant computer, but within 3 or 4 h the computer became inoperable, probably as a result of alarm system switching transients, data "contention" problems, and instrument grounds. Prior to this, the core monitoring computer core operating limit supervisory system (CMC COLSS) and the core element assembly calculator number 2 (CEAC #2) failed. An alert was declared 3.75 h after the annunciators failed. Six additional operators were added to the operating crew to assist in monitoring plant instrumentation, and a program was begun to verify compliance with core thermal limits by hand calculation. Power was reduced to 70% in accordance with technical specification requirements for loss of COLSS. During the power reduction, the generator volts/hertz trip timing light began flashing, and generator excitation switchover to manual was detected. Excitation was adjusted, and the trip was averted. Unnecessary activities on any of the three units which could initiate a Unit 3 transient were suspended.

Troubleshooting of plant annunciator systems and plant computer alarm inputs resulted in replacement of 77 logic cards, 7 relay cards, several fuses, and a power supply transformer. Most of the annunciator lamps on boards 4, 6, and 7 had burned out. The combination of failed lamps indicated that a voltage surge in annunciator cabinet 2 had affected circuits associated with cabinet 1 (wiring for cabinet 2 passes through cabinet 1). Approximately 90% of the failed logic cards had shorted output lamp driver transistors. Most failed relay cards had failed input diodes, shorted capacitors, and burned traces. No damage to the safety-related annunciator system was detected, as its design incorporated optical isolation of inputs and outputs.

Once the annunciator system was returned to service, a program was begun to verify that it was operating correctly and that the associated input circuits had not been damaged. Operators logged incoming alarms, and the associated conditions were checked to verify that an alarm would be expected. In addition, a statistical sampling of field inputs to alarm circuits were tested to ensure that the expected alarms were received. Initially, operators intended to sample 57 of the approximately 2100 field inputs. If no failures were observed in a sample of this size, this would imply that no more than 5% of the alarm inputs were inoperable, at the 95% confidence level. When one failure was observed in the first sampling, additional inputs were tested and the results were aggregated with the initial sampling. As no additional failures were noted for a total sample size of 91 inputs, the annunciator system was considered to be operable. This approach requires the annunciator system failures to be random. However, failures such as those observed during the event can occur along pathways, and an assumption of randomness may be inappropriate.

While the repairs were being performed, operators used the plant simulator to rehearse a plant shutdown with loss of annunciators. Because it was considered a low probability event, no training had previously taken place for loss of all annunciators. Also, prior to this event, loss of all annunicators could not be modeled on the simulator.

Once the annunciators and plant computer systems were returned to service, an orderly plant shutdown was begun. Approximately 3 d after the start of the event, the reactor was manually tripped from 20% power to complete the shutdown.

AIT NO: 530/92-019

D.9.3 Modeling Assumptions

This event was not modeled as an accident sequence precursor.

APPENDIX E: POTENTIALLY SIGNIFICANT EVENTS THAT WERE CONSIDERED IMPRACTICAL TO ANALYZE

E. POTENTIALLY SIGNIFICANT EVENTS THAT WERE CONSIDERED IMPRACTICAL TO ANALYZE

Thirty-nine licensee event reports (LERs) have been identified as potentially significant but impractical to analyze. Such events are believed capable of impacting core damage sequences. However, they involve component degradations where the extent of the degradation could not be determined or where the impact of the degredation on plant response could not be ascertained.

For many events classified as impractical to analyze, an assumption that the affected component or function was unavailable even over a 1-yr period (as would be done using a bounding analysis) resulted in the conclusion that a significant event existed. This conclusion was not supported by the specifics of the event as reported in the LER or by the limited engineering evaluation performed in the Accident Sequence Precursor (ASP) Program. A reasonable estimate of significance for such events requires far more analytical resources than can be applied in the ASP Program. Brief descriptions of these events are provided in Table E.1.

Table E.1. Events identified as potentially significant but impractical to analyze.

LER Number	Title/Summary
155/92-004	**Arcing Cable Found in Safety-Related Cable Tray at Big Rock Point.** The non-safety-related cable feeding a reactor coolant pump motor heater had become brittle with age and subsequently cracked. Non-safety-related cables in this cable tray were either replaced or deenergized.
155/92-006	**Inoperable Containment Water Level Monitors at Big Rock Point.** Two containment water level transmitters were returned from the vendor with water in the sensing line instead of silicone. The water could have flashed to steam during a design basis event degrading the accuracy of the transmitters.
213/92-018 263/92-008 282/92-008 298/92-011 352/92-012 445/92-011	**Failure of Thermo-Lag 330 to Pass Fire Endurance Tests at Multiple Sites.** Testing by the NRC and several utilities has indicated that Thermo-Lag 330 may be inadequate for meeting 1-h and 3-h penetration fire barrier requirements. Degradation of the penetration fire barrier could result in the loss of redundant electrical distribution trains in the event of a fire, thus negatively affecting a plant's ability to achieve and maintain a safe shutdown condition. This generic deficiency has been documented in NRC Bulletin 92-01 and its supplements.
237/92-003	**Design Deficiency for Flood Analysis at Dresden 2.** Design basis flooding in the circulating water intake structure could cause the Unit 2/3 diesel generator cooling water pump to be inoperable. An unsealed power transfer junction box containing control circuitry was located below postulated flood level.
249/92-013	**Motor Control Center (MCC) Distribution Panel Lost at Dresden 3.** One phase of a 120/208-V distribution panel for an MCC was lost because of damage at installation. Similar damage, as yet undiscovered, could exist in other circuits.

Table E.1. Events identified as potentially significant but impractical to analyze.

LER Number	Title/Summary
255/92-028	**Diesel Generator Room Cooling Inadequate at Palisades**. Only one of two fans in the diesel generator cooling room is powered from a class 1E source. This one fan is inadequate to cool the diesel generator room to design basis requirements when the outdoor temperature exceeds 75°F.
270/92-002	**High Lift Pressure for Both Pressurizer Safety Relief Valves (PSRVs) at Oconee 2.** For unknown reasons the lift setpoint of the PSRVs drifted. Testing determined that the valves would not lift within 10% of the setpoint (American Society of Mechanical Engineers (ASME) boiler and pressure vessel code requirement).
270/92-003	**Cold Shutdown Low-Temperature Overpressure Protection (LTOP) Not Maintained at Oconee 2**. During startup LTOP was not established. This resulted in the potential for brittle fracture of the pressure vessel had the high-pressure injection system been operated.
277/92-003	**Potential for Flooding of Residual Heat Removal (RHR) Rooms B and D at Peach Bottom 2**. The discharge check valves of the RHR sump pump were replaced with pipe sections. A pipe break in either RHR Room A or C could have resulted in the flooding of Rooms B and D, thus rendering three RHR pumps inoperable.
281/92-003	**Two Control/Switchgear Room Chillers Unavailable at Surry 2**. One of the three main control room/emergency switchgear room chillers ("C") was off line because of high-heat-exchanger differential pressure. This was concurrent with the "B" unit being declared inoperable while the emergency diesel generator (EDG) that supplies it with power was down for maintenance. The remaining chiller ("A") would have been sufficient to mitigate a design basis accident had there been a concurrent loss of offsite power.
282/92-002	**No Redundant Fusing for Some ESF Control Power Circuits at Prairie Island 1**. The dc control power for the safety injection, RHR, containment spray, component cooling, and auxiliary feedwater pumps was not protected by redundant fusing. These circuits are powered from the 4160-Vac switchgear. A fire in the control room could damage these circuits before the local/remote switch was moved to the "local" position. Control could not be reestablished without a fuse replacement.
282/92-005	**Fire in Relay Room Could Prevent Diesel Cooling Water Pump to Start at Prairie Island 1.** In the event of a fire in the control room, a resultant hot short would continuously energize the shutdown relay for the No. 12 diesel-driven cooling water pump (service water). This would result in an inability to start the pump and a subsequent loss of cooling water.

Table E.1. Events identified as potentially significant but impractical to analyze.

LER Number	Title/Summary
282/92-006	**Error in Control Room Fire Analysis at Prairie Island 1**. In the event of a control room fire, a hot short could develop and cause spurious operation of the head vent solenoid valve(s) in the reactor vessel. The occurrence of such a short in two valves in series could open the valves and create a leak path from the reactor coolant system. Such leakage could result in a decrease of the pressurizer level beyond the ability of the charging pump to make up the loss and drop the pressurizer level off-scale.
285/92-017	**Cracking of Cam Followers on General Electric Type SMB Control Switches at Fort Calhoun.** During an inspection, cracks were found on the Lexan cam followers for GE SMB 4160-V switchgear control switches. Of the 55 switches inspected, 40 were cracked, and 21 of these required control switch replacement. The control switches for the following equipment required replacement: the two EDG output breakers, one low pressure safety injection pump, two raw water cooling pumps, offsite power supplies to the two safeguards buses, the motor driven auxiliary feedwater pump and other safety-related equipment.
286/92-006	**Lack of Fuse Coordination Renders Two Diesel Generators Potentially Unavailable at Indian Point 3**. Design deficiencies identified in the 125-Vdc power system created the potential for deenergizing the distribution panels that supply power to two of the three EDGs. This would render the EDGs inoperable.
295/92-010	**Second-Level Undervoltage Setpoint Set Nonconservatively at Zion 1.** Analysis of the second-level under-voltage protection system determined that the existing under-voltage set-point was nonconservative. Consequently, several engineered safeguards features were considered inoperable because of the low voltages. These components included two vent fans in the service water area, four vent fans in the EDG room, and two penetration pressurization air compressors.
298/92-009	**Appendix R Concerns With Motor Operated Valves (MOVs) at Cooper Station.** An engineering review of the alternate shutdown capability determined that during a control room fire, a hot short was possible in the control circuits of certain MOVs. This short could bypass the torque switch and limit switch and cause the actuator to cycle the valve out of its accident mitigation position, potentially jeopardizing safe shutdown of the unit.
317/92-002	**EDG Sequences Incorrectly Designed at Calvert Cliffs 1**. Load sequencer design could allow several large loads to attempt a simultaneous start. The total voltage drop associated with such a transient could cause failure and/or damage to some or all of the equipment attempting to start.

Table E.1. Events identified as potentially significant but impractical to analyze.

LER Number	Title/Summary
321/92-003	**Solenoid Valve Failure Causes Loss of Emergency Equipment Room Coolers at Hatch 1.** Failure of two solenoid valves caused the Core Spray and RHR room cooler isolation valves to fail in the closed position. The valves failed to open when de-energized. The apparent cause is the gelling of an unanalyzed lubricant used in the assembly process. The room coolers were not immediately unavailable, however it is postulated that at some point the room temperature would exceed the design limit of 148°F.
323/92-001	**Diesel Generator Field Circuitry at Diablo Canyon Does Not Meet Appendix R Criteria.** Appendix R design basis review identified seven conditions with the potential to degrade the safe shutdown capability of the plant. Six of the seven incidents involved circuit separation or isolation; one incident involved inadequate protection from the Thermo-Lag 330 fire barrier.
325/92-016	**EDG Pedestal Seals at Brunswick 1 Violate Appendix A and R.** The oil collection system for the EDGs was leaking and saturated the seismic gap seals and fire barrier seals with oil. Rotofoam 300 was used for the seal around the EDG pedestals. While Rotofoam 300 is not combustible at temperatures under 700°F, a fire could cause the foam to melt through the seismic gap and drip into the cable trays on the elevation below. Loss of the seals could also compromise the halon fire protection system on the level below.
325/92-017	**480-V Substation Breaker Problems at Brunswick 1.** The main contacts for a 480-V substation breaker were closing but not exerting full contact pressure against the stationary contacts. Closure of this type of breaker has been previously addressed in a 1989 10 CFR 21 report. The safety consequences of this event have not been analyzed by the utility.
333/92-004	**Deficiencies in the Cable Tunnel Fire Protection System at Fitzpatrick.** Safety-related 4160-V and 600-V cables connecting EDG switchgear, safety-related load centers, and MCCs are routed through tunnels that have inadequate fire protection. These tunnels also contain power and control cables for motor-driven emergency core cooling system pumps (RHR, low-pressure coolant injection, low-pressure core spray, RHR service water, and emergency service water). A fire in these areas could degrade the ability of the above systems to perform their safe shutdown functions.
333/92-015	**Postulated Fire-Related Safe Shutdown Deficiencies at Fitzpatrick.** Appendix R analysis identified seven deficiencies that could potentially degrade the safe shutdown capability of the plant. Analysis determined that fires within the design basis could render either power or control circuits for certain valves, pumps, or instruments inoperable.

Table E.1. Events identified as potentially significant but impractical to analyze.

LER Number	Title/Summary
333/92-017	**Deficiencies in Vent Duct Fire Dampers at Fitzpatrick.** Two dampers to the east and west electric bays were not installed with enough clearance to allow thermal expansion and thus prevent subsequent binding. There also is no indication of approval by a recognized rating organization (e.g., Factory Mutual or Underwriter's Laboratory). These rooms contain equipment required for safe shutdown of the plant. A fire in these areas could compromise the ability of this equipment to perform safe shutdown.
338/92-003	**RHR Suction Overpressure Relief Inadequate at North Anna 1.** The discharge from the RHR suction relief valve could flash to steam during a charging/letdown mismatch event. Flashing would reduce the flow capacity of the valve and thus degrade the valve's ability to protect the RHR system from overpressurization.
338/92-010	**EDG Fuel Oil Transfer Lines Not Missile-Protected at North Anna 1.** The fuel oil transfer lines for the EDGs are not missile-protected as required by design. Damage to a fuel transfer line could limit EDG operating time to the amount of fuel in the day tank (3 h), increase the possibility of a fire in the diesel generator building, or prematurely deplete the underground storage tanks.
344/92-010	**Low Temperature Overpressurization System Does Not Meet Licensing Basis at Trojan.** The backup air accumulators for the power operated relief valve do not meet the design basis. They are not capable of providing the required volume of air to mitigate a low-temperature overpressure protection event during the 10-min period when credit is taken for operator intervention.
353/92-003	**Watertight Door Left Open at Limerick 2.** A watertight door separating two RHR pump rooms was left open. A high to moderate energy pipe break in one room could potentially flood the other room. This door is also used for fire protection and could have permitted the spread of fire had one occurred.
361/92-001	**Main Steam Line Break Could Disable AFW System at San Onofre 2.** A break in the steam supply line to the turbine driven auxiliary feedwater pump could cause an unanalyzed harsh environment in piping tunnels. Essential valves for the motor driven AFW pumps are located in the piping tunnels. Failure of these valves could disable the motor driven AFW pumps, and with the loss of supply steam to the turbine driven pump would disable the AFW system.
368/92-004	**Foreign Material in Emergency Diesel Generator (EDG) Fuel Oil Tank at Arkansas Nuclear One 2**. Routine surveillance testing of the "A" EDG revealed a blockage of the day tank foot valve suction strainer. An oil absorber sheet was inadvertently left in the tank during previous maintenance. It is possible that the EDG would not be able to supply full load during a design basis event.

Table E.1. Events identified as potentially significant but impractical to analyze.

LER Number	Title/Summary
397/92-034	**Failure of ECCS Pump Room Penetrations Could Result in Common Mode Flooding at Washington Nuclear Plant 2**. Design analysis revealed that a fire barrier foam used on certain ECCS pump room seals was not qualified as water tight. Therefore, a common mode flood could effect all ECCS pump rooms. Subsequent evaluation revealed that door seal leakage could result in concurrent flooding of the pump rooms from stairwell flooding.
458/92-007	**Main Control Room Fire Common Mode Failure of Motor Operated Valves at River Bend 1.** A fire in the main control room could cause hot shorts in the valve circuitry which by-pass limit and torque switches. Without thermal overload protection, spurious operation may result in damage the valve and/or the operator.
528/92-010	**Postulated Fire-Related Safe-Shutdown Deficiencies at Palo Verde 1**. Non-safety fire protection detection and suppression circuits were not included in the Appendix R evaluation. A fire in one train, concurrent with a loss of offsite power, could result in the loss of the opposite train. This could result in a loss of HVac cooling for safe shutdown equipment.

APPENDIX F: LICENSEE EVENT REPORTS CITED IN APPENDICES B, C, AND D

This appendix contains Licensee Event Reports (LERs) cited in Appendices B, C, and D. The LERs are listed in order by docket and LER number.

Note that copies of LERs used in the ASP program are also used in other Oak Ridge National Laboratory programs and may contain markings made during work performed for those programs.

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
BIG ROCK POINT NUCLEAR PLANT	0 5 0 0 0 1 5 5	1 OF 0 1

TITLE (4)
AS-FOUND SETPOINT FAILURE (LOW) OF LIQUID POISON RELIEF VALVE RV-5049

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
0 1	0 9	9 2	9 2	0 0 2	0 0	0 2	0 7	9 2	N/A	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N
POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Robert J Alexander, Technical Engineer	6 1 6 5 4 7 - 6 5 3 7

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
B	B R	R V	L 2 6 5	N					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) — X NO

EXPECTED SUBMISSION DATE (15): MONTH / DAY / YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On January 9, 1992 @ 2300, testing results showed that a Liquid Poison System (LPS) equalization line relief valve did not meet the as-found relief pressure acceptance criteria (1655 psig vs a required 1950-2050 psig). Due to excessive seat leakage, the pressure test was not able to accurately determine the lift pressure. This condition could have affected the volume of poison solution delivered to the core and the establishment of a siphon in the equalizing line that assists in discharging the contents of the poison tank. The plant is in cold shutdown and the fuel has been removed from the reactor and placed in the spent fuel pool.

To correct the deficiency, the failed valve was replaced with another like relief valve and was accepted after testing.

Conservatively assuming the as-found value was the lift pressure of the valve, an analysis was performed to estimate the adequacy of the nitrogen system to supply sufficient liquid displacement fr m the LPS tank to initiate a siphon. Assuming the nitrogen system pressure w s reduced to 1500 psia, the analysis concluded that sufficient nitrogen was available to establish the required siphon for liquid poison injection.

To prevent recurrence, relief valve testing procedures will be revised to accommodate seat leakage testing after valve rebuilding/resetting and set point testing.

NRC Form 366 (9-83) OC0292-0003A-BL01

NRC Form 366A (9-83)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 8/31/85

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
BIG ROCK POINT NUCLEAR PLANT	0 5 0 0 0 1 5 5	9 2	— 0 0 2	— 0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

DISCUSSION OF EVENT

On January 9, 1992, a 3/4 by 1 inch Lonergran/Kunkle (L265) relief valve (RV) model number LCT 40/54, was tested to determine the as-found relief setpoint. (RV-5049 is designed to protect the 2 inch equalizing line entering the Liquid Poison Tank (BR;TK) from overpressurization by inadvertent nitrogen actuation. During this test, the plant was in the cold shutdown condition and defueled. The Liquid Poison System is not required to be operable in this configuration.

The acceptance criteria in the surveillance procedure required the as-found setpoint to be between 1950 and 2050 psig. When pressurized, the relief valve seat started to leak-by at 1655 psig and the setpoint could not be determined, therefore it is considered to fail the test. Two additional tests were performed, and the valve seat leaked by at 1590 and 1575 psig respectively.

On January 10, 1992 @ 1300, pursuant to 10 CFR 50.72(b)(2)(iii), the NRC Operations Center was notified of the potential condition that alone could have prevented the fulfillment of the safety function of the LPS, however further analysis was needed to arrive at a proper conclusion.

CAUSE OF THE EVENT

The valve failed the test because of seat leakage. The setpoint therefore could not be determined. The root cause has been determined to be a lack of post maintenance seat leakage testing, which would insure that the seat is clear of any foreign particles after rebuilding, resetting or relief testing. This line is normally not pressurized, preventing detection of seat leakage while in service.

CORRECTIVE ACTION TAKEN

A rebuilt relief valve was installed and leak tested after setpoint adjustment. The leak test insures absence of seat leakage prior to installation.

ACTION TAKEN TO PREVENT RECURRENCE

All relief valve procedures will be reviewed/revised to incorporate post maintenance seat leakage testing by October 1, 1992.

RV-5049 will be tested during the next Refueling Outage as part of the ASME Code Test Program to insure that corrective actions were effective.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

SAFETY SIGNIFICANCE

The LPS provides a means of rendering the reactor (RCT) subcritical and holding it subcritical during cooldown, in the event of control rod drive system (AA) failure. The LPS uses nitrogen pressurized to 2000 psig to rapidly inject its contents into the reactor vessel. No pumps (P) are utilized in the BRP design.

Upon initiation of the poison valves (INV) admitting full 2000 psig nitrogen pressure to the poison tank (TK), poison is injected into the reactor within a few seconds when the primary system (AD) is depressurized, however, if the primary system is at full or above operating pressure (1335 psig), the nitrogen volume is sufficient for injecting only a few gallons of solution. The driving force for the remaining volume is achieved from the static head due to the elevated position of the tank (roughly 30 feet above the reactor vessel) to establish a siphon.

The primary purpose of nitrogen pressurization is to insure positive displacement of poison solution when the reactor recirculation system is static, such as during refueling, when there is no initial driving head to establish a siphon through the discharge line in the poison tank.

An analysis was performed in 1974 to evaluate the capability of the nitrogen supply to the Liquid Poison System to initiate siphon. This evaluation assumed a maximum primary system pressure of 1600 psia (based upon the maximum safety valve setting for operation at 1350 psia) and concluded that sufficient nitrogen is available from the sixteen (16) size K bottles (TK) at a pressure of 1945 psia to establish the needed siphon action.

The risk assessment analyses performed to address the ATWS rule regarding recirc pump trips (1981) and alternate rod injection (1986) were reviewed with respect to the primary system pressures at which liquid poison was assumed to be functional. These analyses assumed that the LPS would not be functional for sequences in which the steam drum safety valves were cycling in order to control pressure. This assumption was based upon the lack of environmental qualification of the LPS components inside containment. Therefore it was assumed that the primary system pressure would reach about 1400 psia (the bypass valve (JI; FCV) will control the primary system pressure to about 1385 psia when at 100% open). It is important to note that Emergency Operating Procedures (EOP's) for ATWS events, require LPS initiation at a primary system pressure of 1360 psig.

To evaluate whether the LPS would have functioned during the previous operating cycle, it was assumed that at the point of initiation when nitrogen is admitted to the LPS tank the relief valve would lift diverting nitrogen until the valve reseated at some point below its lift pressure. To determine the minimum allowable reset pressure, the 1974 analysis was modified for a primary system pressure of 1400 psia. At this pressure the analysis concluded that the relief valve could stay open down to a pressure

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

SAFETY SIGNIFICANCE (Continued)

of 1500 psia and there would still be sufficient volume displacement to initiate a siphon in the LPS. Reviewing the data from the January 9, 1992 test shows that the lowest pressure at which leakage began to occur was 1575 psig. This is 90 psi above the 1500 psia value determined by the analysis, which concludes the system was functional under these conditions.

Under the extreme assumption that the LPS would not have functioned for any reason, Emergency Operating Procedures (EOP's) would have directed operators to utilize Alternate Boron Injection to shutdown the reactor.

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OC0292-0003A-BL01

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FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
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TITLE (4)
Excessive Fouling Rates Potentially Render Service Water Filters Inoperable

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
0 6	1 0	9 2	9 2	— 0 1 4 —	0 0	0 7	0 7	9 2		0 5 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

OPERATING MODE (9): 1	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10): 0 9 9	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
	20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
	20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
	20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
R. Kasuga, Engineer	AREA CODE 2 0 3 2 5 6 - 2 5 5 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

On June 8, 1992, at 0822 hours, with the plant in Mode 1, at 99 percent power, a routine monthly test of the service water filters indicated that the rate of debris accumulation on the filter elements caused the differential pressure across the filter to reach the maximum allowable in approximately two minutes. The filter design basis was re-evaluated and on June 10, 1992 it was determined that post-DBA, 30 minutes was required prior to reaching the maximum allowable differential pressure. At this time, the fouling rate test was reperformed and the filters found acceptable. The root cause of the event was excessive silt suspension in the Connecticut River from heavy rainfall. Corrective actions consist of (1) frequently testing the filter fouling rate to ensure the design basis is met; (2) stationing a dedicated operator at a filter bypass Motor Operated Valve (MOV) control switch if the design basis rate is exceeded and (3) evaluating a design change to provide automatic bypass MOV opening following a DBA. Due to the operability status of the filters between June 8 and June 10 being unknown, this event is being conservatively reported under 10CFR50.73(a)(2)(i)(B) since it may have resulted in a condition prohibited by the plant's Technical Specifications.

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NRC Form 366A (9-83)

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND INFORMATION

The two service water filters (EIIS Code: FLT) are part of the containment air recirculation (CAR) fan cooling system (EIIS Code: BK) which is required to reduce reactor containment pressure after a design basis accident (DBA). During normal operations, one filter is in service and the other is in standby. These filters remove particulate matter from the cooling water to the CAR fan cooling coils and motor coolers. The filters have a non-safety grade backwash system which runs continuously to extend the time between filter plugging. During normal operation when the in-service filter becomes clogged, as evidenced by operator surveillance and/or a low-flow alarm on the line from the CAR fan coolers, an operator is dispatched to manually switchover to the standby unit thus isolating the clogged filter for cleaning. The filters are equipped with motor-operated bypass valves which provide the capability of remotely bypassing the filters if they become inoperable during an accident condition. Technical Specification 3.6.2 requires all four CAR fan units to be operable in Modes 1 through 4.

EVENT DESCRIPTION

On June 8, 1992, at 0822 hours, with the plant in Mode 1, at 99 percent power, a routine monthly test of the service water filters indicated that the rate of debris accumulation on the filter elements caused the differential pressure across the filter to reach the maximum allowable in approximately two minutes. Although this test was strictly for data gathering to support ongoing service water analyses, the rapid fouling rate prompted an expedited evaluation of the filter design basis. This evaluation was completed on June 10, 1992 and it was determined that post-DBA, CAR cooler operation with filter differential pressure below the maximum allowable differential pressure is required for 30 minutes to maintain acceptable containment temperatures and pressure. At this time, the fouling rate test was reperformed and the filters found acceptable. Over the next several days, the river conditions caused the fouling rates to fluctuate between 25 minutes and 2 hours. Each time the fouling rate failed to meet the design basis, a dedicated operator was stationed at a bypass MOV switch to ensure a maximum opening response time of 10 minutes.

CAUSE OF THE EVENT

The root cause of this event was excessive silt suspension and debris in the Connecticut River caused by heavy rains.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

SAFETY ASSESSMENT

The potential for rapid fouling of the service water filters to the point where insufficient flow may have been provided to the containment air recirculation coolers is reportable under 10CFR50.73(a)(2)(i)(B) as operation in a condition prohibited by the Technical Specifications.

In the event of a LOCA or main steam line break inside containment, the containment air recirculation (CAR) coolers are required to operate at a specified capacity to limit the peak pressure and temperature inside containment so that containment structural and equipment qualification limits are not exceeded. The design basis containment analysis assumes a CAR cooler heat removal rate, based on a specific cooler flow rate and 90 degree service water temperature, that is a function of the containment temperature. In order to meet the assumed flow rate, system pressure drop must be maintained within specified limits. If the service water filters become plugged to a greater extent than assumed in the analysis, service water flow to the CAR coolers could drop below the flow rate assumed in the analysis.

The pressure drop across the service water filters must be maintained relatively low in order to ensure adequate post accident heat removal. Although the allowable pressure drop has only a very minor effect on normal flow rates through the coolers, analysis has shown that the CAR flows in an accident condition are very sensitive to fouling of the filters. This is due to the fact that the temperature of the water exiting the fan coolers (in the accident case) would be above saturation temperature at atmospheric conditions. When the water passes through the fan cooler return throttle valves, flashing could occur if pressure is not maintained above saturation. Excessive flashing of the service water in the CAR cooler discharge line would, in turn, result in a reduction of cooler flow to less than assumed in the analysis.

The design basis containment analysis assumes that one CAR cooler is operating at one minute, two at ten minutes, and three at fifteen minutes following an accident. The coolers are assumed to be operating at their design heat removal capacity. Due to the potential for excessive clogging of the service water filters, in the event of a LOCA or steam line break, the coolers could have been operating at less than design heat removal until the point where the operator opened the motor operated bypass valves. This action is currently specified in EOP E-1, Loss of Reactor or Secondary Coolant, if the automatic filter backwash mechanism is not operating. Further, if containment heat removal were inadequate due to filter fouling and containment pressure exceeded

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

35 psig (containment design is 40 psig), the Safety Parameter Display System critical safety function status tree would direct the operator to Emergency Operating Procedure FR-Z.1, Response to High Containment Pressure, which would also require that the filter bypass MOV be opened to establish adequate service water flow to the CAR coolers.

However, the standard assumption for operator action outside the control room is 30 minutes. Thus, it would have been possible for post accident heat removal to be less than assumed for up to 30 minutes. While analyses have shown that no cooling for up to 10 minutes would not result in exceeding current containment and environmental qualification limits, this would not be true with no cooling for 30 minutes. Although the flow to the CAR coolers would have been less than assumed, there would still have been substantial flow and heat removal available. However, since the effect on flow and heat removal that would have resulted from excessive filter clogging for 30 minutes is not known, it must be assumed that flow would not have been adequate.

At the time of the event, the service water temperature was below 70 degrees. This is significantly less than the 90 degrees assumed in the analyses for the CAR coolers which were used to establish acceptable clogging limits. This would prevent or partially offset the reduction in flow that would result if flashing were to occur in the return lines. Further, the short term containment response is driven mostly by passive heat sinks rather than active heat removal. Thus, based on the low river temperature at the time of the event, the fact that some flow would still have been available to the CAR coolers, and the ability of the operator to take manual action to restore adequate flow in accordance with existing procedures, it is concluded that this event is of low safety significance.

CORRECTIVE ACTION

Once the service water filter design basis was clarified, short term corrective action consisted of the following:

1. Reperforming the routine test which initially discovered the deficiency to determine the current condition of the service water filter. The inservice filter was found to exceed the design limits in approximately 40 minutes, thus the filter was declared operable.

2. A new procedure was created which provided Operators with guidance on performing operability tests on the filters to maintain them within design basis limits.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

Long term corrective actions consists of the following:

1. Performing evaluations and procedure changes which will allow the removal of differential pressure limits on the service water filters whenever a dedicated operator has been stationed at the MOV switch due to river conditions. This has been completed.

2. Evaluate feasibility of a modification which will allow the service water filter bypass MOV's to automatically open upon receiving a safety injection or high containment pressure signal. This modification will eliminate all required fouling rate testing and post-DBA operator actions for filter operability. Design basis differential pressure limits would also be eliminated. This is expected to be completed by startup from the next refueling outage which is scheduled to commence in May 1993.

ADDITIONAL INFORMATION

None

PREVIOUS SIMILAR EVENTS

LER 90-023
90-032
92-012

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TITLE (4)
Reactor Scram & Engineered Safety Features Actuations Caused by Offsite Fire

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 5	0 3	9 2	9 2	0 0 5	0 0	0 6	0 2	9 2		0 5 0 0 0
										0 5 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

OPERATING MODE (9):
POWER LEVEL (10): 1 0 0

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	X 50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Lynne Munzing	AREA CODE 6 0 9 · 9 7 1 - 4 3 8 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15) MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

A reactor scram and subsequent Engineered Safety Features systems actuations were caused by a turbine load rejection due to faults on off-site 230kV transmission lines caused by a forest fire. The scram occurred at 1326 hours on May 3, 1992 and the event concluded at 0635 hours on May 4, 1992. The reactor was operating at approximately 100% power before the scram. Numerous other engineered safety features actuated including Isolation Condensers, Containment Isolation, Diesel Generator fast start, Core Spray and Standby Gas Treatment. Several additional scram signals occurred in the process of bringing the plant to cold shutdown and returning power supplies to off-site sources. An Unusual Event was declared based on high drywell temperature, and an Alert was declared based on the potential of the forest fire to further affect the plant. The plant was brought to cold shutdown at 2234 hours on May 3, and the emergency condition was terminated at 0635 hours on May 4, after off-site power was restored to vital electrical buses. Off-site power had been available since 1331 hours on May 3, but plant management decided not to place the vital buses on off-site power until reliability could be assured. No plant structures or equipment were damaged by the fire. The forest fire which caused the loss of off-site power was the root cause of the event, and the safety significance was minimal because all systems functioned as required. Corrective actions include a revision to the Diesel Generator operating procedure to prevent an avoidable scram when securing diesel generator operation. Utility personnel inspected off-site power lines and found no damage. High resistance contacts on the control rod drive pump time delay relay were replaced due to the pump's failure to start on a diesel generator load sequence.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

DATE OF OCCURRENCE

The event began on May 3, 1992, at 1326 hours and concluded on May 4, 1992, at 0635 hours.

IDENTIFICATION OF OCCURRENCE

A reactor scram and subsequent Engineered Safety Features systems actuations were caused by a turbine load rejection due to faults in off-site 230kV transmission lines. This is reportable in accordance with 10 CFR 50.73 (a)(2)(iii) and (a)(2)(iv).

CONDITIONS PRIOR TO OCCURRENCE

The reactor was critical in the RUN mode at 1920 megawatts thermal (99.5% full power). Xenon buildup was in progress following recovery from a power reduction for Main Steam Isolation Valve (IEEE-SB, CFI-ISV) testing. The turbine-generator (IEEE-TA, CFI-TRB) was on line at 641 megawatts electric with automatic voltage control. Reactor recirculation (IEEE-AD) flow was 15E4 gpm with five pumps in service. Reactor pressure was 1020 psig and level was 160" TAF (above top of active fuel). Primary containment was intact and inerted.

DESCRIPTION OF OCCURRENCE

At 1310 hours on May 3, 1992, a maintenance supervisor reported to the Control Room that a forest fire was burning west of the plant. Security and Operations Department personnel were assigned to observe the fire and the system dispatcher was notified due to the close proximity of the fire to the 230kV distribution lines. At 1325 hours electrical fluctuations were observed and 4160 volt vital electric bus (IEEE-EB) low voltage alarms were received on the Plant Computer System (IEEE-ID), but not on the Control Room annunciators.

At 1326:30, a full reactor scram occurred, caused by operation of the turbine controls acceleration relay (IEEE-JJ, CFI-RLY). The Turbine controls acceleration relay operation resulted from a rapid load rejection which occurred after off-site distribution breakers (CFI-52) tripped due to faults apparently from heavy smoke and heat in the vicinity of the off-site 230kV line insulators. It is believed that these smoke and heat conditions resulted in ionization of the air around the insulators (CFI-INS), causing arcs. The 34.5 kV lines (IEEE-EA) which supply Startup Transformers S1A and S1B (CFI-XFMR) were also lost, resulting in a complete loss of off-site power. When the generator tripped, generator output breakers GC1 and GD1 (IEEE-EL) tripped open, 4160V main breakers 1A and 1B (IEEE-EA) (non-safety-related buses) tripped open, and Startup Transformer breakers S1A and S1B closed to supply the plant with off-site power, although there was no off-site power available (see attached Electrical Distribution schematic diagram). The diesel generators (IEEE-EK, CFI-DG), which had already received a signal to start and idle on the generator trip, received fast start signals at 1326:34 from low-low voltage signals on safety-related 4160V buses 1C and 1D (IEEE-EB).

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

The diesel generators and the loads sequenced as designed, except for Control Rod Drive Pump A.

After the reactor scram, reactor high pressure (a scram signal) and Reactor Recirculation pump trips occurred. Electromatic Relief Valves (CFI-RV) (EMRVs) A and D opened on high pressure (1060 psig). A reactor low level scram signal was then received due to rapid void collapse. Isolation Condensers (IEEE-BL) actuated at 1326:33 from the reactor high pressure signal. The reactor high pressure signal cleared at 1326:36, and EMRVs A and D closed. The reactor low level signal cleared at 1326:46. The Standby Gas Treatment System (SGTS) (IEEE-BH) initiated at 1326:46, apparently due to spurious radiation alarms resulting from voltage transients as the Diesel Generators restored vital bus power. The low-low voltage alarms on safety-related 4160V buses 1C and 1D cleared at 1326:51. Two reactor low level alarms were received and level was approaching the low-low level setpoint, so the Main Steam Isolation Valves (MSIVs) were manually closed at 1328:57 in anticipation of a reactor isolation signal. The reactor low-low level signal was then received at 1329:44 and initiated both Core Spray Systems (IEEE-BM). Water was not injected into the reactor vessel due to the pressure interlock. A pressure increase due to removal of Isolation Condensers from service to control reactor pressure caused a void collapse which resulted in the low-low reactor water level condition. As the Isolation Condensers were cycled in and out of service for reactor pressure control, numerous reactor high and low level alarms and scram signals were received. The Alternate Rod Injection System (ARI) (IEEE-AA) initiated on reactor low-low level at 1333:51.

Off-site power became available to the Startup Transformers at 1331:03. At 1332, 4160V buses 1A and 1B were re-energized from the Startup Transformers. Upon power restoration to these non-safety-related 4160V buses, Circulating Water Pumps (IEEE-KE), Condensate Pumps (IEEE-SD), Feedwater Pumps (IEEE-SJ) and Air Compressors (IEEE-LD) were restarted. A decision was made by plant management not to place the safety-related 4160V buses on off-site power until reliability could be assured. Fires continued to burn near the 230 kV lines.

As required by Emergency Operating Procedures (EOPs), the Feedwater Pumps were started. Their feed regulating valves (CFI-FCV) were locked up in the open position due to the loss of air. Air compressors tripped on loss of offsite power and do not automatically load on a diesel start sequence. Due to the significant number of continuous alarms, the entry into EOPs and restoration of off-site power, the operator did not recognize that the valves were locked up and failed to close in response to a manual closure signal. This caused a high reactor water level, requiring the Isolation Condensers to be removed from service to prevent water hammer. EMRVs A and B were opened to control reactor pressure and reduce reactor level. The Containment Spray System (IEEE-BO) was started in the torus cooling mode due to the discharging EMRVs.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

The associated Emergency Service Water (IEEE-BS) pump started 45 seconds after the Containment Spray Pump, as designed. Both EMRVs were soon closed and the high reactor water level condition cleared.

At 1402 hours the Group Shift Supervisor in the Control Room declared an Unusual Event based on indicated high drywell temperature of 160°F. The scram and ARI were reset. The Group Shift Supervisor then declared an Alert at 1434 due to the potential for the off-site fire to further affect the plant. The Emergency Response organization was activated.

At 1455 the reactor isolation signal was reset. Several low level scram signals in succession were received while maintaining reactor level in the desired band. At 1609 the Containment Spray System was taken out of the torus cooling mode and returned to standby readiness. Isolation Condenser logic was reset at 1742, and Shutdown Cooling (IEEE-BO) was placed in service at 1945. The Main Steam Isolation Valves were opened at 2044 to vent the reactor. The reactor reached cold shutdown conditions at 2234.

At 0240 on May 4, a reactor scram and containment isolation signal were received when power was lost to 4160V bus 1D while securing Diesel Generator 2.

At 0505 the emergency classification was downgraded to an Unusual Event. By 0631 both 4160V buses 1C and 1D were restored to their normal off-site power supplies and the associated Diesel Generators shutdown. The plant secured from the Unusual Event at 0635 hours on May 4, 1992.

No plant structures or equipment were directly affected by the fire. The fire did approach within approximately 70 feet of the Fire Pump House (IEEE-KP), which is located southwest of the main plant site and across the salt water discharge canal. Local fire department and plant personnel were stationed at the Fire Pump House during the period that it was threatened.

ANALYSIS OF OCCURRENCE AND SAFETY SIGNIFICANCE

The generator load rejection scram anticipates the rapid increase in pressure and neutron flux resulting from fast closure of the turbine control valves (CFI-FCV) due to a load rejection. The scram functioned appropriately on a load rejection signal and all control rods fully inserted.

The Diesel Generators are designed to start and automatically load all safety related pumps and auxiliaries required for safe shutdown of the reactor in the event of a design basis accident with a loss of off-site power. All required loads started automatically except Control Rod Drive (CRD) Pump A (IEEE-AA). The significance of this failure to start is minimal, since the other CRD Pump did start.

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NRC Form 366A

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

The high pressure and low-low reactor water level after the scram initiated the Isolation Condensers and EMRVs as designed. The Isolation Condensers remove core residual and decay heat, and depressurize the reactor vessel in the event the main condenser is not available as a heat sink. Both Isolation Condensers initiated and functioned as designed. The EMRVs provide overpressure protection to avoid unnecessary safety valve actuation during plant transients that result in a pressure increase. EMRVs A and D opened appropriately when their setpoint of 1060 psig was reached.

Restart of Reactor Feedwater pumps with their regulating valves locked open caused a high reactor water level, requiring removal of the Isolation Condensers from service. EMRVs were successfully used to control reactor pressure until level returned to the desired control band.

Due to heavy concentration of smoke in the area an assessment of equipment that might be affected by the smoke was warranted. Engineering analysis determined that operation in a smoke environment did not adversely affect the Diesel Generators or Diesel Fire Pumps. A sample charcoal canister from the Standby Gas Treatment System was removed and sent for laboratory analysis. The results indicated no damage to the charcoal beds from the fire's smoke.

All other automatic functions actuated and operated as designed, therefore, safety significance of this event is considered minimal.

APPARENT CAUSE OF OCCURRENCE

The cause of the load rejection scram was the loss of off-site power initiated by a forest fire. When off-site power was lost, the turbine controls acceleration relay responded to rapidly close the control valves to prevent a turbine over speed condition. The rapid response by the acceleration relay was sensed by the Reactor Protection System, which in turn produced a scram.

The cause of the scram and isolation signal at 0240 hours on May 4 was an inadequate procedure. A surveillance procedure contained appropriate instructions to prevent a reactor scram when securing diesel generators, but the operating procedure did not contain the same instructions. In addition, due to inadequate self-checking, the operator was monitoring the incorrect voltage indicator while securing Diesel Generator 2; the voltage indicators labeled "DG" and LINE" are actually reversed during this electrical configuration.

The cause of the failure of Control Rod Drive Pump A to start on the Diesel Generator loading sequence was a set of high resistance contacts on the time delay relay (CFI-2) for pump start on the automatic loading sequence.

NRC FORM 366A

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTION

Utility personnel inspected off-site power lines prior to placing the generator on line and found no damage. The diesel generator operating procedure will be revised to include steps to prevent a scram signal when securing diesel generator operation, and the revised version of the procedure is currently being reviewed with operators on the non-certified plant referenced simulator (operators are participating in simulator development). The high resistance contacts on the Control Rod Drive pump time delay relay were replaced.

SIMILAR EVENTS

LER 91-005 Automatic Reactor Scram Due to Loss of Feedwater Flow Caused by a Grounded Condensate Pump Motor

LER 89-016 Main Transformer Failure Causes Automatic Reactor Shutdown

LER 89-015 Main Generator Trip Causes Automatic Reactor Shutdown Due to Personnel Error

LER 87-11 High RPV Level Trip/Scram Caused by Lost Feedwater Flow Signal Due to Procedural Inadequacy and MSIV Auto Closure Due to Loose Wire

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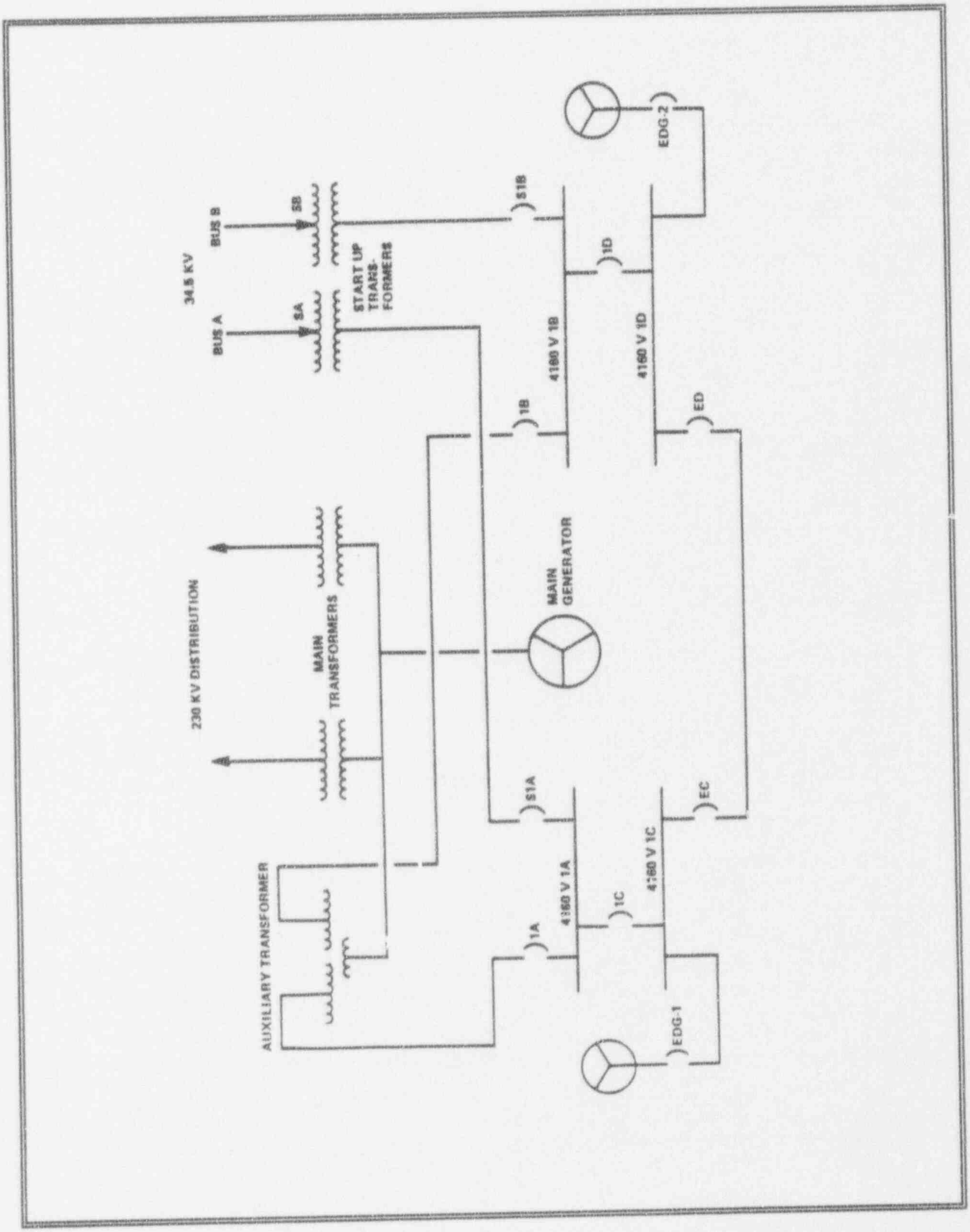
34.5 KV
BUS A
BUS B
SA
SB
START UP
TRANS-
FORMERS
230 KV DISTRIBUTION
MAIN
TRANSFORMERS
MAIN
GENERATOR
AUXILIARY TRANSFORMER
S1B
1D
4160 V 1B
4160 V 1D
1B
ED
EDG-2
S1A
EC
4160 V 1A
4160 V 1C
1C
1A
EDG-1

NRC FORM 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Nine Mile Point Unit 1

DOCKET NUMBER (2): 0 5 0 0 0 2 2 0

PAGE (3): 1 OF 1 4

TITLE (4): Loss of Ultimate Heat Sink While Shutdown due to Ineffective Management Oversight and Supervisory Controls

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 2	2 1	9 2	9 2	— 0 0 5 —	0 1	0 4	2 2	9 2	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

[ ]	20.402(b)	[ ]	20.405(c)	[ ]	50.73(a)(2)(iv)	[ ]	73.71(b)
[ ]	20.405(a)(1)(i)	[ ]	50.36(c)(1)	[ ]	50.73(a)(2)(v)	[ ]	73.71(c)
[ ]	20.405(a)(1)(ii)	[ ]	50.36(c)(2)	[ ]	50.73(a)(2)(vii)	[ ]	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ]	20.405(a)(1)(iii)	[ ]	50.73(a)(2)(i)	[ ]	50.73(a)(2)(viii)(A)		
[ ]	20.405(a)(1)(iv)	X	50.73(a)(2)(ii)	[ ]	50.73(a)(2)(viii)(B)		
[ ]	20.405(a)(1)(v)	[ ]	50.73(a)(2)(iii)	[ ]	50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME: Robert L. Tessier, Manager Operations NMP1

TELEPHONE NUMBER: AREA CODE 3 1 5 | 3 4 9 - 2 7 0 7

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On February 21, 1992, at 0829 hours, reverse flow cooling water inlet gate D to the Screenhouse forebay was closed, thereby isolating the plant from Lake Ontario. The combined flows of the operating service water pump and circulation water pumps lowered forebay level sufficiently to cause degradation of service water pump discharge pressure. At the time of the event, Nine Mile Point Unit 1 (NMP1) was in cold shutdown with reactor water temperature approximately 140 degrees Fahrenheit.

The root cause of the event was the failure to comply with the Work Control Program due to ineffective management oversight and supervisory control over the implementation of procedures which govern this program and a lack of fundamental awareness of licensing basis requirements.

Immediate corrective actions included restoration of water to the forebay to within normal levels by 0844 hours. Safety-related pumps that take suction off the forebay were operated to verify functionality through observation of flow rates. In order to investigate the event, the Plant Manager issued a Restricted Work Order at 1030 hours under which work was restricted to the performance of required Technical Specification surveillances and non-impacting work as approved by the Plant Manager.

Short term and long term corrective actions were identified to address programmatic concerns, personnel performance issues, equipment concerns, organizational issues and plant personnel training issues; the specific corrective actions are identified in Section IV of this LER.

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NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. DESCRIPTION OF EVENT

Background

On February 10, 1992, while corrective maintenance was being performed on the reverse flow cooling water inlet gate D position control button, a configuration that differed from design documents was discovered that consisted of an electrical jumper which bypassed the gate load limit switch. On February 12, the jumper was removed, placing the plant into configuration consistent with design documents. An Emergency Temporary Modification was initiated under which the jumper was reinstalled. Deviation Event Reports (DERs) were initiated upon the initial discovery of the jumper and upon reinstallation under the Emergency Temporary Modification. The removal of the jumper on February 12 and the subsequent jumper removal on February 21 were performed prior to the Engineering review and authorization required by the DER procedure.

Between February 12 and February 21, discussions were held regarding D gate status, which included Site Engineering, System Engineering, Maintenance and Operations personnel. It was determined that continued application of the jumper raised industrial safety concerns and that the jumper should therefore be removed and the gate tested. It was also determined that the post maintenance test should consist of stroking the gate with the jumper removed by going into reverse flow operations to ensure maximum differential pressure across the gate. While the scope of the original Work Request to repair the gate pushbutton was changed to incorporate the jumper removal, the work package was not re-reviewed for plant impact, as required by the Work Controls Program, nor was a procedure identified under which the test was to be performed. The work package also did not specify if the stroke test was to be performed as part of the normal evolution of establishing reverse flow or performed while in reverse flow. On February 19, a blue markup, an equipment tagout that allows for testing, was initiated under which the gate would be stroked in accordance with the work package.

Chronology of Events

Initial Conditions: On February 21, the plant was in cold shutdown with reactor water temperature of approximately 140 degrees Fahrenheit. The plant had shutdown on February 16 due to unrelated causes. At the time of the event, both circulation water pumps and one of two service water pumps were in service.

0700 hours The Station Shift Supervisor (SSS), Chief Shift Operator (CSO), and Electrical Maintenance personnel discussed D gate testing.

SSS authorized system lineup to reverse flow configuration.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. DESCRIPTION OF EVENT (cont.)

0720-0740 hours Licensed operator dispatched to screenhouse to establish reverse flow in accordance with procedure.

Electrical Maintenance discussed work package with SSS and CSO. SSS reviewed previous work completed and plant impact assessment. SSS verified Work Request is on the daily work plan and reviewed the Post Maintenance Test (PMT).

SSS and CSO signed renotification in work package.

Electrical Maintenance discussed PMT with SSS including operation of D gate.

Electrical Maintenance discussed with CSO restoration of wiring to design documents and full open/close of D gate to test overload limit switch.

0730 hours Licensed operator notified CSO and SSS reverse flow established.

0735 hours First Nonlicensed Operator (NLO) dispatched to apply blue markup.

0740 hours Blue markup applied and verified by nonlicensed and licensed operator.

0751 hours Blue markup issued to Electrical Maintenance for C and D gate common breaker.

0800 hours Blue markup verified by Electrical Maintenance and overload limit jumper removed. Electrical Maintenance requested operator support for testing from CSO.

0820 hours Different NLO dispatched to screenhouse to support D gate testing.

~0825 hours System Engineer joined Electrical Maintenance to assist in evolution.

NLO informed CSO that Electrical Maintenance wanted to check switch with gate open, partially closed and fully closed. NLO closed and reopened gate a few inches, then successfully cycled gate a few feet.

NLO closed gate fully; gate did not reopen.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. DESCRIPTION OF EVENT (cont.)

0829 hours High tunnel differential pressure alarm received in control room.

Control room called NLO to reopen gate. NLO notified CSO D gate was stuck closed. CSO demanded closure of D gate contacts to raise gate. Electrical Maintenance held jumper across contacts to raise D gate.

- Circ. Water Intake Level Low alarm received.
- #12 Circulation pump removed from service.
- NLO instructed Electrical Maintenance to reinstall jumper.

Licensed operator dispatched by control room opened the "B" gate to restore level, D gate may have been opened first.

0832 hours Service Water Header Pressure Low alarm received.

- #11 Service Water pump removed from service.
- CSO attempted to start the Emergency Service Water pump #11. Low discharge pressure was observed in the Control Room, the pump was immediately shut down.

NOTE: Subsequent to the event, it was determined that the intake bay low level alarm was set nonconservatively low, thereby not providing control room operators with early indication of level degradation as designed.

0833 hours Fire Header Pressure low alarm received.

- Electrical Fire pump on.

0835 hours Circulation pump Intake Level normal.

0837 hours "D" gate reported open by NLO at screenhouse.

0838 hours Emergency Service Water pumps #11 and #12 on.

- Reactor Building Service Water Header Pressure normal.

0840 hours #11 Service Water pump vented.

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I. DESCRIPTION OF EVENT (cont.)

0844 hours #11 Service Water pump on.

- Turbine Building Service Water Header Pressure normal.

0845 hours #11 and #12 Emergency Service Water pumps off.

0850 hours Electric Fire Pump off.

0900 hours Circulation Water intake flow returned to normal.

- Breathing Air compressor restarted (tripped on low Service Water pressure).
- Fish screen closed and drain valve opened on #12 Circulation Water pump.
- #12 water box vents opened.

II. CAUSE OF EVENT

"D" gate to the screenhouse was closed without an approved procedure. This resulted from inadequate review caused by a failure to comply with the Work Control Program and a lack of fundamental awareness of licensing requirements in implementing Work Control Programs. The root cause of this failure to comply with the Work Control Program was ineffective management oversight and supervisory control over the implementation of procedures which implement this program.

A root cause evaluation was performed for the intake bay low level alarm setpoint being set at 237'-6" versus the design setpoint of 238'-6". This evolution determined the root cause to be a programmatic deficiency as there was insufficient procedural guidance addressing plant impact provided to engineers performing design basis calculations. 1

III. ANALYSIS OF EVENT

This event is considered reportable under:

1. 10CFR50.73 (a)(2)(ii)(B), operation "in a condition that was outside the design basis of the plant." FSAR Section III.F specifies the configuration requirements for normal and reverse flow and tempering operations. No provision exists in the licensing basis for closure of D gate while in reverse flow operations.

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III. ANALYSIS OF EVENT (cont.)

2. 10CFR50.73 (a)(2)(ii)(C), operation "in a condition not covered by the plant's operating and emergency procedures." Existent plant procedures do not provide for closure of D gate while in reverse flow operations nor was a procedure developed for the evolution.

3. 10CFR50.73 (a)(2)(v), "any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to shutdown the reactor and maintain it in a safe shutdown condition; remove residual heat; control the release of radioactive material; or mitigate the consequences of an accident."

For analysis of the event, safety-related systems/equipment considered inoperable due to the loss of ultimate heat sink include Emergency Diesel Generators, Containment Spray, Core Spray, Emergency Service Water, Reactor Building Closed Loop Cooling Water, Spent Fuel Pool Cooling, Diesel and Electric Fire Pumps, and Instrument Air Compressors.

Analysis at Event Conditions

A safety assessment by the Niagara Mohawk Independent Safety Engineering Group concludes that in response to the loss of ultimate heat sink, the plant was effectively maintained in a cold shutdown condition. Operators and plant staff, in response to the event, acted responsibly and effectively in mitigating the event in an expeditious fashion. There was no impact on the health and safety of the public.

The safety significance of the event with respect to residual heat removal from the reactor core were minimal based on the following:

1. The approximate duration of the intake low level condition was five minutes.

2. With reactor water temperature at 140 degrees Fahrenheit, approximately 1.9 hours was required for a temperature increase to 212 degrees Fahrenheit with no operator intervention. No increase in reactor water temperature was noted during the event.

3. Due to low decay heat conditions at the time of the event, sufficient reactor vessel makeup was available for greater than 48 hours without restoration of intake level.

4. Core Spray remained available for service, with torus water available as an injection source and power supplied by offsite power. Sufficient time and alternate mitigative actions were available to operators to ensure cold shutdown could be maintained.

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III. ANALYSIS OF EVENT (cont.)

Analysis at Other Conditions

Had this event occurred at rated power concurrent with both a Design Basis Loss of Coolant Accident (DBALOCA) and a Loss of Offsite Power (LOOP), the requirements of 10CFR50.46 could not be assured. As a result of the loss of the ultimate heat sink, the Emergency Diesel Generators are assumed to be inoperable due to the loss of Diesel Generator raw water cooling. This in turn renders both Core Spray and Containment Spray Systems inoperable. Without Core Spray, compliance to 10CFR50.46 cannot be assured. Additionally, loss of the Containment Spray System results in containment pressure exceeding the Torus design pressure.

The rate of containment pressurization following a DBALOCA, concurrent with a complete loss of both core spray and containment spray is documented in the second supplement to the FSAR. From this rate of pressurization, containment design pressure is reached in 21.6 minutes. However, when engineering analysis is applied, containment integrity is assured for approximately 1.5 hours.

This event would be mitigated by operator action to procedurally crosstie the Unit 1 and Unit 2 Fire Systems and aligning the Unit 1 Fire System to provide for EDG raw water cooling. This action would restore the Diesel Generators and hence Core Spray and Containment Spray Systems to an operable status. Upon restoration of Containment Spray, the rise in containment pressure would be terminated prior to reaching the analyzed pressure. The loss of the ultimate heat sink can only occur when the plant is placed in the reverse flow condition. Reverse flow, used for de-icing the circulating water intake structure, is an infrequent evolution. The probability of a DBALOCA coincident with a LOOP for a five minute loss of the ultimate heat sink is less than one in 1.5E08 reactor years.

As the loss of the ultimate heat sink is beyond the design basis of Nine Mile Point Unit 1, equipment cited to mitigate this event has not been subjected to single failure criteria beyond the loss of the ultimate heat sink.

Based on the analysis, the DBALOCA coincident with a LOOP and concurrent loss of the ultimate heat sink is the worst case bounding scenario. All other scenarios evaluated result in assurance that core cooling and containment integrity are maintained. The scenarios evaluated are as follows:

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III. ANALYSIS OF EVENT (cont.)

Loss of Off-Site Power (LOOP)

If the unit lost its ultimate heat sink concurrent with a LOOP, the event would be similar to a station blackout. 10CFR50.63, "Loss of All Alternating Current Power," requires that for a specified station blackout duration the plant be capable of maintaining core cooling and appropriate containment integrity. Assumptions made and actions taken to mitigate station blackout would apply to this event. The event for NMP1 assumes that either offsite or onsite power can be restored within 4 hours and sufficient core cooling capability is provided by the emergency condenser system. NMP1 is capable of coping with a station blackout as described in an NRC Safety Evaluation dated November 6, 1991. Therefore, the consequences of a loss of the ultimate heat sink with concurrent loss of offsite power are bounded by the station blackout event.

Loss of Ultimate Heat Sink During Refueling

If the plant was in a refueling condition and experienced this event the water contained in the Reactor Head Cavity and Spent Fuel Pool would heat up from decay heat. Saturation temperature would be reached within 10 hours and steaming would commence, thereby removing decay heat. The boil off rate of 55 gpm would be made up by the 75 gpm injection available from the Condensate Transfer System. Assuming Condensate Storage Tank level at Technical Specification minimum, sufficient makeup water is available from the Condensate Storage Tank for approximately 24 hours, thereby allowing time to provide additional sources of water. This heatup and boil off rate were conservatively calculated using only the volume of water contained in the Spent Fuel Pool.

Design Basis Loss of Coolant Accident (DBALOCA)

If the unit lost its ultimate heat sink and experienced a concurrent DBALOCA, the event would be similar to the DBALOCA coincident with a LOOP, except that both Core and Containment Spray Systems would be available to ensure compliance to the requirements of 10CFR50.46 and maintain containment integrity until the ultimate heat sink could be restored.

Conclusion

Based on analysis of the event at event conditions, it is concluded that the safety consequences of the event were minimal. The reactor was unaffected, no equipment damage was sustained, and no radiation release occurred. Operator response to the event was good and safety of the general public was not compromised.

NRC FORM 366A (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 1	0 5 0 0 0 2 2 0	9 2	— 0 0 5 —	0 1	0 9 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

IV. CORRECTIVE ACTIONS

Immediate corrective actions related to this event were restoration of intake bay level by the operators, securing one circulating water pump and one service water pump, intake level restoration, and starting emergency service water pumps in accordance with procedures. All pumps that take suction from the forebay were subsequently operated to prove initial functionality. In addition, the Plant Manager issued a Restricted Work Order at 1030 hours in order to investigate the event.

Corrective actions related to this event are detailed in Attachment 1 and Attachment 2 to this LER.

V. ADDITIONAL INFORMATION

A. Failed components: None.

B. Previous similar events: None.

C. Identification of components referred to in this LER:

COMPONENT	IEEE 803 FUNCTION	IEEE 805 SYSTEM ID
Cooling Water Inlet Gate D	GATE	NN
Screenhouse Forebay	N/A	NN
Service Water Pump	P	BS
Circulation Water Pump	P	BS
Cooling Water Inlet Gate D Position Control Button	HS	NN
Gate Load Limit Switch	LDC	NN
Circulating Water Intake Alarm	LA	BS
Emergency Service Water Pump	P	BI
Shutdown Cooling System	N/A	BO
Emergency Condenser	COND	BL
Condensate Transfer System	N/A	KA

NRC FORM 366A (6-89)
U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 1	0 5 0 0 0 2 2 0	9 2	— 0 0 5 —	0 1	1 0 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

V. ADDITIONAL INFORMATION (cont.)

C. Identification of components referred to in this LER: (cont.)

COMPONENT	IEEE 803 FUNCTION	IEEE 805 SYSTEM ID
Spent Fuel Pool Cooling	N/A	DA
Emergency Diesel Generators (EDG)	DG	EK
EDG Cooling Water Pumps	P	LB
Core Spray Pumps	P	BG
Containment Spray Pumps	P	BE
Containment Spray Raw Water Pumps	P	BE
Reactor Building Closed Loop Cooling Water System	N/A	CC
Diesel and Electric Fire Pumps	P	KP
Instrument Air Compressors	CMP	LD

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 1	0 5 0 0 0 2 2 0	9 2	— 0 0 5 —	0 1	1 1 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT 1
CORRECTIVE ACTIONS

Short Term Corrective Actions - Unit 1	Due Date
1. Trained various management, supervisory and represented personnel in lessons learned from this event.	Completed
2. Recalled all work packages from field.	Completed
3. Work Control group re-reviewed each work package for completeness, accuracy and compliance to applicable procedures.	Completed
4. Operations Planning group re-verified the Work-In-Progress data sheet for completeness, accuracy and compliance to applicable procedures.	Completed
5. To provide management oversight, re-established the Control Room Coordinator to enhance communications, coaching and pre-job briefings.	Completed
6. QA reviewed a sample of the re-reviewed work packages	Completed
7. Initiated simplified job aid as part of the work control process to ensure compliance to the license.	Completed
8. Licensing personnel are on shift to coach and advise personnel involved in the work control process.	Completed
9. Performed Shutdown Safety Review on currently scheduled work which will be updated on an on-going basis.	Completed
10. Directed Licensing group to ensure that all DERs affecting plant equipment go to the SSS for operability review.	Completed
11. Revise intake tunnel differential pressure alarm set point.	Completed
Long Term Corrective Actions	
1. Development of a Work Control Monitoring Program.	Completed
2. Review open DERs relating to plant configuration to determine if any plant changes have been made since the DER was initiated before startup of Unit 1.	Prior to Startup

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 1	0 5 0 0 0 2 2 0	9 2	0 0 5	0 1	1 2 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT 1

CORRECTIVE ACTIONS (cont.)

Long Term Corrective Actions (cont.)	Due Date
3. SROs will re-review open DERs for affect on operability before startup of Unit 1.	Prior to Startup
4. Review Work Control Procedures for enhancements.	5/31/92

Corrective Actions for the improperly set intake bay low level alarm are as follows:

1. The Nuclear design calculation procedure (NEP-DES-340) will be revised to include the requirement to perform a review of potential affected Engineering and Generation documents be completed prior to the issuance of the calculation.	Completed	1
2. Generate a Lessons Learned Transmittal and submit to Training Department for incorporation into Engineering calculation procedure training.	6/15/92	
3. Issue the Lessons Learned Transmittal to personnel in the Electrical, Mechanical, and Structural Engineering groups.	6/15/92	

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LICENSEE EVENT REPORT (LER)
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APPROVED OMB NO. 3150-0104
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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Nine Mile Point Unit 1	0 5 0 0 0 2 2 0	9 2	— 0 0 5 —	0 1	1 3 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT 2
ADDITIONAL CORRECTIVE ACTIONS

The following additional corrective actions related to the event have been identified by the Management Assessment Team:

Equipment Concerns

1. Evaluate modification to "D" gate to ensure that failure of the controls when in full up position in reverse flow will not allow gate closure.

2. Modify/resolve "D" gate control circuit to assure proper operation during high differential pressure conditions.

Operator Training

1. A new lesson plan will be developed to discuss gate operation, potential consequences of improper operation and the affects of improper operation on other plant systems or components.

2. Review training program to identify other plant systems susceptible to similar events.

3. Develop simulator scenarios.

Additional Short Term Corrective Actions

1. Review of Blue Markup process by the General Supervisor to prevent misuse during implementation.

2. Discontinued use of rotational SRO until rotational SSS role reviewed.

3. Operating procedure N1-OP-19, "Circulating Water System," has been revised to require a water watch when in reverse flow configuration.

Additional Long Term Corrective Action

1. Review the Operations shift organization's effectiveness.

2. Evaluate the DER and root cause evaluation processes for enhancements. Revise as necessary and train line organization.

3. Review Blue Markup process relative to the tagging concept.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

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Nine Mile Point Unit 1	0 5 0 0 0 2 2 0	9 2	— 0 0 5 —	0 1	1 4 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT 2
ADDITIONAL CORRECTIVE ACTIONS (cont.)

Additional Long Term Corrective Action (cont.)

4. As part of the Safety Review and Audit Board responsibility for overall assessment, assess effectiveness in estimating and correcting problems related to the findings.

5. Review safety assessment results for enhancements to Operating Procedures.

6. Review safety assessment results for enhancements to design configuration.

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
Dresden Nuclear Power Station, Unit 2	0 5 0 0 0 2 3 7	1 of 0 4

Title (4)
Unplanned Loss of Control Room Annunciators Due to Loose Power Supply Fuse

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
0 7	0 1	9 2	9 2	0 2 2	0 0	0 7	2 4	9 2	N/A	

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR
(Check one or more of the following) (11)

OPERATING MODE (9)	N	___ 20.402(b)	___ 20.405(c)	___ 50.73(a)(2)(iv)	___ 73.71(b)
POWER LEVEL (10)	0 7 6	___ 20.405(a)(1)(i)	___ 50.36(c)(1)	___ 50.73(a)(2)(v)	___ 73.71(c)
		___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	X Other (Specify in Abstract below and in Text) Voluntary
		___ 20.405(a)(1)(iii)	___ 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	
		___ 20.405(a)(1)(iv)	___ 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	
		___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER AREA CODE
Peter J. Karaba Technical Staff System Engineer Ext. 2353	8 1 5 9 4 2 - 2 9 2 0

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
___ Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e, approximately fifteen single-space typewritten lines) (16)

On July 1, 1992, with Unit 2 and Unit 3 both operating at 76% power, intermittent audible and visual alarms were received indicating momentary losses of power to the annunciators on Main Control Room (MCR) Panels 902-3, -4, -5, -6, -7, and -8 and 923-1, -5, and -5A. Operations personnel secured all maintenance work in the MCR and the Auxiliary Electric Equipment Room (AEER). At 1150 hours, an Alert condition was declared in accordance with Dresden Emergency Action Levels. Troubleshooting began and the visual function of the annunicators was restored. However, various annunciator horns were inoperable due to blown annunciator circuit cards. The cause of the event was inadvertent movement of a loose copper link during annunciator modification work in the AEER. This link is located in fuse holder F31 which is the negative 125 VDC supply for all Unit 2 annunciator chassis commons. The failed annunciator cards were a result of power surges resulting from the intermittent energization of the circuit. The annunciator cards were replaced and a jumper wire was placed around fuse holder F31. The Alert was terminated at 1905 hours. Corrective action will also include review of fuse link fabrication policy. The safety significance of this event was considered minimal because both Unit 2 and Unit 3 were operating at steady load and visual annunciator operation was promptly restored. In addition, the Reactor Operators still had instrumentation and indication of vital parameters to determine plant status. A previous event involving the Unit 3 annunciators was reported by LER 91-11/050249.

LER NO: 237/92-022

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)
		Year	///	Sequential Number	///	Revision Number	
Dresden Nuclear Power Station	0 5 0 0 0 2 3 7	9 2	-	0 2 2	-	0 0	0 2 OF 0 4

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor -2527 MWt rated core thermal power.

Nuclear Tracking System (NTS) tracking code numbers are identified in the text as (XXX-XXX-XX-XXXXX).

EVENT IDENTIFICATION:

Unplanned Loss of Control Room Annunciators [IB] Due to Loose Power Supply Fuse

A. CONDITIONS PRIOR TO EVENT:

Unit:	2	Event Date:	July 1, 1992	Event Time:	1130 Hours
Reactor Mode:	N	Mode Name:	Run	Power Level:	76%

Reactor Coolant System (RCS) Pressure: 985 psig

B. DESCRIPTION OF EVENT:

At approximately 1130 hours on July 1, 1992, with Unit 2 and Unit 3 both operating at 76% power, intermittent audible and visual alarms were received indicating momentary losses of power to the annunciators for Main Control Room (MCR) Panels 902-3, -4, -5, -6, -7, and -8, and 923-1, -5, -5A. In addition, various annunciator horns did not function properly. Upon the intermittent loss of the annunciators, the Station Control Room Engineer (SCRE) sent the Shift Supervisor (SS) to the Auxiliary Electric Equipment Room (AEER) to secure annunciator modification work which was being performed by Electrical Maintenance Department (EMD) personnel in the Annunciator Input Cabinet 902-34. The 902-34 Panel contains the main power supply for the annunciator system. All maintenance activities in the MCR and AEER were stopped. At 1150 hours, an Alert condition was declared in accordance with Condition 3.i of Emergency Plan Implementing Procedure (EPIP) 200-T1, Dresden Emergency Action Levels. Initial troubleshooting of the horns determined that several annunciator circuit cards had failed resulting in a horn that could not be silenced and a horn that would not sound. The cards were immediately replaced and the horns were tested and found to be operating properly. Although the annunciators were functional, except during intermittent troubleshooting periods, the Alert condition was not terminated until the cause was determined. At 1600 hours, the cause was determined to be a copper link located in fuse holder F31 of the 902-34 Panel not making sufficient contact. This copper link serves as the negative 125 VDC feed to all annunciator chassis commons. The EMD personnel were installing two single conductors in Section 4R of the 902-34 panel. It is believed that the copper link was inadvertently disturbed during the wire pulling process. The EMD personnel were using appropriate caution and had obtained proper Operations approval prior to start of work.

Temporary Alteration II-21-92 was initiated to place a jumper around fuse holder F31. The Alert condition was terminated at 1905 hours.

C. APPARENT CAUSE OF EVENT:

This event is being voluntarily reported due to its significance and NRC interest.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year	Sequential Number	Revision Number	Page (3)
Dresden Nuclear Power Station	0 5 0 0 0 2 3 7	9 2	- 0 2 2	- 0 0	0 3 OF 0 4

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

The root cause of the copper link not making sufficient contact in fuse holder F31 was attributed to inadequate controls concerning its previous installation. Failure of the annunciator circuit cards is attributed to power surges which resulted from the intermittent energization of the system.

The copper link in question had been installed following a previous event which involved the unplanned loss of the Unit 3 annunciator system due to a blown fuse. This event was reported in LER 92-011/050249. The decision and design processes concerning the installation of this copper link were reviewed. It was concluded that the concept of installing a copper link to prevent future fuse failure pending completion of annunciator modification work was proper. However, the actual implementation of the copper link installation was deficient because the link type (copper tubing) was apparently not compatible with the fuse holder. Field Change Request (FCR) D-6584, which implemented the change from a fuse to a copper link, did not specify the outside diameter of the copper tubing to install. The copper tubing link configuration had a slightly smaller diameter than a standard link type, causing it to be subject to movement as a result of vibration. Due to the "saddle" arrangement of the in-place fuse holder, the fit of the copper link is difficult to check, especially if the circuit is live. In addition, there is no test which can be conducted to determine the gripping force being applied to the link by the fuse clip. At the time of installation, visual observations for looseness and thermography were performed to determine if the fit was adequate. However, these qualitative checks are not a direct, quantitative measure of the acceptance for fit.

In addition to the drawing indicating the location of the link, the work instruction provided was to replace the fuse with a link. This was determined to be adequate instructions because fuse/link installation is considered to be a "craft capability" function which is routinely performed. Further detail in the work package concerning the type of link to be utilized (i.e., a standard fuse link product vs. a fabricated type) could possibly have insured a tighter fit.

D. SAFETY ANALYSIS OF EVENT:

The annunciator system informs the Reactor Operator audibly and visually of abnormal equipment status. Upon the loss of power to the annunciator system, the Alert condition was properly declared in accordance with Condition 3.i of Emergency Plan Implementing Procedure (EPIP) 200-T1, Dresden Emergency Action Levels. Although the annunciators were promptly restored, as a precautionary measure, the Alert was not terminated until troubleshooting was completed and the root cause was determined. The wire jumper which was placed around the fuse holder F31 is acceptable because the positive 125 VDC supply to each branch circuit in the 902-34 is adequately fused. The jumper will not be susceptible to disturbances which caused this event. Prior to this event, both Unit 2 and Unit 3 were operating at steady load. In addition, an extra Reactor Operator was assigned to monitor the 902-5 panel. These Operators still had gauges and recorders of vital plant parameters to determine plant status. Therefore, the safety significance of this event is considered minimal.

E. CORRECTIVE ACTIONS:

The immediate corrective actions were to replace the blown annunciator circuit cards under Work Request (WR) 10250, and to place a jumper around fuse block F31 per Temporary Alteration II-21-92. Additional corrective actions included the placing of a jumper around fuse holder F25 in the Unit 3 903-34 panel, which also contained a copper link, per Temporary Alteration III-22-92. This event was covered as a topic in station tailgate meetings and was also issued as a Nuclear Network item to inform the Industry of the ever

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)						Page (3)
		Year	///	Sequential Number	///	Revision Number		
Dresden Nuclear Power Station	0 5 0 0 0 2 3 7	9 2	-	0 2 2	-	0 0		0 4 OF 0 4

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

These Temporary Alterations will be made permanent during completion of the annunciator modification project. The Nuclear Engineering Department (NED) is completing their review of a task force report concerning difficulties that have occurred during performance of the annunciator work at the Dresden and Quad Cities sites. This review will also consider potential policy improvements concerning specification of fuse links, and will provide further recommendations to the site by 8/28/92 (237-200-92-12601).

The Maintenance Staff is also reviewing current policy concerning fabrication of fuse links, and will implement appropriate improvements. These improvements may include enhanced training and/or procedural controls, and will be identified by 9/4/92 (237-200-92-12602).

F. PREVIOUS OCCURRENCES:

LER/Document Numbers	Title
91-022/050249	Loss of Control Room Annunciators Due to Design Deficiency While the unit was in a normal refuel outage all power was lost to Main Control Room Panels 903-3, -4, -5, -6, -7, and -8 annunciators when a single fuse blew. The root cause of the event was attributed to design deficiency which had a single fuse supplying the negative 125 VDC to all annunciator chassis commons. The corrective action was to replace the fuse with a copper link on both Units 2 and 3.
89-001/050259	Turbine Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer of House Loads During Loss of Offsite Power During this event, power to annunciator panel 902-3 was interrupted due to Fuse F-9 opening. Power was also interrupted for annunciator panel 902-6 due to another fuse opening; no other annunciators were affected. The cause was attributed to 125 VDC system spikes during the event. The appropriate fuses were replaced.
Non Reportable event no.12-3-92-55	Loss of Main Control Room Annunciator Power Due to Loose Electrical Connections While Unit 3 was in a normal refuel outage, power was lost intermittently to Main Control Room Panels 903-3, -4, -5, -6, -7, and -8. The cause of the event was attributed to loose wiring in Annunciator Input Cabinet 903-34. Fuse Block F-15 was replaced and other loose connections were tightened.

G. COMPONENT FAILURE DATA:

As this event was not caused by component failure, this section is not required. This system is not NPRDS reportable.

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Indian Point Unit No. 2	0 5 0 0 0 2 4 7	1 OF 0 5

TITLE (4)

RPS Actuation Resulting from Turbine Trip on High Steam Generator Level

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 4	1 3	9 2	9 2	— 0 0 7 —	0 0	0 5	1 3	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 2 5

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Claude Peart, Senior Engineer	9 1 4 5 2 6 - 5 1 9 0

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		0 7	3 0	9 2

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On April 13, 1992 at approximately 2213 hours, with the Unit operating at 25% power, a reactor trip was initiated by a turbine trip. The turbine trip occurred as a result of a high level in steam generator (SG) No. 23. The SG level excursion occurred as a result of operator actions in response to a condenser low hotwell level condition due to misalignment of condenser hotwell 22 B outlet valve CS-1-3. The operators responded to the plant trip event in accordance with established plant procedures and the plant systems responded as expected, with the exception of the motor driven auxiliary feedwater pumps (MDAFWP). MDAFWP 21 started and tripped several times within a period of approximately 74 seconds, and MDAFWP 23 did not auto start at all due to low suction pressure. This condition was rectified by the closing of condensate level control valve LCV-1128 which was opened earlier by the operators in response to the low hotwell level condition. Also, the main boiler pump was noted as cycling through trip/reset several times after the reactor trip.

The plant entered normal recovery procedures at approximately 2227 hours. No NRC limit was exceeded and there was no impact on public health and safety.

NRC Form 366 (6-89)

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Indian Point Unit No. 2	0 5 0 0 0 2 4 7	9 2	— 0 0 7 —	0 0	0 2 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse 4-Loop Pressurized Water Reactor

IDENTIFICATION OF OCCURRENCE:

Reactor trip on turbine trip initiated by high Steam Generator level.

EVENT DATE:

April 13, 1992

REPORT DUE DATE:

May 13, 1992

REFERENCES:

Significant Occurrence Report (SOR) 92-190, 92-191, 92-191A

PAST SIMILAR OCCURRENCE:

None

DESCRIPTION OF OCCURRENCE:

At approximately 2030 hours on April 13, 1992, a turbine supervisory instrument (TSI) high vibration alarm was received for 22 main boiler feed pump (MBFP). Suction pressures and pump speeds were oscillating for both 21 and 22 MBFP. Abnormal Operating Procedure, A21.1.1 "Loss of Feedwater" was entered and a power reduction from 100% commenced in order to maintain steam generators (SG) within their required levels. SG blowdown was secured and the motor driven auxiliary feedwater pumps (MDAFWP) were manually started at approximately 2033 hours.

The load reduction was discontinued and the unit stabilized at approximately 70% reactor power. At approximately 2036 hours the MDAFWP were secured.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

DESCRIPTION OF OCCURRENCE: (Continued)

However, Feedwater oscillations continued, and reactor power was reduced to 25%. At this point, the Senior Reactor Operator (SRO) determined that hotwell inventory was in fact the problem as opposed to a feedwater system problem and directed valve LCV-1128 be opened. This valve supplies water to the condenser hotwells via a 12 inch pipe from the Condensate Storage Tank (CST). It is normally kept closed since the preferred source of makeup for the condenser hotwells is from the water treatment plant. LCV-1128 was opened at approximately 2205 hours, and had the effect of immediately increasing MBFP suction pressure and eliminating the oscillations.

At approximately 2213 hours, a turbine trip occurred due to 23 SG high level. Reactor power, at 25%, was above the P-8 Turbine trip/reactor trip permissive interlock (20%) when this occurred. Consequently, the reactor tripped immediately upon the turbine trip.

The MDAFWP received a start signal from the tripping of 21 MBFP. MDAFWP 21 attempted to start six times over the next 74 seconds and MDAFWP 23 did not start at all. Seventy-four seconds after the reactor tripped, LCV-1128 was closed and the MDAFWPs were manually started. The reset permissive light on MBFP 21 was reported as cycling through trip/reset several times, after the reactor trip.

ANALYSIS OF OCCURRENCE:

This report is being made since actuation of the reactor protection system (RPS) occurred. Any manual or automatic actuation of the RPS is reportable under 10 CFR 50.73(a)(2)(iv). There were no adverse safety implications for this event. All systems, with the exception of the MDAFWPs and MBFP 21 discussed previously, performed as expected. After its rapid successive cycling, MDAFWP 21 was tested and its condition determined to be acceptable.

CAUSE OF OCCURRENCE:

Prior to the reactor trip, there had been a series of salinity excursions occurring in condenser 22. A tagout package was used to isolate the circulating waterbox pump side of the condenser. Condenser hotwell 22B outlet valve CS-1-3 was closed as part of the isolation of the affected hotwell and was not logged.

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APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

CAUSE OF OCCURRENCE: (Continued)

On April 9, 1992, work on condenser 22 had been completed and the condenser returned to service. The tagout package that had isolated the circulating water side of the water box was cleared. Since the status change of valve CS-1-3 had not been logged, the assumption was made that valve CS-1-3 was open. With CS-1-3 closed, condenser 22B hotwell was isolated from the condensate pumps creating a condition for potential misindication of hotwell level. This indication caused the operator to reduce makeup to the hotwell which resulted in a decrease in the actual hotwell level.

A subsequent human factors evaluation of the circumstances involved in this event revealed that pertinent plant procedures did not address all the appropriate alignments required to isolate the condenser waterboxes for cleaning. Efforts to correct these conditions and enhance procedures as necessary are either planned or have already been initiated.

The root cause of this event is therefore attributed to cognitive error on the part of operations personnel involved.

The reason for the MDAFWPs anomaly when a valid start signal was generated is believed to be due to a hydraulic phenomena that caused the pressure to drop to or below the low pressure switch setpoint, at the suction of the MDAFWPs created by LCV-1128 being open and additional flow due to MDAFWP 21 starts. The root cause for the hydraulic phenomena as well as the MBFP 21 cycling is being evaluated and this LER will be supplemented when this effort is completed.

Subsequent to the trip a test was conducted on MDAFWP 21 to determine if the successive rapid cycling had adversely impacted the pump's functional capability. The test revealed that the pump was still capable of fulfilling its functional requirements. Also, a temporary modification was effected to block valve LCV-1128 in the closed position in order to eliminate the low pressure condition imposed at the suction of the MDAFWPs with LCV-1128 fully open while the condenser is under a vacuum. A test was conducted which verified the ability of the MDAFWP to deliver the required flow while bypass valve LCV-1128A was fully opened and making up to the hotwells. This is an interim measure until a more thorough evaluation to ascertain root cause for both the MBFP and MDAFWP cycling is completed.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Indian Point Unit No. 2	0 5 0 0 0 2 4 7	9 2	— 0 0 7	— 0 0	0 5 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTION:

1. MDAFWP 21 condition was verified by tests and determined acceptable subsequent to its rapid successive cycling after the reactor trip. Also as an interim measure, a temporary modification was affected to block valve LCV-1128 in the closed position and use bypass valve LCV-1128A for normal make up to the condenser. This alignment was confirmed by a test to have no adverse impact on the MDAFWP to deliver the required flow.

2. The root cause for the anomalies observed for MBFP 21 and the MDAFWPs is currently being evaluated by Plant Engineering. When this evaluation is completed this LER will be supplemented to reflect the appropriate corrective action.

3. Our expectations for field operator log keeping, specifically with regard to equipment status and turnover are being re-emphasized by meetings with watch crews and operations management.

4. Pertinent plant procedures regarding water box isolation, log keeping and equipment status are being revised to provide additional clarification as appropriate.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
TURKEY POINT UNIT 4	05000251	1 OF 4

TITLE (4) Automatic Auxiliary Feedwater Start on Main Feedwater Pump Trip

EVENT DATE (5)			LER NUMBER (6)			RPT DATE (7)			OTHER FACILITIES INV. (8)	
MON	DAY	YR	YR	SEQ #	R#	MON	DAY	YR	FACILITY NAMES	DOCKET # (3)
09	29	92	92	007	00	10	29	92	TURKEY POINT UNIT 3	05000250

OPERATING MODE (9)	2	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § 10 CFR 50.73(a)(2)(iv)
POWER LEVEL (10)	2%	

LICENSEE CONTACT FOR THIS LER (12)

	TELEPHONE NUMBER
James E. Knorr, Licensing Engineer	305-246-6757

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	NPRDS?	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	NPRDS?
X	BA	33	E081	N					

	EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
SUPPLEMENTAL REPORT EXPECTED (14) NO X YES ☐ (If yes, complete EXPECTED SUBMISSION DATE)				

ABSTRACT (16) On September 29, 1992, Turkey Point Unit 4 was in Mode 2 at 2% reactor power. At 1450 EST, during the performance of a condensate polisher backwash, an automatic auxiliary feedwater (AFW) actuation occurred. During the backwash evolution, the inlet valve (CV-4-6351D), on the 4D condensate polisher, opened causing the main feedwater pump suction pressure to drop. The pressure drop occurred because the open inlet valve (CV-4-6351D) allowed the main feedwater pump suction pressure to be relieved through the 4D polisher vent valve (CV-4-6353D) to the backwash receiver tank which is kept at atmospheric pressure. The reduced suction pressure on the 4A main feedwater pump caused a pump trip. This pump trip resulted in the automatic start of the in-service auxiliary feedwater pumps and isolation of steam generator blowdown. At 1520 EST the 'A' standby feedwater pump was started to supply feedwater to the steam generators and the auxiliary feedwater pumps were placed in standby. Other than the automatic start of the auxiliary feedwater pumps no manual or automatic reactor protection system or engineered safety feature actuations occurred or were required.

The NRC was originally notified of this event in accordance with 10 CFR 50.72 (b)(2)(ii).

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 4	05000251	92-007-00	02 OF 04

I. **EVENT DESCRIPTION**

On September 29, 1992, Turkey Point Unit 4 was in Mode 2 at 2% reactor power. At 1450 EST, during the performance of a condensate polisher backwash, an automatic auxiliary feedwater (AFW) actuation occurred. During the backwash evolution, the inlet valve (CV-4-6351D) (EIIS-SF,IEEE-V), on the 4D condensate polisher (EIIS-SF,IEEE-DM), opened causing the main feedwater pump suction pressure to drop. This main feedwater pump suction pressure drop occurred because the open inlet valve (CV-4-6351D) allowed the pressure to be relieved through the 4D polisher vent valve (EIIS-SF,IEEE-V) (CV-4-6353D) to the backwash receiver tank (EIIS-SF,IEEE-TK) which is kept at atmospheric pressure. As a result of this pressure drop, the following expected actions occurred. The reduced suction pressure on the 4A main feedwater pump (EIIS-SJ,IEEE-P) caused a pump trip. This pump trip resulted in the automatic start of the A and C in-service auxiliary feedwater pumps (the B AFW pump was out of service for post maintenance testing) (EIIS-BA,IEEE-P) and isolation of steam generator blowdown (EIIS-SB). At 1520 EST the AFW system was returned to the standby condition. Other than the automatic start of the auxiliary feedwater pumps no manual or automatic reactor protection system or engineered safety feature actuations occurred or were required.

The NRC was notified of this event in accordance with 10 CFR 50.72 (b)(2)(ii) at 1845 EDT, September 29, 1991.

II. **EVENT CAUSE**

a. Immediate Cause

The immediate cause of the automatic start of the AFW pumps was the trip of the 4A main feedwater pump upon loss of suction pressure.

b. The loss of suction pressure to the main feedwater pump was caused by the diversion of condensate flow to the "D" polisher vessel, through the open inlet valve (CV-4-6351D) and out the vessel vent valve (CV-4-6353D) to the backwash receiver. The root cause for this flow path to be established was the malfunction of a limit switch on CV-4-6351D. This failure resulted in a logic fault allowing the diversion of the condensate flow. During subsequent inspection of other valves in this non-safety related system, some valves and limit switches in need of preventative maintenance were identified. The maintenance work has been planned and prioritized. The control system for the condensate polisher appeared to function properly.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 4	05000251	92-007-00	03 OF 04

III. EVENT SAFETY ANALYSIS

The condensate polisher (demineralizer) system is a non-safety related system used to improve the purity of condensate water for use in the steam generators by removal of dissolved and suspended solids from the condensate water. In this event, suction pressure was reduced resulting in a trip of the operating 4A main feedwater pump. The trip of the main feedwater pump and the subsequent loss of the main feedwater supply is a previously analyzed event. As a result of these analyses, plant procedures were developed to provide operator guidance in response to such a transient. The procedures and plant design assure that the plant is stabilized in a safe condition in accordance with the plant Technical Specifications. For this event, steam generator water levels were maintained within design operating levels by the automatic start of the auxiliary feedwater system. A standby feed water pump was subsequently started and the auxiliary feedwater pumps were secured and returned to their standby condition in accordance with plant procedures.

During the event, the 'B' auxiliary feedwater pump was out of service for required post maintenance testing prior to return to service. Other than the automatic start of the auxiliary feedwater pumps no manual or automatic reactor protection system or engineered safety feature actuations occurred or were required. Engineered safety features were designed to prevent by anticipation or by reducing the severity through quick automatic response, events that could affect the health and safety of the public.

Based upon the above, the health and safety of plant personnel and the general public were not compromised as a result of the loss of main feedwater and automatic start of the auxiliary feedwater systems.

IV. CORRECTIVE ACTIONS

a. Immediate Corrective Action

The 'A' standby feedwater pump was started and used to supply feedwater to the steam generators. This feedwater supply allowed the auxiliary feedwater pumps to be placed in standby.

b. Corrective Actions to Prevent Recurrence

1. The condensate polisher system valves and operators were walked down in detail to determine needed component repairs or replacement. Appropriate work orders for identified needs were written. Work required to return the system to operation was completed.

2. Procedure OP-7001.3, Condensate Polishing System - Powdex Vessel Operation, was revised to require manual control of inlet and outlet valves to prevent inadvertent opening of the vessel inlet or outlet valves. Further investigation may require other appropriate corrective actions.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER	PAGE NO.
TURKEY POINT UNIT 4	05000251	92-007-00	04 OF 04

V. ADDITIONAL INFORMATION

a. Similar Events

LER 91-006 for Unit 4 discussed a similar auxiliary feedwater actuation caused by a malfunction of the condensate polisher.

b. Reportability

This event was considered reportable in accordance with 10 CFR 50.73(a)(2)(iv).

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
Quad Cities Unit One	0 5 0 0 0 2 5 4	1 of 0 6

Title (4)

HPCI Inoperable Due To Inadequate Weld Procedure Repair On Stop Valve Cover And Poppet Guide

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
										0 5 0 0 0
0 2	0 6	9 2	9 2	0 0 2	0 0	0 3	0 6	9 2		0 5 0 0 0

OPERATING MODE (9)	4	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)			
		20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)	0 9 9	20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	Other (Specify in Abstract below and in Text)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER	
	AREA CODE	
Nick Radloff, Technical Staff, Ext. 2942	3 0 9	6 5 4 - 2 2 4 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
D	B J	S C V	A 5 8 5	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines) (16)

ABSTRACT:

At 1138 hours on February 6, 1992, Unit One was in the RUN mode at 99 percent rated core thermal power. At this time, Unit One High Pressure Coolant Injection (HPCI) system was declared inoperable after the stop valve was verified stuck in the open position. The HPCI stop valve failed while an operator was testing the pushbutton latch on the HPCI remote trip pushbutton.

Upon investigating the problem, it was identified that weld at the base of the poppet guide of the stop valve had drawn the guide over enough to bind up the main poppet disk during operation.

The failure of HPCI was due to inadequate work instructions for the overhaul of the valve. The stop valve was successfully repaired, tested, and declared operable on February 19, 1992, at 0510 hours.

This event is being reported in accordance with 10CFR50.73(a)(2)(v)(D).

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2511 MWt rated core thermal power.

EVENT IDENTIFICATION: HPCI Inoperable due to inadequate weld procedure repair on stop valve cover and poppet guide.

A. CONDITIONS PRIOR TO EVENT:

Unit: One	Event Date: February 6, 1992	Event Time: 1138
Reactor Mode: 4	Mode Name: RUN	Power Level: 99%

This report was initiated by Deviation Report D-4-1-92-010

RUN Mode (4) - In this position the reactor system pressure is at or above 825 psig, and the reactor protection system is energized, with APRM protection and RBM interlocks in service (excluding the 15% high flux scram).

B. DESCRIPTION OF EVENT:

On February 6, 1992, at 1138 hours, Unit One was in the RUN mode at 99 percent rated core thermal power. Prior to this, the Nuclear Station Operator (NSO) was testing the High Pressure Coolant Injection (HPCI) [BJ] remote trip function with a locking pushbutton because of a new procedure. The NSO noticed the light indication [SCV] on the 901-3 panel did not display a full close signal when HPCI stop valve, 1-2317, was tripped the second time. An Equipment Attendant (EA) investigated and found the valve not fully closed.

Unit One HPCI was declared inoperable at 1138 hours on February 6, 1992, and QCOS 2300-2, HPCI Outage Report was initiated. The HPCI MO1-2301-3, HPCI Steam Supply Valve, was taken out of service in order to prevent steam to the HPCI turbine in case of an auto-initiation signal.

The Nuclear Station Operator (NSO) tried to stroke the valve again. The valve opened, but the EA reported the valve did not close when the valve was tripped. Also, no stop valve light indication for full open and full closed positions were received in the control room during this test.

A Shift Foreman, (SF) and Mechanical Maintenance Foreman were sent to investigate the problem. They verified the HPCI stop valve was stuck near the full open position.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

At 1308 hours on February 6, 1992, the NRC was notified of the event via the Emergency Notification System in order to comply with the requirements of 10CFR50.72(b)(2)(iii)(D).

Technical Staff (TS), Maintenance Staff, and General Electric (GE) personnel investigated the stop valve. The upper stem had minimal movement when manual force was applied downward on the coupling. An Operator started the auxiliary oil pump and pushed the HPCI reset and trip pushbuttons to cycle the stop valve. The stop valve opened to near the full open position, however, did not close when the operator pushed the trip pushbutton. Further, there was no full open or full close light indication received in the control room. This was repeated without success.

Further investigation determined that the collar which picks up the limit switches for full open and full close light indication on the stop valve had moved downward. Also, the relay dump valve in the actuator part of the stop valve could be heard closing, signifying it was operating properly. It was decided to loosen the coupling connecting the upper stem to the actuator of the stop valve for further investigation. Mechanical Maintenance (MM) prepared Work Package Q97908.

MM loosened the coupling on the stop valve. They then tried to work the stem loose, but could not. At this point, it was determined to remove the cover to the valve and disassemble the stop valve for possible binding of the upper stem.

At 1300 hours, on February 8, 1992, the Unit One HPCI stop valve was disassembled and internals inspected. The poppet guide was found to have severe galling on the inside diameter. A large weld repair area was found around approximately 1/2 of the outer base circumference of the poppet guide. The rest of the internals were removed, inspected and found to be within vendor recommended tolerances.

MM then performed dimensional checks on the Unit one poppet guide. The poppet guide was found to be out of its perpendicularity enough to exceed recommended tolerance clearances. The poppet guide inside diameter dimensions were determined not to be concentric. Also, linear indications were found on the stellite seat of the stop valve body ring.

Discussions ensued, and it was decided that due to time constraints, the Unit Two poppet guide and cover would be removed and placed on the Unit One stop valve. Unit Two was currently in a refueling outage, and HPCI was not required. MM performed this work under Work Request Q97992.

On February 9, 1992, dimensional checks were made on the Unit Two poppet guide. Slight galling was found on the inside diameter of the guide. The poppet guide was also off its perpendicularity.

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

It was decided to bore out the poppet guide in order to correct the poppet guide perpendicularity offset. The vendor was contacted to determine the acceptable guidelines for the work on the poppet guide for Unit Two. During the work, the allowable inside diameter dimension on the poppet guide was slightly exceeded in two of three different diameter readings taken at the top of the poppet guide away from the cover. Also, the average diameter reading at the top of the guide slightly exceeded the vendor recommendations. Boiling Water Reactor Site Engineering (BWRSE) personnel were contacted to evaluate the final inside diameter dimensions and clearance tolerances. The dimensions were evaluated and accepted.

MM reassembled the stop valve under Work Request Q97908. At 1101 hours on February 16, 1992, the stop valve was stroked four times successfully prior to running QCOS 2300-1, Periodic HPCI Pump Operability Test.

At 0510 hours on February 19, 1992, QCOS 2300-1 was completed successfully. The SE declared HPCI operable and terminated Outage Report, QCOS 2300-2.

C. APPARENT CAUSE OF EVENT:

This event is being reported to comply with 10CFR50.73(a)(2)(v)(D): the licensee shall report any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident.

The cause of the Unit One HPCI stop valve failing to open was due to inadequate work instructions during a previous overhaul of the valve in February, 1991. During this work, a crack was discovered in the weld joining the poppet guide to the valve cover during disassembly and inspection of the valve. The weld was repaired in the field.

The weld repair resulted in the guide being drawn towards the weld. No dimensional verifications or alignment checks were requested or stated in the work instructions prior to or after the welding work was finished.

The weld procedure used was American Society of Mechanical Engineers (ASME) Section IX procedure for P1 to P6 weld. The valve cover is A-515 grade 70 and the poppet guide cylinder is A-511 type 410. This was the correct type of weld procedure to use in order to restore the fillet weld.

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

D. SAFETY ANALYSIS OF EVENT:

The safety of the plant and personnel was not affected in this event. Per Technical Specification 3.5.C.2, if the HPCI subsystem is inoperable, reactor operation is allowed for fourteen days provided all active components of the Automatic Pressure Relief (APR) [SB] subsystems, the Core Spray (CS) [BM] subsystems, Low Pressure Coolant Injection (LPCI) mode of Residual Heat Removal (RHR) [BN] system are operable. These system were operable throughout the event.

Unit One HPCI was last tested January 21, 1992, and fully met Technical Specification 4.5.C.3. pump flow rate requirements. Technical Specifications require HPCI to deliver a minimum of 5000 gallons per minute (gpm) against a corresponding reactor pressure greater than 1150 pounds per square inch gage (psig).

E. CORRECTIVE ACTIONS

The immediate corrective actions for the HPCI system consisted of declaring HPCI inoperable and initiating the system outage report.

Because Unit Two was in a refuel outage, the Unit Two HPCI stop valve cover and poppet guide was removed and installed in the Unit One HPCI stop valve. Prior to installing the cover in Unit One, MM bored out the Unit Two poppet guide to the required dimensions with the assistance from a GE turbine representative and Technical Staff personnel to ensure correct alignment with the poppet and poppet guide.

Also, MM verified tolerance measurements during the repair to ensure correct alignment within the stop valve.

The Unit One stop valve cover and poppet guide will be repaired or replaced and installed in Unit Two prior to starting up the Unit Two reactor.

During the next disassembly of Unit One and Unit Two HPCI stop valves, the tolerances of the poppet guide and poppet will be checked (NTS #2542009201001).

This event will be reviewed with Quality Control personnel, Mechanical Maintenance Work Analysts and Engineering Construction personnel to look for proper tolerances during reassembly of critical components (NTS #2542009201002, NTS #2542009201003, NTS #2542009201004).

Also, a sample of Unit Two work packages performed by contractors involving detailed reassembly will be reviewed for the presence of proper tolerance criteria prior to startup from the present Unit Two refuel outage (NTS #2542009201005).

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A search was conducted of the Nuclear Plant Reliability Data System (NPRDS) to identify other stations that use this component in a safety related system. The only other station found was Dresden Station. A copy of this report will be sent to the Dresden Technical Staff Supervisor (NTS #2542009201006).

F. PREVIOUS EVENTS:

A NPRDS search found no previous events involving failures of the HPCI stop valves manufactured by Atwood & Morrill Co. Inc. that involved the poppet and poppet guide binding due to an incorrect weld procedure. Other HPCI stop valve occurrences are listed below:

LER#	TITLE
91-012	Failure of HPCI to Initiate during QCOS 2300-13

A review of these occurrences did not reveal any significant trends that would require further action.

G. COMPONENT FAILURE DATA:

The HPCI turbine stop valve is manufactured by Atwood & Morrill Co. Inc., model number 20747-H.

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Title (4) Unit One Reactor Scram Due to A Group I Isolation Believed To Be Caused By A Spurious Main Steam Line High Flow Trip Due to An Unknown Cause

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
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										0 5 0 0 0
0 2	0 7	9 2	9 2	0 0 4	0 0	0 3	0 7	9 2		0 5 0 0 0

OPERATING MODE (9)	4
POWER LEVEL (10)	1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

___ 20.402(b)	___ 20.405(c)	X 50.73(a)(2)(iv)	___ 73.71(b)
___ 20.405(a)(1)(i)	___ 50.36(c)(1)	___ 50.73(a)(2)(v)	___ 73.71(c)
___ 20.405(a)(1)(ii)	___ 50.36(c)(2)	___ 50.73(a)(2)(vii)	___ Other (Specify in Abstract below and in Text)
___ 20.405(a)(1)(iii)	___ 50.73(a)(2)(i)	___ 50.73(a)(2)(viii)(A)	
___ 20.405(a)(1)(iv)	___ 50.73(a)(2)(ii)	___ 50.73(a)(2)(viii)(B)	
___ 20.405(a)(1)(v)	___ 50.73(a)(2)(iii)	___ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name		TELEPHONE NUMBER	
		AREA CODE	
David Marmon, Technical Staff Engineer	Ext. 2116	3 0 9	6 5 4 - 2 2 4 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
IM	J B	L I T S	1 2 0 4	Y	PE	S B	J X	G 0 8 0	Y
IE	S B	C N V	F 1 8 0	Y	CM	S B	R V	D 2 4 3	Y

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
___ Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e, approximately fifteen single-space typewritten lines) (16)

ABSTRACT:

At 0201 hours on February 7, 1992, Unit One was in the RUN mode at 100% power. A Channel "B" Main Steam Line (MSL) high flow annunciator was received in the Control Room. Immediately thereafter, a full Primary Containment Isolation Group I isolation occurred and a subsequent reactor scram.

All automatic actuations occurred as designed with the exception that Reactor Feed Pumps (RFP) did not trip on +48 inches reactor high level. Additionally, the "C" Electromatic Relief Valve (ERV) failed to open upon manual initiation. Reactor shutdown was accomplished by 1100 hours.

The root cause of the Group I isolation could not be determined. It is believed to be due to spurious initiation of MSL high flow instrumentation. Monitoring instrumentation was installed to evaluate future similar events.

The RFP high level trip did not occur due to setpoint drift. The applicable instruments were calibrated and functionally verified. The "C" ERV did not actuate due to loss of continuity between solenoid electrical contacts. The ERV's were inspected and all worn parts were repaired or replaced.

This report is being submitted to comply with 10 CFR 50.73 (a)(2)(iv).

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LER NO: 254/92-004

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PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2511 MWt rated core thermal power.

EVENT IDENTIFICATION: Unit One Reactor Scram Due To a Group I Isolation Believed To Be Caused By A Spurious Main Steam Line High Flow Trip Due To An Unknown Cause.

A. CONDITIONS PRIOR TO EVENT:

Unit: One	Event Date: February 7, 1992	Event Time: 0201
Reactor Mode: 4	Mode Name: Run	Power Level: 100%

This report was initiated by Deviation Report D-4-1-92-012

RUN Mode (4) - In this position the reactor system pressure is at or above 825 psig, and the reactor protection system is energized, with APRM protection and RBM interlocks in service (excluding the 15% high flux scram).

B. DESCRIPTION OF EVENT:

At 0201 hours on February 7, 1992, Unit One was in the RUN mode at 100% of rated core thermal power. The High Pressure Coolant Injection [BJ] (HPCI) system was out-of-service in day one of a fourteen day Limiting Condition for Operation (LCO) due to a stop valve [VLV] failure. At this time, Annunciator [ANN,IB] C-16, "CHANNEL B MAIN STM LINE HIGH FLOW", was received on the 901-5 panel in the Control Room. Immediately thereafter, a full Primary Containment Isolation [JM] (PCI) Group I isolation occurred, and a subsequent reactor [RCT] scram due to Main Steam Line Isolation Valve [SB,JM] (MSIV) closure. The Reactor Mode Switch was moved to SHUTDOWN as per procedure QCGP 2-3, REACTOR SCRAM. The "B" Main Steam Line [SB] (MSL) flow indicator [FI] (FI) on the 901-5 panel in the Control Room, FI-1-640-23B, was observed to be spiking erratically during the event. FI-1-640-23C was observed to be indicating off-normal.

Reactor water level dipped to approximately -20 inches due to rapid power decrease and steam void collapse and then immediately began to recover. As designed, upon reactor water level reaching the low level trip of +8 inches, PCI Group II and III isolations occurred, Standby Gas Treatment [BH] (SBGT) autostarted, and Reactor Building Vents [VA] (RBV) isolated. The "B" Reactor Feedwater Pump [P,SJ] (RFP) was taken off to help control rising reactor water level. At 0202 hours, reactor water level reached +48 inches and continued to rise. The Main generator [TB,GEN] protective relaying [RLY] scheme sensed a reverse power condition, caused by no steam flow to the Main Turbine [TA,TRB]. This reverse power condition energized the back-up lock-out relay and tripped the Main Generator and Main Turbine. Auxiliary power was transferred automatically upon the generator trip. The Shift control Room Engineer (SCRE) initiated entry into General Abnormal Procedure QGA 100, REACTOR PRESSURE VESSEL CONTROL.

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At 0203 hours the Shift Engineer entered the Control Room and assumed command and control following a short briefing from the SCRE. Reactor water level continued to increase to greater than +52 inches. The Unit One NSO recognized that the +48 inches feedwater pump trip did not occur, and manually tripped the "A" RFP.

At 0205 hours, reactor pressure reached 1041 pounds per square inch (PSI). Under Shift engineer direction, the extra NSO opened the "B" Electromatic Relief Valve [RV,20,SB] (ERV) to control reactor pressure between 800 and 1000 psi. The acoustic monitor [MON,SB,JE] for the "B" ERV gave erratic indication during this event. At 0206 hours, reactor pressure peaked at 1052 psi. In anticipation of a rise in suppression pool [NH] water temperature due to ERV actuation, the Residual Heat Removal [BO] (RHR) system was placed in operation in the torus [NH] cooling mode at 0207 hours.

At 0208 hours, the Unit One NSO continued water level control and established Reactor Water Clean-up [CE] (RWCU) blowdown. Although the MSL high flow annunciation was the only condition present indicative of a MSL break, the Shift Engineer dispatched the Shift Foreman to inspect for evidence of a steam line break. Additionally, he directed Equipment Attendants (EA) to investigate the possibility of accidental damage or bumping of the differential pressure (DP) switches which initiate a MSL high flow signal. The Instrument Maintenance (IM) Foreman was also sent to check the dp switches for any abnormalities.

At 0212 hours the Unit One NSO started the "A" RFP to maintain level between +8 and +48 inches as per QGA 100. Reactor pressure had slowly decreased to 800 psi and the extra NSO closed the "B" ERV at 0214 hours. At 0219 hours, the extra NSO placed the Reactor Core Isolation Cooling [BN] (RCIC) system in service in the pressure control mode to assist in reactor pressure control. However, pressure continued to slowly increase to 1000 psi.

At 0228 hours, the extra NSO attempted to open the "C" ERV. The "B" and "C" ERV's are to be opened alternately as per operating procedure QCOP 203-1, REACTOR PRESSURE CONTROL USING MANUAL RELIEF VALVE ACTUATION. The "C" ERV did not open as indicated by the following: the open light [IL] did not illuminate, the acoustic monitor [MON,IJ] did not actuate, and reactor pressure continued to rise.

At 0229 hours, the "B" ERV was re-opened. Reactor pressure peaked at approximately 1018 psi. As pressure began to drop, reactor level took a sharp increase due to void swelling. AT 0230 hours, noticing this change, the Unit One NSO tripped the "A" RFP. Within three minutes , water level was approximately 30 inches and decreasing. The "A" RFP was restarted. However, the pump did not achieve the necessary pressure quick enough and, at 0233 hours, Group II and III isolations occurred at +12.7 inches indicated reactor water level. An additional reactor scram signal was received but no rod motion occurred because the initial scram had not been reset at this point.

At 0236 hours, the extra NSO closed the "B" ERV. RWCU blowdown was re-established for water level control at 0239 hours.

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

At approximately 0245 hours, the IM Foreman reported that the MSL high flow dp switches all appeared to be indicating normal. Investigations by the operating crew could find no evidence of a MSL break, nor any evidence that personnel were in the area of the MSL high flow switches at the time of this event. Therefore, the Group I isolation was reset and the MSIV's were opened. The "B" inboard MSIV was left closed because of erratic behavior of Flow Indicator [FI,SB] (FI) 1-640-23B as noticed by the Unit One NSO during the recovery operations. The reactor scram was reset at 0317 hours and Reactor Building Ventilation was reset at 0330 hours. At 0400 hours RCIC was taken off, as the Main Condenser [SG,COND] was being utilized as the heat sink for removing reactor heat. At 0402 hours, procedure QGA 100 was exited.

An Emergency Notification System (ENS) phone notification was completed at 0412 hours on February 7, 1992, as required under 10CFR50.72 (b) (2) (ii).

At approximately 1100 hours, the reactor was brought to cold shutdown with reactor water temperature less than 212 degrees. An investigation team was formed in accordance with QAP 1780-11. An investigation report was given to the station prior to start-up.

Procedures QIS 21-1, MSL HIGH FLOW CALIBRATION, and QIS 21-2, MSL HIGH FLOW FUNCTIONAL TEST, were completed for each of the 16 MSL high flow dp switches. As per Technical Specification Table 3.2-1, the trip setting for MSL high flow is $\leq$140% of rated steam flow, which is equivalent to 148 pounds per square inch differential (psid). The as found data showed that all 16 switches tripped within the Technical Specification limit.

Work Request #Q97927 was written to investigate the failure of the "C" ERV. Troubleshooting the actuator, EM personnel identified a resistance of 182 ohms across the shorting bar and contacts of the cut off switch. The switch was replaced and resistance measured to be less than 1 ohm. A reddish dust was observed within the actuator housing. The "B", "D", and "E" ERV's were actuated after cold shutdown and all were verified to operate properly.

Work Request #Q97935 was written to investigate the RFP reactor high level trip which should have occurred at +48 inches. Level Indicating Transmitter With Switches [LIT, LS, JB] (LITS) 1-263-59A and LITS 1-263-59B provide for this high level trip. Switch #4 from each LITS is arranged such that both switches must open to trip the RFP's and the turbine. LITS-1-263-59A Switch #4 was found to trip at a reactor level of +53.5 inches. LITS-1-263-59B Switch #4 was found to trip at a reactor level of +48.1 inches. The trip of the RFP's would have occurred at +53.5 inches. The A and B switches were recalibrated to trip at 47.6 and 48.7 inches reactor level, respectively.

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The erratic MSL flow indication was investigated. There are four MSL flow indication loops, each composed of a dp transmitter [PDT] (DPT) {1-645A, B, C, & D}, power supply [JX], square-root converter [CNV], and Control Room indicator {FI-1-640-23A, B, C, & D}. These loops have no trip function. The "B" loop power supply was found to be faulty, creating a spurious spike. All four square-root converters were identified as having a non-linearity problem resulting in inaccurate readings at low flows. The 1-645B transmitter was replaced under Minor Design Change #P04-1-90-092 which was implemented by Work Request #Q97971. The 645A, C, & D transmitters were calibrated satisfactorily.

C. <u>APPARENT CAUSE OF EVENT</u>:

This report is being submitted to comply with 10CFR50.73 (a)(2)(iv); "The licensee is required to report any event or condition that resulted in manual or automatic actuation of any Engineered Safety Feature [JE] (ESF), including the Reactor Protection System [JC] (RPS), except an actuation which is part of a preplanned sequence during testing or reactor operation."

The apparent cause of this event is a Group One Isolation caused by MSL high flow signal due to an unknown cause. MSL high flow annunciation was received in the Control Room and no evidence of a MSL break could be found. The MSL high flow switches were calibrated and functionally tested and found to be within Technical Specification limits. A search of past history of these switches showed excellent accuracy and reliability. A walkdown inspection of the sensing line piping and all electrical connections was performed and no abnormalities were found. An extensive search of security data and radiation area access control revealed a very limited number of personnel could have been in the vicinity at the time of the reactor scram. Interviews concluded that no one was in the area near the racks at the time of the trip. Two flow check valves were removed from the sensing lines of the dp switches to inspect for possible blockage. No blockage was found. There are four dp switches on each MSL. They are arranged in PCI initiation logic in a {1 of 4} out of 2 taken twice logic, such that the right combination of 2 of the 4 switches connected to the same MSL can initiate a full Group I isolation.

The switches were pressurized to simulate normal operating dp, and vibration induced testing methods were used to test the sensitivity of the switch actuations. No actuations occurred during extensive testing. Since no evidence of an actual steam flow or pressure transient could be identified and all the associated equipment was found to be working properly, the root cause of the Group I isolation and subsequent reactor scram remains unknown.

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

There were two contributing causes which resulted in the failure of the "C" ERV. Vibration induced wear created enough brass and phenolic dust from components within the actuator to result in a loss of continuity between the solenoid electrical contacts. Also, a more thorough root cause analysis from a similar recent event could have prevented this failure. (Reference DVR# 4-1-91-131 described in the Previous Events section.)

The root cause of the failure of the RFP high level trip is setpoint drift of LITS-1-263-59A Switch #4. The switch is calibrated to trip at 48 ±1.7 inches reactor water level. Upon investigation, this switch was found to trip at +53.5 inches reactor water level. The switch was last calibrated on July 20, 1991, to trip at 46.7 inches.

The cause of erratic MSL flow indication on FI-1-640-23B was a faulty power supply. Also, the 1-645B transmitter was determined to be in need of replacement due to calibration adjustment problems and drift history. The cause of off-normal indication on FI-1-640-23C was non-linearity problems with the square root converter.

The "B" ERV Acoustic Monitor was inspected by Instrument Maintenance (IM) personnel. The erratic indication was determined to be due to the mounting clamp having become loose. The clamp was inspected and no wear or abnormalities were found. The clamp was tightened and the acoustic monitor was verified to be operating properly.

D. <u>SAFETY ANALYSIS OF EVENT</u>:

The safety of the public and plant personnel was not affected by this event and the safety significance of this event was minimal. Both vessel pressurization and consequences of a loss of coolant accident have been previously analyzed for a situation with the HPCI system and one relief valve out of service.

During this event, the main feedwater system [SJ] was available at all times to maintain reactor water level. Reactor water level was maintained at least 120 inches above the top of active fuel at all times, thereby assuring adequate core cooling.

Vessel overfill was not a concern during this event since the highest reactor water level reached during this event was approximately +60 inches, which is approximately 47 inches below the main steam lines. Although the reactor feed pumps were manually secured by the NSO, subsequent calibration and functional testing of the trip instruments showed that the automatic trip would have occurred at a reactor water level of +53.5 inches. Therefore, adequate margin was available for vessel overfill protection.

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The highest reactor pressure achieved during the event was 1052 psi, which is 63 psi below the lowest relief valve setpoint and 293 psi below the reactor pressure safety limit. Reactor pressure control during the time that the MSIV's were closed was accomplished according to the Emergency Operating Procedure within a band of 780 to 1015 psi using the "B" ERV. The failure of the "C" ERV did not hinder reactor pressure control during the time that the MSIV's were closed. The "B" ERV operation was sufficient to control pressure with the amount of decay heat present at the time of the event. The "A", "D", and "E" relief valves would have been available to control reactor pressure if they had been needed during the event. In addition, the failure of the "C" ERV would not have degraded the performance of the Automatic Depressurization System [SB,JE] (ADS) below that assumed in the transient and accident analysis previously performed for Quad Cities Station.

All automatic actions, except for the RFP high level trip described above, functioned as expected during the event.

E. CORRECTIVE ACTIONS:

The immediate corrective actions taken were to use procedures QCGP 2-3, REACTOR SCRAM, and QGA 100, REACTOR PRESSURE VESSEL CONTROL, to safely control reactor pressure, level, and other parameters following the scram. The reactor was depressurized and brought to cold shutdown conditions.

A pressure transducer [TD] was installed in each of the eight sensing lines for the MSL dp switches. Recorders [PR,PDR] were installed prior to start-up to continuously monitor MSL pressure and dp, and to monitor the MSL high flow switches and the MSL low pressure switches at the 901-15 and 901-17 panels [pnl] in the Control room. Minor Design Change (MDC) P04-1-92-021 was installed to log all PCI Group I relay actuations on the Sequential Event Recorder [IQ]. The recorders and MDC P04-1-92-021 will enhance the Station's ability to evaluate any future events involving the MSL dp switches and PCI Group I relays.

The investigation of the ERV's identified that some vibration is inherent to the MSL's and that complete mitigation of the vibration is not likely. Therefore, the following corrective actions have been completed or are in progress. The "B", "D", & "E" ERV actuators were also inspected. The resistance of the shorting bar and contact of these valve actuators varied from 0.2 to 8 ohms. All were cleaned reducing the resistance to less than 0.5 ohms. The reddish dust was observed in the "D" and "E" ERV's as well. All worn parts were repaired or replaced on each ERV actuator. The Station will enhance its maintenance procedures to include acceptance criteria for resistance across the shorting bar, a periodic inspection of the actuator parts, and lubrication of actuator parts which could exhibit wear (NTS #2542009201201). The applicable parts were lubricated prior to starting up Unit One. The Station will evaluate the actuator brass parts for possible material replacement (NTS #2542009201202). To prevent repeat failures, the Station will evaluate its failure analysis process to assure critical equipment failures are sufficiently investigated prior to start-up from outages and re-start from scrams. (NTS #2542009201203).

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

The instruments that caused the RFP high reactor level trip, LITS-1-263-59A&B, were recalibrated and functionally tested. The calibration interval of these transmitters on both units will be changed from once per refuel cycle to quarterly to minimize the possibility of excessive drift (NTS #2542009201204). The system engineer has provided Operations personnel with a discussion of the RFP high level trip tolerances and inaccuracy of the indications. This information has been covered during shift turnover meeting. An evaluation on the replacement of the transmitters with appropriate state-of-the-art technology determined that the transmitters are functioning as designed, but the equipment is obsolete. The Station will determine the need for upgrading the transmitters with new models (NTS #2542009201205).

The "B" MSL flow transmitter, FT-1-645B, was replaced with a new model as per MDC P04-1-90-092. The "B" MSL flow indication loop power supply was replaced. The square-root converters for all four indication loops were replaced with calibrated units having no non-linearity problems.

The "B" ERV Acousitc Monitor was repaired by tightening its clamp and verifying proper operation. The other ERV acoustic monitors functioned properly during startup testing.

F. PREVIOUS EVENTS:

The following previous similar events are summarized below:

Date	DVR#	Description
CAUSE ASSOCIATED WITH MSL HIGH FLOW SWITCHES:		
6/23/89	4-2-89-032	1/2 Group I due to Instrument Maintenance Tech bumping MSL high flow switch after performing functional procedure.
1/30/90	4-2-90-003	1/2 Group I due to Contractors bumping the MSL high flow switches.
CAUSE UNKNOWN:		
11/3/90	4-2-90-064	Spurious Group I Alarm
3/18/91	4-1-91-045	Spurious MSL high flow alarm and 1/2 Group I
4/26/91	4-1-91-070	Spurious 1/2 Group I

ASSOCIATED WITH ERV'S:

4-1-90-073	Failure of "C" ERV to open due to worn bushing in solenoid valve.
4-1-91-131	Failure of "B" ERV to open due to a defective cutout switch and binding of the actuator. The shorting bar exhibited high resistance and the guide assembly of the actuator was found to be bent slightly.

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

A nationwide Nuclear Plant Reliability Data System (NPRDS) search was conducted for the 59A&B LITS, the 645B transmitter, the square-root converters, and the loop power supply. The results are as follows:

	Total Failures Nationwide	Failures at Quad Cities Station
59A & B LITS	8	3
645B transmitter	21	0
Square-Root Converter	2	0
Power Supply	22	0

An NPRDS search was recently conducted for the ERV's as per Deviation Report 4-1-91-031. Eighteen failures nationwide were reported. The ERV Acoustic Monitor is not an NPRDS reportable item.

G. COMPONENT FAILURE DATA:

The MSL high flow switches are manufactured by Barton, model 288. LITS 1-263-59A&B, which provide for reactor high level RFP and turbine trips, are manufactured by Yarway, model 4418CE. The "C" ERV, 1-203-3C, is a 6-inch automatic relief valve manufactured by Dresser Industries Inc., model 1525-VX. The failed MSL flow loop components are as follows:

Flow Transmitter FT-1-645B	Barton, model 296
Square-Root Converters 1-640-39A,B,C&D	Foxboro, model 66AT-OH
Loop Power Supply 1-640-10	General Electric, model 50-570062FAAC1

The "B" ERV Acoustic Monitor is manufactured by NDT International, model 104D.

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Title (4) Loss of Main Control Room Annunciators on Unit One and Control Room Ventilation Isolation Following Loss of Line 0405 Due to a Lightning Strike

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
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										0 5 0 0 0
0 2	1 4	9 2	9 2	— 0 0 6	— 0 0	0 3	1 2	9 2		0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 0 %

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

__ 20.402(b)	__ 20.405(c)	X 50.73(a)(2)(iv)	__ 73.71(b)
__ 20.405(a)(1)(i)	__ 50.36(c)(1)	__ 50.73(a)(2)(v)	__ 73.71(c)
__ 20.405(a)(1)(ii)	__ 50.36(c)(2)	__ 50.73(a)(2)(vii)	__ Other (Specify in Abstract below and in Text)
__ 20.405(a)(1)(iii)	__ 50.73(a)(2)(i)	__ 50.73(a)(2)(viii)(A)	
__ 20.405(a)(1)(iv)	__ 50.73(a)(2)(ii)	__ 50.73(a)(2)(viii)(B)	
__ 20.405(a)(1)(v)	__ 50.73(a)(2)(iii)	__ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER (AREA CODE)
Michael Harms, Ext. 2159	3 0 9 6 5 4 - 2 2 4 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	I B	F U	B 5 6 9	N					

SUPPLEMENTAL REPORT EXPECTED (14)

		Expected Submission Date (15)	Month	Day	Year
__ Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e, approximately fifteen single-space typewritten lines) (16)

ABSTRACT:

On February 14, 1992, Unit One was in the SHUTDOWN mode at 0 percent of rated core thermal power. Unit Two was in the REFUEL mode at 0 percent of rated core thermal power. At 2235 hours, a lightning strike in or near the 345 KV switchyard [FK] caused line 0405 to trip. When this line tripped, all Unit One annunciators [ANN] were lost and the Control Room (CR) ventilation [VI] isolation dampers [DMP] failed closed.

The apparent cause of the loss of the CR annunciators was a power surge due to the lightning strike which caused fuse [FU] failures. The apparent cause of the CR vent isolation was a power surge or failure to the Toxic Gas Analyzer panel [PL].

The corrective actions taken for the loss of annunciators included checks on the breakers [BKR] and fuses, replacement of fuses, a walkdown of 125 VDC panels, and requests for Site Engineering studies to increase the station's lightning protection. The corrective actions taken for the CR vent isolation included verifying proper manual and automatic operation of the isolation dampers.

This report is being submitted to comply with 10CFR50.73(a)(2)(iv).

DVR 52

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					Page (3)
		Year		Sequential Number		Revision Number	
Quad Cities Unit One	0 5 0 0 0 2 5 4	9 2	-	0 0 6	-	0 0	0 2 OF 0 6

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION:

General Electric - Boiling Water Reactor - 2511 MWt rated core thermal power.

EVENT IDENTIFICATION: Loss of Main Control Room Annunciators on Unit One and Control Room Ventilation Isolation Following Loss of Line 0405 due to a Lightning Strike.

A. CONDITIONS PRIOR TO EVENT:

Unit: One	Event Date: February 14, 1992	Event Time: 2235
Reactor Mode: 1	Mode Name: Shutdown	Power Level: 00%

This report was initiated by Deviation Report D-4-01-92-017.

SHUTDOWN (1) - In this position, a reactor scram is initiated, power to the control rod drives is removed, and the reactor protection trip systems have been deenergized for 10 seconds prior to permissive for manual reset.

B. DESCRIPTION OF EVENT:

On February 14, 1992, Unit One was in the SHUTDOWN mode at 0 percent of rated core thermal power. Unit Two was in the REFUEL mode at 0 percent of rated core thermal power. At 2235 hours, lightning struck in or near the 345 KV switchyard [FK]. Transmission line 0405 tripped and all of the Unit 1 annunciators [ANN] were lost.

At 2240 hours, a Generating Station Emergency Procedure (GSEP) Alert was declared. Per QEP 200-T1, "Quad Cities Emergency Action Levels", the loss of annunciators on the Emergency Core Cooling System panel (901-3), Reactor Control panel (901-5), and the Electrical panel (901-8) in the main Control Room [NA] (CR) requires a GSEP declaration.

A Shift Foreman (SF) and Equipment Operator (EO) were immediately dispatched to the Unit One battery charger [BYC] room to determine the condition of the DC feed breaker [BKR] for the 901-34 panel, annunciator control panel. All DC power for the Control Room annunciator panels is fed from the 901-34 panel. The SF and EO reported that the annunciator feed breaker was in the normal ON position and no problems were found.

The SF and EO proceeded to the 901-34 panel located in the Auxiliary Electric Room. The EO pulled the fuse [FU] block [BLK] that contained the main positive and negative fuses for the 901-34 panel. Electrical Maintenance (EM) personnel performed a continuity check on the fuses and determined that the fuses had not blown. At 2256 hours, the fuse block was reinstalled with the original fuses and annunciator power was restored except for the 901-6 panel.

DVR 52

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)						Page (3)
		Year		Sequential Number		Revision Number		
Quad Cities Unit One	0 5 0 0 0 2 5 4	9 2	-	0 0 6	-	0 0		0 3 OF 0 6

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

The Unit One Nuclear Station Operator (NSO) tested all panel annunciators satisfactorily except the 901-6 panel and determined that there were no unusual alarms. At 2308 hours, the SF and EO found a blown fuse in the 901-34 panel associated with the control room 901-6 annunciator panel circuitry. The EO replaced the fuse and the 901-6 annunciators were restored.

At 2329 hours, an Electrical Maintenance Foreman recommended replacing the main fuses that were previously removed and reinstalled. The Foreman could not explain why this action restored power to the annunciators. On February 16, 1991, the main fuses removed from the 901-34 panel were continuity tested a second time. One of the fuses tested bad indicating a loss of fuse integrity. At 2332 hours, the fuses were replaced with like-for-like fuses. In addition, a 1 hour Emergency Notification System (ENS) telephone call and a Nuclear Accident Response System (NARS) call were made at this time.

At 2340 hours, an EO was dispatched to inspect DC batteries and busses for damage and later reported that no damage was found and the DC systems appeared normal. At 2354 hours, the GSEP Alert was terminated because all Unit One annunciators were working properly. At 2358 hours, ENS and NARS telephone calls were made for the GSEP termination. Operating personnel were cautioned to closely monitor indications and alarms over the next several days to verify proper annunciator response. Line 0405 was reclosed at 1615 hours on February 15, 1992.

Also at 2235 hours, immediately following the lightning strike, the CR ventilation system [VI] automatically entered the recirculation mode of operation and the "Control Room Standby HVAC System Major Trouble" alarm [ALM], G-12, annunciated on the 912-1 panel in the Main CR. An Equipment Operator (EO) was dispatched to the Toxic Gas Analyzer panel, 1/2-9400-103, and the CR Standby Heating, Ventilation, and Air Conditioning (HVAC) local control panel, 1/2-9400-105. The EO identified that the "Toxic Gas Concentration High" and the "Toxic Gas Analyzer Trouble" alarms were annunciating on the 1/2-9400-105 panel. However, the EO identified that no alarms were present on the Toxic Gas Analyzer panel. The EO then acknowledged and reset alarms on the 1/2-9400-105 panel. The EO also verified that the CR isolation dampers [DMP] had failed closed as per design. A Shift Foreman (SF) was dispatched to the panels to further investigate. The CR isolation dampers were then reset, manually isolated, and reset again to verify proper manual operation of the system. At 0200 hours on February 15, 1992, the Instrument Maintenance Department (IMD) performed QIS 79-2, "Chlorine Analyzer Functional Test Procedure," and verified that the dampers isolated properly from an automatic isolation signal. An Emergency Notification System (ENS) phone call was made at 0207 hours per 10CFR50.72(b)(2)(ii).

C. APPARENT CAUSE OF EVENT:

This report is being submitted in accordance with 10CFR50.73(a)(2)(iv), which requires the reporting of any event or condition that results in manual or automatic actuation of an Engineered Safety Feature (ESF).

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year		Sequential Number		Revision Number	Page (3)
Quad Cities Unit One	0 5 0 0 0 2 5 4	9 2	-	0 0 6	-	0 0	0 4 OF 0 6

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

The apparent cause of the loss of annunciators was a lightning strike in the vicinity of the plant. The lightning strike initiated a power surge which caused one of the main power fuses, F1 and F2, for the 901-34 panel to fail. The power surge also blew fuse F24 in the 901-34 panel which protects circuitry associated with the 901-6 annunciator panel located in the CR.

The main power fuse failure was determined to be a mechanical failure rather than a purely electrical failure. This would explain why the fuse was found to have good continuity on February 14 when it was originally checked and reinstalled and poor continuity after Electrical Maintenance recommended replacing the fuse. The metal inside the fuse that carries current was degraded by the lightning strike to where it was making fluctuations in continuity influenced by physical movement of the fuse. If the fuse failed electrically, the current carrying metal would have disintegrated so that continuity through the fuse would have been impossible. The EM Foreman also noted the fuse to be warm at the time it was replaced which was attributed to a high resistance internal fuse connection.

The apparent cause of the CR ventilation isolation was a power surge or disruption to Motor Control Center [MCC] (MCC) 16-3-1 due to the lightning strike. MCC 16-3-1 is the source of power for the Toxic Gas Analyzer panel, 1/2-9400-103. Upon a power loss or surge to this panel, the CR isolation dampers are designed to fail in the safe direction of closed.

D. SAFETY ANALYSIS OF EVENT:

Safety of the public and plant personnel was not affected by the loss of Unit One annunciators. Unit One was in cold shutdown during the event. This decreased the number of evolutions which could cause alarms to annunciate, thereby making it easier for the NSO to use monitoring instrumentation for the status of the unit.

A walkdown was performed immediately after the annunciators were restored, both in the CR and in the plant, to determine if any other equipment associated with the AC or DC distribution systems were effected. No other signs of equipment degradation or unusual indications were found.

Therefore, all indication and control equipment necessary to maintain the reactor in a safe shutdown condition were available and sufficient for operator use, if required.

The safety significance of the CR ventilation isolation was also minimal. When power to the Toxic Gas Analyzer panel surged or was interrupted, the CR isolation dampers failed closed causing the CR ventilation system to enter the recirculation mode of operation. This system response was the design response and was fail-safe.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0		
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)						Page (3)		
		Year		Sequential Number		Revision Number				
Quad Cities Unit One	0 5 0 0 0 2 5 4	9 2	-	0 0 6	-	0 0		0 5	OF	0 6

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

E. CORRECTIVE ACTIONS:

The immediate corrective action taken as a result of the loss of annunciators was to check the 901-34 panel supply breaker and main fuses. The supply breaker was determined to be closed and functioning properly. Therefore, the main fuses were satisfactorily tested for continuity, reinstalled, and the annunciators were reenergized. A fuse was replaced in the 901-34 panel to reenergize the 901-6 CR panel annunciators. All annunciators were then tested satisfactorily with no unusual alarms lit for the plant conditions.

Upon a recommendation by the EM Foreman, the main fuses for the 901-34 panel, previously continuity tested, were replaced.

The Operations department performed a walkdown of fuses in the CR, Auxiliary Electric room, and 345 KV relay [RLY] house. In addition, all 125 VDC panels were checked for tripped relays and breakers. No discrepancies were found.

On February 16, 1992, Nuclear Work Request Q98184 was initiated to inspect all of the Unit One annunciator fuses. The work package was completed with no degraded wiring or fuses found. The main fuses that were replaced were continuity tested a second time at the request of station Technical Staff personnel. One of the main fuses tested bad and was cut open. It was then observed that the fuse failed mechanically rather than electrically.

As further corrective action, Site Engineering will commission a study to determine enhancements that can be done to the Station's lightning protection system (NTS# 2542009201701).

The immediate corrective actions taken for the CR ventilation isolation were to dispatch an EO to the Toxic Gas Analyzer panel and the CR Standby HVAC local control panel. At the panels, the EO verified that the isolation dampers had failed closed as designed.

A SF was then dispatched to the panels to assist in the investigation. The EO and SF reset, isolated, and reset the dampers again to verify proper manual operation of the dampers. The IMD then performed QIS 79-2, "Chlorine Analyzer Functional Test Procedure," and verified proper automatic operation of the dampers.

No further corrective actions for the CR ventilation isolation are necessary.

DVR 52

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year		Sequential Number		Revision Number	Page (3)
Quad Cities Unit One	0 5 0 0 0 2 5 4	9 2	-	0 0 6	-	0 0	0 6 OF 0 6

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

F. PREVIOUS EVENTS:

Previous events that involved a lightning strike in the vicinity of the station are as follows:

1) DVR 04-02-87-031 (LER 87-007), "RWCU Isolation (Group III) and One Half of a Group I, Group II, and a Channel A 1/2 Scram From Loss of Bus 28 Due to Lightning Strike."

2) DVR 04-02-90-054, "Lightning Strike Causing Valve 1-220-45 to Close."

3) DVR 04-01-91-050 (LER 91-008), "Reactor Building Ventilation Isolation Due to Lightning Strike."

There was one previous event in the past five years that involved the loss of annunciators. Deviation Report 04-02-92-016 reported that all annunciators for Unit Two were lost due to a main fuse failure on the 902-34 panel during a modification to enhance the annunciator system.

Previous events where the CR isolation dampers failed closed due to a surge or loss of power to the Toxic Gas Analyzer panel are as follows:

1) DVR 04-01-87-048 (LER 87-010), "Control Room Ventilation Trip Due to Power Loss to Toxic Gas Analyzer - Design Deficiency and Late Notification - Personnel Error."

2) DVR 04-01-87-071 (LER 87-014), "Control Room Ventilation Isolation Caused by Chlorine Analyzer Spike During Electrical Storm."

G. COMPONENT FAILURE DATA:

The fuse was manufactured by Bussman, part number #NON-60.

There is no component failure data associated with the CR ventilation isolation.

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE PNO-III-92-17 Date April 6, 1992

This preliminary notification constitutes EARLY notice of events of POSSIBLE safety or public interest significance. The information is as initially received without verification or evaluation, and is basically all that is known by the Region III staff on this date.

Facility: Dresden Unit 3
Commonwealth Edison Co.
Morris, IL 60450

Docket No: 50-249

Licensee Emergency Classification
General Emergency____ Site Area Emergency____
Alert X Unusual Event____ N/A____

Subject: LOSS OF ALL CONTROL ROOM ANNUNCIATORS

At 8:25 p.m. (CST) on April 4, 1992, Dresden Unit 3 lost all its control room annunciators and the licensee declared an Alert in accordance with Dresden's Emergency Plan. Unit 3 was in cold shutdown mode and had been in a scheduled refueling outage for 210 days. The reactor coolant temperature was at 133 degrees F and the system was at atmospheric pressure. All control room instrumentation was functional with offsite and emergency onsite power available. All Unit 3 systems and equipment continued to function as required to maintain Unit 3 in its existing safe shutdown condition. Unit 2 was not affected by this event.

Several brief losses of annunciators occurred intermittently following the initial alert declaration. The annunciators were restored at 8:58 p.m. They were lost again at 9:30 p.m. and restored at 9:45 p.m.

A major upgrade of the annunciators was performed during the current refueling outage and the licensee's investigation included the areas which were affected. At 11:59 p.m., the licensee confirmed that the cause of the problem was a loose wire connector within the annunciator cabinet. The loose connector was due to stripped screw threads on a fuse block.

At 1:55 a.m. on April 5, 1992, the licensee terminated the Alert after replacing the problem fuse block and testing the system satisfactorily.

The State of Illinois will be informed. The information in this preliminary notification has been reviewed with licensee management.

The licensee notified the NRC Operations Center of this event at 8:43 p.m. on April 4, 1992. The NRC Senior Resident Inspector reported to the site. The appropriate NRC staff at Region III and Headquarters were in communication with the licensee and monitored the event until termination of the Alert. This information is current as of 4:00 p.m. on April 5, 1992.

CONTACT: A. Hsia FTS 388-5543 B. Clayton FTS 388-5574
Anthony H. Hsia Robert Clayton

9204100047 920406
PDR I&E
PNO-III-92-017 PDR

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2	0 5 0 0 0 2 6 1	1 OF 0 4

TITLE (4)

PLANT SHUTDOWN DUE TO SAFETY INJECTION PUMP INOPERABILITY

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 7	0 9	9 2	9 2	— 0 1 3	— 0 0	0 7	2 7	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.72(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
DAVID CROOK, SR. SPECIALIST, REGULATORY COMPLIANCE	8 0 3	3 8 3 - 1 1 7 9

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On July 8, 1992, at 2307 hours, H. B. Robinson Unit No. 2 entered a 24 hour Limiting Condition for Operation (LCO) due to inadequate recirculation flow for "B" Safety Injection Pump. An investigation of the cause of the low flow condition was initiated. At 2030 hours on July 9, 1992, a plant shutdown to hot shutdown condition was initiated.

The cause of this event is attributed to personnel error. Event investigation identified the cause of the "B" Safety Injection pump's reduced recirculation flow to be foreign material blockage within the associated minimum flow recirculation check valve and flow orifice. This foreign material was subsequently identified as a plastic sheet material fabricated for use as purge dam material for welding operations associated with a recent modification to the RHR minimum flow recirculation system. Removal of the debris was accomplished through extensive system flushing. Repairs associated with the "B" Safety Injection pump were satisfactorily completed at 0812 hours on July 12, 1992, and the plant was returned to service at 1301 hours.

This report is submitted pursuant to 10 CFR 50.73(a)(2)(i)(A) as the completion of a plant shutdown required by the plant's Technical Specifications.

NRC Form 366 (6-89)

LER NO: 261/92-013

NRC Form 366A

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
H. B. ROBINSON, UNIT 2	0 5 0 0 0 2 6 1	9 2	— 0 1 3	— 0 0	0 2 OF 0 4

I. DESCRIPTION OF EVENT

On July 8, 1992, at 2307 hours, H. B. Robinson Unit No. 2[1] entered a 24 hour Limiting Condition for Operation (LCO) due to inadequate recirculation flow for "B" Safety Injection Pump. An investigation of the cause of the low flow condition was initiated. At 2030 hours on July 9, 1992, a plant shutdown to hot shutdown condition was initiated. The NRC was notified of this shutdown via the ENS as required by 10 CFR 50.72(b)(1)(i)(A).

Following an additional day of investigation, it was determined that repairs could not be made within the allowed LCO time period. Technical Specification 3.3.1.2 requires that if the system cannot be restored within an additional forty eight hours of achieving hot shutdown condition, the unit must be placed in cold shutdown condition using normal plant cooldown procedures. This LCO would expire on July 11, 1992 at 2259 hours. On July 11, at 1600 hours, the licensee contacted the NRC to request a Regional Waiver of Compliance that would extend the period of hot shutdown condition from 48 hours to 96 hours.[2] Following this discussion, NRC-Region II verbally granted the requested waiver, effective until July 13, 1992, at 2259 hours.

Repairs associated with the "B" Safety Injection pump were satisfactorily completed at 0817 hours on July 12, 1992 and the plant was returned to service at 1301 hours.

II. CAUSE OF EVENT

The cause of this event is attributed to personnel error. Event investigation[3] has identified the cause of the "B" Safety Injection pump's reduced recirculation flow to be the result of foreign material blockage within the associated minimum flow recirculation check valve and flow orifice. This foreign material was subsequently identified as a plastic sheet material which had been fabricated for use as a purge dam material for welding operations associated with a recent modification to the Residual Heat Removal (RHR) minimum flow recirculation system. It is believed that the material was introduced as a result of breakage of one of four, nine inch diameter purge dam pieces.

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[1] H. B. Robinson Steam Electric Plant Unit No. 2, is a Pressurized Water Reactor in commercial operation since March, 1971.

[2] H. B. Robinson Serial No. RNPD/92-1882, dated July 11, 1992.

[3] Adverse Condition Reports ACR 92-249 & ACR 92-250

NRC FORM 366A

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
H. B. ROBINSON, UNIT 2	0 5 0 0 0 2 6 1	9 2	— 0 1 3	— 0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The investigation identified that use of the plastic purge dams was abandoned after the attempted use of two dams was terminated by their removal from the RHR system piping because the plastic dams could not be adequately sealed. A small, unidentified portion of this material was inadvertently introduced into the system piping associated with the RHR system, the Refueling Water Storage Tank, and the Safety Injection and Containment Spray Pump suction piping.

III. ANALYSIS OF EVENT

At the time of this condition, all ECCS systems were operable with the exception of the "B" Safety Injection pump. With the plant at Hot Shutdown, the boron concentration was raised to cold shutdown levels to compensate for a steam line break accident, and licensee operators were reminded of the Emergency Operating Procedure Function Restoration Procedures that would mitigate an accident, should one occur with the loss of Safety Injection. Therefore, the Safety Injection Pumps were not an immediate concern to prevent a restart accident during a steam line break cooldown. The Charging Pumps were maintained fully operable as a backup to the Safety Injection Pumps. The amount of decay heat inventory was evaluated based on the Units' operation prior to shutdown, and it was determined that a single Charging Pump had capacity that exceeded the heat removal requirements. Additional operator attention to the capability of the Function Restoration Procedures would ensure a reliable compensatory performance could be achieved.

The basis of Technical Specification 3.3 states that "For a single component to become inoperable does not negate the ability of the system to perform its function, but reduces the redundancy provided in the system design and thereby limits the ability to tolerate additional equipment failures." The reactor had been placed in a hot shutdown condition at the time, borated to cold shutdown levels, and the decay heat from the fuel continued to decrease during the additional time repairs were being performed. Additionally, a Probability Risk Assessment of the additional risk associated with the additional 48 hour extension requested was conducted by the licensees Nuclear Engineering Department, and found to be negligible.

Since the plant was borated to cold shutdown boron concentration and the Charging System was capable of providing adequate core cooling at the reduced heat loading, any reduction of margin created by one inoperable Safety Injection Pump had been compensated for.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
H. B. ROBINSON, UNIT 2	0 5 0 0 0 2 6 1	9 2	— 0 1 3	— 0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

IV. CORRECTIVE ACTIONS

Removal of the debris was accomplished through extensive system flushing. The SI system was operated at design flow rates, with no additional blockage of the orifice flow due to material present in that system. Because of the plastic material geometry, it is believed that any material introduced into the Refueling Water Storage Tank would have settled to the bottom of the tank. It is unlikely for the material to be caught in the flow stream due to the geometry of the material and the relationship of the tank to the Safety Injection System's supply line. Therefore it was considered not to represent a blockage threat to any related equipment and piping systems.

The "A" SI Pump had been operated at full flow following the completion of the RHR minimum flow recirculation modification, and has operated greater than thirty minutes in the minimum flow configuration with no evidence of foreign material blockage in that system. Additionally, flow testing was completed on both Containment Spray Pumps in a minimum flow configuration with acceptable results. These pumps are normally aligned with the minimum flow recirculation lines closed, with the pump discharge aligned directly to the containment.

This report is submitted pursuant to 10 CFR 50.73(a)(2)(i)(A) as the completion of a plant shutdown required by the plant's Technical Specifications.

V. ADDITIONAL INFORMATION

A. Component Failures

None

B. Previous Similar Events

None

NRC FORM 366A (9-83)

*U.S.GPO 1986-0-624-538/455

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION	APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92
LICENSEE EVENT REPORT (LER)	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
H. B. ROBINSON UNIT NO. 2	05000261	1

TITLE (4)

ENTRY INTO TECHNICAL SPECIFICATION 3.0 DUE TO SAFETY INJECTION PUMP INOPERABILITY

EVENT DATE (5)			LER NUMBER (6)					REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR		SEQ. NO.		REV. NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
07	09	92	92	-	014	-	00	08	08	92		05000

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)							
			20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10)	100		20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract and Text)
			20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
DAVID CROOK, SENIOR SPECIALIST - REGULATORY COMPLIANCE	(803)383-1179

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single space typewritten lines) (16)

On July 9, 1992, H. B. Robinson Unit No. 2 was operating at one hundred percent power. A 24 hour Limiting Condition for Operation (LCO) was in effect in accordance with Technical Specification 3.3.1.2.b for the "B" High Head Safety Injection (SI) Pump due to unscheduled maintenance. At 1839 hours, while starting "A" High Head SI Pump to verify flow measuring equipment operation, one of two control power fuses blew in the pump breaker closing circuit, and licensee operators declared the "A" SI Pump inoperable. Due to the inoperability of all High Head Safety Injection pumps, the action statement for Technical Specification 3.0 was entered.

Both control power fuses were removed from the "A" SI Pump breaker and replaced with identical fuses from the "B" SI Pump breaker. At 2009 hours, after three successful pump starts from the Control Room, the "A" SI Pump was declared operable, and the action statement for Technical Specification 3.0 was exited. Two possible causes have been identified for the fuse failure. Either the fuse failed to withstand its tested, nominal breaker closing current under the fuse's closing curves, or there occurred a current of enough magnitude and duration to blow the fuse during this one closing.

This report is submitted pursuant to 10 CFR 50.73(a)(2)(i)(B).

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR		SEQ NO.		REV NO.	PAGE (3)
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	014	-	00	2

TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. DESCRIPTION OF EVENT

On July 9, 1992, H. B. Robinson Unit No. 2[1] was operating at one hundred percent power. A 24 hour Limiting Condition for Operation (LCO) was in effect in accordance with Technical Specification 3.3.1.2.b for the "B" High Head Safety Injection (SI) Pump due to unscheduled maintenance.[2] At 1839 hours, while starting "A" High Head SI Pump to verify flow measuring equipment operation, one of two control power fuses blew in the pump breaker closing circuit[3], and licensee operators declared the "A" SI Pump inoperable. Due to the inoperability of all High Head Safety Injection pumps, the action statement for Technical Specification 3.0 was entered. This action requires that, if a Limiting Condition for Operation cannot be satisfied because of circumstances in excess of those addressed in the specification, the unit shall be placed in hot shutdown within eight hours, and in cold shutdown within the next thirty hours, unless corrective measures are taken that permit operation under the permissible Limiting Condition for Operation statements for the specified time interval as measured from initial discovery.

The NRC was notified of the entry into the Technical Specification action statement via the ENS on July 9, 1992, at 1927 hours pursuant to 10 CFR 50.72(b)(1)(ii).

Both control power fuses were removed from the "A" SI Pump breaker and replaced with identical fuses from the "B" SI Pump breaker. At 2009 hours, after three successful pump starts from the Control Room, the "A" SI Pump was declared operable, and the action statement for Technical Specification 3.0 was exited.

II. CAUSE OF EVENT

Although the root cause of this event cannot be specifically determined, two possible causal factors have been identified. The manufacturer concluded the fuse was progressively weakened by repeated breaker closures until it opened to clear the circuit. Although it is presumed the fuse performed as designed, the first possible cause is a failure of the fuse to withstand the tested and nominal breaker closing currents under the fuse's published curves.

The second possible cause is that a current anomaly occurred with a current of enough magnitude and duration to blow the fuse during this one closing cycle that did not occur during previous or subsequent closings.[4]

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[1]H. B. Robinson Steam Electric Plant Unit No. 2, is a Westinghouse Pressurized Water Reactor in commercial operation since March, 1971.

[2]LER 92-013, Plant Shutdown Due to Safety Injection Pump Inoperability

[3]Westinghouse Type DB-50

[4] EIIS Codes System: BQ; Component: CKTBKR; Manufacturer: W120, B569

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQ NO.		REV NO.	
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	014	-	00	3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

III. ANALYSIS OF EVENT

Entry into Technical Specification 3.0 represents a "condition prohibited by the plant's Technical Specifications." Therefore, this LER is submitted pursuant to the requirements of 10 CFR 50.73(a)(2)(i)(B).

The safety significance of this condition is considered to be minimal. At the time of this condition, all ECCS systems were operable with the exception of the "B" Safety Injection pump. Due to the relatively short period of time that both pumps were inoperable, the likelihood of a plant transient requiring safety injection during that time period is considered to be negligible. In addition, Function Restoration Procedure FRP-C.1 provides plant operators with actions to restore core cooling available if Safety Injection flow in all trains is not obtained.

IV. CORRECTIVE ACTIONS

An investigation was initiated to determine the cause of the fuse failure.[5] The blown fuse was installed in this circuit on April 18, 1992 under Work Request WR/JO 91-AGNY1, replacing a Bussmann REN-10 fuse. Calculation No. RNP-E-9.005, performed under the H. B. Robinson Fuse Control Program, verified the adequacy of the fuse for this application.

On July 10, 1992, as part of the investigation, licensee engineers recorded the closing circuit current draw during closing of the breaker. The results demonstrated that the recorded value was 11.55 peak amperes during the 156ms closing cycle, which falls within the breaker manufacturer's nominal values. Time-current curves for the control power fuse indicates it could withstand up to 55 amperes for 150ms, which is two and one half times the manufacturers' nominal rating, and five times the measured current draw on the DB-50 closing circuit. Additionally, the fuse can withstand 15 amperes for five minutes, or 20 amperes for 50 seconds. The time-current curves indicate the fuse is adequate for the requirements of the breaker (when compared to the manufacturers nominal time-current values and CP&L tested values) and should be capable of withstanding repeated closing operations. This fuse is presently being used in DB-50 closing circuits at H. B. Robinson and there have been no other reported incidents of failure.

The blown fuse was returned to the manufacturer for inspection. Based on the manufacturer's analysis of the fuse, information was provided that the fuse opened under load, and that there was no apparent evidence of any defect within the fuse. Therefore it is presumed the fuse performed as designed. The manufacturer concluded the fuse was progressively weakened by repeated breaker closures until it opened to clear the circuit.

Work request WR/JO 92-ALHY1 has been initiated to inspect the breaker to determine if any function of the closing operation of the breaker could have caused a condition of excess current draw sufficient to blow the 10 ampere fuse, and to perform any necessary maintenance to correct such a condition.

The fuse manufacturer has recommended to use a LPN-RK fuse in DB-50 breaker closing circuits. This recommendation has been entered into the H. B. Robinson Technical Manual/Vendor Recommendation program under tracking number 92-0140 where it will be appropriately evaluated through the Fuse Control Program as a possible alternate fuse selection.

[5] Adverse Condition Report 92-277

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQ NO.		REV NO.	
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	014	-	00	

TEXT (If more space is required, use additional NRC Form 366A's) (17)

V. ADDITIONAL INFORMATION

A. Component Failures

None

B. Previous Similar Events

None

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2	05000261	1

TITLE (4)

UNUSUAL EVENT DUE TO LOSS OF OFF-SITE POWER AND REACTOR TRIP

EVENT DATE (5)			LER NUMBER (6)					REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR		SEQ. NO.		REV. NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
08	22	92	92	-	017	-	00	09	21	92		05000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

OPERATING MODE (9): N		20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10): 100		20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
		20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract and Text)
		20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
		20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
		20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
R. D. CROOK, SR. SPECIALIST - REGULATORY COMPLIANCE	(803)383-1179

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)				EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
	YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single space typewritten lines) (16)

On Saturday, August 22, 1992, H. B. Robinson Unit No. 2 was operating at one hundred percent power. At 1007 hours a loss of offsite power occurred due to a trip of the Startup Transformer. The loss of the Startup Transformer caused a loss of Emergency Bus E-2 and Instrument Bus 4, causing a turbine runback. At 1009 hours, a high level in "A" Steam Generator caused a turbine trip and a subsequent reactor trip. At 1010 hours the Auxiliary Transformer tried to transfer its load to the Startup Transformer as designed, and a loss of E-1 resulted. At 1012 hours the Emergency Operating Procedures network was entered and immediate actions were begun for response to the reactor trip. In accordance with the Emergency Plan, an Unusual Event was declared at 1025 hours due to loss of offsite power. The plant was stabilized and repairs were initiated on the Startup Transformer.

The Startup Transformer trip was caused by a short circuit in the sudden pressure fault protective relay sensing circuitry. During the event, the plant response performed as expected. There was no threat to public safety since both Emergency Diesel Generators started as required and provided power to the Emergency Busses. Repairs to the Startup Transformer were completed and normal power was restored to the Emergency Busses at 0050 hours on Sunday, August 23, 1992. The Unusual Event was terminated at 0124 hours.

This report is submitted pursuant to 10 CFR 50.73(a)(2)(i)(C) and 10 CFR 50.73(a)(2)(iv).

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR		SEQ NO.		REV NO.	PAGE (3)
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	017	-	00	2

TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. DESCRIPTION OF EVENT

On Saturday, August 22, 1992, H. B. Robinson Unit No. 2[1] was operating at one hundred percent power, with no major evolutions or activities in progress. At 1007 hours a loss of offsite power occurred due to a trip of the Startup Transformer.[2] The loss of the Startup Transformer caused a loss of Emergency Bus E-2 and Instrument Bus 4, causing a turbine runback. Due to the loss of E-2, Emergency Diesel Generator "B" started and loaded properly. The primary plant transient caused the Reactor Coolant System (RCS) inventory to shrink, lowering the level in the Pressurizer to below ten percent. At 1009 hours, a high level in "A" Steam Generator caused a turbine trip and a subsequent reactor trip. At 1010 hours the Auxiliary Transformer tried to transfer its load to the Startup Transformer as designed, and a loss of E-1 resulted, causing the "A" Emergency Diesel Generator to start and load as required. At 1012 hours the Emergency Operating Procedures network was entered and immediate actions were begun for response to the reactor trip. A manual safety injection was initiated at 1018 hours due to the decrease in Pressurizer level and the inability to maintain level with the Charging Pumps. Pressurizer level recovered within a short period of time and the safety injection was reset at 1021 hours. In accordance with the Emergency Plan, an Unusual Event was declared at 1025 hours due to loss of offsite power. As a precautionary measure due to the nature of the event, the onsite Technical Support Center and Operations Support Center were activated to support plant response. At 1037 hours, the safety injection was terminated. At 1052 hours, the backup Pressurizer Heaters were energized from the emergency buses, and at 1103 hours Natural Circulation was verified with RCS temperatures stable at approximately 500 degrees F. The plant was stabilized and repairs were initiated on the Startup Transformer. At 1348 hours, a deviation from Emergency Operating Procedure EPP-021 was taken in order to restore power to the Deepwell Pumps to supply the Condensate Storage Tank.

The NRC was notified of this event via the ENS pursuant to 10 CFR 50.72(a)(1)(i) as a declaration of one of the Emergency Classes specified in the licensee's approved Emergency Plan. The NRC was notified via the ENS of the procedure deviation mentioned above pursuant to 10 CFR 50.72(b(1)(i) as a deviation from the plant's Technical Specifications pursuant to 50.54(x).

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[1] H. B. Robinson Steam Electric Plant, Unit No. 2, is a Westinghouse Pressurized Water Reactor in commercial operation since March, 1971.

[2] Adverse Condition Report ACR 92-307

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQ NO.		REV NO.	
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	017	-	00	3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

II. CAUSE OF EVENT

The start-up transformer trip was caused by a short circuit in the sudden pressure fault protective relay sensing circuitry. This short circuit was the result of water collecting in the base of the cable connector at the relay (see attached photograph). A cable connects the relay to a junction box approximately two and one half feet away, and about six inches above the relay. The cable houses three conductors which connect the relay to the transformer protective circuitry. This cable is hollow with the conductors loose inside. The junction box, which is designed with a drain hole for removal of moisture, had been inadvertently rotated to the point where the drain hole allowed water to collect inside. The water subsequently entered the hollow cable and traveled to the base of the relay/cable connector, where it shorted across two soldered connections.

The reactor trip was caused by a high steam generator level resulting from loss of instrument busses powered from the start-up transformer.

III. ANALYSIS OF EVENT

During this event, there was no threat to public safety since both Emergency Diesel Generators started as required and provided power to the Emergency Buses. In addition, the Dedicated Shutdown Diesel Generator was available throughout the event to supply power if called upon. Appropriate provisions are available in the Emergency Operating Procedures to control the Plant for an extended period of time until some form of AC power is restored (i.e., offsite power, Emergency Diesels, or the Dedicated Shutdown Diesel).

This report is submitted pursuant to 10 CFR 50.73(a)(2)(i)(C) and 10 CFR 50.73(a)(2)(iv).

IV. CORRECTIVE ACTIONS

Repairs to the start-up transformer were completed and normal power was restored to the emergency busses at 0050 hours on Sunday, August 23, 1992. The Unusual Event was terminated at 0124 hours.

V. ADDITIONAL INFORMATION

A. Failed Component Information

None

B. Previous Similar Events

LER-86-005

LER NO: 261/92-017

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

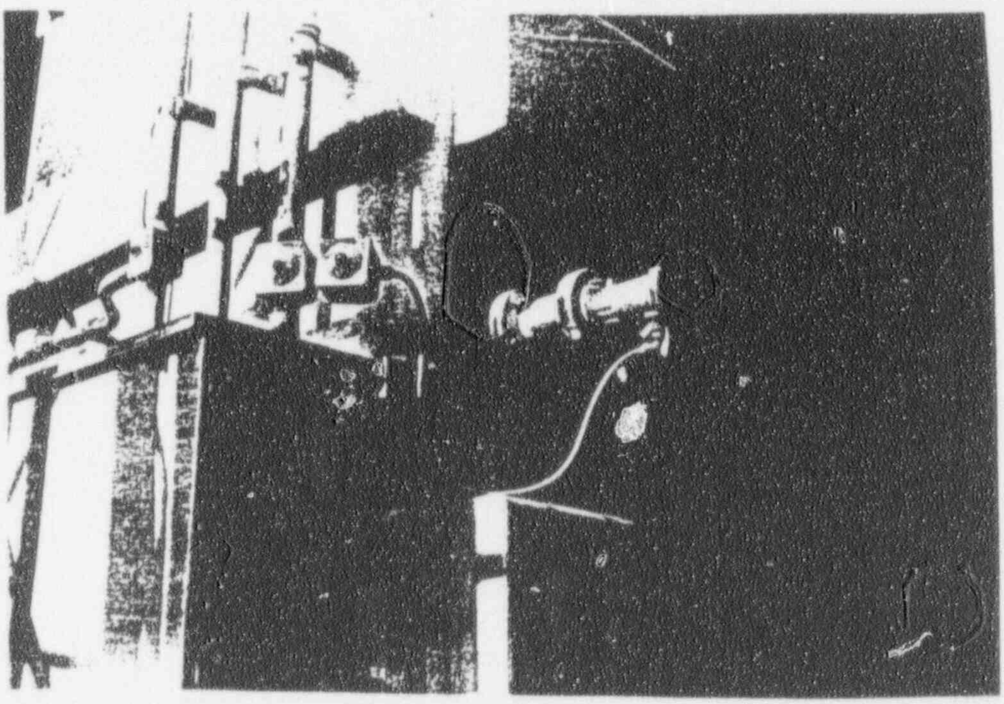
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR		SEQ NO.		REV NO.	PAGE (3)
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	017	-	00	4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

SUDDEN PRESSURE FAULT PROTECTIVE RELAY CIRCUITRY

(CORRECT POSITION)



NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2	05000261	1

TITLE (4)
DEGRADED CONDITION: LOSS OF BOTH SAFETY INJECTION PUMPS DUE TO FOREIGN MATERIAL INTRUSION

EVENT DATE (5)			LER NUMBER (6)					REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR		SEQ. NO.		REV. NO.	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
08	24	92	92	-	018	-	00	09	22	92		05000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

OPERATING MODE (9)	N		20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10)	000		20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract and Text)
			20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
DAVID CROOK, SENIOR SPECIALIST - REGULATORY COMPLIANCE	(803)383-1179

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single space typewritten lines) (16)

On August 24, 1992, H. B. Robinson Unit No. 2 was in hot shutdown condition and preparing for startup. At 1826 hours during performance of a surveillance test, the licensee declared Safety Injection pump "B" inoperable due to inadequate recirculation flow. At 2258 hours, Safety Injection pump "A" was declared inoperable due to an observed declining trend in the pump's recirculation flow. With both Safety Injection pumps inoperable, Technical Specification 3.0 was entered, which requires that the plant be placed in cold shutdown condition within 30 hours. The plant achieved cold shutdown condition at 0020 hours on August 25, 1992.

The cause of the Safety Injection pump "B" reduced recirculation flow is attributed to foreign material blockage within the associated minimum flow recirculation line flow orifice. This material had been previously identified and reported in LER 92-013. A system recovery plan was initiated, which included extensive system inspection, cleaning, and pump testing, and installation of permanent recirculation line strainers.

This report is submitted pursuant to 10 CFR 50.73(a)(2)(i)(A) as the completion of a plant shutdown required by the plant's Technical Specifications.

LER NO: 261/92-018

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION **LICENSEE EVENT REPORT (LER) TEXT CONTINUATION**	APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (8)					PAGE (3)
		YEAR		SEQ NO.		REV NO.	
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	018	-	00	2

TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. DESCRIPTION OF EVENT

On August 24, 1992, H. B. Robinson Unit No. 2[1] was in hot shutdown condition and preparing for startup following a reactor trip.[2] At 1826 hours, following performance of an unscheduled surveillance test to redemonstrate Safety Injection system operability, the licensee declared Safety Injection pump "B" inoperable due to inadequate recirculation flow. At 2258 hours, Safety Injection pump "A" was declared inoperable due to an observed declining trend in the pump's recirculation flow. Although the recirculation flow acceptance criteria was satisfied, after consultation with the licensee's Operations Manager, the pump was conservatively declared inoperable based on a greater than ten percent decline in flow rate from the last three tests. With both Safety Injection pumps inoperable, Technical Specification 3.0 was entered, which requires that the plant be placed in cold shutdown condition within 30 hours. A shutdown was initiated and the plant achieved cold shutdown condition at 0020 hours on August 25, 1992. The NRC was notified of this shutdown via the ENS as required by 10 CFR 50.72(b)(1)(i)(A).

II. CAUSE OF EVENT

Event investigation[3] has been completed. The cause of the Safety Injection pump "B" reduced recirculation flow is attributed to foreign material blockage within the associated minimum flow recirculation flow orifice. Through tracing materials used on site, the likely source of the material and its system entry point were determined.

It was confirmed through interviews that during Refueling Outage 14, the construction crew on Modification 1087, RHR Minimum Flow Recirculation Line Modification, had experienced problems resulting from inadequate purge during the welding process. They employed the use of a plastic sheet material to attempt a mechanical line block, or purge dam. Four circular pieces were cut for use as purge dams to support installation of check valves RHR-782 and RHR-783. All of the pieces were taken into the RHR Heat Exchanger room, but only two were taken up the scaffolding to the immediate work area. The line was sufficiently large to attempt the installation of these plastic dams, and they were taped in place inside the ten inch piping for RHR Train "A". However, it was determined to be too difficult to obtain a satisfactory seal in the line with the material, and this effort was subsequently abandoned. During completion of the job the material was used to protect the seats of the check valves during grinding work.

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[1]H. B. Robinson Steam Electric Plant Unit No. 2, is a Pressurized Water Reactor in commercial operation since March, 1971.

[2]Licensee Event Report LER 92-017.

[3]Adverse Condition Reports ACR 92-249 & ACR 92-250

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQ NO.		REV NO.	
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	018	-	00	3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

It is suspected that pieces entered the RHR system piping due to breakage. Although the exact amount and mechanism of material introduction is unknown, it is suspected that a maximum of two discs (approximately 155 square inches) may have entered the piping. Follow-up interviews and investigations were unsuccessful in quantifying the amount of material that entered the piping or the mechanism for entry. During closure of the line, Quality Control personnel employed the use of a camera to inspect the line for cleanliness. This was performed by inserting a camera into the vertical line, and looking down and up through the open check valve. This did not include inserting the camera beyond the elbow below the valve, and they were not able to see around the elbow into the horizontal run. As such, the QC inspection did not detect the presence of any foreign material.

The modification was completed and the system refilled for testing and return to service. Acceptance testing for Modification 1087 operated the RHR system at various flowrates using various flowpaths. During testing and operation, it is assumed that the material was pumped through the RHR system. It is further theorized that some of the material was deposited behind the SI-863A valve, which was a "dead leg" projecting at a right angle away from the main flow path during recirculation. This made a natural trap for the material. Later, when the cavity was drained, this valve was opened, and the material was swept toward the RWST and SI pump suction header. When the RWST level reached forty percent, cavity draining was suspended, and SI pump full flow was conducted. Cavity draining was then resumed. The material was discovered during testing in July in the SI Pump "B" recirculation orifice.[4]

The blockage identified in August was thought not to be a new piece, but a residual that was too large to enter the recirculation line during July. It is speculated that subsequent use of the SI pumps eroded the material sufficiently to allow it to enter the recirculation line during August. It had been originally thought that the material was broken into very small pieces from the SI pump and the material would easily enter the piping. This observation was determined by the fragments found in the orifice in July. No other material has since been recovered from the any of the SI pumps or associated piping.

The only other material located has been in the RWST as expected and previously communicated.

III. ANALYSIS OF EVENT

The blockage of the limiting flow orifice in the Safety Injection pump recirculation piping prevented the minimum recirculation flows needed to assure reliability of the pump during periods when the pump is not flowing water to the Reactor Coolant System. During periods of operation under minimum recirculation flow conditions, this recirculation flow provides the only source of cooling to the pump.

Evaluation of the chemical composition and physical properties of the foreign material found determined that, had the material entered the Reactor Coolant System (RCS), it would decompose. No material remnants have been found, and there has been no evidence seen through sampling of a substantial deposition in the RCS.

This report is submitted pursuant to 10 CFR 50.73(a)(2)(i)(A) as the completion of a plant shutdown required by the plant's Technical Specifications.

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[4] LER 92-013, Plant Shutdown Due to Safety Injection Pump Inoperability, July 27, 1992.

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR		SEQ NO.		REV NO.	PAGE (3)
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	018	-	00	4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

IV. CORRECTIVE ACTIONS

Adverse Condition Report (ACR) 92-333 was initiated to document the unsuccessful efforts to remove debris from the Safety Injection system as initially identified in July, 1992 and documented by ACR 92-249.

Two teams were established for system recovery which was initiated in August, 1992. One team was established to determine operability and cleanliness of the Safety Injection pumps. The second team was to investigate the source, potential locations, effects, and significance of the foreign material. A single project manager was established for the total effort. Special procedures were developed to control work, responsibilities, and evaluation of items found. The reactor was to remain in cold shutdown until all activities were completed to ensure the reliability and operability of the SI System.

The recovery efforts were intended to accomplish the following:

- Identification of the foreign material.
- Identification of possible entry points of the foreign material, its possible present locations, and a method to retrieve or flush material from the system, as appropriate.
- Evaluate potential damage and assure potentially effected Emergency Core Cooling System (ECCS) equipment is operable and can be relied upon during any flow condition.
- Assure that the potential presence of foreign material will not impact the operability of plant systems or components in the future.
- Identify the root cause of the problem and the corrective actions which will be taken to preclude recurrence.

In order to facilitate identification of the foreign material and the potential impact it may have had on plant safety systems, visual inspections of the interior of tanks, components, and piping determined through evaluation to potentially contain foreign material were conducted. Documentation of the evaluation of areas, piping, and components determined not to require visual inspection was also prepared. These areas included:

- The Reactor Coolant System
- Portions of the Residual Heat Removal (RHR) System
- The Chemical and Volume Control System Purification
- The Spent Fuel Pool Cooling System
- The Charging Pump Suction
- Portions of the Safety Injection System
- The Containment Spray Pump Eductor

NRC FORM 366A U. S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)					PAGE (3)
		YEAR		SEQ NO.		REV NO.	
H. B. ROBINSON, UNIT NO. 2	05000261	92	-	018	-	00	5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The components inspected included:

- The Refueling Water Storage Tank, (Using Divers and Cameras)
- Both SI pump Minimum Flow Recirculation Line
- The SI Pump "B" Discharge
- The SI and Containment Spray Pump Suction Line
- The Spray Additive Tank Flow Transmitter
- Piping From the RWST to the SI-862A Valve
- Containment Spray Pump Discharge Lines

As a result of the RWST inspection, cleaning of the tank was performed. For Safety Injection Pump "B", the piping and orifice were removed and the source of blockage was determined to be one thin piece of white plastic, approximately one-half inch in diameter, identical to the foreign material discovered during investigations in July 1992. Analysis of material confirmed it to be Delrin, the same material found in previous investigations.

Plant Modification M-1134 was developed and implemented to install permanent strainers in SI pump recirculation lines. Original plant design did not provide equipment to prevent plugging of the recirculation line flow orifices. These strainers, which would include flush and vent valves for each SI pump recirculation line, would serve to facilitate removal of any foreign material that should enter the system, and prevent the orifices from plugging.

A high velocity flush of each SI pump was conducted to provide assurance that the pumps were free of additional foreign material. The SI Pump vendor was consulted, and full flow testing of each pump was conducted on August 30, 1992 to assure no damage effecting pump performance had occurred as a result of the passage of the material through the pumps, or as a result of running the SI pump "B" with inadequate recirculation flow.

The inspections discussed above showed that the Delrin material was only in the RWST and SI pump "B". Since none of the material was found in the SI pump "A", the decision made regarding the trend seen during the previous flow tests was considered to be conservative with respect to the condition of the SI pump "B". Evaluations and tests of choke points and system interconnections reveal no other places where Delrin, if present, could cause a significant safety problem. Pump and valve tests have demonstrated acceptable performance of equipment, and cleaning and flushing of piping and components has assured that the material should not reenter systems or components.

All results, evaluations, and conclusions were reviewed on September 10, 1992 by the Plant Nuclear Safety Committee prior to plant restart.

V. ADDITIONAL INFORMATION

A. Component Failures

None

B. Previous Similar Events

LER 92-013

NRC FORM 366 U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1): Point Beach Nuclear Plant, Unit 1
DOCKET NUMBER (2): 0 5 0 0 0 2 6 6
PAGE (3): 1 OF 0 4

TITLE (4): Isolation of SI Pump Flow Path During IST of Minimum Flow Recirc Line Isolation Valves

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
1 2	0 8	9 2	9 2	0 1 0	0 0	0 1	0 7	9 3	PBNP Unit 2	0 5 0 0 0 3 0 1
										0 5 0 0 0

OPERATING MODE (9): N
POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

X 50.73(a)(2)(iii)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Mr. Tom Staskal, Sr. Project Engineer--Performance Eng
TELEPHONE NUMBER: 4 1 4 7 5 5 - 2 3 2 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14): YES (If yes, complete EXPECTED SUBMISSION DATE) / X NO

EXPECTED SUBMISSION DATE (15): MONTH / DAY / YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

At 1450 on December 8, 1992, while Point Beach Nuclear Plant (PBNP) Units 1 and 2 were operating at 100% and 95% power respectively, it was discovered that Inservice Tests IT-40, "Safety Injection Valves (Quarterly), Unit 1," and IT-45, "Safety Injection Valves (Quarterly), Unit 2," could lead to the isolation of all available flow paths for the safety injection (SI) pumps. Tests IT-40 and IT-45 perform quarterly stroke tests of safety injection/containment spray minimum flow recirculation line isolation valves 1&2SI-897A and 1&2SI-897B (hereinafter referred to as valves 897A&B). IT-40 and IT-45 place the plant in a condition in which pump damage could occur if the SI pumps automatically started while reactor coolant system (RCS) pressure was greater than SI pump shutoff head and either Valve 897A or Valve 897B remained shut. Operating the SI pumps at shutoff head would cause pump damage after approximately one minute. The tests were last performed on 11/15/92 (Unit 1) and 11/19/92 (Unit 2). A 4-hour NRC ENS notification was made in accordance with 10 CFR 50.72(b)(2)(iii)(D). The NRC Resident Inspector was also notified. A Probabilistic Risk Assessment (PRA) was subsequently performed and determined that the probability of this event occurring is approximately 1.0 E-6 events/year, or an increased pump damage risk of approximately 2 percent. Due to the increased risk of damaging the SI pumps by testing Valves 897A&B on a quarterly frequency, the tests will subsequently be performed on a cold shutdown frequency.

NRC Form 366 (6-89)

NRC FORM 366A

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Point Beach Nuclear Plant, Unit 1	0 5 0 0 0 2 6 6	9 2	— 0 1 0	— 0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

At 1450 on December 8, 1992, while Point Beach Nuclear Plant (PBNP) Units 1 and 2 were operating at 100% and 95% power respectively, it was discovered that Inservice Tests IT-40, "Safety Injection Valves (Quarterly), Unit 1," and IT-45, "Safety Injection Valves (Quarterly), Unit 2," place the plant in a condition in which damage could occur to both SI pumps. IT-40 and IT-45 perform quarterly stroke tests of SI/CS mini-recirculation line isolation Valves 1&2SI-897A and 1&2SI-897B (hereinafter referred to as Valves 897A&B). The damage could occur if the SI pumps automatically started while either Valve 897A or 897B was shut. Operating the SI pumps with either Valve 897A or 897B shut would cause SI pump damage due to operation of the SI pumps at shutoff head without minimum recirculation flow if reactor coolant system (RCS) pressure was greater than SI pump shutoff head and plant operators failed to open one of the valves, 897A or 897B, within approximately one minute. The tests were last performed on 11/15/92 (Unit 1) and 11/19/92 (Unit 2). Upon identification of this condition on December 8, 1992, a 4-hour NRC ENS notification was made in accordance with 10 CFR 50.72(b)(2)(iii)(D). The NRC Resident Inspector was also notified.

Although the ENS notification identified that the containment spray (CS) pumps could also be damaged under the same circumstances, this condition is now considered to be of less concern. The CS pumps have a flow path to containment regardless of the position of Valves 897A&B unless both of the two parallel motor-operated discharge valves per CS pump fail to open on an automatic signal. Because the CS pump discharge valves are powered from separate safeguards trains, concurrent failure of both pairs of discharge valves is not a credible event.

A Probabilistic Risk Assessment (PRA) was subsequently performed and determined that the probability of an automatic initiation of SI occurring while either Valve 897A or 897B is shut is approximately 1.0 E-6 events/year, or an increased pump damage risk of approximately 2 percent. Section XI of the ASME Boiler and Pressure Vessel Code, Article IWV-3412a, 1986 Edition, allows plants to identify those valves which cannot be tested during plant operation and provide for full-stroke testing of these specific valves during cold shutdowns. The PBNP Inservice Testing (IST) program accounts for valves requiring this type of testing in Appendix G, "Cold Shutdown Justifications." Therefore, due to the elevated risk of pump damage while testing Valves 897A&B during plant operation, testing of Valves 897A&B will be deferred to periods when the respective unit is in cold shutdown and both SI pumps may be taken out of service.

Wisconsin Electric addressed a related issue in a letter to the NRC dated July 24, 1985. The letter, submitted in accordance with 10 CFR 21, notified the NRC that the failure of a single component in the control circuitry for the SI recirculation path isolation valves could, under specific circumstances, result in the failure of both safety injection pumps. During a post-implementation review of the Emergency Operating Procedures (EOPs), it was discovered that a failure of the power supply breaker in the remote control circuitry for Valves 897A&B would result in those valves closing. This failure would simultaneously result in loss of valve position indication and defeat the annunciation for 897A&B valve closure on the main control board. The corrective actions specified in response to this issue included gagging the manual handwheel operators on Valves 897A&B in the open position so that the automatic operators would be overridden. This corrective action was also referenced in our response to NRC IEB 86-03, "Potential Failure of Multiple ECCS Pumps Due to Single Failure of Air-Operated Valve in the Minimum Flow Recirculation Line," dated November 12, 1986. However, quarterly inservice stroke tests in which the valves were ungagged for a short period of time and repositioned for testing were considered at that time to pose no significant increase in risk to the SI pumps.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Point Beach Nuclear Plant, Unit 1	0 5 0 0 0 2 6 6	9 2	0 1 0	0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EQUIPMENT DESCRIPTION (Note: Information in [] indicates Energy Industry Identification System (EIIS) identifiers)

An orificed minimum flow bypass line is provided at the discharge of each SI [BQ] pump [P] to recirculate flow to the refueling water storage tank (RWST)[TK] through a common header (or, "mini-recirc" line) in the event the pumps are run while the RCS [AB] pressure is above the pumps' shutoff head. These bypass lines also permit the performance of periodic surveillance tests required by the Technical Specifications to prove pump operability. The recirculation line is provided with air-operated isolation Valves 897A&B [ISV], in series, which are closed to prevent flow of contaminated water to the RWST when in the containment sump recirculation phase following an accident. Because Valves 897A&B fail shut, they are normally gagged open to prevent closure on a loss of instrument air. If the SI pumps are operated without a flow path, the pumps will overheat and quickly deteriorate.

Valves 897A&B are interlocked with containment sump "B" isolation Valves 1&2SI-851A&B [ISV] (hereinafter referred to as Valves 851A&B). These motor-operated gate valves are normally closed except when required for containment sump recirculation following an accident. This interlock insures that Valves 851A&B cannot be opened until at least one valve, 897A or 897B, is closed which prevents the inadvertent release of containment sump vapor or liquid to the RWST during the containment sump recirculation phase of long-term cooling following a design basis accident.

The manual handwheel operators on Valves 897A&B are currently maintained in the open position to prevent closure on a loss of instrument air.

CAUSE

The re-evaluation of the PBNP quarterly inservice testing practices for Valves 897A&B was prompted by INPO Nuclear Network Message OE 5692, "Loss of All ECCS Pumps During Monthly Surveillance Testing," transmitted on November 24, 1992, by Calvert Cliffs Nuclear Plant.

Prior to this re-evaluation, quarterly inservice stroke tests in which Valves 897A&B were ungagged for a short period of time and repositioned for testing were deemed necessary and considered to pose no significant increase in risk to the SI pumps.

CORRECTIVE ACTIONS

A. Immediate:

1. Further testing of Valves 897A&B was suspended.

B. Short term:

1. A Probabilistic Risk Assessment (PRA) was performed to determine the probability of an SI actuation during the time Valves 897A&B are being tested. Station logs were reviewed and indicated that the approximate time to complete IT-40/45 is on the order of two hours (however, the valves are not shut for the full duration of the test) and therefore the time that the valves are ungagged each calendar quarter is small. Given this information, it was determined that the probability of this event occurring is approximately 1.0 E-6 events/year, or an increased pump damage risk of approximately 2 percent.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Point Beach Nuclear Plant, Unit 1	0 5 0 0 0 2 6 6	9 2	— 0 1 0	— 0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

2. The pumps' manufacturer, Byron Jackson, was consulted and stated that the SI pumps can be operated at shutoff head for up to one minute before pump degradation begins. Therefore, control operators would have up to one minute after an automatic pump start to restore the flow path if instrument air is available. If instrument air is not available, the valves would require manual handwheel operation.

C. Long Term:

1. A Cold Shutdown Justification (CSJ) for Valves 1&2SI-897A&B will be included in the IST program to allow testing on a cold shutdown frequency. This change was submitted to the NRC on December 23, 1992.

2. Test procedures will be developed to provide for the inservice testing (stroke time, fail-safe, position indication verification, leak rate testing) of Valves 1&2SI-897A&B on a cold shutdown frequency. This will be completed by the Operations Group by February 28, 1993.

3. The Operations Group will ensure that all other valves currently tested under Procedures IT-40 and IT-45 on a quarterly basis will continue to be tested on a quarterly basis. Procedures to accomplish this testing will be developed if necessary. All necessary procedure revisions will be completed or new procedures developed by February 28, 1993.

REPORTABILITY

This event is being reported under the requirements of 10 CFR 50.73(a)(2)(v)(D), "The licensee shall report...any event or condition that alone could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident." A 4-hour NRC ENS notification was made in accordance with 10CFR50.72(b)(2)(iii)(D). The NRC Resident Inspector was also notified.

SAFETY ASSESSMENT

A Probabilistic Risk Assessment (PRA) was performed and determined that the probability of operating an SI pump at shutoff head after Valves 897A&B have been ungagged and the valves have failed shut is 1.0 E-6 events/year. The probability of failure of the SI pumps for other reasons is calculated to be 5.3 E-5 events/year. Therefore, this identified condition would result in an increased risk of failure of the SI pumps of about 2%. This condition is a small contributor to the failure of the SI pumps. Hence, the probability of pump damage occurring as a result of the scenario described above is determined to not be a significant contributor to core damage frequency. The safety of the plant and the health and safety of the public and plant employees were not jeopardized by this plant condition.

GENERIC IMPLICATIONS

No generic implications have been identified.

SIMILAR OCCURRENCES

There have been no similar occurrences identified at PBNP.

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	1 OF 0 7

TITLE (4) Reactor Trip Results From Low Main Feedwater Pump Dischrge Pressure Due to Management Deficiency

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
0 5	0 8	9 2	9 2	— 0 0 4	— 0 1	0 7	1 5	9 2		0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 1 4

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
S. G. Benesole, Safety Review Manager	8 0 3	8 8 5 - 3 5 1 8

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
F	S J	P S P	X 0 0 0	Yes					
F	B A	X C V	V 0 3 0	Yes					

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

On May 8, 1992 at 0342:23 hours, Unit 1 reactor tripped from 14 percent full power on a Reactor Protective System anticipatory trip signal due to low discharge pressure on the Main Feedwater Pump (MFDWP). The low discharge pressure occurred when operators were attempting to decrease a high hotwell level, which diverted flow from the suction of the MFDWP. After the trip, the Emergency Feedwater (EFDW) System actuated due to the low MFDWP discharge pressure. Once the MFDWP was verified to be operating, the EFDW Pumps were secured. The two root causes identified for this event were management deficiency, less than adequate training given and lack of a task specific procedure. Corrective actions include Operator training to inform Operators of the hotwell level oscillations, correct methods of reducing hotwell level, and development of a task specific procedure.

NRC Form 366 (6-89)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	0 0 4	0 1	0 2 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND

The main condenser is designed to condense turbine exhaust steam for reuse in the steam cycle. The main condenser also serves as a collecting point for various steam cycle vents and drains to conserve condensate which is stored in the hotwell. The hotwell has an emergency high level alarm (72 inches), High level alarm (69 inches), Low level alarm (57 inches), and Emergency low level alarm (10 inches). The condenser also serves as a heat sink for the Turbine Bypass Valves (TBVs) [EIIS:SO] which are capable of passing 25 percent of rated main steam flow.

The TBVs are designed to dump Main Steam [EIIS:SB] load directly to the main condenser during startup and shutdown operation, thereby creating an artificial load on the reactor.

The Condensate Steam Air Ejectors (CSAEs) remove air and noncondensable gasses from the main condenser to maintain proper Condenser vacuum.

The Condensate System [EIIS:SD] originates at the condenser hotwell. The Hotwell Pumps and Condensate Booster Pumps increase system pressure to that required for the Main Feedwater Pump (MFDWP) net positive suction head. The Upper Surge Tank provides a surge volume for the Condensate System. (See Attachment 1)

The MFDWP increases the Feedwater System [EIIS:SJ] pressure to provide adequate feeding of the Steam Generators.

The Reactor Protective System (RPS) [EIIS:JC] consists of four identical protective channels, each terminating in a trip relay within a reactor trip module. The coincidence logic in all reactor trip modules actuate when any two of the four protective channels trip. The RPS monitors Reactor Coolant System (RCS) [EIIS:AB] parameters related to safe operation and trips the reactor to protect against fuel rod cladding damage. It also assists in protecting against exceeding RCS pressure limits by providing an anticipatory trip on low MFDWP discharge pressure.

The Emergency Feedwater [EIIS:BA] will actuate on loss of both Main Feedwater Pumps (MFDWPs). The actual initiating conditions are low discharge pressure (<800 psig) on both MFDWPs or low of hydraulic oil pressure on both MFDWPs. MFDWPs will trip on high discharge pressure.

The Auxiliary Steam System [EIIS:SA] consists of a header which is supplied by Main Steam and each unit's header is normally cross-connected to the other units. When a unit is starting up the Auxiliary Steam header is normally supplied by another units main steam to supply various steam loads.

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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EVENT DESCRIPTION

On May 7, 1992 at 2330 hours, Unit 1 was at Hot Shutdown following a Unit trip due to a Generator Lockout. The Hotwell Level was observed at 67 inches by the Control Room Operator (CRO). The CRO identified this to the Control Room Senior Reactor Operator (CR SRO).

At 0145 hours on May 8, 1992, Unit 1 was returned to criticality. Reactor Power was increasing and the Condensate and Feedwater Systems were aligned utilizing 1B Main Feedwater Pump (MFDWP) to maintain minimum Steam Generator level. All steam being produced was bypassing the Main Turbine [EIIS:TA] via the Turbine Bypass Valves to the condenser. Unit 1's Auxiliary Steam header, being supplied by another unit, was supplying steam to the Condensate Steam Air Ejectors (CSAEs), 'E' Heaters, MFDWP and various steam seals and exhausting into Unit 1's condenser.

At 0325 hours, the hotwell high level alarm (setpoint 72 inches) was received. The hotwell level was fluctuating between 73 and 78 inches, and trending upward. The CRO reviewed the Alarm Response Manual to determine the appropriate actions to be taken. The CR SRO and Shift Manager were concerned with the possibility of flooding the CSAEs suction lines due to high hotwell level. At approximately 0330 hours, the Shift Supervisor was notified of the high hotwell level by the CR SRO. The CR SRO, Shift Manager, and Shift Supervisor discussed the need and the method to reduce the hotwell level.

At 0340 hours, the CR SRO, Shift Manager, and Shift Supervisor decided on a method to reduce hotwell level, which only involved opening two valves in the Condensate System. This included opening 1C-124 (Condensate Recirc to Upper Surge Tank) and then opening 1C-128 (Condensate Recirc Control) to divert condensate to the Upper Surge Tank and then to the Condensate Storage Tank. After completing this lineup it would be transferred to another unit. The CR SRO stated that he had performed this method on other occasions. The CR SRO stated that actions in the Alarm Response Manual would not solve the high level, because the Alarm Response procedure (1SA6/C-12) did not address the unit's specific operating condition.

At approximately 0342 hours, the CR SRO told CRO to verify that 1C-128 (Condensate Recirc Control) was in the closed position. After verifying 1C-128 closed, the CR SRO instructed the RO to open 1C-124. Upon opening 1C-124, 1B MFWDP discharge pressure decreased to approximately 800 psig, causing Reactor Protective System Channels A, B, C, and D Feedwater Pump Anticipatory Trip to initiate a Reactor and Main Turbine Trip at 0342:16 hours. The CRO immediately closed 1C-124.

At 0342:23 hours, 1A and 1B Motor Driven Emergency Feedwater Pumps (MDEFDWPs) started on low Feedwater Pump discharge pressure. 1B MFDWP did not trip and the CRO secured the MDEFDWPs at 0343:06 hours, after verifying proper operation of the 1B MFDWP. The automatic control of 1-FDW-315 (Emergency Feedwater Loop A throttle valve) was disabled due to the failure

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of a solenoid valve. This resulted in no Emergency Feedwater flow to A Steam Generator. This was not identified during the Post-Trip Review. The Turbine Driven Emergency Feedwater Pump did not actuate due to a time delay that allows the pump to reset automatically if the automatic initiation signal is present for less than fifteen seconds.

All full length control rods [EIIS:ROD] fully inserted into the core and the reactor was shutdown.

Following the reactor trip, the Reactor Coolant System (RCS) average temperature decreased from 580 degrees F to approximately 555 degrees F. RCS pressure decreased from approximately 2145 psig to 1985 psig. Pressure then slowly increased to 2130 psig. Pressurizer [EIIS:VSL] level reached a minimum of 136 inches and stabilized at approximately 150 inches. Steam Generator (SGs) pressures increased to a maximum of 1009 psig and then decreased to a minimum of 892 psig on both A and B SGs before leveling off at approximately 1000 psig. SGs levels decreased to a minimum of 18 inches for approximately 14 seconds on both SGs before the 25 inch post trip setpoint was maintained.

During a routine inspection of equipment on May 8, 1992 at 0730 hours, a leak was discovered on the impulse line connected to the 1A MFDWP suction line.

CONCLUSIONS

The root cause of this event is Management Deficiency, lack of 'task specific' procedure and less than adequate training given. When the Emergency High HW level alarm was received the Alarm Response Manual was referenced. It was determined by Operations personnel that the Alarm Response Manual did not provide the proper guidance to reduce HW level during this condition. Operators were concerned with the HW level trending upward and extending past the level instrumentation range (0 to 7 feet) and flooding the suction line of the Condensate Steam Air Ejectors. The Operators felt a need to reduce HW level, realizing they would be at this power level for two hours, because they were waiting for the completion of shell warming of the Main Turbine [EIIS:TA]. A decision was made to divert a portion of Condensate flow to the Upper Surge Tank (UST) and then to the Condensate Storage Tank, where it could be pumped to another unit. The volume between 1C-124 and 1C-128 is large. The Operators were not aware that the piping was empty due to evaporation of the water to the UST, via leakage through 1C-128. Upon opening 1C-124 the void in the piping was filled, reducing the suction pressure of the Main Feedwater Pump, thus decreasing the pump discharge pressure. The flow path utilized by the Operators to lower HW level was performed because of a lack of understanding on the proper method to reduce HW level. Additionally a procedure did not exist to reduce HW level under this operating condition.

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Response of the primary system to the trip was normal. Reactor Coolant System inventory, pressure, and temperatures were all maintained within the normal post-trip range. The immediate response of the secondary system was also normal. Both steam generators' pressure and level were maintained at or near their proper setpoints.

A review of events over the last two years, indicates that this is not a recurring problem.

The leak discovered on the impulse line (1/2 inch, carbon steel, ASTM A106, grade B, seamless, schedule 40) for the 1A Main Feedwater Pump was corrected under work request 37321C by replacing the damaged section with a new section of piping. The probable cause of the failure was due to the pressure surge during the Feedwater transient. Engineering is currently evaluating the cause of the piping material failure. A search for the piping material manufacture was performed and the manufacturer could not be determined. This piping is Duke Class G (Non-Safety) and was installed during the initial construction of the plant.

A solenoid valve (SV) failure disabled the automatic control of FDW-315, the Emergency Feedwater Loop A throttle valve. The SV is normally energized but is required to operate to the de-energized position upon Emergency Feedwater actuation to permit automatic control. The failure of this valve and the violaton of the Technical Specification will be addresed in Licensee Event Report 269/92-05.

The equipment failure of 1A Main Feedwater Pump suction line instrumentation piping and 1-SV-200 is NPRDS reportable. The manufacturer and Model number for the piping material is unknown. The SV was a Valcor V-70900-21-3 and the serial number is 1495. There was no release of radioactive material or exposure to radiation involved. This event did not involve any personnel injuries.

CORRECTIVE ACTIONS

Immediate

1. The CRO Closed 1C-124

2. Operations personnel took appropriate actions per the Emergency Operating Procedure to bring the unit to stable conditions.

Subsequent

1. Enclosure 3.22 (Control of High Hotwell Level) was added to OP/0/A/1106/02 (Condensate and Feedwater System) as a written method to reduce high Hotwell level.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

2. The Alarm Response Manual for Hotwell Level Emergency High Statalarm (1SA6 / C-12) was revised to reference OP/0/A/1106/02 (Condensate and Feedwater System) enclosure 3.22 (Control of High Hotwell Level).

Planned

1. Operator training will be conducted to inform Operators of the Hotwell level oscillations and the correct method of reducing Hotwell level.

SAFETY ANALYSIS

Low Main Feedwater Pump (MFDWP) discharge pressure is an anticipated transient and is described in Section 10.4 of the Final Safety Analysis Report. Low MFDWP discharge initiates a reactor trip and starts the Emergency Feedwater (EFDW) System to provide decay heat removal. In this event all the systems and equipment operated as designed to mitigate the consequences of low MFDWP discharge pressure. Instrumentation detected the low MFDWP discharge pressure, initiated the Main Turbine and Reactor trips, and provided the start signal to EFDW System. Both Motor Driven Emergency Feedwater Pumps (MDEFDWPs) started as required. The MFDWP did not trip, after verifying proper operation of MFDWP the Operators secured the MDEFDWPs. The health and safety of the public was not compromised by this event.

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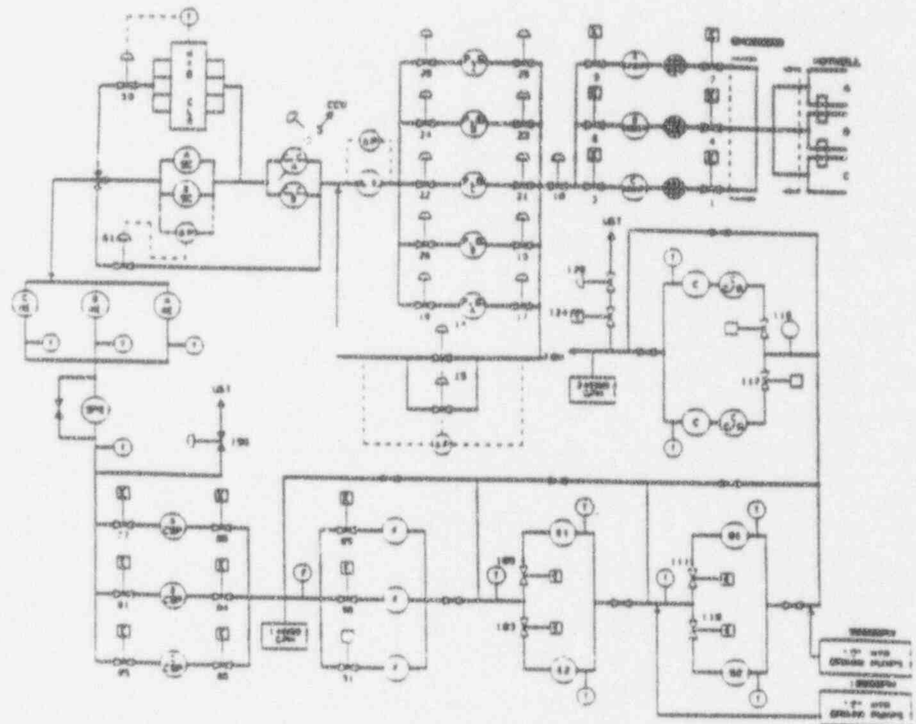
DUKE POWER COMPANY

ATTACHMENT 1

CONDENSATE SYSTEM ARRANGEMENT



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FACILITY NAME (1): Oconee Nuclear Station, Unit 1

DOCKET NUMBER (2): 0 5 0 0 0 2 6 9 — PAGE (3): 1 OF 0 8

TITLE (4): Equipment Failure and Defective Procedure Result In Operation In Violation of Technical Specification

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
0 5	1 0	9 2	9 2	— 0 0 5 —	0 0	0 7	0 9	9 2		0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): - 0 -

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)(B)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME: S. G. Benesol[illegible], Safety Review Manager

TELEPHONE NUMBER: AREA CODE 8 0 3 — 8 8 5 - 3 5 1 8

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
F	B A	X C V	V 0 3 0	Yes					

SUPPLEMENTAL REPORT EXPECTED (14)

☐ YES (If yes, complete EXPECTED SUBMISSION DATE) — [N] NO

EXPECTED SUBMISSION DATE (15): MONTH / DAY / YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

On May 8, 1992, at 0342 hours, Unit 1 tripped from 14% full power and Emergency Feedwater (EFDW) actuated. The Main Feedwater pump did not trip and the operators secured the Motor-Driven EFDW pumps.

The Post-Trip Review, Reactor Transient Analysis, and the subsequent Licensee Event Report did not identify the fact that flow did not exist in the EFDW train A that contains control valve (1FDW-315). Technical Specifications require two flow paths to be operable when the unit is above 250 F. Seventeen days after the reactor was heated above 250 F the control valve (1FDW-315) was discovered to be inoperable, in the automatic mode, when a periodic stroke test was performed. Therefore, Unit 1 had operated outside of Technical Specification requirements.

There were two root causes for this event: Equipment Failure and Defective Procedure, Technical Deficiency. Corrective Actions include replacing the solenoid valve and revising the Post Trip Review Directive.

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BACKGROUND

The purpose of the Emergency Feedwater (EFDW) [EIIS:BA] system is to remove decay heat and Reactor Coolant Pump heat following a loss of Main Feedwater (MFDW) [EIIS:SJ]. Three EFDW pumps are provided for each unit. Two motor driven pumps are powered by emergency AC power while the turbine driven pump is aligned to Main Steam [EIIS:SB] or Auxiliary Steam [EIIS:SA]. Each unit's EFDW system is designed to supply feedwater to the Steam Generators (SG) in the event MFDW is lost.

There are three systems at Oconee which are designed to automatically actuate when the setpoints of low MFDW pump hydraulic oil pressure and/or MFDW pump discharge header pressure are reached on both MFDW pumps. The systems are the EFDW system, the Reactor Protective System (RPS) [EIIS:JC] and the Anticipated Transient Without Scram (ATWS) Mitigation System Actuation Circuitry (AMSAC). Each of these systems use diverse means to determine when MFDW has been lost. Each system actuates when signals are received that both MFDW pumps can no longer provide feedwater to the SGs. The EFDW system (all 3 pumps) will start automatically upon loss of both MFDW pumps (indicated by low MFDW pump turbine hydraulic control oil pressure of 75 psig and/or low MFDW pump discharge header pressure of 800 psig decreasing). This actuation will also enable a circuit which controls SG level [EIIS:JB] at predetermined setpoints (30 inches on the start-up range with Reactor Coolant Pumps in operation). The loss of MFDW provides a signal to the RPS as an anticipatory trip that trips the Reactor prior to Reactor Coolant System [EIIS:AB] parameters reaching their own trip setpoints. The pressure switches and/or AMSAC initiates the start of the EFDW pump turbine. If the start signal clears (i.e. MFDW pump discharge pressure increases above 800 psig) within 15 seconds +/- 1 second, the EFDW pump turbine will reset. The AMSAC signal will initiate the two Motor Driven EFDW pumps and trip the main turbine if it is on line.

EFDW control valve 1FDW-315 is a pneumatically-operated valve that regulates the flow of EFDW to SG A, for control of the water level. The 125VDC, three-way solenoid valve 1FDW SV0200 selects whether control of 1FDW-315 will be manual or automatic.

Technical Specification 3.4 requires two EFDW flow paths to be operable when the reactor is heated above 250 F. The flow path is defined in the Technical Specification Bases as: The flow path to either steam generator including associated valves and piping capable of being supplied by either the turbine driven or the associated motor driven pump. Additionally, the EFDW system is designed to start automatically upon receiving an initiating signal.

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EVENT DESCRIPTION

On May 8, 1992, at 0145 hours, the Unit 1 Reactor was critical and preparations were being made to increase Reactor power and place the Electrical Generator [EIIS:EL] on line, following a previous Reactor trip (which was was reported in LER 269/92-03).

At 0325 hours, with the Reactor at 14% full power and the B Main Feedwater (MFDW) pump in service, problems were encountered with high Hotwell [EIIS:KA] level. While trying to lower the level in the Hotwell, the Reactor and Main Turbine [EIIS:TA] tripped at 0342:23 hours due to a feedwater transient. This event was reported in LER 269/92-04.

At 0342:23 hours, the A and B Motor Driven Emergency Feedwater Pumps (MDEFDWPs) started on a low Main Feedwater Pump (MFDWP) discharge pressure. The B MFDWP did not trip and Control Room Operator A (CRO-A) secured the MDEFDWPs at 0343:06 hours, after verifying proper operation of the B MFDWP. CRO-A stated that he also verified the Steam Generator levels were being controlled by the B MFDWP. CRO-A did not observe or verify flow through the two trains of Emergency Feedwater (EFDW). The Emergency Operating Procedure does not require the CRO to verify EFDW flow unless there is a loss of MFDW.

A Post-Trip Review Report was completed on May 8, 1992 by Shift Manager (SM) A, with assistance from SM-B, the Engineering Supervisor and the duty Reactor Engineer. SM-A noted in the Plant Response section of the report that the MFDWP trip signal had not occurred but the MDEFDWP A and B had started. The MDEFDWP start signal was from low MFDWP discharge pressure. The start and stop times for each pump were recorded. The Turbine Driven Emergency Feedwater Pump (TDEFWP) initiated, but the MFDWP discharge pressure went above the setpoint before the 15 second seal-in timed out. This satisfied the logic for the TDEFDWP. SM-A stated that, during his review, the failure of the TDEFDWP to start was questioned and verified to be the correct response.

On May 10, 1992, at 1509 hours, the Reactor Coolant System (RCS) temperature was increased to 325 F.

The Reactor was critical at 1517 hours on May 11, 1992. On May 12, 1992 at 1827 hours the Unit reached 100% Full Power. The Unit continued to operate at 100% Full Power until May 24, 1992, at 2010 hours, when a Reactor power reduction was begun to repair the 1A2 Reactor Coolant Pump Seals. The Reactor was shutdown at 0438 hours, on May 25, 1992. The RCS was cooled to < 250 F by 2040 hours.

On May 27, 1992, Performance Technicians performed the 1FDW-315 and 1FDW-316 Stroke Test procedure (PT/1/A/0150/22M). The test is performed on a "Quarterly at Cold Shutdown" frequency to determine operability of the automatic function of 1FDW-315 (Steam Generator A EFDW Control Valve) and 1FDW-316 (Steam Generator B EFDW Control Valve)

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The 1FDW-316 valve stroke times were in the acceptable range but the 1FDW-315 valve failed to operate. A work request was issued to investigate and repair 1FDW-315 valve. Investigations by the Instrument and Electrical (IAE) Technicians revealed that the solenoid valve used for enabling the automatic functioning of 1FDW-315 had failed. The failures are due to the valve being energized continually, resulting in overheating and binding. This causes the control valve (FDW-315) to be inoperable in the automatic mode. This was also identified in LER 287/91-07.

On May 30, 1992, Station Management discussed the need and intent to review the Post Trip data with respect to 1FDW-315.

On June 1, 1992 the solenoid valve (1SV-200) was replaced with a newer model valve as directed by the previous commitment (LER 287/91-07) due to failure of the original solenoid valve.

On June 2, 1992, the stroke test (PT/1/A/0150/22M) was performed on 1FDW-315 valve after the solenoid valve (1SV-200) had been replaced. The valve operated and stroke times were in the acceptable range.

The IAE Section issued a Problem Report on June 4, 1992 for identification of 1FDW-315 not working in automatic. This was to document the fact that this was a repetitive failure.

The Reactor Trip (LER 269/92-04), reporting the May 8, 1992 Reactor trip, was approved and sent to the Nuclear Regulatory Commission on June 8, 1992.

On June 11, 1992, the Safety Review Section held discussions and reviewed data with the Reactor Engineering Group concerning the EFDW actuation, following the Unit trip of May 8, 1992. It was noted that the A EFDW train had exhibited no flow. From a more detailed review of existing Transient Monitor information, it was determined that 1FDW-315 valve had not opened.

The last time the 1FDW-315 valve stroke test was performed satisfactorily was September 22,1991, during a refueling shutdown.

CONCLUSIONS

There were two root causes associated with this event: Equipment Failure and Defective Procedure, Incomplete Information. Technical Specification 3.4.1.b requires two flow paths to be operable when the reactor is heated above 250 F. The reactor operated at power for 15 days with one flow path inoperable in the automatic mode.

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The root cause of Equipment Failure was due to the failure of 1SV-200. This is similar to the event documented in LER 287/91-07. The valves in Unit 2 have been replaced. The valves in Units 1 and 3 are scheduled to be replaced during the next refueling outages. The solenoid valve failure is NPRDS reportable. The valve is a Valcor V-70900-21-3, Serial Number 1495. This root cause is considered recurring.

The root cause of the failure to identify that one Emergency Feedwater (EFDW) flow path was inoperable, is Defective Procedure, Technical Deficiency. If the Post Trip Review had explicitly required the verification of EFDW flow in each train this event could have been prevented. The fact that no flow was present in the SG A EFDW train could have been verified by a more detailed review of the transient monitor charts. Since this was not observed in the Post Trip Review, the approval to restart was made and the Unit was heated above the temperature that EFDW is required to be operable.

The safety systems which respond to a loss of Main Feedwater (MFDW) receive automatic actuation from the presence of a low MFDW pump discharge header pressure (800 psig) or low MFDW pump hydraulic oil pressure (75 psig) signal. The A MFDW pump was off and the B MFDW pump was supplying the feedwater to the Steam Generators (SG) at the time of the event.

The transient monitor plot (See Attachment A) for Emergency Feedwater (EFDW) flow that was submitted as part of the Reactor Transient Analysis was plotted on a 15 minute time line. The MDEFDWPs were on for approximately 43 seconds. The amount of time the EFDW controls called for 1FDW-315 and 1FDW-316 to be open was only 15-30 seconds. Unless the flow parameter had been observed by the Control Room Operator during this time frame, it would not have been detected. The personnel performing Post Trip Review and Transient Analysis stated that they did not place sufficient emphasis on the EFDW flow aspect since the B MFDW pump remained on during the event and both Motor Driven EFDW pumps started. They also observed that steam generator levels tracked together to approximately 18 inches immediately following the reactor trip and progressed to the level where EFDW maintains (30 inches).

The Post Trip Review Checklist did not explicitly require documentation that flow had been established in both SG trains. The transient monitor plot showing EFDW train A and B flow was not clear in showing that both EFDW trains had exhibited flow.

The Defective Procedure is considered recurring based on a review of Problem Investigation Report Database.

There were no personnel injuries, radiation exposures, or releases of radioactive materials associated with this event.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTIONS

Immediate

1. The solenoid valve (1SV-200) was replaced and tested.

Subsequent

1. The Performance Testing frequency was changed to require valves FDW-315 and 316 to be stroked tested quarterly without an exception as to the Unit status.

Planned

1. Enhance the Post Trip Review process as necessary, specifically addressing the verification of Emergency Feedwater Flow.

SAFETY ANALYSIS

The purpose of the Emergency Feedwater (EFDW) System is to remove decay heat and cool down the Reactor Coolant System (RCS), in the event that Main Feedwater (MFDW) is unavailable. This system is composed of three EFDW pumps supplying two independent trains, with a control valve present in each train to throttle flow. Each unit has the ability of cross-connecting to either of the other two units if necessary. Two of the EFDW pumps are motor-driven while the third is turbine driven. The accident analyses in the Final Safety Analysis Report (FSAR) only credit EFDW flow from one pump to one steam generator (SG). Thus, any one of these pumps is capable of providing adequate flow to remove RCS heat from any initial power condition. All three pumps receive a start signal on low Main Feedwater (MFDW) header pressure, low turbine oil pressure, or low steam generator level. In the event of a single failure, adequate redundancy is present to assure that the EFDW system will function as designed.

In the event that one of the control valves is inoperable while in the automatic control mode, as was the case with 1FDW-315, a single failure in the other train (1FDW-316) could isolate all EFDW flow to the SGs. This would prevent the EFDW System from performing its intended safety function as assumed in the FSAR accident analyses. However, the operators have the ability to switch control of these valves into manual. Testing of these valves prior to unit start-up was performed in the manual mode. The results of these tests showed that the valves opened as required. The

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APPROVED OMB NO. 3150-0104
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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

Emergency Operating Procedure (EOP) instructs the operator to take manual control of these valves in the event that no flow is indicated in the EFDW header(s). Thus, during the time period that 1FDW-315 was inoperable in the automatic mode, operator action could have restored feedwater to the steam generator, even in the event of a single failure in the other train.

In the event that 1FDW-315 was inoperable in both the automatic and manual modes and a single failure in the other train occurred, other means of RCS heat removal are available. The EOP directs the operators to initiate High Pressure Injection (HPI) [EIIS:BG] feed and bleed cooling upon a loss of all primary-to-secondary heat transfer. Adequate time is available between the initiation of a total loss of feedwater event and the time at which feed and bleed begins such that no core damage would occur. This manner of RCS heat removal can be used until MFDW or EFDW flow is restored. If the EOP is followed properly, feed and bleed cooling is capable of removing decay heat and preventing core damage.

In the absence of MFDW and EFDW, an alternative method of heat removal to HPI feed and bleed is the use of the Standby Shutdown Facility (SSF) Auxiliary Service Water (ASW) [EIIS:BA] pump. The design purpose of this pump is to supply secondary inventory at flow rates as high as 500 gpm to each unit during SSF event. An SSF scenario can result in a loss of MFDW and EFDW, as well as other safety systems. Flow from the ASW pump enters the EFDW System downstream of control valves FDW-315 and FDW-316. Analyses have been performed to verify that sufficient time is available for an operator to line this system up before any core damage would occur.

Although the potential existed for the automatic control of the EFDW system to be inoperable, assuming a single failure, adequate means of RCS heat removal were available through the use of operator action to restore EFDW flow, HPI feed and bleed cooling, or use of the SSF ASW pump. Each of these alternate methods of decay heat removal would have been successful in preventing core damage. Therefore, this event did not result in a significant risk to the health and safety of the public.

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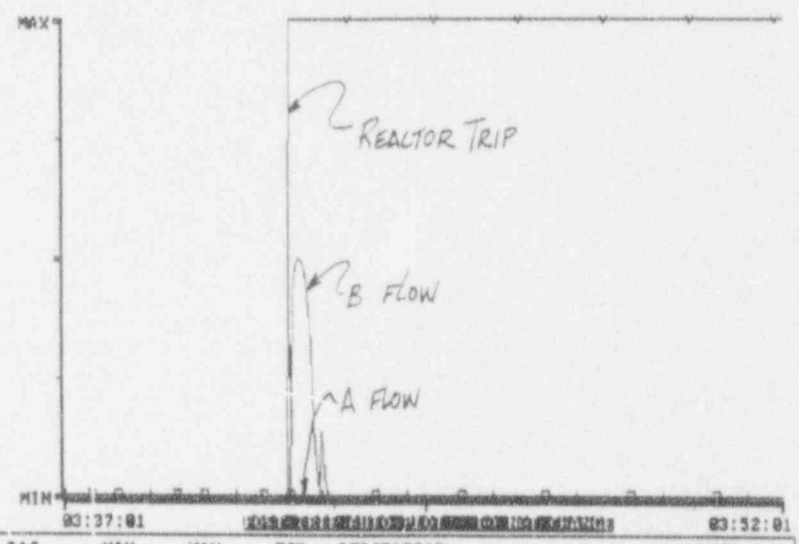
TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT A



STY	TAG	MIN	MAX	EGU	DESCRIPTOR	MODE
———	A5049	0.00	1200.0	GPM	EFDW FLOW A	OC1030
—o—	A5050	0.00	1200.0	GPM	EFDW FLOW B	OC1030
—o—	D50??	FALSE	TRUE		REACTOR TRIP	OC1030

[redacted] 03:44:31.98 05-08-92

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TITLE (4) Equipment Failure And Inappropriate Action Result In The Concurrent Inoperability Of Both Onsite Emergency Power Sources And A Technical Specification Violation

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									Oconee, Unit 2	0 5 0 0 0 2 7 0
0 7	1 7	9 2	9 2	— 0 0 8 —	0 0	0 8	1 7	9 2	Oconee, Unit 3	0 5 0 0 0 2 8 7

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

OPERATING MODE (9)	N							
POWER LEVEL (10)	1 0 0		20.402(b)		20.405(c)		50.73(a)(2)(iv)	73.71(b)
			20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v) (D)	73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
			20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)	
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)	
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER: AREA CODE	
S. G. Benesole, Safety Review Group	8 0 3	8 8 5 - 3 5 1 8

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

On July 17, 1992, at 1330 hours, all three Oconee units were at 100 percent Full Power. With Keowee Unit 1 out of service for planned maintenance, it was discovered that the closing circuit fuse in ACB-8 breaker was blown causing an inoperability of Keowee Unit 2. With these conditions both onsite emergency power sources were technically inoperable. Procedures were implemented to energize the Standby Buses via the Lee Gas Turbines through the 100 KV dedicated lines. The blown fuse was replaced, returning Keowee Unit 2 to operable status. Problems with the start up of the Lee Gas Turbines and a misunderstanding led to exceeding the Technical Specifications time frame by 58 minutes. The root causes of this event are classified as Equipment Failure and Inappropriate Action (proper response identified but not in time). Corrective actions include diagnosing the specific failure mode of the fuse, implementing administrative procedural controls, and training on the modes of control power indicator failures and the time restraints of Technical Specifications.

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BACKGROUND

The Keowee Emergency Power System (EIIS:EK) consists of two hydroelectric generators which provide an emergency onsite power source for Oconee Nuclear Station via two separate and independent paths. One path is the underground feeder through transformer CT-4 (EIIS:XFMR) and the Standby Buses (EIIS:EB) and the other is the overhead through the 230 KV Switchyard (EIIS:FK).

Each Keowee Unit is provided with its own automatic start equipment. Both units undergo a simultaneous automatic start and run in standby on: a loss of the grid, an Engineered Safeguards actuation on any of the three Oconee Units, or an extended loss of voltage on any Oconee unit's main feeder bus. On an emergency automatic startup, the Keowee Unit connected to the underground feeder supplies the Oconee Standby Bus while the other Keowee Unit, remains in standby. If there is a grid disturbance, the unit in standby ties to the overhead path and is automatically connected to the Oconee 230 KV Switchyard Yellow Bus after the yellow bus is automatically isolated from the grid. Therefore, in the event of a Loss of Coolant Accident and the simultaneous loss or degradation of the grid, emergency power is available from either Keowee Unit through the underground feeder and/or the overhead transmission line. Technical Specification (TS) 3.7.2 allows one Keowee Unit to be out of service for 72 hours provided the other unit is aligned to the underground and verified operable within one hour and every eight hours thereafter. Operability is verified by starting the available Keowee Unit and energizing the Standby Bus.

The Keowee 600 VAC Switchgears 1X and 2X with their normal and alternate feeder breakers will provide power to the Keowee auxiliary loads. (See Attachment 1) Keowee's Auxiliary Switchgear 1X and 2X receive their normal, non-emergency power from the 230 KV switchyard back charging Keowee's Main Step-up Transformer through ACB-5 and ACB-6. An alternate power source is provided to 1X and 2X Switchgear from one of Oconee Unit 1's 4160 VAC Switchgear (1TC) through Keowee's CX Transformer and the Alternate Feeder Breakers ACB-7 and ACB-8, respectively. With only one Keowee Unit available and tied to the underground and a Loss of Offsite Power occurs, the only available Keowee Auxiliary power source is through CX. Therefore, a loss of CX or ACB-7 or 8 makes the associated Keowee Unit tied to the underground technically inoperable.

If both Keowee Units are unavailable, the Oconee Standby Buses can be energized from the Lee Steam Station Combustion Turbines through the dedicated 100 KV transmission lines. TS 3.7.7 requires that, in the event that both Keowee Units become unavailable for unplanned reasons, the Oconee Standby Buses shall be energized within one hour by the Lee Gas Turbines through the 100 KV transmission lines and shall be separated from the system grid and all offsite non-safety related loads.

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EVENT DESCRIPTION

On June 7, 1992, at approximately 1400 hours, with Oconee Nuclear Station (ONS) Unit 1 at Hot Shutdown (Start-up in progress), and Unit 2 and 3 at 100 percent Full Power, an operability test (PT/0/A/610/05B "Electro-Mechanical Relay Breaker Trip Test") was performed on Keowee Unit 2's 2X Alternate Feeder Breaker (ACB-8) and the Normal Feeder Breaker (ACB-6). This test opened ACB-6 and closed ACB-8 to 2X , then returned the breakers to a normal status by opening ACB-8 and closing ACB-6. Test results were satisfactory.

On July 16, 1992, at 0436 hours, while all three Oconee units were at 100 percent Full Power, Keowee Unit 2 was verified operable in accordance with Technical Specifications (TS) 3.7.2 prior to removing Keowee Unit 1 from service. This test was completed approximately every eight hours, thereafter, per requirements. At 0515 hours, Keowee Unit 1 was removed from service for implementation of Nuclear Station Modification (NSM) 52917 (Replacing Keowee X Relay Electro-Mechanical Scheme With a X-Y Electrical Scheme) and a Limiting Condition for Operation (LCO) was entered. NSM 52917 was a response/commitment item initiated in response to Licensee Event Report (LER) 269/92-02 (Equipment Failure in Emergency Power System and Inappropriate Action Result in Technical Specification Violation). This LER is related to the failure of Keowee's field and field flashing breakers' X relay.

On July 16,1992, at approximately 1200 hours, Hydro Operations Specialist (HOS), while performing a inspection of plant equipment, found the Green (Trip) control power indicating light for ACB-8 glowing, but not as bright as expected for normal conditions; however, it is not unusual to have varying degree of brightness of indicating lights.

At approximately 1430 hours, the HOS noticed, after cupping his hand over the Red (Close) Control Power indicating light for ACB-8, it was also glowing but not as bright as the Trip light. At this time, ACB-8 was open and ACB-6 was closed as required for the plant conditions. Keowee Unit 2 was scheduled to be taken out of service on July 17th for implementation of NSM 52917. Suspecting dirty contacts in the control power light circuits and not an operability question, the HOS decided to wait and investigate the problem during the outage.

Due to modification delays, Keowee Unit 1 remained out of service and on July 17,1992, at approximately 1200 hours, the HOS, the Component Engineer (CE) and the Instrumentation and Electrical Plant Maintenance Supervisor (IEPMS) began investigating several possible causes for the control power lights to be lit in that combination.

At approximately 1330 hours, the CE and the IEPMS decided to remove one of the bulbs to troubleshoot the lighting problem. This action caused both control power indicating lights to go out. While tracing the circuitry for series power sources, the investigation revealed that the close circuit

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"1B" positive 10 amp (OT10) fuse feeding ACB-8 had blown. A check of the close circuit "1B" negative fuse for ACB-8 revealed that a 15 amp (OT15) fuse was installed instead of a OT10 fuse as called for on electrical print KEE-27-2. The OT15 fuse was not blown. The HOS recognized that he had an operability/Limiting Condition for Operation concern and began to make contacts to the Commodities and Facilities department in search for replacement fuses, and Quality Control Staff to monitor the work. Unsuccessful attempts were made to contact the Oconee Operations Support Manager and the Oconee Operations Switchyard Coordinator for assistance in addressing and resolving the operability of the Keowee Units in accordance with TS.

At 1415 hours, the HOS notified ONS Unit 2 Supervisor that a blown fuse had been found in ACB-8. The ONS Unit 2 Supervisor recognized that this caused the CX Transformer to be out of service. Therefore, Keowee Unit 2 was declared technically inoperable. With Keowee Unit 1 out of service for modifications, a 24 hour Limiting Condition for Operations (LCO) in accordance with TS 3.7.7 was entered. This required the energizing of the Standby Buses via the Lee Gas Turbines through the 100 KV dedicated lines. Lee Steam Station (Lee) personnel were notified of the condition of the Keowee Units as a "heads-up" that their services would be required.

At 1423 hours, Operations began performing OP/O/A/1107/03 (100 KV Power Supply) Enclosure 3.3 (Charging Standby Bus No. 1 and 2 from Lee Steam Station for Backup Power) due to both Keowee Units being inoperable.

At 1436 hours, Lee was notified per OP/O/A/1107/03, enclosure 3.3 that backup power was required.

Replacement OT10 fuses requested from Commodities and Facilities were determined to be Quality Assurance (QA) qualified fuses and none were in stock at ONS.

Attempts were made by the CE to find qualified QA OT10 fuses and a dialogue was opened with the Electrical Engineer Supervisor (EES) from Oconee Engineering Division. The EES suggested to the CE to use the OT10 fuses from a spare compartment, since these fuses came with the original equipment and should be of the same grade as those installed in ACB-8. The fuses in the spare compartment were examined and were OT10 fuses. They were tested and found to be in good condition and appeared to be the original equipment. The OT10 fuses were replaced at 1445 hours using Work Request number 59726C.

At 1509 hours, Keowee Operators tested ACB-8 by swapping supplies to 2X from ACB-6 to ACB-8. This tested the closing circuit and fuses on ACB-8 which showed satisfactory results. 2X was then swapped back to it's normal source, ACB-6.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

At 1510 hours, Lee was called and questioned by ONS Operation personnel as to the status of the Lee Combustion Gas Turbines. Lee Operators indicated that trouble was being experienced in the sequencing circuit and the startup of another Gas Turbine was in progress.

At 1513 hours, ONS Operations personnel were notified that Keowee Unit 2 was operable and the 24 hour LCO was exited.

At 1528 hours, ONS was notified by Lee that the Lee Gas Turbines were in operation and the 100 KV line was energized to CT-5. This was 1 hour and 58 minutes after the time that Keowee Unit 2 was declared technically inoperable. The Standby Buses were never energized from Lee because Keowee Unit 2 was returned to service prior to receiving power from Lee.

The blown fuse and similar good fuses were sent to Nuclear Services, Instrumentation and Electrical department for diagnostic testing and evaluation to determine the failure mechanism.

CONCLUSIONS

The root cause of Keowee Unit 2's inoperability is Equipment failure. With the failure of the "1B" positive 10 amp (OT10) fuse feeding ACB-8, one source of power available to the 2X Switchgear was lost, thus, rendering the CX Transformer and Keowee Unit 2 technically inoperable. It is not known exactly when the fuse blew, but it is assumed that on June 7, 1992, at approximately 1400 hours, the "1B" positive close fuse failed during the closure test performed on ACB-8 and the failure went unobserved until approximately 1200 hours on July 16, 1992.

Normally, only one of the indicating lights is illuminated to show the appropriate breaker position. However, when the "1B" positive fuse was blown, both the Trip and Close indicating lights were illuminated. This occurs because a bypass, series, circuit path exists. This path was from the positive power bus through contacts in the closed circuit of ACB-6, the Trip and Close indicating bulbs of ACB-8, and completing the circuit to the negative power bus; thus allowing both bulbs to be illuminated. When one bulb is removed or both the positive and negative are blown, the series circuit will be broken extinguishing both lights.

A Configuration and Control Inspection/Program will be initiated during the Unit 3's, EOC-13, outage to check the condition of fuses, terminal links, and housekeeping within Oconee and Keowee's electrical cabinets.

The blown fuse and similar good fuses were sent to Nuclear Services, Instrumentation and Electrical department for diagnostic testing and evaluation to determine the failure mechanism. A review of Work Requests written between February 19, 1981 and the event revealed no indication as to when the OT10 fuse was replaced with a OT15 fuse. This fuse failure is not considered NPRDS reportable. A review of past Problem Investigation Reports indicate no similar failures, thus this part of the event is not considered recurring.

The root cause of failing to provide power to ONS's Standby Buses within 1 hour is Inappropriate Action (proper response identified but not in time). The one hour time limit begins at the time of the discovery of the equipment being out of service.

The initial observation of the problem with the lights on ACB-8 was on July 16, 1992 at 1200 hours. The time Keowee Unit 2 was confirmed to be technically inoperable was approximately 1330 hours, July 17,1992, and, as a minimum, the time for compensatory actions should have started then. However, Operations personnel were not notified until 1415 hours, at which point compensatory actions were initiated. Therefore, the Technical Specifications time requirements for action was violated when power was not available to the Oconee Standby Bus from Lee Gas Turbines at 1430 hours.

The HOS recognized that Keowee Unit 2 was into a Technical Specification issue. Once the blown fuse was identified, the HOS should have notified the Operations shift personnel (i.e. the Control Room), immediately, versus attempting to contact the Operations staff personnel or expediting the replacement of the fuses. This resulted in a 45 minute delay in the initiation of compensatory actions. Licensee Event Report 269/92-02 (Equipment Failure in Emergency Power System and Inappropriate Action Result in Technical Specification Violation) addresses the need for immediate notification of operability status of the Keowee Units to the ONS Control Room. Keowee operators have been directed to notify Oconee Control Room, immediately, during an operability concern of the Keowee Units. Corrective actions from that report did not prevent the recurrence of this communications issue. Therefore, this portion of the event is recurring.

At 1415 hours, ONS Unit 2 Supervisor was notified that a blown fuse was found in ACB-8 at 1330 hours. The Unit 2 Supervisor recognized that this made Keowee Unit 2 technically inoperable. This required the energizing of the Standby Buses via the Lee Gas Turbines through the 100 KV dedicated lines. Lee Steam Station (Lee) was notified that their services would be required. After experiencing problems with the sequencing circuit on the 5C Turbine, 4C Gas Turbine was started. Interviews revealed that Lee understood that they had one hour to start and close into the 100 KV line to CT-5 after they were officially notified through the ONS procedures, rather than the actual time of inoperability. At 1528 hours, ONS was notified by Lee that the Lee Gas Turbines were in operation and the 100 KV lines were energized to CT-5. This was 1 hour and 58 minutes after the time that Keowee Unit 2 was determined to be technically inoperable, which exceeded the time limit. To prevent a misunderstanding, ONS will revise OP/O/A/1107/03, Enclosure 3.3 to include notifying Lee Steam Station of the

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time the Combustion Gas Turbines are required to be in service. ..ee will change their operating practices to initiate a start of a second Combustion Gas Turbine if the primary turbine does not start, or trips after initial starting.

Offsite personnel who operate equipment which provides safety related support functions to ONS need to adequately understand the appropriate communication paths for reporting equipment problems and to report these problems immediately. The fact that the Control Room was not notified more promptly indicates a lack of understanding of associated requirements.

There were no releases of radioactive material, radiation overexposures, or personnel injuries associated with these events.

CORRECTIVE ACTIONS

Immediate

1) Fuses OT10 and OT15 from ACB-8 Control Power were removed and replaced by OT10 fuses. ACB-8 was tested satisfactorily. Keowee Unit 2 declared operable.

Subsequent

1) Keowee's Breaker Status checklist has been revised to include additional breaker and indicator status for each breaker; also, the checklist gives direction on what to look for and who to call for guidance on other than normal conditions.

2) Quality Assurance qualified OT10 fuses and a maximum and a minimum to be maintained in rtock has been established.

Planned

1) A formal rounds and turnover procedure will be initiated to enhance the monitoring of Keowee Hydro equipment.

2) Training will given to Keowee personnel on the new Keowee procedures, checklists, and the time restrains of Technical Specifications.

3) Nuclear Services, Instrumentation and Electrical department will investigate the cause of the fuse failure and test similar fuses for possible failure mode(s).

4) Training will be given to Lee Steam Station personnel concerning the operating practice of initiating a start of the second Combustion Gas Turbine if the primary turbine does not start or trips after initial start.

5) Oconee Nuclear Station's OP/O/A/1107/03, Enclosure 3.3 will be revised to include notifying Lee Steam Station of the time the Combustion Gas Turbines are required to be in service and establish a notification step early in the procedure as possible.

6) Problem Investigation Process 0-092-0293 was initiated on July 27, 1992 to resolve the problem with the bypass, series, circuit. A proposed resolution will be developed by October 26, 1992.

SAFETY ANALYSIS

Keowee Hydro Station provides an emergency power source to Oconee Nuclear Station for scenarios which involve a Loss of Offsite Power (LOOP). As mentioned earlier in this report, Keowee can feed Oconee through either an overhead or an underground path. Additionally, in the event both Keowee Units are unavailable, the busses connected to the underground path can be supplied from the Central Switchyard or from Lee Steam Station (Lee) Gas Turbines via dedicated lines. The supply from Lee should be available within one hour of identifying the need, but, in this event, it was not available until approximately one hour and fifty-eight minutes after the initial inoperability of the Keowee Unit was recognized.

Each Keowee Unit shall be capable of starting and accelerating without AC power to either of its auxiliaries. They can black start. A review of the Final Safety Analysis Report (FSAR) indicates that the worst case accident for this event is a LOOP affecting all three Oconee units and a concurrent Loss of Coolant Accident (LOCA) on one unit.

FSAR 15.8.3 addresses a simultaneous LOOP event on all three units. This analysis shows that natural circulation of the Reactor Coolant System (RCS) [EIIS:AB], Turbine Driven Emergency Feedwater System [EIIS:BA], Condenser Circulating Water gravity induced flow, and gravity insertion of the control rods [EIIS:ROD] are among the design features provided to ensure the removal of decay heat for the RCS without offsite power being available. Additionally, FSAR Section 15.8.3 states that "Each reactor can sustain a complete electrical power loss without emergency cooling for about 23 minutes before the steam volume in the pressurizer is filled with reactor coolant" and that "beyond this time reactor coolant will boil off, and an additional 83 minutes will elapse before the boil off will start to uncover the core." Therefore, even without cooling from the Turbine Driven

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APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	0 0 8	0 0	0 9 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's)

Emergency Feedwater Pump or the Standby Shutdown Facility, the FSAR states that core uncovery will not occur for 106 minutes after the initial loss of power. Even though it was delayed in this event, power was available from Lee within 73 minutes.

In a scenario involving a LOOP affecting all three Oconee units and a concurrent LOCA on one unit, Emergency Feedwater and/or the SSF would not be able to assist in mitigating the LOCA. FSAR 15.14.3.3.6 states that "The failure of transformer CT-4 has been identified as a more limiting single failure for the large break LOCA. With the assumed LOOP, this single failure results in a 48 second delay until Emergency Core Cooling System fluid is delivered to the RCS." If an event had occurred that would have rendered the normal power source to 1X and 2X inoperable, the alternate power source could have been aligned by the manual operation of ACB-8 or ACB-7 breaker. Several factors allow time for this manual operation to occur: 1) ACB-8 and ACB-7 are manually operable, 2) Keowee Station is manned 24 hours per day, 3) Keowee Batteries can carry the DC loads for approximately one hour, 4) Keowee Alarm Response Manual directs the operator on a loss of voltage to the 600 VAC Switchgear (1X and 2X) to verify feeder breaker tripped and close the alternate breaker, 5) the Keowee governor controls can be operated four and one half full cycles of the wicket gates before depleting the accumulator pressure (1 1/2 to 2 cycles are required for start-up, then minor changes afterwards). During a normal start the accumulator low trip of 250 psi will trip the Unit, but during a emergency start this trip is bypassed. Therefore, power can be regained manually to 1X or 2X within a short time once the event is recognized.

However, even though technically inoperable, Keowee would still have been able to respond in a significant manner. Even in the condition described in this event, if a LOOP or LOCA/LOOP had occurred, Keowee Unit 2 would have responded to an emergency start signal by starting up with all necessary support systems powered by the Keowee DC Battery System and compressed air stored in an accumulator. Keowee would have been able to operate for an indeterminate time, during which the Keowee operator on duty should have time to diagnose the loss of AC power with the use of existing Abnormal Procedures and manually close ACB-8 to connect to the alternate power source.

As described above, emergency power would have been available, and even if a LOCA/LOOP had occurred during this time, the health and safety of the public would not have been endangered.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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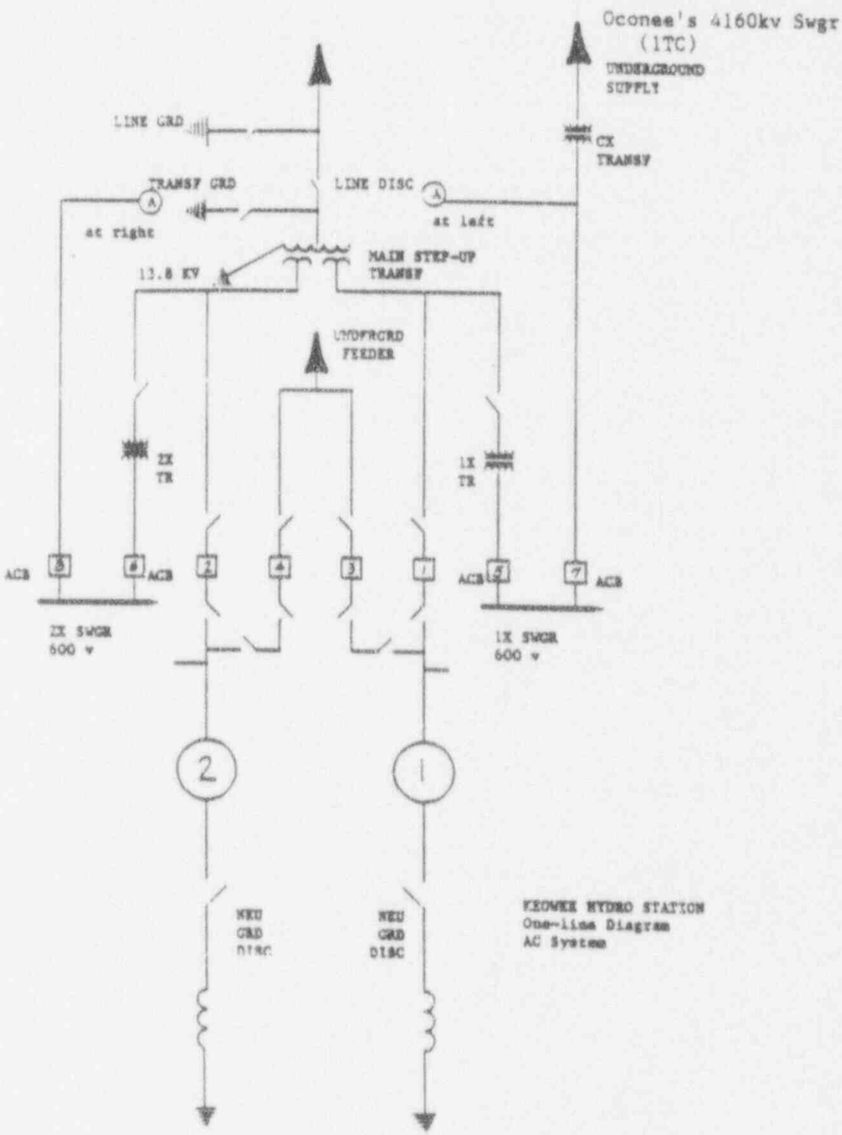
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, All Units	0 5 0 0 0 2 6 9	9 2	— 0 0 8	— 0 0	1 0 OF 1

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT 1



NRC Form 366A (6-89)

NRC FORM 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
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FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	1 OF 0 7

TITLE (4): Potential Single Failure During A LOCA/LOOP Event May Result In The Loss Of Emergency Power Due To Design Deficiency

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									Oconee, Unit 2	0 5 0 0 0 2 7 0
0 8	2 7	9 2	9 2	— 0 1 1 —	0 0	0 9	2 4	9 2	Oconee, Unit 3	0 5 0 0 0 2 8 7

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

☐ 20.402(b)	☐ 20.405(c)	☐ 50.73(a)(2)(iv)	☐ 73.71(b)
☐ 20.405(a)(1)(i)	☐ 50.36(c)(1)	X 50.73(a)(2)(v) (D)	☐ 73.71(c)
☐ 20.405(a)(1)(ii)	☐ 50.36(c)(2)	☐ 50.73(a)(2)(vii)	☐ OTHER (Specify in Abstract below and in Text, NRC Form 366A)
☐ 20.405(a)(1)(iii)	☐ 50.73(a)(2)(i)	☐ 50.73(a)(2)(viii)(A)	
☐ 20.405(a)(1)(iv)	☐ 50.73(a)(2)(ii)	☐ 50.73(a)(2)(viii)(B)	
☐ 20.405(a)(1)(v)	☐ 50.73(a)(2)(iii)	☐ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER: AREA CODE	
S. G. Benesole, Safety Review Group	8 0 3	8 8 5 - 3 5 1 8

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

☐ YES (If yes, complete EXPECTED SUBMISSION DATE)   X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

At 2255 hours on August 27, 1992, Oconee Units 1 and 2 were at 100% Full Power and Oconee Unit 3 was shutdown for refueling. During follow-up on a Self Initiated Technical Audit recommendation, Oconee Engineering (OE) identified a scenario that could result in the loss of both on site emergency power sources. OE determined that a postulated failure of the Keowee Hydro (KH) underground feeder air circuit breaker (ACB) could cause the KH overhead feeder ACB of the unit which is aligned to the underground to close. This could tie both KH units together through the main step up transformer, possibly out of phase. The root cause of this event is Design Deficiency: Unanticipated Interaction of Systems, (Design Oversight). Corrective actions are to open and remove from service the overhead feeder ACB for the unit aligned to the underground feeder and perform a modification which precludes the postulated failure.

NRC Form 366 (6-89)

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	— 0 1 1 —	0 0	0 2 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND

In the event of an accident and the simultaneous loss of the external transmission grid, the Keowee Hydro (KH) units [EIIS:EK] become the primary emergency power source.

The KH Station contains two generating units. Power from KH to the Oconee units can be supplied through two separate and independent paths.

One path is an overhead 230 Kv transmission line to the 230 Kv switchyard yellow bus [EIIS:FK] at Oconee which supplies each unit's start-up transformer. The overhead transmission line is arranged with double air circuit breakers (ACB 1 & ACB 2) so that it can be connected to either KH unit.

The second path is an underground cable feeder to the Oconee transformer CT-4 [EIIS:XFMR] which supplies the redundant standby power buses. The underground feeder is arranged with double air circuit breakers (ACB-3 & ACB-4) so that it, too, can be connected to either KH unit (See Attachment 1). This underground feeder is connected, at all times, to one KH generator [EIIS:GEN] on a predetermined basis and is energized along with CT-4 whenever the associated KH unit is in service. The underground feeder and associated transformer (CT-4) are sized to carry full engineered safeguards loads of one Oconee unit plus the auxiliary loads required for safe shutdown of the other two Oconee units.

Each KH unit is provided with its own automatic start-up equipment. Both units undergo a simultaneous automatic start on a loss of the grid, an engineered safeguards actuation on any of the three Oconee units or an extended loss of voltage on any unit's main feeder bus. On an emergency automatic start-up, the unit connected to the underground feeder supplies that feeder. If there is a grid disturbance, the other unit is automatically connected to the Oconee 230 Kv switchyard yellow bus only after the yellow bus is automatically isolated from the grid. Therefore, in the event of a Loss of Coolant Accident and the simultaneous loss of the grid, emergency power is available from either KH unit through the underground feeder or the overhead transmission line.

If power is not available from the grid or the KH units, power can be made available to the standby power buses from one of the Lee Steam Station combustion turbines (CT). The power is provided through a 100 Kv transmission line from the Lee CT's via the Central switchyard to Oconee's CT-5 transformer. If an emergency occurs that would require the use of this 100 Kv line it can be isolated from the balance of the transmission system in order to supply power to Oconee. One of the Lee CT's can be started and supply power within one hour.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	0 1 1	0 0	0 3 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Technical Specification 3.7 requires both KH units and both power paths from KH to be operable. One KH unit may be removed from service for 72 hours if the other KH unit is tied to the underground power path and proven operable. Both KH units may be inoperable for up to 72 hours for planned reasons if the standby buses are first energized from CT-5 transformer using the dedicated line from the Lee CT's. This last limiting condition for operation is reduced to 24 hours if both KH units are inoperable for unplanned reasons and the Standby Bus is energized from a dedicated Lee CT within 1 hour.

EVENT DESCRIPTION

On May 15, 1992 a Self-Initiated Technical Audit was completed for the Electrical Distribution System at Oconee Nuclear Station. A section of this audit covered Emergency Hydro Generators at Keowee. A recommendation was made that engineering develop a formal single failure analysis of the Keowee Hydro (KH) Units operating in parallel with the off site network to ensure that all possible scenarios are reviewed and properly evaluated with formal calculations.

On August 25, 1992, engineering was in the process of performing the single failure analysis. Engineer-A (E-A) concluded that during a design basis event of a Loss of Coolant Accident/Loss of Off site Power, a single failure could cause the overhead path Air Circuit Breaker (ACB) 1 or 2, for the unit aligned to the underground, to close. This would tie the two KH Units together, possibly out of phase. At approximately 1000 hours, E-A contacted Engineering Supervisor A (ES-A), who was in a training class, and informed him of the postulated single failure. ES-A believed that this event had been previously documented. ES-A began a search for the documentation, after completion of the training.

On August 26, 1992, at approximately 1400 hours, ES-A located a response to an INPO Operation and Maintenance Reminder for a similar but not identical scenario. ES-A initiated a Problem Investigation Process to document the problem and determine if the KH units were operable. Discussions were held with other engineers and technicians to analyze the scenario. The conclusion that both KH Units were inoperable was made at 2255 hours.

The KH Units were declared inoperable at 2255 hours and a 24 hour Limiting Condition for Operation (LCO) was entered (per Technical Specification (TS) 3.7).

The Lee Combustion Turbines were started and the dedicated line was aligned to the Standby Bus at 2340 hours, which was in accordance with TS requirements.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	— 0 1 1	— 0 0	0 4 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

An existing key switch interlock was used to inhibit the closure of the overhead ACB of the unit tied to the underground. The LCO was exited and KH Unit 1 and 2 were declared operable at 0954 hours on August 27, 1992.

CONCLUSIONS

A design deficiency in the logic of the Keowee Hydro (KH) Air Circuit Breakers (ACB) resulted in both KH Units being technically inoperable. The design of the KH generating units considered and included safety provisions to ensure its reliability as the emergency power source for Oconee. It is not apparent that the design considered a single failure which would cause an underground feeder ACB to trip as a creditable failure. Therefore, the root cause of this event is Design Deficiency: Unanticipated Interaction of Systems or Components (Design Oversight).

A review of the LERs generated over the last two years revealed that two LERs (269/90-12 and 269/91-01) reported similar postulated failures of ACB's on the KH Station. LER 269/90-12 reported on two accident scenarios that would prevent KH from providing adequate emergency power to Oconee due to overloading the KH generators. LER 269/91-01 involved a Loss Of Coolant Accident/Loss Of Off site Power (LOCA/LOOP) Design Basis Event when one KH unit is in operation and the other unit shutdown concurrent with a single failure, simultaneously connecting the two KH generators together.

The event described in this report involved a LOCA/LOOP Design Basis Event with the unit tied to the underground experiencing a single failure of its' underground feeder ACB, causing it to trip, allowing the overhead ACB's to close, thus tieing both KH units together. Therefore, this event is considered recurring. Since this problem originated with the initial design of the KH units, the corrective actions for subsequently identified problems could not be expected to have prevented this situation.

This event did not involve actual equipment failure and therefore was not NPRDS reportable. There were no radiological over exposures, radioactive releases or personnel injuries associated with this event.

CORRECTIVE ACTIONS

Immediate

1) Both Keowee Hydro (KH) units were declared inoperable, a Lee Combustion Turbine was started, aligned to the standby bus and a 24 hour Limiting Condition for Operation was entered.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92 ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	— 0 1 1 —	0 0	0 5 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Subsequent

1) The appropriate overhead Air Circuit Breaker (ACB) 1 or 2 was opened by locking an existing key switch interlock and is to remain open until completion of a modification.

Planned

1) Modify the ACB's control circuitry to preclude the postulated failure as described in this report.

2) Complete the single failure analysis of KH Units' power system.

SAFETY ANALYSIS

The postulated event described in this report requires a single failure which causes a Keowee Hydro (KH) underground feeder Air Circuit Breaker (ACB) to trip due to a fault. This would allow the overhead ACB's to close simultaneously, tieing the two KH units together. This could result in the potential damage of both KH units, rendering them inoperable. This event could result in the loss of all automatic emergency power sources for Oconee Nuclear Station.

The scenario for this postulated event requires the following events to occur simultaneously:

1) a Loss of Coolant Accident (LOCA) on one of the three Oconee units in progress.

2) a Loss of Off site Power (LOOP) event where the 230 Kv switchyard is separated from the grid.

3) a failure within the breaker or the control circuit of a closed Keowee Hydro generator underground feeder ACB (either ACB-3 or ACB-4).

4) the overhead feeder breaker time delay relays would have to time out within 200 milliseconds or less of each other.

Final Safety Analysis Report (FSAR) Section 8.1 describes an alternate power alignment for emergency off site power which would be to connect the 100 Kv transmission line from Lee Steam Station's combustion turbines (CT) to Oconee's standby power buses. If the CT's are not running when they are needed, a period of about 15 to 60 minutes would elapse before power could be obtained from the CT's. Otherwise, the alternate power alignment would be from the Central Switchyard.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	— 0 1 1	— 0 0	0 6 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Two of Oconee's three units would experience a simultaneous LOOP during this postulated event. FSAR Section 15.8.3 addresses a simultaneous LOOP event on all three units. This analysis shows that natural circulation of the reactor coolant system [EIIS:AB], turbine driven emergency feedwater system [EIIS:BA], condenser circulating water gravity induced flow, and gravity insertion of the control rods [EIIS:ROD] are among the design features provided to ensure the removal of decay heat from the reactor coolant system without off site power being available. Additionally, FSAR Section 15.8.3 states that "Each reactor can sustain a complete electrical power loss without emergency cooling for about 23 minutes before the steam volume in the pressurizer is filled with reactor coolant" and that "beyond this time reactor coolant will boil off, and an additional 83 minutes will have elapsed before the boil off will start to uncover the core". Therefore, the 106 minutes given in the FSAR for core uncovering is well beyond the 60 minute time frame for establishing emergency power from the CT's.

Another alternative for mitigating the consequences of the loss of power on these two units would be the Standby Shutdown Facility (SSF). The SSF has the capability to bring the units to hot shutdown without off site power. Therefore, the two units would be brought to and maintained in hot shutdown by using the SSF and natural recirculation.

The remaining Oconee unit is assumed to experience a LOCA/LOOP event concurrent with the postulated single failure. If power could not be restored to the unit within a reasonable period of time, then the emergency core coolant flow would have been delayed beyond what was assumed in the accident analyses. Given this situation, fuel damage resulting in a radioactive release to the containment would occur on the unit. The FSAR states that without Reactor Building Spray [EIIS:BE] and Reactor Building Cooling Systems [EIIS:BK] the reactor building pressure would not exceed the design pressure for the containment following the LOCA. Given the 60 minute duration for the restoration of power, it is expected that the reactor building leak rate would not exceed the LOCA analysis rate, but dose rates may be higher due to the loss of filtered ventilation until unit power is restored. A containment response evaluation has shown that equipment qualification conditions would not be exceeded in under two hours for the expected temperature and pressure resulting from this event. Therefore, reactor building equipment should be operable when unit power is restored.

The frequency of a LOCA/LOOP scenario with a simultaneous failure of a KH ACB is considered to be extremely low, well below the 1.0 E-07 threshold considered in Probability Risk Assessments. The ACB's at KH have been very reliable. This type of failure has not occurred with these breakers or their control circuits.

This event did not lead to the release of radioactive material, exposure to radiation, or personnel injury. It did not compromise the health and safety of the public.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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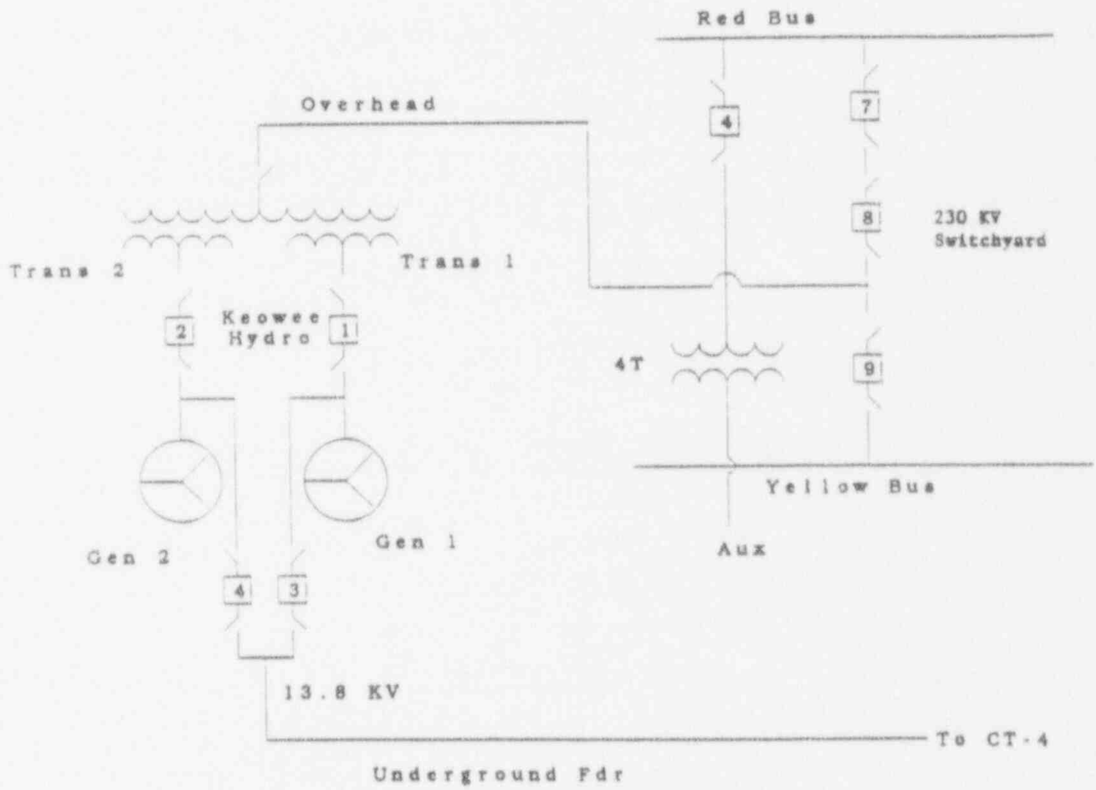
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	9 2	— 0 1 1 —	0 0	0 7 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ATTACHMENT 1



NRC FORM 366 (5-92)	U.S. NUCLEAR REGULATORY COMMISSION	APPROVED BY OMB NO. 3150-0104 EXPIRES 5/31/95
LICENSEE EVENT REPORT (LER)	(See reverse for required number of digits/characters for each block)	ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit 1	05000 269	1 OF 8

TITLE (4) Equipment Failure Results In The Inoperability of Keowee Hydro Unit 2 Overhead Emergency Power Path And A Technical Specification Violation

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									Unit 2	05000 270
09	29	92	92	— 14 —	00	10	29	92	Unit 3	05000 287

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

OPERATING MODE (9)	N	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)	100	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v) (D)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
S. G. Benesole, Safety Review Manager	803-885-3518

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
F	EK	RLY	W121	Y					

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

ABSTRACT

On September 29, 1992 at 2200 hours, Oconee Units 1 and 2 were operating at 100 percent Full Power and Unit 3 was operating at 30 percent Full Power and increasing. While performing post-modification testing a relay was found to have failed resulting in the inoperability of Keowee Unit 2's overhead emergency power path. Technical Specification 3.7 requires both Keowee Hydro (KH) units and both power paths from KH to be operable. The relay was repaired and retested. The root cause of this event is Equipment Failure. Corrective actions include inspecting and repairing if necessary other MG-6 type relays at Oconee.

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BACKGROUND

In the event of an accident and the simultaneous loss of the external transmission grid, the Keowee Hydro (KH) units [EIIS:EK] become the primary emergency power source.

The KH Station contains two generating units. Power from KH to the Oconee units can be supplied through two separate and independent paths.

One path is an overhead 230 Kv transmission line to the 230 Kv switchyard yellow bus [EIIS:FK] at Oconee which supplies each unit's start-up transformer. The overhead transmission line is arranged with parallel double air circuit breakers (ACB 1 & ACB 2) so that it can be connected to either KH unit.

The second path is an underground cable feeder to the Oconee transformer CT-4 [EIIS:XFMR] which supplies the redundant standby power buses. The underground feeder is arranged with parallel air circuit breakers (ACB-3 & ACB-4) so that it, too, can be connected to either KH unit (See Attachment 1). This underground feeder is connected, at all times, to one KH generator [EK:GEN] on a predetermined basis and is energized along with CT-4 whenever the associated KH unit is in service. The underground feeder and associated transformer (CT-4) are sized to carry full engineered safeguards loads of one Oconee unit plus the auxiliary loads required for safe shutdown of the other two Oconee units.

Each KH unit is provided with its own automatic start-up equipment. Both units undergo a simultaneous automatic start on a loss of the grid, an engineered safeguards actuation on any of the three Oconee units or an extended loss of voltage on any unit's main feeder bus. On an emergency automatic start-up, the unit connected to the underground feeder supplies that feeder. If there is a grid disturbance, the other unit is automatically connected to the Oconee 230 Kv switchyard yellow bus only after the yellow bus is automatically isolated from the grid. Therefore, in the event of a Loss of Coolant Accident and the simultaneous loss of the grid, emergency power is available from either KH unit through the underground feeder or the overhead transmission line.

If power is not available from the grid or the KH units, power can be made available to the standby power buses from one of the Lee Steam Station combustion turbines (CT). The power is provided through a 100 Kv transmission line from the Lee CT's via the Central switchyard to Oconee's CT-5 transformer. If an emergency occurs that would require the use of this 100 Kv line it can be isolated from the balance of the transmission system in order to supply power to Oconee. One of the Lee CT's can be started and supply power within one hour.

Technical Specification 3.7 requires both KH units and both power paths from KH to be operable. One KH unit may be removed from service for 72 hours if the other KH unit is tied to the underground power path and proven operable. Both KH units may be inoperable for up to 72 hours for planned reasons if the standby buses are first energized from CT-5 transformer using the dedicated line from the Lee CT's. This last limiting condition for operation is reduced to 24 hours if both KH units are inoperable for unplanned reasons and the Standby Bus is energized from a dedicated Lee CT within 1 hour.

EVENT DESCRIPTION

On May 15, 1992 a Self-Initiated Technical Audit was completed for the Electrical Distribution System at Oconee Nuclear Station. The audit team was comprised of Duke Power personnel and Contractor personnel. A section of this audit covered the Keowee Hydro Generators that supply emergency power to Oconee. A recommendation was made that engineering develop a formal single failure analysis of the Keowee Hydro (KH) Units operating in parallel with the off site network to ensure that all possible scenarios are reviewed and properly evaluated with formal calculations.

On August 25, 1992, engineering was in the process of performing the single failure analysis. It was concluded that during a design basis event of a Loss of Coolant Accident/Loss of Off site Power, a single failure could cause the overhead path Air Circuit Breaker (ACB) 1 or 2, for the unit aligned to the underground, to close. This would tie the two KH Units together, possibly out of phase. The KH Units were declared inoperable on August 26,1992. This event was documented in LER 269/92-11. Corrective actions included modifying the ACB's control circuitry to preclude the postulated failure.

On September 29, 1992, at 1029 hours a Limiting Condition for Operation (LCO) was entered, to perform a modification on ACB(s) 1 and 2. The modification included installing interlocks so that ACB 1 and ACB 2 could not be closed simultaneously.

On September 29, 1992 at 2200 hours, Oconee Units 1 and 2 were operating at 100 percent Full Power and Unit 3 was operating at 30 percent Full Power and increasing. During the performance of post-modification testing, it was discovered that ACB 2 did not close immediately after opening ACB 1 as the procedure required. An investigation was initiated immediately to

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determine the reason ACB 2 did not close as required. The investigation revealed that relay 27T2X (Westinghouse MG-6 style 289B360A22, 115 volts, 60 hertz) had a one half inch gap instead of the seven sixteenths inch gap as specified by manufacturer. The plastic armature stop nut broke apart while the technician was adjusting the gap between contacts. This relay was unaffected by the modification. The relay was repaired by installing a new armature stop nut and adjusting the contacts in accordance with the manufacturers bulletin. The post-modification testing was performed again as required by procedure and ACB 2 operated as required.

A subsequent investigation into other MG-6 relays at Keowee to verify stop nut condition and proper armature gap, revealed two other relays with the plastic armature stop nut missing. These relays were tested and functioned as required. Work Orders were written to replace the plastic stop nut on these relays.

On September 30, 1992 at 1236 hours, it was concluded that KH Unit 2 overhead power path had been inoperable for an undetermined amount of time due to the failure of relay 27T2X.

On September 30,1992 at 1402 hours, the KH overhead power path was declared operable after completing modifications and testing. KH returned to a normal alignment with KH Unit 2 aligned to the underground power path and KH Unit 1 aligned to the overhead power path.

CONCLUSIONS

The root cause of Keowee Unit 2's overhead power path inoperability is Equipment failure. The failure of the relay associated with Air Circuit Breaker 2 resulted in the inability of Keowee Unit 2 to energize the overhead power path. The failure of the relay is mechanical rather than electrical. The relay was repaired and retested and performed its required function. The manufacturer recommends cleaning the contacts periodically, however, they do not recommend verifying the gap. The relays are shipped from the factory correctly adjusted, and it should not be necessary to disturb the adjustment. Oconee Nuclear Station utilizes this type relay in many applications throughout the plant and at Keowee. Many of these relays have been in place for approximately 20 years. The failures noted in this LER appear to be age related. Of the seven relays inspected three were identified with the armature stop nut in a degraded state. Therefore it is concluded that, in order to address this problem all MG-6 relays should be

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inspected and the results of this inspection be used to develop an appropriate Preventive Maintenance program. It should be noted that the Keowee Design Basis Document requires a test to be performed that would have identified the failure of the MG-6 relay. This test was being coordinated with plans for other test at Keowee at the time of this event.

A review of Oconee Problem Investigation Reports over the last years revealed several events had occurred which involved equipment failures. However, none of these equipment failures were found that were related to age. Therefore, this event is considered non-recurring.

The equipment failure of Westinghouse relay MG-6 style 289B360A22 is NPRDS reportable. This event did not involve radioactive releases, exposures to radiation, or personnel injuries.

CORRECTIVE ACTIONS

Immediate

1. The relay was repaired by replacing the plastic stop nut, adjusting the gap according to manufacturer's bulletin and retesting the relay to ensure the operability.

Subsequent

none

Planned

1. Inspect and repair other MG-6 type relays at Oconee Nuclear Station and Keowee.
2. Based on the results of planned action 1 develop and implement an appropriate Preventive Maintenance program for MG-6 relays.
3. Perform test per the Keowee Design Basis Document.

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SAFETY ANALYSIS

Keowee Hydro Station provides an emergency power source to Oconee Nuclear Station for scenarios which involve a Loss of Offsite Power (LOOP). As mentioned earlier in this report, Keowee can feed Oconee through either an overhead or an underground path. Additionally, in the event both Keowee Units are unavailable, the busses connected to the underground path can be supplied from the Central Switchyard or from Lee Steam Station (Lee) Gas Turbines via dedicated lines.

Each Keowee Unit shall be capable of starting and accelerating without AC power to either of its auxiliaries. A review of the Final Safety Analysis Report (FSAR) indicates that the worst case accident for this event is a LOOP affecting all three Oconee units and a concurrent Loss of Coolant Accident (LOCA) on one unit.

FSAR 15.8.3 addresses a simultaneous LOOP event on all three units. This analysis shows that natural circulation of the Reactor Coolant System (RCS) [EIIS:AB], Turbine Driven Emergency Feedwater System [EIIS:BA], Condenser Circulating Water gravity induced flow, and gravity insertion of the control rods [EIIS:ROD] are among the design features provided to ensure the removal of decay heat for the RCS without offsite power being available. Additionally, FSAR Section 15.8.3 states that "Each reactor can sustain a complete electrical power loss without emergency cooling for about 23 minutes before the steam volume in the pressurizer is filled with reactor coolant" and that "beyond this time reactor coolant will boil off, and an additional 83 minutes will elapse before the boil off will start to uncover the core." Therefore, even without cooling from the Turbine Driven Emergency Feedwater Pump or the Standby Shutdown Facility, the FSAR states that core uncovery will not occur for 106 minutes after the initial loss of power.

In a scenario involving a LOOP affecting all three Oconee units and a concurrent LOCA on one unit, Emergency Feedwater and/or the SSF would not be able to assist in mitigating the LOCA. FSAR 15.14.3.3.6 states that "The failure of transformer CT-4 has been identified as a more limiting single failure for the large break LOCA. With the assumed LOOP, this single failure results in a 48 second delay until Emergency Core Cooling System fluid is delivered to the RCS." If an event had occurred that would have rendered the normal power source to 1X and 2X inoperable, the alternate power source could have been aligned by the manual operation of ACB-8 or ACB-7 breaker. Several factors allow time for this manual operation to occur: 1) ACB-8 and ACB-7 are manually operable, 2) Keowee Station is manned 24 hours per day, 3) Keowee Batteries can carry the DC loads for approximately one hour, 4) Keowee Alarm Response Manual directs

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the operator on a loss of voltage to the 600 VAC Switchgear (1X and 2X) to verify feeder breaker tripped and close the alternate breaker, 5) the Keowee governor controls can be operated four and one half full cycles of the wicket gates before depleting the accumulator pressure (1 1/2 to 2 cycles are required for start-up, then minor changes afterwards). During a normal start the accumulator low trip of 250 psi will trip the Unit, but during a emergency start this trip is bypassed. Therefore, power can be regained manually to 1X or 2X within a short time once the event is recognized.

However, even though technically inoperable, Keowee would still have been able to respond in a significant manner. Even in the condition described in this event, if a LOOP or LOCA/LOOP had occurred, Keowee Unit 2 would have responded to an emergency start signal by starting up with all necessary support systems powered by the Keowee DC Battery System and compressed air stored in an accumulator. Keowee would have been able to operate for an indeterminate time, during which the Keowee operator on duty should have time to diagnose the loss of AC power with the use of existing Abnormal Procedures and manually close ACB-8 to connect to the alternate power source.

As described above, emergency power would have been available, and even if a LOCA/LOOP had occurred during this time, the health and safety of the public would not have been endangered.

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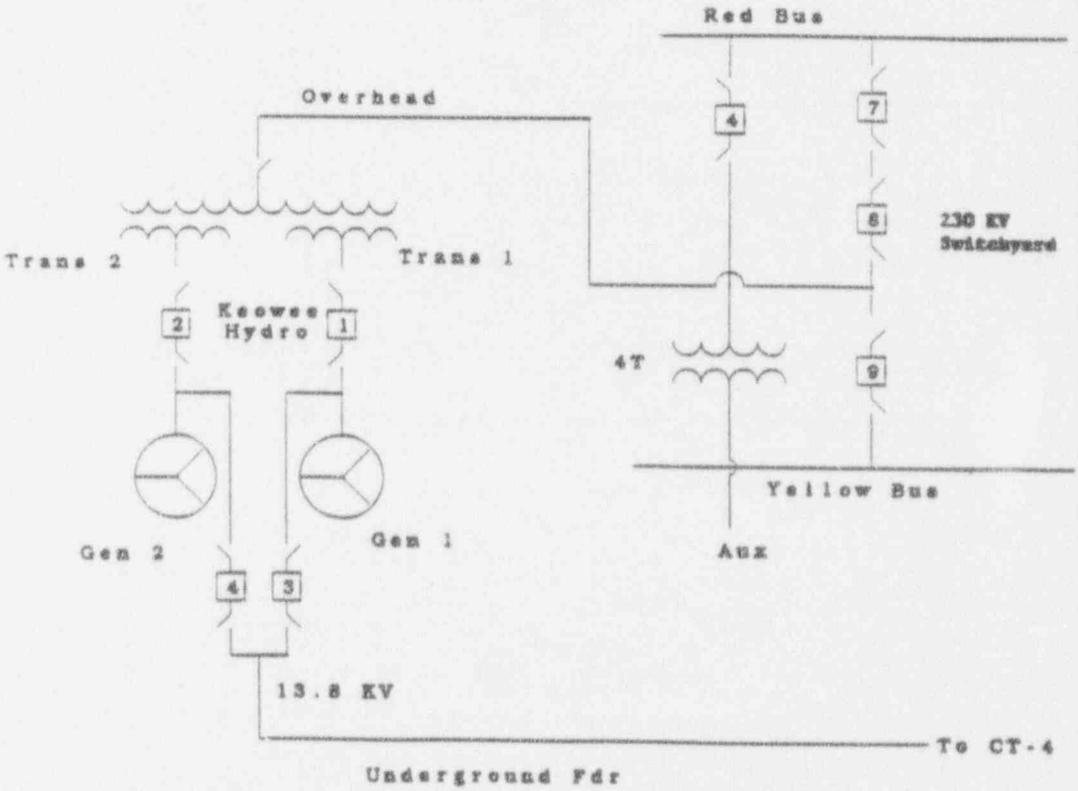
ATTACHMENT 1



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(See reverse for required number of digits/characters for each block)

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TITLE (4) Postulated Single Failure That Would Result In The Loss Of Emergency Power System As Result Of A Design Deficiency

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									Oconee, Unit 2	05000 270
10	12	92	92	– 16 –	00	11	12	92	Oconee, Unit 3	05000 287

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
			20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10)	100		20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)(D)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
			20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
S. G. Benesole, Safety Review Manager	803-885-3518

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On October 12, 1992 at 1800 hours, Oconee Nuclear Station Units 1 and 2 were operating at 100 percent Full Power and Unit 3 was at hot shutdown conditions. As a result of a Self Initiated Technical Audit recommendation, a single failure analysis for the Keowee Emergency Power System was being performed. It was determined that a potential existed for a single fault to cause a loss of both Oconee emergency power paths (the Overhead and the Underground). Oconee Engineering determined that protective relays (87G and 87T), in clearing a fault, could isolate the Keowee Hydro Units (KHU) from the overhead and underground emergency power paths, thus rendering both KHUs inoperable. The root cause of this event is classified as Design Deficiency (Unanticipated interaction of System or Component - Design Oversight). Immediate corrective action taken to prevent the loss of both KHUs due to a single fault included dedicating one KHU to the underground emergency power path, opening its overhead breaker's disconnects, and aligning the other KHU to the overhead emergency power path. Additional actions include a system modification to preclude this failure and completing the single failure analysis.

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BACKGROUND

The Keowee Emergency Power System (EIIS:EK) consists of two hydroelectric generators which provide an emergency on-site power source for Oconee Nuclear Station via two separate and independent paths. One path is the underground feeder through transformer CT-4 (EIIS:XFMR) and the Standby Buses (EIIS:EB) and the other is the overhead through the 230 KV Switchyard (EIIS:FK).

Either Keowee Hydro Unit (KHU) can be tied to the underground or overhead power paths. The normal lineup is to dedicate one KHU to the underground emergency power path by closing Air Circuit Breakers (ACB-3 or 4) and to aligned the other KHU to the overhead power path through ACB-1 or 2 (See Attachment 1). No power seeking circuitry has been designed into the Keowee electrical system to automatically close ACB-3 or 4 in the event of a loss of power to the underground emergency power path.

A network of current transformers, differential relays and lockout relays are employed to monitor and isolate faults on the Keowee electrical distribution busses. Faults are detected by comparing the conditions of various zones within the electrical distribution system. If a fault is detected, the fault detection system coordinates the necessary breakers to isolate the fault from the rest of the system. The relays are set to accomplish this fault detection and to clear the fault as rapidly as possible, in order to limit the damage resulting from the fault. The relay schemes are also designed to minimize equipment outage by de-energizing only the smallest section of the system necessary to clear the fault. Protective zones are normally overlapped to ensure protection of the entire power system. There are protective zone overlaps located at the KHU overhead ACBs.

Technical Specification 3.7 requires both KHUs and both power paths from Keowee to be operable. One Keowee unit may be removed from service for 72 hours. Both Keowee units may be inoperable for up to 72 hours for planned reasons if the standby buses are first energized from CT-5 using the dedicated line from the Lee gas turbines. This last limiting condition for operation is reduced to 24 hours if both Keowee units are inoperable for unplanned reasons and the Lee Gas Turbine is aligned to the Standby Bus within 1 hour.

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EVENT DESCRIPTION

On May 15, 1992, a Self-Initiated Technical Audit of the Keowee Emergency Power systems recommended that a formal single failure analysis be performed concerning the Keowee Hydro Units (KHU) operating with both KHUs generating to the grid.

On October 12, 1992 at 1800 hours, with Oconee Nuclear Station Units 1 and 2 operating at 100 percent Full Power and Unit 3 at hot shutdown conditions, Oconee Engineering was in the process of performing this single failure analysis. It was determined that with one KHU aligned to the underground, a fault could occur within the overlap region of its overhead breaker. Due to the zone protection overlap occurring at the overhead breaker, both the generator (87G) and the transformer (87T) zone protection relays would detect the fault. The 87T relay would lock out the overhead power path by opening both KHU's overhead breakers and the Oconee 230 KV Switchyard tie breakers (PCB-8 and 9). The 87G relay would lock out the KHU aligned to the underground path, blocking it's restart, and opening it's overhead (also opened by the 87T) and underground breaker. The other KHU would remain operable, but could not generate to the overhead or the underground because its overhead breaker is open and it's underground breaker is not closed. With no automatic closure on the underground breakers, emergency power would not be supplied by either KHU.

It was determined that the postulated fault described above constituted a single failure vulnerability. At 1800 hours, the appropriate Limiting Condition for Operation (LCO) per Technical Specification 3.7 was entered.

At 1810 hours, KHU-2 was tied to the underground power path and both disconnects on ACB-2 were opened to remove the possibility of a fault in the overlap region resulting in the single failure event. The LCO was exited.

At 1847 hours, the NRC was notified of the potential single failure that could cause the loss of both Keowee emergency power paths.

CONCLUSIONS

The design of the Keowee Hydro Units (KHU) included safety provisions to ensure their reliability as the emergency power source for Oconee Nuclear Station (ONS). Protective relaying overlap is a standard electrical design; however, single failure criteria was not properly applied to the overlap region of the Keowee differential relay circuitry. Therefore, the

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root cause of this event is classified as Design Deficiency (Unanticipated Interaction of System or Component - Design Oversight).

To preclude this condition, where a fault could result in the loss of both emergency power paths to ONS, KHU-2 was aligned to the underground path and the disconnects for the overhead power path were opened. This removed the differential relay overlap region at this breaker and a fault occurring within this overlap region would not be detected by the protective relays. Therefore, removing the overlap region from the system does not have an adverse affect on the designed system response. Also, removing the overlap region does not impact the ability of the protective relaying to protect the remaining zone area. This essentially removed the ACB from service and prohibited the KHU tied to the underground from supplying power to the overhead path. The other KHU would automatically be aligned to the overhead path. In the event of a single failure in this alignment, an overhead or underground path is available to supply emergency power to ONS.

Future corrective action is a modification of the protective relaying circuit to preclude this postulated failure from affecting both KHUs.

A review of past Problem Investigation Reports, within the last two years, indicates several problems which have resulted in the inoperability of the KHUs. Several of these problems involved design deficiencies from a failure to anticipate interaction of components. This problem is therefore considered recurring. As with the problem addressed in this report, many of these deficiencies were discovered as a result of an ongoing review of Keowee electrical system by Oconee Engineering. Because this problem has existed since the initial design of the Keowee electrical system, the corrective actions for previously identified problems could not have prevented this situation.

This postulated event did not involve equipment failure and therefore was not NPRDS reportable.

This event did not involve any personnel injuries, radiation overexposures, or release of radioactive material.

<u>CORRECTIVE ACTIONS</u>

Immediate

1) A Limiting Condition for Operation was entered concerning the inoperability of the Keowee Hydro Units.

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Subsequent

1) The transformer and generator side disconnect of ACB-2 were opened and ACB-4 was closed tieing KHU-2 to the underground and the Limiting Condition for Operation was exited.

Planned

1) Modify the Keowee breaker protective relaying circuitry to preclude the postulated failure as described in this report.

2) Complete the single failure analysis of KHUs' electrical distribution system.

SAFETY ANALYSIS

If a fault on the overhead Air Circuit Breaker (ACB-1 or 2) for the unit committed to the underground path occurred in the area of the overlap between the 87T and 87G differential protective relay zones, during a Loss Of Coolant Accident/Loss Of Offsite Power (LOCA/LOOP) design basis accident, a trip and lockout of both the overhead path and the underground Keowee Hydro Unit (KHU) would result. This would cause a loss of both on-site emergency power sources.

The scenario for this postulated event requires the following events to occur simultaneously:

1) a Loss of Coolant Accident (LOCA) on one of the three Oconee units in progress,

2) a Loss of Off site Power (LOOP) event where the 230 Kv switchyard is separated from the grid,

3) a fault within the overlap region of the overhead ACBs.

Final Safety Analysis Report (FSAR) Section 8.1 describes an alternate power alignment for emergency off site power which would be to connect the 100 Kv transmission line from Lee Steam Station's combustion turbines (CT) to Oconee's standby power buses. If the CT's are not running when they are needed, a period of about 15 to 60 minutes would elapse before power could be obtained from the CT's. Otherwise, the alternate power alignment would be from the Central Switchyard.

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FSAR Section 15.8.3 addresses a simultaneous LOOP event on all three units. This analysis shows that natural circulation of the reactor coolant system [EIIS:AB], turbine driven emergency feedwater system [EIIS:BA], condenser circulating water gravity induced flow, and gravity insertion of the control rods [EIIS:ROD] are among the design features provided to ensure the removal of decay heat from the reactor coolant system without off site power being available. Additionally, FSAR Section 15.8.3 states that "Each reactor can sustain a complete electrical power loss without emergency cooling for about 23 minutes before the steam volume in the pressurizer is filled with reactor coolant" and that "beyond this time reactor coolant will boil off, and an additional 83 minutes will have elapsed before the boil off will start to uncover the core". Therefore, the 106 minutes given in the FSAR for core uncovering is well beyond the 60 minute time frame for establishing emergency power from the CT's.

Another alternative for mitigating the consequences of the loss of power on the two non-LOCA units would be the Standby Shutdown Facility (SSF). The SSF has the capability to bring the units to hot shutdown without off site power.

The remaining Oconee unit is assumed to experience a LOCA/LOOP event concurrent with the postulated single failure. If power could not be restored to the unit within a reasonable period of time, then the emergency core coolant flow could be delayed beyond that assumed in the accident analyses. Given this situation, fuel damage resulting in a radioactive release to the containment could occur. The FSAR states that without Reactor Building Spray [EIIS:BE] and Reactor Building Cooling Systems [EIIS:BK] the reactor building pressure would not exceed the design pressure for the containment following the LOCA. Given the 60 minute duration for the restoration of power, it is expected that the reactor building leak rate would not exceed the LOCA analysis rate, but dose rates may be higher due to the loss of filtered ventilation until unit power is restored. A containment response evaluation has shown that equipment qualification conditions would not be exceeded in under two hours for the expected temperature and pressure resulting from this event. Therefore, reactor building equipment should be operable when unit power is restored.

The frequency of a LOCA/LOOP scenario with a simultaneous postulated fault within the overlap region is considered to be extremely low, well below the 1.4 E-07 threshold considered in Probability Risk Assessments. The ACB's at KHU have been very reliable. This type of failure has not occurred with these breakers or their control circuits.

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The immediate corrective action for this postulated failure was to open both disconnects for the overhead breaker for the unit designated to supply the underground. This removed the differential relay overlap region at this breaker and had a fault occurred within this overlap region, it would not have been detected by the protective relays. During a LOCA/LOOP scenario, this overhead feeder breaker is not required to close, therefore removing it from the system does not have adverse affect on designed system response. Also, the removal of the overlap region does not impact the ability of the protective relaying to protect the remaining zone area.

Based on the precautionary measures taken, the KHUs are considered operable.

The health and safety of the public were not compromised due to the single failure vulnerability. There were no releases, radiation exposures, or injuries associated with this event.

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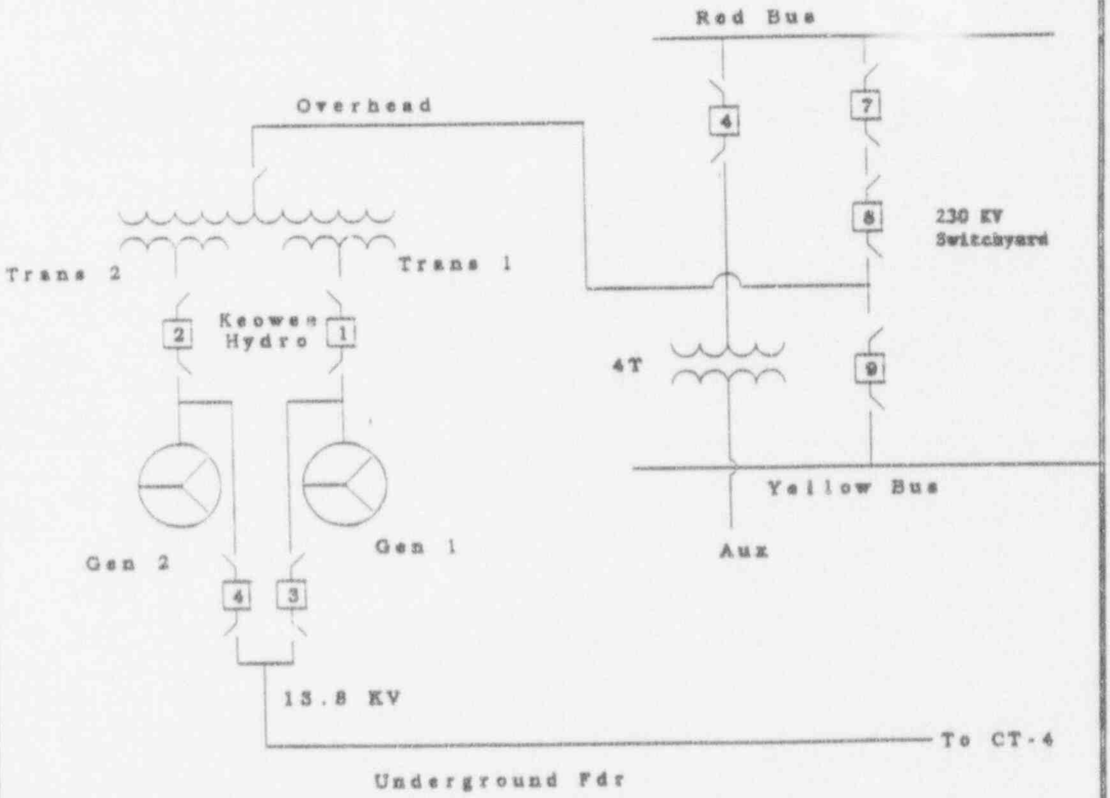
ATTACHMENT 1



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See reverse for required number of digits/characters for each block

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TITLE (4) Design Deficiency Results In The Inoperability of Oconee Emergency Electrical Power Source

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									Oconee, Unit 2	05000 270
12	02	92	92	18	00	12	31	92	Oconee, Unit 3	05000 287

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)			
POWER LEVEL (10)	100%	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	X 50.73(a)(2)(ii) (A)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
S. G. Benesole, Safety Review Manager	803-885-3518

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On December 2, 1992 at 1605 hours, Oconee Nuclear Station Units 1, 2, and 3 were operating at 100% Full Power. While testing the control circuitry for the Auxiliary Power Air Circuit Breakers (5, 6, 7, 8), generator field and field supply breakers for both Keowee Hydro (KH) Units, it was discovered that, during emergency conditions, available DC voltage may be inadequate to close the breakers. These breakers are Westinghouse DB-50 breakers, which had been recently modified to revise the control circuits. As a result, both KH Units, the Emergency Power Generators for Oconee, were declared inoperable and entered Technical Specification 3.7. The root cause of this event is a Design Deficiency (Unanticipated interaction of Systems or Components - Design Oversight). Corrective actions include modifying the control circuitry for all Westinghouse DB type breakers at Keowee. This modification will permit the close coil to remain energized for a longer period to ensure breaker closure during an emergency start without AC power.

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BACKGROUND

The Keowee Emergency Power System [EIIS:EK] consists of two hydroelectric generators which provide an emergency onsite power source for the Oconee Nuclear Station via two separate and independent paths, one of which is the underground feeder through transformer CT4 and the standby buses [EIIS:EB] and the second is the overhead path through the 230 KV switchyard [EIIS:FK]. One unit is required to be connected to the underground path at all times.

Each Keowee Hydro (KH) Unit is provided with a separate 125V DC Power System consisting of one battery and charger, which is powered from the 1X or 2X load centers. On a loss of power to the charger, the battery will supply loads necessary for unit starting. The loads on the DC system include the Generator Field and Supply Breakers, which are required to operate on an emergency start.

Each KH Unit is provided with its own automatic start equipment. Both units undergo a simultaneous automatic start and run in standby on a loss of the grid, an engineered safeguards actuation on any of the three Oconee Units, or an extended loss of voltage on any unit's main feeder buses. On an emergency automatic startup, the unit connected to the underground feeder supplies that path while the other unit, remaining in standby, is available to supply the overhead transmission line. If there is a grid disturbance, this unit is automatically connected to the Oconee 230 KV switchyard yellow bus only after the yellow bus is automatically isolated from the grid. Therefore, in the event of a Loss of Coolant Accident and the simultaneous loss or degradation of the grid, emergency power is available from either Keowee Unit through the underground feeder and/or the overhead transmission line.

The field, supply, and field flashing breakers are closed to provide DC to the field, which will allow the generator to produce electricity. The "X" relays are the anti-pump relays used in Westinghouse type DB breakers. The anti-pump circuitry prevents the breaker from cycling back and forth between closed and tripped when a close and trip signal are both present. The "X" relay is operated by a coil which is energized on the close signal.

If power to the Oconee units is not available from the grid or the KH units, power can be made available to the standby power buses from the Central Switchyard or one of the Lee Steam Station combustion turbines (CT). The power is provided through a 100 Kv transmission line from the Lee CT's via the Central switchyard to Oconee's CT-5 transformer. If an emergency occurs that would require the use of this 100 KV line it can be isolated from the balance of the transmission system in order to supply

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power to Oconee. One of the Lee CT's can be started and supply power within one hour.

Technical Specification (TS) 3.7.2 allows one Keowee unit to be out of service for 72 hours provided the other unit is verified to be operable within one hour. This is verified by starting the Keowee Unit and energizing the standby power bus.

TS 3.7.3 requires that if certain conditions are not met within the time specified in TS 3.7.2, except as noted in TS 3.7.4 and 3.7.7, the reactor shall be placed in a hot shutdown condition within 12 hours. If these requirements are not met within an additional 48 hours, the reactor shall be placed in the cold shutdown condition within 24 hours.

TS 3.7.4 allows Oconee unit operation for an additional 45 days (beyond the 72 hours provided for in TS 3.7.2) with one KH Unit unavailable, under certain conditions.

TS 3.7.7 requires that if both Keowee units become unavailable for unplanned reasons, the reactor shall be permitted to remain critical for periods not to exceed 24 hours provided the 4160 volt standby buses are energized within 1 hour by the Lee gas turbine through the 100 KV transmission circuit and it shall be separate from the system grid and all offsite non-safety related loads.

EVENT DESCRIPTION

On January 29, 1992 at 2104 hours, Keowee Hydro (KH) Unit 2 failed to start during a routine attempt to supply power to the grid. The failure of KH Unit 2 to start was caused by a mechanical failure of the "X" relay. This event was reported in LER 269/92-02. Corrective actions included a Nuclear Station Modification (NSM) 52917, which replaced the existing electromechanical anti-pump scheme with an electrical anti-pump scheme. The design process of the modification included a review by Westinghouse. Westinghouse identified a concern with keeping the closing coil energized too long, potentially damaging the coil. They did not have a concern with maintaining the coil energized long enough to ensure breaker closure. As a result of Westinghouse's concern every DB breaker was individually time tested before and after the modification to ensure the new anti-pump scheme would maintain the closing coil energized as long as the old anti-pump scheme. This was documented in the calculations.

The NSM for KH Unit 1 was completed and tested successfully on July 19, 1992. The NSM for KH Unit 2 was completed and successfully tested on November 18, 1992.

On November 24, 1992, the annual KH Emergency start test was being performed for both KH units. One feature of this test, which differed from the post modification testing performed earlier, was that it assumed, and simulated, a loss of auxiliary AC power as part of the emergency condition. Therefore, the DC battery charger was not assisting the battery during the test. While attempting to tie KH Unit 2 to the overhead power path, it was discovered that after opening the KH Unit 2 Auxiliary Power Normal Feeder Breaker (ACB-6), the KH Unit 2 Auxiliary Power Alternate Feeder Breaker (ACB-8) could not be manually closed. Engineering Supervisor A suspected this failure was due to a voltage problem in ACB-8's closing coil. The problem was attributed to a possible wiring or connection problem, since the breaker closed in the test position after failing in the operate position. Both KH Units auxiliaries were placed in a dedicated alignment so they would be available if they were needed during an emergency, since they were already in their closed position. Under this alignment the suspect circuit would not have been challenged during a Design Basis Event. It was decided that further testing would be performed.

At 1201 hours on December 1, 1992, KH Unit 1 was generating to the grid when voltage swings and a loss of field alarm occurred due to problems with a voltage regulator. KH Unit 1 was shutdown manually and declared inoperable. An investigation was initiated to find the cause. A 72 hour Limiting Condition for Operation (LCO) was entered under Technical Specification (TS) 3.7.2 and KH Unit 2 was operability tested within one hour and subsequently every eight hours as required by TS.

Since KH Unit 1 was inoperable, no testing of breakers could be performed on KH Unit 2 at this time. Later that day KH Station's spare breakers and KH Unit 1's Auxiliary Power Alternate Feeder Breaker (ACB-7) were tested and a potential problem was identified. This testing showed that KH Unit 1's ACB-7 failed to close at low voltages. The results of the testing raised a question about the test equipments accuracy and speed, since ACB-7 had been known to close at lower voltages than those measured during the test. It was determined that high speed measuring equipment would be required to adequately test the breakers. This equipment was located off-site and would be on-site the next day. Also during this period of time, the investigation into Unit 1's voltage regulator problem continued.

At approximately 1000 hours on December 2, 1992, Engineering Supervisor A met with the NRC Resident and Station Management during a routine weekly meeting to discuss the status of problems at Keowee. During this meeting he notified them of the possibility of breaker problems and the need to do further testing. After this meeting, Station Management decided to take

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further compensatory actions by energizing the Standby Buses from a Lee Gas Turbine. This action was taken as a precaution, due to the fact that KH Unit 1 was already inoperable and the breaker problem had the potential for affecting KH Unit 2.

At 1605 hours on December 2, 1992 with KH Unit 1 already inoperable, KH Unit 2 locked out due to an indicated generator ground fault during operability testing as required by TS 3.7.2. An investigation was initiated into the generator ground fault. At approximately this same time testing of the control circuitry for DB-50 breakers utilizing the high speed measuring equipment was completed. Test results indicated that available DC voltage may be inadequate to close the breakers. At this time KH Unit 2 was declared inoperable due to inadequate DC voltage to close the DB-50 breakers. This affected the field and field supply breakers which made the Unit inoperable. At this time, all three Oconee Units were placed in a 24 hour LCO under TS 3.7.7.

An investigation revealed that with reduced DC voltages the closing mechanism moves slower, therefore has less momentum. Under reduced voltage situations the close coil becomes deenergized in the travel such that the available momentum is not adequate to complete the breaker travel. To correct this problem, a Minor Modification was implemented. This modification added a time delay to increase the amount of time the closing coil is energized. This increased time compensates for the effects of decreased voltage, and ensures breaker closure.

On December 2, 1992 at approximately 2121 hours, it was discovered that KH Unit 1's voltage regulator problem was due to a faulty voltage error card. This was repaired but KH Unit 1 remained inoperable due to the breaker problems.

At 0129 hours on December 3, 1992, Oconee Unit 1's Turbine Generator was taken off line in preparation for a scheduled Refueling Outage. The reactor was shutdown, and the Unit entered cold shutdown at 2324 hours on December 4, 1992.

A Minor Modification was completed on KH Unit 1 and the unit was restored to an operable status at 0835 hours on December 3, 1992. At this time TS 3.7.7 was exited and TS 3.7.2 was reentered with approximately 27 hours of the 72 hours remaining.

At 1201 hours on December 4, 1992, Oconee Units 2 and 3 entered TS 3.7.4.d due to one unit of KH being unavailable for more than the 72 hours provided for in TS 3.7.2. The NRC was notified. During the notification it was stated that Oconee Units 2 and 3 would be considered to have been under TS

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3.7.3, rather than TS 3.7.4.d, if KH Unit 2 could be repaired and declared operable by 0001 hours on December 5th.

A Minor Modification was completed on KH Unit 2 at approximately 1700 hours on December 4, 1992. The investigation into the cause of KH Unit 2's lockout continued.

At 2100 hours on December 4, 1992, the cause of KH Unit 2's lockout, which occurred on December 2 was discovered. As part of a corrective action for an earlier identified problem, Station Instrument and Electrical (I&E) personnel had implemented a Configuration Control Inspection. The inspection is verifying that safety related cabinets' internal wiring agrees with the as-built drawings. On December 2, at approximately 1100 hours, I&E technicians were replacing a coverplate on the Voltage Regulator Control Cabinet as part of this inspection. Unknowingly, a screw from the coverplate had penetrated the insulation of a wire associated with the Voltage Regulator circuitry, thus creating a ground and causing the unit to lockout. The wire was replaced. An operability test was performed satisfactorily at 2300 hours.

At 2336 hours on December 4, 1992, KH Unit 2 was restored to operable status. The NRC Regional Office was notified at 2348 hours on December 4th. As stated in the earlier notification it was considered that Oconee Units 2 and 3 had been operating under provisions of TS 3.7.3 from 1201 hours until 2336 hours when, KH Unit 2 was declared operable. TS 3.7.4 was never entered.

CONCLUSIONS

A design deficiency in the anti-pump relay scheme on DB-50 breakers associated with Keowee Hydro (KH) Units 1 and 2 Supply and Field Breakers resulted in both KH Units being inoperable. This design problem also affected both KH Unit's Air Circuit Breakers (ACB) 5, 6, 7 and 8. The breaker operation is such that, upon receiving the close signal, the breaker close coil is energized through the "X" relay. As the breaker mechanism travels to the closed position, the "X" relay is deenergized before the breaker is fully closed. This removes power from the breaker's closing coil, but by then the closing mechanism has moved far enough in it's travel, allowing the breaker to travel to it's fully closed position by inertia. Under the original design the "X" relay was opened by a mechanical action associated with the breaker closing mechanism, which mechanically opened the "X" relay as it traveled to the closed position. Under the new design, the "X" relay is opened by breaker auxiliary contacts which operate as the breaker mechanism travels to the closed position. Time testing of the breakers was performed as part of the modification to ensure the closing coil remained energized in the new design as long as it did under the original design. The results of the testing indicated that the time in which the closing coil remained energized was compatible with the original design. This appeared to indicate that as the closing coil mechanism traveled to the fully closed position, the "X" relay dropped out at relatively the same location on the closing travel range in the new and old design.

Although attempts were made to ensure that the new design allowed the close coil to remain energized to the same point in the breaker mechanism's travel as the original design did, it appears that the threshold of operability at reduced DC voltages was raised. It is not known if the same breakers would have closed with the original design under the worst case DC voltage conditions. It is apparent that the design process did not anticipate that low control circuit voltage could prevent breaker closure. Therefore, the root cause of this event is Design Deficiency (Unanticipated Interaction of System or Components - Design Oversight).

A review of previous events involving KH, that have resulted from a root cause of design deficiency - unanticipated interaction of systems or components, revealed two LERs (269/92-11 and 269/92-16). Neither of these previous events involved DB-50 breakers, therefore this event is considered non-recurring.

This event did not involve actual equipment failure and therefore was not NPRDS reportable. There were no releases, radiation exposures, or injuries associated with this event.

CORRECTIVE ACTIONS

Immediate

1) Both Keowee Hydro units were declared inoperable, a Lee Gas Turbine was in operation, aligned to the standby bus and a 24 hour Limiting Condition for Operation was entered.

Subsequent

1) All Westinghouse DB type breakers at Keowee were modified to permit the closed coil to remain energized for a longer period to ensure breaker closure when operating with a degraded DC system voltage.

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Planned

1) Complete the Design Basis Document for Keowee's 125 VDC Power System.

SAFETY ANALYSIS

Keowee Hydro (KH) Station provides an emergency power source to Oconee Nuclear Station for scenarios which involve a Loss of Offsite Power (LOOP). In this event, the design deficiency produced a common mode failure that could have made both KH Units and the associated emergency power paths inoperable. If both KH Units are inoperable an alternate power alignment for emergency offsite power is through the 100 KV transmission line from Lee Steam Station's gas turbines within 60 minutes. An alternate power alignment is from the Duke grid via the Central Switchyard.

Final Safety Analysis Report (FSAR) 15.8.3 addresses a simultaneous LOOP event on all three units. This analysis shows that natural circulation of the reactor coolant system [EIIS:AB], turbine driven emergency feedwater system [EIIS:BA], condenser circulating water gravity induced flow, and gravity insertion of the control rods [EIIS:ROD] are among the design features provided to ensure the removal of decay heat for the reactor coolant system without offsite power being available. Additionally, FSAR Section 15.8.3 states that "Each reactor can sustain a complete electrical power loss without emergency cooling for about 23 minutes before the steam volume in the pressurizer is filled with reactor coolant" and that "beyond this time reactor coolant will boil off, and an additional 83 minutes will elapse before the boil off will start to uncover the core." Therefore, the 106 minutes given in the FSAR for core uncovering is well beyond the 60 minutes required for establishing emergency power from the Lee gas turbines.

The Standby Shutdown Facility (SSF) is a separate seismically qualified building which houses the systems and components necessary to provide an alternate and independent means to achieve and maintain hot shutdown conditions for one or more of the three Oconee Units. The SSF was designed to resolve the safe shutdown requirement for fire protection, turbine building flooding, and physical security. The SSF has the capability of maintaining hot shutdown conditions on all three units for approximately three days following a loss of normal AC power.

In the event that a Loss of Coolant Accident (LOCA) occurs simultaneously with a LOOP and power cannot be restored in a reasonable period of time, the emergency core coolant flow would have been delayed beyond what was assumed in the accident analysis. FSAR 15.14.3.3.6 assumes 48 seconds for

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the loss of Transformer CT4. If this happens, fuel damage could occur which will result in a radioactive release to the containment building. The FSAR states that without Reactor Building Spray [EIIS:BE] and Reactor Building Cooling Systems [EIIS:BK] the reactor building pressure would not exceed the design pressure for the containment following the LOCA. Given the 60 minute time frame to restore power, it is expected that the reactor building leak rate would not exceed the LOCA analysis rate, but dose rates may be higher due to a loss of filtered ventilation until power is restored. A design containment response evaluation has shown that equipment qualification conditions would not be exceeded in under two hours for the expected temperature and pressure resulting from this event. Therefore, reactor building equipment would be operable when unit power is restored.

This event did not lead to the release of radioactive material, exposure to radiation, or personnel injury. It did not compromise the health and safety of the public.

2

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6″

PHOTOGRAPHIC SCIENCES CORPORATION
770 BASKET ROAD
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

2

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

PHOTOGRAPHIC SCIENCES CORPORATION
770 BASKET ROAD
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

2

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

PHOTOGRAPHIC SCIENCES CORPORATION
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See reverse for required number of digits characters for each block

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TITLE (4) Postulated Single Failure That Could Result In The Loss Of Emergency Power System As Result Of A Design Deficiency

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									Oconee, Unit Two	05000 270
12	10	92	92	19	00	01	11	93	Oconee, Unit Three	05000 287

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

OPERATING MODE (9)	N	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)	100%	20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v) (D)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
S. G. Benesole, Safety Review Manager	(8) 885-3518

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On December 10, 1992 at 1200 hours, Oconee Nuclear Station Units 2 and 3 were operating at 100 percent Full Power and Unit 1 was at cold shutdown conditions. Because of a Self Initiated Technical Audit recommendation, a single failure analysis for the Keowee Emergency Power System was being performed. Oconee Engineering determined that a postulated fault could cause the Keowee Hydro Units (KHU) to isolate from the overhead path and cause the loss of auxiliary power to the KHU aligned to the underground path. This would render the KHU aligned to the underground and the overhead emergency power path inoperable. The root cause of this event is classified as Design Deficiency (Unanticipated interaction of System or Component - Design Oversight). In response to an unrelated event, corrective action was taken on October 22, 1992 that required the auxiliary power source for the underground KHU to be aligned to the transformer, CX, which is supplied from Oconee Nuclear Station Unit 1 and the auxiliary power source for the overhead path KHU was aligned to the normal source, which is supplied by the overhead path KHU. This action eliminated the possibility of this scenario. Additional actions will be to implement a system modification to allow return to normal configuration, and to continue the evaluation of the single failure analysis.

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BACKGROUND

The Keowee Emergency Power System (EIIS:EK) consists of two hydroelectric generators that provide an emergency on-site power source for Oconee Nuclear Station via two separate and independent paths. One path is the underground feeder through transformer CT-4 (EIIS:XFMR) and the Standby Buses (EIIS:EB) and the other is the overhead path through the 230 KV Switchyard (EIIS:FK).

Either Keowee Hydro Unit (KHU) can be tied to the underground or overhead power path. The normal lineup is to dedicate one KHU to the underground emergency power path by closing Air Circuit Breakers (ACB) -3 or 4 and to align the other KHU to the overhead power path through ACB-1 or 2 (See Attachment 1).

The Keowee 600 VAC Load Centers 1X and 2X will provide power to the Keowee auxiliary loads. Keowee's Auxiliary Load Centers 1X and 2X receive their normal, non-emergency power from the 230 KV switchyard via Keowee's Main Step-up Transformer through ACB-5 and ACB-6. An alternate power source is provided to 1X and 2X Load Centers from Oconee Unit 1's 4160 VAC Switchgear (1TC) through Keowee's CX Transformer and the Alternate Feeder Breakers ACB-7 and ACB-8. Each Keowee Unit can start and accelerate without AC power from either of its auxiliary sources. This condition is known as a "Black Start."

A network of current transformers, differential relays and lockout relays are employed to monitor and isolate faults on the Keowee electrical distribution buses. Faults are detected by comparing the conditions of various zones within the electrical distribution system. If a fault is detected, the fault detection system trips the necessary breakers to isolate the fault from the rest of the system. The relays are set to accomplish this fault detection and clearing as rapidly as possible, to limit the damage resulting from the fault. The relay schemes are also designed to minimize equipment outage by de-energizing only the smallest section of the system necessary to clear the fault.

Technical Specification 3.7 requires both Keowee units and both power paths from Keowee to be operable. The Keowee station auxiliary transformers (1X and 2X) and alternate auxiliary transformer (CX) are included in this requirement. One Keowee unit may be removed from service for 72 hours. Both Keowee units may be inoperable for up to 72 hours for planned reasons if the standby buses are first energized from CT-5 using the dedicated line from the Lee Gas Turbines. This last limiting condition for operation is reduced to 24 hours if both Keowee units are inoperable for unplanned reasons and the Lee Gas Turbine is aligned to the Standby Bus within 1 hour.

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EVENT DESCRIPTION

On May 15, 1992, a Self-Initiated Technical Audit of the Emergency Power systems at Oconee Nuclear Station recommended a formal single failure analysis be documented for the conditions where both Keowee Hydro Units (KHU) are generating to the grid.

On October 22, 1992, an event occurred which required a "dedicated alignment" be established concerning the Auxiliary Power system at Keowee. The "dedicated alignment" included aligning alternate auxiliary power (CX) to the KHU connected to the underground. The other KHU was aligned to receive auxiliary power via the main step-up transformer, through Air Circuit Breaker (ACB) -5 or 6. The transfer logic was placed in manual. This event was reported under LER 270/92-04.

On December 10, 1992, at 1200 hours, with Oconee Nuclear Station Units 2 and 3 operating at 100 percent Full Power and Unit 1 at cold shutdown conditions, Oconee Engineering was in the process of performing the single failure analysis. It was discovered that, during a Loss of Coolant Accident concurrent with a degraded grid event, a postulated fault between the Load Center side of the Normal Supply breaker (ACB-5 or ACB-6) and the Load Center (1X or 2X) for the KHU aligned to the underground could have affected the operability of both KHUs prior to entering the "dedicated alignment" on October 22, 1992. This postulated fault would have been detected by the transformer fault detection relaying (87T1X or 87T2X) and the supply breakers' (ACB-5, 6, 7, and 8) overcurrent device, which picks up auxiliary bus lockout relays (86S/1X or 86S/2X). The 87T1X or 87T2X relays would actuate the Main Transformer Lockout Relay (86T) locking out the overhead power path by opening both KHU's overhead breakers (ACB-1 and ACB-2) and the Oconee 230 KV Switchyard tie breakers (PCB-8 and 9). The 86S/1X or 86S/2X relays would actuate to lock out the 1X or 2X Normal Feeder breakers (ACB-5 or ACB-6), the Alternate Feeder breakers (ACB-7 or ACB-8) and block automatic swapover. The KHU aligned to the underground path would be functional and would "Black Start" if required, providing power through the underground emergency power path for a limited time. However, it would be considered inoperable due to the loss of its Auxiliary Load Center power supply. The other KHU would remain functional, but could not generate to the overhead or the underground paths because its overhead breaker would be locked open and it's underground breaker would not automatically close. Manual alignment via the Keowee and/or the Oconee Control Rooms were available.

From December 10 through December 15, 1992, the credibility of this postulated fault was evaluated. At 1600 hours, on December 15, Oconee Engineering determined that the postulated fault was credible, but only

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during breaker movement. ACB-5 and ACB-6 are required to cycle during a Loss of Coolant Accident for Oconee units 2 or 3 coupled with a degraded grid situation. Therefore, in the past, all three ONS units have been in operation while this vulnerability existed. Presently, the Keowee Auxiliary power system is in a "dedicated alignment", which does not require breaker movement for the KHU connected to the underground path and thus precludes any credible fault from affecting both emergency power paths. For this reason, no Limiting Condition for Operation was entered upon discovery of this problem.

On December 15, 1992 at 1732 hours, the NRC was notified of this potential past operability.

CONCLUSIONS

The design of the Keowee Hydro Units (KHU) included safety provisions to ensure their reliability as the emergency power source for Oconee Nuclear Station (ONS). Protective relaying is a standard electrical design, however, single failure criteria was not properly applied to the protective zone between the Load Center incoming breaker and the Load Center itself. Therefore, the root cause of this event is classified as Design Deficiency (Unanticipated Interaction of System or Component - Design Oversight).

The establishment of the "dedicated alignment" of the Keowee Auxiliary Power system on October 22, 1992 removed the possibility of this postulated failure occurring. If this postulated fault were to occur on either Load Center (1X or 2X) while in this alignment, an overhead or underground path would be available to supply emergency power to ONS.

The control circuit will be modified to preclude this postulated failure from affecting both KHUs before restoring the Keowee Auxiliary system to automatic transfer mode.

Oconee Engineering will complete the documentation of the single failure analysis of KHUs' electrical distribution system.

A review of past Problem Investigation Reports for the last two years indicates several problems which potentially result in the inoperability of the KHUs. Several of these problems involved design deficiencies from a failure to anticipate interaction of components. On October 12, 1992 at 1810 hours, the single failure analysis discovered a similar postulated fault within the zone protection overlap region of the KHU output breakers [Air Circuit Breaker (ACB) -1 or 2]. This event was reported under LER 269/92-016. KHU-2 was aligned to the underground path and the disconnects for the overhead power path were opened. This removed the differential

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relay overlap region and essentially prevented the ACB from closing and prohibited the KHU tied to the underground from supplying power to the overhead path. The other KHU would automatically align to the overhead path. Based on this review, this problem is considered recurring. As with the problem addressed in this report, many of these deficiencies were discovered as a result of an ongoing review of the Keowee electrical system by Oconee Engineering. Because this problem existed since the initial design of the Keowee electrical system, the corrective actions for previously identified problems could not have prevented this situation. Enhancements in the design process since the original design should prevent this type of design oversight in future designs.

This postulated event did not involve equipment failure and therefore was not NPRDS reportable.

CORRECTIVE ACTIONS

Immediate

1) Confirmed that the existing lineup of the Keowee Hydro Units, which was being administratively maintained for other reasons, would also preclude this postulated event.

Subsequent

1) None

Planned

1) Implement modifications to the Keowee breaker control circuitry to preclude the postulated failure as described in this report.

SAFETY ANALYSIS

A fault occurring in the area protected by the transformer differential relay and the Load Center supply breaker overcurrent protection device (between Normal supply breaker and the Load Center) on the unit aligned to the underground path, would result in a trip and lockout of the auxiliary Load Center's Normal and Alternate Feeder breakers, the overhead path breakers, and the Oconee Switchyard Tie breakers. A similar postulated fault on the unit aligned to overhead power path would affect the overhead unit only.

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FSAR Section 8.1 describes an alternate power alignment for emergency off site power that would connect the 100 Kv transmission line from Lee Steam Station's Combustion Turbines (CT) to Oconee's standby power buses. If the CT's are not running when they are needed, a period of about 15 to 60 minutes would elapse before power could be obtained from the CT's. Otherwise, the alternate power alignment would be from the Central Switchyard. This time to establish an alternate power source to the Oconee standby buses is within the estimated time frame for operability of the Keowee batteries and air accumulators. The KHU would have been able to operate for an indeterminate time (estimated at 60 minutes). Therefore, the KHU should be available to power the LOCA unit with power until the CTs are connected to the standby power buses.

Although, this event includes a degraded grid it is bounded by the following analysis. FSAR Section 15.8.3 addresses a LOOP event on all three units. This analysis shows that natural circulation of the reactor coolant system [EIIS:AB], turbine driven emergency feedwater system [EIIS:BA], condenser circulating water gravity induced flow, and gravity insertion of the control rods [EIIS:ROD] are among the design features provided to ensure the removal of decay heat from the reactor coolant system without off site power being available. Additionally, FSAR Section 15.8.3 states that "Each reactor can sustain a complete electrical power loss without emergency cooling for about 23 minutes before the steam volume in the pressurizer is filled with reactor coolant" and that "beyond this time reactor coolant will boil off, and an additional 83 minutes will have elapsed before the boil off will start to uncover the core". Therefore, the 106 minutes given in the FSAR for core uncovering is well beyond the 60 minute time frame for establishing emergency power from the CT's.

Another alternative for mitigating the consequences of the loss of power to units not subject to a LOCA would be the Standby Shutdown Facility (SSF). The SSF has the capability to bring the units to hot shutdown without on-site or off-site power available.

In a scenario involving a Loss of Offsite Power (LOOP) affecting all three Oconee units and a concurrent Loss of Coolant Accident (LOCA) on one unit, Final Safety Analysis Report (FSAR) 15.14.3.3.6 states that "With the assumed LOOP, this single failure results in a 35 second delay until Emergency Core Cooling System fluid is delivered to the RCS." If a LOCA/LOOP occurred, the KHU tied to the underground would respond to an emergency start signal by starting with all necessary support systems powered by the Keowee DC battery System and compressed air stored in an accumulator.

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The event can be further mitigated by manual operation by the Keowee Operator and the Oconee Control Room Operator. They should have time to diagnose the loss of AC power at Keowee and manually close Air Circuit Breaker (ACB) -3 or 4 to energize the underground power path.

The frequency of a LOCA/degraded grid scenario with a simultaneous postulated fault within the region of concern is considered extremely low, well below the 6.0 E-08 threshold considered in Probability Risk Assessments. This type of failure has not occurred with these breakers or their control circuits.

As described above, emergency power should have been available, even if a LOCA/degraded grid had occurred during this time. Therefore, the health and safety of the public were not compromised by this postulated failure. There were no releases, radiation exposures, or injuries associated with this event.

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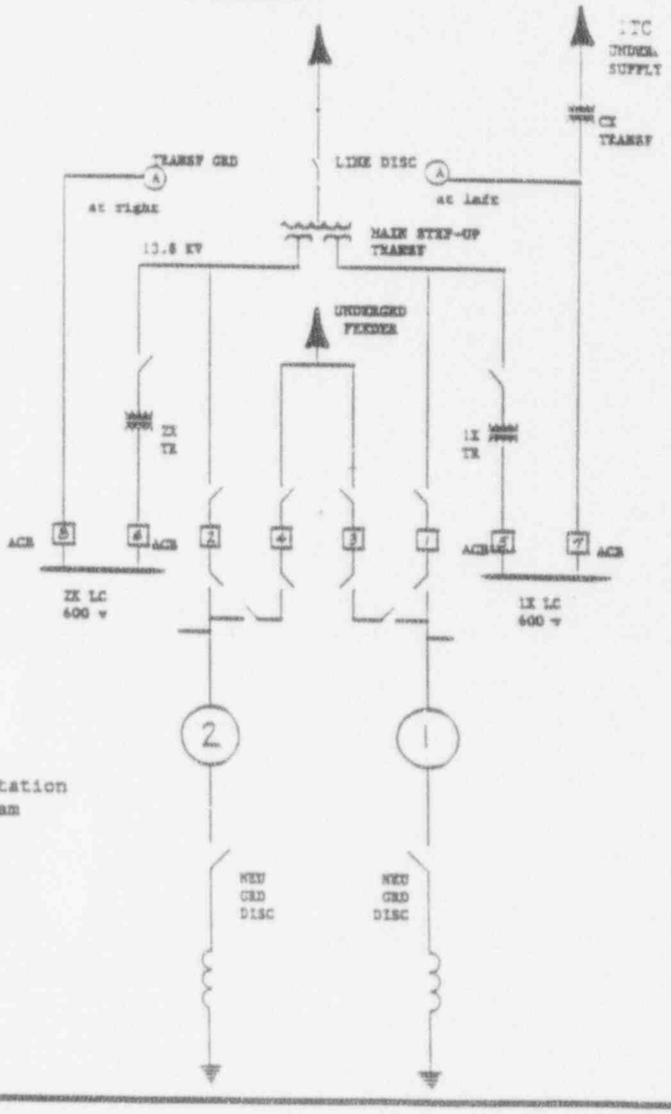
ATTACHMENT 1



Keowee Hydro Station
One-line Diagram
AC system

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APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

See reverse for required number of digits/characters for each block

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Oconee Nuclear Station, Unit 1	05000 269	1 OF 7

TITLE (4) Design Deficiency Results in the Technical Inoperability of the Oconee Emergency Power Source Due to a Postulated Failure of Keowee Hydro Units

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
									Oconee, Unit 2	05000 270
01	11	93	93	- 01 -	00	02	10	93	Oconee, Unit 3	05000 287

OPERATING MODE (9)	N
POWER LEVEL (10)	000

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v) (D)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
S. G. Benesole, Safety Review Manager	(803) 885-3518

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On January 11, 1993, at 2230 hours, Oconee Nuclear Station Units 2 and 3 were operating at 100% Full Power and Unit 1 was shut down for refueling. During the follow-up of a Self Initiated Technical Audit recommendation, Oconee Engineering (OE) identified a scenario that could have impacted the ability of the Keowee Hydro (KH) Station to supply the Oconee emergency power paths. A KH unit generating to the system grid at a high load when an emergency start initiates, would separate from the grid and would over speed. If the speed reaches the trip set point, the unit would trip and excitation to the KH unit would be lost and result in inoperability of the KH unit. The root cause of this event is Design Deficiency: Unanticipated Interaction of Systems, (Design Oversight). Immediate corrective action was to administratively prohibit the use of KH units for generation to the system grid. Subsequent OE analysis permitted limited output of a KH unit when supplying the system grid.

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LER NO: 269/93-001

NRC FORM 366A (5-92) U.S. NUCLEAR REGULATORY COMMISSION

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TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

BACKGROUND

The Keowee Hydro (KH) Station consists of two 87.5 MVA hydroelectric generators that supply power to the Duke Power transmission grid. In addition to normal generation, KH is part of the Keowee Emergency Power System [EIIS:EK], which is designed to serve as the emergency on site power source for Oconee Nuclear Station (ONS). Upon loss of power from the Oconee generating units and the 230KV switchyard [EIIS:FK], power can be supplied from the KH units via two separate and independent paths.

One path is an overhead 230 KV transmission line to the 230 KV switchyard yellow bus [EIIS:FK] at Oconee which supplies each unit's start-up transformers. The overhead transmission line is arranged with air circuit breakers (ACB 1 and 2) so that it can be connected to the KH Units.

The second path is an underground feeder cable to the Oconee transformer CT-4 which supplies the redundant standby power buses. This path is sized to carry full engineered safeguard loads of one Oconee unit plus the auxiliary loads required for safe shutdown of the other two Oconee units ([illegible].228 MVA total). The underground feeder is arranged with ACB's 3 and 4 so that it can be connected to either KH unit. This underground feeder is connected, at all times, to one KH unit on a predetermined basis and is energized along with CT-4 whenever the associated KH unit is in service.

Each KH unit is provided with its own automatic emergency start-up equipment. Both units undergo a simultaneous emergency start on a loss of the grid, an engineered safeguards actuation on any of the three Oconee units or an extended loss of voltage on any unit's main feeder bus. On an emergency start-up, the unit connected to the underground feeder supplies that feeder. If there is a grid disturbance, the other unit is automatically connected to the Oconee 230 KV switchyard yellow bus only after the yellow bus is automatically isolated from the grid. Therefore, in the event of a Loss of Coolant Accident and the simultaneous loss of the grid, emergency power is available from a KH unit through either the underground feeder or the overhead transmission line.

The field, supply, and field flashing breakers are closed to provide DC to the field, which will allow the generator to produce electricity. Anti-pump circuitry prevents breakers from cycling back and forth between closed and tripped when a close and trip signal are both present.

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EVENT DESCRIPTION

On May 15, 1992, a Self-Initiated Technical Audit was completed for the Electrical Distribution System at Oconee Nuclear Station. A section of this audit covered Emergency Hydro Generators at Keowee Hydro (KH). A recommendation was made that engineering develop a formal single failure analysis of the KH units operating in parallel with the off site grid to ensure that all possible scenarios are reviewed and properly evaluated with formal calculations.

On January 11, 1993, Oconee Engineering (OE) was continuing the single failure analysis. Engineers A and B were evaluating scenarios where a KH unit could over speed if the unit is generating at full load to the system grid when an emergency start is initiated. The emergency start causes the KH units to separate from the system grid (i.e., load rejection). The KH unit could trip on over speed if lake levels for Lakes Keowee and Hartwell are different enough to produce a high net head and the KH units are generating at full load to the system grid.

Engineers A and B determined that Turbine/Governor control circuitry is such that if the KH units over speed approximately 140% of rated speed, the shutdown solenoid auxiliary relay will de-energize and give a trip permissive to the KH units field breakers. The field breakers have a maintained close signal already present (via the emergency start signal), therefore the field breakers will trip and not re-close due to an anti-pump feature. Excitation to the KH units would be lost and the KH units would not be capable of performing their intended function. Engineering Supervisor A and Engineering Manager A were informed concerning the postulated event. After they concurred that the potential problem could adversely impact the Emergency Hydro Generator capability, the Superintendent of Operations was notified at 2230 hours and administrative controls were established preventing the KH units from supplying the system grid.

On January 12, 1993, the evaluation continued to determine the impact of the scenario on previous KH operation. At 1557 hours, it was determined that the postulated event could have impacted the ability of the KH units to supply the Oconee emergency power paths in the past. This scenario could result in common mode failure of both units. Prior to a previous postulated event on October 12, 1992 (LER 269/92-16), both units routinely had been generating to the grid. Even after the corrective actions (restricting the KH unit dedicated to the underground path from supplying the grid) were completed on the previous event, if only one unit was generating to the grid then that unit would be technically inoperable and the other unit would be subject to postulated single failure.

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On January 12, 1993, at 1702 hours, the NRC was notified of the past technical inoperability.

The KH units were limited from supplying the system grid from January 11, 1993, at 2230 hours until approximately 1600 hours on January 14, 1993. On January 14, 1993, OE completed a conditional operability evaluation and determined that with no more than 66 megawatts on a unit supplying the system grid and a gross head of no more than 146 feet, the postulated event could not occur. A modification is being planned to restore full power generation capability to the system grid while not impacting the emergency power capability.

Because the KH units were restricted from supplying the grid after the determination of the postulated scenario, no Limiting Condition for Operation was entered upon discovery of this problem.

CONCLUSIONS

The design of the Keowee Hydro (KH) units included safety provisions to ensure their reliability as the emergency power source for Oconee Nuclear Station. Although it was recognized the possibility of an over speed trip existed, it is not apparent that the design considered that the shut down auxiliary relay would activate the anti-pump protection for the field breaker circuitry. Therefore, the root cause of this event is Design Deficiency: Unanticipated Interaction of Systems or Components (Design Oversight).

In the past, all three Oconee units have been in operation while this vulnerability existed, however, no event has occurred which resulted in physical inoperability of a KH unit due to this scenario. On October 19, 1992, a loss of switchyard event occurred at Oconee (LER 270/92-04), which resulted in inoperability of KH units for reasons other than overspeed trip actuations. Subsequent to that event, a load rejection test was performed on October 25, 1992, where actual unit load was above the conditional operability limit but below the maximum postulated load analyzed in this event. The KH unit did not over speed enough to trip, therefore the KH unit remained operable. This indicates that the calculations used in this analysis are conservative.

A review of past Problem Investigation Reports for the last two years indicates several problems which potentially result in the inoperability of the KH units. Several of these problems involved design deficiencies from a failure to anticipate interaction of components. LER 269/92-19 identified that a postulated fault could cause the KH units to isolate from the overhead path and cause the loss of auxiliary power to the KH unit

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aligned to the underground path rendering both KH units inoperable. LER 269/92-16 determined that a potential existed for a single fault to cause a loss of both Oconee emergency power paths (overhead and underground). LER 269/92-11 identified that a postulated failure of the KH underground feeder Air Circuit Breaker (ACB) could cause the KH overhead feeder ACB of the unit aligned to the underground to close tieing both KH units together. As with the potential event addressed in this report, many of these deficiencies were discovered as a result of an ongoing review of the KH electrical system by Oconee Engineering. Because this event is classified as a design deficiency associated with the failure to anticipate interaction of systems or components; it is considered recurring. Because the problem originated with the original design of the KH units, the corrective actions for subsequently identified problems could not be expected to have prevented this situation. Enhancements in the design process, since the original design of KH, should prevent this type of design oversight in the future.

This postulated event did not involve equipment failure and therefore was not NPRDS reportable.

CORRECTIVE ACTIONS

Immediate

1) The Keowee Hydro (KH) units were administratively prohibited from generating to the system grid.

Subsequent

1) A conditional operability evaluation was performed indicating that a KH unit could generate to the system grid at no more than 66 megawatts and no greater than a gross head of 146 feet.

2) On January 15, 1993, a restricted change to the Keowee Modes of Operation procedure (OP/O/A/2000/041) was issued and approved, limiting the KH output to the grid to 60 megawatts at a gross head of no more than 146 feet. It also prevented the dispatcher from using load control.

3) The single failure analysis of KH units' power system was completed on January 21, 1993.

Planned

None

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SAFETY ANALYSIS

Keowee Hydro (KH) Station provides an emergency power source to Oconee Nuclear Station for scenarios which involve a Loss of Offsite Power (LOOP). In this event, the design deficiency introduced a failure mode that could have made a KH unit inoperable. If both KH units are inoperable an alternate power alignment for emergency offsite power is through the 100 KV transmission line from Lee Steam Station's gas turbines within 60 minutes. An alternate power alignment is from the Duke electrical grid system via the Central Switchyard.

Final Safety Analysis Report (FSAR) 15.8.3 addresses a simultaneous LOOP event on all three Oconee units. This analysis shows that natural circulation of the reactor coolant system (RCS) [EIIS:AB], turbine driven emergency feedwater system [EIIS:BA], condenser circulating water gravity induced flow, and gravity insertion of the control rods are among the design features provided to ensure the shutdown of the reactor and removal of decay heat for the RCS without offsite power being available. Additionally, FSAR Section 15.8.3 states that "Each reactor can sustain a complete electrical power loss without emergency cooling for about 23 minutes before the steam volume in the pressurizer is filled with reactor coolant" and that "beyond this time reactor coolant will boil off, and an additional 83 minutes will elapse before the boil off will start to uncover the core." Therefore, the 106 minutes given in the FSAR for core uncovering is well beyond the 60 minutes required for establishing emergency power from the Lee Steam Station gas turbines.

The Standby Shutdown Facility (SSF) is a separate seismically qualified building which houses the systems and components necessary to provide an alternate and independent means to achieve and maintain hot shutdown conditions for one or more of the three Oconee units. The SSF was designed to resolve the safe shutdown requirement for fire protection, turbine building flooding, and physical security. The SSF has the capability of maintaining hot shutdown conditions on all three units for approximately three days following a loss of normal AC power.

In the event that a Loss of Coolant Accident (LOCA) occurs simultaneously with a LOOP and power cannot be restored in a reasonable period of time, the emergency core coolant flow would have been delayed beyond what was assumed in the accident analysis. FSAR 15.14.3.3.6 assumes 48 seconds for the time required to begin delivering flow. If this happens, fuel damage could occur which will result in a radioactive release to the containment building. The FSAR states that without Reactor Building Spray [EIIS:BE] and Reactor Building Cooling Systems [EIIS:BK] the reactor building pressure would not exceed the design pressure for the containment following

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the LOCA. Given the 60 minute time frame to restore power, it is expected that the reactor building leak rate would not exceed the LOCA analysis rate, but dose rates may be higher due to a loss of filtered ventilation until power is restored. A design containment response evaluation has shown that equipment qualification conditions would not be exceeded in under two hours for the expected temperature and pressure resulting from this event. Therefore, reactor building equipment would be operable when unit power is restored.

The event described in this report did not lead to the release of radioactive material, exposure to radiation, or personnel injury. The health and safety of the public was not compromised.

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LICENSEE EVENT REPORT (LER)

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TITLE (4) Loss of Off-site Power and Unit Trip Due to Management Deficiency, Less Than Adequate Corrective Action Program

EVENT DATE (5)			LER NUMBER (6)			REPORT NUMBER (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAME	DOCKET NUMBER
10	19	92	92	04	00	11	18	92	Oconee, Unit 1	05000 269
									Oconee, Unit 3	05000 287

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more) (11)							
			20.402(b)		20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
POWER LEVEL (10)	100		20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
			20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
			20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
			20.405(a)(1)(iv)	X	50.73(a)(2)(ii) (C)		50.73(a)(2)(viii)(B)		
			20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (Include Area Code)
S. G. Benesole, Safety Review Manager	803-885-3518

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)			EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X	NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately 15 single-spaced typewritten lines) (16)

On October 19, 1992, at 2121 hours, Oconee Unit 2 experienced a Loss of Off-site Power, a generator load rejection, and a trip from 100 % Full Power. A battery charger was placed in service without a connected battery. It produced excessive voltages which caused a series of spurious breaker failure relay actuations, locking out both buses in the 230 KV Switchyard. The relays had been identified as susceptible to spurious operation due to excessive voltages in 1980 but were not modified. Also, during recovery actions, shutdown of one emergency generator, after the emergency start signal had been reset, resulted in the unanticipated trip of the operating emergency generator leading to a second loss of power on Oconee Unit 2. The root cause of the event was determined to be Management Deficiency, (Deficient Program, less than adequate corrective action). Corrective actions included several modifications, procedure changes, and equipment reviews.

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BACKGROUND

Each Oconee unit is provided with several sources of normal and backup electrical power. The Start-up and Stand-by Sources are part of the Emergency Power System [EIIS:EB] as described below.

The Normal source of power for an operating Oconee Unit is from the unit's generator via the Auxiliary Transformer (1T, 2T, or 3T). The Auxiliary Transformer provides 6900 V power [EIIS:EA] for operating Reactor Coolant Pumps (RCPs), and 4160 V power to two Main Feeder Buses (MFBs) for the rest of the normal loads.

The Start-up source of power is from the 230 KV Switchyard (SWYD) [EIIS:FK] via the unit's Start-up transformer (CT1, CT2, or CT3), and it also provides both 6900 V power for RCPs and 4160 V power to the MFBs.

The Stand-by source can receive power from the underground feeder from Keowee Hydro (KH) Station [EIIS:EK], which serves the function of emergency diesel generators typically used at nuclear stations, via CT4 or from the Central Switchyard via CT5. The underground feeder and associated transformer (CT4) are sized to carry full Engineered Safeguards [EIIS:JE] loads of one Oconee unit plus the auxiliary loads required for safe shutdown of the other two Oconee units. However, the Stand-by source only provides 4160 V power to the MFBs and cannot provide 6900 V power for RCPs.

Each Oconee unit's power sources are monitored by the Emergency Power Switching Logic (EPSL) and the Main Feeder Bus Monitor Panels (MFBMP). EPSL will monitor the voltage available to the Normal Source, and will initiate a breaker trip to isolate the Normal Source if an undervoltage condition exists. It will then attempt to transfer to the Start-up Source by closing the Start-up breakers if voltage is available there. For "routine" events, such as a unit trip, this transfer is all that is necessary to provide uninterrupted power to station loads.

In the event that power is not available via the Start-up Source, due to a Loss of Off-site Power (LOOP), the MFBMP will initiate automatic actions to provide power. The Stand-by Bus is not normally energized, but, after a 20 second time delay, the MFBMP will automatically emergency start KH, and actuate EPSL to loadshed unnecessary loads, and connect one unit to energize the Stand-by Buses. After an additional 10 second time delay, EPSL will initiate Stand-by Breaker closure to energize the MFBs from the Stand-by

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Buses.

In the event of a Loss of Coolant Accident (LOCA) concurrent with a LOOP, power is needed by the LOCA unit almost immediately. Therefore, Engineered Safeguards initiate an immediate KH emergency start, EPSL actuates loadshed and, after ten seconds, the Stand-by Breakers close to provide power to the MFB.

Per Technical Specifications (TS), offsite power must be available from the system grid via the Oconee 230 KV Switchyard. The SWYD (see Attachment 1) has two electrical buses and a number of circuit breakers that connect the generators with the transmission system. The buses provide junction points for the power exchange between generators and the system. The SWYD can receive power from the generator output transformers for Oconee Units 1 and 2, and Keowee Hydro Station. In addition, the SWYD can supply power to the Start-up transformers for Oconee Units 1, 2, and 3. The SWYD also connects to four pairs of 230 KV transmission lines (Jocassee, Dacus, Oconee, and Calhoun) and to the 525 KV SWYD which connects the Oconee Unit 3 generator to the 525 KV distribution system.

In the SWYD, Power Circuit Breakers (PCBs) control the flow of AC power and isolate any section that may be faulted. The SWYD is arranged in a breaker-and-a-half scheme, so called because three PCBs are used to connect two circuits. The two SWYD buses are designated as the RED bus and the YELLOW bus. Each PCB is designated with a number as shown on Attachment 1.

Keowee Hydro Station consists of two hydroelectric generators [EIIS:GEN]; Air Circuit Breakers (ACBs) 1 through 8; the Main Step-up transformer; auxiliary power load centers 1X and 2X, and associated support equipment and auxiliaries. (See Attachment 2.)

The "overhead" emergency power path is from one KH unit, through the unit overhead generator breaker (ACB-1 or 2), the main step-up transformer, the switchyard yellow bus, the applicable Oconee unit startup transformer (CT-1, 2, or 3), and the associated startup breakers (E1 and E2) to the main feeder buses. An External Grid Protective System monitors voltage and frequency on the RED and YELLOW buses, and Degraded Grid System monitors the voltage at the startup transformers to detect a switchyard or grid disturbance. If voltage or frequency is degraded on both buses or an undervoltage condition exists on two of the three startup transformers simultaneously with an Engineered Safeguard signal on any Oconee unit, the system initiates. It isolates the switchyard by tripping appropriate PCBs, starts both KH units, and aligns the SWYD to distribute power from the appropriate KH unit to the startup transformers via the YELLOW bus.

The "underground" emergency power path is from the second KH unit, through the unit underground generator breaker (ACB-3 or 4), an underground feeder, transformer CT-4, the CT-4 feeder breakers (SK-1 and SK-2), the standby buses (SdB), and unit standby breakers (S1 and S2) to the main feeder buses. This underground feeder is connected, at all times, to one KH generator on a predetermined basis and is energized along with CT-4 whenever the associated KH unit is in service.

Each KH unit is provided with its own automatic start equipment. Both units undergo a simultaneous automatic start and run in standby on a loss of the grid, an engineered safeguards actuation on any of the three Oconee Units, or an extended loss of voltage on any unit's main feeder buses. On an emergency automatic start, the unit connected to the underground feeder supplies that feeder while the other unit, remaining in standby, is available to supply the overhead path. If there is a grid disturbance, this unit is automatically connected to the Oconee SWYD YELLOW bus after switchyard isolation as described above. Therefore, in the event of a LOCA/LOOP or degradation of the grid, emergency power is available from either KH unit through the underground path and/or the overhead path.

Within KH, when one or both KH units are generating to the Duke system, auxiliary power is fed via the KH Main Step-up Transformer to the 1X and 2X load centers which serve KH Units 1 and 2, respectively, as shown on Attachment 2. When the KH units are shut down, auxiliary power is backfed through the transformer from the SWYD. A backup source is available to each load center by automatically connecting to an underground feeder from Oconee Unit 1. The feeder breakers to each load center are designed such that, on loss of normal power, the normal feeder breaker (ACB-5 or 6) will open and the back-up breaker (ACB-7 or 8) will immediately close. If power is restored to the normal breaker for ten seconds, the back-up feeder breaker will open and the normal breaker will immediately reclose. An interlock will prevent normal operation of a KH unit if voltage is lost at the main Step-up Transformer. However, the KH units are capable of operating for a limited period of time (estimated to be between 30 to 60 minutes) without auxiliary power and this trip is bypassed if an emergency start signal is present.

Power can be made available to the standby power buses from one of the Lee Steam Station combustion turbines (CT). The power is provided through a 100 KV transmission line from the Lee CT's via the Central switchyard to Oconee's CT-5 transformer. If an emergency occurs that would require the use of this 100 KV line it can be isolated from the balance of the transmission system in

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order to supply power to Oconee. One of the Lee CT's can be started and supply power within one hour. An alternate power alignment is from the Central Switchyard, which has been modified to include relaying for degraded grid protection. Use of Central Switchyard as an emergency power source is allowed by the station's abnormal procedures as a last resort for restoring power.

TS 3.7 requires both KH units and both power paths from KH to be operable. One KH unit may be removed from service for 72 hours if the other KH unit is tied to the underground power path and is verified to be operable within one hour. This is verified by starting the Keowee Unit and energizing the Standby Bus. Both KH units may be inoperable for up to 72 hours for planned reasons if the standby buses are first energized from CT-5 transformer using the dedicated line from the Lee CT's. This last limiting condition for operation is reduced to 24 hours if both KH units are inoperable for unplanned reasons and the Standby Bus is energized from a dedicated Lee CT within 1 hour.

The DC power system [EIIS:EJ] for the Oconee 230 KV SWYD is divided into two DC buses (SY-1 and SY-2), each supplied by a battery and an associated battery charger (see Attachment 3). A spare charger can be connected to either DC bus to allow testing and maintenance of the installed charger. The buses can be connected to each other by closing a set of connecting breakers. Each of the two buses provide power for PCBs and associated protective relays located in the SWYD and the nearby relay house. The loads are divided such that the SY-1 bus provides power to all of the primary controls and relays for all of the PCBs. The SY-2 bus provides power to back-up relaying, including the Breaker Failure Relays for each PCB.

TS normally permit a single string or component of the 125 VDC power system for the SWYD to be out of service for 24 hours. However, the NRC approved a limited TS amendment to allow one battery and associated distribution center to be inoperable for 7 days due to the extended period of time required for a battery replacement modification.

EVENT DESCRIPTION

In 1989, a Station Problem Report was initiated which requested replacement and upgrade of the existing batteries in the 230 KV Switchyard (SWYD) at Oconee Nuclear Station. In December 1990, the associated Nuclear Station Modification (NSM) was initiated. In May, 1992, Duke Power Company submitted a request for a revision to Technical Specifications in order to extend a Limiting Condition for Operation (LCO) from 24 hours to 7 days. This would

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allow one battery or associated DC distribution panel to be out of service long enough to replace the batteries in accordance with the NSM. In the submittal for this revision, Duke Power stated that, as part of compensatory action, the two DC buses would be tied together "whenever practical."

As part of the modification package, two implementation procedures were developed, one for each battery. During the development of these two procedures, it was decided that the preferred configuration of the two DC buses would be to maintain separation of the buses, and to use the associated battery charger as the only power supply to each bus as its battery was replaced. During this decision making process, personnel in Engineering and Operations were consulted and concurred. After review, procedure TN/5/A/2863/00/AL2 "Replace 230KV SWYD Batteries SY-2", was approved October 15, 1992.

During the period from October 6 until October 12, 1992, the SY-1 battery was replaced. During this time DC power was supplied to the SY-1 bus by the associated charger alone, without any incident.

On the evening of October 19, 1992, Oconee Units 1, 2, and 3 were all operating at 100% Full Power and Keowee Unit 1 was also generating to the system. Keowee Unit 2 was dedicated to the underground power path, with ACB-4 closed.

TN/5/A/2863/00/AL2 "Replace 230KV SWYD Batteries SY-2", was in progress. The procedure had reached a status where the breakers connecting SY-1 and SY-2 buses were closed and the breakers connecting the SY-2 battery and associated charger were open. The cables connecting the battery to the charger had been disconnected. Because the SY buses were connected, all three Oconee units were in an LCO.

The Unit 1 Supervisor (US1) went to the switchyard (SWYD) relay house with several electrical technicians to perform steps in the NSM procedure to reconnect the charger and separate the DC buses. In accordance with the procedure, US1 verified that DC voltage on the charger was reading 132.6 (-0,+2) volts, then closed breakers to connect it to the SY-2 bus. At approximately 2121 hours, he opened the tie breakers which had connected the SY-1 bus to the SY-2 bus. US1 noted that SY-2 charger picked up load and was supplying approximately 20 amps.

Within the next several seconds many events occurred including a loss of switchyard, a trip of Oconee Unit 2, a normal trip of Keowee Hydro (KH) Unit 1, and emergency start of both KH units. Operator actions were taken in the

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switchyard, the Oconee control rooms, and the Keowee control room. A detailed, integrated sequence of events is included as Attachment 4 for reference and each significant event is discussed below.

One of the electrical technicians with US1 reported that several seconds after the tie breakers were opened on SY-2 he heard several relays in the relay house actuate. Seconds later both the technician and US1 heard the sound of the main steam relief valves opening on one of the Oconee units. They also reported that the output meter of the charger fell to zero, (which is expected because its source of power is Unit 2). Suspecting that his actions had affected the switchyard, US1 "backed out" of the procedure by reclosing the SY-1 to SY-2 tie breakers and opening the breaker from the SY-2 charger.

The Events Recorder (ER) [EIIS:IQ] for the SWYD showed numerous relay actuations and Power Circuit Breaker (PCB) trips. Bus lockout relays were actuated on both buses. The overall result was that all PCBs connected directly to the RED and YELLOW buses tripped open, leaving only PCBs 11, 14, and 20 closed.

One result of these PCB trips, was that the RED and YELLOW buses were totally isolated, resulting in undervoltages being detected which actuated the External Grid Protection System. This system initiated a Switchyard Isolation signal designed to isolate the YELLOW bus, send an Emergency Start signal to both KH Units, then reclose PCBs to connect one KH unit to the Start-up transformers of all three Oconee units to provide emergency power. However, due to the YELLOW bus lockout, PCB-9 (connecting to KH) and PCBs 18, 27, and 30 (connecting to the Start-up transformers) could not close. This left all three Oconee Units without power available to their Start-up source.

As stated above, KH Unit 1 had been generating to the grid prior to the SWYD isolation. Both PCBs 8 and 9 opened due to the SWYD relay actions, therefore, KH Unit 1 underwent a load rejection. However, at approximately the same time, the Emergency Start signal was received, which caused Keowee ACB-1 to open for approximately 6 seconds then reclose.

According to Keowee Operator A (KO A), he was in the turbine room when the event began. His first indication of the event was that he heard a loud "bang" and the overhead lights went out. The "bang" was apparently ACB-1 opening, which isolated KH auxiliary power load centers from the KH Unit 1 generator. He heard another "bang" moments later (ACB-1 reclosing) while he returned to the control room, where he immediately observed multiple flashing alarms. He failed to observe the specific alarm which indicated that an

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Emergency Start signal had been received. He did note the meter that indicated that KH Unit 1 was operating with no load.

Thinking that KH Unit 1 was still generating to the grid and was undergoing a failure that might damage equipment, KO A operated the control switch to manually trip ACB-1, and observed that all AC power to KH auxiliaries was lost. This included power to statalarms for both units, the plant telephone, the KH ER, and the KH Operator Aid Computer (OAC) output printer. As a result, KO A lost normal communications with Oconee and access to much of the data he was accustomed to using for diagnosing problems and determining unit status.

At this point, KO A observed from meter indications that KH Unit 2 was starting and concluded that an Emergency Start had occurred. At some point in this sequence, a KH main transformer lockout relay was actuated. Due to the transformer lockout, he was unable to reclose ACB-1.

During this portion of the event, the KH auxiliary power breakers for load centers 1X and 2X should have transferred to the backup power feeder from Oconee Unit 1. However, these transfers apparently did not occur.

KH Unit 2 started and energized CT-4 via the underground path within approximately 20 seconds from the initiation of the Emergency Start signal.

The first alarm received by the Oconee Unit 2 ER was an alarm which indicated that the breaker failure relay actuated on either PCB-23 or 24 at 2121 hours. If it had been the PCB-23 relay, the expected result would have been a trip of breakers at the other end of the Calhoun White line, which did not occur. If it had been the PCB-24 relay, the expected results would have been activation of a YELLOW bus lockout and the trips of PCB-23, PCB-24, and all other PCBs connected to the YELLOW bus. Also, the Unit 2 generator would receive a lockout, which would, in turn, trip the reactor. The Oconee OACs and ERs indicated that these results did occur.

N1 and N2 (Normal Source 4160 V breakers which supply power from the Oconee Unit 2 generator to auxiliary loads) opened. Because PCBs 26 and 27 had tripped, which isolated the Start-up Transformer (CT-2), E1 and E2 (Start-up Source breakers) were unable to provide power, resulting in a loss of power to both Unit 2 Main Feeder Buses.

The Main Feeder Bus Monitor Panels (MFBMPs) detect undervoltage on the Main Feeder Buses. If the undervoltage exists on both buses for 20 seconds, the MFBMP circuits actuate causing several automatic actions. One is the generation of a KH Emergency Start signal (in this case, the signal was already present from switchyard isolation). A second action is the actuation of the Emergency Power Switching Logic (EPSL) load shed and Stand-by Breaker closure logic. It also generates start signals to High Pressure Injection [EIIS:BG] pumps and Component Cooling [EIIS: CC] pumps to protect the Reactor Coolant Pump seals by providing seal injection and seal cooling. By design, after a one second time delay, the load shed circuit trips 4160 VAC breakers which provide non-essential loads on the affected Oconee unit. After an additional ten seconds, the Stand-by Bus breakers are allowed to close. The closure of the Stand-by Bus breakers restored power to all essential components on Unit 2, approximately 33 seconds after the trip, and ended the first loss of power event.

In the shared Oconee Unit 1 and Unit 2 control room, the Control Room Supervisor (CRSRO) stated that he heard the sound of an ER printing out just prior to the receipt of numerous alarms. He observed that the control rod position indications showed that a trip had occurred and noted that normal room lighting had gone out on the Unit 2 side of the control room and backup lights had come on, indicating a loss of power. He obtained the Emergency Operating Procedure and began reading steps for the Reactor Operators (ROs) to verify proper post-trip automatic responses and to identify the unit status. Upon observation that the Main Feedwater [EIIS:SJ] Pumps had tripped (as expected following a loss of power), RO-A obtained the Abnormal Procedure for Loss of Main Feedwater. RO-B monitored the control board and responded to the CRSRO. After verifying that Unit 1 had not tripped and was relatively unaffected, RO-C (one of two ROs assigned to Unit 1) obtained the Unit 2 Abnormal Procedure for Loss of Power, and began performing actions within that procedure as directed by the CRSRO.

The Operations Shift Supervisor (OSS) and the Unit 3 Unit Supervisor (US3) were in the Unit 3 control room prior to the event. When the loss of the Unit 3 Start-up source was indicated by alarms and the sound of the Unit 2 Main Steam Relief valves was heard, they rapidly verified that Unit 3 was stable, then both OSS and US3 left Unit 3 and proceeded to Unit 1 & 2 control room to assist. Upon entering the Turbine Building, they observed the loss of Unit 2 lighting, which they recognized as being the result of a loss of power event. While still in the Turbine Building they heard a page from the control room announcing the trip and requesting OSS and the Shift Manager, who is also the Shift Technical Advisor, to report to the control room.

The Shift Manager arrived in the control room and monitored the plant stabilization.

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US1 called the control room from the SWYD. He notified the personnel there of the probable relationship between his actions with the battery charger, SWYD events, and the unit trip. He was informed that the affected unit was Unit 2, and was requested to stand by at the SWYD in case action was needed to reset the various lockout relays located in the relay house.

The immediate post trip response of Unit 2 was nominal for a loss of power event. The Reactor Protective System [EIIS:JC] was actuated by the generator trip signal, the control rod drive breakers tripped as required and all control rods [EIIS:ROD] inserted into the core, shutting down the reactor.

The response of several systems was specifically affected due to the loss of power. The Reactor Coolant Pumps (RCPs) coasted to a stop. The Condenser Cooling Water (CCW) [EIIS: BS] system went into the gravity flow mode. Main Feedwater was lost due to loss of power to the Hotwell and Condensate Booster Pumps. The Motor Driven Emergency Feedwater [EIIS:BA] Pumps (MDEFWPs) could not start.

The Turbine Driven Emergency Feedwater Pump (TDEFWP) started automatically. Within a few seconds after start, the Emergency Feedwater flow dropped to zero for approximately 3 to 5 seconds, then returned. Due to the short duration, it was not observed by the operator. As the TDEFWP picked up flow again, power was restored and both MDEFWPs started. The control system for emergency feedwater began to fill the steam generators (SG) to establish natural circulation cooling of the core. At approximately 2125 hours, with all indications that both MDEFWPs were operating, RO-A shutdown the TDEFWP as directed by the Loss of Main Feedwater Abnormal Prodcedure (AP).

Normal Reactor Coolant System (RCS) [EIIS:AB] operating temperatures are approximately 601F at the hot legs and 557F at the cold legs for an average RCS temperature of 579F. After a normal trip, when RCPs continue to operate, the hot leg and cold leg temperatures converge at approximately 555F. In this case, the RCS hot leg and cold leg temperatures began to converge while the RCPs coasted down with a corresponding drop in RCS flow. When emergency feedwater (EFDW) flow reached the SG, the hot leg an cold leg temperatures diverged, as expected, to create a density differential which forces flow through the core and steam generators in natural circulation. The temperature differential varied from a low of approximately 21F to a high of approximately 56F, stabilizing 30 minutes after the trip at around 33F and slowly decreasing thereafter as decay heat reduced. During this time the cold leg temperature decreased from 557F to a low of 511F and stabilized at approximately 535F.

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Normal RCS pressure is 2155 psig. Due to routine fluctuations it dropped to 2144 psig prior to the trip. As the RCS temperature dropped, the post-trip pressure dropped to 1921 psig approximately one and a half minutes after the trip. 2RC-1 (pressurizer spray control valve) did not control properly. It should have closed at 2155 psig but operator action was required to manually close it at 2145 psig. RCS pressure increased when power was restored and HPI flow was restored. Pressure reached a maximum of 2232 psig before stabilizing at approximately 2155 psig. Pressurizer (PZR) level decreased from about 220 inches prior to the trip to approximately 93 inches as the RCS temperature and pressure dropped. When power was restored and HPI flow was restored, PZR level returned to approximately 125 inches. As the system was being stabilized, PZR level dipped again, rose to a post-trip peak of 129 inches before being maintained at approximately 100 inches.

Steam generator levels dropped from 161/156 inches (steam generators 2A and 2B, respectively) before the trip to a minimum of 68/66 inches after the trip. They then filled and stabilized at approximately 241/236 inches. The set point for natural circulation is 240 inches. Steam pressures were approximately 900 psig before the trip. After the trip, pressures ranged from a high of 1124 psig, which is slightly higher than expected, to lows of 772 and 734 psig. The low pressures were the result of the EFDW flow rate as the steam generators filled to the 240 inch setpoint. This flow rate cooled both the RCS and the steam in the steam generator, thus reducing the steam pressure. When RO-A shut down the TDEFWP, the EFDW flow was reduced, the RCS cooldown rate stayed within limits, and the steam pressure stabilized. As the SG level setpoint was reached, the SG pressure was controlled at 900 psig.

The primary Instrument Air (IA) compressor is powered from the SWYD via PCB-4, so it lost power when the SWYD RED bus lockout occurred. Additionally, one backup IA compressor is powered from Unit 2, but was load shed and could not automatically start. Two other backup compressors, powered from Unit 1, started and attempted to maintain pressure in the IA system. Alarms were received on Unit 1 and Unit 2 at approximately 2122 hours indicating low pressure in the IA system. Therefore RO-D (assigned to Unit 1) obtained and entered the AP for Loss of Instrument Air. In accordance with this procedure, he called the Unit 3 control room and had operators there dispatch a non-licensed operator to start a diesel power air compressor which is connected to the Instrument Air header. This resolved the immediate problem.

Approximately one to two minutes into the event, after power had been restored, the operators observed that Reactor Building Cooling Unit (RBCU)

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[EIIS:VA] Fan A had not restarted. The operator attempted to restart it but it would not go into HIGH (normal) speed. It would run in LOW (emergency) speed.

At this point in accordance with the Loss of Power AP, RO-C reset the Main Feeder Bus Monitor Panel, which also reset the EPSL loadshed signal. This allowed the operators to begin returning loadshed equipment to normal service.

At 2130 hours, US3 called the Operations staff duty person at home to notify him of the event. The duty person then initiated notification of various members of station management and staff of the event. The NRC site resident inspector was also contacted. Several members of management and staff technical experts were called in to assist with the recovery.

At 2134 hours, the CCW system was realigned and CCW Pump A was started to terminate the gravity flow mode of operation. At this time a problem with 2CCW-24, Condenser 2C1 Outlet Valve, was observed and a work request initiated for investigation and repair.

At about this time, KO A contacted the Duke System Dispatcher via a dedicated dispatcher phone line, which was still in service. KO A requested that the dispatcher contact KO B, a member of the KH technical support staff, and have him come in. The Dispatcher was also able to tie in the Dispatcher phone in the Oconee Unit 1&2 control room so that KO A and US2 could talk to each other.

KO A told US2 that there were "problems" with the KH auxiliary power system, but it is not apparent that US2 understood that all auxiliary power had been lost and that continued operation of KH Unit 2 was in jeopardy. US2 told KO A that Oconee Unit 2 was dependent on KH Unit 2 for power and for him (KO A) "not do anything to affect Unit 2 at this time." KO A stated after the event that he understood this to mean take no action at all, so he waited for KO B to arrive. While waiting, he made a quick tour, using a flashlight, to assess the status of the equipment.

Upon notification that KH had "problems" with auxiliary power, OSS contacted the Dispatcher to consult about restoring the SWYD. The Loss of Power AP is written such that it assumes that a SWYD isolation has occurred due to real faults that need to be evaluated and isolated prior to restoring the affected breakers, buses, and transmission lines. Therefore, up to this point, OSS had anticipated a lengthy check out of equipment to assure that the event was not due to a real fault. However, the Dispatcher confirmed that he had no

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indication of faults or breaker actuations outside the SWYD. With this information and a new urgency due to the status of KH, OSS reassessed the situation and decided, with the Dispatcher's concurrence, to go ahead and try to restore the SWYD.

At approximately 2150 hours, KO B arrived at the KH control room. KO A briefed him of the situation. The most immediate concern was the loss of auxiliary power, which affected the operation of KH by preventing make-up to the hydraulic oil accumulator tanks on each unit. These accumulators provide the oil to operate the governor and wicket gates to control turbine speed, and, therefore, generator output. The normal operating level in the accumulator is approximately 48 inches on a sight glass. When KO-B arrived, the level on both accumulators was between 4 to 8 inches.

KO B used the Dispatcher phone to talk to the Dispatcher and US2 at Oconee. They decided to attempt to reset the KH main transformer lockout. At this same time, it was decided to have the Dispatcher call Lee Steam Station to start a combustion turbine and begin actions to establish the dedicated line from Lee.

At approximately 2158 hours, KO B reset the transformer lockout. This allowed ACB-1 to close automatically, which, in turn, allowed KH Unit 1, which had been running with no load, to energize the transformer. With voltage available, ACB-6, the normal power supply breaker to 2X loadcenter, closed in, restoring auxiliary power to KH Unit 2.

At 2159 hours, the KH operators observed that 1X loadcenter for KH Unit 1 was locked out. They attempted to reset it but it would not reset.

At 2200 hours, US1 reset the RED and YELLOW bus lockouts for the SWYD.

At 2201 hours, the Dispatcher logged that he had told the Lee Steam Station operators to start up a combustion turbine for Oconee.

At 2206 hours, KO B determined that ACB-7, the backup supply breaker to 1X, had a local lockout. This was reset at the breaker. KO B returned to the KH control room and closed ACB-7. This restored auxiliary power to KH Unit 1.

At 2213 hours, Operations closed PCB-10. This re-energized the RED bus, clearing the undervoltage condition on the bus. As a result, PCBs 7, 13, 16, 19, and 22 were able to automatically reclose.

At 2214 hours, Operations attempted to close PCB-26 to restore power to the

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Unit 2 Start-up Transformer from the RED bus. It cycled but tripped back out due to the continued Switchyard Isolate signal. However, due to this movement, PCB-26 momentarily interrupted the Switchyard Isolate Complete logic, which provides a close permissive signal to PCB-9. This allowed the anti-pump logic to reset and PCB-9 closed automatically at 2214 hours, connecting KH Unit 1 to the YELLOW bus, restoring voltage there.

Operators then reset the Switchyard Isolate signal. This made it possible to restore the Start-up Source for the Oconee units by aligning the Start-up transformers to either the RED or YELLOW bus. OSS had directed the operators to focus on restoring the Start-up source to Unit 2, so they manually closed PCB-26, which supplied voltage to the Unit 2 Start-up transformer from the RED bus, at 2218 hours.

At 2221 hours, the dedicated line from Lee was available with the combustion turbine on-line.

OSS was concerned about the potential for inadvertent or automatic connection of the RED bus, energized from the grid, to the YELLOW bus, energized from KH Unit 1, while the two sources were not synchronized. Rather than closing PCBs to restore power to the Start-up Transformers for Units 1 and 3, the decision was made to shutdown KH Unit 1 to remove voltage from the YELLOW bus, then re-power the bus by closing a PCB-to reconnect the YELLOW bus to the RED bus.

Some of the management and staff personnel who had been notified earlier began arriving and were briefed on the situation. One of the first to arrive was the Superintendent of Operations (SOPS). The action plan for restoring the SWYD was discussed and SOPS concurred with the plan.

OSS reviewed the plant status and declared an Unusual Event at 2225 hours. Appropriate notifications were made by approximately 2237 hours.

In order to shut down KH Unit 1, it was necessary to reset the emergency start signal. Since this signal goes to both KH units, resetting it would affect both units. This signal was reset at 2242 hours.

The KH operators were still in the process of evaluating and trying to correct the problem with ACB-5, the Unit 1 normal auxiliary power breaker. At 2247 hours, they tried to reclose ACB-5 and inadvertently tripped ACB-7 and locked out 1X again. The lockouts were reset and ACB-7 was reclosed to restore auxiliary power to Unit 1.

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At 2251 hours, OSS requested that KH Unit 1 be shutdown. This was done but some of the results were unexpected. The YELLOW bus de-energized as expected, but KH Unit 2 tripped also. This was due to protective logic which monitors the voltage on the Main Step-up Transformer. Since there was an undervoltage condition with KH unit 1 no longer supplying power, and no Emergency Start signal, this logic assumed that KH Unit 2 was trying to generate to the grid with no auxiliaries and no output, and tripped KH Unit 2. This trip de-energized the Underground feeder and, therefore, the Stand-by buses and the Unit 2 Main Feeder Buses.

The EPSL contains circuitry to retransfer from the Stand-by Buses to the Start-up Source if necessary. However, this portion of the circuit is only active if a load shed signal is present. Since that signal had been reset previously, the logic now required
that the MFBMP actuate, which included a 20 second time delay.
At the end of that time, the MFBMP initiated another KH Emergency Start and, after an additional second, another load shed. Another ten second time delay was included in the retransfer logic so that it took a total of approximately 31 seconds for the associated time delay relays to time out. At the end of this delay time, the Stand-by Breakers tripped open and the Start-up Breakers closed as designed to restore power.

KH Unit 1 responded to the new emergency start signal as expected. It restarted, but did not close into the YELLOW bus because PCB-26 was out of position so there was no SWYD Isolate Complete permissive to reclose ACB-1. Since the RED bus did not have an undervoltage, there was no SWYD Isolate Initiation signal to cause PCB-26 to reposition itself.

KH Unit 2 did not respond as desired. After the trip, it had begun to slow down but the emergency start signal caused it to restart prior to resetting a speed switch in the field breaker anti-pump circuit. This speed switch and the anti-pump circuit prevented the field from energizing and, therefore, kept the generator from functioning.

Again, while power was off, the MDEFWPs and HPI pump B ceased to provide flow. The TDEFWP was manually re-started and provided EFDW flow. HPI A pump received an auto start signal, but could not provide flow without power. When power was restored, the TDEFWP and HPI A pump were secured. Also, the Unit 2 CCW system had re-aligned for gravity flow and had to be restored to the normal lineup and a CCW pump restarted. Plant parameters such as RCS temperature, pressure, and inventory were temporarily affected but remained within normal limits and were promptly restored when power was restored.

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Shortly after power was restored, additional staff personnel arrived on site, including technical experts on the systems involved. They were briefed and contributed their ideas as to appropriate actions/methods to use to restore the SWYD to normal.

The group was divided into two teams. One made plans for recovery of the YELLOW bus. The second was assigned to review and investigate the sequence of events thus far to make sure that the event and current equipment status was adequately understood.

On October 20, 1992, at 0018 hours, KH Units 1 and 2 were shutdown.

By 0024 hours, KH Unit 2 had slowed down enough to reset the speed switch in the field flashing circuit, and had been restarted and realigned to CT-4.

At 0041 hours, PCB-8 was closed, re-energizing the YELLOW bus from the RED bus and the Duke system.

Between 0048 and 0057 hours, Operations closed PCBs 4, 18, 27, 30, 21, 17, 28, 12 and 15 to restore the SWYD to its normal alignment.
This restored power to the Start-up Sources for Units 1 and 3.

At 0114 hours, the first reactor coolant pump was restarted. This reestablished forced cooling of the core and ended the natural circulation cooling mode. The other pumps were subsequently restarted, with the last one being started at 0229 hours.

At 0125 hours, Operations notified Security that the Standby Shutdown Facility was in a Degrade condition due to loss of normal power, which is fed from Unit 2. The loss of power had occurred at 2121 hours when Unit 2 lost power the first time.

At 0344 hours, the Unusual Event was terminated.

Power was restored to the SSF and the Degrade mode was exited at 0415 hours.

Duke Power activated a Significant Event Investigation Team (SEIT) of personnel from the General Office, Oconee Site, and INPO. The NRC activated an Augmented Inspection Team. These teams assembled at the Oconee Site during the day on October 20, 1992.

Due to the problems with the auxiliary power at KH, the decision was made to temporarily maintain the dedicated line from Lee. Oconee was in a 72 hour

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LCO due to the configuration of the KH auxiliary power breakers. After discussions with the NRC, it was concluded that it was acceptable to maintain KH in standby with auxiliary power being fed from Oconee via CX transformer (from ACB-7 or 8) to whichever unit was connected to the underground path. The other KH unit would be aligned to receive auxiliary power via the main step-up transformer (from ACB-5 or 6). The transfer logic would be placed in manual until the automatic transfer circuits could be modified. At 2245 hours on October 22, 1992, this LCO was exited after appropriate procedures had been implemented to specify this alignment. At 2302 hours, on October 22, 1992, the combustion turbine at Lee was secured.

Subsequent investigation revealed that the SY-2 charger did not maintain bus voltage at approximately 130 VDC as expected. When tested using test instrumentation rather than the built-in output voltage meter, a series of rapid voltage swings occurred such that its voltage output exceeded 200 VDC. It was observed that the output voltage meter did not indicate the full magnitude of these swings as the seen by the test equipment. The vendor manual for the battery charger provides some specifications for current and voltage stability while connected to a battery, but no data is given for operation without a battery. No specific statement prohibits operation without a connected battery, but the setup instructions call for connecting a battery, and wording indicates that connection to a battery is assumed.

The charger vendor was consulted and stated that the chargers were not intended to be used without a battery in the circuit. Without a battery, the vendor expected the output voltage to vary, although the observed magnitude of the variation on SY-2 was "more than expected."

A review of the Preventive Maintenance procedure for this device indicated that it is checked in normal service with the battery and prevailing system load on the output. Also, the PM is performed using only the installed output voltage and current meters. Additional diagnostic testing and inspections have been performed on the SY-2 charger, subsequent to the event. The testing indicates that the charger is not operating properly, but no specific defective component has been identified at the time of this report. This testing will continue in an attempt to identify the cause.

The observed voltage swings exceeded the ratings of several relays connected to the SY-2 bus, including the breaker failure relays for all PCBs in the SWYD. The investigation also revealed that, in 1980, the vendor of the breaker failure relays had sent out "Product Reliability Letters" stating that these relays could actuate spuriously if exposed to a 200 VDC differential for greater than 2 milliseconds. The letters also contained

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directions for a field change to correct the problem. Although the Duke personnel reviewing the letters recommended making the changes, the relays in the Oconee SWYD were not modified.

Tests were performed where a breaker failure relay was connected to SY-2 charger with additional loads to simulate the conditions seen during the event. Test equipment showed that the relay actuated every time the charger output voltage went above 200 volts. The relay was then modified per instructions in the vendor's letter and the test was repeated. The modified relay did not actuate, even though the charger output voltage continued to swing above 200 volts. As a result of this test, the rest of the breaker failure relays in the SWYD were modified prior to Unit 2 restart.

This investigation also noted that a similar event had occurred at Vermont Yankee (VY) on April 23, 1991. The VY event had also involved operation with one switchyard DC bus powered by a battery charger while isolated from the battery, inadequate voltage control by the charger partially due to failed components, and activation of breaker failure relays due to voltage surges associated with establishing that battery configuration. This event was evaluated per the Duke Power Operating Experience Program. The evaluations with respect to Oconee concluded, in part, that, due to differences in the breaker failure relay circuits, the relays in service at Oconee were less susceptible to voltage spikes than those at VY, that procedures did not permit simultaneous cross-connection of the spare battery charger to both DC buses (a factor at VY), and that an LCO limited the time the two buses could be connected. The evaluations also addressed the adequacy of general maintenance activities in the switchyard, but did not address periodic maintenance of the battery chargers, which was a specific item addressed in the report on the VY event.

As a precautionary measure, PCB-23 and PCB-24, were tested prior to Unit 2 restart to assure that no real faults existed on either breaker. These breakers were selected because the initial trip signal indicated by the Unit 2 ER came from them.

The KH computer receives AC power from the KH batteries via an inverter. Investigation revealed that the KH computer was provided with an AC outlet to be used by the printer. However, at some point in the past, the KH computer printer had been replaced with a newer model. When this replacement occurred, the printer was also relocated. The new location was closer to a wall outlet powered from KH Auxiliary power than it was to the outlet on the computer, therefore it was plugged into the wall outlet. This made the printer vulnerable to a loss of auxiliary power. As a result of this event,

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it has now been reconnected to the computer outlet.

A significant effort was made to determine the causes of the problems with the KH auxiliary power breakers. On the 1X (KH Unit 1) bus, it was concluded that ACBs 5 and 7 failed to transfer properly due to a mis-actuation of a breaker actuator device. This resulted in a Lockout of the 1X bus, and ACBs 5 and 7.

Also, on the 1X bus, the auto throwover circuit, which transfers between sources, was not functioning properly. An intermediate relay (Westinghouse Model MG-6) contact that drives the timing relay was not conducting, therefore the timer was not operating. As a result, the retransfer circuit would be actuated with no time delay. However, this problem had little or no effect on operation during this event. MG-6 relays are used in many applications throughout Oconee Nuclear Station and at Keowee. An MG-6 relay problem discovered on September 29, 1992, involving a mechanical failure which made Keowee ACB-2 inoperable, resulted in LER 269/92-14.

On the 2X bus, throughout this event, KH Unit 2 auxiliary power transferred successfully to ACB-6 whenever it was energized. However, it was concluded that, when power was lost to ACB-6 from the main transformer, ACB-8 failed to close due to either dirty contacts on a model MG-6 intermediate relay activated by an undervoltage relay, or a stuck "X" relay. "X" relays are the anti-pump relays used in Westinghouse type DB breakers. The anti-pump circuitry allows the breaker to receive only one close signal. This prevents the breaker from cycling back and forth between closed and tripped on a trip signal.

In addition, testing and inspection showed that the retransfer logic was wired in accordance with a wiring diagram which was in conflict with the circuit schematic diagram. A ten second time delay relay was wired such that the bus was dead for ten seconds during retransfer from ACB-8 to ACB-6. However, this problem also had no effect on operation during this event.

Subsequent to this event, KO-B has reviewed the design of the hydraulic oil accumulator and has determined that, after oil level has dropped off scale, a float valve operates to seal off the supply line to the turbine speed control governor. When level is lost, the valve should close and "lock-in" the existing speed and load. Therefore, the affected KH unit could continue to operate as long as there is no significant change in load.

During the loss of power, a personnel injury occurred. A Radiation Protection technician was in the process of establishing backup power to

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sampling equipment which had lost power due to the loadshed on Unit 2. In the reduced lighting, the technician hit his head on a welding receptacle and received a cut. He was transported to a nearby hospital for examination and treatment. He returned to work after the examination. The cut did not require stitches and contamination was not an issue. Site industrial Safety personnel classified this as a non-recordable minor injury.

Several items were identified by the post trip review as requiring maintenance prior to restarting the unit.

RBCU 2A fan did not restart in high speed when power was restored. This was investigated per WR 38187C. High and Low speed contactors were found to be pitted and burned on the respective half-side to each contact, indicating misalignment. These contactors were replaced and contact alignment verified. A functional test demonstrated proper operation. Current readings dropped 2 to 4 amps.

2CCW-24 (Condenser outlet valve in the Condenser Cooling Water system) did not reclose when the CCW system was restored to normal. This was investigated per WR 38186C. The I&E technicians found a 1 inch air line supplying the valve pulled out of the ferrule of a fitting. The line was repaired.

The momentary loss of EFDW low from the TDEFWP was investigated by System Engineering. The investigation found an accumulation of water in the Auxiliary Steam supply line to the TDEFWP turbine. The cause was thought to be a faulty steam trap. A Problem Investigation Report was generated to address the root cause and recommend long term action. Site Engineering personnel have concluded that this is not an operability question in regards to potential turbine damage.

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CONCLUSIONS

The root cause of the trip of Oconee Unit 2 event is considered to be Management Deficiency, (less than adequate policy) due to a less than adequate corrective action program, for reasons described below.

Three specific factors combined to produce this event. First, the breaker failure relay zener diodes would pass a spurious signal when subjected to greater than 200 VDC for 2 milliseconds or longer. Second, the 230 KV Switchyard DC power system was being operated with the battery isolated from the SY-2 bus and with the battery charger as the only source of voltage. Third, the SY-2 battery charger, when operated in this configuration, produced an output voltage which varied from approximately 70 to over 200 VDC.

The problem with the breaker failure relay design was identified and communicated to Duke Power in 1980. Duke Power personnel reviewed the notice and recommended corrective action be taken. However, the problem was not corrected on the relays in the Oconee 230 KV Switchyard. Due to the time elapsed since the evaluation and the lack of definitive documentation, it cannot be determined if the failure to correct this problem was due to a subsequent technical or management decision or due to a failure to follow-up on the recommendation.

The Operating Experience Program (OEP) review by Duke Power for the Vermont Yankee (VY) April 23, 1991, loss of off-site power event provided a second opportunity to discover the problem. The actuation of breaker failure relays due to voltage surges in the DC power system was a causal factor in VY event. However, the relay models involved were similar but not exactly the same. The zener diode involved in the VY event does not exist in the equivalent circuit in the model used at Oconee. As a result, the OEP review of the VY event concluded that the equivalent portion of the circuit would not fail the same way. The OEP review did not discover that a different circuit was subject to the same failure mode, with the same result: actuation of the relay.

If the breaker failure relay problem had been corrected, this event would not have occurred. Conversely, while relays with the problem design were in place, ground faults or lightning strikes could have caused a similar event at any time by producing voltage surges through the DC bus and actuating the breaker failure relays.

The DC system is designed to be at approximately 125 VDC. It was not

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anticipated that it should operate at 200 VDC. Few, if any, of the connected relays are rated for exposure to 200 VDC. However, a review of these relays indicates that none of the other relays should have failed or spuriously actuated if the breaker failure relays had not actuated first. Therefore, exposure to this high voltage is only a problem if the breaker failure relays are not modified.

The other two causal factors (operation of a battery charger as a source without a battery and the fact that the charger voltage swings were excessive, indicating a defective component) were also causal factors in the VY event. The OEP review of the event at VY failed to address the issue of use of the battery charger connected to the load without a battery. It also failed to adequately address the issue of inadequate battery charger maintenance. As a result, Oconee personnel were not adequately aware of these aspects of that event and did not take appropriate action to prevent similar problems from occurring at Oconee. Correction of either of these factors would have prevented this specific event.

Many of the subsequent problems were known problems with corrective actions in various stages of implementation. Several of these corrective actions involved routine upgrades to replace aging and/or obsolete equipment. Other actions were considered more urgent and had higher priorities and significant management attention. It is concluded that the scope and schedule for these planned corrective actions were reasonable. However, these corrective actions were not implemented promptly enough to prevent the known problems from affecting this event. These include:

1. Wiring at Keowee Hydro (KH) not per design drawings. Inspections to determine and evaluate deviations were in progress.

2. "X" relays failing to reset properly. One upgrade modification was completed on both KH units, on October 2, 1991. After KH Hydro Unit 1 was successfully started approximately 100 times, three additional "X" relay failures occurred between January 29 and February 20, 1992. A second modification had been performed on KH Unit 1, and was pending on KH Unit 2. It had been delayed to correct to problems encountered during the KH Unit 1 installation.

3. Speed switch in the KH Field circuit. This was being resolved by the "X" relay modification.

4. MG-6 relay problems had been discovered on September 29, 1992. Inspections were in progress.

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5. Loss of normal telephone communication at KH. Modification was being designed.

6. Switchyard battery chargers had been identified as obsolete and were scheduled to be replaced by battery eliminators.

7. Events recorders for the Oconee units and 230 KV switchyard were scheduled for upgrade.

Several problems/concerns became apparent due to this event.

1. Operator response was less than adequate. Specifically, KH Operator A (KO-A) performed an action which could have interfered with the safety function of KH Unit 1 by manually tripping ACB-1. Also, he failed to take timely action to restore auxiliary power to both KH units. These were inappropriate actions arising from Human Factors Deficiencies related to training, procedural guidance, and habit intrusion.

2. Procedural guidance was less than adequate in several areas indicated below.

   One problem was that procedures did not provide sufficient instructions for verification of proper operation of the KH unit providing emergency power. In the absence of a KH emergency procedure, this guidance should have been in the Oconee Loss Of Power Abnormal Procedure (AP).

   The AP also lacked adequate guidance for recovering from a SWYD isolation. This led to KH Unit 2 subsequently tripping unexpectedly at 2252 hours. In this condition, no power would have been available automatically to Units 1 and 3 if either of them had tripped without an Engineering Safeguards actuation. Operators would have had to take manual action to connect to a power source (either LEE or the RED bus). This mode continued until 0018 hours.

   Also, guidance was less than adequate in relation to the operability of the Standby Shutdown Facility (SSF). A degrade mode was declared at 0125 hours, on October 20th, retroactive to 2121 hours on October 19th. The principle concern was the status of the SSF battery. No guidance was included in the Loss of Power AP to declare this condition earlier, nor was a measurable criteria such as battery voltage provided. As a result, the personnel involved elected to conservatively make the

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declaration retroactive.

4. The vendor manual for the battery charger provides some specifications for current and voltage stability while connected to a battery, but no data is given for operation without a battery. No one consulted the manufacturer on this subject prior to the event. The vendor stated after the event that voltage swings of undetermined magnitude are expected in this mode.

   Guidance not to use battery chargers without a connected battery is not specifically stated in the manufacturer's manuals and was not generally known at Oconee. This indicates potential training and/or communication deficiencies.

5. A concern was raised with respect to the appropriateness, with respect to single failure, of having certain loads (such as ALL breaker failure relays) on specific DC buses. Additionally, concerns were raised as to the appropriateness of having specific loads, such as the Keowee control room alarms, powered by auxiliary AC power rather than by some other source. NRC IE Bulletin 79-27, "Loss of Non-class 1E Instrumentation and control power system bus during operation" contains generic guidance, but has not been used to assess the Keowee and Switchyard systems.

A review of loss of power and reactor trip events at Oconee indicates that this event is not recurring.

The Breaker Failure Relays used in the SWYD are Westinghouse type SBFU styles 203C552A08, 203C552A21, 203C552A32, and 204C179A19. The SY-2 battery charger is an Exide Model USF 130-3-50. These items are currently not identified as NPRDS reportable.

There were no excessive exposures, or releases of radioactive materials associated with this event.

CORRECTIVE ACTIONS

Immediate

1. The SY-2 bus was reconnected to the SY-1 bus and the SY-2 charger was removed from service.

2. Oconee Operators performed actions as directed in appropriate

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procedures to stabilize Unit 2 at hot shutdown following the trip.

3. Lee Steam Station started a combustion turbine and the dedicated transmission line to Oconee was established.

4. KH personnel reset lockouts and restored power to KH auxiliaries.

5. The Oconee Switchyard was restored to normal status.

Subsequent

1. The modification procedure was revised to maintain SY-1 and SY-2 tied together and powered from SY-1 for the rest of the battery replacement.

2. The breaker failure relays in the switchyard were modified per vendor instructions. Similar breaker failure relays in the switchyard at Duke Power's McGuire Nuclear Station were also modified.

3. Other solid state equipment supplied by SY-2 were inspected for damage due to exposure to voltages higher than the system design. No damage was discovered.

4. Other Oconee procedures were reviewed, and precautions added where appropriate, to avoid use of a battery charger connected to a load without the battery in the circuit.

5. Indicating lights were installed on the KH control panels to provide direct indication of an emergency start signal. These lights are powered from the KH batteries and are independent of the KH Auxiliary AC power which provides power for the KH Statalarm system.

6. The KH computer printer has been reconnected to the computer power supply.

7. An Abnormal Procedure was issued to provide guidance for the KH operators following an emergency start. This included provisions for verifying proper operation of the KH units and corrective actions to restore or compensate for unexpected equipment response. The procedure also requires that any "abnormalities"

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in the operation of the Keowee Units during an emergency be communicated immediately to the Oconee Control Room.

8. Duke Power management has revised the organizational structure such that KH Station is now part of the Nuclear Generation Department rather than the Hydro department. KH personnel will now report to the Oconee Site Vice President.

9. A dedicated "ringdown" phone was installed to connect KH control room to the Oconee control room.

10. Procedures were revised to temporarily maintain 1X and 2X switchgear in manual to prevent automatic transfers.

11. A review of maintenance history for the last three years and interviews with KH personnel were conducted to identity any other recurring problems. None were found.

12. A special test, TT/0/A/0620/02,"Keowee Hydro Load Rejection Test," was performed to confirm the proper response of KH to a simulated switchyard isolation signal when aligned to the grid.

13. A modification was made to the KH circuitry so that the units will no longer trip due to undervoltage on the main step-up transformer. This interlock was moved in the circuitry such that it must be satisfied to enable a normal start, but will neither prevent an emergency start nor trip a running unit.

14. Dedicated flashlights were provided in the KH control room pending the assessment and resolution of permanent emergency lighting needs.

15. As an interim measure, Oconee Licensed Reactor Operators have been assigned to man KH and work with the KH operators. The purpose is to sh Oconee's operating practices and standards with the Keowee operators by utilizing the experience Reactor Operators have in control room and plant operations.

Planned

1. The adequacy of KH and Oconee operator and staff knowledge of KH design will be assessed. Appropriate training will be provided as needed to meet expectations.

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2. A dedicated emergency radio (battery powered) will be provided for communications from the KH control room to the Oconee control room. This will require an antenna system to be installed at KH.

3. An upgraded phone cable will be installed between the Oconee site phone system and KH.

4. Improvements to the Oconee Loss of Power Abnormal Procedure will include guidance for recovery of off-site power sources. These will assure that recovery actions do not result in the unexpected loss of a KH unit.

5. Emergency lighting needs will be assessed for KH and any discrepancies identified will be resolved appropriately.

6. A modification will be implemented to preclude the transfer problem that was experienced during the event.

7. The pending modification to the X-relay circuit to change the mechanical anti-pump logic to an electrical logic will be implemented. This modification will also remove the speed switch logic which prevented KH Unit 2 from providing power after the second emergency start.

8. A planned corrective action from LER 269/92-14 is to develop a program to address the on-going reliability of all model MG-6 relays in safety related applications. This program is still under development.

9. A review will be performed to identify and implement improvements in surveillance testing to verify proper performance of the Keowee auxiliary power system transfer logic.

10. The testing requirements specified by Test Acceptance Criteria sheets referenced in the design basis document for KH emergency power will be reviewed to identify and evaluate any other surveillance testing deficiencies.

11. A station modification will be implemented to replace the switchyard sequence of events recorder with a newer model with enhanced capabilities.

12. The KH auxiliary power systems and the 230 KV switchyard 125 VDC

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power system will be assessed in accordance with NRC Bulletin 79-27 (or any appropriate guidance which may have superseded Bulletin 79-27).

13 The Operating Experience Program will be reviewed for enhancements to improve both the program and the periodic assessments of program effectiveness.

14. Site Engineering will determine the appropriate document (procedure, directive, etc.) to contain guidance to assure that "lessons learned" are available for review and reference in the preparation and review of Nuclear Station Modification implementation procedures (and/or other temporary procedures as appropriate). This will specifically address guidance on proper operation of battery chargers.

15. Testing will continue in order to identify problems with SY-2 charger and to verify operability of SY-1 and SY-S battery chargers.

SAFETY ANALYSIS

The high voltage from the battery charger and the unexpected interaction with the breaker failure relays provided the initiator to enter this design basis scenario and represents a single failure mode for the overhead path.

The Final Safety Analysis Report (FSAR) section 15.8 addresses loss of power scenarios. During this event Oconee Unit 2 experienced a loss of load condition, caused by separation of the unit from the transmission system and two momentary losses of all system and unit power.

The FSAR analysis shows that natural circulation of the reactor coolant system, turbine driven emergency feedwater system, condenser circulating water gravity induced flow, and gravity insertion of the control rods [EIIS:ROD] are among the design features provided to ensure the removal of decay heat for the reactor coolant system for the time power is not available. Furthermore, the analysis shows that, even without the emergency feedwater system, a total of 106 minutes will elapse before boiloff will start to uncover the core. With emergency feedwater available, calculations indicate an Oconee unit can withstand approximately six hours without electrical power before reactor coolant pump seal leakage will reduce inventory and begin to uncover the core.

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In this event, power was lost to Oconee Unit 2 for two occasions of approximately 31 seconds each. During the first loss of power, the control rods inserted into the core to shutdown the reactor and maintain it subcritical. During both losses, emergency feedwater, Condenser Cooling Water gravity flow, and natural circulation in the RCS all functioned and removed decay heat as designed. All operating parameters remained within anticipated limits while in this mode.

The emergency power systems generally performed as expected to restore power after the first loss of power. The loss of the overhead path due to the YELLOW bus lockout essentially constituted a design scenario single failure. The action of the KH operator to trip ACB-1, potentially defeating the safety function of KH Unit 1, is significant in that it provides one mode of failure of a safety train.

Even though power was not available from the switchyard, it was available from the underground path. The unsuccessful transfers to auxiliary power at KH are significant in that they provided potential common mode failures which could possibly have resulted in the loss of both KH trains, and, therefore, all automatic emergency power. Specifically, in this event, the operating KH unit could have been lost due to these failures. During this event KH Unit 1 operated 31 minutes without auxiliary power. KH Unit 2 operated 37 minutes without auxiliary power.

Backup power from Central Switchyard was available and could have been aligned within minutes if needed. The dedicated line from a Lee gas turbine was made available one hour after the start of the event, and within 31 minutes of the time it was requested.

When Keowee (KH) Unit 1 was shutdown and KH Unit 2 was unexpectedly tripped as a result, the emergency power system did not function as anticipated.

The action of the speed switch in the anti-pump circuit prevented KH Unit 2 from being able to perform its safety function. It also represents a single failure mode for one unit. Prior to modification of KH Unit 1, the speed switch design would have represented a potential single mode failure for both KH units.

KH Unit 1 was unavailable due to the abnormal switchyard configuration which, essentially, defeated the External Grid Protective System. However, a path from the RED bus had been established prior to shutting down KH Unit 1 and the Emergency Power Switching Logic (EPSL) automatically re-established power by connecting to that source. The backup source from Lee was still

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available.

Therefore, at no time during the two loss of power events was there less than two backup power sources available by manual action within minutes.

Oconee Units 1 and 3 were also affected by this event. The RED and YELLOW bus lockouts took the Start-up Source out of service on both units, therefore placing them within a Limiting Condition for Operation (LCO). While KH Unit 2 was out of service due to the anti-pump circuit, Oconee Unit 1 and 3 did not have an automatic source of power if one of them experienced a unit trip. However, if needed, power could have been manually restored by connecting the RED bus to the Start-up Source or by connecting Lee to the Stand-by bus. Therefore, these units also had two sources of backup power.

In the event of a LOCA on one of these units, power would have been available automatically from KH Unit 1 due to action of the Degraded Grid Protection circuits.

FSAR 15.14.3.3.6 assumes 33 seconds for the power outage after a LOOP prior to restoration of power from KH via Transformer CT4 and an additional 15 seconds for the operation of pumps and valves to establish system flow. In the remote event that a LOCA had occurred on one of the other Oconee units and an additional failure prevented the automatic restoration of power to the affected unit, the emergency core coolant flow would have been delayed beyond what was assumed in the accident analysis. If this happens, fuel damage could occur which will result in a radioactive release to the containment building. The FSAR states that without Reactor Building Spray [EIIS:BE] and Reactor Building Cooling Systems the reactor building pressure would not exceed the design pressure for the containment following the LOCA. Given the 60 minute time frame to restore power, it is expected that the reactor building leak rate would not exceed the LOCA analysis rate, but dose rates may be higher due to a loss of filtered ventilation until power is restored. A design containment response evaluation has shown that equipment qualification conditions would not be exceeded in under two hours for the expected temperature and pressure resulting from this event. Therefore, reactor building equipment would be operable when unit power is restored.

The Standby Shutdown Facility (SSF) is a separate seismically qualified building which houses the systems and components necessary to provide an alternate and independent means to achieve and maintain hot shutdown conditions for one or more of the three Oconee Units. The SSF was designed to resolve the safe shutdown requirement for fire protection, turbine building flooding, and physical security. The SSF has the capability of

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maintaining hot shutdown conditions on all three units for approximately three days following a loss of normal AC power.

However, during this event, an additional concern arose because power was interrupted to the SSF for a significant period of time. Without power to the battery chargers in the SSF, the potential existed that the main SSF battery might have been drained below the point of operability. This raised the concern that the SSF might not be available if needed. However, the SSF is equipped with a spare battery which could have been aligned and used if needed.

A precursor study has been performed to provide a quantitative estimate of the significance of this event in terms of core damage likelihood. The conditional probability estimated for a precursor is useful in ranking an event because it provides an estimate of the measure of protection against core damage remaining once the observed failures have occurred. The Oconee annual average core damage frequency estimated by the Oconee Probabilistic Risk Assessment study is 1.8E-5 events per year for internal event initiators and 9.2E-5 for external event initiators, combining for a total of 1.1E-4 events per year. The conditional core damage probability for this event has been estimated to be 2.0E-5. Therefore, it is estimated that core damage would occur in only one of 50,000 similar events. Failures and potential equipment degradation occurring during this event which are significant include: the loss of off-site power initiating event, the failure of the KH Auxiliary Power system, potential SSF battery depletion, and Emergency Feedwater turbine-driven pump starting problems. Oconee has features which tend to decrease the significance of this event which might not be available to many other plants. These include the dedicated 100 KV path from the Central Switchyard and Lee combustion turbines, the SSF and its independent power source, and the ability to cross-connect power and emergency feedwater from the other units. Also the quick recovery of off-site power to the CT-2 start-up transformer helped to mitigate the significance of this event.

There were no releases of radioactive materials or excessive radiation exposures associated with this event.

The health and safety of the public was not impacted by this event.

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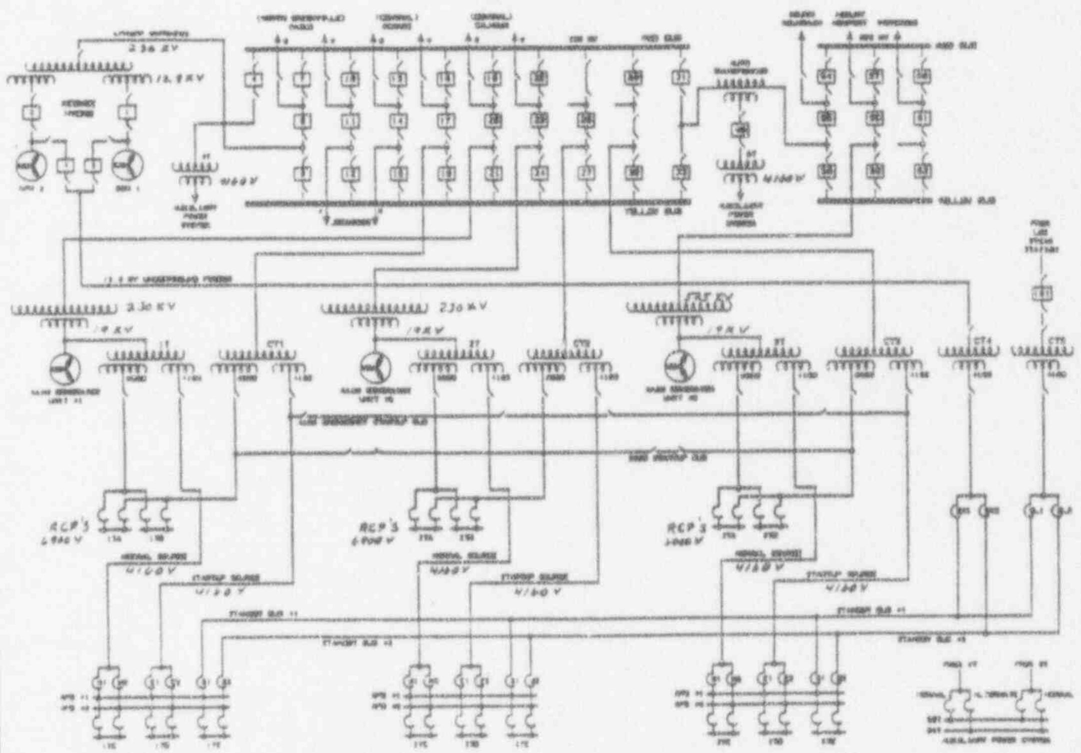
ATTACHMENT 1

EMERGENCY POWER DISTRIBUTION



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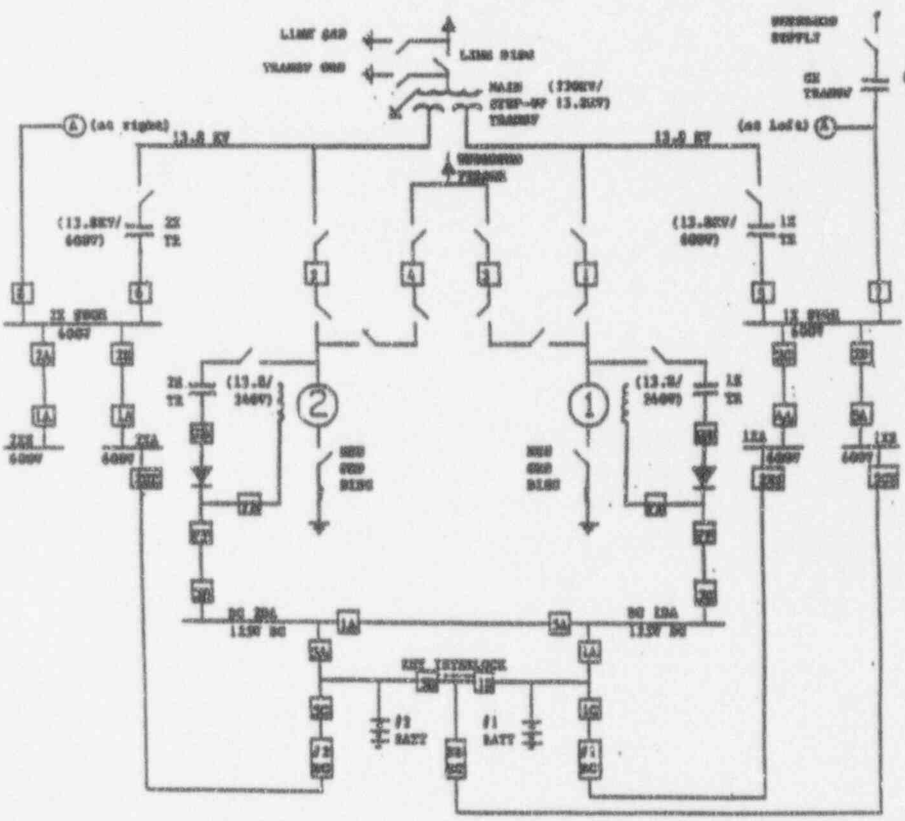
ATTACHMENT 2

KEOWEE HYDRO STATION AC & DC SYSTEMS



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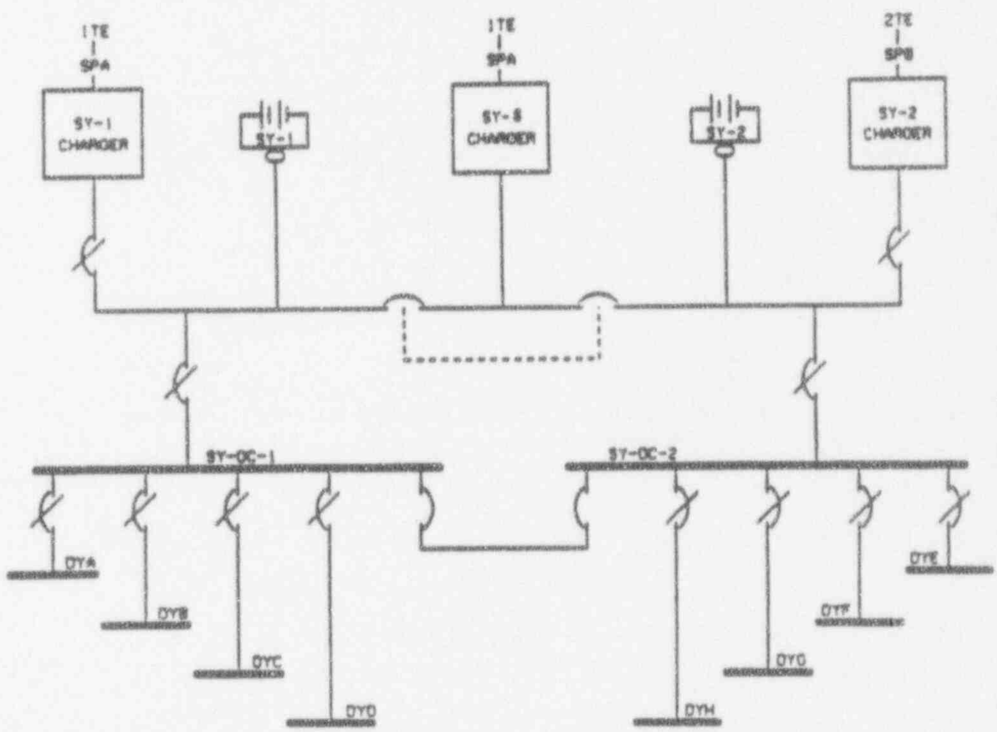
ATTACHMENT 3

230KV SWITCHYARD DC POWER DISTRIBUTION



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ATTACHMENT 4

SEQUENCE OF EVENTS

TIME	DESCRIPTION
October 19, 1992	
	Keowee Unit 1 is generating to the grid
21:21:00	TN/5/A/2863/00/AL2, in progress.
	US1 opens SY-1/SY-2 cross tie breaker
	SY-2 bus voltage spikes in excess of 200 VDC
21:21:08	PCB-27, Breaker Failure (SBFU) relay actuated
	PCB-24, SBFU relay actuated
	SBFUs give YELLOW bus LOCK-out
	PCB-24 SBFU initiates an ONS Unit 2 Generator Lockout. N1 and N2 open
	E1 and E2 close
	SBFUs give RED bus LOCK-out
	E1 and E2 open on under voltage when PCB-26 and 27 open
	I&E Technician hears relays actuating.
	US1 hears main steam relief valves lift. (ONS Unit 1 stays On-Line because PCB-20 does not trip.)
	ALL SWYD PCBs OPEN except PCB-11, 14, and 20
	External Grid Protection initiates SWYD Isolation

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SEQUENCE OF EVENTS

TIME	DESCRIPTION
	SWYD Isolation gives Keowee Emerg. Start
	ACB-1 opens for 6 seconds
	ACB-5 and 6 open and ACB-7 and 8 close
	SY-2 Charger de-energized by ONS 2 loss of power Unit 2 RCPs, Condensate and Feedwater pumps trip.
	Turbine Driven EFW Pump starts CCW Gravity Flow starts
21:21:14	ACB-1 re-closes. ACB-7 and 8 open and ACB-5 and 6 re-close.
	KH Unit 2 energizes CT-4.
21:21:28	Main Feeder Bus Monitor Panel (MFBMP) times out sends 2nd Emerg. Start to KH initiates ONS Unit 2 Load Shed.
	TDEFWP momentary loss of flow
	SK1 and SK2 close
21:21:39	S1 and S2, close 10 seconds later HPI A, HPI B, CC, MDEFW pumps all start
21:21:28	KO-A opens ACB-1 ACB-6 opens and ACB-8 fails to close KH Unit 2 loses Auxiliary Power. ACB-5, 7, and 1X Lockout

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SEQUENCE OF EVENTS

TIME	DESCRIPTION
	US1 recloses SY-1/SY-2 tie breaker another surge on SY-2 causes SBFU to Lockout the
	Keowee Main Step-up Transformer Both KH Units spinning w/o Auxiliary power.
21:22	ONS-1 gets Low Inst Air Press. Alarm, enters AP and has Diesel compressor started.
21:23	ROs note that RBCU A did not restart
21:25	ROs stop TDEFWP
21:26	ROs stop HPI A pump
	ROs reset MFBMP/Load Shed Signal and begins recovery,
21:30	US3 calls Staff duty person, who initiates notifications
21:34	restart CCW pump (ends gravity flow) 2CCW-24 fails to reopen, Work Request initiated
	KO-A calls Dispatcher, asks for call-out of KO-B KO-A and US-2 talk, US-2 informed of KH problem OSS talks to Dispatcher, starts SWYD recovery
21:50	KO-B arrives KO-B, US-2, Dispatcher discuss situation

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ATTACHMENT 4

SEQUENCE OF EVENTS

TIME	DESCRIPTION
21:58	KO-B resets KH Main Step-Up Transformer Lockout. ACB-1 closes, energizes Main Step-Up Transformer. ACB-6 closes, restores Aux power to KH 2
22:00	US-1 resets RED, YELLOW lockouts
22:01	Dispatcher notifies LEE to start Gas Turbine, get dedicated line
22:06	ACB-5 trip reset at breaker, allows ACB-7 to close
22:12	KO-B resets 1X Bus and ACB-7 Lockouts KO-B manually closes ACB-7.
22:13	Operator closes PCB-10 ,energizes Red Bus Reclosers close PCB-7, 13, 16, 19, and 22.
22:14	Operator tries to close PCB-26 which momentarily clears the Switchyard Isolate Complete Signal and the Anti-Pump Signal on PCB-9 which allows PCB-9 to auto close and energize Yellow Bus.
22:18	Operator resets the Switchyard Isolation Signal manually closes PCB-26 (energizes CT-2)
22:21	Lee CT/dedicated line operable
22:25	OSS declares Unusual Event
22:37	Unusual Event notifications complete

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Oconee Nuclear Station, Unit 2	05000 270	92	- 04 -	00	39 OF 40

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

ATTACHMENT 4

SEQUENCE OF EVENTS

TIME	DESCRIPTION
22:42	Operator resets KH Emergency Start Signal allows shutdown of KH 1
22:47	KOs inadvertent lockout of 1X, ACB-7 trips Lockout reset, ACB-7 closed
22:52	KH-1 shut down , results in shutdown of KH-2 causes 2nd loss of power to ONS-2
	MFBMP senses loss of voltage, 20 sec time out initiates Emerg Start of KH-1,2, Load Shed of ONS-2 this time ACB-6 opens, ACB-8 closes.
	KH-1 emergency starts , but can't feed YELLOW bus (PCB-26 out of position, no SWYD Isol. signal)
	KH-2 Field Breaker does not close due to Anti-Pump, the speed switch and the X-Relay.
	EPSL re-energizes the Unit 2 MFBs from CT-2 using the Re-transfer To Startup logic.
	Operators manually initiate TDEFWP start. CCW returns to gravity flow mode
22:54	Operator resets MFB Monitor Panel/Load Shed signals and begins recovery.

NRC FORM 366A
U.S. NUCLEAR REGULATORY COMMISSION

APPROVED BY OMB NO. 3150-0104
EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE INFORMATION AND RECORDS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Oconee Nuclear Station, Unit 2	05000 270	92	- 04 -	00	40 OF 40

TEXT (If more space is required, use additional copies of NRC Form 366A) (17)

ATTACHMENT 4

SEQUENCE OF EVENTS

TIME	DESCRIPTION
October 20, 1992	
00:18	Operator resets KH Emergency Start shuts down KH 2, RPMs drop, allowing the Field Breaker X-Relay to reset.
00:24	Operator starts KH 2 and energizes CT-4.
00:41	Operator energizes Yellow Bus from the Red Bus by closing in PCB-8.
00:48-00:57	Operator closes PCB-18, 27, 30, 21, 17, 28, 12, and 15. This completes restoration of the 230 KV Switchyard.
01:14-02:29	Restart all Reactor Coolant Pumps.
01:25	Declare SSF degrade, retroactive to 21:21
03:44	Declare event terminated
04:15	restore SSF power, exit degrade

NRC FORM 366A (5-92)

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DIABLO CANYON UNIT 1
DOCKET NUMBER (2)	0 5 0 0 0 2 7 5
PAGE (3)	1 OF 6
TITLE (4)	DOSE LIMITS POTENTIALLY EXCEEDED FROM CHEMICAL AND VOLUME CONTROL SYSTEM VALVE DIAPHRAGM LEAKAGE DUE TO THERMALLY INDUCED DEGRADATION

EVENT DATE (5) MON	DAY	YR	LER NUMBER (6) YR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MON	DAY	YR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER (S)
										0 5 0 0 0
06	22	92	92	- 0 0 9 -	0 1	01	11	93		0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)

X 10 CFR 50.73(a)(2)(ii)(B)

OTHER -
(Specify in Abstract below and in text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
DAVID P. SISK, SENIOR REGULATORY COMPLIANCE ENGINEER	805	545-4420

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	F E	T H	T 1 8 5	N						

SUPPLEMENTAL REPORT EXPECTED (14)

[ ] YES (if yes, complete EXPECTED SUBMISSION DATE) [X] NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (16)

On June 26, 1992, with Unit 1 in Mode 1 (Power Operation) at 100 percent power, PG&E determined that identified leakage from the chemical and volume control system (CVCS) could potentially cause design-basis dose limits to be exceeded during the recirculation phase of a loss-of-coolant accident (LOCA). A one-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72 (b)(1)(ii)(B) on June 26, 1992, at 1549 PDT.

On June 22, 1992, diaphragm valve CVCS-1-547, the emergency borate flow to the volume control tank outlet isolation, was found to be leaking approximately 0.5 gallon per minute. This leakage could have caused 10 CFR 100 and GDC 19 dose limits to be exceeded during a design-basis LOCA.

The root cause of the leakage has been determined to be thermally-induced premature degradation of the valve diaphragm caused by a malfunctioning heat trace controller, resulting in distortion of the diaphragm at the body-to-bonnet joint and breaching of the system pressure boundary.

During the Unit 1 fifth refueling outage, the valve bonnet and diaphragm of CVCS-1-547, as well as the heat trace controllers, were replaced to return the valve to an acceptable configuration. All heat-traced diaphragm valves in the post-LOCA recirculation flow path were inspected and reconfigured as necessary.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	92	- 0 0 9 -	0 1	2 OF 6

TEXT (17)

I. Plant Conditions

Unit 1 was in Mode 1 (Power Operation) at 100 percent power.

II. Description of Event

A. Summary:

On June 22, 1992, diaphragm valve CVCS-1-547 (CB)(V), the emergency borate flow to the volume control tank (VCT)(CB)(TK) outlet isolation in the chemical and volume control system (CVCS)(CB), was found to be leaking approximately 0.5 gallons per minute (gpm) to the auxiliary building (NF) atmosphere.

On June 26, 1992, PG&E determined that identified leakage from the CVCS could potentially cause design-basis dose limits to be exceeded during the recirculation phase of a loss-of-coolant accident (LOCA). A one-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B) on June 26, 1992, at 1549 PDT.

B. Background:

Leakage from the post-LOCA recirculation flow path must be limited to meet design-basis dose limits. As specified in the Final Safety Analysis Report (FSAR) Update, the maximum permissible leakage outside of containment from the post-LOCA recirculation loop, while pressurized to post-LOCA pressure, is 0.10 gpm in areas where the plant ventilation exhaust is not filtered by charcoal filters (VF)(FLT) and 0.94 gpm when filtered through charcoal filters (in addition to a postulated residual heat removal pump seal (BP)(SEAL) leakage of 50 gpm).

CVCS-1-547 is located in the boric acid blender (CB)(MIX) room on the 100 foot elevation of the auxiliary building. The boric acid blender room ventilation (VF) exhausts to the plant vent (VL) without passing through charcoal filters. Therefore, any radioactive material that may be released as a result of leakage in this area would be released to the plant vent, which is filtered only by high efficiency particulate air (HEPA) filters (VF)(FLT).

CVCS-1-547 is a manually operated diaphragm valve in the CVCS system. During power operation, this valve normally remains in the open position with system pressure at approximately 23 pounds per square inch, gauge (psig). This valve does not have a safety function to close during either normal or accident conditions. However, this valve does become pressurized as part of the reactor coolant (AB) flow path pressure boundary during the recirculation phase of a LOCA.

This valve also forms part of the flow path for emergency boration. Because the dissolved boron present in the water will precipitate out of

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
DIABLO CANYON UNIT 1	0 5 0 0 0 2 7 5	92	- 0 0 9	- 0 1	3 OF 6

TEXT (17)

solution at low temperatures, electric heat trace circuitry (FE) is installed to maintain the temperature of lines above 145°F as required by Technical Specifications 3.5.4.2 and 4.1.2.2. Heat tracing is not installed on the bonnet of CVCS-1-547 to minimize any valve diaphragm degradation due to excessive heat.

C. Event Description:

On June 22, 1992, the VCT and centrifugal charging pump (CB)(P) header, including CVCS-1-547, were pressurized to approximately 55 psig. This system condition was the result of maintenance unrelated to CVCS-1-547. Such an evolution is unusual but not outside the allowable CVCS operational limits. The VCT is normally pressurized to approximately 23 psig.

On June 22, 1992, during a routine radiation survey, diaphragm valve CVCS-1-547 was found to be leaking to the room drain at the rate of approximately 0.5 gpm. No boric acid crystals were present, which indicated that the valve had not been leaking for an extended period of time.

The valve bonnet retaining nuts were determined to be "finger-tight" and retorquing the nuts stopped the leakage. The as-left torque on the nuts was in accordance with the valve supplier's requirements.

Investigation determined that the bonnet temperature of CVCS-1-547 was approximately 304°F. No estimate of the time the valve had been at this temperature could be made. Information from the valve vendor (ITT) indicated that the qualified operating limits for the valve diaphragm are 100 psig at 300°F, 175 psig at 250°F and 235 psig at 200°F. Therefore, the as-found condition was in excess of the vendor-recommended limits. No other CVCS diaphragm valves had a measured body temperature over 200°F.

On June 26, 1992, an evaluation determined that the leakage from CVCS-1-547 could have resulted in the control room (NA) and exclusion area boundary 10 CFR 100 thyroid dose limits being exceeded during the recirculation phase of recovery from a design-basis LOCA. A one-hour, non-emergency report was made for Unit 1 in accordance with 10 CFR 50.72 (b)(1)(ii)(B) at 1549 PDT.

During the Unit 1 fifth refueling outage (1R5), which started on September 12, 1992, and ended on November 11, 1992, the valve bonnet and diaphragm of valve CVCS-1-547, as well as the heat trace controllers (FE)(TH), were replaced to return the valve to an acceptable configuration. All heat-traced diaphragm valves in the post-LOCA recirculation flow path were inspected and reconfigured as necessary.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (17)

D. Inoperable Structures, Components, or Systems that Contributed to the Event:

None.

E. Dates and Approximate Times for Major Occurrences:

1. June 22, 1992: Event date. CVCS-1-547 was found to be leaking approximately 0.5 gpm.

2. June 26, 1992: Discovery date. Investigation identified that the leakage condition could have resulted in exceeding dose limits. A one-hour, non-emergency report was made to the NRC in accordance with 10 CFR 50.72(b)(1)(ii)(B).

3. July 1, 1992: A leak repair enclosure was installed on CVCS-1-547 to provide system pressure boundary integrity until valve repairs could be performed.

4. November 4, 1992: Unit 1 entered Mode 4 (Hot Shutdown) with CVCS-1-547 operational.

F. Other Systems or Secondary Functions Affected:

None.

G. Method of Discovery:

The leakage was discovered by radiation protection personnel during the performance of a routine radiation survey.

H. Operator Actions:

An operator retorqued the body-to-bonnet nuts on CVCS-1-547 and stopped the leak.

I. Safety System Responses:

None.

III. Cause of the Event

A. Immediate Cause:

CVCS-1-547 had a body-to-bonnet leak exceeding the maximum permissible leakage for unfiltered plant effluent.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (17)

B. Root Cause:

Although heat tracing is not installed on the bonnet of CVCS-1-547, the valve had insulation installed. The heat trace controller (thermostat) for this segment of system piping is not at CVCS-1-547. The physical arrangement of the piping at CVCS-1-547 resulted in heat accumulation at the valve, as evidenced by measured valve body temperature. Investigation determined that the heat trace controller for CVCS-1-547 was not turning off.

Although the vendor's qualification for the valve diaphragm temperature was only slightly exceeded, the root cause of the leakage was thermally induced degradation of the CVCS-1-547 diaphragm caused by the heat trace controller for the valve not turning off, resulting in valve diaphragm distortion and breaching of the system pressure boundary.

IV. Analysis of the Event

The leakage from CVCS-1-547 was estimated to be approximately 0.5 gpm. However, this leakage was occurring with the system pressure at approximately 55 psig. Under post-LOCA conditions, the system pressure at this valve would be approximately 200 psig. The equivalent leakage under post-LOCA conditions is postulated to be approximately 9.0 gpm.

A leak of 9.0 gpm in the auxiliary building, filtered only by HEPA filters, could potentially have resulted in control room operator dose exceeding the 10 CFR 50 Appendix A General Design Criterion 19 thyroid limit over the 30-day duration of the design-basis LOCA.

However, post-LOCA emergency response procedures provide for use of self-contained breathing apparatus (SCBAs) and potassium iodide prophylaxis, which would mitigate control room operator dose. Control room radiation conditions would be monitored by area radiation monitors (IL)(MON) located in the control room. Although the monitors are design Class II, they are powered from Class 1E power supplies (IL)(JX). The area radiation monitors would provide sufficient indication to allow control room operators to don SCBA equipment or take additional corrective measures.

A leak of 9.0 gpm from the auxiliary building, filtered only by the HEPA filters, could potentially have resulted in exceeding the 10 CFR 100 2-hour site boundary thyroid dose limit.

However, a design-basis LOCA dose analysis contains many conservative assumptions, particularly with regards to the source term (i.e., fuel damage). Therefore, an analysis was performed using "expected case" LOCA assumptions (no fuel damage). The analysis determined that a 9.0 gpm leak would result in 2-hour site boundary and low population zone doses significantly less than the 10 CFR 100 limit of 300 rem.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (17)

Therefore, this event did not adversely affect the health and safety of the public.

V. Corrective Actions

A. Immediate Corrective Actions:

1. Personnel tightened the body-to-bonnet nuts on the valve, which stopped the leakage.

2. A leak repair enclosure was installed on CVCS-1-547.

B. Corrective Actions to Prevent Recurrence:

1. PG&E will document the heat trace program implementation (i.e., that thermostats are appropriately located and components and piping are at a temperature between 70 and 170°F).

2. PG&E replaced the bonnet and diaphragm of CVCS-1-547 during 1R5.

3. PG&E has set the temperature on the piping immediately adjacent to CVCS-1-547 to between 70 and 170°F following replacement of the heat trace controllers during 1R5.

4. PG&E has established acceptable body/bonnet surface temperatures on all diaphragm valves that are in heat-traced systems, including the post-LOCA recirculation flow path.

VI. Additional Information

A. Failed Components:

Heat Trace Temperature Controller, Thermon Manufacturing Co., Type FP Thermon Econtrace, 120 vac.

B. Previous LERs on Similar Events:

LER 2-91-009-01, "10 CFR 100 Dose Limits Potentially Exceeded in the Event of a Design Basis Loss of Coolant Accident Recovery as a Result of Valve Leakage"

This previous LER was also caused by leakage from diaphragm valves in the post-LOCA flow path. The root cause was that one of the valves and certain vendor recommendations were not included in the preventive maintenance program. Because the scope of previous corrective actions did not include heat tracing on diaphragm valves in the post-LOCA flow path, the corrective actions could not have prevented the current LER.

10695/85K

NRC FORM 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	1 OF 1 9

TITLE (4): Reactor Trip Due to Inverter Malfunction and Subsequent Pressurizer Safety Valve Leak

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 7	0 3	9 2	9 2	— 0 2 3 —	0 0	0 8	0 3	9 2	N	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1
POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	X 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Scott A. Lindquist, Shift Technical Advisor	AREA CODE 4 0 2 5 3 3 - 6 8 2 9

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	E E	I N V T	E 2 0 9	Y					
B	A B	R V	C 7 1 1	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On July 3, 1992, at 2336, while the plant was operating at 100% power, the Reactor Protection System automatically tripped the reactor due to high pressurizer pressure. The event was initiated as a result of maintenance on a non-safety related inverter. During replacement of a degraded circuit board, power was momentarily lost to the instrument bus that supplies power to the Turbine Electrohydraulic Control System, resulting in closure of the turbine control valves. A subsequent failure of a pressurizer code safety valve resulted in high pressure in the pressurizer quench tank that blew the tank's rupture disk and resulted in the loss of approximately 21,500 gallons of contaminated water to the containment building sump.

The consequences of the event are bounded by the Fort Calhoun Station Updated Safety Analysis Report.

The root cause of the momentary loss of power to the instrument bus was determined to be the inability to isolate and test the non-safety related inverters after maintenance without potentially losing power to the respective 120V AC instrument buses. The root cause of the malfunction of Pressurizer Safety Valve RC-142 was determined to be the adjusting bolt locknut that loosened and allowed the set pressure adjusting bolt to back out.

Corrective actions include a modification to enhance the ability to test the non-safety related inverters, addition of a positive mechanical locking device for the pressurizer safety valve adjusting bolts and completion of a comprehensive Recovery/Restart Action Plan.

LER NO: 285/92-023

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 3	— 0 0	0 2 OF 1 9

TEXT (If more space is required, use additional NRC Form 366A's)(17)

BACKGROUND

The Reactor Protection System (RPS) monitors certain critical plant operating parameters and compares them to predetermined setpoints. If one or more of the monitored parameters reaches the setpoint on two of four channels, the RPS will initiate a reactor trip. There are twelve different reactor trips that can be initiated from the RPS. The trip unit of interest for this event is High Pressurizer Pressure.

The reactor trip for High Pressurizer Pressure is provided to prevent Reactor Coolant System (RCS) over-pressurization. In the event of a loss of load without a reactor trip, the temperature and pressure of the RCS would increase due to reduction in heat removal from the reactor coolant by the steam generators. The over-pressure trip setpoint is set at 2400 psia.

Two Power Operated Relief Valves (PORV) are designed to provide sufficient relief capacity during abnormal RCS pressure transients to prevent opening of the pressurizer safety valves. The PORVs are opened on High Pressurizer Pressure at 2400 psia. The valves are located in parallel pipes which are connected on the inlet side to a single relief valve nozzle on top of the pressurizer and to the relief line piping to the pressurizer quench tank on the outlet side. A motor operated isolation (block) valve is provided upstream of each of the PORVs to permit isolating a valve in case of failure or excessive leakage.

Two pressurizer code safety valves located on top of the pressurizer provide over-pressure protection for the RCS. They are totally enclosed, back pressure compensated, spring loaded safety valves meeting ASME code requirements. A loop seal is provided to minimize valve leakage.

The pressurizer quench tank is designed to collect and condense the normal discharges from the pressurizer during normal operation and to collect non-condensable gas discharges from the reactor vessel head or the pressurizer during post-accident situations. In either case, the pressurizer quench tank prevents RCS discharges from being released to the containment atmosphere. The steam discharged from the pressurizer is discharged underwater by a sparger to enhance condensation by uniform distribution.

The pressurizer quench tank can condense the steam discharged during a loss of load incident without exceeding the rupture disc setpoint, assuming normal blowdown of the relief valves at the end of the incident. It is not designed to accept continuous safety valve discharge. The pressurizer quench tank vents to the containment atmosphere following rupture of the rupture disk.

NRC FORM 366A (5-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 3 —	0 0	0 3 OF 1 9

TEXT (If more space is required, use additional NRC Form 366A's)(17)

The 120V AC Instrument System is comprised of four safety related and two non-safety related buses, each supplied by a separate solid state inverter fed from a 125V DC bus. Each bus has a backup source of power via a 480/120V voltage regulating transformer. An inverter functions to electronically convert DC to a reliable source of AC power. Each inverter is equipped with a static switch that monitors the output of the inverter and automatically switches the load to the backup power source without a loss of power to the load if the inverter output is lost. A manual switch is available to bypass the inverter for maintenance.

Non-safety related Inverter #2 (EE-8Q) supplies power to 120V AC Instrument Bus #2 located in panel AI-42B which in turn supplies power to Turbine Electrohydraulic Control (EHC) Panel #2 (AI-50). The Turbine EHC system supplies the control signals to the turbine steam admission valves during startup, normal operation, shutdown, testing and transient conditions.

The Pressurizer Pressure Low Signal (PPLS) is initiated, in the event of a Loss of Coolant Accident (LOCA), at a pressurizer pressure of 1600 psia. When PPLS actuates the following actions are initiated:

1) A Containment Isolation Actuation Signal (CIAS) is generated.

2) A Safety Injection Actuation Signal (SIAS) is generated. SIAS in turn initiates a Ventilation Isolation Actuation Signal (VIAS).

3) The Emergency Diesel Generators are started.

4) Sequential starting of Engineered Safeguards and essential support systems equipment is initiated.

The Containment Isolation Actuation Signal (CIAS) is intended to prevent the release of radioactivity from the containment, especially in the event of an accident. Containment building piping penetrations are considered potential paths for the escape of radioactivity and are therefore, equipped with isolation valves. The CIAS is generated by a PPLS, or a Containment Pressure High Signal (CPHS). CIAS initiates the following actions:

1) Closes the containment isolation valves for flow paths which are not required to control or mitigate the accident.

2) Secures component cooling water flow through unnecessary heat loads.

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 3	— 0 0	0 4 OF 1 9

TEXT (If more space is required, use additional NRC Form 366A's)(17)

The Safety Injection Actuation Signal (SIAS) automatically actuates safety injection in the event of a LOCA or Main Steam Line Break, to cover and cool the core and ensure adequate shutdown margin. SIAS is generated by a Pressurizer Pressure Low Signal (PPLS), or a Containment Pressure High Signal (CPHS). SIAS initiates the following actions:

1) High and low pressure safety injection loop injection valves open and emergency boration is initiated.

2) A Ventilation Isolation Actuation Signal (VIAS) is initiated.

3) Shedding of selected non-essential loads supplied from 480V motor control centers and shedding of complete 480V motor control centers serving loads which are not essential to support safeguards systems is initiated.

The Ventilation Isolation Actuation Signal (VIAS) is intended, in part, to prevent the release of significant radioiodine or radioactive gas from the containment to the atmosphere. One possible source of such nuclides could be reactor coolant leaks below the range that would be detected by coolant or containment pressure instrumentation. The VIAS is generated by an SIAS, a Containment Spray Actuation Signal (CSAS) or a Containment Radiation High Signal (CRHS). VIAS initiates the following actions:

1) Containment ventilation realigns to prevent a significant release of radioactive gas or particulates from containment.

2) Control Room ventilation shifts to the filtered air makeup mode.

3) Safety Injection Pump Room dampers reposition for safety injection pump operation.

The Containment Radiation High Signal (CRHS) radiation monitors detect gaseous and particulate radiation and provide alert and high alarms. CRHS is derived on a one out of five logic from separate contact outputs from each of five radiation monitors, Containment Particulate (RM-050), Containment Gas (RM-051), Stack Iodine (RM-060), Stack Particulate (RM-061) and Stack Gas (RM-062). CRHS initiates a Ventilation Isolation Actuation Signal (VIAS).

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EVENT DESCRIPTION

At 0433 on July 3, 1992, with the plant in Mode 1 (Power Operation) at 100% power, the Fort Calhoun Station Control Room received an Inverter #2 Trouble Alarm. Inverter #2 had automatically transferred to the "Bypass" mode, which provides power from a 480/120V AC step-down bypass transformer through the inverter static transfer switch to Bus AI-42B. Upon placing the inverter in "Bypass", Bus AI-42B was declared inoperable due to being powered from its emergency source. Technical Specification Limiting Condition for Operation (LCO) 2.7(2)m was invoked with an eight hour time limit for restoring Bus AI-42B to its normal source of power. A priority one Maintenance Work Order was written to troubleshoot and repair the inverter, and Electrical Maintenance and System Engineering personnel were called out. By the time these personnel arrived, a Fan Failure Alarm on Inverter #2 had cleared. At 0636, Inverter #2 was returned to the inverter (normal) mode of operation and the Technical Specification LCO was cleared.

The Inverter #2 Trouble Alarm was received again at 1510 on July 3, and the inverter was transferred to "Bypass" for seventeen minutes before being returned to the Inverter mode. At 1921, the Inverter #2 Trouble Alarm was received for the third time. At this time, the inverter was manually bypassed by taking the Manual Transfer Switch from the "Static Switch" to the "Bypass" position. By manually bypassing the inverter, the DC input breaker to the inverter could be opened to allow troubleshooting and repair of the inverter. Two circuit boards in Inverter #2 were replaced, the Inverter Drive Board and the Static Switch Drive Board.

When placing an inverter back in service the operator must first close the DC input breaker, then place the Manual Transfer Switch back to the "Static Switch" position. He would then normally depress a "Forward Transfer" push-button, which would transfer power back to the inverter.

At 2335, when the operator placed the manual transfer switch in the "Static Switch" position, prior to depressing the "Forward Transfer" push-button, the static switch began cycling back and forth from the bypass transformer to the inverter. This caused Instrument Bus AI-42B voltage to oscillate between 0 and 120V AC. The operator immediately returned the Manual Transfer Switch to the "Bypass" position, restoring normal voltage to AI-42B. The voltage oscillations on AI-42B affected several pieces of equipment powered from AI-42B. Among the equipment affected was Toxic Gas Monitor YIT-6286B, which resulted in the tripping of all Control Room ventilation fans; and Breaker AI-42B-CB2 which tripped, causing a loss of power to the Electrohydraulic Control Supervisory Panel, AI-50. Although other equipment was affected by the voltage fluctuations, this had no significant impact on subsequent events.

Upon loss of power to AI-50, four pressure transmitter loops powered by Power Supply A-86 in the EHC Supervisory System became de-energized. The rest of the components in the system remained energized because they receive backup power from the Permanent Magnet Generator (PMG), which is driven directly off the Main Turbine shaft.

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The four pressure transmitter loops which became de-energized, Throttle Pressure (PT-943), First Stage Pressure (PT-945), Initial Pressure Limiter (PT-939) and Power Load Unbalance (PT-944) provide input to the EHC Supervisory System for the purpose of modifying turbine control valve position under various conditions. When power was lost to these instrument loops, the output voltage from those transmitters (normally 0.1 to 5 volts DC) went to zero. This resulted in the control valve positioning units calling for a closed position on the valves. The sequence described above does not result in a turbine trip.

The closing of the turbine control valves resulted in a large mismatch between reactor power and steam demand. Since the Main Turbine did not trip, the Steam Dump and Bypass System was limited in its ability to respond to the Reactor Power/Steam Demand mismatch. The Steam Dump and Bypass System is a non-safety related system which normally acts to control RCS temperature and remove decay heat. However, it is designed for use primarily when the Main Turbine is off-line. While the Main Turbine is operating, the Steam Dump and Bypass System is limited to a modulation mode of operation, with a capacity of five percent steam flow.

The overall effect of the turbine control valves closing without significant steam dump and bypass capacity was to cause a sharp increase in RCS temperature. Pressurizer level, pressurizer pressure, and steam generator pressure also increased in response to the increase in RCS temperature.

At 2336, the reactor tripped due to High Pressurizer Pressure, and the PORVs and possibly Pressurizer Safety Valve RC-142 opened to lower RCS pressure. At approximately the same time, several main steam safety valves also opened. Upon receiving the reactor trip, the Main Turbine tripped, which enabled the Quick Open feature of the Steam Dump and Bypass System to rapidly open all steam dump and bypass valves to their full capacity of 38% steam flow. This reduced RCS temperature and pressure, allowing the PORVs and main steam safety valves to close.

At 2337 Fire Zone 33 (Room 81) went into alarm due to steam flow through the main steam safety valves.

For the first seven (7) minutes following the reactor trip, plant response was as expected for a load rejection event, and plant parameters were trending toward steady state post-trip conditions. Pressurizer pressure had reached a minimum of 1745 psia and was recovering, pressurizer level had reached a minimum of 33% and was recovering, and RCS temperature had stabilized at 532 degrees F. PORV tailpipe temperatures and pressurizer quench tank parameters indicated that the PORVs had opened, but the pressurizer quench tank parameters had stabilized, indicating that the PORVs had closed properly. The operators entered Emergency Operating Procedure EOP-00, Standard Post Trip Actions, and began to place plant systems in a normal post trip configuration. Since there was no indication of PORV leakage, the Primary System Operator elected to leave the PORV block valves open. A Containment Pressure Reduction, which had been in progress at the time of the trip, was secured at the direction of the Shift Supervisor.

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At 2343, with pressurizer pressure at approximately 1923 psia, Pressurizer Safety Valve RC-142 lifted and RCS pressure began to decrease rapidly. At approximately 1020 psia, RC-142 apparently re-closed, but did not re-seat, resulting in a leak rate of approximately 200 gallons per minute through RC-142. RC-142 continued to leak throughout the remainder of the event.

At the time RC-142 opened, the operators were still completing their Standard Post Trip Actions. Upon observing lowering pressurizer pressure, the Primary System Operator closed the PORV block valves, and verified the valves indicated fully closed by limit switch indication. At this time, the Primary System Operator also noted that the RC-142 tailpipe temperature was in alarm. Pressurizer pressure continued to lower after the PORV block valves were closed, and at 1600 psia, a PPLS was generated, initiating actuation of Engineered Safeguards equipment (including High Pressure Safety Injection Pumps SI-2A, SI-2B and SI-2C, and Low Pressure Safety Injection Pumps SI-1A and SI-1B). The Primary System Operator verified that all Engineered Safeguards equipment had operated as expected for a PPLS actuation. At 2344, as RCS pressure fell below 1400 psia, the Primary System Operator tripped one reactor coolant pump in each loop as directed by EOP-00. The running turbine plant cooling water pump was load shed as a result of the Engineered Safeguards actuation. This caused the running instrument air compressor to shut down, and as a result a low instrument air pressure alarm was received.

As result of the PPLS actuation, the containment isolation valves supplying component cooling water to the reactor coolant pump seal coolers (HCV-438A, B, C and D) received a CIAS. The CIAS, combined with a momentary reduction in component cooling water pressure, resulted in HCV-438A through D closing. After verifying component cooling water pressure had returned to greater than 60 psig, the Primary System Operator re-opened HCV-438A through D. The duration of reduced component cooling water flow to the reactor coolant pump seals was 38 seconds, from the first valve coming off its open seat until the last valve was fully re-opened. There was no impact on the reactor coolant pump seals from this momentary reduction in cooling water flow.

At 2346, the Licensed Senior Operator completed EOP-00 and entered the Functional Recovery Procedure EOP-20. The transition was made to the Functional Recovery Procedure rather than the LOCA procedure because along with indications of a leaking safety valve, the status of AI-42B was not clear (three annunciator panels were de-energized, indicating that other problems may exist) and one pressurizer level indicator (LRC-101Y) was indicating zero (0) pressurizer level while the two other indicators were reading at or near 100%. It was subsequently determined that the erroneous readings from LRC-101Y were due to partial blockage of the reference leg tap. Immediately after entering EOP-20, the Secondary System Operator started a turbine plant cooling water pump, which allowed restart of the instrument air compressors. The Primary System Operator stopped two of the three high pressure safety injection pumps (SI-2B and SI-2C) after verifying that Safety Injection Stop and Throttle Criteria were met per EOP-20, Floating Step A.

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Throughout the remainder of the event, the Primary System Operator adjusted high pressure safety injection flow to maintain greater than 20 degrees F subcooling at the highest temperature core exit thermocouple. Subcooling was monitored by plotting the maximum core exit thermocouple temperature and the low range pressurizer pressure (PI-118Y) on EOP Attachment 2, RCS Pressure-Temperature Limits. EOP Attachment 2 provides a manual means of plotting subcooling against a 20 degree F subcooling curve.

The Primary System Operator chose to use EOP Attachment 2 rather than the Emergency Response Facility Computer System (ERFCS) for subcooling indication, because he observed the ERFCS indicating zero subcooling with flashing question marks (denoting questionable data) at a time when he knew from various other indications that subcooling existed. The ERFCS indication of zero subcooling with a questionable data notation resulted from the ERFCS applying a conservative value of zero subcooling when high range pressure instruments (PI-120A/B) used in the subcooling calculation ranged low. Subsequent analysis of ERFCS printout data using wide range instruments indicates that from 2347 on July 3 until 0019 on July 4, the ERFCS indicated less than 20 degrees F subcooling and from 2352 on July 3 to 0001 on July 4, the ERFCS indicated saturated or slightly superheated conditions existed in the RCS. The discrepancy between the ERFCS calculated value of subcooled margin and the EOP Attachment 2 plots was due to an apparent difference in RCS pressure values supplied to the ERFCS from Wide Range Pressure Instruments PI-105 and PI-115, and the low range pressure instrument (PI-118Y) used by the Primary System Operator. The Primary System Operator used PI-118Y as his pressure indication for subcooled margin because it was readily available on the control board and appeared to be tracking properly.

At 2349, the Primary System Operator secured the two remaining reactor coolant pumps as directed by EOP-20. At 2350, the Plant Manager was notified by the Duty Supervisor (who was on-site monitoring the Inverter #2 maintenance) of the event in progress.

At 2352, the Primary System Operator secured two charging pumps (CH-1B and CH-1C), to avoid the potential for RCS over-pressurization with the PORV block valves closed and uncertainty over the status of RC-142. Safety Injection Stop and Throttle Criteria were met (using EOP Attachment 2) at the time of charging pump shutdown.

At 2352, the Shift Supervisor declared an Alert classification based on Emergency Plan Implementing Procedure EPIP-OSC-1, Emergency Action Level (EAL) 1.10, Failure/Challenge to One Fission Product Barrier.

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At 2353 on July 3, the Secondary System Operator took manual control of the Steam Dump and Bypass System in preparation for a rapid cooldown to shutdown cooling conditions.

At 2355, approximately 20 minutes into the event, the pressurizer quench tank rupture disk ruptured at approximately 75 psig. This resulted in Fire Zones 10 and 11 inside containment alarming, containment pressure, temperature and sump level rising (containment sump level would eventually reach a level of 12.5 ft. which corresponds to approximately 21,500 gallons) and slight increases in containment area radiation.

At 2358, Charging Pumps CH-1B and CH-1C were started to ensure boration criteria were met until a shutdown margin calculation could be performed. After determining that only one charging pump was needed to meet boration criteria, Charging Pumps CH-1B and CH-1C were periodically started and stopped throughout the remainder of the event.

At 0000 on July 4, High Pressure Safety Injection Pump SI-2B was restarted to provide additional injection flow. Additional safety injection flow was necessary to maintain RCS subcooling as RCS hot leg temperatures were increasing during establishment of natural circulation. At 0003, SI-2B was again secured.

At 0006, with containment temperature rising, Containment Cooling Units VA-7C and VA-7D were started to reduce containment pressure by providing additional cooling to condense steam in containment. Containment pressure peaked at 2.5 psig, and gradually decreased through the remainder of the event.

At 0010, notification of the states of Nebraska and Iowa was completed. The NRC Senior Resident Inspector was notified at 0020, and at 0029, the NRC Operations Center was notified of the event pursuant to 10 CFR 50.72(a)(3), via the Emergency Notification System, and an open line was maintained throughout the remainder of the event.

At 0012, the Shift Supervisor directed that a plant cooldown be initiated. Pressurizer pressure was approximately 1100 psia and RCS cold leg temperature was approximately 524 degrees F at the start of the cooldown. Supporting evolutions included inserting the non-trippable control element assemblies, restarting a condensate pump to refill the Emergency Feedwater Storage Tank, and performing a shutdown margin calculation.

At 0024, the hydrogen analyzers were placed in service, as required by the EOPs for High Energy Line Breaks inside containment.

At approximately 0030, an operator observed the acoustic flow monitor for RC-142 indicating flow. Two lights were lit (approximately 20% of scale), indicating RC-142 was leaking significantly, but was not fully open.

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By 0050, with safety injection flow maintaining RCS pressure, the Operators began throttling safety injection flow. As the plant cooldown and de-pressurization continued, RCS and steam generator pressures continued to decrease. In accordance with the EOPs, the signal which initiates a Steam Generator Isolation Signal (SGIS) on low steam generator pressure (SGLS) was blocked at 0102 to prevent automatic closure of the main steam and feedwater isolation valves. At 0103 the Pressurizer Pressure Low Signal (PPLS) which initiated the SIAS was also blocked per the EOPs. This step is intended to initiate Low Temperature Over-pressurization Protection (LTOP) by enabling the LTOP function of the PORVs. Additionally, blocking PPLS would subsequently allow resetting of Engineered Safeguards equipment, which would allow restoration of certain normal system functions that are used during a cooldown. With the PORV block valves closed, however, LTOP protection could not be achieved. Due to concerns over the possibility of the PORVS not being reseated, the PORV block valves remained closed until 0334.

At 0110, all PORV and pressurizer safety valve acoustic flow monitors indicated zero flow.

At 0113, with pressure controlled, and well above the shutoff head of the low pressure safety injection pumps, SI-1A and SI-1B were secured in accordance with the EOP floating steps.

Normally, after a shutdown, auxiliary electric power to the non-vital buses is returned to the House Service Transformers by back-feeding through the Main Transformer. At 0119, following opening of the Main Generator disconnect switch, the Main Generator output breakers were closed to back-feed the non-vital buses. At 0122, the back-feed alignment was complete.

At 0131, with the Electric Driven Auxiliary Feedwater Pump supplying the steam generators, the Turbine Driven Auxiliary Feedwater Pump (FW-10), which started on PPLS/SIAS, was secured. Although no primary to secondary leakage was suspected, securing the pump minimized the potential for an unmonitored release from that source. At 0138, the manual isolation valve for the atmospheric dump valve was closed. Again, the Steam Dump and Bypass System was providing heat removal capabilities, and shutting the manual atmospheric dump isolation valve isolated a potential release path.

At 0146, Engineered Safeguards were reset, which allowed several desired actions over the next three hours:

1) The electric fire pump, which had started after fire header pressure decreased in response to the electrical load shedding of the jockey pump, was secured.

2) The Chemical and Volume Control System was restored to a normal configuration, which would allow the subsequent restoration of pressurizer level to the normal band.

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3) The containment isolation valves for the containment gas and particulate monitors (RM-050/051), which had previously closed due to PPLS/CIAS, were re-opened to provide an indication of containment atmosphere conditions. At 0156, a CRHS was received from RM-050/051, initiating a second VIAS (VIAS had previously been initiated due to PPLS/SIAS) due to high containment activity. The VIAS re-closed the valves.

4) The steam generator and primary system sample valves were opened.

5) The Emergency Diesel Generators, which had started on the reactor trip were secured.

6) Auxiliary building ventilation was restored.

7) One of three component cooling water pumps was secured.

8) Two of the four raw water pumps were secured.

9) The motor control centers which had been load shed by the SIAS were re-energized.

At 0218, while attempting to lower pressure during the cooldown, the Primary System Operator observed possible reactor vessel head voiding over a period of approximately five minutes. The cause was likely inadequate cooling of the reactor vessel by natural circulation. The RCS was re-pressurized slightly, and the void collapsed. The lowest level in the reactor vessel head was 83% as indicated by the Reactor Vessel Level Monitoring System.

At 0329, with the Chemical and Volume Control System operating for RCS inventory control, the safety injection loop injection valves were fully closed. With these valves closed, makeup for RCS leakage was provided by the charging pumps only.

At 0334, PORV Block Valve HCV-151 (the isolation valve for PORV PCV-102-1) was re-opened. At 0337, PORV Block Valve HCV-150 (the isolation valve for PORV PCV-102-2) was re-opened. PORV tailpipe temperatures began increasing, so HCV-150 was immediately re-closed. With HCV-151 open, Low Temperature Over-pressurization Protection was re-established.

At 0406, a continuous fire watch was established in Room 81. Technical Specification 2.19(1) requires a fire watch to be established within one hour when specified fire detection instrumentation is inoperable. This requirement was not met within one hour of Fire Zone 33 going into alarm. Although a formal fire watch was not in place between 2337 (when the zone went into alarm) and 0406, several individuals, including fire watch qualified personnel, did enter Room 81 during this time.

At 0416, the fire alarms previously received for Fire Zone 33 (Room 81) and Fire Zones 10 and 11 (Containment) were reset. Technical Specification 2.19 requires a fire watch to be established if more than one fire zone in containment is inoperable, however due to containment conditions the watch was not established. Therefore, this Technical Specification requirement was not met while Fire Zones 10 and 11 were in alarm.

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At 0420, the last high pressure safety injection pump, SI-2A was secured. At 0431, the safety injection tanks were isolated per EOP-20 to prevent injection as the RCS was de-pressurized in preparation for shutdown cooling.

At 0615, the containment isolation valves for the containment gas and particulate monitors (RM-050/051) were again opened to provide an indication of containment atmospheric conditions. The monitors remained in service for the remainder of the event.

At 0630, with RCS leak rate estimated at less than five gallons per minute the event was downgraded from an Alert classification to a Notification of Unusual Event with the concurrence of the NRC.

At 1024, one reactor coolant pump (RC-3C) was started to assist in cooling the reactor vessel head.

At 1053, preparations began for initiation of shutdown cooling and at 1312 shutdown cooling was established. EOP-20 was then exited and normal operating procedures for cold shutdown were implemented. The plant entered Mode 4 (Cold Shutdown) at 1825.

At 1840 on July 4, 1992, the Notification of Unusual Event was terminated.

This Licensee Event Report (LER) is being submitted pursuant to the following federal regulations:

1) 10 CFR 50.73(a)(2)(iv), due to the automatic actuation of numerous Engineered Safety Features including the Reactor Protection System.

2) 10 CFR 50.73(a)(2)(ii), due to the failure of RC-142 which resulted in the reactor coolant pressure boundary being seriously degraded.

3) 10 CFR 50.73(a)(2)(i)(B), due to the failure to establish fire watches in Room 81 and containment as required by Technical Specifications 2.19(1) and 2.19(2).

4) 10 CFR 50.73(a)(2)(x), due to containment conditions preventing the establishment of a fire watch patrol as required by Technical Specification 2.19(2).

5) 10 CFR 50.73(a)(2)(i)(B), due to previously unreported failures of Pressurizer Safety Valves RC-141 and RC-142 to meet Technical Specification 2.1.6(1) acceptance criteria during as-found testing performed in 1975, 1980, 1984 and 1985. (This was discovered during a detailed review of historical maintenance and testing records for RC-141 and RC-142.)

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EVALUATION/SAFETY ASSESSMENT

The initial Nuclear Steam Supply System (NSSS) response to this event was a normal response to a load rejection event, and is bounded by the Updated Safety Analysis Report (USAR) accident analysis for a load rejection event. Peak RCS pressure was approximately 2430 psia, peak temperature of reactor coolant leaving the core was approximately 602 degrees F, and peak steam generator pressure was approximately 1033 psia.

USAR Section 14.15, Loss of Coolant Accident, indicates that a LOCA with an RCS break size of less than 0.5 sq ft is considered to be a Small Break LOCA. Using the nominal three inch size for the open Pressurizer Safety Valve (RC-142), the break size would be calculated as 0.049 sq ft. Therefore, by definition, this event was a Small Break LOCA.

The consequences of the event are bounded by the USAR analysis for a Small Break LOCA. The leak rate was greater than the 40 gallons per minute capacity of one charging pump while the RCS was at operating pressure. The Reactor Protection System functioned as designed to provide an automatic reactor trip and the Engineered Safeguards equipment actuated to cool the reactor core. The reactor core remained covered with coolant throughout the event. Post event analysis has determined that there are no apparent fuel rod failures in the reactor core. The fuel vendors have confirmed the maintenance of fuel integrity. During the event the ERFCS indicated saturated or slightly superheated conditions existed in the RCS for a period of approximately ten minutes. The fuel vendors have verified that there was no detrimental effect on the fuel or its integrity and that continued operation with existing fuel performance guidelines is acceptable.

The NSSS stress reports for key components have been reviewed and revised as required as a result of this event. The reactor vessel structural integrity was evaluated to ensure there were no pressurized thermal shock concerns from the High Pressure Safety Injection System operation or submerging the bottom of the reactor vessel. The results of the review and evaluation indicated no adverse impacts to the NSSS from this event.

Containment integrity was maintained throughout the event and containment pressure was maintained below three psig. Post-event containment releases were well within the requirements of 10 CFR 20.

The following average containment general area contamination levels were observed prior to the event (at the end of the last refueling outage), by initial survey after the event (on July 4, 1992), and following decontamination (between July 11 and July 15, 1992).

Containment Elevation	Pre-event (dpm/100 sq cm)	Initial Post-Event (dpm/100 sq cm)	Post-decontamination (dpm/100 sq cm)
1045'	1,186	87,751	16,691
1013'	1,263	39,740	972
994'	1,344	3,334,545	10,134

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CONCLUSIONS

Following the event, investigations were initiated to determine the root causes of the momentary loss of power to Panel AI-42B and the malfunction of Pressurizer Safety Valve RC-142.

The following is a summary of findings regarding the failure of Inverter #2.

1) Both circuit boards which were replaced on July 3 (Static Switch Drive Board and Inverter Drive Board) were found to have components (ceramic resistors) that showed signs of discoloration due to overheating.

2) One of the resistors on the Static Switch Drive Board was found to have a bad connection which resulted in the connection being intermittent (i.e., making when it cooled off and breaking when it was hot). The bad connection of the resistor caused the inverter to go to the bypass mode three times in the same day.

3) When the Static Switch Drive Board was replaced, plant personnel failed to remove a metal jumper between terminal points 6 and 7 of TB204 on the old board and install it on the new board. The missing metal jumper caused the inverter to oscillate between Forward and Reverse.

4) A wire feeding the signal from the Static Switch Drive Board to the gate of Static Switch Inverter SCR12 in the inverter was found to be loose, thus not providing the signal to the gate of SCR12. It appears that this wire was unintentionally pulled off the gate during the replacement of the Static Switch Drive Board. The wire inadvertently pulled from the gate of SCR12, caused SCR12 not to gate on, resulting in zero voltage on the reverse side while silicone controlled rectifiers on the forward side were providing 120V AC. Therefore, the oscillation observed between Forward and Reverse caused a voltage fluctuation of 120V to zero (zero on the Reverse side and 120V AC on the Forward side) on Instrument Bus AI-42B.

The root cause of the momentary loss of power to AI-42B was determined to be the inability to isolate and test the non-safety related inverters (Inverters #1 and #2) after maintenance, without potentially losing power to the respective 120V AC instrument buses.

The following five contributing causes were identified with respect to the momentary loss of power to AI-42B:

1) Failure of vendor to inform utilities of potential for human error associated with the jumpers during board replacement,
2) Lack of a troubleshooting guide,
3) Poor workmanship during manufacture,
4) Single clad board design,
5) Unavailability of an inverter qualified Electrician.

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APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

The significance of this event on the inverter is marginal. The troubleshooting activities and subsequent repair activities during the day and night of July 3, 1992, while ineffective in returning the inverter to service, did not significantly affect the long term operation of the inverter.

In order to address the malfunction of Pressurizer Safety Valve RC-142, both RC-141 and RC-142 were sent to Wyle Laboratories for a post-incident investigation of the failure of RC-142. The investigation revealed that only RC-142 had lifted and that it had sustained damage to its internals including indications of valve chatter and failure of the bellows assembly. One of the effects of this damage was to establish contact between the disc ring and the nozzle ring. This did not allow the valve to reseat properly, therefore the valve continued to leak. In addition, the valve setpoint adjusting bolt was found to be backed out, significantly lowering the valve setpoint.

The following is a postulated sequence of events regarding the failure of RC-142. Following the closing of the main turbine control valves, RCS pressure spiked to approximately 2430 psia. The PORVs and RC-142 opened, and then closed by the time RCS pressure had decreased to approximately 1750 psia. The inlet piping to RC-142 includes a loop seal with approximately 1.2 gallons of water. RC-142 is designed for steam service and will tend to chatter when relieving the loop seal volume. Although there may have been some initial chatter, the valve did close and RCS pressure began to recover. The pressure then recovered to approximately 1923 psia after approximately seven minutes. During this seven-minute period, the pressurizer quench tank level was stable, which indicates that RC-142 did fully close.

During the initial lift, it is postulated that valve vibration loosened the adjusting bolt locknut. This allowed the adjusting bolt to back off approximately one turn, thereby lowering the valve setpoint pressure to between 1900 and 2000 psia. The respective blowdown was also affected.

During the RCS pressure recovery, when the pressure reached approximately 1923 psia, RC-142 lifted again. This led to additional valve vibration and further reduction in the valve setpoint pressure and further changes in blowdown. The valve did not properly reseat and therefore continued to leak for the remainder of the event.

The root cause of the malfunction of RC-142 was the adjusting bolt locknut that loosened and allowed the set pressure adjusting bolt to back out during valve actuation. Valve vibration during discharge caused the adjusting bolt locknut and adjusting bolt to turn. This lowered the set pressure of the valve and adversely affected blowdown.

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The following two contributing factors were identified:

1) Inadequacy of the valve refurbishment procedure with respect to documenting the proper tightening of the adjusting bolt locknut.

2) The lack of a positive locking device to prevent the adjusting bolt from moving.

The failure of RC-142 had a significant impact on RCS inventory. Only the failure of Pressurizer Safety Valve RC-141 could achieve a similar impact on RCS inventory. Consequently, the issues concerning RC-142 failure are also being incorporated into RC-141. The adjusting bolt locknut or similar device is generic to many of the safety valves throughout the plant. However, no other safety valves incorporate a loop seal into their design which could result in the chatter which was a contributor to the failure of RC-142. In addition, the location of other safety valves relative to the RCS indicate that a similar valve failure would not result in a loss of RCS inventory and would therefore, be a much less significant event.

A review of historical maintenance and testing records was performed for RC-141 and RC-142. The review revealed that the "as-found" setpoints for Pressurizer Safety Valves RC-141 and RC-142 have been outside of +/- 1% of their respective set pressures on several occasions. Details are provided on the following list:

RC-141 setpoint is 2545 psia (2530 psig) +/- 1% (i.e., range of 2505 to 2555 psig)
RC-142 setpoint is 2500 psia (2485 psig) +/- 1% (i.e., range of 2460 to 2510 psig)

Year	Valve	"As-Found" Setpoint (psig)
1975	RC-141	2475
	RC-142	2453
1976	RC-141	2588
	RC-142	< 2317
1977	RC-142	2720
1980	RC-142	2548
1983	RC-141	2562
1984	RC-142	2592
1985	RC-141	2493
	RC-142	2434
1987	RC-141	2628

In each case, corrective maintenance required to return RC-141 and RC-142 to operability was completed. Technical Specification 2.1.6(1) indicates that the reactor shall not be made critical unless two pressurizer safety valves are operable with their lift settings adjusted to ensure valve opening between 2500 psia and 2545 psia +/- 1%. LERs were submitted in 1976 (LER 76-038), 1977 (LER 77-028), 1983 (LER 83-001), and 1987 (LER 87-014) reporting out-of-tolerance as-found test results, however, it appears that no LERs were submitted for out-of-tolerance as-found test results in 1975, 1980, 1984 and 1985.

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TEXT (If more space is required, use additional NRC Form 366A's)(17)

Pressurizer safety valve test results are now reviewed as part of the relief valve program. This should prevent recurrence of a failure to report an out-of-tolerance condition. These unreported test results had no impact on the failure of RC-142 during this event.

In addition to the specific investigations of the Inverter #2 failure and the RC-142 failure, an overall investigation of the event was also conducted. One issue addressed in the overall investigation was the Turbine/Generator EHC System.

The EHC System original design had redundant power supp ies, with normal power supply from an inverter and alternate power supply from the Permanent Magnet Generator (PMG). The PMG is driven by the turbine shaft and can supply an adequate source of power to the EHC system whenever the turbine is at rated speed.

In October of 1978, a design change modified the EHC System by replacing the original steam pressure transmitters with Rosemount transmitters. The original pressure transmitters were powered from the EHC panel and would continue to function in the event of a loss of power from the inverter because they had PMG backup power. When the new Rosemount transmitters were installed in 1978, they were supplied power from safety related Inverter "A" with no backup from the PMG.

On July 2, 1986, the failure of safety related Inverter "A" caused a transient similar to this event. At that time, the safety related inverters did not have the capability to automatically transfer to a bypass transformer for backup power, while the non-safety related inverters did. The corrective actions in 1986 included transferring the EHC panel from safety related Inverter "A" to non-safety related Inverter #2 so that an automatic backup power supply was available via fast transfer. The Inverter #2 failure on July 3, 1992 resulted in the loss of both primary and backup power to the pressure transmitters, which caused them to indicate zero pressure conditions. This caused the EHC System to close the turbine control valves, which resulted in a Loss of Load transient. This subsequently caused a reactor trip due to high pressurizer pressure similar to the 1986 trip.

The overall investigation concluded that addition of a second backup power supply to all EHC panel components from the PMG should be evaluated.

CORRECTIVE ACTIONS

As a result of this event OPPD developed a comprehensive Recovery/Restart Action Plan. Some of the points covered by the plan included investigation into system response, development and analysis of the sequence of events, evaluation of the transient's impact on the reactor vessel, assessment of potential equipment damage inside containment, incorporation of lessons learned into procedures, assessment of the effects of transients on mechanical systems, evaluation of the impact of high temperatures on systems, evaluation of fuel integrity, defining modifications to be performed, evaluation of reactor coolant pump seals and evaluation of non-safety related inverter loads. The Fort Calhoun Station was returned to power operation July 23, 1992 following completion of appropriate short-term corrective actions included in the Recovery/Restart Action Plan.

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TEXT If more space is required, use additional NRC Form 366A's (17)

The following corrective actions have been or will be implemented as a result of the failure of non-safety related Inverter #2:

1) A modification has been installed which will allow isolation of the non-safety related inverters to perform maintenance and testing without losing the power to the 120V AC instrument bus.

2) An enhanced troubleshooting guide for all safety related and non-safety related inverters will be developed by January 1, 1993.

3) The wires leading to gates and cathodes of accessible inverter silicone controlled rectifiers (all six inverters) will be inspected, and soldered if required during the next refueling outage.

4) Training of Electrical Maintenance personnel regarding this event has been conducted. Lesson Plans for initial training for Electrical Maintenance personnel will be upgraded by September 30, 1992 to include lessons learned from this event.

5) Single clad circuit boards in the six inverters will be inspected during the next refueling outage for signs of degradation, and replaced if necessary.

6) Metal jumpers on inverter circuit boards will be replaced with wire jumpers by the end of the 1993 Refueling Outage.

The following corrective actions have been or will be implemented as a result of the failure of RC-142.

1) RC-142 has been refurbished and reinstalled.

2) A mechanical locking device has been added to the RC-141 and RC-142 adjusting bolts.

3) Adjusting ring and nozzle ring settings were reviewed to ensure optimum settings are being used for loop seal applications.

4) The effect on valve body temperature and valve setpoint pressure with the presence of valve insulation was investigated by installing temporary thermocouples on the valve and monitoring them during heatup and power operation. The temperature, as a result of the presence of the valve insulation, was found to have a negligible effect on the setpoint pressure.

5) A review of disc and nozzle materials which could be utilized to improve safety and performance of the pressurizer safety valves will be performed by December 31, 1992.

6) Further analysis will be completed, prior to the 1993 Refueling Outage, with respect to the failed bellows assembly removed from RC-142.

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7) A review of the pressurizer safety valve testing procedures will be performed prior to the 1993 Refueling Outage to determine if changes are necessary (e.g., adding a routine back pressure test to verify bellows integrity, instructions for adjusting valve setpoint).

8) An evaluation will be performed by December 31, 1992 of the options for possible relocation of the pressurizer safety valves to eliminate the loop seal.

9) Lessons learned from the event will be incorporated into the relief valve testing program prior to the 1993 Refueling Outage.

The following corrective actions have been or will be implemented with respect to the EHC System:

1) Two turbine trips for loss of load have been installed. One will be actuated by a limit switch on Turbine Control Valve #1, when the valve approaches its closed seat. The other turbine trip will actuate when a Power Load Unbalance occurs.

2) An evaluation will be performed by September 30, 1992 to consider providing a second source of backup power (via the Permanent Magnet Generator) for EHC pressure transmitters.

PREVIOUS SIMILAR EVENTS

LER 86-001 reported a reactor trip resulting from the failure of a safety related inverter. On July 2, 1986 the Fort Calhoun Station reactor tripped due to High Pressurizer Pressure. The cause of the trip was determined to be loss of safety related Inverter "A" resulting in a loss of power to the turbine EHC panel. It was determined that on loss of EHC power, the turbine control valves shut but the steam dump and bypass valves do not actuate. A modification was installed to transfer EHC panel power to non-safety related Inverter #2.

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TITLE (4)
Partial Loss of Load Resulting in Pressurizer Safety Valve Lift and Subsequent Reactor Trip

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 8	2 2	9 2	9 2	— 0 2 8 —	0 0	0 9	2 1	9 2	N	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1
POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

[ ] 20.402(b)	[ ] 20.405(c)	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[X] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[X] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ] 20.405(a)(1)(iii)	[X] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[X] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
Daniel J. Rosloniec, Shift Technical Advisor	4 0 2	5 3 3 - 6 8 9 9

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
B	I T	C N V	A 0 3 8	Y					
D	A B	R V	C 7 1 1	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On August 22, 1992 at 0152 (CDT) while the plant was operating at 100% power, the Reactor Protection System automatically tripped the reactor on Thermal Margin/Low Pressure (TM/LP). The event was initiated by the failure of an AC to DC power converter which affected the first stage turbine pressure signal and resulted in the repositioning of the Turbine Control Valves. The decrease in secondary steam demand caused an increase in Reactor Coolant System (RCS) pressure which was terminated by a premature opening of one of two Pressurizer Safety Relief Valves, followed by the Reactor trip.

The root cause of this event was the failure of an AC to DC power converter in the Turbine Electrohydraulic Control (EHC) panel. The root cause of the premature lift of RC-142 was that the (laboratory) test environment in which valve set pressure qualification was performed, did not provide an adequate representation of the actual field environment.

Corrective actions include a modification to change the power source for EHC pressure transmitters, reducing the pressure setpoint for initiating a High Pressurizer Pressure trip and Power Operated Relief Valve operation and adjusting Pressurizer Safety Valve set pressures using revised test procedures.

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BACKGROUND

The Reactor Protective System (RPS) monitors certain critical plant parameters and compares them to predetermined setpoints. If one or more of the monitored parameters reaches its setpoint on two of four channels, the RPS will initiate a reactor trip. There are 12 different reactor trips that can be initiated by the RPS. The trip units of interest for this event are High Pressurizer Pressure and Thermal Margin/Low Pressure.

A Reactor trip signal is initiated when two of four High Pressurizer Pressure channels approach 2400 psia. This trip is provided, in conjunction with the Pressurizer and steam system safety valves, to prevent the Reactor Coolant System (RCS) from exceeding 110% of its design pressure of 2500 psia.

The Thermal Margin/Low Pressure (TM/LP) trip signal is provided to prevent operation when the Departure from Nucleate Boiling Ratio (DNBR) is less than 1.18. A TM/LP trip signal is initiated when two of four channels indicate that RCS pressure has reached a low pressure trip limit. The trip limit used is the higher of a fixed (1750 psia) and a variable low pressure trip limit. The variable low pressure trip limit is calculated using a combination of RCS temperature, pressurizer pressure, core power and axial shape index.

Two Power Operated Relief Valves (PORV) (PCV-102-1 and PCV-102-2) are designed to provide sufficient relief capacity during RCS high pressure transients to prevent the opening of the Pressurizer Safety Valves. The PORVs operate when two of four of the High Pressurizer Pressure channels approach 2400 psia.

Two Pressurizer Code Safety Valves provide over-pressure protection for the RCS. They are totally enclosed, spring loaded safety valves meeting ASME code requirements. A loop seal is provided to minimize valve leakage. The Technical Specifications require the lift settings of one valve (RC-142) to be adjusted to ensure valve opening at 2500 psia +/- 1% and the second (RC-141) at 2545 psia +/- 1%.

The pressurizer quench tank is designed to collect and condense the normal discharges from the pressurizer during operation and to collect non-condensable gas discharges from the reactor vessel head or the pressurizer during post-accident situations. In either case, the pressurizer quench tank prevents normal relief or safety valve discharges from being released directly to the containment atmosphere and/or sump. The steam discharged from the pressurizer is injected underwater by a sparger to enhance condensation by uniform distribution. The pressurizer quench tank can condense the steam discharged during a loss-of-load incident without exceeding the rupture disc setpoint, assuming normal blowdown of the relief valves.

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TEXT (If more space is required, use additional NRC Form 366A's)(17)

The Turbine Electrohydraulic Control (EHC) System supplies control signals to the turbine steam admission valves during startup, normal operation, shutdown, testing and transient conditions. The Turbine Control Valves regulate steam flow to the Turbine. Two pressure transmitters combine to regulate positioning of the turbine control valves. Pressure transmitter PT-945 provides a pressure feedback signal and PT-943 provides throttle pressure compensation. The power supply for these two pressure transmitters is located in Turbine EHC Panel #2 (AI-50).

EVENT DESCRIPTION

On August 22, 1992 the Fort Calhoun Station was in Mode 1 (Power Operation) operating at 100% power. At approximately 0152 (CDT), a 115V AC to 28V DC power converter failed inside AI-50 (EHC Cabinet). This converter powered turbine control transmitters PT-945 (first stage pressure feedback to the control valve amplifier) and PT-943 (throttle pressure sensor for throttle pressure compensation). Inaccurate feedback signals from the de-energized pressure transmitters caused the Turbine Control Valves to move from a 40% open position to an approximately 22% open position resulting in a partial loss of load. The change in control valve position resulted in a generator load drop of 120 MW(E).

The first control room annunciator indication of a malfunction occurred several seconds later when a low steam generator level alarm was received for both steam generators. A rapid reduction in steam flow will result in a low level indication due to the design of the level instrumentation (commonly referred to as a "shrink" condition). The Reactor Operator for the secondary system immediately started actions to verify that a loss of feedwater had not occurred. However, after the steam generator levels appeared to be recovering, the primary board operator noticed RCS temperature and pressure increasing.

The mismatch between steam demand and reactor power due to the partial closure of the turbine control valves caused an increase in Reactor Coolant System (RCS) pressure and temperature. This resulted in one of the two Pressurizer Code Safety Valves (RC-142) opening at approximately 2398 psia. This valve has a required setpoint of 2500 psia +/- 1%. Secondary system pressure increased to 1003.8 psia on the "A" Steam Generator which resulted in one or more Main Steam Safety Valves opening.

Just before RC-142 opened, one of the four High Pressurizer Pressure Trip Units tripped providing one of two signals required to initiate a Reactor trip and opening of the PORVs on high pressure. The subsequent rapid depressurization of the RCS due to RC-142 opening, cleared the High Pressurizer Pressure indication and, shortly thereafter, resulted in the RPS automatically tripping the reactor on Thermal Margin/Low Pressure (TM/LP). The Reactor trip occurred 37 seconds after the power converter failed. Upon receiving the Reactor trip, the Main Turbine tripped and the Emergency Diesel Generators started.

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Except for the premature lift, RC-142 functioned as designed. RCS pressure dropped to 1721 psia before it started to recover, approximately 1 minute into the event. Pressurizer level responded normally.

The steam from RC-142 discharged to the pressurizer quench tank. The pressurizer quench tank peak pressure was 12.51 psig with a level increase of approximately 5% (i.e., from 77% to 82% level).

Following the turbine trip, Fuse F-5 in AI-50 blew as a result of the power converter failure. This caused some turbine valves to indicate a mid-position.

The operations crew implemented Emergency Operating Procedure EOP-00, "Standard Post-Trip Actions," and then proceeded to EOP-01, "Reactor Trip Recovery." All safety functions were satisfied and all major plant equipment performed as expected with the exception of RC-142 having lifted prematurely.

The plant was stabilized in hot shutdown (Mode 3) and maintained at normal RCS temperature and pressure limits until in-situ testing of both Pressurizer Safety Valves was completed. The in-situ testing was completed on August 25, 1992 and a plant cooldown was then initiated to allow removal of the valves. The valves were then shipped to Wyle Laboratories for inspection and testing.

The NRC was notified of this event on August 22, 1992, at 0358, pursuant to 10 CFR 50.72(b)(2)(ii). This Licensee Event Report (LER) is being submitted pursuant to the following federal regulations:

1) 10 CFR 50.73(a)(2)(iv), due to the actuation of the Reactor Protective System and automatic start of the Emergency Diesel Generators;

2) 10 CFR 50.73(a)(2)(i)(B), due to a Pressurizer Safety Valve opening below the pressure range specified in Technical Specification 2.1.6(1);

3) 10 CFR 50.73(a)(2)(ii), due to the premature opening of a Pressurizer Safety Valve constituting a degradation of the reactor coolant pressure boundary;

4) 10 CFR 50.73(a)(2)(v)(D) and 10 CFR 50.73(a)(2)(vii)(D), due to the conclusion that the cause of the premature opening of RC-142 also resulted in a similarly low effective set pressure for RC-141 (indicating that both valves had potentially been outside their Technical Specification required settings).

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 8	— 0 0	0 5 OF 0 9

TEXT If more space is required, use additional NRC Form 366A's (17)

SAFETY ASSESSMENT

The Nuclear Steam Supply System (NSSS) response to this event was normal for a loss-of-load event and was bounded by the Updated Safety Analysis Report (USAR) accident analysis. Peak RCS pressure was approximately 2398 psia, peak RCS hot leg temperature was 603 degrees F, and peak Steam Generator Pressure was 1003.8 psia.

USAR Section 14.9 "Loss of Load" indicates that the acceptance criteria for this transient are:

a. The peak RCS pressure remain below 110% of the design pressure (i.e., below 2750 psia),

b. A sufficient thermal margin must be maintained in the hot fuel assembly to assure that departure from nucleate boiling does not occur.

The significance of the EHC transmitter power converter failure is that a non-safety related equipment failure challenged safety-related equipment.

The consequence of the safety valve opening at approximately 2398 psia is minimal since the Pressurizer is equipped with two Power Operated Relief Valves (PORV's) which are designed to operate at approximately 2400 psia. The significance of challenging a Pressurizer Safety Valve is that it increases the probability of experiencing a valve malfunction and creating an unisolable Loss of Coolant Accident (LOCA). A function of the PORV's is to limit the number of challenges to the Pressurizer Safety Valves.

CONCLUSIONS

A root cause analysis was initiated to establish the cause of the partial loss of load. Prior to 1978, Pressure Transmitters PT-939, PT-943, PT-944 and PT-945 were "Schaevitz" brand pressure transmitters. These pressure transmitters had a high failure rate which had caused a Reactor trip and several near-misses. The Schaevitz transmitters were powered from an oscillating power supply inside AI-50. Power was provided by 115V AC house power and backed up by the Permanent Magnet Generator which is driven directly off the Main Turbine shaft.

In 1978, Design Change Request (DCR) 76-19 replaced the Schaevitz transmitters with "Rosemount" brand transmitters. However, the Rosemount transmitters could not use Schaevitz' oscillating power supply and backup power supply. Per General Electric's design, the 115V AC power source was then used to supply the new pressure transmitters via 115V AC to 28V DC "Acopian" brand converters "A" and "B." Though the new transmitters were more reliable, their power supply did not have a redundant backup supply via the Permanent Magnet Generator.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 8	— 0 0	0 6 OF 0 9

TEXT (If more space is required, use additional NRC Form 366A's)(17)

During the 1990 Refueling Outage, the periodic (every refueling outage) calibration of these pressure transmitters uncovered a high ripple output from power converter "A" on card "A86" inside AI-50. The power converter was replaced under Maintenance Work Order (MWO) 902334. The power converter was an "Acopian" brand, Model 28E15, "Miniature AC to DC Power Module." This power converter was replaced after approximately 12 years of service. Approximately two years after the "A" power converter was replaced, the "B" power converter failed, causing the partial loss-of-load event and subsequent reactor trip discussed in this LER. This pressure transmitter loop and power converter output had been successfully calibrated during the 1992 Refueling Outage approximately four months earlier.

The root cause of this event was determined to be the failure of AC to DC power converter "B" on card "A86" in AI-50 (EHC Cabinet).

The modification in 1978 which removed the backup power supply to the transmitters was determined to be a contributing cause. DCR 76-19 did not address the consequences of removing the backup power supply to these pressure transmitters. This design was supplied by General Electric. The modification process has changed significantly at Fort Calhoun Station since this DCR was written. Procedures are currently in place to thoroughly review and approve vendor designs.

In addition to the analysis of the cause of the partial loss of load, an investigation was initiated to establish the root cause of the premature opening of Pressurizer Safety Valve RC-142. RC-141 and RC-142 are Crosby Style HB-BP-86, size 3K6, Self-Actuated Safety-Relief Valves. The body and bonnet of the valves are carbon steel and the disc, nozzle and spindle are stainless steel. Set pressure is controlled by varying the compression of the spring by means of the adjusting bolt. Turning the adjusting bolt one flat (1/6 turn) changes the set pressure approximately 75 psi. Differential thermal expansion of the valve components can also affect the set pressure, as changes in the dimensions of the components can vary the compression of the spring.

With the plant in hot shutdown, Furmanite Corporation was brought onsite to perform in-situ setpoint testing on the pressurizer safety valves with their Trevitest test equipment. The Trevitest was used to determine the lift pressures with the valve in the as-installed configuration, and then trend lift pressure versus temperature as the safety valve heated up. The in-situ testing showed that set pressure varied with temperature changes in the valve body. The pressurizer safety valves were then sent to Wyle Laboratories for disassembly, inspection and set pressure qualification.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 8	— 0 0	0 7 OF 0 9

TEXT (If more space is required, use additional NRC Form 366A's)(17)

In an attempt to substantiate the effect of valve temperature distribution on set pressure, the plant insulation was sent to Wyle with the valves to be used during testing. An experimental low temperature test was devised in an attempt to test the set pressure with the valves as close to the field measured temperatures as possible. The results of this test were inconclusive because the valve temperatures could not be kept stable and constant when high pressure saturated steam was applied. This was partially due to test equipment limitations. Qualitatively, as the valve temperatures rose, there was an initial increase in the set pressure (due to nozzle thermal growth) and then a decrease (due to body thermal growth). However, when the valve was tested with the valve in thermal equilibrium with the high pressure steam, the valve "pop" pressure was repeatable within +/- 1%.

Previous set pressure testing at Wyle (including testing performed in July 1992, following a previous Pressurizer Safety Valve lift), had utilized an arrangement in which an environmental chamber was installed over an uninsulated bonnet, and fiberglass cloth was placed over the valve body. A revised testing method was used for the August, 1992 tests and was conducted at Wyle with the plant insulation installed on the valves and the valves at equilibrium temperatures. This testing indicated a lower effective set pressure for both valves. It appears that these valves were set at a lower effective set pressure during previous testing because of the different methods used in controlling temperature distribution throughout the valve during testing. The set pressures of both safety valves were raised by approximately one flat (approximately +75 psi, or about 3%).

It was concluded that the root cause of the premature lift of RC-142 was that the previous valve (laboratory) test environment did not provide an adequate representation of the actual field environment. Specifically, the temperature distribution throughout the valve body and bonnet differed significantly from the as-installed temperature distribution and was the cause for the effective lift pressure being lower than the test set pressure. Insulating the valve using the valve's actual plant insulation during the most recent set pressure tests provided a more accurate representation of the actual field environment.

A contributing factor is the fact that the FCS Pressurizer Safety Valves have a carbon steel valve body and bonnet and a stainless steel nozzle, disc and spindle. This material difference is believed to accentuate the problem because of different thermal expansion coefficients.

Significant differences in temperature distribution during set pressure testing in comparison to installed conditions is only expected to be a concern with insulated safety valves that are installed on loop seals in high temperature systems, or with uninsulated valves on high temperature systems that may be subjected to forced cooling from ventilation drafts. At Fort Calhoun Station, the only safety valves that this is applicable to are the Pressurizer Safety Valves, RC-141 and RC-142.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	— 0 2 8	— 0 0	0 8 OF 0 9

TEXT (If more space is required, use additional NRC Form 366A's)(17)

CORRECTIVE ACTIONS

The following corrective actions have been or will be completed:

1) Engineering Change Notice (ECN) 92-308 was installed prior to plant startup to provide power directly from the power bus within Panel AI-50 to pressure transmitters PT-939, PT-943, PT-944 and PT-945. Panel AI-50 receives its power from the Permanent Magnet Generator with back-up from the Station 120V AC.

2) The setpoint for initiating a High Pressurizer Pressure trip in the RPS has been decreased to 2350 psia and the setpoint for PORV operation has been decreased to 2350 psia for Cycle 14 to increase the available margin between the PORVs and the Pressurizer Safety Valve set pressures. The setpoint change was justified by Engineering Analyses EA-FC-92-066 and EA-FC-92-067 and a 10 CFR 50.59 evaluation. Appropriate EOPs and Abnormal Operating Procedures (AOPs) were revised and Operator training conducted to address the setpoint change.

3) The test procedures for set pressure testing of the Pressurizer Safety Valves have been revised to ensure that adequate control of valve temperature distribution is maintained during set pressure testing. The set pressures of RC-141 and RC-142 were adjusted using the revised qualification procedure.

4) A failure analysis of the failed Acopian AC to DC power module will be performed by March 31, 1993.

5) The EHC System has been reviewed and single failure components (i.e., components whose single failure could cause a Reactor trip) have been identified. Upgrades to the Preventive Maintenance Program, monitoring enhancements or possible modifications/replacements which would enhance system reliability are being factored into ongoing programs.

6) An evaluation will be performed by December 31, 1992 of the options for possible relocation of the Pressurizer Safety Valves to eliminate the loop seal (reference LER 92-023).

NRC FORM 366A U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fort Calhoun Station Unit No. 1	0 5 0 0 0 2 8 5	9 2	0 2 8	0 0	0 9 OF 0 9

TEXT (If more space is required, use additional NRC Form 366A's)(17)

PREVIOUS SIMILAR EVENTS

This is the second occurrence of a premature lift of a pressurizer safety valve at Fort Calhoun Station. The first occurrence was on July 3, 1992 and involved the same valve, RC-142. The initial investigation revealed that RC-142 had lifted and that it sustained damage to its internals including indications of valve chatter, failure of the bellows assembly and malfunction of the setpoint adjusting bolt locknut. Previous industry test data regarding temperature effects on setpoint indicated that no more than a 1% setpoint shift would be expected due to temperature effects. Discussions with the valve manufacturer had indicated that only bonnet temperatures would be significant with respect to setpoint shift. Additionally, the obvious malfunction involving the adjusting bolt (which allowed the valve setpoint to shift during the event) tended to mask the significance of the temperature related effect. The Pressurizer Safety Valve bonnets were instrumented with thermocouples to verify the valve operating conditions following startup from the event.

The July 3, 1992 event was initiated by an inverter problem which caused a momentary loss of power to the instrument bus that supplies power to the Turbine EHC System, resulting in closure of the Turbine Control Valves. The event was reported under LER 92-023. LER 86-001 also reported a Reactor trip following a loss of power to the Turbine EHC panel.

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Indian Point Unit 3	0 5 0 0 0 2 8 6	1 OF 0 5

TITLE (4) #32 EDG Inoperable at Cold Shutdown Due to Disconnected Wire on Undervoltage Relay Circuit

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 7	0 6	9 2	9 2	0 1 1	0 0	0 8	0 7	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9) N

POWER LEVEL (10) 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
Edward Diamond, Senior Plant Engineer	9 1 4	7 3 6 - 8 0 4 5

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15) MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On July 1, 1992, with the reactor at cold shutdown, instrumentation and controls (I&C) technicians performing a surveillance test found that relay protection for 480 volt bus 5A did not respond as expected. The I&C technicians discovered a wire physically in place, but not making full electrical contact in the 480 volt bus 5A interlocking relay circuits. They reconnected the wire and the relay protection system was retested satisfactorily. On July 6, 1992 a technical review of this event determined that the electrically disconnected wire had made emergency diesel generator (EDG) 33 inoperable. During the period of inoperability, other EDGs had been removed from service for maintenance, causing the number of operable EDGs to decrease below the minimum of two required by Technical Specifications. The event did not affect decay heat removal capability. The suspected cause of the event was contractor electricians working in the area and inadvertently bumping an adjacent wire. The root cause of the event was a procedural insufficiency. Corrective action will be to provide a precaution and limitation in work package step lists.

NRC Form 366 (9-83)

LER NO: 286/92-011

DESCRIPTION OF THE EVENT

On July 1, 1992, with the reactor at cold shutdown, instrumentation and controls (I&C) technicians performing 3PT-M62, Revision 7, "Undervoltage/Degraded Grid Protection System Functional," found that the undervoltage/degraded grid protection associated with 480 volt bus 5A did not respond as expected. Upon investigation, the I&C technicians discovered that wire 5A-N1, while physically in its proper location, was not properly connected to its terminal on six and one-quarter ampere fuse, FU 1971. The electrically disconnected wire deenergized portions of the 480 volt bus 5A interlocking relay circuits. The wire provides the negative leg of the 125 volt DC control power circuit to the 480 volt bus 5A interlocking relay circuits. Working under work request 92-0630-04, the I&C technicians reconnected the wire. The undervoltage/degraded grid protection system subsequently retested satisfactorily.

INVESTIGATION OF THE EVENT

At 1100 hours on July 6, 1992 a technical review of this event determined that the electrically disconnected control power wire would have prevented emergency diesel generator (EDG) 33 (EG) (A152) (ALCO Model No. 251E16MS) from automatically starting and tying into 480 volt bus 5A during an undervoltage or degraded grid condition. Therefore, 33 EDG was inoperable during the period that the 5A-N1 negative control power wire was electrically disconnected.

The last verification of proper operation of the 480 volt bus 5A undervoltage and degraded grid relays was during the last performance of 3PT-M62, Revision 7, "Undervoltage/Degraded Grid Protection System Functional," on June 19, 1992.

On June 24, 1992 contractor electricians worked in the cabinet containing the 480 volt bus 5A interlocking relays (switchgear #31, compartment 25H) installing modification number 89-03-231 CVCS, "Charging Pump SI Lockout Elimination." While the modification did not directly affect wire 5A-N1, it is suspected that the electricians bumped or disturbed wire 5A-N1. The electricians involved have left employment at the site and are not available for questioning. The 5A-N1 wire is multi-stranded, and the wire termination does not use a crimp-on connector. The

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Indian Point Unit 3	0 5 0 0 0 2 8 6	9 2	— 0 1 1	— 0 0	0 3 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

fuse holder's terminal strip has a compression-type termination that captures wires under a metal plate compressed by a screw. A review of in-house experience revealed this to be an isolated incident. A review of industry experience revealed similar problems of wires being pulled from compression-type, clamp-down terminations.

CAUSE OF THE EVENT

The suspected cause of the event was the contractor electricians working in the confines of the 480 volt bus 5A interlocking relay cabinet (switchgear #31, compartment 25H) bumping or disturbing wire 5A-N1.

The root cause of the event was a procedural insufficiency. While addressed in the pre-job briefing, the work step list did not alert the craftsmen to use caution while working in the field on or near safety-related equipment. The work step list also did not advise the craftsmen to report any possible inadvertent damage imparted to adjacent equipment to their supervisor.

CORRECTIVE ACTIONS

The immediate corrective action was to reconnect the disconnected negative leg control power wire to the terminal on the fuse holder.

Satisfactory completion of 3PT-M62, Revision 7, "Undervoltage/Degraded Grid Protection System Functional," on July 1, 1992 verified the operability of all 480 volt bus undervoltage and degraded grid circuits.

Long term corrective actions will be to insert a precaution and limitation in work step lists prepared for use by contractor craftsmen. The precaution and limitation will alert the craftsmen to review their work area before starting work, use caution around safety-related equipment, and report unintentional interactions with adjacent equipment to their supervisor.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES 4/30/92

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Indian Point Unit 3	0 5 0 0 0 2 8 6	9 2	— 0 1 1	— 0 0	0 4 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ANALYSIS OF THE EVENT

This event is reportable under 10 CFR 50.73(a)(2)(i)(B), the plant was operated in a condition prohibited by the facility's Technical Specifications. Technical Specification 3.7.F.4 requires a minimum of two EDGs operable at all times, including cold shutdown. It is not known when, the wire 5A-N1 became electrically disconnected. Surveillance test 3PT-M62, Revision 7, "Undervoltage/Degraded Grid Protection System Functional," verified operability of the relays on June 19, 1992 at 1500 hours. The undervoltage/degraded grid protection system was returned to service at 0930 hours on July 1, 1992.

During the period of #33 EDG's inoperability #31 EDG or #32 EDG were, at various times, inoperable. Considering the time that the EDGs were out of service, Indian Point Three was operated at cold shutdown for a maximum of three days, eleven hours and thirty-five minutes with less than two EDGs operable. As previously noted, this is contrary to the facility's Technical Specifications.

During the times that less than the minimum two EDGs were operable, the following conditions mitigated the problem:

1) #33 EDG could have been manually started and tied-in from its local control station.

2) The 480 volt buses were continuously energized from offsite via 138KV feeder 95331.

3) Offsite power was also available from 13.8KV feeders 13W92 and 13W93.

4) The "Appendix R" diesel generator was available as an additional onsite power source.

No similar LERs have been reported to date.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Indian Point Unit 3	0 5 0 0 0 2 8 6	9 2	0 1 1	0 0	0 5 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

SAFETY SIGNIFICANCE

The event did not effect public health or safety. Although the plant was operated outside Technical Specifications for a maximum time of three days, eleven hours and thirty-five minutes, this event did not affect decay heat removal because normal offsite power was available. Had a loss of offsite power occurred while two EDGs were inoperable, a full train of components necessary for decay heat removal was immediately available, powered by the operable EDG.

SECURING FROM THE EVENT

I&C technicians reconnected the wire 5A-N1 on July 1, 1992. The undervoltage/degraded grid protection system subsequently retested satisfactorily. The plant remained at cold shutdown throughout the event.

NRC Form 366
(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Cooper Nuclear Station	0 5 0 0 0 2 9 8	1 OF 0 8

TITLE (4) Reactor Vessel Water Level Setpoint Inaccuracy Resulting From Reference Leg Temperature Effects That Had Not Been Correctly Addressed

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 2	0 3	9 2	9 2	— 0 0 2 —	0 0	0 3	0 4	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	X 50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Donald L. Reeves, Jr.	4 0 2 8 2 5 - 3 8 1 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On February 3 and 4, 1992, Technical Specification Limiting Conditions for Operation (LCOs) were entered, requiring plant load reduction and shutdown due to discovery of non-conservative Reactor Vessel Water Level 1 nominal instrument setpoints. For Reactor Vessel Water Level instruments NBI-LIS-72A,B,C and D, this determination was made upon reviewing setpoint calculations performed in 1981 in response to General Electric (GE) Service Information Letter (SIL) Number 299, "High Drywell Temperature Effect on Reactor Vessel Water Level Instrumentation". For Reactor Vessel Water Level instruments NBI-LIS-57A and B and 58A and B, this determination was made upon reviewing the Setpoint Change Request issued in 1983 in conjunction with a Mark I Containment Program design change. The functions of the affected instruments are to initiate low pressure Emergency Core Cooling Systems, start the Diesel Generators, satisfy a portion of the Automatic Depressurization System logic and initiate the Group 1 and 7 Isolations. The reviews were performed as a result of issuance of SIL 299, Supplement 2 by GE. When these discrepancies were found on February 3, the plant was at full power; on February 4, at approximately 80 percent power.

The revised instrument setpoints were implemented within the respective LCO timeframes, eliminating the required shutdowns and allowing a return to power. The cause of the deficient setpoints was attributed primarily to personnel error on the part of NPPD employees in 1981 and 1983. The existing procedural controls are expected to eliminate errors of the type that were found. A contributing cause included the lack of a formalized setpoint procedure in 1981 and 1983 when the setpoints had last been established. This deficiency no longer exists. In addition, a communications error by GE occurred. GE will issue another supplement to SIL 299, advising of its applicability to the Group 1 and 7 Isolations.

NRC Form 366
(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Cooper Nuclear Station	0 5 0 0 0 2 9 8	9 2	— 0 0 2	— 0 0	0 2 OF 0 8

TEXT (If more space is required, use additional NRC Form 366A's) (17)

A. Event Description

On January 20, 1992, an advance copy of supplement 2 to GE SIL 299 was received. The purpose of the supplement was to notify BWR owners that the information in SIL 299, dated July 25, 1979, had been misinterpreted by one utility and was potentially subject to misinterpretation by others. A clarification of the information was provided, along with a recommendation that a check of level instrument setpoint calculations be conducted.

An evaluation was performed which determined that although SIL 299 had been reviewed and properly considered when it was originally received, incorrect initial conditions and incomplete calculations for the Reactor Water Level 1 (-145.5 inches) setpoint, prescribed in the CNS Technical Specifications, resulted in a non-conservative value. This calculation performed in 1981 led to implementation of a non-conservative setpoint for Reactor Vessel Water Level instruments NBI-LIS-72A,B,C, and D. A new calculation (NEDC 92-010) was performed, based on information from SIL 299, and a new setpoint was calculated. The setpoint calculation confirmed that the existing nominal setpoint of -118.5 inches H_2O (indicated) was non-conservative and could have been below the Technical Specification value (-145.5 inches) by 15.34 inches during accident conditions (e.g., LOCA) that would result in high drywell temperatures.

On February 3, 1992, at 12 noon, due to the non-conservative setpoints, the following actions were taken:

1) The associated level instruments, NBI-LIS-72A, B, C, and D, were declared inoperable,

2) A plant shutdown, specified in the Technical Specifications in Definition 1.0.J, Limiting Conditions for Operation, was initiated,

3) Readjustment of the level instrument setpoints in accordance with Setpoint Change Request 92-09 was initiated, and

4) The need for a Temporary Waiver of Compliance was discussed with the NRC due to the uncertainty associated with the amount of time needed to readjust and verify the new instrument setpoint.

(6-89)

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

A. Event Description (Continued)

During discussions with the NRC regarding the need for a Temporary Waiver of Compliance, the acceptability of other similar Reactor Vessel Water Level instrument (NBI-LIS-57A and B and 58A and B) setpoints was discussed. The District committed to reviewing the setpoints for those instruments within twenty-four (24) hours to determine if a similar condition existed. Upon performing the evaluation, it was determined that the instrument inaccuracy caused by reference leg heating that could occur as a result of a LOCA had not been incorporated into the Setpoint Change Request issued in 1983 for these instruments when the Group 1 and 7 reactor vessel water level setpoints were reduced from ≥ -37 inches (Level 2) to ≥ - 145.5 inches. Thus, a non-conservative setpoint had also been implemented. A new setpoint calculation (NEDC 92-016) was performed based on the information from SIL 299, and two new setpoint change requests (92-010 for NBI-LIS-57A and B and 92-011 for NBI-LIS-58A and B) were initiated. The calculation confirmed that the existing nominal setpoint of -138.0 inches H_2O (indicated) was non-conservative and could also have been below the Technical Specification value (-145.5 inches) during accident conditions (e.g., LOCA) that resulted in high drywell temperatures.

On February 4, 1992, at 11:00 a.m., due to the non-conservative setpoints, the following actions were taken:

1) The associated level instruments, NBI-LIS-57A and B and NBI-LIS-58A and B, were declared inoperable,

2) A plant shutdown, in accordance with Note 2.A of Table 3.2.A of the Technical Specifications was initiated, and

3) Readjustment of the level instrument setpoints in accordance with Setpoint Change Requests 92-010 and 92-011 was initiated.

B. Plant Status

On February 3, 1992, prior to the initial event associated with level instruments NBI-LIS-72A,B,C, and D, the plant was in operation at full power. At 1:00 p.m., a load reduction was commenced to achieve Hot Shutdown within six hours as prescribed by Technical Specifications. By 5:00 p.m., the setpoint for three of the four instruments had been readjusted, and shortly thereafter, the Technical Specification Hot Shutdown LCO was exited. The setpoint for the fourth instrument was readjusted by 5:40 p.m. Approximately one half hour later, a return to full power commenced.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

B. Plant Status (Continued)

Power had been restored to approximately 80 percent when at 11:00 a.m., on February 4, 1992, the setpoint deficiency with level instruments NBI-LIS-57A and B and 58A and B was confirmed. Preparations for a plant shutdown to achieve Cold Shutdown in 24 hours in accordance with Technical Specification requirements were made, and within an hour, the second load reduction commenced. By 4:30 p.m., the setpoint for all four instruments had been readjusted. At 6:10 p.m., following confirmation that all required actions had been completed, the Technical Specification LCO was exited and preparations were made to return the plant to full power operation.

C. Basis for Report

The non-conservative setpoint deficiency for all eight of these instruments was determined to be a condition prohibited by Technical Specifications, reportable in accordance with 10CFR50.73(a)(2)(i)(B). Additionally, under the conditions specified in SIL 299, the lowest indicated Reactor Vessel Water Level could have been only -114 inches. Since the existing setpoints for all eight level instruments were lower than this value, the setpoint deficiency is considered to be reportable in accordance with the following additional criteria:

10CFR50.73(a)(2)(ii), an event or condition that resulted in the plant including its principal safety barriers being seriously degraded (lack of automatic initiation of the Group 1 and 7 Isolations), and

10CFR50.73(a)(2)(v)(C) and (D) and 10CFR50.73(a)(2)(vii)(C) and (D), an event or condition that alone could have prevented the fulfillment of the safety function of structures or systems needed to control the release of radioactive materials and mitigate the consequences of an accident.

D. Cause

The principal root cause for the setpoint deficiency is personnel error. At the time when the setpoint change request for level instruments NBI-LIS-72A,B,C, and D was initiated, an informal calculation was generated. This informal calculation contained various errors associated with the values used to formulate the setpoint. In the case of level instruments NBI-LIS-57A and B and 58A and B, the personnel involved should have compared the new setpoint to the other Level 1 setpoint, and resolved the apparent discrepancy.

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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D. Cause (Continued)

A contributing root cause for the setpoint deficiency is procedure deficiency. In the case of level instruments NBI-LIS-72A,B,C, and D, when the setpoint was first evaluated for the effects of high drywell temperature, the setpoint methodology did not include any requirements for design basis review. With regard to the setpoint for level instruments NBI-LIS-57A and B and 58A and B, had a formal setpoint calculation methodology existed, a design basis review would have resulted in determining that the guidance provided in SIL 299 was applicable.

Finally, with regard to the setpoint deficiency associated with level instruments NBI-LIS-57A and B and 58A and B, an additional contributing root cause (communications deficiency) has been assigned. This cause is considered appropriate due to the lack of communications from General Electric concerning the applicability of SIL 299 to the Group 1 and 7 Isolation instruments setpoint change from Level 2 (≥ -37 inches) to Level 1 (≥ -145.5 inches), associated with Mark I Containment changes.

E. Safety Significance

Large changes in drywell temperature, such as those associated with a LOCA, can result in differences between the measured (indicated) and actual reactor vessel water level. This issue was originally described in General Electric's Service Information Letter (SIL) No. 299, "High Drywell Temperature Effect on Reactor Vessel Water Level Instrumentation", issued July 25, 1979. With respect to Yarway water columns used at CNS, the actual level indication changes due to increasing temperature occur rather slowly, because the thermal constant of the Yarway reference leg is calculated to be 20 to 30 minutes.

With regard to level instruments NBI-LIS-72A,B,C, and D, the Reactor Water Level 1 (Low-Low-Low) initiates the Residual Heat Removal (RHR) System in the Low Pressure Coolant Injection (LPCI) mode of operation, initiates Core Spray (CS), satisfies a portion of the Automatic Depressurization System (ADS) logic, and starts the standby Diesel Generators (DGs). The Diesel Generators are started to ensure that the Emergency Core Cooling Systems (ECCSs) are available during a coincident Loss of Off-Site Power. The trip signals for Reactor Water Level 1 are set high enough to allow time for the low pressure core flooding systems to actuate or the reactor vessel to depressurize, if necessary, by actuation of ADS. The above mentioned Emergency Core Cooling Systems are used to insure that fuel cladding integrity is maintained under postulated Loss-of-Coolant Accident (LOCA) conditions.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

E. Safety Significance (Continued)

The Reactor Water Level 1 signal from NBI-LIS-57A and B and 58A and B initiates closure of the Main Steam Isolation Valves (MSIVs) and Main Steam Line Drain Valves (Group 1) and closure of the Reactor Water Sample Valves (Group 7). These isolations function to maintain coolant inventory in the reactor vessel and limit the release of radioactive material in the event of gross fuel failure.

The drywell temperature related events of concern are small line breaks in the drywell. Analysis of those events shows that the diverse parameter, high drywell pressure, will initiate the RHR System in the LPCI mode of operation and the CS System before Reactor Water Level 2 (Low-Low) or Level 1 is reached. It should be noted that these low pressure systems of ECCS cannot inject into the reactor vessel until reactor pressure is below their system operating pressures (injection valve interlock is 400 psig).

The high drywell pressure signal will also initiate the DGs and the High Pressure Coolant Injection (HPCI) System. It should also be noted that the Reactor Core Isolation Cooling (RCIC) System would automatically initiate early in the LOCA scenario. This system is initiated at Level 2 which is not affected by high drywell temperature because Low-Low Level is reached before significant drywell heatup occurs.

The underlying concern addressed by SIL 299 is that the actual water level may fall below the lower instrument line tap when the high drywell temperature condition exists. If the water level falls below this tap the connected instruments will not sense further level decreases. At CNS, the control room indicator would show a level of approximately -114 inches under the conditions postulated in SIL 299. Therefore, there exists the potential that the level trips will not occur due to the effect that high drywell temperatures could have on the Yarway level instruments.

As specified in the Technical Specifications, the Reactor Water Level 1 trip signals generated by NBI-LIS-72A,B,C, and D are to be set ≥ 19 inches above the top of active fuel (TAF), or ≥-145.5 inches indicated level. In the transient analyses for the reload licensing submittal (Supplement Reload Licensing Submittal for Cooper Nuclear Station, Reload 14, Cycle 15), CNS is analyzed for a reactor vessel water level initiation signal as low as 0 inches above TAF. Due to the fact, however, that under the conditions postulated by the SIL, indicated reactor vessel water level might not decrease to the level setpoint of -118.5 inches (indicated) that existed, automatic actuation of ADS would not have been assured.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

E. Safety Significance (Continued)

The Reactor Water Level 1 Trip signals generated by NBI-LIS-57A and B and 58A and B, are also specified by the Technical Specifications to be set ≥ 19 inches above TAF, or ≥-145.5 inches indicated level. General Electric document NEDE-22197 "Low-Low Set Relief Logic System and Lower MSIV Water Level Trip for CNS", justified lowering the Group 1 and 7 Isolation setpoints on Low Reactor Water Level, from Level 2 to Level 1. As previously noted, however, the level instruments setpoint had not been adjusted for the effects of drywell heating when the setpoint had been changed. This was because the concern expressed in SIL 299 had not been recognized as being applicable. With the level setpoint of -138 inches (indicated) that existed, automatic actuation of the Group 1 and 7 Isolations would not have been assured.

F. Safety Implications

Per SIL 299 the reference leg heating concerns are only relative to a small break LOCA inside containment that results in drywell temperature being raised beyond the ranges for which the instruments are calibrated. The specific scenario of concern is a small break LOCA, coincident with a loss of off-site power (resulting in the loss of feedwater), where HPCI is inoperable and where RCIC either trips after initiation due, for example, to high turbine exhaust pressure (SIL 299, Supplement 1) or is also inoperable. The probability of occurrence of this particular scenario is quite low due to the multiple failures that are required (pipe break, loss of feedwater due to loss of off-site power, HPCI inoperable, and RCIC inoperable or tripped).

Since all LOCA's inside containment will result in high drywell pressure before low water level is reached, LPCI, CS, and DG will all start (HPCI assumed inoperable) during a LOCA regardless of temperature effects on water level instrumentation. While the Yarway level instrumentation will be affected by the drywell temperature increase, alternate indications of reactor water level from newer wide range water level instrumentation (NBI-LI-85A, NBI-LI-85B, NBI-LI-91A, NBI-LI-91B, NBI-LI-91C, NBI-LI-92) are available to the operator. Reference leg injection from which correct reactor water level indication can be achieved using correction factors in the Emergency Operating Procedures is provided for these instruments. Emergency Operating Procedure guidelines require automatic ADS override for all accident scenarios when the ADS timer is activated (see Safety Evaluation of "BWR Owners' Group - Emergency Procedure Guideline, Revision 4" NEDO-31331, March 1987). The slow heatup of the instrument lines would allow the operator to follow the Emergency Operating Procedures (EOPs) and manually actuate the Safety Relief Valves (SRVs), as required. Thus, plant safety would be assured even though automatic initiation of ADS had been overridden.

(6-89)

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

F. Safety Implications (Continued)

As previously noted, entry into the EOPs will occur well before high drywell temperature affects reactor vessel level instrumentation. The EOPs also specify ensuring that all required Group Isolations have occurred. The slow heatup of the instrument lines would allow the operator to follow the EOPs and manually isolate the MSIV's, Main Steam Line Drain Valves, and Reactor Water Sample Valves, if required. As before, plant safety would also be assured even though automatic isolation of Groups 1 and 7 might not have occurred.

G. Corrective Action

As specified in Section A, Event Description, immediate corrective action was taken to comply with applicable Technical Specification LCOs and reset the level instruments to an acceptable value based upon the concerns addressed in GE SIL 299. The setpoint calculations were performed in accordance with, and consistent with, the setpoint methodology prescribed in CNS Procedure 3.26, Instrument Setpoint and Channel Error Calculation Methodology.

The existing revision of CNS Procedure 3.26, approved August 6, 1991, requires independent design basis review and/or setpoint calculations for new setpoint changes. The setpoint calculations conform with the GE Setpoint Methodology. Therefore, future personnel errors of the type that occurred are not expected. The new procedure and setpoint methodology specifically calls for possible error terms, (e.g., high temperature effects), which must either be incorporated into the new setpoint or dismissed with adequate justification.

During the February 3, 1992 discussion with NRC related to the need for a Temporary Waiver of Compliance, the District committed to review all remaining Reactor Water Level instrumentation setpoint calculations by March 4 to ensure conservative setting limits have been implemented. This review is complete and has not revealed any further Technical Specification violations associated with Reactor Vessel Water level instrument setpoints.

Finally, with regard to the communications concern, General Electric has indicated that they will issue another supplement to SIL 299 to specifically address inclusion of high drywell temperature affects on the MSIV closure setpoint for those BWR/4 plants that changed the Technical Specification for this setpoint from Level 2 to Level 1.

H. Similar Events

None.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Point Beach Nuclear Plant, Unit 2	0 5 0 0 0 3 0 1	1 OF 1 0

TITLE (4): One Train of Safety Injection & Containment Spray Inoperable

EVENT DATE (5) Month	Day	Year	LER NUMBER (6) Year	Sequential Number	Revision Number	REPORT DATE (7) Month	Day	Year	OTHER FACILITIES INVOLVED (8) Facility Names	Docket Number(s)
0 9	1 8	9 2	9 2	– 0 0 3 –	0 1	1 1	0 5	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N
POWER LEVEL (10)	1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER Area Code	
N. L. Hoefert, Manager-Operations	4 1 4	7 5 5 - 2 3 2 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
E	B E	P	1 0 7 5	X					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	Month	Day	Year
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

ABSTRACT

On September 18, 1992, at 0804, quarterly test IT-06, "Containment Spray Pumps And Valves, Unit 2," was commenced on the "A" train of the containment spray system. This test satisfies the testing requirements for the containment spray system as defined in the Technical Specifications or the ASME Boiler and Pressure Vessel Code, Section XI, "Rules For Inservice Inspection Of Nuclear Power Plant Components." Testing determined that the pump was inoperable. The pump was disassembled. A foam rubber plug was discovered blocking the pump suction. The plug was removed and the pump tested satisfactorily. The plug was determined to have most likely been placed in the residual heat removal system, in a location where under certain post-accident modes of operation, Train A of the containment spray or safety injection systems was inoperable. This condition likely existed during the entire operating cycle. Subsequent testing of the residual heat removal, safety injection and containment spray systems in both PBNP units verified that all systems, except the Unit 2 Train A residual heat removal, containment spray system and safety injection systems remained operable.

Attachment OP 16-5.1

Rev. 0

LER NO: 301/92-003

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EVENT DESCRIPTION

On September 17, 1992, Annual Test IT-545A, "Leakage Reductions and Preventive Maintenance Program Test of Containment Spray System, Unit 2," was performed on the Point Beach Nuclear Plant (PBNP) Unit 2, containment spray system. This test stipulates a series lineup of a residual heat removal (RHR) system train and the containment spray system train, with the containment spray pump (P-14) suction aligned to the same trains' residual heat removal pump (P-10) discharge. During this test, the residual heat removal pump takes suction from the refueling water storage tank (RWST) and the discharge from the containment spray pump recirculates to the RWST. The test was completed satisfactorily on both the "A" and "B" trains of the RHR and containment spray systems.

After completing the "B" train test, the operators reported a significant difference in the discharge pressures of the "A" train (P-14A) and "B" train (P-14B) containment spray pumps. The recorded discharge pressure for P-14A was approximately 270 psig. The recorded discharge pressure for P-14B was approximately 400 psig. No other abnormalities were noted that would indicate an operational problem with Containment Spray Pump P-14A. A maintenance work request (MWR) was issued on September 17, 1992, to check the calibration of the pressure gauges associated with Containment Spray Pump P-14A. Instrumentation and Control technicians performed the calibration check and found the gauges to be indicating accurately. The next shift of Operations personnel followed up by verifying that the gauge sensing lines were clear. ASME Section XI Quarterly Test IT-06, "Containment Spray Pumps and Valves, Unit 2," was previously scheduled to be performed on the morning of September 18, 1992. Further investigation of the difference in the pressure reading was deferred pending performance of this test.

On September 18, 1992, IT-06 was commenced on Unit 2 Containment Spray Pump P-14A at 0804. A 48-hour Limiting Condition of Operation (LCO) was entered for Containment Spray Pump P-14A in accordance with Technical Specification Section 15.3.3, "Emergency Core Cooling System, Auxiliary Cooling Systems, Air Recirculation Fan Coolers, and Containment Spray," Specification B.2.b, at the start of the test. This test consists of testing each train of the containment spray system individually, with the spray pump suction aligned to the RWST and the discharge recirculating back to the RWST. When Pump P-14A was started, an operator stationed at the pump noted the pump suction pressure was oscillating. The operator contacted the control room and directed them to secure the pump so that the pump casing could be vented. Spray Pump P-14A was secured and a small amount of air was removed from the pump during venting. Following completion of the venting, the control

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room was contacted and the pump restarted. The operator stationed at Pump P-14A noted that the pump discharge pressure was zero. He again contacted the control room and the pump was secured for venting. No air was removed from the pump casing during this second venting operation. The pump was subsequently started for the third time. The operator noted abnormal noise emanating from the pump. Test IT-06 was aborted at 1130 and system lineups returned to normal. Pump P-14A was secured and declared inoperable effective 0804.

Containment spray pump P-14A was disassembled and a foam rubber plug was found blocking the pump suction. The plug was removed and the pump reassembled. The pump was subsequently tested satisfactorily. Pump P-14A was declared operable at 1923 on September 19, 1992.

An incident investigation team was chartered to investigate this event and determine appropriate corrective action. The team could not conclusively determine the origin of the foam rubber plug. However, the team determined that the plug was most likely utilized as a temporary cleanliness barrier during modifications to the RHR system, performed during the fall 1991 Unit 2 refueling outage. These modifications installed full flow test lines in response to NRC Bulletin 88-04, "Potential Safety-Related Pump Loss." The investigation team concluded that the plug was most likely placed in the portion of the line between the Train A RHR pump discharge to the Train A containment spray pump and safety injection pump suction. In this location the foam rubber plug could have rendered the Train A containment spray pump or safety injection pump inoperable when operated with pump suction aligned to the RHR pump discharge.

EQUIPMENT DESCRIPTION

The purpose of the containment spray system is to provide water spray to the containment atmosphere following a design basis loss of coolant accident. This water spray serves to cool the containment atmosphere, thereby controlling the internal containment pressure, and to remove elemental iodine from the containment atmosphere should it be released to the containment atmosphere from damaged reactor fuel. The system is actuated on a Hi-Hi containment pressure signal. The containment spray system consists of two pumps, one spray additive tank, spray ring headers and nozzles inside containment and the necessary pumps and valves. The spray pumps normally take suction directly from the RWST.

The purpose of the safety injection system is to provide borated water to cool the reactor core and ensure reactor shutdown in response to a loss of coolant accident. The safety injection system consists of two

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pumps, concentrated boric acid storage tanks and the necessary piping and valves. The safety injection pumps normally take suction from the RWST.

The spray pumps and safety injection pumps can be aligned to take suction from the discharge of the RHR pumps during the long-term recirculation phase of reactor core and containment cooling. During this phase, the RHR pumps take suction from the containment sump and discharge through the RHR heat exchangers back to the reactor coolant system. A portion of this flow can be directed to the containment spray pump and safety injection pump suctions.

The containment spray pumps are horizontally mounted, single stage, centrifugal pumps designed to provide 1200 gpm at 300 psig. The pumps are manufactured by Ingersoll-Rand.

The safety injection pumps are horizontally mounted, multi-stage, centrifugal pumps manufactured by Byron-Jackson.

CAUSE

The spray pump impeller suction was blocked by a foam rubber plug. The origin of the plug could not be conclusively identified by the incident investigation team formed to investigate and recommend corrective actions following this event. However, the investigation team determined that the plug was most likely installed in a portion of the piping between the Unit 2 RHR Pump P-10A discharge and the Containment Spray Pump P-14A and Safety Injection Pump P-15A suctions as a temporary cleanliness barrier during system modifications performed during the Unit 2 Fall 1991 refueling outage, and subsequently not removed. This modification installed test lines allowing full flow testing of the RHR pumps. We committed to install this modification in response to potential concerns with operating pumps at less than manufacturer's recommended minimum flows identified in NRC Bulletin 88-04, "Potential Safety-Related Pump Loss."

CORRECTIVE ACTION

A. Immediate

1. The pump was declared inoperable. The 48-hour LCO in Technical Specification 15.3.3.B.2.b for Containment Spray Pump P-14A had been entered at the 0804 on September 18, 1992, at the start of Test IT-06.

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2. The Duty Shift Superintendent (DSS) and Duty and Call Superintendent (DCS) made a determination that there was reasonable assurance that the containment spray system Train B as well as the safety injection and RHR systems remained operable.

B. Short-Term

1. Maintenance Work Request (MWR) 924946 was initiated to investigate the failure of Containment Spray Pump P-14A. The "B" train containment spray pump, P-14B, was tested in accordance with the requirements of Technical Specification 15.3.3.B.2.b prior to initiating maintenance on P-14A. The test was successful.

2. Containment Spray Pump P-14A was disassembled and a foam rubber plug found in the impeller suction. The plug was removed, and the pump reassembled. A modified IT-545A, with flow through the RHR cross-connect line, and IT-06 were completed satisfactorily and the pump declared operable at 1210 on September 19, 1992.

3. The Unit 2 Train B Containment Spray Pump P-14B was tested utilizing IT-06A on September 18, 1992. The test was successful.

4. Additional tests of Unit 2 Containment Spray Pumps P-14A and P-14B were performed on September 19 and 20, 1992, utilizing a modified test procedure IT-545A and IT-06, to test the ability of the pumps to develop full flow with water supplied to the pump suction from the RHR system. The tests were completed satisfactorily.

5. On September 20, 1992, Test IT-06 was completed on Unit 2 Containment Spray Pumps P-14A and P-14B. The tests were completed satisfactorily.

6. A quorum of the Manager's Supervisory Staff (MSS) met on September 21, 1992, to review the event, the results of system testing, and to define additional necessary actions to ensure the operability of the containment spray, RHR and safety injection systems in both PBNP units. The staff determined that there was reasonable assurance that failure of the Unit 2, Train A containment spray pump did not indicate a common-mode failure problem and that these other systems remained operable. Similar modifications had been performed on the Unit 1 systems during the Unit 1 Spring 1992 refueling outage. Additional controls

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were implemented in the installation work plan (IWP) for this modification that were not included in the IWP for the Unit 2 modifications. These controls included additional sign-offs by Wisconsin Electric personnel ensuring system cleanliness.

7. The MSS prescribed a testing plan for the containment spray, RHR and safety injection systems in both units to provide additional assurance of the operability of these systems. The following tests were conducted and results achieved:

   a. Radiography was performed, on September 21, 1992, on a section of piping from the Unit 2 Train A RHR pump discharge to the Train A safety injection pump suction. No foreign material was detected.

   b. On September 21 and 22, 1992, Unit 2 Safety Injection Pumps P-15A and P-15B were tested with water supplied to the pump suction from the RHR system. The tests were completed satisfactorily.

   c. On September 23 and 24, 1992, testing was performed on the Unit 1 Containment Spray Pumps P-14A and P-14B with water supplied to the pump suction using the Unit 1 RHR system. The tests were completed satisfactorily.

   d. On September 24, 1992, testing was performed on the Unit 1 Safety Injection Pumps P-15A and P-15B with water supplied to the pump suction using the Unit 1 RHR system. The tests were completed satisfactorily.

8. An incident investigation team was chartered to investigate the event in order to determine the root cause. The team completed its investigation and reported to the MSS on October 5, 1992. The team could not conclusively identify the origin of the foreign material. The foam rubber plug was most likely placed into the piping during modifications performed during the Unit 2 fall refueling outage to install full flow test lines in the RHR, containment spray and safety injection systems.

9. Inspections are being performed during the current Unit 2 refueling outage, which commenced September 26, 1992, of portions of the Unit 2 containment spray, RHR and safety injection systems to identify any additional foreign material in these systems. The inspections include, to the extent practicable, the portions of the systems affected by the full flow test line modifications, as well as piping dead legs and

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flow restrictions. The inspections are being performed using a combination of borescopic examinations and radiography of the potentially affected piping sections. As of November 4, 1992, the majority of the planned examinations are complete. Small amounts of foreign material discovered are being removed from the system where practicable. Any material that cannot be recovered will be evaluated to ensure system operability. The inspections will be completed during the presently ongoing refueling outage.

10. The interior of the Unit 2 RWST has been inspected using a remote controlled minisub and video camera and by personnel entry. Minor debris was found. The debris included small pieces of tape, herculite, and other material. The debris will be removed prior to the end of the present refueling outage. The debris has been determined to not be safety significant. The MSS has concurred with this determination.

11. Management has reinforced to engineers and supervisors the importance of foreign material controls and the need for specific instructions in the Installation Work Procedures covering work for which they are responsible.

12. Quality Assurance personnel have reviewed all Unit 2 outage modification packages prior to installation specifically for system cleanliness concerns.

13. Maintenance Planners have been instructed to provide specific steps in work plans delineating the appropriate system and component cleanliness controls for the work. Supervisors are required to ensure the requirements of the work plans are properly implemented and documented.

14. The Manager-Maintenance is stressing foreign material control during his refueling outage related weekly meetings with maintenance personnel.

C. Long-Term

1. To address the root cause of foreign material introduction into a system during modification and maintenance, the incident investigation team recommended corrective actions in the areas of improved foreign material control and cleanliness inspections prior to system closing. These recommendations have been evaluated and upgrades to our foreign material control procedures are being implemented. Upgraded procedures are

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expected to be approved by November 13, 1992, with full implementation by December 31, 1992. These upgrades include:

a. Maintenance Instruction MI-32.4, "Guidelines For Exclusion Of Foreign Material From Plant Systems," is being replaced by a PBNP procedure to ensure that the procedural requirements are applied to all maintenance and modification work as appropriate.

b. The above procedure will also be upgraded to include foreign material control provisions based on the guidance in the preliminary draft of INPO Good Practice MA-315, "Exclusion Of Foreign Materials."

2. The maintenance group's job observation checklist will be upgraded to specifically include cleanliness controls as an observation area by November 30, 1992.

SAFETY ASSESSMENT

No design basis accident (DBA) presented in the PBNP Final Safety Analysis Report assumes the operation of the containment spray system during the containment sump recirculation mode of operation of the RHR system. PBNP Emergency Operating Procedures (EOPs) do not require the operation of a containment spray pump during the time that the RHR system is operating in the containment sump recirculation mode of operation. However, the EOPs do require the operators to evaluate the need for containment spray during containment sump recirculation. Testing of the containment spray pump performance in accordance with the Inservice Test Program since Unit 2 fall 1991 outage has not indicated any pump abnormalities with containment spray pump suction aligned to the RWST. Therefore, there is reasonable assurance that both trains of containment spray remained operable to perform their function as analyzed for all design basis accidents and as required by the PBNP EOPs.

Due to the suspected origin of the foam rubber plug, if the RHR system was used to provide suction to the safety injection system, the potential existed for the plug to block flow to the Train A safety injection pump (P-15A), thereby rendering Train A inoperable. Both trains of safety injection could not have been rendered inoperable due to train independence.

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The design basis accidents for PBNP that assume operation of a safety injection pump in the boosted injection mode or recirculation mode, in which the suction of a safety injection pump is aligned to the discharge of an RHR pump, are the small break loss of coolant accidents (SBLOCA) as analyzed in the PBNP FSAR. Performance testing of the safety injection pumps in accordance with the Inservice Test Program since the fall 1991 outage has not revealed any degradation in pump performance with pump suction aligned to the RWST. Therefore, there is reasonable assurance that both safety injection pumps would have performed their function as analyzed for all DBAs except a SBLOCA. One train of safety injection remained available and was operable in the event of a SBLOCA.

REPORTABILITY

The most probable scenario, the plug being placed in the RHR system during the Unit 2 fall 1991 refueling outage, results in the conclusion the PBNP Unit 2 was made critical and operated for approximately 10 months with an inoperable safety injection train. This is a violation of Technical Specification Section 15.3.3, "Emergency Core Cooling System, Auxiliary Cooling Systems, Air Recirculation Fan Coolers and Containment Spray," Specification A.1.c, which requires two safety injection pumps to be operable prior to taking a reactor critical. The Train A safety injection pump was also inoperable for greater than the allowed outage time in the limiting condition for operation. Specification A.2.b specifies a 24-hour allowed outage time for a safety injection pump. Therefore, this event is being reported in accordance with 10 CFR 50.73(a)(2)(i)(B), "any event or condition prohibited by the plant's Technical Specifications."

GENERIC IMPLICATIONS

Foreign material exclusion from systems which are opened for routine or non-routine maintenance and during modifications of systems is essential to ensure system operability. Foreign material introduced into a system during modification and maintenance must be controlled and the appropriate testing and inspections performed during and following modification and maintenance to ensure system operability.

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SIMILAR OCCURRENCES

A review for similar occurrences at PBNP has identified other incidents of foreign material intrusion into systems including the secondary side of the steam generators and the reactor coolant system. Evaluations which were performed for these previous events concluded that a safety concern did not result. None of the previous occurrences were found to be reportable.

Attachment QP 16-5.2

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
CRYSTAL RIVER UNIT 3	0 5 0 0 0 3 0 2	1 OF 0 6

TITLE (4) Relay Design Combined with Maintenance Trouble Shooting Leads to De-energized ES Busses, Reactor Trip, and Emergency Diesel Generator Start

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 3	2 7	9 2	9 2	— 0 0 1	— 0 0	0 4	2 7	9 2	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 8

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

[ ]	20.402(b)	[ ]	20.405(c)	[X]	50.73(a)(2)(iv)	[ ]	73.71(b)
[ ]	20.405(a)(1)(i)	[ ]	50.36(c)(1)	[ ]	50.73(a)(2)(v)	[ ]	73.71(c)
[ ]	20.405(a)(1)(ii)	[ ]	50.36(c)(2)	[ ]	50.73(a)(2)(vii)	[ ]	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
[ ]	20.405(a)(1)(iii)	[ ]	50.73(a)(2)(i)	[ ]	50.73(a)(2)(viii)(A)		
[ ]	20.405(a)(1)(iv)	[ ]	50.73(a)(2)(ii)	[ ]	50.73(a)(2)(viii)(B)		
[ ]	20.405(a)(1)(v)	[ ]	50.73(a)(2)(iii)	[ ]	50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER: AREA CODE	
W. A. STEPHENSON, NUCLEAR SAFETY SUPERVISOR	9 0 4	7 9 5 - 6 4 8 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On March 27, 1992, Crystal River Unit 3 was operating in MODE 1 at 98% Rated Thermal Power. Maintenance was in progress on the 'C' Vital Bus inverter. The inverter was malfunctioning and troubleshooting was in progress to determine the root cause of the problem. Leads had been lifted to partially isolate a constant voltage transformer internal to the inverter. At 1306, with the inverter output isolated, it was connected to the DC system input. This imposed a 350 volt peak-to-peak AC feedback signal on the DC system. This caused two relays which receive control power from the DC system to actuate, opening the feeder breakers and isolating the 230 KV Offsite Power Transformer. This de-energized the 4160 volt Engineered Safeguards (ES) busses, causing a reactor trip and an Emergency Diesel Generator start. A four hour report was made as required by 10CFR50.72(b)(2)(ii). This event is reportable under 10 CFR 50.73(a)(2)(iv). The relays, which are used for normal operation of the transformer feeder breakers and do not perform any protective relaying function, were disabled prior to restart to preclude future spurious trips.

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EVENT DESCRIPTION

On March 27, 1992, Crystal River Unit 3 was operating in MODE 1 at 98% Rated Thermal Power. Maintenance was in progress on the 'C' Vital Bus inverter [EE,INVT]. The inverter had malfunctioned as evidenced by blown fuses, and troubleshooting was in progress to determine the root cause of the problem.

A planned test configuration required that the Constant Voltage Transformer [EE,XFMR], (General Electric model number 9T91Y7244) within the inverter, be isolated by lifting the transformer leads. The inverter was then to be repowered by connection to the DC power supply [EE,UJX] by closing the DC input breaker. The inverter output remained isolated with the output breakers open. In the process of isolating the transformer, the electricians had only lifted one lead. While this did take it out of the circuit, it did not isolate the transformer. When the DC input breaker was closed, at 1308 pm, a 350 volt peak-to-peak square wave was superimposed on the DC system with respect to ground.

When the AC signal was imposed onto the DC voltage, the Offsite Power Transformer (OPT) [EL,XFMR] feeder breaker [EL,BKR] remote opening relays [EL,RLY] began to chatter. The chattering almost immediately picked up the contacts for the relay, sending an "OPEN" command to both breakers feeding the OPT. Both breakers opened, isolating the OPT from the 230 KV switchyard. This removed power from both Engineered Safeguards (ES) 4160 volt busses [JE,BU], as their normal alignment is to the OPT.

Both Emergency Diesel Generators (EDG), [EK,DG] started on bus undervoltage and powered their associated ES bus. The loss of ES 4160 volt bus power also de-energized the Control Rod Drive (CRD) motors [AA,MO] causing the rods to fully insert.

When the ES busses lost power, the normal control room overhead lights [LF] extinguished. The reactor operator looked at the reactor control panel, saw all the rods indicating fully inserted (the "rod full in" lights [AA,IL] were illuminated), announced a reactor trip and began the immediate actions of the reactor trip procedure. As required by procedure, the operator depressed the manual reactor trip pushbutton [JC,HS] which activated the "reactor trip confirmed" electronics, opened all the CRD breakers and tripped the turbine [SB,TRB]. At the time the turbine tripped, the Reactor Coolant System (RCS) pressure had decreased and approached the low pressure trip setpoint. The other licensed operator in the control room noted that pressurizer [AB,PZR] level had decreased and that no Make Up Pump (MUP) [CB,P] was running due to the initial loss of power. The operator manually started a MUP to control RCS inventory. The immediate post trip RCS temperature was somewhat lower than the expected post trip envelope; but timely operator response prevented this event from being classified as an "overcooling transient".

The reactor was stabilized in MODE 3, Hot Standby. The OPT was checked, re-powered, and the ES busses returned to normal alignment. The Diesel Generators were secured. The plant was cooled down to MODE 5 for maintenance work on control rod position indication prior to post-trip restart. A four hour report was made as required by 10CFR50.72(b)(2)(ii). This event is reportable under 10 CFR 50.73(a)(2)(iv).

CAUSE:

The root cause of this event was relay design combined with the specific off-normal alignment of equipment utilized in the troubleshooting effort. Failed components in the inverter may have additionally contributed to the event.

The emergency power scheme for Crystal River 3 incorporates several levels of power sources, one of these being four uninterruptible power supplies (UPS) [EE,UJX] called the Vital Busses. Each 120 volt AC bus is powered from two sources, the preferred being the Vital Bus Static Inverter [EE,INVT] (a dual input inverter), and the alternate source being the 480 volt ES bus via a dedicated voltage regulating transformer which bypasses the inverter.

The inverter normally rectifies 480 volt ES AC power to DC power. The inverter then inverts the DC power back to 120 volt AC power, through a constant voltage transformer [EE,XFMR] within the inverter, which supplies the load. If the AC power input is lost, the inverter will instantly draw power from banks of lead-acid batteries [EE,BTRY] providing DC power and invert that to 120 volt AC power for the Vital busses.

At the beginning of this event, the 'C' Vital bus was being supplied from the alternate source, the 480 volt ES bus and voltage regulating transformer, because the normal source, the inverter, was out of service for maintenance. Under the troubleshooting package, several test configurations were to be established in the inverter to locate the root cause of the problem. A test configuration required that the Constant Voltage Transformer [EE,XFMR], within the inverter, be isolated by lifting the transformer leads. The inverter was then to be connected to the DC power input by closing the DC input breaker. In the process of isolating the transformer, the electricians had only lifted one lead. While this did take it out of the circuit, it did not isolate the transformer. When the DC input breaker was closed, the partially isolated transformer induced an AC voltage (350 volts peak-to-peak) onto the DC bus. The only apparent effect was the tripping of the interposing relays used for normal OPT feeder breaker control.

Later testing showed a unique sensitivity in these relays, not shared generically throughout the DC power system. The relay actuation isolated the transformer and de-powered both ES 4160 volt busses. The loss of ES bus power caused the EDGs to start.

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EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50.0 HOURS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 2	— 0 0 1	— 0 0	0 4 OF 0 8

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT EVALUATION:

There were four main consequences of the loss of ES busses: first, both EDGs started on a valid undervoltage signal on the ES 4160 volt busses. Second, the motor driven Emergency Feedwater Pump (EFWP) auto started on ES bus undervoltage and EDG output breaker closure. Third, there was no power to the 'C' Vital Bus because it was normally aligned to the "A" ES 4160 volt bus/"A" ES 480 volt bus. Fourth, due to electrical alignment and effected busses, there was no power to the CRD motors and all control rods inserted on loss of power. Each of these consequences is discussed below.

The loss of power to the ES 4160 volt busses is accounted for in the design of the plant. Should power be lost to the busses, the EDGs auto start, come to synchronous speed and automatically power the ES bus loads. This action occurred as expected. The EDGs carried the ES 4160 bus loads until 1538 for the "B" EDG and until 1918 for the "A" EDG. The only anomaly in EDG performance was a leak in the jacket cooling system for the 'B' diesel.

The EFWP auto started, though there was no Emergency Feedwater Initiation and Control (EFIC) system actuation. This is as designed. Whenever there is an undervoltage on the ES 4160 volt busses followed by an EDG output breaker closure, the motor driven EFP (EFP-1) auto starts as the bus is block loaded by the EDG. The EFIC system and EFP-1 both worked as designed and expected.

The 'C' vital bus was deenergized because it was being fed by the ES 4160 volt bus/ES 480 volt bus. This bus powers the 'C' Channel of the Reactor Protection System (RPS). When the power to the system fails, the channel trips. In addition to the RPS, channel "C", the "C" Vital Bus also powers the Recall system, a passive data recording system, and an annunciator events recorder. The loss of power caused a loss of some transient information normally used to analyze an event.

The CRD motors lost power and all the control rods inserted into the core. The CRD motors are designed so that a sectioned roller nut engages a lead screw on the control rod. The roller nut sections are designed to be disengaged from the lead screw by springs. The roller nut is held in the engaged position by electromagnetic force. The roller nut is turned by progressing the electromagnetic field around the contol rod (moving in discrete steps), turning the roller nuts around the lead screw, raising and lowering the rod in the core. When power was lost to the CRD motors, the roller nuts disengaged and the rods inserted.

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50.0 HOURS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 2	0 0 1	0 0	0 5 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTIONS:

There were several corrective actions taken to preclude recurrence of this event. Prior to plant restart, the relays that send the remote open signal to the feeder breakers for the OPT were disabled. These relays provided no protective relaying functions so there is no loss of equipment protection. The feeder breakers can now be manually opened with control switches installed in the 230 KV switchyard prior to startup. A second action to monitor the DC bus for noise prior to reduced RCS inventory operations will be implemented during the upcoming refueling outage. Lastly, a human performance review will be conducted on the inverter troubleshooting evolution to determine if the risks should have been known or anticipated. The first action is already completed, the others are scheduled for completion by July 1, 1992.

PREVIOUS SIMILAR OCCURRENCES:

A similar actuation of these relays occurred during the mid-cycle 8 maintenance outage. See LER 91-10 for details of that event.

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U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER)

MAY [illegible] 92

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	1 OF 0 3

TITLE (4) Shutdown Required By Technical Specification 3.0.5 Due To Inoperable Emergency Diesel Generator and Inoperable Vital Bus Inverter

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 3	2 7	9 2	9 2	0 0 2	0 0	0 4	2 7	9 2	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): 3

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
W. A. Stephenson, Nuclear Safety Supervisor	AREA CODE 9 0 4 7 9 5 - 6 4 8 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	E K	P	F 0 1 0	YES					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO | EXPECTED SUBMISSION DATE (15) MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On March 27, 1992, Crystal River Unit 3 was shutdown in HOT STANDBY with a Reactor Coolant temperature of 515 degrees F and at a pressure of 2000 psig. The plant was being cooled down to approximately 300 degrees to allow work on the Position Indicator system of the Control Rod Drive Mechanisms. Vital Bus Inverter/Transformer 1C (VBIT-1C) was out of service. The Emergency Diesel Generators (EDG) were supplying power to the 4160V Engineered Safeguards (ES) busses. A loss of power to the 4160V ES Busses earlier in the day had resulted in a reactor trip and subsequent starting/loading of the EDGs. EDG-3B had a one gallon per hour leak from the Jacket Coolant Pump (DJP-2) seal prior to the trip. Following the autostart of EDG-3B, the nuclear shift supervisor decided the 'B' EDG was not "OPERABLE" because leakage from DJP-2 had increased to 2-3 gpm. The inoperability of EDG-3B with VBIT-1C out of service required the plant to enter Technical Specification 3.0.5. This required a cooldown to less than 200 degrees (MODE V). The jacket coolant leakage was caused by an end-of-life failure of elastomer components in the shaft seal on the DJP-2 of the diesel. The seals were replaced. An addition to the Preventative Maintenance program will cause replacement of the elastomer components before end-of-life failure occurs. This event is reportable under 10 CFR 50.73(a)(2)(i)(A and B).

NRC Form 366 (6-89)

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST 50.0 HOURS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 2	0 0 2	0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

On March 27, 1992, Crystal River Unit 3 was shutdown in MODE III (HOT STANDBY) with a Reactor Coolant System (RCS) temperature of 515 degrees F and a pressure of 2000 psig. A reactor trip had occurred earlier. The plant was being cooled down to approximately 300 degrees to accommodate work on the Position Indicator (PI) system of the Control Rod Drive Mechanisms (CRDM)[AA,ZI]. Vital Bus Inverter/Transformer 1C (VBIT-1C) [EE,INVT] was out of service and Technical Specification 3.8.2.1 Action Statement b applied. VBIT-1C is the normal power supply to the 'C' Vital Bus [EF,BU]. The reactor trip resulted from a loss of power to the Engineered Safeguards (ES) 4160V Busses [JE,BU] which also automatically started and loaded the Emergency Diesel Generators (EDG)[EK,DG]. Prior to the reactor trip, EDG-3B had a one gallon per hour (gph) leak from the jacket coolant pump (DJP-2) [EK,P]. The leakage was being made up regularly. Repair of the leak had been scheduled for the following week.

The Nuclear Shift Supervisor On Duty (NSSOD) was informed by an off-duty Shift Technical Advisor that leakage from the seal of DJP-2 had increased to approximately 2-3 gallons per minute (gpm) with the diesel running and make up to account for the increased leakage was difficult. At this point, the operability of EDG-3B was questioned. The ES Busses were placed on the Offsite Power Transformer (OPT) [EA,XFMR] and EDG-3B was shut down at 1538.

After the diesel was shutdown, the Auxiliary Building Operator reported that the leakage had decreased although the volume of the leak was higher than before the trip. Discussions were held with the Engineer responsible for the EDG system, the On Duty Shift Technical Advisor, and management personnel concerning condition and operability of EDG-3B. The NSSOD contacted the Director of Nuclear Plant Operations and informed him of the situation and that he was declaring EDG-3B inoperable at 2330 on March 27, 1992. The combination of VBIT-1C and EDG-3B being inoperable required that the plant enter Technical Specification 3.0.5. This required a cooldown into MODE V (Cold Shutdown). This event is reportable under 10 CFR 50.73(a)(2)(i)(A) and 10 CFR 50.73(a)(2)(i)(B).

CAUSE

Investigation revealed the shaft seals for DJP-2 contained elastomer O-rings and seal bellows. These components were original plant equipment and had worn out in service. The original 1 gph leak had been evaluated as not being sufficient to cause an operability problem prior to the repair scheduled for the following week. However, following the automatic start of EDG-3B on loss of the OPT, the leakage had increased to the point where makeup for the leak was no longer practical and the Nuclear Shift Supervisor determined the EDG was not OPERABLE. The EDG is manufactured by Colt Industries, model number 38TD8-1/8.

NRC FORM 366A
(6-89)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HOURS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON DC 20503.

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CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 2	— 0 0 2	— 0 0	0 3 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT EVALUATION

Imposition of the Action Statement for the inoperable EDG resulted in cooling down to less than 200 degrees (COLD SHUTDOWN) and instituting decay heat removal cooling as the method of cooling the core. There were no radioactive releases associated with placing the plant in MODE V. The evolution was accomplished using normal operating procedures. Emergency procedures were not required. Public health and safety was not compromised by the inoperability of the EDG because other power sources were available to power vital equipment. All vital equipment could have been retained in service by placing the 4160V ES Bus 3B on the Startup Transformer [EA,XFMR]. Each piece of equipment affected also has redundant equipment powered from the other EDG (EDG-3A).

CORRECTIVE ACTION

1. The leak was repaired on DJP-2A.
2. The Preventative Maintenance (PM) program will be modified to include routine replacement of the elastomer components in the seals of pumps on the EDGs.
3. Remaining pumps on EDG-3A and EDG-3B will be evaluated to determine if the elastomer seals require replacement.

PREVIOUS SIMILAR EVENTS

No previous similar events have occurred.

NRC Form 366A (6-89)

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
Zion Unit 2	0 5 0 0 0 3 0 4	1 of 0 5

Title (4)
Loss of Shutdown Cooling due to an Inadvertent Containment Spray

Event Date (5) Month	Day	Year	LER Number (6) Year	Sequential Number	Revision Number	Report Date (7) Month	Day	Year	Other Facilities Involved (8) Facility Names	Docket Number(s)
0 5	1 3	9 2	9 2	— 0 0 2 —	0 0	0 6	1 2	9 2		

OPERATING MODE (9)	5
POWER LEVEL (10)	0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR
(Check one or more of the following) (11)

__ 20.402(b)	__ 20.405(c)	X 50.73(a)(2)(iv)	__ 73.71(b)
__ 20.405(a)(1)(i)	__ 50.36(c)(1)	__ 50.73(a)(2)(v)	__ 73.71(c)
__ 20.405(a)(1)(ii)	__ 50.36(c)(2)	__ 50.73(a)(2)(vii)	__ Other (Specify in Abstract below and in Text)
__ 20.405(a)(1)(iii)	__ 50.73(a)(2)(i)	__ 50.73(a)(2)(viii)(A)	
__ 20.405(a)(1)(iv)	__ 50.73(a)(2)(ii)	__ 50.73(a)(2)(viii)(B)	
__ 20.405(a)(1)(v)	__ 50.73(a)(2)(iii)	__ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER
Ron Placko, Regulatory Assurance ext. 2287	AREA CODE 7 0 8 7 4 6 - 2 0 8 4

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
A				Y					

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
__ YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e, approximately fifteen single-space typewritten lines) (16)

On May 13, 1992 at approximately 0100, Unit 2 shift personnel began performing Periodic Test (PT)-2B-ST, Verification of Containment Recirculation Sump Valve Stroke and ECCS Continuity. After receiving numerous alarms and indications, control room personnel determined that a spray down of containment had occurred. The appropriate actions and notifications were made.

The cause of the loss of shutdown cooling and inadvertent containment spray was a personnel error. Neither the Unit Supervisor nor the Unit Operator ensured that the plant was in the correct condition as specified in the prerequisites of the PT. Since Unit 2 was in Cold Shutdown (Mode 5) at the time of this event and had been in this condition for approximately 37 days prior to the event, the safety significance of this event was minimal. However, this event held the potential for draining the Reactor Coolant System [AB] to approximately three and one-half feet of water above the top of the core if 2MOV-CS0049 had failed to shut and no operator actions were taken.

Corrective Actions include convening the Performance Review Board and intiating a remediation course for the individuals involved, reviewing all PTs to ensure that all prerequisites and precautions are clear and complete, evaluating the method of reviewing and scheduling surveillances during outages, and reviewing the unit supervisor qualification process.

ZDVRLER-481(2)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0
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Zion Unit 2	0 5 0 0 0 3 0 4	9 2	-	0 0 2	-	0 0	0 2 OF 0 5

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

A. CONDITION PRIOR TO EVENT

MODE 5 - Cold Shutdown RX Power 0% RCS [AB] Temperature/ Pressure 180 °F/ 380 psig

B. DESCRIPTION OF EVENT

On May 13, 1992, at approximately 0100 hours, Unit 2 was in Mode 5 with the shift personnel preparing to perform Periodic Test (PT)-2B-ST, Verification of Containment Recirculation Sump Valve Stroke and ECCS Continuity. This PT was scheduled to be performed through the general surveillance program (GSRV) to verify the operability of various Residual Heat Removal (RHR) [BP] and Containment Spray (CS) [BE] system valves.

After consulting the GSRV schedule, which showed the due date for PT-2B-ST as 5/22/92 and the critical date as 6/14/92, the unit supervisor assumed that since the PT was on the "5 day rolling window" schedule that this was a "normal" evolution/test. The unit supervisor only looked for additional manpower requirements before handing the PT to the unit operator. The unit supervisor had never performed this PT before. The unit operator wasn't sure if he had performed this particular PT before, but he was familiar with other PT's within this series. The unit operator stated that he did not feel rushed, had read the precautions, and assumed that the procedure would provide steps to depressurize RHR. He also reviewed the prerequisites and the applicability section and concluded that he could begin the procedure, after being informed by the unit supervisor that this PT was a normally scheduled PT. However, the unit operator started the PT without meeting all of the prerequisites or the precaution. In accordance with step 5.1.2, 2MOV-RH8700A, 2A RHR pump suction valve, was stroke timed closed, 2MOV-SI8811A, 2A RHR pump recirc suction valve, was stroked open, and 2MOV-CS0049, train A RHR to containment spray isolation valve, was started to be stroke timed open. At this time (0114:06) multiple alarms were received and the consensus in the control room was that this was classic indications of a Loss of Coolant Accident (LOCA) (Pressurizer level and pressure at 0). The Unit 2 Unit Operator secured the 2B Reactor Coolant Pump (RCP) in the pull to lock position at 0115:47. It was at this time that the unit supervisor and Fire Brigade were dispatched in response to a containment fire alarm (2B and 2D RCP area). Letdown flow was secured, charging flow was increased, and the Shift Engineer directed the operators to monitor RHR and thermocouples. At 0125 operators noted containment pressure increasing to 17" and containment humidity increasing to 70%, incore thermocouples rising and at that point they increased RHR flow. At 0130 operators confirmed the water came from the containment spray header, and verified no elevated radiation levels on any containment radiation monitors, by making a containment entry with radiation protection. At 0134 the 2B and 2E Reactor Containment Fan Coolers were secured from high speed and restarted to low speed. At 0145 it was noted that the pressurizer level and pressure (45 psi) were increasing, and at 0146 it was determined that opening 2MOV-CS0049 was the cause of the inadvertent containment spray. The operators then closed 2MOV-SI8811A and determined this was an Alert condition in accordance with Emergency Action Level (EAL) 2M and the duty Operating Engineer was informed at 0149. Pressurizer level and Reactor Coolant System (RCS) [AB] pressure were noted to be increasing and at 0200 Pressurizer level was 25%, RCS pressure was 80 psig and containment pressure at 15". At 0204 the EAL 2M notification commenced via the NARS system. RHR letdown was reestablished at 0210 with the plant stable at 85 psig and 157 degrees farenheit. At 0216 the Generating Station Emergency Plan (GSEP) was terminated, the ENS worksheets were completed and notification was made. At 0225 the operators noted that control board indications were functioning properly and that no indication of the effects of the spray were evident. The lineup was restored to that prior to starting PT-2B-ST at 0310.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION							Form Rev 2.0
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Zion Unit 2	0 5 0 0 0 3 0 4	9 2	-	0 0 2	-	0 0	0 3 OF 0 5

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

C. APPARENT CAUSE OF THE EVENT

The cause of the inadvertent containment spray was a personnel error. Neither the Unit Supervisor nor the Unit Operator ensured that the plant was in the correct condition as specified in the prerequisites of the PT. A contributing cause to this event was a procedural deficiency. PT-2B-ST is technically correct, but the Prerequisites section of the PT does not specifically state the requirements for Section 5.1. The mode requirements for all other sections are specifically addressed, but the performer of the PT is left to assume that since mode 6 is not addressed, the PT cannot be performed in that mode.

D. SAFETY ANALYSIS OF EVENT

Unit 2 was in Cold Shutdown (Mode 5) at the time of this event and had been in this condition for approximately 37 days prior to the event. The RCS was being maintained at 180°F and 390# on RHR shutdown cooling.

The stroking of valve 2MOV-CS0049 in the plant conditions that existed at the time of the event caused several potentially significant consequences, including:

1) Loss of reactor coolant system inventory,
2) Momentary loss of Residual Heat Removal capability,
3) Damage to the seals of the single running Reactor Coolant Pump, and
4) Spray of equipment in containment with borated water.

The loss of RC inventory and RHR capability were both consequences of the flowpath that existed during the time that the valve 2MOV-CS0049 remained open. With this valve open, the discharge of the RHR pump was diverted to the CS Ring Header and sprayed into the containment atmosphere. Valve 2MOV-CS0049 was already reclosed per PT-2B-ST prior to the cause of the loss of inventory being identified. Closure of this valve terminated flow to the CS Ring Header and prevented further loss of RC inventory. In addition, letdown to the Chemical and Volume Control System was manually isolated and charging flow increased in an effort to restore pressurizer level. The resultant loss of 5557 gallons from the RCS inventory drained the Pressurizer and Pressurizer Surge Line, but only caused minimal (approximately 200 gallons) loss of vessel inventory. Normal pressurizer level was restored within one hour of the start of the event. RCS incore thermocouple temperature indication rose from 180°F to 198°F due to the interruption of RHR flow. RCS temperature never exceeded the 200°F criteria for maintaining Cold Shutdown. Normal makeup from the Refueling Water Storage Tank (RWST) through the charging system provided adequate capability for restoring Pressurizer level.

The 2B RCP was in operation at the time of this event. The rapid depressurization of the RCS caused the pump rotating element to drop due to the induced hydraulic imbalance. This sudden drop caused the faces of the #1 seal to rub and become damaged. This damage to the #1 seal may have permitted excessive RCS leakage and loss of inventory in a worst case. However, the #2 seal remained intact and is designed to provide a boundary to full RCS pressure if the #1 seal is damaged. In this case, the RCS was at a sufficiently low pressure that the 2B RCP seal pressure boundary was not challenged and no external seal leakage was noted. Therefore, there is no safety significance due to the damage to the 2B RCP #1 seals which occurred during this event.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0		
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)						Page (3)		
		Year	///	Sequential Number	///	Revision Number				
Zion Unit 2	0 5 0 0 0 3 0 4	9 2	-	0 0 2	-	0 0		0 4	OF	0 5

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

D. SAFETY ANALYSIS OF EVENT (Continued)

The effects of the borated water that was discharged into the containment through the CS Ring Header did not impact the safe operation of the plant. The equipment in containment that provides a safety function is qualified for post-LOCA environmental conditions which are far more severe than those resulting from this spray event. A walkdown of the containment following the event identified numerous junction boxes that contained small amounts of water which were later dried and cleaned. Most exposed surfaces were wetted by the spray. No items of significance to the safety of the plant in Cold Shutdown were noted. The spray did cause a fire alarm in containment to be annunciated during the event, but this was later determined to be spurious. The impingement of borated water on equipment in containment did not impact the safety of the plant since the Unit was in Mode 5, Cold Shutdown, at the time of the event. All affected items will be dried and repaired prior to unit startup to ensure all equipment in containment is available to support plant operation. Extensive steam cleaning or hand cleaning was done to remove boric acid residue from exposed surfaces.

If valve 2MOV-CS0049 had failed to reclose, it is postulated that the loss of inventory from the RCS would have continued until vessel level reached the bottom of the hot legs or until the operators secured the RHR system. In the event that the vessel water level reached the bottom of the hot legs, approximately three and one-half feet of water would have remained above the top of the core. Makeup capability from the RWST through the charging system would have provided the Operators with a means for restoring vessel level. This makeup water also would help maintain core temperature until the A RHR train was able to be isolated and the B RHR train placed in service to restore shutdown cooling. Restoration of vessel level via charging and isolation of the affected RHR train would permit a return to stable plant operation following this worst-case scenario.

At no time did a condition exist that required mitigation by any of the plant emergency systems. It should be noted that containment integrity was in place throughout the event. The health and safety of the public were not affected by this event. A GSEP Alert was declared as a conservative measure in response to the event.

E. CORRECTIVE ACTIONS

1. The Operating Department is currently evaluating previous events relative to personnel performance, and taking corrective actions as deemed appropriate.

2. The Operating Department will review all RHR PT's to ensure that relevant information (i.e., clarify applicability, RHR depressurization, control of crosstie valves, etc.) is included. (304-180-92-01601)

3. The Operating Department will review Mode requirements for the RHR PT's and compare them to GSRV to ensure that the GSRV requirements are correct. (304-180-92-01602)

4. Based on this event, the Station will perform an effectiveness review of their response to INPO SOER 82-04, Improper Alignment of Spray System to RHR System. (304-180-92-01603)

5. A review of GSRV to identify partial surveillances will be performed for the last two refuel/maintenance outages. Each partial surveillance will be evaluated to determine procedural adequacy. The purpose of this evaluation is to eliminate partial surveillances, where possible, due to inappropriate plant conditions. (304-180-92-01604)

6. The Performance Review Board was convened and specialized remedial training was performed for both individuals involved in this event. (304-180-92-01605)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION								Form Rev 2.0
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)						Page (3)
		Year	///	Sequential Number	///	Revision Number		
Zion Unit 2	0 5 0 0 0 3 0 4	9 2	-	0 0 2	-	0 0		0 5 OF 0 5

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

E. CORRECTIVE ACTIONS (Continued)

7. The Operating and Work Planning Departments will evaluate the method of reviewing and scheduling surveillances during outages. (304-180-92-01606)

8. The Operating Department and the Training Department will review the Unit Supervisor qualification process. (304-180-92-01607)

9. The Operating Department will define "complex evolution" as related to shift briefings in Zion Administrative Procedure (ZAP) 0, Conduct of Operations (304-180-92-01608)

F. PREVIOUS EVENTS

A search of the titles of the DVR/LER database was conducted using the keywords 'containment', 'spray' and 'inadvertent'. No similar events were found.

G. COMPONENT FAILURE DATA

None

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Prairie Island Nuclear Generating Plant Unit 2	0 5 0 0 0 3 0 6	1 OF 1 0

TITLE (4) Interruption of Ore Train of Residual Heat Removal During a Unit 2 Reactor Coolant System Draining Operation

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									PINGP Unit 1	0 5 0 0 0 2 8 2
0 2	2 0	9 2	9 2	— 0 0 2 —	0 1	0 9	1 6	9 2		0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	[ ] 20.402(b)	[ ] 20.405(c)	[ ] 50.73(a)(2)(iv)	[ ] 73.71(b)
		[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
		[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[XX] OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
		[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	Voluntary Report
		[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
.rne A Hunstad	6 1 2	3 8 8 - 1 1 2 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC TURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[XX] NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On February 20, 1992, Unit 2 was in the cold shutdown condition for a scheduled refueling and maintenance outage. Reactor Coolant System (RCS) temperature was being maintained at about 135 degrees F as indicated on core exit thermocouples. Water was being drained from the RCS to establish conditions for removing steam generator manways and installing steam generator nozzle dams in preparation for eddy current inspection of steam generator tubes. The RCS water level was allowed to decrease to too low a level and the inservice Residual Heat Removal (RHR) pump (Train B) began entraining air. The RHR pump was stopped, makeup water to the RCS was accomplished in accordance with procedures and the standby (Train A) RHR pump was placed in service for shutdown cooling. Although one core exit thermocouple reached 221.5 degrees F, the RCS average temperature remained below 200 degrees F. A Notification of Unusual Event was reported and immediately terminated because the event rapidly de-escalated to a non-reportable condition. Normal shutdown cooling flow was off for about 22 minutes. Train A RHR was available for cooling throughout this event, first via the Refueling Water Storage Tank (RWST), then in the normal shutdown cooling mode.

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U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Prairie Island Unit 2	0 5 0 0 0 3 0 6	9 2	— 0 0 2 —	0 1	0 2 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

On February 20, 1992, Unit 2 was in cold shutdown for refueling. Reactor Coolant System (RCS)(EIIS System Identifier AB) temperature was being maintained at about 135 degrees F, as indicated on core exit thermocouples, by Train B of the Residual Heat Removal System (RHR)(EIIS System Identifier BP). In preparation for inservice inspection of steam generators, plant operators were in the process of draining the Reactor Coolant System to the centerline of the Reactor Coolant System piping. This operation normally takes approximately 6 hours. The Reactor Coolant System was being drained from the loop drain to the Chemical and Volume Control System (CVCS) Holdup Tank (HUT) No. 121. In accordance with procedure D2, Reactor Coolant System Reduced Inventory Operation, the Reactor Coolant System pressure boundary was intact and was vented to the Pressurizer Relief Tank (PRT) by way of the pressurizer power-operated relief valves. The Reactor Coolant System was being pressurized with nitrogen to aid in draining. See attached Figure. An engineer was assigned to provide assistance to the operating crew; this is customary for this evolution. However, the engineer assigned did not have as much experience with reduced inventory operations as engineering personnel assigned to this task in the past. The engineer also had an assignment to complete a functional test on a computer-based Reactor Coolant System level alarm and display system that had been installed during its last refueling outage. A similar system was tested and used during the last Unit 1 Reactor Coolant System draining and reduced inventory operation. The functional test procedure contained a note which stated that the Reactor Coolant System nitrogen overpressure should be minimized so the electronic level indicators would come on scale as early as possible. This note was missed by the engineer. The control room operators were not aware of the test note.

The procedure being used for draining, D2, in effect states in several places that pressure should be maintained at about 6 psig, and that the pressure should be allowed to decay as water is drained so that the pressure is less than 1 psig when the water level reaches Reactor Coolant System loop centerline. However, no guidance on how to accomplish this is given. The procedure did not contain guidance on reducing the draining rate as the end point was approached nor on pausing occasionally to verify conditions.

Draining of the Reactor Coolant System was begun at 1704 hours, February 20, 1992. The Reactor Coolant System was being pressurized to about 6 psig using nitrogen. Near the end of the day shift, the draining was stopped to allow for shift change and turnover to the night crew. The night crew resumed draining at 1934. Reactor Coolant System level was being continuously monitored locally (in the containment building) by an operator observing a clear tube, referred to as

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

the "tygon tube". Since the top of this tube is open to containment atmosphere, any nitrogen overpressure in the Reactor Coolant System causes the level in the tube to be higher than the actual water level in the Reactor Coolant System, making corrections to the indicated level necessary. This correction for overpressure was being calculated by personnel in the control room, first by licensed operators and the engineer, later only by the licensed operators. Similarly, the computer-based Reactor Coolant System level on the computer display (ERCS-D2) is referenced to containment atmosphere but is corrected for Reactor Coolant System pressure by the computer.

The draining procedure provides a table of level correction values for Reactor Coolant System overpressures up to 1.5 psig. Since Reactor Coolant System overpressure was being maintained above 1.5 psig, many sequential manual calculations to correct indicated level were necessary. Occasionally, errors were made in the calculations necessary to correct the tygon tube indication and convert it to the reference point used for the centerline of the Reactor Coolant System loops. These errors were caused by rounding off the pressure input to the calculations to expedite the calculation process. The sensitivity to rounding off the pressure input was not realized by the operators. The elevated Reactor Coolant System overpressure also over-ranged the new level transmitters, causing the computer to display "FAIL" for these points. However, the reason that the level was not available on the control room display (ERCS-D2) was not known to the operators nor to the assigned engineer. As concern over the unavailability of level on ERCS-D2 increased, the engineer left the control room at the request of the shift manager to investigate and attempt to resolve the problem.

At about 2250 hours, the duty Shift Manager checked on the draining progress (as was done several times during the evolution by both the Shift Manager and Unit 2 Shift Supervisor) and calculated that it would take 32 minutes to reach Reactor Coolant System centerline at the current draining rate. This was announced to the operators. This determination was made by obtaining the level increase observed in the tank receiving the water (the Chemical and Volume Control Holdup Tank) and converting it from percent to gallons. In making this conversion the Shift Manager used tank book data that has subsequently been determined to be in error. This calculation overestimated the volume to be drained.

Shortly after 2300 hours a corrected tygon tube level of about 723 feet was calculated. This corresponds to a level 4 inches below the loop centerline and raised operators' concern. In a short time frame, another tygon tube level reading was obtained from one operator in containment to confirm the level. A second operator in containment was directed to vent the RHR pump suction header and a control room operator began to depressurize the Reactor Coolant System by

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92
ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Prairie Island Unit 2	0 5 0 0 0 3 0 6	9 2	0 0 2	0 1	0 4 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)

opening the pressurizer and reactor head vents. The operator venting the RHR suction reported the presence of air in the venting line. Also about this time the ERCS-D2 display was noted to have the level on scale and that the level was below the reactor coolant piping centerline. The operator who was venting the RHR pump suction was directed to close the Reactor Coolant System drain valves. A third operator in containment heard this order and closed the drain valves.

The Unit 2 Shift Supervisor heard the order to close the drain valves and went to the control area. The time was about 2308 hours. The Shift Supervisor observed that the No. 22 RHR Pump motor current and flow were fluctuating. RHR trouble alarms were being received on the ERCS. The Shift Manager was in the control area also and saw RHR pump suction pressure low and fluctuating. The operators also saw these indications. The Shift Supervisor promptly ordered that No. 22 RHR Pump be stopped. No. 22 RHR Pump was stopped at 2310:05 hours. No. 21 charging pump was started. The Shift Supervisor ordered entry into contingency procedure D2 AOP1, Loss of Coolant While in a Reduced Inventory Condition, to respond to the condition (the draindown procedure referred the operator to this contingency procedure if suction problems occurred). No. 22 Charging pump was started in accordance with D2 AOP1. As core exit temperatures increased to 190 degrees F, a transition step to emergency procedure 2E-4, Core Cooling Following Loss of RHR Flow, was encountered and procedure 2E-4 was entered. In accordance with 2E-4, the Refueling Water Storage Tank (RWST) was lined up to supply water to the Reactor Coolant System via the unaffected RHR pump (No. 21 RHR Pump). This lineup does not include any of the common suction piping from the Reactor Coolant System; therefore, air entrained by the No.22 RHR pump did not affect No 21 RHR Pump. No. 21 RHR Pump was started at 2325:57 hours. After the Reactor Coolant System water level was restored to approximately the reactor vessel flange level, makeup from the RWST was stopped. No. 21 RHR loop was then placed in service in the shutdown cooling mode at 2329:28 hours. The Reactor Coolant System was cooled down to a core exit temperature of about 135 degrees F at 2336 hours. A Notification of Unusual Event was reported and immediately terminated because the event rapidly de-escalated to a non-reportable condition.

<u>CAUSE OF THE EVENT</u>

PRIMARY CAUSES

1. Supervisory Methods - An appropriate level of in-task supervision was not properly determined prior to performing the task.

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APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Prairie Island Unit 2	0 5 0 0 0 3 0 6	9 2	— 0 0 2 —	0 1	0 5 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)

2. Work Organization/Planning - Sufficient engineering expertise was not continuously available to the control room personnel, as it had been in the past.

3. Written Communications

   - Procedure D2 did not provide adequate guidance on what pressure to maintain related to the volume drained, did not provide guidance on pauses in the draining process to assess plant conditions, and did not provide information regarding the sensitivity of the level correction calculation to rounding off input values. Procedure D2 did not provide sufficient detail to be used without expert technical assistance and close supervisory oversight.

   - The tank book contained an incorrect conversion factor for Chemical and Volume Control Holdup Tank level percent to gallons.

4. Interface Design/Equipment Condition - A nitrogen overpressure required local instrumentation readings to be correctec to obtain actual level. It also caused the electronic level instrumentation to be out of range at elevated pressures.

5. Verbal Communications - There was inadequate pre-job briefing.

6. Work Practices

   - A note in a work request procedure was not observed.

   - Administrative procedure SWI-O-34, Conduct of Off-Normal Activities, which spells out requirements for management oversight of infrequently performed evolutions, was not used.

SECONDARY CAUSES

7. Training/Qualification - Training provided did not contain sufficient detail on the nuances required for the draining evolution.

8. Change management - Effectiveness of SWI-O-34 implementation had not been validated since its approval three weeks earlier.

9. Resource management - The tank book is not a controlled document.

ANALYSIS OF THE EVENT

For the draining and reduced inventory evolution, seven pumps were available to provide makeup water to the core and five sources of power were being maintained. Outage activities that could affect these sources had been curtailed prior to the evolution. At all times at least one steam generator and one auxiliary feedwater pump were being maintained available for heat removal contingencies by procedure. With one steam generator available for decay heat removal, loss of RHR flow can be tolerated for more than several hours.

The maximum recorded core exit temperature during the event was 221.5 degrees F. At this point, the combination of the nitrogen pressure (3.2 psig) and the head of water above the fuel pins at that time (4.43 feet) prevented boiling. A review of the data shows that the maximum recorded core exit temperature remained less than the saturation temperature throughout the transient. The lowest water level reached during the transient was 3.74 feet above the top of the fuel pins.

The average temperature of the water in the reactor vessel did not exceed 200 degrees F. Therefore, the unit remained in the cold shutdown mode throughout the event. This conclusion is based on 3 independent methods of estimating Reactor Coolant System temperature.

An evaluation of the effects of the event on the fuel in the core was performed. Based on the relative temperatures and heatup rates during the event compared to normal operational values, it was concluded that the event had no adverse effects on the fuel. Also, Reactor Coolant System samples after the event showed a slight decrease in activity, consistent with the addition of makeup water.

The heatup rate of some portions of the water in the Reactor Coolant System exceeded the Technical Specification value of 60 degrees F per hour stated in paragraph 3.1.B.1.a.1. The action required for this condition specified in 3.1.B.1.b is to perform an engineering evaluation. A conservative evaluation of the Reactor Coolant System pressure boundary was completed assuming a step heatup of 80 degrees F. This evaluation showed that the structural integrity of the Reactor Coolant System remains acceptable for continued operation.

As a precautionary measure, all unnecessary personnel were evacuated from the containment building in accordance with procedures. Prior to the evacuation, the operators in containment were notified of the reason for the upcoming evacuation and were instructed to remain at their posts.

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Prairie Island Unit 2	0 5 0 0 0 3 0 6	9 2	— 0 0 2	— 0 1	0 7 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The Reactor Coolant System was intact throughout the event. Effluent radiation monitors showed no increase in readings. Air samples from containment showed no increase in radioactivity level. Therefore, no release of radioactivity to the environment occurred as a result of this event.

Based on the above, there was no effect on public health and safety.

This event is not reportable under 10 CFR Part 50, Section 50.73. This report is being provided because of the generic implications of this event.

CORRECTIVE ACTIONS

Actions Taken Specifically for the Unit 2 February 1992 Refueling:

1. Immediately after the incident the pressurizer manway was removed to vent the Reactor Coolant System to containment atmosphere to bring all level indications into agreement.

2. The level compensation due to PRT pressure was deleted from the ERCS-D2 display to allow all instruments to be referenced to containment atmosphere.

3. For this draining operation, administrative controls were added for all instruments that could have an effect on Reactor Coolant System level indication.

4. Procedure D2.3, Reactor Coolant System Reduced Inventory Operation while Vented to Containment Atmosphere, was written for one-time use to allow draining of the Reactor Coolant System to install steam generator nozzle dams. Highlights of the differences in this procedure from the original draining procedure are as follows:

   - A senior engineer experienced in reduced inventory operation was required to be present during the draining.

   - Shift personnel with no concurrent duties were assigned to perform the draining.

   - Shift management personnel with no other concurrent duties were required to supervise the draining.

   - D2.3 was reviewed in accordance with SWI-0-34, which spells out requirements for management oversight of infrequently performed evolutions.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Prairie Island Unit 2	0 5 0 0 0 3 0 6	9 2	— 0 0 2 —	0 1	0 8 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)

- Steps in the procedure specifically required stopping the draining to allow refocusing of the team prior to draining below the top of the Reactor Coolant System hot leg.

- Pre-job briefing requirements were spelled out in detail.

- Containment closure times were made consistent with the time to boiling rather than the time to core uncovery.

- Precautions were added to specifically address work around electrical equipment that could affect RHR.

5. New procedure 2D2.1 was developed for draining the Reactor Coolant System to remove the nozzle dams. This procedure had many of the same enhancements as D2.3.

Actions Taken to Prevent Future Occurrences:

6. Draining procedures have been removed from the approved procedure list to assure they are not used again until revised with the recommendations of the task force.

7. A Prairie Island multidisciplinary task force was formed to assess the event in detail and to assure all areas for improvement are extracted from the event.

8. Emergency Procedure 2E-4, Core Cooling Following Loss of RHR Flow, was changed as follows:

   - Entry condition thermocouple temperature was changed from 190 to 150 degrees F to allow earlier entry.

   - An entry condition based strictly on the operators' judgement was added to allow quicker inventory makeup.

   - Initial response strategies were changed to use the safety injection pumps earlier in the scenario, rather than relying on the limited flow of the charging pumps.

9. Emergency plan procedures for RHR interruption events were clarified.

10. All operations crews using the above procedures were trained on them.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Prairie Island Unit 2	0 5 0 0 0 3 0 6	9 2	— 0 0 2	— 0 1	0 9 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)

11. Requests have been initiated to review designs for draining the Reactor Coolant System which precludes going below mid-loop, and to review the thermo-hydraulics of the Reactor Coolant System during draining and during events when the Reactor Coolant System is not completely filled.

12. The Reactor Coolant System pressure boundary has been evaluated due to the heatup during the incident and found to be acceptable.

13. The Error Reduction Task Force has completed its event investigation.

14. Other procedures involving RHR manipulations were reviewed, and some changed, to be more conservative in the valving operations associated with RHR.

15. The tank book was removed from the control room and can only be used for information and not used for making safety related decisions.

16. Power Supply Quality Assurance has performed surveillances on both the Reactor Coolant System draining and the Modification package which installed the new Reduced Inventory equipment.

17. Operability assessments of No. 22 RHR Pump and surveillance testing have been performed to assure the pump was not damaged during the event.

A long-term action plan is being developed that will implement improvements in procedures, hardware, training, and management of draining operations and other critical functions. An action plan has been developed that contains a current list of the actions which are determined to be prudent to prevent recurrence. The action plan includes, as a minimum, those items listed in this report and those actions discussed in the following: the Augmented Inspection Team Inspection Report (Inspection Report 50-306/92005), our June 15, 1992 response to a Level III violation (Inspection Report 50-306/92006), the Enforcement Conference Inspection Report (Inspection Report 50-306/92009), and our June 1, 1992 response to a deviation (Inspection Report 50-306/92009).

FAILED COMPONENT IDENTIFICATION

None.

PREVIOUS SIMILAR EVENTS

There have been no previous similar events reported at Prairie Island.

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U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104
EXPIRES: 4/30/92

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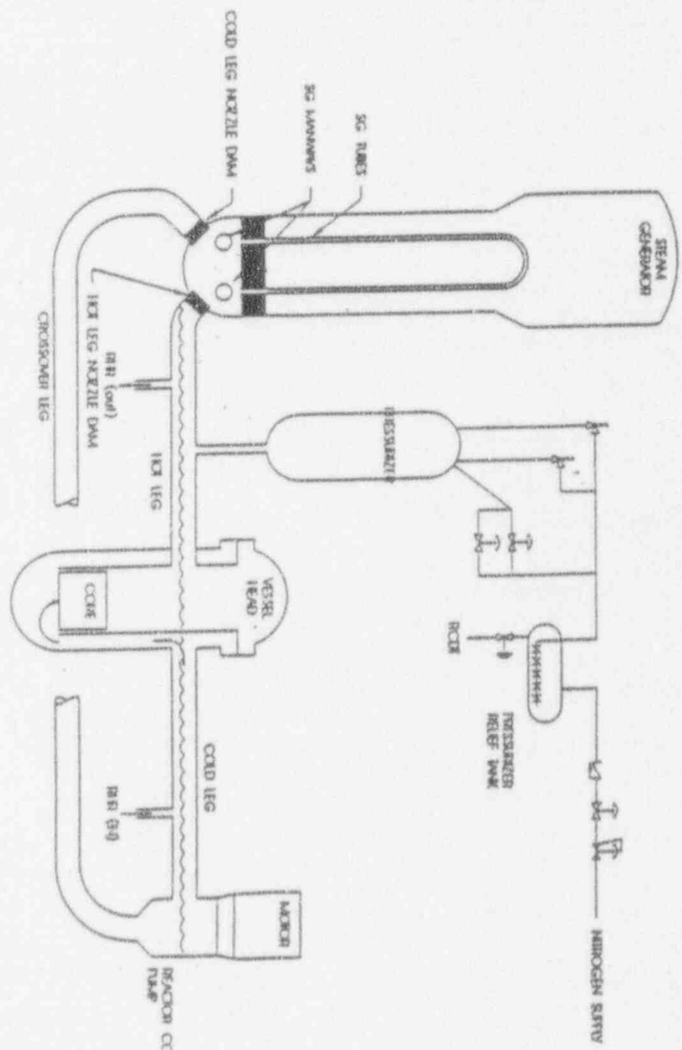
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Prairie Island Unit 2	0 5 0 0 0 3 0 6	9 2	0 0 2	0 1	1 0 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)



NRC FORM 366 (6-89)

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Salem Generating Station - Unit 2	0 5 0 0 0 3 1 1	1 OF 0 6

TITLE (4): Unrecognized loss of Overhead Annunciator System alarm indication

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
1 2	1 3	9 2	9 2	0 1 7	0 0	0 1	2 9	9 3		0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 9

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	Voluntary
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
M. J. Pollack - LER Coordinator	6 0 9	3 3 9 - 2 0 2 2

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On 12/13/92, at 2122 hours, Control Room personnel observed that Overhead Annunciators (OHAs) were not alarming upon receipt of alarm signals. The OHAs were returned to service at 2123 hours that day. They had stopped annunciating at 1946 hours. The Auxiliary Alarm System and other Control Room alarms and indicators continued to function. The root cause of this event is "Design, Manufacturing, Construction/Installation". The OHA System did not provide indication to the control room operator that the system had been reconfigured to a non operational mode preventing OHA alarm actuation. This manifested when Operations personnel did not follow procedures in assessing the cause of the spare OHA A-45 annunciations. The main controller will stop sending events to any connected display devices when a specific combination of commands are entered into the computer. Operations personnel involved in this event have been disciplined. This event will be reviewed with applicable personnel. This event will be reviewed by the Nuclear Training Center. A third party assessment of the Beta OHA System design modification is being performed. A design modification is being prepared to install an independent alarm circuitry system to monitor OHA operation. Procedure S2.OP-SO.ANN-0001 was revised. OHA System preventive maintenance and corrective maintenance procedures will be developed. Abnormal Operating Procedures, for OHA System partial or total loss, have been issued.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 2	DOCKET NUMBER	LER NUMBER	PAGE
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PLANT AND SYSTEM IDENTIFICATION:

Westinghouse - Pressurized Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as {xx}

IDENTIFICATION OF OCCURRENCE:

Unrecognized loss of Overhead Annunciator System alarm indication

Event Date: 12/13/92

Report Date: 1/29/93

This report was initiated by Incident Report No. 92-822.

CONDITIONS PRIOR TO OCCURRENCE:

Mode 1 Reactor Power 99% - Unit Load 1170 MWe

DESCRIPTION OF OCCURRENCE:

On December 13, 1992, at 2122 hours, Control Room personnel observed that Overhead Annunciators (OHAs) {IB} were not alarming upon receipt of alarm signals. As identified in the Sequence of Events section, the OHAs were returned to service at 2123 hours that day.

Investigation identified that the OHAs had stopped annunciating at 1946 hours (that day). The Auxiliary Alarm System (AAS) and other Control Room alarms and indicators continued to function. The Nuclear Regulatory Commission (NRC) was notified of the OHA System loss per Code of Federal Regulations 10CFR 50.72(b)(1)(v).

The OHA system electronics, for both Salem Units, were modified during the recently completed refueling outages (i.e., 1R10 design modification completed on June 12, 1992 and 2R6 design modification completed on March 26, 1992). This new system is microprocessor based. It is manufactured by Beta Products Division of Hathaway Industries.

SEQUENCE OF EVENTS:

Date	Time (Hours)	Event
12/12/92	~1500	OHA A-45, a spare alarm, annunciates - the alarm is reset
12/13/92	1200	OHA A-45 annunciates - the alarm is not cleared in support of further investigation

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 2	DOCKET NUMBER 5000311	LER NUMBER 92-017-00	PAGE 3 of 6

SEQUENCE OF EVENTS:

Date	Time (Hours)	Event
	~1800	Operations personnel access the Beta Remote Control Workstation to obtain information on OHA A-45
	1946	Beta System CRT display clock stops updating
	1955	AAS prints "Chilled Water Expansion Tank Level Low"; the associated OHA for "AUX ALM SYS PRINTER" does not alarm
		Operations responds to the AAS printout by directing an Equipment Operator to fill the tank; the absence of the OHA actuation is not recognized by Operations
	2008	Radiation Monitor channels 2R13A and 2R13B causes the "Radiation Alarm Process" alarm to actuate on the 2RP1 Control Room panel; OHA A-6, "RMS TRBL", does not alarm
		Operations personnel respond to the 2RP1 alarm
	2122	The "Chilled Water Expansion Tank Level Low" alarm returns to normal. This prints out on the AAS typewriter.
		NCO's recognize that the OHA A-41 does not annunciate and that the clock on the OHA CRT is indicating 1946 hours and not updating
	2123	Operations personnel reset Sequential Event Recorders (SERs) "A" and "B"; four (4) OHA alarms annunciate 1. Annunciator Logic; 2. RMS Trouble; 3. 104 Panel Trouble; and 4. AAS Printer.

APPARENT CAUSE OF OCCURRENCE:

The root cause of this event is "Design, Manufacturing, Construction/ Installation" (per NUREG 1022, "Licensee Event Report Program"). The OHA System did not contain adequate protection to prevent inadvertent access to software control functions which would place the system in an indefinite "lockup" condition. Investigation identified that the

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 2	DOCKET NUMBER 5000311	LER NUMBER 92-017-00	PAGE 4 of 6

APPARENT CAUSE OF OCCURRENCE: (cont'd)

main controller will stop sending events to any display devices that are connected when a specific combination of commands are entered into the computer. This occurs when the RCW is in the "PROCOM PLUS" program and the "Black Box" switch is in RCW-A (rather than SER-A) and the "Cntrl L" command is entered twice.

A causal factor of personnel error was also a contributor to the event. The software design inadequacy was manifested when Operations personnel did not follow procedure S2.OP-SO.ANN-0001(Q), "Overhead Annunciators Operation", in assessing the cause of the spare OHA A-45 annunciations. Contrary to the procedure, Operators did not ensure the "Black Box" switch was in the "SER A" position. The operator then loaded the PC installed "PROCOM" software program and inadvertently pressed the "Cntrl L" keys twice, instead of the "Alt L" keys, resulting in the controller being in a "wait for information from the keyboard" mode.

Causal factors associated with the root cause of this event include:

1. OHA System lockup was not readily detectable. The OHA System did not provide a direct means to inform Operations personnel that the SER had been reconfigured such that it was no longer processing inputs through to the alarm windows.

2. The design specification for the Beta OHA System did not adequately specify software security.

3. Procedure S2.OP-SO.ANN-0001(Q) was inadequate. It implied that the Beta OHA System could not be affected without use of a password.

ANALYSIS OF OCCURRENCE:

The control room OHA System consists of a Betalog 4100 (a high performance sequential events recording system) a Betalog 1500 (a microprocessor based serial input distributed annunciator system, and a RCW Computer with printer. The OHA consists of ten (10) overhead boxes with forty-eight (48) windows per box and a redundant Control Room CRT.

The OHA system electronics, for both Salem Units, were modified during the recently completed refueling outages (i.e., 1R10 design modification completed on June 12, 1992 and 2R6 design modification completed on March 26, 1992). This new system is microprocessor based. It is manufactured by Beta Products Division of Hathaway Industries. In addition to the principal design modification, the alarm window displays were rearranged, relabeled and system reflash capability modified. Also a CRT with keypad controls and new

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 2	DOCKET NUMBER	LER NUMBER	PAGE
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ANALYSIS OF OCCURRENCE: (cont'd)

pushbutton/switches was installed on the control console.

The Updated Final Safety Analysis Report (UFSAR) states that the OHA System is not safety related. System alarms are not part of the plant protection scheme and failures cannot affect protective system operation.

Those component failures which would result in OHA System annunciation, during OHA System inoperability, were addressed by Control Room personnel as appropriate. Therefore, failure of the OHA System did not affect the health or safety of the public.

Review of operator response to this event identified that a procedure for partial or total loss of the OHA System did not exist at the time of this event. Abnormal Operating Procedures, S1/S2.OP-AB.ANN-0001, which address this, have been issued.

CORRECTIVE ACTION:

Operations personnel involved in this event have been disciplined as appropriate.

This event will be reviewed with applicable Operations, Engineering and Technical Department personnel.

This event will be reviewed by the Nuclear Training Center for inclusion in applicable training programs.

The engineering department is performing a third party assessment of the Beta OHA System design modification. Appropriate corrective actions will be taken based on the assessment findings. The assessment includes the role of the Nuclear Computer Group's responsibilities for the review of design modifications and design specifications that involve digital systems. Other proposed digital system design change packages are being reassessed for adequacy of software design.

A design modification is being prepared to install an independent alarm circuitry system to monitor OHA operation. The design will provide OHA failure alarms in the Control Room.

Procedure S2.OP-SO.ANN-0001 (and the comparable Unit 1 procedure) was revised. It was revised to include resetting and testing the OHA System with an operability determination description.

OHA System preventive maintenance and corrective maintenance will be developed.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

Salem Generating Station Unit 2	DOCKET NUMBER 5000311	LER NUMBER 92-017-00	PAGE 6 of 6

CORRECTIVE ACTION: (cont'd)

Abnormal Operating Procedures, S1/S2.OP-AB.ANN-0001, have been issued which address operator response to OHA System partial or total loss.

General Manager -
Salem Operations

MJP:pc

SORC Mtg. 93-009

NRC Form 366 (6-89) U.S. NUCLEAR REGULATORY COMMISSION Approved OMB No. 3150-0104 Expires 4/30/92

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Sequoyah Nuclear Plant, Unit 1

DOCKET NUMBER (2): 0|5|0|0|0|3|2|7

PAGE (3): 1 OF 1|6

TITLE (4): Reactor Trips as a Result of a Switchyard Power Circuit Breaker Faul... , Unit 2 Entry Into Limiting Condition for Operation (LCO) 3.0.3 When Both Centrifugal Charging Pumps Were Removed From Service

EVENT DAY (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
1 2	3 1	9 2	9 2	0 2 7	0 0	0 2	0 1	9 3	Sequoyah, Unit 2	0 5 0 0 0 3 2 8
										0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following)(11)

__ 20.402(b)	__ 20.405(c)	XX 50.73(a)(2)(iv)	__ 73.71(
__ 20.405(a)(1)(i)	__ 50.36(c)(1)	XX 50.73(a)(2)(v)	__ 73.71(c)
__ 20.405(a)(1)(ii)	__ 50.36(c)(2)	__ 50.73(a)(2)(vii)	__ OTHER (Specify in Abstract below and in Text, NRC Form 366A)
__ 20.405(a)(1)(iii)	XX 50.73(a)(2)(i)	__ 50.73(a)(2)(viii)(A)	
__ 20.405(a)(1)(iv)	__ 50.73(a)(2)(ii)	__ 50.73(a)(2)(viii)(B)	
__ 20.405(a)(1)(v)	__ 50.73(a)(2)(iii)	__ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: Jan Bajraszewski, Compliance Licensing

TELEPHONE NUMBER: AREA CODE 6 1 5 | 8 4 3 - 7 7 4 9

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	E L	| | | 5 2	B 4 5 5	N					

SUPPLEMENTAL REPORT EXPECTED (14)

__ YES (If yes, complete EXPECTED SUBMISSION DATE) | X | NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On December 31, 1992, at approximately 2148 Eastern standard time (EST), with Units 1 and 2 in power operation at approximately 100 percent, both units received a reactor trip signal because of reactor coolant pump bus undervoltage. The reactor trips were followed by turbine trips. Undervoltage on the 6.9-kV shutdown boards initiated board load stripping, diesel generator (D/G) starts, and D/Gs tying onto their respective shutdown board. Electrical loads were appropriately sequenced back to the boards. Main feedwater isolated and auxiliary feedwater pumps started. Loss of power to a radiation monitor resulted in an auxiliary building isolation. With limited staffing in the Unit 2 main control room, recovery evolutions for Unit 2 resulted in isolation of centrifugal charging pump suction and removal of both centrifugal charging pumps from service. Unit 2 entered LCO 3.0.3 for approximately one minute until a suction flow path was reestablished. The cause of the event was an internal fault in a switchyard power circuit breaker resulting from inappropriate testing methodology. Corrective actions include strengthening of switchyard controls and increasing minimum Operations control room staffing.

LER NO: 327/92-027

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LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Sequoyah Nuclear Plant, Unit 1	0|5|0|0|0|3 |2 |7	9 |2	-- 0 | 2 | 7	-- 0 | 0	0| 2 OF |1 |6

TEXT (If more space is required, use additional NRC form 366A's) (17)

I. PLANT CONDITIONS

Units 1 and 2 were in power operation at approximately 100 percent power.

II. DESCRIPTION OF EVENT

A. Event

On December 31, 1992, at approximately 2148 Eastern standard time (EST), both units received a reactor trip signal because of reactor coolant pump bus undervoltage (EIIS Code EA). The undervoltage condition resulted from an internal fault in a new switchyard power circuit breaker (PCB) (EIIS Code FK) that had been in service approximately 11 minutes. Before the event, switchyard crews were in the process of placing the PCB in service. The PCB (PCB 5058) was in the 500-kV switchyard to intertie transformer position. Primary protective relays applicable to the PCB had been disabled by opening the associated trip cutout switches to facilitate differential relay circuit phasing.

The reactor trips were followed by turbine trips. Undervoltage on the 6.9-kV shutdown (S/D) boards (EIIS Code EB) initiated diesel generator (D/G) (EIIS Code EK) starts and loading onto their respective S/D boards. The S/D board loads were stripped and upon D/G loading, loads were appropriately sequenced back to the boards with the exception of the thermal barrier booster pumps (TBBPs), which did not restart. Main feedwater isolated and auxiliary feedwater (AFW) (EIIS Code BA) pumps started. Loss of power to a radiation monitor (EIIS Code IL) resulted in an auxiliary building isolation. The fault was cleared within 88 cycles, and offsite power to the start busses was restored. Following the trip the reactor coolant pumps (RCPs) transferred from the unit station service transformer (USST) to the common station service transformer (CSST) as designed; forced reactor coolant flow was maintained.

During the transient, Unit 2 recovery evolutions resulted in isolation of centrifugal charging pump (EIIS Code CB) suction and both pumps being removed from service. Unit 2 entered Limiting Condition for Operation (LCO) 3.0.3 for approximately one minute until a suction flow path was reestablished. Normal charging seal flow was not in-service during this time. Approximately 20 seconds into that minute, the TBBPs were manually started to provide RCP seal flow cooling.

The transmission system network consists of a 500-kV and a 161-kV switchyard at Sequoyah Nuclear Plant (SQN). Unit 1 is connected to the 500-kV network and Unit 2 is connected to the 161-kV network. These two networks are joined by the intertie transformer (Intertie Bank 5 - see page 16 of LER). PCB 5058 can be used as an intertie-transformer PCB and/or a spare-line PCB. Preferred electric power to the emergency busses and to start up and shut down the generating units at SQN is supplied by circuits from the 161-kV switchyard.

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LICENSEE EVENT REPORT (LER)
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Sequoyah Nuclear Plant, Unit 1	0|5|0|0|0|3|2|7	9|2	0|2|7	0|0	0|3 OF 1|6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

B. Inoperable Structures, Components, or Systems That Contributed to the Event

The handswitches for the TBBPs of both units were in the A-Auto position (in accordance with procedure) instead of the AP-Auto position (in accordance with design). The TBBPs were shed following the loss of offsite power indication, as designed. However, as a result of the handswitch position, the TBBPs did not reload upon D/G loading.

C. Dates and Approximate Times of Major Occurrences

November 20, 1992	Switchyard PCBs inadvertently tripped during tests to locate a ground on the 250-volt direct current control wiring. Two phases of one PCB closed automatically because of a malfunction and loss of air pressure. The remaining phase did not close. The PCB then failed.
November 23, 1992	The decision was made to replace PCB 5058 with a new 550-PM type ABB breaker. A PCB that had been purchased for the Jackson, Tennessee 500-kV substation was chosen as the replacement PCB. ABB was contacted to obtain the necessary information to install the breaker at SQN.
November 30, 1992	The replacement PCB arrived at SQN from Jackson, Tennessee. A design change notice and work order were prepared and approved to install the breaker.
December 14, 1992	PCB 5058 installation began under the guidance of a TVA-ABB factory-trained power maintenance specialist.
December 29, 1992	The Chickamauga load coordinator was informed that PCB 5058 would be ready to be placed in service on December 31, 1992. The breaker was satisfactorily factory and field tested (the breaker had not been energized) as required by the work order.
December 31, 1992 at 2137 EST	Following review and approval of the switching order and testing methodology by the main control room (MCR) staff, PCB 5058 was placed in service to be followed by verification of phasing on the differential relay circuit. The primary trip cut-out switches were placed in the open position and provided no primary relay protection for PCB 5058 during this timeframe. Secondary delayed relay protection was available and did operate after approximately 88 cycles.

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Sequoyah Nuclear Plant, Unit 1	0 5 0 0 0 3 2 7	9 2	0 2 7	0 0	0 4 OF 1 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

December 31, 1992 PCB 5058 faulted internally, resulting in breaker failure. From the annunciator printout, the first alarms to come in indicated oscillograph operation and opening of PCB 5074 (Plant Bowen line). The condenser circulating water pump motors tripped followed by alarms for overcurrent on Generator 1 exciter field, 161-kV supply voltage failure, station frequency excessive error, and undervoltage on the RCP bus.

Additional events during this first minute included:

1) Opening of the 500-kV switchyard PCBs and the intertie PCBs in the 161-kV switchyard.

2) Undervoltage on the 6.9-kV S/D boards resulted in the appropriate relays stripping the major equipment from the boards. This included the centrifugal charging pumps (CCPs) on both units, which subsequently resulted in letdown isolations.

3) Both units received a reactor trip signal because of RCP bus undervoltage. The reactor trips were followed by turbine trips and 161-kV bus voltage-failure alarms. Automatic transfer from USST to CSST was successful, and the 6.9-kV unit boards remained energized from offsite power. Undervoltage on the four 6.9-kV S/D boards initiated transfer to the D/Gs. The four D/Gs started; feeder breakers closed and energized their respective S/D boards.

4) An engineered safety feature (ESF) auxiliary building isolation actuated because of a loss of power to 0-RM-90-101.

5) The alarm for the Unit 1 ice condenser lower inlet doors opening was received.

6) Nonaccident equipment sequenced back on the S/D boards. Both CCPs restarted on each unit.

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Sequoyah Nuclear Plant, Unit 1	0 5 0 0 0 3 2 7	9 2	-- 0 2 7	-- 0 0	0 5 OF 1 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Unit 1 at 2150 EST	The operator took manual control of AFW (minimum average temperature [T_{avg}] was 542 degrees Fahrenheit [F]) by reducing the speed of the turbine-driven auxiliary feedwater pump (TDAFWP) and manually throttling the motor-driven auxiliary feedwater pump (MDAFWP) level control valves (LCVs). The letdown orifices were reopened followed by reestablishing the steam-dump operation. After the instrument mechanics (IMs) checked the P-4 contacts for the reactor trip breakers, the feedwater isolation was reset and steam generator blowdown was established.
Unit 2 at 2151 EST	The operator took manual control of the TDAFWP to bring the pump to minimum speed.
Unit 2 at approximately 2155 EST	The T_{avg} temperature had decreased to less than 540 degrees F. The assistant shift operations supervisor (ASOS) determined that boration was required. He directed boration through the blender at greater than 10 gallons per minute (gpm) with high concentration boration. The operator then took manual control of the MDAFWP LCVs to control the temperature decrease.
Unit 2 at 2208 EST	Suction to the CCPs swapped over from the volume control tank (VCT) to the refueling water storage tank (RWST) because level in the VCT had decreased to 7 percent. At that time, the ASOS realized that letdown had been previously isolated. The ASOS directed that one CCP be stopped. Since the blackout relays were sealed in, the pump was placed in pull-to-lock (P-T-L).
Unit 2 at 2209 EST	Letdown was reestablished.
Unit 2 at 2211 EST	After the reactor operator (RO) and ASOS verified sufficient VCT level, the VCT outlet valves were opened. The operator then closed the RWST valves. The operator observed that the VCT outlet valves were traveling closed. The second CCP was stopped and letdown automatically isolated. With both CCPs not in service, LCO 3.0.3 was entered. Approximately 20 seconds after the second CCP was stopped, the shift operations supervisor (SOS) started the TBBPs. The Unit 1 TBBPs were then started after the Unit 2 TBBPs.

LER NO: 327/92-027

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Sequoyah Nuclear Plant, Unit 1	0 5 0 0 0 3 2 7	9 2	-- 0 2 7	-- 0 0	0 6 OF 1 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Unit 2 at 2212 EST	VCT valves were opened, the second CCP was started, and letdown was reestablished. The handswitches for both the VCT and RWST valves were either placed in or verified to be in AP-AUTO position. LCO 3.0.3 was exited.
Unit 2 at 2313 EST	The 6.9-kV S/D boards were returned to normal offsite power.
January 1, 1993 at 0011 EST	Unit 2 was stabilized in Mode 3.
January 1, 1993 at 0013 EST	Unit 1 was stabilized in Mode 3.

D. Other Systems or Secondary Functions Affected

The low voltage condition resulted in the Units 1 and 2 condenser circulating water (CCW) pumps tripping. The loss of these pumps is not considered abnormal for this event. The unit boards sustained a voltage drop that would cause a drop in excitation voltage and result in a speed deviation trip or a power-factor deviation trip. CCW flow is necessary to maintain condenser vacuum and to provide an enable signal for steam dump controls.

E. Method of Discovery

The switchyard buzzers, reactor trips, and blackout sequence alarms were annunciated on the MCR panels. Oscillograph charts identified that a fault had occurred in the C-phase of PCB 5058, which was in the process of being placed in service.

F. Operator Actions

The operators promptly diagnosed the plant conditions and took actions necessary to stabilize the units in the hot standby condition (Mode 3).

Unit 1 MCR personnel (one ASOS and two ROs) responded as prescribed by emergency procedures. The secondary side of the plant was secured, and the operators took manual control of the TDAFWP and placed the motor-driven auxiliary MDAFWP LCVs in manual bypass mode. The plant responded as expected and the operators performed the designated actions of the procedures.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Sequoyah Nuclear Plant, Unit 1	0 5 0 0 0 3 2 7	9 2	— 0 2 7 —	0 0	0 7 OF 1 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Unit 2 MCR personnel (one ASOS and one RO) proceeded through the actions described by the emergency procedure. With only one RO, securing of the secondary side was delayed. The RO took manual control of the TDAFWP and reduced its speed to minimum. The MDAFWP LCVs were left in the auto position resulting in twice the AFW flow of that in Unit 1, resulting in a greater cooldown rate. With blowdown isolated, feedwater pumps tripped, main turbine tripped, and steam dumps not available, the effect of the higher AFW flow caused Unit 2 to cooldown to about 537 degrees F. The ASOS recognized that RCS boration was required if T_{avg} was less than 540 degrees F and made the decision to leave the MDAFWP LCVs in auto and borate first. The ASOS and RO discussed which flow path was to be used. The normal boration path was chosen because it was considered to require less operator intervention and monitoring than the emergency path. The ASOS made the decision to borate through the blender and directed the RO to initiate 135 gallons of high concentration (20,000 parts per minute) boration at greater than 10 gpm. The ASOS did not read the procedure and believed that the procedure allowed boration through the path chosen. The procedure required boration through the emergency boration path. The normal boration path was allowed only if flow could not be achieved through the emergency boration path. The decision to borate through the normal rather than emergency path, as required by the procedure, set up the sequence of events ultimately leading to the loss of both CCPs and charging RCP seal injection.

The ASOS had noted early in the transient that the component cooling system (CCS) TBBPs did not automatically start after the D/Gs energized the S/D boards. The ASOS did not direct manual starting of the TBBPs at that time because he did not have the resources available to evaluate the impact on D/G loading.

At the time of the reactor trip, the undervoltage condition had resulted in load stripping of the 6.9-kV S/D boards. The load shedding tripped off the running CCP. With no CCPs running, a letdown isolation automatically occurred. After the ASOS initiated boration and manual control of the MDAFP LCVs, an automatic swapover from the VCT to the RWST occurred as the level in the VCT reached 7 percent. At this time, the ASOS realized that letdown was isolated, and normal boration was only providing approximately 10 gpm makeup. After swapover, the ASOS directed the operator to stop the one CCP. The handswitch was placed in the P-T-L position to ensure that it would not immediately restart, since the blackout relays had not been reset. The SOS, ASOS, and RO had verified that no condition existed that would indicate the need for operation of both CCPs. Stopping the CCP was based on adequate RCS inventory, letdown isolation, and potential for equipment (CCPs and subsequently RCP seals) damage as a result of low indicated oil pressure on the CCPs and no running TBBPs. The ASOS directed the RO to reestablish letdown flow to restore VCT level.

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TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Sequoyah Nuclear Plant, Unit 1	0 5 0 0 0 3 2 7	9 2	0 2 7	0 0	0 8 OF 1 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The RO and ASOS observed VCT level indication increase and agreed that the VCT was capable of supporting sustained transfer of the CCP suction from the RWST back to the VCT to restore normal conditions. Handswitches for the VCT outlet valves were taken to A-Auto, to the OPEN position. When the RO observed the valves reaching the full open position (red lights), he took the handswitches to the AP-Auto position. The RO then took the RWST outlet valve handswitches to A-Auto and to the CLOSED position. The RO observed the valves reaching the full closed position (green lights). It is believed that the RWST valve handswitches were left in the A-Auto position. This evolution took place in approximately 18 seconds based on printouts.

At this point, the RO recalled the RWST valves being closed and the VCT valves being open. The RO stated that as he looked away from the handswitches, he noticed green and red lights on the VCT valves, indicating the valves traveling closed. The RWST valves remained closed with green lights. With the RWST valve handswitches left in the A-Auto rather than the AP-Auto position, automatic transfer back to the RWST did not occur when the VCT valves traveled closed. The RO called out the condition to the ASOS. Not knowing whether the VCT valves were partly closed or almost fully closed, the RO prepared to stop the running 2A-A CCP. With concern for potential imminent failure of the CCP on loss of suction, the ASOS directed the RO to stop the 2A-A CCP. The RO held the pump handswitch in the STOP position (not in P-T-L). When told by the ASOS that the second CCP was being stopped, the SOS manually started the TBBPs approximately 20 seconds after the 2A-A CCP was stopped. The VCT outlet valves were reopened and remained open, the handswitch for the 2A-A CCP was released, and the pump restarted approximately one minute after being stopped. Letdown was reestablished and the system stabilized.

G. Safety System Responses

Safety systems performed and plant parameters responded as expected for the reactor and turbine trips. Details of specific safety system responses are as follows:

Upon receipt of the trip signals, the S/D and control bank rods for both units dropped into the core and reactor power rapidly decreased as expected.

The RCPs for both units were in service during the transient and forced flow was maintained.

Main feedwater flow for both units terminated on the reactor trips. The AFW pumps for both units started as designed, and steam flow continued to the TDAFW pumps. The operator of each unit took manual control of the TDAFW pumps and MDAFW pumps as the transient progressed.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

The auxiliary building vent radiation monitor lost power at the start of the event. This equipment is powered from the instrument power distribution panel, which is not backed by the vital inverters. This condition resulted in a control room alarm "Auxiliary Building Vent Monitor Hi Rad" and was not a result of an actual high radiation condition. The equipment performed as expected.

The normal feeder to the 6.9-kV S/D boards is designed to open when its undervoltage relays sense less than 80 percent voltage for more than 0.5 seconds. After the 6.9-kV S/D board voltage had decreased to less than 70 percent undervoltage, a D/G start signal was generated. The load shedding occurred as expected. After each D/G reached the appropriate speed and voltage, the breaker that connects each D/G to the S/D board closed, and the load sequencing timers started. Loads were then automatically reconnected for a nonaccident loading sequence. During this event, the load shed/load sequence logic functioned as designed on the four S/D boards, with the exception of the TBBPs.

The TBBPs failed to start following S/D board reloading. The SOS took manual action to restart the TBBPs. Further investigations into the failure to start revealed that the handswitches for the pumps had been placed in the A-Auto position in accordance with procedure. With the handswitch in this position, the pumps will not start upon actuation of the blackout relays. The handswitch position described by procedure was found to be incorrect relative to design.

During the time that the S/D boards were without power, a control power alarm was received on D/G 1A-A and a low lube oil pressure alarm was received on the four D/Gs. The low lube oil pressure alarm was expected for the event and was cleared. The control power alarm was reviewed and found to be the result of the test pushbutton being depressed or momentarily shorted. This condition was evaluated and no D/G operability concerns were identified.

During this transient, Unit 1 RCS temperatures remained above the analysis value of 540 degrees F, relative to S/D margin. The FSAR or technical specification (TS) requirements were not violated.

During this transient, Unit 2 RCS temperatures dropped to approximately 537 degrees F. The cooldown on Unit 2 was greater than Unit 1 because of a delay in taking manual control of AFW as described in Section F. A boration of 10 gpm through the blender was initiated and was replaced by RWST water on VCT swapover. Calculations show that approximately 600 ppm boron was required to maintain adequate S/D margin for an RCS temperature of 537 degrees F. Boron concentration before the event was 735 ppm. The FSAR or TS requirements were not violated.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

Unit 1 pressurizer level was constant at approximately 57 percent before the event, sharply decreased to 33 percent (expected for the reactor trip while under load), and then settled to approximately 29 percent. The 29 percent level was reasonable for pressurizer level with two CCPs running, and letdown initially isolated. Actual and programmed levels returned to agreement upon stabilization of the plant and return to normal hot standby conditions.

Unit 2 pressurizer level was constant at approximately 59 percent before the event and then decreased upon the reactor trip to approximately 33 percent. Level subsequently increased to approximately 48 percent. Letdown was isolated when both CCPs were stopped as a result of S/D board load stripping and again later when both CCPs were stopped by operator action. Actual levels, posttrip, remained well above programmed levels principally because of the operation of both CCPs and the duration for which letdown was isolated. No challenges to any FSAR analysis limits were observed.

Except for a temporary upward trend on the Unit 1 upper containment radiation monitors, no perturbations were observed in containment pressure, temperature, or radiation. The exact cause for the increase in the particulate count rate could not be determined. Two plausible explanations of the rate increase are: (1) preexisting particulate activity that was disturbed upon restart of the radiation monitor (RM) pump, or (2) the restart of the upper compartment cooling fans after reloading on the S/D boards. Additionally, three Unit 1 lower ice condenser doors opened during the transient. The most likely cause for ice condenser door operation is the restart of the three lower compartment coolers (LCCs) after loading back on the S/D boards. The Unit 2 doors did not open; however, only two LCCs were restarted.

When the Unit 2 CCPs started, the red low oil pressure light illuminated on each of the pump handswitches. These low oil pressure lights remained illuminated when the CCPs were running. These lights cleared after the blackout relays were reset. An operator was dispatched to check the oil pressure on the CCPs locally. When he arrived, one CCP was in service and the oil pressure for that pump was normal. Troubleshooting verified that the circuitry associated with the low oil pressure light was installed in accordance with design requirements, and the auxiliary oil pump and light for the CCP worked as designed. An independent review was performed and no existing equipment deficiency was identified that could impact CCP operability.

III. CAUSE OF EVENT

A. Immediate Cause

The immediate cause of the event (ESF and RPS actuations) was an internal fault with the C-phase of the PCB that was being placed in service. This fault dropped bus voltages for both units through the intertie transformer below the undervoltage protection setpoints.

The immediate cause of the LCO 3.0.3 entry was the loss of CCP suction and the removal of both CCPs from service.

B. Root Cause

The root cause analysis for the internal fault of the PCB determined that the fault was the result of particle contamination of the gas insulating system. During breaker timing tests, the breaker appears to have been "pumped" (the breaker was in motion toward opening with a closure signal initiated). The pumping action results in the production of metallic particles that allowed flashover in the resistor assembly area. Breaker timing test methodology did not provide guidance to ensure that breaker pumping would be prevented. The system configuration and testing methodology of bypassing primary breaker protection was the cause of the extent of subsequent undervoltage conditions on both units. This undervoltage condition resulted in activation of undervoltage protection, precipitating the dual unit trips, load shedding, and D/G start.

Although minimum TS staffing was maintained, effective control of the transient for Unit 2 was hampered by the fact that only one licensed operator was on duty. The other scheduled operator had called in sick and the Operations superintendent made the decision not to hold another operator over. As a result of the extent of the specific event (i.e., reactor trips and undervoltage on both units combined with a major upset to the offsite electrical distribution system), other MCR personnel were not available to assist in the Unit 2 response. During the transient, the Unit 2 operator was delayed in securing the secondary plant and taking manual control of the MDAFW LCVs. This action precipitated the unit cooldown, boration evolution, and eventual LCO 3.0.3 entry.

C. Contributing Factors

The removal of primary breaker protection relays (trip cut-out relays) before placing the new PCB in service prevented early breaker actuation (3.5 cycles) for protection of switchyard busses and the generating units. Before placing the breaker in service, an assessment was made for disablement of relay protection, and it was determined that failure of the new PCB was highly unlikely. This was founded on successful factory and field testing. Also, it was considered that the potential for an intertie trip resulting from miswiring or improper phasing might exist without the trip cut-out relays removed. It is concluded that the testing methodology did not appropriately assess potential risks involved and that alternatives were not adequately evaluated. Communication between the Transmission and Power Service organization and site management was inadequate for assessing acceptability of inherent risk. Additionally, the testing documents did not contain sufficient detail for site management to understand or assess the potential risks involved.

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The Unit 2 operators failed to follow procedures regarding alignment of the emergency boration path. This set up the sequence of events ultimately resulting in loss of CCP suction and removing both CCPs from service for approximately one minute. It also appears that operator error resulted in mispositioning the VCT and RWST outlet valve handswitches, directly resulting in loss of CCP suction. Staffing factored into key decisions made during these evolutions as described in Section II.F. The magnitude of the event, compounded by having only one licensed operator, resulted in challenges to the operators (RO and ASOS). From a human factors standpoint, this situation heightened the potential for inadvertent/unrecognized operator action "in the heat of the battle." Investigation results conclude that the RWST handswitches were incorrectly left in A-Auto and that inadvertent operator action appears to have resulted in reclosure of the VCT valves. While not recalled, the action could have taken place under the urgency/pressure of the situation and not have been consciously recognized. While the effect of minimum staffing on this event was apparent, it is considered that recovery evolutions could have been successfully performed had procedures been explicitly followed.

IV. ANALYSIS OF EVENT

A C-phase to ground fault on the 500-kV system caused both Units 1 and 2 to trip. The fault caused the C-phase voltage in the 500-kV switchyard to drop to zero and the 161-kV switchyard C-phase voltage to dip to approximately 50 percent. The fault caused the 161-kV voltage to dip because of the intertie transformer being in service at the time of the fault. The intertie transformer ties the 161-kV switchyard to the 500-kV switchyard; therefore, the 161-kV switchyard was supplying power to the fault, which caused its voltage to dip. With a fault of this nature and the intertie transformer in service, the 161-kV switchyard responded as expected. The reduced voltage on both the 500-kV and 161-kV switchyards is reflected back to the auxiliary power system (APS). The undervoltage relays on the RCPs initiate a reactor trip signal in seventeen and one-half cycles when the voltage goes below 5022V (approximately 73 percent). Therefore, each unit's reactor protection system responded to the degraded voltage and tripped. The undervoltage relays on the 6.9-kV S/D boards' normal feeder breakers trip the breakers if the voltage dips to 80 percent or less for one-half second. This would cause the 70 percent loss-of-voltage relays to start the D/Gs and sequence the loads onto them. The RCPs did not trip since an underfrequency signal of less than 56 Hertz on the RCP bus did not occur.

The Unit 1 unit boards fast transferred from the USST to the CSST because of the loss of the 500-kV switchyard. The Unit 2 boards did not transfer immediately from the USSTs to the CSSTs since there was not a fault in the Unit 2 main generator or any of the 161-kV sources tied to the generator. The Unit 2 unit boards transferred approximately 30 seconds after the reactor tripped as designed. The reaction of the APS to the undervoltage for 90 cycles was as expected and as designed. The response to the event is part of the design basis for SQN.

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In addition, both units' TBBPs were shed following the loss of offsite power indication as designed. However, upon D/G reloading, they were not reloaded because of the position of the handswitches. The RCP thermal barrier heat exchanger functions as a backup to the seal injection system to ensure that hot RCS water will not enter the RCP bearings and seals in the event of a loss of seal injection. While the thermal barrier heat exchanger provides a backup function; operation of the RCPs with reduced or no CCS flow to the thermal barrier heat exchanger will not result in damage to the RCP seals or bearings as long as normal seal injection flow is maintained. The operator recognized during the event that the TBBPs had not restarted and waited until D/G loading could be verified to start the TBBPs. Therefore, the operator at this point maintained the primary cooling source for the seals (i.e., charging pumps). Later in this event, both CCPs for Unit 2 were removed from service approximately 20 seconds before manual start of the TBBPs.

Evaluation indicated that there is approximately 50-55 gallons of cold water contained in the shaft alley area of the reactor coolant pumps. With a nominal leak-off rate of 3 gpm, it is estimated that it would take 10 to 20 minutes for hot RCS water to contact the seals. Although there would be some increase in temperature of the water in the seal area as it leaks through, any loss of flow for a period of less than 10 minutes is not considered to have adverse effects on seal condition or performance. The period of time without normal charging seal injection or normal thermal barrier cooling was approximately 20 seconds. No TBBP high-temperature alarms were present during this event. There was no RCS inventory loss outside of the RCS or to interfacing systems. The capability to provide adequate long-term core cooling remained unimpaired.

Unit 1 was S/D and stabilized in Mode 3 with no other anomalies. Plant parameters associated with the trip function responded as designed and operator actions were considered appropriate via the emergency procedures.

During the event response, Unit 2 RCS T_{avg} trended below 540 degrees F and emergency procedures required emergency boration to compensate for potential reduction in S/D margin. Given the actual amount of boration required and the fact that all rods inserted upon reactor trip, no challenge to the FSAR or TS requirements occurred.

During the loss of power, low oil pressure indications were received in the MCR for both of the Unit 2 CCPs. Under S/D board load sequencing, the CCP auxiliary oil pump is started immediately when power is returned to the S/D board. The CCP starts two seconds later regardless of oil pressure. Assuming that the low oil pressure indicating lights were a true indication that no auxiliary oil pump start had not occurred, the effects of operating the CCPs with low oil pressure were evaluated. It was concluded that:

1. The low oil pressure condition would have only existed during pump startup. Once the pump was up to full speed, sufficient oil pressure would have existed to adequately lubricate the pump bearings.

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2. If one of the charging pumps was in normal operation when the event occurred, sufficient bearing lubrication would have been provided if the time interval for which the charging pump was without power was short (i.e., within the start-up and wind-down times). Sufficient pressure would have existed to bathe the pump bearings with lube oil.

An investigation was performed on the lube oil light anomaly and no equipment deficiency was found.

In conclusion, primary safety systems responded as designed during this transient. Adequate S/D margin, well within prescribed safety analysis limits, was maintained for both units. No primary safety system component was faulted or degraded during this event. Safety parameters remained within the design basis of the plant. This event did not result in adverse consequences to plant personnel or the public.

V. CORRECTIVE ACTION

A. Immediate Corrective Actions

The control room staff promptly diagnosed the plant conditions and took actions to stabilize the unit in a safe condition. Additionally, the motor-operated disconnects for PCB 5058 were opened, which completely isolated the PCB from the bus.

Follow-up investigations were initiated for identified anomalies and appropriate corrective actions were identified.

B. Corrective Action to Prevent Recurrence

The transmission and Power Service field test manual has been revised to provide specific guidance for breaker timing testing. This guidance ensures that the field timing test does not bypass the anti-pumping circuit within the breaker. Additional controls have been established to strengthen communications between the Transmission and Power Service organization and the site, increase plant visibility of switchyard work, implement improved risk assessment for disablement of protective relays, and change testing methodology to minimize disablement of protective relays.

Administrative controls have been implemented to ensure that control room staffing will be maintained at two ROs for each operating unit. The need for additional training at diluted staffing levels (i.e., common MCR staffing such as shift technical advisor/SOS not available) is being evaluated.

The operators involved in the Unit 2 recovery evolutions have been counselled on procedure adherence and are providing the lessons learned from this event to other operators. Operations management has met with the operator crews and discussed this event focusing on procedure adherence and operator actions outside procedural steps.

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The procedure used to position the TBBP switches was revised to be in agreement with design requirements. Other MCR handswitch positions were reviewed against design requirements to ensure proper positioning. A broader effort is in progress to provide overall improvements in the control of configuration of plant equipment. This effort includes specific improvements in the configuration control process, review to properly identify components needing configuration control, and to ensure that appropriate administrative controls are in place to reflect the required configuration. This broad effort is complemented by a field configuration verification.

The lube oil light anomaly on the Unit 2 CCP lube oil system was investigated. The investigation recommendations are under evaluation for further action.

VI. ADDITIONAL INFORMATION

A. Failed Components

The failed component of this event was an Asea Brown Boveri 550-PM power circuit breaker.

B. Previous Similar Events

A review of previous events did not identify an LER associated with failure to provide adequate relay protection during breaker testing, VCT isolation/CCP suction isolation, or operator staffing. No additional previous events were identified relative to operator error or failure to follow procedures during a transient. A previous event (LER 50-328/88010) was identified associated with an operator taking the CCP to the P-T-L position. In that event, the responsible RO did not recognize that placing the CCP handswitch in the P-T-L position would result in the CCP being inoperable during plant operation in Mode 3. Two LERs (50-327/92018 and 92025) were identified that addressed single system/component failure affecting both units. Those LERs provided information on water intrusion into the station non-essential control air system and station air compressor selector-switch failure. The causes and corrective actions of those events would not have prevented the event described by this LER. LERs were identified (LERs 327/92006, 90009, and 328/90009) associated with procedure noncompliance involving failure to properly verify RCS flow, failure to adhere to a precaution resulting in an automatic start of the AFW system, and failure to properly implement a surveillance requirement. The broader issues of human performance and control of work are being evaluated under the site improvement plan that is currently being developed.

VII. COMMITMENTS

None.

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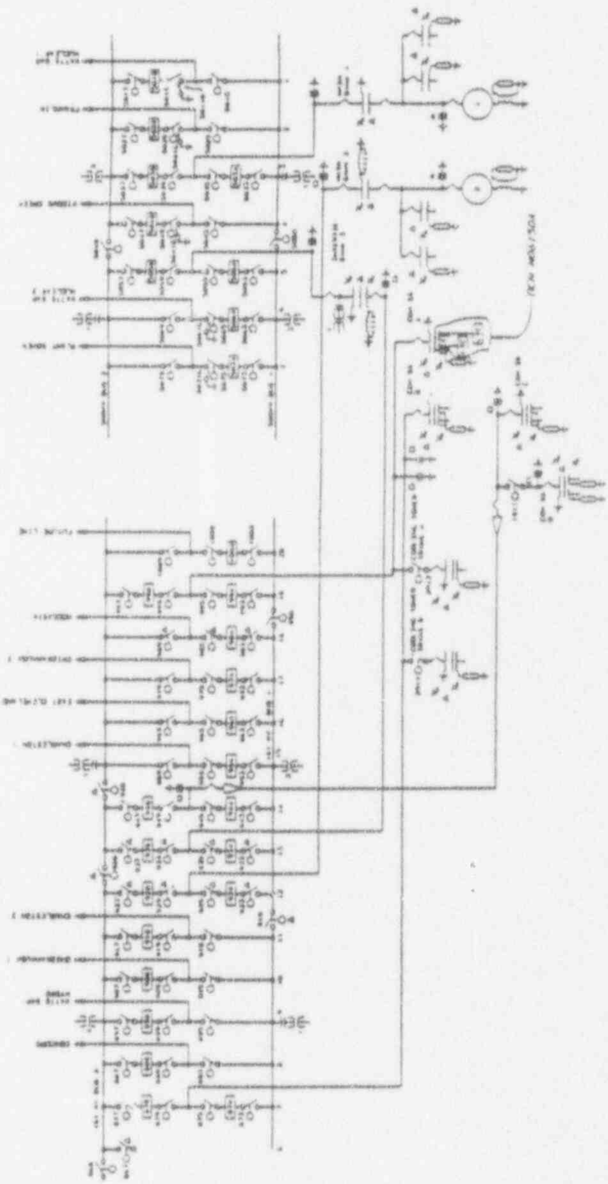

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TITLE (4) Entry Into Mode 4 Operation Without Two Operable Containment Spray Systems Caused by Inadequate Configuration Control

EVENT DAY (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 5	0 8	9 2	9 2	0 0 7	0 1	0 8	3 1	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 4

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following)(11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	XX 50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	XX 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: C. D. McDuffy, Compliance Licensing | TELEPHONE NUMBER: AREA CODE 6 1 5 | 8 4 3 - 7 7 6 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO | EXPECTED SUBMISSION DATE (15) MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

This LER is being revised to update a corrective action. On May 8, 1992, at 0330 Eastern daylight time (EDT), TVA discovered that both containment spray (CS) pump suction valves (2-FCV-72-21 and -22) were closed, rendering both trains of CS inoperable. Investigation revealed that this condition existed during the transition from Mode 5 to Mode 4 on May 7 at 1748 (EDT). Upon discovery of the valves in the closed position, Limiting Condition for Operation (LCO) 3.0.3 was entered, and the valves were opened. LCO 3.0.3 was then exited. The root cause of this event is considered to be not implementing the configuration control process. Additionally, operators had not accepted the importance of using the basic operational tools to achieve the expected level of plant operations. Immediate corrective actions included a complete walkdown of the control boards to ensure correct configuration of the equipment and disallowing use of the procedural exceptions that had been misinterpreted regarding configuration control. Long-term corrective actions include the establishment of a task force to review and streamline the configuration control process.

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I. PLANT CONDITIONS

Unit 2 was in Mode 4 at 337 degrees Fahrenheit (F) and 446 pounds per square inch gauge (psig), preparing for return to service during Day 56 of the Cycle 5 refueling outage.

II. DESCRIPTION OF EVENT

A. Event

On May 8, 1992, at 0330 Eastern daylight time (EDT), TVA discovered that both containment spray (CS) pump suction valves (2-FCV-72-21 and -22) were closed, rendering both trains of CS inoperable. Investigation revealed that this condition existed during the transition from Mode 5 to Mode 4 on May 7 at 1748 EDT.

B. Inoperable Structures, Components, or Systems That Contributed to the Event

The closed suction valves rendered both trains of CS inoperable.

C. Dates and Approximate Times of Major Occurrences

April 27, 1992	A valve alignment in accordance with the system operations checklist for B train containment spray system (CSS) was started.
April 28, 1992	A valve alignment in accordance with the system operations checklist for A train CSS was started.
May 2, 1992	The CS pump suction valves were configured open according to the valve checklists.
April 30-May 3, 1992	Several test activities were conducted requiring CSS operation. Following completion of these activities, operators closed the suction valves to ensure that maintenance activities did not result in a flow path from the refueling water storage tank (RWST) to the containment sump. This action was not positively controlled by use of the configuration control process; however, operators considered that procedural exceptions allowed this manipulation without a configuration log entry and that barriers to mode change would place the valve in the correct configuration.

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May 5, 1992	The valve alignment checklists for A and B train CSSs were completed.
May 5, 1992 at 1100 EDT	Shiftly performance of shift turnover periodic instruction indicated suction valves were closed. This checklist allowed the operators to check the valves as open or closed; it did not specify the required position.
May 5, 1992 at 1700 EDT	A surveillance instruction (SI) was completed to verify CSS alignment as required by Technical Specification (TS) SR 4.6.2.1.1.a.
May 5, 1992 at 2222 EDT- May 6, 1992 at 0126 EDT	The A train CS pump was started to recirculate the refueling water storage tank. The suction valve was discovered closed before the evolution. Following recirculation, the operator returned the valve to the as-found condition, i.e., closed.
May 6, 1992 to May 8, 1992	Shiftly performance of the shift turnover periodic instruction indicated that the suction valves remained closed.
May 7, 1992 at 1630 EDT	The general operating instruction (GOI) emergency core cooling system (ECCS) master checklist was performed to verify control board switch alignment before mode change. Although the CSS is included in the checklist, these valves were not included.
May 7, 1992 at 1748 EDT	Unit 2 entered Mode 4.
May 8, 1992 at 0330 EDT	A senior reactor operator (SRO) discovered both Unit 2 CS suction valves in the closed position, immediately entered Limiting Condition for Operation (LCO) 3.0.3, and opened the valves. LCO 3.0.3 was then exited. 10 CFR 50.72 applicability was evaluated.
May 8, 1992 at 0700 EDT	10 CFR 50.72 notification was evaluated by oncoming and offgoing shift operations supervisors and Operations management. The event was not considered reportable under 10 CFR 50.72, based on plant conditions. Applicability of 10 CFR 50.73 was recognized.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

May 8, 1992 at 0830 EDT	Further management evaluation concluded that a 10 CFR 50.72 report was required.
May 8, 1992 at 1006 EDT	The event was reported in accordance with 10 CFR 50.72.

D. Other Systems or Secondary Functions Affected

None.

E. Method of Discovery

While reviewing the control board, the refueling coordinator SRO identified the condition.

F. Operator Actions

Upon discovery of both 2-FCV-72-21 and 2-FCV-72-22 in the closed position, LCO 3.0.3 was entered, and the valves were opened. LCO 3.0.3 was then exited.

G. Safety System Responses

No safety system responses were required.

III. CAUSE OF THE EVENT

A. Immediate Cause

The immediate cause of this event was inappropriate personnel actions. The valves were maintained closed in Mode 5 by operators because of concerns for inadvertent draining of the RWST to the containment sump through the CS pump suction valves. Operators considered that the valves were not required to be open in Mode 5, and barriers to mode change would place the valves in the correct configuration. This action was not positively controlled through the configuration control process and, thus, incorrect valve positions were not identified before mode change.

B. Root Cause

The root cause of this event is considered to be operators not adequately implementing the configuration control process. Additionally, the operators did not understand the importance of using the basic operational tools (i.e., turnover, configuration control, daily journal, etc.) to achieve the expected level of plant operations.

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C. Contributing Factors

The complexity of configuration control requirements and insufficient training on these procedural requirements contributed to this event. Additionally, barriers to mode change, such as the ECCS master checklist, did not result in correcting the configuration before mode change.

IV. ANALYSIS OF THE EVENT

The CSS is designed to prevent the peak containment pressure from exceeding the 12 psig design value after a large loss of coolant accident (LOCA) at full power. The CSS works in conjunction with other systems to remove heat from the containment and, thus, control the peak pressure. The ice condenser provides essentially all of the heat removal in the containment during the early phases of an accident. As long as ice remains, the CSS removes little or no energy from the containment atmosphere.

Significant physical damage to the spray pumps was likely had the pumps been started in the condition found on May 8. If the pumps had started automatically, the operators would have had a very short time period to open the suction valves before the volume of water in the suction piping was exhausted. The operators would not reach the step in Emergency Operating Procedure E-0 that requires verification of spray flow for several minutes after event initiation. This condition could result in the loss of both CS trains.

At the time of this event, the reactor had been shut down for a refueling outage for 56 days, and approximately one third of the fuel assemblies were new and had not been irradiated. The reactor coolant system (RCS) conditions were about 336 degrees F at a pressure of 458 pounds per square inch absolute. With respect to the design basis events discussed in the preceding section, the effects of a large and small LOCA were evaluated for Mode 4.

Based on evaluation, the following conclusions were reached. A large LOCA in Mode 4 would be a much less challenging event than the design-basis LOCA. The latent and sensible heat of the RCS would be much less than that assumed in the design basis accident (DBA) analysis because of the lower temperature and pressure of the reactor during Mode 4. After the initial blowdown of the RCS, steam releases from the RCS would be terminated because the decay heat rate would not be high enough to heat the ECCS flow to boiling temperature. Thus, no steam releases would be expected after a few hundred seconds, and the CSS would not be needed.

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In support of this evaluation, hand and computer calculations were performed and concluded that conservatively-calculated steam releases would be condensed on the containment shell and other passive heat sinks, and the CSS would not be needed to control containment pressure.

Even though it would not be needed for this event, the residual heat removal spray would be available to the operator. The 2000 gpm flow rate is more than sufficient to condense the conservatively-calculated steam release for the conditions at discovery.

The cases of a small-break LOCA and a main steam line break were also evaluated. Based on the evaluations and the large-break LOCA evaluation discussed above, it is concluded that having both trains of CS inoperable during Mode 4 at the end of a refueling outage is well within the bounds of the accident analysis results presented in the Final Safety Analysis Report (FSAR).

In conclusion, the safety significance of having both CSS trains inoperable in Mode 4 was evaluated both qualitatively in comparison with the accidents in the FSAR and quantitatively for the conditions that existed in Mode 4 after a 56-day shutdown. The evaluation considered large and small LOCAs and main steam-line breaks inside the primary containment. These evaluations concluded that the CSS is not required because the ice condenser handles the initial blowdown energy and the passive heat sinks can condense the conservatively-calculated steam release when the ice bed eventually melts. The containment temperature and pressure for these events would be less severe than those presented in the FSAR. Therefore, this event had limited safety significance.

V. CORRECTIVE ACTIONS

A. <u>Immediate Corrective Actions</u>

1. Work was stopped on both Units 1 and 2 until system alignments were verified.

2. A complete walkdown of Units 1, 2, and common main control room switches and bench-board alignments was conducted to verify proper configuration.

3. A standing order was issued covering configuration control and mandatory configuration log entries. The standing order included disallowing use of the exceptions to configuration log entries, requiring a systematic control board walkdown by the oncoming and offgoing licensed personnel, requiring configuration log entries for in-process procedures, and additional restrictions on isolation of pump suction valves.

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4. The Operations superintendent and the Operations manager conducted discussions with the Operations staff. These meetings discussed recent Sequoyah Nuclear Plant (SQN) operational events and Operations performance relative to those events. The use of basic operational tools such as configuration control, shift turnover, procedure use, and daily journal entries as an aid in performing duties versus merely requirements to be followed, was discussed in detail. The role that absence of proper use of these tools played in the recent events was evaluated. This evaluation reinforced the position that rigorous, consistent application of tools in everyday performance of work will prevent mistakes.

5. The operators' shift turnover periodic instructions were revised to delete switch alignment choices.

B. Corrective Actions to Prevent Recurrence

1. A task force is being established to review and streamline the configuration control process. Recommendations provided will be incorporated into the configuration control procedure.

2. In-depth training will be conducted on configuration control requirements following the upgrade of the requirements.

3. The GOI ECCS master checklist was reviewed to determine if appropriate valves were included. The CS pump suction valves from both the RWST and containment sump were not included in the GOI. The GOI will be revised to include these valves.

4. In an effort to improve overall Operations performance, a meeting was conducted with the on-shift assistant shift operations supervisors (ASOSs) to discuss performance and required improvements. The ASOSs were tasked to identify problem areas and recommend and implement associated solutions. This meeting resulted in a consensus that performance needs improvement and a commitment to implement the improvements. It also developed a sense of empowerment and an unwillingness to relinquish that empowerment. Initial recommended areas to improve include professionalism, delegation of responsibilities, shift manning, succession planning and encouraging performance, SRO input to plant work activities, communications, and configuration control. Methods to improve these areas were determined. Implementation is ongoing.

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

VI. ADDITIONAL INFORMATION

A. Failed Components

None.

B. Previous Similar Events

Several SQN events involving configuration control and operator performance have been reported (e.g., LER 50-327/92006, "Failure to Properly Verify Reactor Coolant System Flow Above TS Limits," LER 50-327/91025, "Main Steam Isolation Valves Inoperable Because Jumpers on the A Train Closure Circuitry Had Not Been Removed Following Maintenance Activities," and LER 50-328/91008, "Failure of the RWST Wide Range Level Transmitters Because of Inadequate Administrative Controls"). Corrective actions for these events involved correcting specific aspects of Operations' administrative processes without an integrated review of the processes and implementation. Additionally, corrective actions for previous events have been directive in nature, with management determining the problems and associated solutions; the corrective actions for the event discussed in this report are participative rather than directive. This approach charges the operators with the problem determination and the ability to effect change. Past corrective actions such as for the events listed did not prevent the event discussed in this report.

VII. COMMITMENTS

1. A task force is being established to review and streamline the configuration control process. Recommendations provided will be incorporated, as appropriate, into the configuration control procedure by October 8, 1992.

2. In-depth training will be conducted on configuration control requirements following the upgrade of the requirements through special operator training by February 8, 1993.

3. The GOI ECCS master checklist will be revised by September 8, 1992, to include the CS pump suction valves from both the RWST and containment sump.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Sequoyah Nuclear Plant, Unit 2
DOCKET NUMBER (2): 0|5|0|0|0|3|2|8
PAGE (3): 1 OF 07

TITLE (4) Residual Heat Removal Pump Inoperable due to a Miswired Flow Switch for the Miniflow Valve

EVENT DAY (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 7	1 7	9 2	9 2	0 1 0	0 0	0 8	1 7	9 2		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1
POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following)(11)

__ 20.402(b)	__ 20.405(c)	__ 50.73(a)(2)(iv)	__ 73.71(b)
__ 20.405(a)(1)(i)	__ 50.36(c)(1)	__ 50.73(a)(2)(v)	__ 73.71(c)
__ 20.405(a)(1)(ii)	__ 50.36(c)(2)	__ 50.73(a)(2)(vii)	__ OTHER (Specify in
__ 20.405(a)(1)(iii)	XX 50.73(a)(2)(i)	__ 50.73(a)(2)(viii)(A)	Abstract below and in
__ 20.405(a)(1)(iv)	XX 50.73(a)(2)(ii)	__ 50.73(a)(2)(viii)(B)	Text, NRC Form 366A)
__ 20.405(a)(1)(v)	__ 50.73(a)(2)(iii)	__ 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: C. M. Whittemore, Compliance Licensing
TELEPHONE NUMBER: AREA CODE 6 1 5 | 8 4 3 - 7 2 1 0

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

__ YES (If yes, complete EXPECTED SUBMISSION DATE) | X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On July 17, 1992, with Unit 2 in Mode 1 at 100 percent power operations, personnel performing a surveillance instruction identified a Residual Heat Removal (RHR) Pump 2B-B miniflow valve to be malfunctioning. Operations personnel declared the RHR pump inoperable, and Limiting Conditions for Operation (LCOs) 3.5.2 and 3.6.2.1 were entered at 1100 Eastern daylight time (EDT) on July 17, 1992. An investigation determined the problem to be an incorrectly terminated wire on the flow switch. The wire was correctly terminated and the flowswitch was functionally tested and returned to service. LCOs 3.5.2 and 3.6.2.1 were exited at 2249 EDT on July 17, 1992. A subsequent investigation into the event identified the root cause of the mislaid wire as being inattention to detail with an inadequate second-party verification. Maintenance personnel have been briefed on specific problems identified in this event. A less than adequate post maintenance test (PMT) also contributed to the event. On July 28, 1992, during the review of the event by the Plant Event Review Panel (PERP), it was discovered that a potential issue existed involving the RHR systems being outside of design basis of the plant. A one-hour telephone call notifying NRC of the issue was made at 1928 EDT on July 28, 1992.

LER NO: 328/92-010

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

I. PLANT CONDITIONS

Unit 2 was operating at approximately 100-percent reactor thermal power.

II. DESCRIPTION OF EVENTS

A. Event

On July 17, 1992, with Unit 2 in Mode 1 and 100-percent power, Operations personnel performing a quarterly residual heat removal (RHR) pump surveillance instruction, identified the 2B-B RHR (EIIS Code BP) pump (EIIS Code P) miniflow valve (EIIS Code FCV) to be malfunctioning. The miniflow valve was cycling open and closed instead of remaining open. Operations personnel declared the RHR pump inoperable, and Limiting Condition for Operation (LCOs) 3.5.2 and 3.6.2.1 were entered at 1100 Eastern daylight time (EDT). An investigation revealed the flow switch for the miniflow valve had been miswired on July 1, 1992. It should be noted that between July 1 and July 17, 1992, there were 10 instances where Train A safety equipment, i.e., centrifugal charging pump (CCP), safety-injection pump, diesel generator (D/G), and 6.9 kilovolt shutdown boards were inoperable for short periods of time. With the exception of two instances that are described in the following paragraph, the periods of inoperability were of short duration.

B. Inoperable Structures, Components, or Systems That Contributed to the Event

On July 8, 1992, D/G 2A-A was inoperable for 17 hours.

On July 9, 1992, CCP 2A-A was inoperable for six hours.

C. Dates and Approximate Times of Major Occurrences

June 30, 1992 0600 EDT	Flowswitch quarterly preventive maintenance (PM) was started.
June 30, 1992 0820 EDT	A work request (WR) was written to replace a flowswitch when a problem was found that prevented calibration and testing.
July 1, 1992 0627 EDT	A WR was completed (flowswitch replaced).
July 1, 1992 0730 EDT	A PM was completed and the RHR pump was declared operable.
July 8, 1992 0600 EDT	Diesel Generator (D/G) 2A-A was inoperable - LCO 3.8.1.1 was entered.

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July 8, 1992 2301 EDT	D/G 2A-A was operable - LCO 3.8.1.1 was exited.
July 9, 1992 1841 EDT	CCP 2A-A was inoperable for maintenance, LCOs 3.5.2, 3.1.2.4, and 3.1.2.2 were entered.
July 10, 1992 0059 EDT	CCP 2A-A was operable, and LCOs 3.5.2, 3.1.2.4, and 3.1.2.2 were exited.
July 17, 1992 1100 EDT	Quarterly operability surveillance instruction test for RHR pump 2B-B identifies miniflow valve cycling open and closed. LCOs 3.5.2 and 3.6.2.1 were entered.
July 17, 1992 1830 EDT	Miniflow valve flowswitch was found to be miswired - the wiring was corrected.
July 17, 1992 2249 EDT	LCOs 3.5.2.1 and 3.6.2.1 were exited for 2B-B RHR pump.
July 18, 1992 0015 EDT	The wiring on Unit 1 Train A and both trains of Unit 2 RHR pump miniflow switches was verified as correct.
July 28, 1992 1928 EDT	Following management's review of the event in the Plant Event Review Panel (PERP) meeting, NRC was notified of the condition under 10 CFR 50.72 as potentially having placed the plant outside of design basis, because of Train A safety equipment and/or components out of service between July 1 and July 17, 1992.

D. Other Systems or Secondary Functions Affected

None.

E. Method of Discovery

Operations personnel performing a quarterly operability test on the 2B-B RHR pump identified the abnormal operation of the miniflow valve. Investigation into the cause of the abnormal operation of the valve revealed the flowswitch that controls the miniflow valve had a field wire incorrectly terminated.

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F. Operator Actions

Operations personnel identified that the miniflow valve was malfunctioning and took appropriate action by declaring the 2B-B RHR pump inoperable and for entering LCOs 3.5.2 and 3.6.2.1. A WR was initiated to investigate and troubleshoot the cause. After corrective action was concluded and the miniflow valve was functionally verified as being able to perform its intended function, LCOs 3.5.2 and 3.6.2.1 were exited.

G. Safety System Response

No safety system responses were required.

III. CAUSE OF EVENT

A. Immediate Cause

The immediate cause of this event was the incorrectly terminated wire for the miniflow valve, which rendered the 2B-B RHR pump inoperable. The inoperability of opposite train equipment contributed to the event.

B. Root Cause

There were three root causes for the event:

1. Inadequate self-checking and inattention to detail was the cause for the craftmen to incorrectly terminate the field wire. There was only one wire removed and reterminated during the July 1, 1992, flowswitch calibration PM.

2. Secondary-party verification was not effectively implemented. The verifier did not identify that the field wire was terminated on the correct terminal. The terminal block was correctly labeled and the label corresponded to the procedure and drawing. The wire was misterminated on a terminal that was not labeled.

3. A third root cause for this event was that the postmaintenance test (PMT) for the maintenance activity was ineffective. The WR did not clearly specify requirements necessary to verify that the miniflow valve functioned properly after the flowswitch was replaced in conjunction with the PM. The PMT as stated in the WR was to properly calibrate and functionally check the flowswitch. The ambiguity in the PMT led the craftsmen to belief that a system functional test or independent verification was not required.

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IV. ANALYSIS OF EVENT

This event involves a wiring error that resulted in the miniflow recirculation valve cycling when the valve should have remained open.

The flowswitch that was miswired controls closure of the recirculation valve when the RHR pump discharge exceeds a setpoint of approximately 1,250 gallons per minute (gpm). (This setpoint accounts for instrument inaccuracies.) The basis for the valve closure is to ensure adequate flow goes to the core whenever reactor coolant system (RCS) pressures are low enough to allow RHR to inject.

The design logic requires the valve to be open at 500 gpm (decreasing) through the pump to protect the pump from heating damage, and for the valve to close at 1,500 gpm (increasing) to assure adequate flow to the reactor core for accident mitigation. The recirculation valve, which is motor operated, is part of the safety injection logic; therefore, it does not use thermal overloads. The actuator motor is rated for intermittent duty and can fail after approximately fifteen minutes of continuous operation. The pump recirculation requirement of 500 gpm is a continuous operation value. The continuous cycling of the valve ramped the flow from zero to approximately 750 gpm with each valve cycle. This may meet the cooling requirements for continuous flow through the pump, but the action puts a thrust cycle on the pump impeller and motor bearings that creates additional wear on the pump.

During an accident situation, the pump normally would be in recirculation mode during the injection phase of the accident. The pump is then used for net positive suction head (NPSH) boost during the recirculation phase until the RCS pressure drops below the pump deadhead pressure. With the recirculation valve open, the pump would operate normally and complete the accident mitigation task as designed.

The worst-case scenario involves a small break loss of coolant accident with the miniflow-valve motor failing in the fully closed position. Failing in the closed position, the RHR pump is subject to overheating and ultimate failure. This scenario, coupled with opposite train safety component unavailability, results in a condition outside design basis.

Further investigation and computer-simulated scenarios revealed that no damage would result from the valve cycling for approximately 25 minutes. It is fully expected that operators in the main control room would detect the abnormal operation from annunciators signaling the rapid change of position of the valve, and the fluctuation of the motor amperage. Upon detection, the RHR pump would then be turned off. This expectation was demonstrated by submitting the problem to operators during requalification training. These simulations did not cycle the miniflow valve, stopping the RHR pump relied on normal SI termination criteria contained in emergency procedures. The times ranged between 21 and 25 minutes before the RHR pump was removed from service. Therefore, the added indications of position status lights and motor amps should prompt the operators to earlier intervention.

V. CORRECTIVE ACTIONS

A. Immediate Corrective Actions

Operations personnel immediately entered LCOs 3.5.2 and 3.6.2.1 for Unit 2.

Operations personnel exited LCOs 3.5.2 and 3.6.2.1 for Unit 2 after the misplaced wire was correctly terminated and the functional test verified the miniflow valve performed as designed.

B. Corrective Actions to Prevent Recurrence

1. Wiring on the other miniflow switches for Unit 1 and Unit 2 was checked and verified as being correctly terminated.

2. The instrument PMs data packages associated with the RHR miniflow valve switches have been revised to require independent verification for wire connections and also for jumpers.

3. Maintenance craftsmen, planners, and procedure writers have been briefed on this event with an emphasis on the need for an adequate PMT or specifying an independent verification in lieu of a PMT.

4. Maintenance planners will be trained on the proper way to specify acceptance criteria for verifying that components can perform their intended functions. This will be accomplished by September 14, 1992.

VI. ADDITIONAL INFORMATION

A. Failed Components

None.

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B. Previous Similar Events

A review of the licensee event report data base was conducted to identify any previous or similar events, and if so, to determine if corrective actions had been unsuccessful in preventing recurrence. Several events were identified that were caused by or had contributing factors similar to those noted in the investigation of this event, i.e., inattention to detail, inadequate verification, and inadequate PMT. Actions have been taken in response to previous events to ensure that expectations of management were clearly conveyed, understood, and concurred with by working-level personnel. Following this event, an independent team was assembled to evaluate the verification and PMT processes and their implementation. Corrective actions from this evaluation will be pursued as part of the overall SQN performance improvement efforts.

VII. COMMITMENT

Maintenance planners will be trained on the proper way to specify acceptance criteria for verifying that components can perform their intended functions. This will be accomplished by September 30, 1992.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Trojan Nuclear Plant	0 5 0 0 0 3 4 4	1 OF 7

TITLE (4) Reactor Trip Caused by the Failure of the Controller on Main Feedwater Pump 'B' Due to Electronic Component Failures

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									N/A	0 5 0 0 0
07	22	92	92	- 0 2 0 -	0 0	08	21	92		0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR: (11)			
		[ ] 20.402(b)	[ ] 20.405c	[X] 50.73(a)(2)(iv)	[ ] 73.71(b)
		[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
POWER LEVEL (10)	1 0 0	[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[ ] OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)A	
		[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)B	
		[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER: AREA CODE	
D. L. Claridge, Compliance Engineer	503	556-5541

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	JB	TC	W120	YES		D	JB	65	W290	YES
X	BA	65	W290	YES						

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[X] YES (If yes, complete EXPECTED SUBMISSION DATE)	[ ] NO		10	16	92

ABSTRACT (16)

On July 22, 1992, the Trojan Nuclear Plant experienced a reactor trip from 100 percent power. The trip was caused by the loss of flow from the 'B' Main Feedwater Pump (MFP). At the time of the trip, both MFPs were in manual control due to oscillations in automatic flow control. Following the reactor trip, the 'A' Auxiliary Feedwater Pump (AFW Pump) started, but tripped on overspeed shortly after starting. Subsequent attempts to start the 'A' AFW Pump failed. The failure of the 'B' MFP was due to an electronic component failure on its governor's electronic control assembly (Woodward Model 8270). The control problems with the 'A' MFP were caused by a failed electronic component on its flow controller (Westinghouse-Hagan Model 124). The 'A' AFW Pump failure was caused by a failed integrated circuit on the Ramp Generator Signal Converter in the Woodward Governor turbine startup control circuitry. Corrective Actions included repairing and/or replacing the failed components and circuit boards. There were no safety consequences resulting from the component failures. The 'B' AFW Pump functioned as required to provide cooling water to the steam generators. Other plant systems functioned as expected.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Trojan Nuclear Plant	0 5 0 0 0 3 4 4	92	- 0 2 0 -	0 0	2 OF 7

TEXT (17)

DESCRIPTION OF EVENT

On July 22, 1992, the Trojan Nuclear Plant was in Operational Mode 1 (Power Operation) at 100 percent power. At 0126 hours a reactor trip occurred on low-low steam generator level due to a loss of feedwater flow from the 'B' Main Feedwater Pump (MFP) [SJ, P].

Both 'A' and 'B' MFPs were in manual at the time of the reactor trip. Manual control had been established on the 'A' MFP on July 6, 1992 due to oscillations in the controller while in automatic flow control. On July 20, 1992, the 'B' MFP was placed in Manual when operating personnel were unable to maintain stable feedwater flows while in automatic. On July 22, 1992, while in manual and with no operator action, the 'B' MFP slowed to its minimum speed and flow. Manual attempts to increase pump speed were unsuccessful, and the Control Operator tripped the 'B' MFP, which initiated a turbine runback. Approximately one minute later, the reactor tripped on low-low steam generator level.

Immediately after the reactor trip, the Turbine-driven Auxiliary Feedwater Pump (the 'A' AFW Pump) [BA, P] Auto-started. A few seconds later, the 'A' AFW Pump tripped on overspeed. Two subsequent attempts to restart the 'A' AFW Pump also resulted in overspeed trips. The Diesel-Driven Auxiliary Feedwater Pump (the 'B' AFW Pump) [BA, P] operated properly to supply cooling water to the steam generators during the transient.

The reactor trip was a Reactor Protection System (RPS) [JE] actuation, and the initiation of Auxiliary Feedwater was an Engineered Safety Features (ESF) [JE] actuation. Both events were reported under 10 CFR 50.72(b)(2)(ii) on July 22, 1992 at 0330 hours, using the Emergency Notification System. This report is being submitted to fulfill the requirements of 10 CFR 50.73(a)(2)(iv).

Sequence of Events

July 6, 1992 2350 hours	Control Operator (CO) received 'Lube Oil Pressure Lo' alarms on the 'A' MFP and noticed the pump controller oscillating. CO placed controller in Manual and oscillations stopped. Troubleshooting efforts were initiated.
July 20, 1992 1613 hours	CO received the 'B' MFP 'Shaft Coupling Vibration High' alarm. CO noted the 'A' MFP was running at approximately 10,000 gpm and the 'B' MFP was running at approximately 20,500 gpm. CO manually increased the 'A' MFP flow in order to decrease the 'B' MFP flow. This cleared the high vibration alarm.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
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TEXT (17)

1634 hours	CO was unable to maintain stable feedwater flows. CO placed the 'B' MFP in Manual.
1759 hours	Troubleshooting determined that the 'B' MFP picked up excessive feedwater flow while in Auto.
2100 hours	While in Manual, the 'B' MFP flow had to be increased slowly over approximately a two-hour period to prevent flow from shifting over to the 'A' MFP. Stable Main Feedwater conditions were established. The 'B' MFP was inspected, but no problems were noted.
July 21, 1992 1608 hours	Instrumentation and Control (I&C) personnel completed installation of monitoring equipment on MFP instrument control signals in the Westinghouse-Hagan Controller racks.
1636 hours	Started increasing feedwater flow on the 'B' MFP.
1721 hours	Established a 195 psi differential pressure between the MFPs to allow monitoring of instrument speed control signals.
July 22, 1992 0125 hours	The 'B' MFP slowed to minimum speed. Attempt was made to increase the 'B' MFP speed manually, but was unsuccessful. The CO tripped the 'B' MFP, which initiated a turbine runback.
0126 hours	Reactor tripped on low-low steam generator water level. The 'A' AFW Pump Auto-started, then tripped on overspeed. The 'B' AFW Pump Auto-started. The 'A' AFW Pump tripped on overspeed on subsequent attempts to start it.

Event Analysis

The 'A' MFP Failure

The controller module and Manual/Auto Station (Westinghouse-Hagan Controller Model 124) [JB, TC] for the 'A' MFP were removed for bench testing. During the first two hours of the test period the controller was placed in automatic and a small step change signal was introduced. The module outputs remained satisfactory during this period. When a second step change was input to the controller, the output integrated off-scale high. The controller output would remain stable when it was placed in Manual. For the next several hours attempts to place the controller in Auto caused the output signal to integrate off-scale high.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

The 'B' MFP Failure

Troubleshooting was performed on the 'B' MFP governor controller (Woodward Governor Model 2301, Electronic Control Assembly Model 8270) [JB, SC]. Several components on the signal converter [JB, CNV], amplifier [JB, AMP], and voltage switch [JB, JS] modules of the Electronic Control Assembly were found to be overheating. Measurements taken during troubleshooting identified several failed components. The component failures were determined to be associated with the power supplied to each module.

During troubleshooting, the Zener Diodes on the amplifier module were found to be hot to the touch. Measurement of the output of the auctioneered power supplies [JB, RJX] determined that the lead (primary) power supply was set at 24 VDC and the follower (backup) power supply at 19 VDC. For an auctioneered power supply, the lead power supply is supposed to be set only slightly higher than the follower to forward-bias the diode circuit. The lead power supply was adjusted to 19.3 VDC and approximately 17.7 VDC was measured at the Control Assembly. After this reduction, the Zener diodes were noticeably cooler.

The 'A' AFW Pump Failure

The cause of the overspeed trip of the 'A' AFW Pump was originally diagnosed as a failure of the pump's Electric Overspeed Trip circuitry [BA, SC]. However, subsequent testing (manually starting and controlling the pump locally at various speeds) verified that the electric overspeed trip circuitry was functioning normally. Fast starting the pump, however, produced an electric overspeed trip signal. Additional testing was then conducted on the Woodward Governor control circuitry [BA, 65]. A start up circuit (Ramp Generator Signal Converter) in the Woodward Governor programs turbine speed to prevent overspeed on turbine startup. It was determined that the Ramp Generator Signal Converter was not generating a ramp or idle speed signal. Without these signals present to control pump startup, the turbine would quickly run up to full speed, overshooting to its overspeed trip setting. The failed Ramp Generator Signal Converter was returned to the vendor for repair and failure analysis.

CAUSE OF OCCURRENCE

The 'A' MFP Westinghouse-Hagan Controller failure was caused by a component failure. The erratic operation of the controller was due to a failed electrical component within the controller module. The particular failed component (or components) has not yet been identified, and is still under investigation.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

The 'B' MFP governor electronic control assembly failure was caused by a misadjusted controller power supply. The 24 VDC power supply was set at 24 VDC when it should have been set slightly higher than 19 VDC. Investigation to determine why the supply was set too high identified a Maintenance Request initiated in 1991 to replace a burned out indicating lamp in the lead power supply to the 'B' MFP Governor controller circuit. While performing the replacement the maintenance personnel discovered that the lead power supply was not functioning properly. The power supply (Lambda Electronics Model LJS-10A-24-OV) [BA, RJX] was replaced on April 27, 1991. However, the work instructions directed the personnel to verify that the power supply provided 24 VDC, and did not specify that the supply was to be adjusted to slightly higher than 19 VDC (Output Voltage). The higher voltage and current conditions that the controller circuits were subjected to caused several of the electrical components to overheat and eventually fail. Further investigation as to the reason why the new power supply was not adjusted to the proper voltage is ongoing. The results of that investigation will be reported in a supplement to this report.

The 'A' AFW Pump failure was caused by a faulty Ramp Generator Signal Converter in the Woodward Governor control circuitry. This converter had failed on June 1, 1992, and had been replaced on June 3, 1992, with a new converter. The failure of the new converter on July 22, 1992, was determined to be the result of a failed integrated circuit on the printed circuit board. According to the vendor, the failure did not appear to be the result of an external cause, but was probably due to a premature failure of the integrated circuit due to an internal flaw on the chip.

CORRECTIVE ACTIONS

Actions Completed

1. The failed components on the 'B' MFP governor electronic control assembly were replaced, the power supply was adjusted, the governor was tested satisfactorily, and the 'B' MFP was returned to service.

2. The Westinghouse-Hagan Controller Module for the 'A' MFP was replaced, the control circuitry was tested satisfactorily, and the 'A' MFP was returned to service.

3. The failed 'A' AFW Pump Ramp Generator Signal Converter was replaced and tested successfully. Power supply voltages were checked when the circuit was replaced and found to be correct.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

Actions in Progress

1. Increased frequency testing of the Turbine Driven Auxiliary Feedwater Pump has been implemented. The increased testing frequency will continue for six months as follows: once per week for the first month, twice per month for the next two months, and once per month for the last three months. This testing is intended to monitor for premature component failure by verifying proper operation of the Ramp Generator Signal Converter, and will be done under fast start conditions.

Actions to be Taken

1. Investigation to determine the root cause of the inadequate work instructions for replacing the failed power supply on the 'B' MFP Governor controller circuit will be completed and the results reported in a supplement to this report by October 16, 1992. Corrective actions deemed necessary as a result of this investigation will also be reported in the supplement.

ANALYSIS OF SAFETY CONSEQUENCES AND IMPLICATIONS

There were no safety consequences resulting from the failure of the 'B' MFP or the 'A' AFW Pump. Following the reactor trip, safety systems functioned as required, with the exception of the 'A' AFW Pump. However, the 'B' AFW Pump started and ran normally, and supplied cooling water to the steam generators, as required. Also, it would have been possible to manually start and control locally the 'A' AFW Pump, had it been needed. In addition, the electric-driven auxiliary feedwater pump [BA, P] could have been started, if required. Therefore, the subject failures did not prevent the steam generators [SB, SG] from receiving an adequate supply of cooling water.

PREVIOUS SIMILAR EVENTS

A reactor trip occurred on June 5, 1992, due to a steam generator high-high water level signal caused by a failed controller for the 'B' Main Feedwater Regulating Valve [SJ, FCV]. This event was reported on LER 92-14, dated July 6, 1992. The failure in that event was a manual pushbutton, in which the switch contacts would intermittently stick closed, which caused the 'increase flow' signal to stay in until the steam generator water level reached its high-high setpoint. This was a mechanical failure, not an electronic circuit failure, and was due to a combination of a manufacturing defect and age-relaxation of the switch contacts' spring.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (17)

Another reactor trip event, as reported in LER 88-43, dated December 13, 1988, also involved the controller for the 'B' Main Feedwater Regulating Valve. That event was not due to a solid state circuit failure, but a failed capacitor in the controller's power supply. The failed power supply caused the valve to fail open.

In addition to the above two events, the 'A' AFW Pump Ramp Generator Signal Converter that failed on July 22, 1992, was the replacement for the converter that had failed on June 1, 1992, during testing of the 'A' AFW Pump. The June 1, 1992, failure, which also caused the turbine to trip on startup, was caused by a component failure. The component that failed then was also an integrated circuit, but not the same one that failed on July 22, 1992.

LICENSEE EVENT REPORT

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
HOPE CREEK GENERATING STATION	0 5 0 0 0 3 5 4	1 OF 5

TITLE (4): Reactor Shutdown to comply with Technical Specification 3.6.1.1, due to Failure of Suppression Chamber to Drywell Vacuum Breakers.

EVENT DATE (5)			LER NUMBER (6)					REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	*	NUMBER	*	REV	MONTH	DAY	YEAR	FACILITY NAME(S)	DOCKET NUMBER(S)
0 5	2 6	9 2	9 2	-	0 0 6	-	0 0	0 6	2 4	9 2		

OPERATING (9) MODE: 1

POWER LEVEL %: 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR: (CHECK ONE OR MORE BELOW) (11)

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text)
20.405(a)(1)(iii)	XX 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	XX 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Louis Aversa, Senior Staff Engineer - Technical	6 0 9 3 3 9 3 3 8 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE NOTED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS?	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS?
B	[illegible]	VACB	G202	Yes					

SUPPLEMENTAL REPORT EXPECTED? (14)	YES		NO	X	DATE EXPECTED (15)	MONTH	DAY	YEAR

ABSTRACT (16)

On 5/25/92 at 1000, Operations department personnel declared the Suppression Chamber inoperable based on the results of an 18 month surveillance which measures the change in Delta pressure between the Drywell and Suppression Chamber air space. The SNSS (Senior Nuclear Shift Supervisor - SRO Licensed) declared Primary Containment Inoperable and entered Technical Specification 3.6.1.1 which requires restoration of Primary Containment within 1 hour or place the unit in HOT SHUTDOWN within the following 12 hours. An Unusual Event was declared at 1145 due to loss of Primary Containment Integrity IAW the Event Classification Guide. Operations department Personnel conducted a check of the Suppression Chamber to Drywell Vacuum breakers to verify integrity of the position indication of the valves and re-performed the leak down test. A reactor shutdown was commenced as the leak down test was repeated with similar results to those initially obtained. The plant was shutdown at 2215 by the initiation of a manual scram at approximately 20% power. All plant systems and components operated as expected. The Unusual Event was terminated at 0615 on 5/27/92, after the plant had achieved Cold Shutdown conditions. The test failure was due to leakage through 3 Suppression Chamber to Drywell Vacuum breakers. The valves were repaired and the bypass leakage test was performed satisfactorily.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION											
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)									PAGE (3)
HOPE CREEK GENERATING STATION	05000354	YEAR		-	NUMBER			-	REV		
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PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor (BWR/4)
Containment Suppression Chamber to Drywell Vacuum Breakers EIIS Designator BF

IDENTIFICATION OF OCCURRENCE

TITLE: Reactor Shutdown to comply with Technical Specification 3.6.1.1, due to Failure of Suppression Chamber to Drywell Vacuum Breakers.

Event Date: 5/26/92
Event Time: 1700 hrs
This LER was initiated by Incident Report No. 92-094

CONDITIONS PRIOR TO OCCURRENCE

Plant in OPERATIONAL CONDITION 1 (Power Operation)
Reactor Power 100% of rated, 1110 MWe.

DESCRIPTION OF OCCURRENCE

On 5/25/92 at 1000, Operations department personnel declared the Suppression Chamber inoperable based on the results of an 18 month surveillance which measures the change in Delta pressure between the Drywell and Suppression Chamber air space. The SNSS (Senior Nuclear Shift Supervisor - SRO Licensed) declared Primary Containment Inoperable and entered Technical Specification 3.6.1.1 which requires restoration of Primary Containment within 1 hour or place the unit in HOT SHUTDOWN within the following 12 hours. An Unusual Event was declared at 1145 due to loss of Primary Containment Integrity IAW the Event Classification Guide. Operations department Personnel conducted a check of the Suppression Chamber to Drywell Vacuum breakers to verify integrity of the position indication of the valves and re-performed the leak down test. A reactor shutdown was commenced as the leak down test was repeated with similar results to those initially obtained. The plant was shutdown at 2215 by the initiation of a manual scram at approximately 20% power. All plant systems and components operated as expected. The Unusual Event was terminated at 0615 on 5/27/92, after the plant had achieved Cold Shutdown conditions.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION										
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HOPE CREEK GENERATING STATION	05000354	YEAR	*	NUMBER	*	REV				
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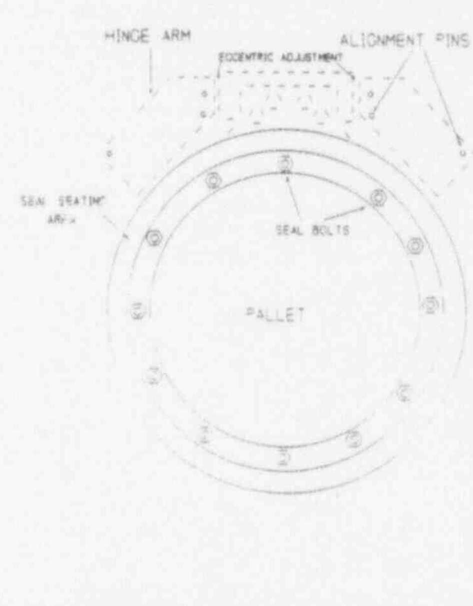
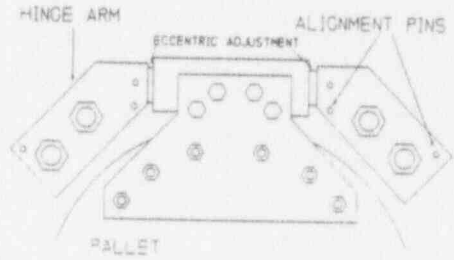
ANALYSIS OF OCCURRENCE

The Suppression Chamber to Drywell Vacuum breakers are designed to allow non condensable gases to return to the drywell during the blowdown phase of a Design Basis Accident (DBA). The valves also act as a boundary between the Drywell and Suppression Chamber air space to ensure steam from the drywell will pass into the suppression chamber water volume and be condensed limiting the Drywell pressure rise following a DBA to less than the design limit of 62.4 PSIG. The valves are tested monthly for position indication verification and free movement, and are tested on an 18 month frequency as part of the overall bypass leakage surveillance.

Testing performed on 5/26/92 indicated bypass leakage was present, but the actual path of the leakage could not be determined. Once the unit was placed in shutdown and the drywell purged, an entry into the Suppression Chamber was made to determine the location of the leakage. Three Suppression Chamber to Drywell Vacuum Breakers, "F", "G" and "H" were identified as having leakage as air flow passing through the valves was audible. The "G" vacuum breaker seal was replaced terminating the leakage through the valve. The "F" and "H" vacuum breaker seals were replaced but the leakage through these two valves continued. Further investigation revealed that the valve pallets were misaligned, not allowing the seal to properly seat. When the valves were disassembled, the alignment pins for the hinge arm, which maintains the alignment of the pallet, were found sheared. Maintenance Department Personnel replaced the hinge alignment pins and adjusted the pallet to attain proper seating of the seal. When the valves were reinstalled, leakage through the valve persisted. Maintenance personnel then readjusted the seal bolting to attain a satisfactory seal.





LICENSEE EVENT REPORT (LER) TEXT CONTINUATION			
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HOPE CREEK GENERATING STATION	05000354	9 2 - 0 0 6 - 0 0	0 4 of 0 5

ANALYSIS OF OCCURRENCE

A review of the previously performed bypass leakage surveillances did not reveal any adverse trends which would have projected a failure at this time. The surveillance test had been completed successfully on 9/17/87, 3/13/89 and 9/15/90. A review of the work order history did not indicate that any work on the valves, other than limit switch adjustments, had been performed. A valve which had been inspected during Refuel outage 3 as a basis for extending the EQ for the valves did not indicate any similar problems to those found on the "F" and "H" valves. Data collected during disassembly was insufficient to perform an assessment of the cause of the misalignment.

APPARENT CAUSE OF OCCURRENCE

Three probable causes have been identified for the increased leakage through the vacuum breakers: seal alignment, seal aging and the pallet alignment. Also in 1988, the method of purging and inerting the Drywell and Suppression Chamber was revised to admit gas or air into the Suppression Chamber and exhaust via the drywell outlet valves. This method of purging and inerting increased the number of cycles the vacuum breakers experience and may be contributing factor to the failure. Increased monitoring of vacuum breaker operation during purge and inert evolutions will be performed as part of ongoing root cause investigation.

PREVIOUS OCCURRENCES

No previous occurrences of Suppression Chamber to Drywell vacuum breaker failures due to similar causes have occurred at Hope Creek.

SAFETY SIGNIFICANCE

This event posed minimal safety significance as the leakage was only slightly above acceptable limits. The Suppression Chamber Spray System was available and operable to condense steam that may have entered the Suppression Chamber air space for the period of time the vacuum breakers were inoperable.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION																	
FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)										PAGE (3)					
HOPE CREEK GENERATING STATION	05000354	YEAR		*	NUMBER			*	REV								
		9	2	-	0	0	6	-	0	0		0	5	of	0	5	

CORRECTIVE ACTIONS

1. The inoperable Vacuum Breakers were repaired and the bypass leakage surveillance was completed satisfactorily.

2. Additional monitoring of vacuum breaker operation will be performed during evolutions which cycle the valves, such as purging and inerting of containment.

3. Engineering will evaluate the need to obtain additional data when the remaining valves are inspected during the next Refuel Outage.

Sincerely,

J. J. Hagan
General Manager -
Hope Creek Operations

LLA/

SORC Mtg. 92-046

LICENSEE EVENT REPORT (LER)

Form Rev 2.0

Facility Name (1)	Docket Number (2)	Page (3)
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	1 of 0 8

Title (4)

Reactor Scram Due To A Main Turbine Trip Caused By A Thrust Bearing Wear Detector Signal

Event Date (5)			LER Number (6)			Report Date (7)			Other Facilities Involved (8)	
Month	Day	Year	Year	Sequential Number	Revision Number	Month	Day	Year	Facility Names	Docket Number(s)
										0 5 0 0 0
0 8	2 7	9 2	9 2	0 1 2	0 0	0 9	2 5	9 2		0 5 0 0 0

OPERATING MODE (9)	1
POWER LEVEL (10)	0 8 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10CFR (Check one or more of the following) (11)

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	Other (Specify in Abstract below and in Text)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

Name	TELEPHONE NUMBER	
	AREA CODE	
John C. Klika, Asst. Tech Staff Supervisor, Extension 2533	8 1 5	3 5 7 - 6 7 6 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	T A	D E T	G 0 8 4	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		Expected Submission Date (15)	Month	Day	Year
Yes (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e, approximately fifteen single-space typewritten lines) (16)

On August 27, 1992 at 0305 hours, Unit 2 experienced a Reactor Scram as a result of a Main Turbine trip which was caused by a Thrust Bearing Wear Detector signal. All rods successfully inserted as a result of the Automatic Scram signal.

During the scram response, both Turbine Driven Reactor Feed Pumps failed to trip from either remote manual operation, High Reactor Level 8 automatic trip, or local mechanical trip operation. As a result of this failure, the Reactor Water level increased to a level requiring the Main Steam Isolation Valves (MSIV) to be closed.

The MSIV closure resulted in the Safety Relief Valves (SRV) being used to control reactor pressure. During operation of two SRVs (A&B), remote position indication failed to show that the valves closed when demanded.

Also during the event, the Reactor Core Isolation Cooling (RCIC) System auto started due to a Level 2 initiation signal which resulted from a pressure spike sensed at the instrument racks containing the level transmitters for the RCIC initiation signal.

When reactor level was brought under control, a MSIV (Group I) Isolation High Steam Flow signal was received when a Main Steam Line was being unisolated. This occurred when the MSIV was opened with approximately 760 psi differential pressure across the valve.

Root cause investigations were performed to determine the reason for all the above noted failures. This is reportable pursuant to 10CFR50.73(a)(2)(iv) due to an automatic reactor scram.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION — Form Rev 2.0

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) Year	Sequential Number	Revision Number	Page (3)
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	9 2	- 0 1 2 -	0 0	0 2 OF 0 8

TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

A. CONDITION PRIOR TO EVENT

Unit(s): 2 Event Date: 8/27/92 Event Time: 0305 Hours

Reactor Mode(s): 1 Mode(s) Name: Run Power Level(s): 80%

B. DESCRIPTION OF EVENT

Reactor Power was being reduced from 1100 Mwe to 850 Mwe at 120 Mwe/hour using Reactor Recirculation (RR)[AD], Flow Control. At the time of the scram, actual flow control manipulations were briefly suspended to allow for xenon burnout.

On August 27, 1992 at 0305 hours, Unit 2 experienced a Reactor Scram as a result of a Main Turbine Stop Valve (TSV) (TG) [TA] closure trip. The Turbine Trip was caused by a Thrust Bearing Wear Detector Turbine Trip signal to the Electro-Hydraulic Control (EHC, EH) [TG] System. As a result of the automatic scram signal, all control rods inserted to their full in position.

During the first seconds of the event, the Reactor Core Isolation Cooling (RCIC, RI) [BN] System auto started due to a spurious (FW) [SJ] Level 2 (-50 inches) initiation signal.

During the scram response, in an attempt to control reactor water level, the Motor Driven Reactor Feed Pump (MDRFP) (FW) [SJ] was successfully started in preparation for tripping of the Turbine Driven Reactor Feed Pumps (TDRFPs). When attempting to shutdown the TDRFPs, all methods of initially tripping them failed including remote manual trip operation, High Reactor Level 8 automatic trip, or local mechanical trip operation.

As a result of this failure, the Reactor Water level increased above the Level 8 High Level setpoint (+55.5 in) resulting in a trip of the MDRFP and the RCIC System. The Outboard Main Steam (MS) [SB] Isolation Valves (MSIVs) were manually closed at 0308 hours when the +73 inch reactor level administrative limit was reached. This limit is provided to prevent flooding the steam lines outboard of the MSIV's (bottom of the Main Steam lines is at +108 inches). The level transient resulted in a maximum level of +130 inches.

The closure of the MSIVs resulted in TDRFP shutdown and also caused a loss of the Main Condenser as a heat sink.

The loss of the Main Condenser as a heat sink required use of the Safety Relief Valves (SRV) for manual control of reactor pressure. During operation of 'A' and 'B' SRVs, remote position indication failed to show that the valves fully closed when demanded. Subsequent review showed that earlier in the event 'U' SRV had automatically cycled on reactor pressure as designed with final position indicated as full closed. No "SRV Full Open" Alarm was seen by the operators during any SRV operations. Additional review of SRV tailpipe temperatures showed that the SRVs had, in fact, closed.

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TEXT Energy Industry Identification System (EIIS) codes are identified in the text as [XX]

B. DESCRIPTION OF EVENT CONTINUED

After reactor water level was returned to the normal operating range and brought under control, an attempt was made to reestablish the Main Condenser as a heat sink. All the inboard MSIV's were closed and all outboard MSIVs were opened. Pressure was being equalized across the Inboard MSIVs. When the "A" Inboard MSIV was opened, a MSIV (Group I) isolation High Steam flow signal was received resulting in closure of all five open MSIVs.

Attempts to use the RCIC System to help control reactor pressure were made and the turbine tripped on high exhaust pressure on the first two start attempts. The system was successfully started on the next attempt and operated normally to control pressure.

The failure of the thrust bearing wear detector signal and the failure of the TDRFPs to trip were the principle concerns of this event. Other indication concerns were identified during the investigation and are listed below.

1. 2E51-F066 RCIC Testable Check Valve Position Indication showed the valve to not be full closed (RCIC Running Alarm).
2. Scram Annunciator "First Out" Indication did not function.
3. High Drywell Temperature Alarm.

On 8/27/92, Confirmatory Action Letter (CAL) RIII-92-011 was issued, and an Augmented Inspection Team (AIT) was formed by the NRC to investigate this event. Further information is available in the AIT report (Inspection Report 374/92020), the CAL response, and the startup onsite review (OSR-92-33).

C. APPARENT CAUSE OF EVENT

The cause of the Turbine Thrust Bearing Wear/Failure Signal was determined to be due to a shift in the setpoint for the Thrust Bearing Wear Detector. This shift was caused by a failure of the manufacturer to build the assembly unit per design.

Following extensive investigations into the TDRFP trip failure, the root cause was determined to be suspended particulate in the Turbine Oil System which accumulated on the spool interfaces creating flow blockages thereby preventing proper operation of the trip system. In addition, the disk dump valve spool on 2A TDRFP was found to have a runout (bent shaft) of 5 mils and the 2B TDRFP Trip Solenoid Pilot Valve had a runout of 4 mils, both of which are above the 1 mil specification. The spool on the 2B TDRFP also had a minor interference problem with the trip assembly.

The spurious "Reactor Level 2 Low" Signal was due to a pressure oscillation/ringing which resulted from the closure of the Turbine Stop Valves. The individual spikes lasted approximately 80 milliseconds and decayed to nearly a zero amplitude in approximately 3-4 seconds. This phenomenon was previously documented as a result of the March 1, 1992 scram on Unit 1 in LER 92-003-00. The duration of the spikes have not been sufficient nor have they been in phase such that all isolation or actuation instrumentation are able to sense the trip signals simultaneously. For this reason there is a randomness in the actuation of the various protective signals.

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C. APPARENT CAUSE OF EVENT CONTINUED

The Group I High Steam Flow Signal was received when the MSIV was opened with approximately 760 psi differential pressure across the valve. This was due to the operator reading the wrong indicator, which resulted in him thinking that the differential pressure was within the 200 psi differential pressure administrative limit for opening the MSIVs.

Failure of the SRV Position Indication on 'A' and 'B' SRVs was due to failure of the Linear Variable Differential Transformer (LVDTs) to return to their "null" position. This was determined to be the result of accumulations of fretting induced corrosion between the actuating pin and the guide bushings. Also, within a second of the scram, the 'U' SRV automatically opened for about 11 seconds but the "SRV Fully Open" annunciator did not function. This was determined to be due to a faulty annunciator logic card connector.

The Scram Annunciator "First Out" Indication failure was due to burned out light bulbs in the applicable annunciator window. This was due to lack of surveillance of these bulbs.

The High Drywell Temperature Alarm Annunciation was a valid alarm based on the actual signals which were received by the instrument. One of the sensors was located in the vicinity of the Control Rod Drive System Header which contained hot process fluid as a result of the scram. This heat load caused the local temperature to rise about 18 degrees which was enough to cause the 135 degree setpoint to be exceeded.

The RCIC trips on High Exhaust Pressure were caused by the passage of water, which had accumulated in the steam line, through the turbine, and into the exhaust header. The water flashed to steam creating a momentary high pressure condition. In both cases the RCIC Steam Line Drain Valves operated properly but there was insufficient time to drain all the water from the steam lines before RCIC was attempted to be used for Reactor pressure control.

Following the initial shutdown of the RCIC System, the RCIC Testable Check Valve 2E51-F006 failed to indicate full closed and this was due to the check valve position cam hanging up on the valve packing and insufficient system backflow. This caused the "RCIC Running" Alarm to remain in the alarm condition. In all other cases, the RCIC System functioned as designed in response to operator demands.

D. SAFETY ANALYSIS OF EVENT

A complete shutdown of the reactor was successful as a result of the automatic scram signal. Reactor Pressure Vessel (RPV) level never was below the 0 inch level (more than 13 feet above the top of active fuel).

The effect of the TDRFP trip failure was minimized by closure of the MSIVs which resulted in a shutdown of the feed pumps. The lack of SRV Position indication made the ability to verify primary coolant boundary integrity more difficult. The fact that reactor pressure stopped decreasing and tailpipe temperatures decreased to normal values following the attempts to close the SRVs provided sufficient information to assure that the valves were closed.

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D. SAFETY ANALYSIS OF EVENT CONTINUED

Based on the results of the investigations, it was determined that the 2E51-F066 Check Valve did not close during the shutdown of the RCIC System as indicated by Control Room Valve Position Indication. When the RCIC System was shutdown, the 2E51-F065 valve closed eliminating the system backflow through the piping and equalizing the pressure across the 2E51-F066 valve. Without the system backflow, the 2E51-F066 valve remained partially open after the RCIC injections. The additional force required to assist the valve closed was very minimal based on manual closure tests performed on August 29 and 30, 1992. If backflow conditions existed, the valve would have closed performing the valve's design function.

With the exception of the above mentioned failures, all safety systems performed their intended protective functions as required.

E. CORRECTIVE ACTIONS

THE THRUST BEARING WEAR DETECTOR FAILURE

Following the turbine trip, trends in bearing temperatures were reviewed to determine if there was any other indication of thrust bearing problems. A slight increase (approximately 2-3 degrees) in thrust bearing metal temperatures was noted but was consistent with oil supply temperature affects of power reduction.

The Thrust Bearing Assembly was disassembled to check as found dimensions to determine if there was any shift in the bearing parts. These investigations revealed no signs of wear on the thrust bearing that would have lead to or required a turbine trip.

A series of local and remote Wear Detector operations and turbine rotor thrust checks were performed. These tests identified that the span between Turbine End and Generator End trip points had changed from the previously recorded span of 110 mils (-40 to +70) to 84 mils (-80 to +4). This shift in the span, and not thrust bearing failure, is believed to be the actual cause of the trip. This test also showed that the Wear Detector was able to consistently follow Thrust Collar position accurately. In addition, the wear detector mechanical integrity of the bushing drive between the detector motor clutch and the bushing coupling was checked to identify any problems with the wear detector.

Findings from the wear detector inspection included:

1. Slight clutch face contact irregularities,
2. Inadequate clutch spring compressive torque settings,
3. A ball bearing (lower bearing) that felt a little rough, and
4. Loose set screw for the lower coupling half attachment to the bushing stem which caused a change in the calibration of the setpoint for the trip.

The clutch faces were dressed up, the clutch spring was retorqued, the lower bearing was exchanged (new bearing not available) with the upper bearing, the bushing drive coupling and stem were drilled to accommodate a roll pin, and the set screw was re-applied and firmly tightened.

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E. CORRECTIVE ACTIONS CONTINUED

TDRFP TRIP FAILURE

Following unit shutdown both TDRFPs were taken out of service and an action plan was developed to determine the root cause of the failures. This plan included a complete check of the trip system consisting of:

1. Voltage checks at the trip solenoid (SV-12),
2. Resistance check of the trip solenoid,
3. Compare results to vendor requirements,
4. Manual trip and reset of the turbines from the front standard while measuring Trip Dump Valve shaft travel,
5. Trip and reset turbine from Control Room while measuring SV-12 shaft travel, and
6. Logic test of the Reactor Level 8 Trip.

Because the 2A TDRFP was still in its original tripped condition, a complete visual inspection of the tripping mechanism was conducted to identify oil contamination, scoring of pistons and cylinders, burrs, or other mechanical damage.

Following these inspections, the results were reviewed by Technical Staff, Engineering, and General Electric Turbine Engineers to determine further corrective actions. As a result of this review the following was done:

a. The control system, including the Trip Dump Valve and related Trip Assembly Servos, was oil flushed,

b. Runout checks were made on the hydraulic dump valve and remote trip actuating pistons resulting in the replacement of the 2A TDRFP Trip Dump Valve and the 2B TDRFP Trip Solenoid Pilot Valve. In addition, an O-ring was found in the guide hole for the trip dump valve of 2A TDRFP and was removed, and

c. The K7A and K7C relays in the Reactor Level 8 Trip circuit were replaced and the circuit was retested satisfactory.

REACTOR LEVEL 2 LOW SIGNAL

The actual cause of the ringing experienced by the level instrumentation is a natural phenomena which has been seen at LaSalle in the last three scrams due to turbine trips. The effect of this ringing has been reviewed and installation of a modification which would affectively provide a time delay of the signal is being reviewed. Action Item Record (AIR) 374-180-92-06701 will track completion of this review.

GROUP I HIGH STEAM FLOW ISOLATION

The root cause of the isolation signal was the use of the wrong pressure indications in determining the differential pressure across the MSIVs. As a result of the high flow condition, the steam lines were "walked down" to identify any potential integrity problems, none were found. In order to ascertain any potential internal problems with the MSIV's, Local Leak Rate Tests, Actuator Leak Tests, and Valve Timing Tests were performed with satisfactory results. In addition, the Training Department is highlighting this event in subsequent training activities to emphasis the affects of opening MSIVs with excessive differential pressure and to assure that operators use the proper indications in determining the differential pressure. Actions related to this issue are discussed in more detail in HPES Report 92-014.

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E. CORRECTIVE ACTIONS CONTINUED

SRV POSITION INDICATION
Calibrations in accordance with LaSalle Instrument Procedure, LIP-NB-613, "Unit 2 SRV LVDT Refuel Calibration," were performed on the 'A' and 'B' SRV LVDTs. Results of this surveillance indicated that the "as found" null positions were out of tolerance. In addition, it was determined that the Signal Conditioner/Logic Card received the position signals but failed to process the "SRV Full Open" Alarm. The logic card was replaced and was tested satisfactory.

Both 'A' and 'B' SRV LVDTs were visually inspected with no conclusions being made. Further inspections consisted of obtaining detailed voltage and fit measurements which showed that the LVDTs were stuck in the intermediate position. Additional investigation determined that the LVDTs were not bent but there was evidence of corrosion or fretting corrosion between the stainless steel actuating pin and the brass guide bushings. Analysis by Station Material Analysis Department (SMAD) showed that the corrosion was fretting induced.

As a result of these findings, three additional LVDTs were removed and inspected, with one exhibiting the same type of problem. Due to this additional problem, all SRV LVDTs were removed, inspected, and refurbished in accordance with vendor and engineering recommendations. No further problems were identified.

Based on these findings, the LVDTs for A, B, and all 7 Automatic Depressurization System (ADS) [SB] SRV's were replaced with new LVDTs with the remaining LVDTs being refurbished and reinstalled.

Periodic disassembly inspections and replacement of the LVDTs is being evaluated. This will be documented in AIR 374-121-92-01101B.

Because the SRVs experienced passage of water, the vendor (Crosby) was consulted about the possible affects of passing high pressure water. Results of that consultation indicate that there are no concerns about the operability of the valves.

FIRST OUT INDICATION
The burnt out light bulbs in the Annunciator "First Out" Indication was due to inadequate testing of the first out circuitry. An Electrical Maintenance Department procedure had been developed for testing this circuitry but had been overlooked as a result of a failure to enter the surveillance into the General Surveillance (GSRV) Program. This surveillance was performed shortly following the event and determined that the light bulbs were burnt out. The bulbs were replaced and tested satisfactory. A similar test was performed on Unit 1. In addition the following actions were initiated:

a. The GSRV was updated to include the surveillance item, and

b. All departments will review the GSRV items against department surveillances to assure that all necessary surveillances are included in the GSRV Program. AIR 374-180-92-06702 will track completion of this review.

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E. CORRECTIVE ACTIONS CONTINUED

HIGH DRYWELL TEMPERATURE

The area temperature sensor in the vicinity of the Control Rod Drive (CRD) Lines has been temporarily shielded per a Temporary System Change (TSC 2-958-92) to minimize the affect of the hot CRD Lines on Drywell Temperature Indication during a scram. Also, the Safety Parameter Display System (SPDS) algorithm for the interpretation of the inputs is being revised to discount any indication which is not within a set range of other indications. AIR 374-180-92-06703 will track this revision.

RCIC EXCESS FLOW CHECK VALVE INDICATION

Following the event, the 2E51-F066, RCIC Inboard Testable Check valve, was visually inspected to compare it's as found condition to that of the 2E51-F065, RCIC Outboard Testable Check valve. The Micro Switch Lever Arm for the closed limit was not in contact with the closed limit cam while the lever arm for the open limit was in contact with the open limit cam. This would result in the Open indication in the Control Room.

The valve was disassembled to address potential frictional forces which might have prevented valve closure, indicator hinge pin packing or other internal component degradation. Upon inspection, the indicator hinge pin bearing support surface showed signs of scoring between the bearing surface and the stuffing box bushing confirming the presence of additional friction forces preventing valve closure. Mechanical Maintenance repaired the indicator hinge pin bearing surface and repacked the stuffing box. Valve operation was verified through the work request test.

The original concern causing the RCIC Valve to remain open due to opposing frictional forces had been resolved allowing the valve to close on it's own accord from approximately 60 - 0% open.

F. PREVIOUS EVENTS

LER Number	Title
373/82-077/03L-0	RCIC Testable Check Valve Indication Failure
374/87-014-00	High Thrust Bearing Wear Scram/Foreign Material In Wear Detector

G. COMPONENT FAILURE DATA

Manufacturer	Nomenclature	Model Number	MFG Part Number
Crosby/Trans-Tec	Linear Voltage Differential Transformer	0304-001	
General Electric	Thrust Brg Wear Detector		
Anchor Darling	Testable Check Valve		
General Electric	TDRFP Trip System		
Hathaway	Annunciator Logic Card		B367901

NRC FORM 366 (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
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TITLE (4): Unit 2 Manual Scram Following Loss of Engineered Safeguards 4.16 KV Bus

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
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										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Richard R. Wehry - Power Production Engineer	7 1 7 5 4 2 - 3 6 6 4

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	E K	D I O D E	P 2 9 2	YES					

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On March 18, 1992, with Unit 2 operating in Condition 1 at 100% power and Unit 1 in refueling, Condition 5, at 0% power, the 'B' Emergency Diesel Generator (EDG) was being run for its monthly surveillance test. At 0831 hours on 3/18/92, the 'B' EDG tripped on "Generator Loss Of Field". While in the process of substituting in the 'E' EDG for the 'B' EDG, the Operator reset a relay target on Engineered Safeguard System (ESS) 4.16 KV Bus 2C. When the relay target was reset at 0949 hours on 3/18/92, the bus locked out. The loss of the ESS Bus 2C resulted in several ESF actuations including, auto start of the 'C' EDG, Reactor Water Cleanup and Containment Instrument Gas (CIG) containment isolations and Unit 2 Reactor Building HVAC Zones II and III isolations. Additional bus loads, including Drywell cooling fans were lost and additional isolations occurred. Because the CIG system became isolated from the Main Steam Isolation Valves (MSIV), operators manually scrammed Unit 2 in anticipation of MSIV closure. Following the scram, reactor water level reached Level 3 (+13") resulting in Level 3 isolations. Unit 2 was taken to Cold Shutdown. The root cause of this event was attributed to misoperation of a primary bus differential relay, which occurred when the target reset pushbutton was depressed by the Operator. Following electrical investigation/evaluation of the bus and its protective circuitry, power was restored to the bus at 2053 hours on 3/18/92. The subject relay was tagged to identify that in the event a relay target is observed, Operations should contact Systems Engineering prior to resetting. The relay will be replaced at a later date and more thoroughly examined/tested to aid in understanding the misoperation resulting from resetting the target. All similar relays on Unit 2 were inspected and those on Unit 1 will be inspected prior to startup from its 1992 refueling outage. Repairs were completed on the 'B' EDG and it was restored to operable status. There were no safety consequences or compromise to public health or safety as a result of this event.

NRC Form 366 (6-89)

LER NO: 388/92-001

NRC FORM 366A (6-89) U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO. 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

DESCRIPTION OF EVENT

On March 18, 1992, with Unit 2 operating in Condition 1 at 100% power and Unit 1 in refueling , Condition 5, at 0% power, the 'B' Emergency Diesel Generator (EDG; EIIS Code: EK) was being run for its monthly surveillance test. At 0831 hours on 3/18/92, the 'B' EDG tripped on "Generator Loss Of Field". While in the process of substituting in the 'E' EDG (which is a fifth and spare EDG) for the 'B' EDG, the Operator reset a relay target on Engineered Safeguard System (ESS) 4.16 KV Bus 2C (EIIS Code: EB). When the relay target was reset (at 0949 on 3/18/92), the ESS Bus 2C locked out. The loss of the ESS Bus 2C resulted in several Engineered Safety Feature (ESF) actuations including, auto start of the 'C' EDG (remained unloaded), Reactor Water Cleanup (RWCU; EIIS Code: CE) and Containment Instrument Gas (CIG) system containment isolations and Unit 2 Reactor Building Heating, Ventilating and Air Conditioning (HVAC) Zones II and III (EIIS Code: VA) isolations. Additional ESS Bus 2C loads were lost, including Drywell Cooling Fans (EIIS Code: VB) and additional isolations occurred. Because the CIG system became isolated to the inboard Main Steam Isolation Valves (MSIV; EIIS Code: SB), Operators reduced reactor recirculation flow to minimum and manually scrammed Unit 2 in anticipation of MSIV closure. All control rods fully inserted. Following the scram, reactor water level reached Level 3 (+13") resulting in associated Level 3 isolations. Minimum reactor level reached was -17.6 inches. Maximum reactor pressure reached was 994 psig. Average Drywell temperature reached 165 degrees F. Unit 2 was taken to Cold Shutdown to allow Drywell entry for inspection.

CAUSE OF EVENT

An Event Review Team was formed to perform investigations and root cause analysis of this event. Investigations into the cause of the 'B' EDG trip identified a failed diode in the generator field rectifier bridge as a potential cause. Also investigated was the effect on EDG stability when a large load, Reactor Building Chiller (EIIS Code: VA), was started during the 'B' EDG surveillance test run. Preliminary computer modeling has indicated that the start of a large load, such as this chiller, can result in a large increase of KVAR output from the EDG when in the test (DROOP) mode. When the chiller was started at 0831 on 3/18/92, the 'B' EDG load increased from 4000 KW to 5075 KW and KVARS increased from +161 to -6025 KVARS and the 'B' EDG tripped on "Generator Loss Of Field". The large increase in KVARS measured correlates with the computer model data and may have precipitated failure of the generator field rectifier diode, resulting in the loss of field trip.

The lockout of ESS Bus 2C was unrelated to the trip of the 'B' EDG. It was during the evolution of substituting in the 'E' EDG for the 'B' EDG that the Bus lockout occurred. Specifically, in accordance with operating procedures, the Operator (utility; non-licensed) was checking all Unit 2 ESS 4.16 KV buses for indicating targets and resetting the targets as necessary. The Operator

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

found the relay target actuated on Primary Bus Differential Relay 87A1-B on ESS Bus 2C. When the Operator reset the relay target, he noticed a "spark" in the area of the relay seal-in unit (internal to the relay) and bus lockout relays actuated, tripping and locking out all ESS Bus 2C circuit breakers.

The investigation of the ESS Bus 2C lockout relay operation was divided into two areas:

- Physical and electrical checks of the bus and its appurtenances to determine if physical damage occurred which could have caused the 87A1-B relay to operate in a normal fashion for bus protection.

- Physical and electrical checks of the 87A1-B Primary Bus Differential Relay and its associated circuits to determine if relay misoperation was the cause of the ESS Bus 2C lockout.

The ESS Bus 2C was found intact and not degraded. This was determined by megger testing of the bus and associated potential transformer circuitry. No faults were detected. Additionally, a faulted bus condition is likely to trip at least two Primary Bus Differential Relays, which did not occur.

The 87A1-B Primary Bus Differential Relay and its associated circuits were found to function properly. No physical or electrical defects or anomalies were observed. The relay was checked for functional calibration and alignment/distortion both in place and removed and manually manipulated several times to verify that no mechanical binding or erratic motion was present.

It is PP&L's engineering judgement that the root cause of the ESS Bus 2C lockout was a misoperation of the 87A1-B Primary Bus Differential Relay which occurred when the target reset pushbutton was depressed by the Operator. Several factors support this conclusion:

- The operation of the 87A1-B Primary Bus Differential Relay is designed to cause the lockout of ESS Bus 2C in the exact manner observed on 3/18/92.

- The observations of the Operator, from the moment he depressed the target reset pushbutton, are consistent with the intended design function of this electrical protection scheme for the bus alignment which existed prior to the event.

- The mechanism for the postulated misoperation of the 87A1-B Relay could not be replicated during subsequent investigation. However, the seal-in contact of the 87A1-B Relay is part of the seal-in target assembly. The action of depressing the target reset applies a force in the direction of seal-in contact closure. The seal-in contact is the primary circuit path to trip the lockout relays. As such, the Operator's observation of a

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

APPROVED OMB NO 3150-0104 EXPIRES 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Unit 2 Susquehanna Steam Electric Station	0 5 0 0 0 3 8 8	9 2	0 0 1	0 0	0 4 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

"spark" leads to the conclusion that the seal-in circuit conducted for a sufficient period to initiate lockout relay operation at the same moment the Operator was depressing the target reset pushbutton. The absence of any other anomaly after thorough investigation of all related buses, relays, relay circuitry and station activities at the time of the event leads to the conclusion that the Operator action and the lockout relay operation were not coincidental. Therefore, the misoperation of the 87A1-B Relay, on this occasion, was directly related to the operation of the target reset pushbutton.

REPORTABILITY/ANALYSIS

The events resulting from the lockout of the ESS Bus 2C and the subsequent manual scram of the Unit 2 reactor were determined reportable per 10CFR50.73(a)(2)(iv) as unplanned Engineered Safety Feature (ESF) actuations and an ESF actuation in response to a plant transient (manual scram). The following unplanned ESF actuations occurred upon the lockout of the ESS Bus 2C:

- 'C' EDG auto start (remained unloaded)
- RWCU containment isolation
- CIG containment isolation
- Unit 2 Reactor Bldg. HVAC Zones II and III isolations

In anticipation of a MSIV closure, Unit 2 was manually scrammed resulting in an ESF actuation of the Reactor Protection System (RPS; EIIS Code: JC). Following the scram, reactor water level reached Level 3 (+13"). The reactor water Level 3 isolations constituted unplanned ESF actuations.

All control rods fully inserted during the manual scram. Maximum reactor pressure reached was 994 psig. Minimum reactor water level reached was -17.6 inches. All system initiations and isolations occurred per design in response to both the lockout of the ESS Bus 2C and the manual scram of the Unit 2 reactor.

The 'B' EDG was declared inoperable following its surveillance run trip at 0831 on 3/18/92 and the 'C' EDG could not energize ESS Bus 2C due to the bus being locked out. This constituted a condition reportable per 10CFR50.73(a)(2)(v) and 10CFR50.73(a)(2)(vi) in that a condition existed which alone could have prevented fulfillment of the safety function of structures or systems needed to shutdown the reactor and maintain it in a safe shutdown, remove residual heat, control rad release or mitigate consequences of an accident. Specifically, the Susquehanna Safety Analysis requires three OPERABLE EDGs to safely shut down the plant in the event of a design basis accident. The locked out ESS Bus 2C (Channel 'C') and the inoperable 'B' EDG (Channel 'B') represented the potential for two channels being unavailable in the event of an accident. The 'C' EDG successfully started and continued running in an unloaded condition, as per design, given the locked-out bus condition.

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APPROVED OMB NO. 3150-0104 EXPIRES: 4/30/92

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Unit 2 Susquehanna Steam Electric Station	0 5 0 0 0 3 8 8	9 2	— 0 0 1	— 0 0	0 5 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The plant was safely shut down and there were no radioactive releases recorded by effluent instrumentation. The emergency operating procedures were properly implemented by Operations personnel.

An engineering evaluation concluded that the maximum average Drywell temperature of 165 degrees F reached during the event had insignificant effect on equipment qualified life and no effect on Drywell or piping structural integrity. A Drywell walkdown confirmed that there were no visual indications of heat induced damage present.

There were no safety consequences or compromise to public health or safety during this event.

Investigations into the cause of the 'B' EDG trip at 0831 on 3/18/92 identified a failed diode in the generator field rectifier bridge. It is believed that the start of a large load (Reactor Bldg. Chiller) while the 'B' EDG was in the Test (DROOP) mode resulted in a large increase in the KVAR output from the EDG and may have precipitated failure of the diode, resulting in the trip on "Generator Loss Of Field". The 'E' EDG was substituted in for the 'B' EDG within the required Technical Specification 72 hour LCO Action time. The 'B' EDG was unavailable for 19 days, 7 hours and 49 minutes. However, the total time out of service included time in which the 'B' EDG was kept out of service as a result of Unit 1 ESS Bus refueling outage modification activities. The 3/18/92 'B' EDG trip is considered a valid test and valid failure. The 'B' EDG Start Log indicates there is one (1) 'B' EDG failure in the last 20 valid tests. The 'B' EDG test interval is one start at least once per 31 days per Technical Specification Table 4.8.1.1.2-1. This Licensee Event Report also satisfies reportability pursuant to Technical Specification section 4.8.1.1.4.

In accordance with the guidelines provided in NUREG 1022 Supp. 1 Item 14.1 and 10CFR50.4(d), the required submission date for this report was determined to be April 20, 1992.

CORRECTIVE ACTIONS

Following investigations and evaluations of the ESS Bus 2C and its protective circuitry, power was restored to the ESS Bus 2C via its normal offsite supply at 2053 hours on 3/18/92.

The subject 87A1-B Relay was tagged to identify that in the event a relay target is observed, Operations should contact Systems Engineering prior to resetting the target. The relay will be replaced at a later date and thoroughly examined/tested to aid in understanding the misoperation resulting from resetting the target. The incident was reviewed with all Operations personnel including a discussion of proper relay target reset practices. All similar Primary Bus Differential Relays on Unit 2 were

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LICENSEE EVENT REPORT (LER)
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ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HRS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (P-530), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON, DC 20503.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Unit 2 Susquehanna Steam Electric Station	0 5 0 0 0 3 8 8	9 2	— 0 0 1	— 0 0	0 6 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

inspected for proper relay alignment and operation of the seal-in relay target. The similar relays on Unit 1 will be inspected prior to startup from its 1992 refueling/inspection outage.

An engineering evaluation was performed to determine the effects, if any, of reaching an average Drywell temperature of 165 degrees F during the event. The evaluation concluded that the increase in Drywell temperature had insignificant effect on equipment qualified life and no effect on Drywell or piping structural integrity. A Drywell walkdown confirmed that there were no visual indications of heat induced damage present.

The diode was replaced on the 'B' EDG generator field rectifier and the EDG was successfully retested and restored to operable status. Engineering is continuing to study the dynamics of EDG response to voltage transients.

ADDITIONAL INFORMATION

Failed Component Identification: The 87A1-B Relay is not considered to be a failed component but rather a relay misoperation.

Field rectifier diode
Manufacturer: PORTEC, Inc. P292
Diesel Manufacturer: Cooper-Bessemer C634

Previous Reported Similar Events: None identified.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
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TITLE (4): Non-Conservative Technical Specification Value

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR	OTHER FACILITIES INVOLVED (8) FACILITY NAMES	DOCKET NUMBER(S)
0 2	1 2	9 2	9 2	— 0 0 2 —	0 1	0 4	0 8	9 3		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)		50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
Mr. James M. Peschel, Regulatory Compliance Manager, ext. 3772	6 0 3	4 7 4 - 9 5 2 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On February 12, 1992 at 1405 it was determined that the existence of a non-conservative value in Technical Specification 4.5.2h.3) and in Station implementing procedures created a condition that could have prevented the fulfillment of the safety function of the Residual Heat Removal (RHR) System relied upon to remove residual heat or mitigate the consequences of an accident. This condition was reported to the NRC as a four hour report on February 12, 1992 at 1612 pursuant to the requirements of 10CFR50.72(b)(2)(iii)(B) and (D).

A value of 2828 gpm rather than 3868.4 gpm was included in the Technical Specifications as the acceptance value for the sum of the RHR injection line flow rates for Surveillance Requirement 4.5.2h.3).

North Atlantic Energy Service Corporation (North Atlantic) determined that on November 11, 1989 the RHR "B" train was tested per Station Procedure ES-89-1-18, "Residual Heat Removal Injection Flow Verification Following Installation of Section Check Valves Per 87DCR311," and a flow rate of less than 3868.4 gpm was accepted. However, North Atlantic has determined through a review of completed tests that the RHR system was always capable of greater than 3868.4 gpm of RHR injection flow if the system had been actuated to provide ECCS flow and that the plant was never in an unanalyzed condition nor in a condition outside its design basis.

North Atlantic subsequently determined during a review of Technical Specification inputs supplied by Westinghouse that Figure 2.1-1, "Reactor Core Safety Limit - Four Loops in Operation," does not accurately depict the loci of points which form the basis for the figure.

Corrective actions include the submittal of Technical Specification change requests and the verification of Technical Specification values supplied to North Atlantic by Westinghouse.

LER NO: 443/92-002

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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SEABROOK STATION	0 5 0 0 0 4 4 3	9 2	— 0 0 2	— 0 1	0 2 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Description of Event

On February 12, 1992 at 1405 it was determined that the existence of a non-conservative value in Technical Specification 4.5.2h.3) and in Station implementing procedures created a condition that could have prevented the fulfillment of the safety function of the Residual Heat Removal (RHR) System relied upon to remove residual heat or mitigate the consequences of an accident. This condition was reported to the NRC as a four hour report on February 12, 1992 at 1612 pursuant to the requirements of 10CFR50.72(b)(2)(iii)(B) and (D).

During a routine review of Station Procedure OX1413.05, "RHR Cold Shutdown Testing", which performs a full-stroke exercise of the RHR pump discharge check valves and associated cold leg injection check valves, an inconsistency was noted between the procedure's acceptance value and that of Technical Specification 4.5.2h.3). The procedure contained a value of 4350 gpm for RHR injection flow while the Technical Specification value was 2828 gpm for RHR injection flow.

North Atlantic requested that Westinghouse review the Emergency Core Cooling System analysis to determine if the RHR flow rate used in the analysis was consistent with the value provided in Technical Specification 4.5.2h.3). Westinghouse notified North Atlantic on August 27, 1991 that 2828 gpm is the appropriate value for flow through three of the four RHR injection lines and that the correct value for flow through four RHR injection lines is 3868.4 gpm and this should be the Technical Specification value. Westinghouse also stated that the inconsistency would not constitute a significant safety issue since Westinghouse procedure TAC-02, "Low Head Safety Injection Test Procedure" required that each RHR subsystem be able to deliver a minimum of 3868.4 gpm, and as long as the plant initially satisfied the TAC-02 procedure requirements and had not made any flow altering modifications the RHR system is assured of meeting the 3868.4 gpm flow requirement.

North Atlantic has determined based on its review of preoperational test records that system flowrates were satisfactory.

During the development and review of a proposed Technical Specification change to revise the value of 2828 gpm to 3868.4 gpm it was determined that the non-conservative value of 2828 gpm was utilized as an acceptance value for post modification testing performed in 1989 related to the installation of check valves in the suction lines to the RHR pumps from the Refueling Water Storage Tank and the Containment Emergency Sump. In this case the RHR injection lines from the RWST were tested per Station Procedure ES-89-1-18, "Residual Heat Removal Injection Flow Verification Following Installation of Suction Check Valves per 87DCR311". The "A" train was tested in September 1989 and the "B" train was tested in November 1989 with the accepted flow values being 4012 gpm for the "A" train and 3776 gpm for the "B" train. The test was performed injecting into the loops with the Pressurizer vented to atmosphere and flow to the Reactor Coolant System (RCS) throttled to ensure that it exceeded the 2828 gpm acceptance value but did not overfill the RCS. Upon discovery of the acceptance of the non-conservative value, North Atlantic reviewed additional test records and determined that on September 10, 1991 during the first refueling outage the RHR system was tested per Station Procedure EX1804.039, "ECCS System Injection Check Valve Testing" which verified system flow rates as 5013 gpm for the "A" train and 4696 gpm for the "B" train. This procedure was performed to verify ECCS check valve operability with the reactor vessel head off and was not performed pursuant to Technical Specification 4.5.2h.3). However, the flow rates obtained for both trains exceeded 3868 gpm verifying that no operability concern or design basis concern exists.

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*U.S.GPO 1986-0-624-538/455

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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SEABROOK STATION	0 5 0 0 0 4 4 3	9 2	— 0 0 2	— 0 1	0 3 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

North Atlantic determined that the existence of the non-conservative value in the Technical Specifications and in the related implementing procedures created a condition whereby a plant modification that restricted RHR injection flow capability could have been implemented and accepted with less than adequate RHR injection flow rates. This condition then could have prevented the fulfillment of the RHR safety function relied upon to remove decay heat or mitigate the consequences of an accident. Therefore, North Atlantic reported this condition to the NRC as a four hour report pursuant to 10CFR50.72(b)(2)(iii)(B) and (D).

The condition was reported soon after it was identified that a value less than the Technical Specification revised value (3868.4 gpm) had been accepted. The original inconsistency in values was questioned by an engineer in the Technical Support organization on May 1, 1990 but it was not until February 6, 1992, during the review of the proposed Technical Specification change, that it was determined that a value less than the revised Technical Specification value had been accepted as a test result. Once this condition was identified it was reviewed and the reporting determination was made.

North Atlantic subsequently performed a detailed review of the appropriate Technical Specification inputs supplied by Westinghouse that were not verified during a previous audit of Westinghouse by Yankee Atomic Electric Company (YAEC). This review identified no additional values that could not be verified as appropriate for Seabrook Station based upon the Westinghouse design documentation. However, it was determined that the curves of Figure 2.1-1, "Reactor Core Safety Limits - Four Loops in Operation," do not accurately depict the loci of points which form the basis for the figure. As an example, the value of Tavg at 1960 PSIA for 100% of Rated Thermal Power from the Westinghouse design data is 605.0°F while the curve from Figure 2.1-1 (copy attached as Figure 1) depicts a value of approximately 606.5°F.

Safety Consequences

There were no adverse safety consequences as a result of this event.

The RHR system was always OPERABLE per the Technical Specifications and was capable of performing its ECCS design function if called upon to do so. The RHR system flowrate was verified through testing, prior to plant operation and again on September 10, 1991, that it would deliver injection flows greater than those required by the ECCS analysis. The potential did exist for a plant modification which reduced the RHR injection flow capability to be implemented and accepted with a flow value less than the ECCS analysis required value. However, no such modifications were made to the plant.

The inaccuracies in Figure 2.1-1 did not create a condition that allowed a safety limit to be exceeded. The normal operation of the plant is controlled by Operations Department procedures which control Tavg to ± 4°F of the Tavg program and a nominal 587°F and maintain Reactor Coolant System Pressure between 2205 psig and 2265 psig. The Reactor Protection System includes the overtemperature ΔT trip and the overpower ΔT trip which would have tripped the reactor, prior to the safety limits of Figure 2.1-1 being approached. These trip setpoints are set such that a reactor trip occurs before the safety limit values of Figure 2.1-1 are reached and are designed to provide positive assurance that the Departure from Nucleate Boiling Ratio of 1.30 is not exceeded.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
SEABROOK STATION	0 5 0 0 0 4 4 3	9 2	— 0 0 2	— 0 1	0 4 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Root Cause

1. RHR Injection Flow

During the development of the Seabrook Station Technical Specifications the non-conservative value for RHR injection flow was entered into the draft Technical Specifications. The original draft Technical Specifications were based upon the Westinghouse Standard Technical Specifications (STS), Revision 3. This version of the draft Technical Specifications was formatted to provide acceptance values for RHR injection flow through three loops and through four loops. The 2828 gpm value was correctly listed for three loop flow while a separate number was to be provided for four loop flow.

Subsequent drafts of the Technical Specifications were provided in the STS Revision 4 format and the flow for RHR injection through four loops was incorrectly listed as 2828 gpm due to administrative error. This error was carried through the final review of the Technical Specifications and was included in the version issued with Operating License No. NPF-56, which was in the STS Revision 5 format.

The actual cause for the discrepancy in the RHR injection flow values has not been determined, but it is attributed to personnel error in the Technical Specification certification process. During the review and certification process, a table of the Technical Specification values was compiled by YAEC for North Atlantic. This table was reviewed by North Atlantic, Westinghouse, United Engineers and Constructors and YAEC and the discrepancy was not identified. In addition, YAEC performed an audit of the Westinghouse calculations that formed the basis for the Technical Specification values. This audit, which sampled approximately 10% of the Technical Specification values, did not identify any discrepancies, however, the audit did not specifically include Surveillance Requirement 4.5.2h.3).

2. Figure 2.1-1

Figure 2.1-1, which was created from the loci of points provided by Westinghouse, was drawn by North Atlantic personnel during the development of the Technical Specifications in 1986. The original draft figure included the existing curves on a grid with 20°F graduations. The nonconservative curves were not identified during the Technical Specification review process. The actual cause for the discrepancy has not been determined, but it is attributed to personnel error in the Technical Specification certification process.

Corrective Actions

Surveillance Requirement 4.5.2h.3) is only performed during shutdowns after modifications are made to the RHR system that alter the system flow characteristics. A Technical Specification change was developed and submitted to the NRC on October 22, 1992 to revise the value for Surveillance Requirement to at least 3868.4 gpm.

A review of Station procedures was performed to identify and revise any procedures that utilize the RHR injection flow acceptance value of 2828 gpm. This review identified no incorrect procedures and was completed in September 1992.

A revision was made to the Station Information Report (SIR) Procedure to require that an SIR be initiated if information is identified that calls into question the adequacy of any value

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
SEABROOK STATION	0 5 0 0 0 4 4 3	9 2	— 0 0 2	— 0 1	0 5 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

specified in the Technical Specifications. This procedure revision was issued on December 16, 1992.

A detailed review was performed of appropriate Technical Specification inputs supplied by Westinghouse, that were not reviewed in the 1986 YAEC audit, to validate the numbers that exist in the current Technical Specifications. There were no additional values identified that could not be verified as appropriate for Seabrook Station by applicable Westinghouse design documentation. However, the curves provided in Figure 2.1-1 do not accurately depict the Westinghouse tabular data upon which the figure is based.

North Atlantic will submit a License Amendment Request to the NRC to revise Technical Specification Figure 2.1-1 to reflect the Westinghouse supplied design data.

Plant Conditions

At the time of the identification of this condition the plant was in MODE 1 and operating at 100% power.

Previous Occurrences

This is the first event of this type at Seabrook Station.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	1 OF 0 7

TITLE (4) A Loss Of Main Control Board Annunciators Caused By Blown Power Supply Fuses During Maintenance Was Not Declared An ALERT Due To Lack Of System Knowledge

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REV. NO.	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
1 0	1 7	9 2	9 2	- 0 1 1	- 0 0	1 1	1 3	9 2		0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR : (Check one or more of the following) (11)

[ ] 20.402(b)	[ ] 20.405(c)	[ ] 50.73(a)(2)(iv)	[ ] 73.71(b)
[ ] 20.405(a)(1)(i)	[ ] 50.36(c)(1)	[ ] 50.73(a)(2)(v)	[ ] 73.71(c)
[ ] 20.405(a)(1)(ii)	[ ] 50.36(c)(2)	[ ] 50.73(a)(2)(vii)	[X] OTHER (Specify in Abstract below and in Text, NRC Form 366A) VOLUNTARY
[ ] 20.405(a)(1)(iii)	[ ] 50.73(a)(2)(i)	[ ] 50.73(a)(2)(viii)(A)	
[ ] 20.405(a)(1)(iv)	[ ] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
Thomas P. Sharkey, Supervising Engineer, Site Licensing	3 1 4 6 7 6 - 8 3 3 6

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	I B	J X	P 0 5 5	N					

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
[ ] YES (If yes, complete EXPECTED SUBMISSION DATE)	[X] NO				

ABSTRACT (Limit to 1400 spaces, i.e. approximately fifteen single-space typewritten lines) (16)

At 0100 CDT, on 10/17/92 during restoration from replacement of a failed power supply, all four field contact power supply output fuses blew causing all RK system Main Control Board (MCB) annunciators to become inoperable. Because only 371 of 683 (MCB) annunciators lit, the licensed operators incorrectly believed that those annunciators which had remained dark were operable. Therefore, an ALERT was not declared as required by plant Emergency Action Levels. The fuses were successfully replaced at 0156. The plant was in Mode 1 - Power Operations at 100 percent reactor power at the time of the event.

The cause of the initial failure of the power supply was a short in the power transformer internal to the field power supply. During restoration following replacement of this power supply, a short occurred while removing jumpers, causing the fuses to blow. The operators failed to declare an ALERT because inadequate knowledge of the RK system led them to believe that some annunciators remained operable.

Training will be provided to personnel on the operation of the annunciator system. Actions to be taken in case of annunciator failures have been detailed in procedures. A modification will be evaluated to improve the reliability of field power supplies and provide detection of power supply failures to the operating crews.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REV NO	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	9 2	- 0 1 1 -	0 0	0 2 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's)(17)

BASIS FOR A VOLUNTARY REPORT:

On 10/19/92, at approximately 1240 CDT, utility engineers reviewing plant operation data from 10/16/92 and 10/17/92, determined that, between 0100 and 0156 on 10/17/92, all of the Main Control Board (MCB) RK system annunciators(1) were inoperable. A phone call was made at 1320, on 10/19/92, in accordance with 10CFR50.72(b)(v) to report an event that resulted in a major loss of emergency assessment capability. This report is being made voluntarily to address root cause and corrective action for the loss of annunciators and the failure to declare an ALERT.

PLANT CONDITIONS AT TIME OF EVENT:

Mode 1 - Power Operations

100 percent reactor power

DESCRIPTION OF EVENT:

At 1840, on 10/16/92, an annunciator (RK system) field contact power supply(2) failed, causing approximately 76 MCB annunciator windows to be lit. At 0058, on 10/17/92, the power supply was replaced and all applicable annunciators cleared.

At 0100, during restoration from the power supply replacement, all four field contact power supply output fuses(3) blew, causing all RK system MCB annunciators to become inoperable. This resulted in 371 of 683 MCB annunciators to be lit. Although loss of all RK system annunciators is considered an ALERT under the plant's Emergency Action Levels, the licensed operators incorrectly believed that those annunciators which had remained dark were operable. The licensed operators were also not aware that all four power supply output fuses had been blown. Therefore, an ALERT was not declared on 10/17/92.

Troubleshooting by the Instrumentation and Controls (I&C) technicians revealed the four blown field power supply fuses. They were successfully replaced at 0156. Other fuses in the logic cabinets(4) of the annunciator system had also failed sometime during the 0100 restoration, but were not initially discovered. Therefore, 164 of the annunciators (those with reflash capabilities) remained inoperable, although the work document was signed off as complete.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REV NO.	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	9 2	- 0 1 1 -	0 0	0 3 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's)(17)

During the day shift on 10/17/92, I&C technicians and the system engineer continued to troubleshoot what was originally believed to be individual annunciator window problems. At 1400, a logic power supply fuse was replaced, reducing the number of inoperable annunciators to 135. At 1800, an additional seven fuses in the logic power supplies were replaced. At 1937, all RK system annunciators were retested and verified operable.

ROOT CAUSE:

A. Failure to Declare an ALERT

The failure to declare an ALERT at 0100, when all RK system annunciators were lost, can be attributed to inadequate knowledge by plant personnel of how the annunciator system functions. Although the licensed operators involved with this event were aware that an ALERT should be called if all annunciators were lost, the fact that about half of the annunciators failed in an unlit state led the licensed operators to believe that those annunciators remained operable. There is no MCB indication of a total loss of RK system annunciators.

Inadequate training exists on the annunciator system for engineers and Operations Department personnel. The lack of knowledge did not allow the determination that the blown fuses resulted in a loss of all MCB annunciators.

B. Equipment Failures

The cause of the initial failure of the field power supply was a turn-to-turn short in the power transformer internal to the field power supply. An evaluation has determined that a short which occurred while removing jumpers following the power supply replacement caused the four field contact power supply fuses to blow. The logic power supply fuses were probably also blown as a result of this short.

C. Contributing Factors

Several other factors were determined to have contributed to this event.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REV NO.	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	9 2	- 0 1 1 -	0 0	0 4 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's)(17)

1. Lack of Communication.

   Prior to the troubleshooting to replace the failed fi[illegible]d power supply, there was no pre-job briefing between the operating crew and the I&C te[illegible]hnicians, planner and engineer performing the work. In addition, the fact that all fo[illegible]r power supplies fuses were blown was not conveyed to the licensed operators by the personnel working in the RK system cabinets located behind the MCB.

2. Supervision

   There was no direct supervision of the I&C techn[illegible]ians during the power supply replacement. An engineer and a planner were pro[illegible]ng technical assistance to the technicians, but their supervisory responsibilities were not clearly defined.

3. Work Controls

   A caution existed in the work package to warn personnel that a loss of all MCB annunciators would require the declaration of an ALERT. However, only the planner who prepared the work request and the operating crew read the work package and were familiar with the caution noted thereon. The specific fuses that were replaced during the job performance were not noted on the work completion form.

4. Retest Considerations

   No retest was specified on the work document for the field power supply replacement. The retest performed measured voltage across the field contact power supply outputs and performed a lamp test of the system. However, this did not reveal that the logic power supply fuses were blown.

5. System Design

   The design of the annunciator system requires the power supplies to be connected in parallel. Thus, temporary jumpers are required whenever one of the power supplies is being replaced. The configuration also causes difficulty in troubleshooting the system, and tends to make individual logic power supply failures undetectable. This design is in part attributable to the fact that the annunciator system is non-safety related.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REV NO.	PAGE (3)
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TEXT (If more space is required, use additional NRC Form 366A's)(17)

CORRECTIVE ACTIONS:

A. Failure to Declare an ALERT

Training will be provided to Operations and Engineering personnel to assure a greater level of expertise on the operation of the annunciator system. Actions to be taken in case of annunciator failures have been detailed in Operations Department procedures.

B. Equipment Failures

A modification will be evaluated to improve the reliability of RK system field power supplies, improve DC power redundancy and provide detection of power supply failures to the operating crews.

C. Contributing Factors

The circumstances surrounding this event have been reviewed with the individuals involved to ensure management expectations are understood. In order to enhance future power supply replacement work practices, the following actions are being taken:

1. A guidance has been developed for retesting of RK system power supplies. This will ensure that Engineering personnel are contacted to determine the scope of retest.

2. Requirements for direct field supervision of critical maintenance activities will be clarified.

3. The requirements for pre-job briefings for critical maintenance activities will be defined and communicated to appropriate personnel.

4. Work completion documentation associated with the fuse replacement has been upgraded to document the fuses which were replaced.

SAFETY SIGNIFICANCE:

Compensatory alarming and non-alarming indications were available to the control room operators throughout the event. These included:

- Engineering Safety Features (ESF) Status Panels with alarm indication for safety-related valves, pumps, and breakers which enables the operators to assess ESF system status and performance.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REV NO.	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	9 2	- 0 1 1 -	0 0	0 6 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's)(17)

- Safety Parameter Display System (SPDS) to assist the operators to assess the onset and severity of accident conditions.
- Digital Rod Position Indication, Control Rod Group Demand Indication, Power Range Nuclear Instruments, and the automatic Reactor Protection System (RPS) to enable the operators to initiate a manual reactor trip, if required, or to be made aware of an automatic RPS actuation.
- Partial Trip Status Panel to indicate a potential or actual RPS or ESF actuation signal is present.
- Permissive/Interlock status panel for OT delta T rod stops, overpower stops, steam dump arming, and condenser availability.
- Radiological Release Information System (RRIS) and the RM-11 Radiation Monitoring panel were available to assist the operators in monitoring meteorological data and radiological monitoring systems in the case a release has occurred.
- MCB analog indications of power, pressures, temperatures, levels, flows, valve positions, etc. to assist the operators in controlling the various plant systems.
- Plant computer CRT displays and alarm typer for approximately 2,836 field input computer points.

Corrective maintenance on the annunciator system was near completion at the time of the unplanned loss of the field contact power supplies. The operators had previously undergone a crew brief of this planned maintenance and were aware of the risk of losing additional annunciators. Therefore, they had a heightened awareness of the MCB indications and a desire to maintain steady state plant conditions by avoiding any distractions or operator induced transients. Due to the loss of the annunciators, the licensed Shift Supervisor delayed the scheduled weekly testing of the main turbine to preclude any change in the plant's steady operation.

Even though the annunciator system is not safety related, the importance of the annunciators to the operators is recognized. The loss of non-safety related annunciators alone for this event did not pose a threat to the public health and safety.

PREVIOUS OCCURRENCES:

None.

LICENSEE EVENT REPORT (LER)
TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REV NO.	PAGE (3)
Callaway Plant Unit 1	0 5 0 0 0 4 8 3	9 2	- 0 1 1	- 0 0	0 7 OF 0 7

TEXT (If more space is required, use additional NRC Form 366A's)(17)

FOOTNOTES:

The system and component codes listed below are from IEEE Standard 805-1984 and 803A-1984, respectively.

(1) System - IB, Component - ANN

(2) System - IB, Component - JX

Manufacturer - PANALARM

Model #70-IDC-2

(3) System - IB, Component - FU

(4) System - IB, Component - CAB

APPENDIX G:
RESOLUTION OF COMMENTS ON THE PRELIMINARY 1992 ASP STATUS REPORT

G. RESOLUTION OF COMMENTS ON THE PRELIMINARY 1992 ASP STATUS REPORT

NRC requested that a list of industry comments on the draft report and the changes which were made as a result of those comments be provided as an appendix to the report. The material presented in this appendix responds to that request. The comments for each potential precursor are listed and discussed in docket number order where the docket number refers to the plant reporting the event. Comments for each potential precursor are further separated between licensee and NRC comments. Only those comments considered pertinent to the ASP study are addressed; that is, comments simply pointing out grammatical or spelling errors are not included.

G.1 LER 219/92-005 Oyster Creek

G.1.1 Licensee Comments

No comments were received.

G.1.2 NRC Comments

No comments were received.

G.2 LER 247/92-007 Indian Point 2

G.2.1 Licensee Comments

Reference: Letter from M. L. Miele, Consolidated Edison Company of New York, Inc., Indian Point Station to the U.S. Nuclear Regulatory Commission, dated June 25, 1993, Docket No. 50-247.

Comment 1: The event is described as a "reactor trip and auxiliary feedwater pump failures". This description suggests that the auxiliary feedwater (AFW) pump failed during this event. In fact, the pumps were fully capable of providing the required flow, even under the reduced suction pressure condition, but were prevented from starting by a protective feature. To more accurately reflect the condition experienced, we suggest that the event description be revised to read: "reactor trip and auxiliary feedwater pump protection actuation".

Response 1: Motor-driven auxiliary feedwater pump (MDAFWP) 21 started and stopped 6 times in rapid succession. MDAFWP 23 did not start when a valid start signal was present and the turbine-driven auxiliary feedwater pump (TDAFWP) was not started. For the purposes of the accident sequence precursor (ASP) analysis, this is assumed not to be nominal system performance. The title has been changed to "reactor trip and AFW pump problems."

Comment 2: In the fifth sentence of this paragraph [B.5.1] it is noted that one of the two MDAFWPs failed to start. As stated above, a more accurate representation of this anomaly is that the pump was prohibited from starting by its protection circuit. Accordingly, this sentence should be revised to reflect this.

Response 2: The sentence was revised to, "... and the other did not start."

Comment 3: In line 10 of this paragraph [B.5.2] it is noted that "No information was available concerning the TDAFWP; presumably its operation was not demanded." We confirm that the TDAFWP did not receive a demand to start signal, however, it would have performed its function on demand during this event. Its function was not demanded due to the immediate mitigating action of closing valve LCV-1128. The TDAFWP would have functioned on demand because its required net positive suction head (NPSH) was well below the low pressure transient condition existing at the suction of the MDAFWP. Furthermore, as noted in the supplemental information provided in Licensee Event Report (LER) 92-17, the TDAFWP does not have a low suction pressure trip. This pump's availability was further confirmed in a test subsequent to the event.

Response 3: It is unclear why the TDAFWP was not employed as indicated in plant procedures during the event, unless there were concerns about its availability. In any event, the ASP AFW model employed correctly reflects the fact that manual intervention is required to utilize the TDAFWP. The Updated Final Safety Analysis Report (UFSAR) for Indian Point indicates that, "The pump itself will only operate on recirculation flow since the AFW regulating valves in its discharge are normally closed. In order to deliver flow to the steam generators (SGs) using this pump, the operator must open one or more of the associated AFW regulating valves, and manually adjust the speed controller for the turbine."

LER 92-017 reports that the MDAFWPs were found to be incapable of performing their safety functions under some design basis conditions. It also reports, in apparent contradiction to LER 92-007, that "it was discovered that both MDAFWPs tripped on low suction pressure when a demand to-start occurred concurrent with the interconnected hotwell vacuum drag make-up line fully open." No data regarding the TDAFW test was provided.

Comment 4: This paragraph [B.5.4] reflects several potential misunderstandings. First, the second sentence indicates that reduced condensate inventory to the AFW system could have occurred had the operators not responded in a prompt manner. However, there are specific system design features to ensure adequate condensate inventory. Had the operators failed to isolate valve LCV-1128, valve LCV-1158 would have closed automatically when a preset storage tank level was achieved. This action would also have alleviated the low suction pressure condition (i.e., isolated the vacuum drag from the condenser). This valve-tank level control system interlock ensures a minimum water level will be maintained in the condensate storage tank (CST) to preserve AFW system inventory. Second, AFW system design provisions, as noted in our UFSAR and in your report includes an alternate supply of water from the 1.5 million gallon city water storage tank.

Response 4: Wording has been modified to make it clear that the concern is for system operability, not water inventory.

Comment 5: Third, the omission of appropriate valve actuation and diverse makeup capability represented by the TDAFWP in your model substantially affects the analysis results. Inclusion of this capability alone would cause the analysis results to approach the cut off frequency. Moreover, an additional recovery was available through the condensate pumps, one of which continued to operate throughout this event. This SG makeup path does not require operation of the main boiler feed pump (MBFP) and is called for by procedure should both the AFW system and MBFPs fail. Further, the operator's response and early recognition of the problem were the result of knowledge and understanding of this phenomena, due to similar past experiences with condensate and AFW system interactions.

Response 5: The ASP analysis assumes the aberrant AFW system behavior indicates or could itself cause a reduction in system availability. For example, starting a large electric motor six times in 74 seconds can cause the motor windings to overheat or cause the supply breaker for the motor to trip. Subsequent removal of the low suction pressure condition does not necessarily restore the system to full availability.

In the actual event, the TDAFWP was not started even though both MDAFWPs were not performing their required function. This implies that there may have been some concern about its availability. In any event, the TDAFWP must be manually aligned to supply condensate to the SGs. Therefore, it is appropriate to model it as requiring operator action to succeed.

Limited data is available concerning the thermal hydraulics, reactor physics, human factors, and other issues related to secondary side depressurization and alignment of a condensate pump for SG makeup. Using available information, an attempt was made to credit this strategy.

It is possible that a review of prior events involving interactions between the condensate and AFW systems could provide additional information on the event analyzed, however no information was available regarding these events so they were not considered.

Comment 6: Lastly, in the third sentence of this paragraph [B.5.4], reference is made to the operation of the AFW pumps with inadequate suction supply, which could result in damage to the pumps. As noted previously, the AFW pumps required NPSH is below the low pressure suction switch setpoint. Thus, the pumps were prevented from starting by a conservatively set protection device. The pumps would have functioned as designed, and were therefore not challenged by this specific condition. As a result of extensive analyses subsequent to this event, we have eliminated the trip function of the MDAFWPs low suction pressure switch, retaining only the alarm function. In regards to the fourth sentence, we confirm that a high SG level trip would result in the trip of the main feedwater (MFW) pumps.

Response 6: This sentence was rephrased.

With respect to the MFW pumps, the LER indicated that a subsequent report was to be issued regarding the aberrant behavior of the MBFP 21, however this report has not been received. In addition, the status of the other feedpump is not clear. If neither of the feedpumps could have been promptly put back in service, then the ASP model for this event may be non-conservative, as it allows for recovery of MFW.

Comment 7: Actuation of the TDAFWP (which was available throughout the event and would have been demanded by procedur. had valve LCV-1128 not been immediately closed) was not modeled.

Response 7: The TDAFWP is modeled in the ASP analysis as not being automatically available to supply the SGs, but credit is given for its manual alignment. This is consistent with the information provided in the UFSAR. See the response to comment 3.

Comment 8: An additional, available and operating recovery path, i.e. condensate pumps, one of which continued to operate throughout this event was omitted from the model.

Response 8: This path was credited in the analysis.

Comment 9: The nonrecovery value assigned (i.e., 0.04) is too pessimistic in as much as the immediate response of the operators reflected a knowledge and understanding of the potential for an open path to the condenser to cause a low AFW pump suction pressure.

Response 9: No information was provided regarding other events in which AFW operability was compromised by use of the condensate makeup line. The recovery value employed is a standard value used in the ASP program for recoveries which may be performed from the control room and which are considered routine or procedurally based. See Vol. 17, Section A.1.3 of this report and references therein for further discussion.

Comment 10: Adequate inventory to the AFW system was never threatened given the automatic control features of the valve LCV-1158 mentioned previously; and

Response 10: Wording of the description has been changed to clarify that pump availability, not water inventory, is the concern.

Comment 11: Automatic operation of LCV-1158 would allow the start (automatic and/or manual) of both MDAFWPs,

Response 11: As above, the concern is that the events described could indicate or cause reduced availability of AFW pumps.

Comment 12: It is our assessment that the estimated conditional probability of core damage of 2.9×10^{-4} is too high and excessively overstates the true risk significance of this event. We believe that the additional information provided herein calls for a conditional core damage probability below the ASP cutoff (i.e., 1×10^{-6}).

Response 12: The event has been re-analyzed, incorporating recently provided information. While the conditional core damage probability estimate has been reduced, this event is still classified as a precursor. In the ASP program, a reactor trip, AFW demand and AFW pump failure or failures will inevitably result in a conditional core damage probability estimate greater than the cutoff.

G.2.2 NRC Comments

G.2.2.1 Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993.

Comment 1: According to the licensee, each MDAFWP receives a signal to start when the respective MFW pump trips. This is the reason why the MDAFWPs received a start signal and the TDAFWPs did not. Also, the MDAFWPs repeatedly tripped because they were equipped with a protective low suction pressure trip feature. The TDAFWP does not have this feature. The licensee asserts that the low suction pressure protective trip for the MDAFWPs was set too high and that the pressure in the AFW suction supply line was adequate at all times during the event. In light of this information, it seems that the failure probability for the TDAFWP should be left at its nominal value with a modification to include that operator action is needed from the control room for the TDAFWP to inject flow into the SGs.

Response 1: The existing model attempts, in a simplified way, to do exactly what this comment suggests. The TDAFWP is modeled as not being available without manual action, but the small non-recovery probability assigned for AFW (0.04) reflects the fact that the TDAFWP was believed to be available for manual alignment to a SG.

Comment 2: [Personnel from] ORNL informed SPSB that the TDAFWP operability had been accounted for in the system nonrecovery value. However, the modeling assumptions state that "because cues existed to indicate the need to isolate LCV-1128, and because an alternate suction supply for the AFW system existed, a nonrecovery value of 0.04 was applied for AFW." The modeling assumptions do not state that the TDAFWP was accounted for in the system nonrecovery value. It would be helpful to either expand the modeling assumptions section to be more explicit or change the modeling assumptions.

Response 2: The text of the analysis has been modified to incorporate this comment.

Comment 3: According to the licensee, there is an automatic protection for CST level which will shut off supply to the condenser to make sure adequate suction supply to the AFW system is still available.

Response 3: The analysis description has been modified to incorporate this comment.

G.2.2.2 NRR Division of Reactor Projects - I/II

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Robert A. Capra, Director, Project Directorate I-1, Division of Reactor Projects - I/II, Office of Nuclear Reactor Regulation, June 30, 1993.

Comment 1: The licensee concluded that the draft ASP contains factual errors concerning system design, equipment design capabilities, and the configuration and capabilities for the event described in the LER.

Response 1: Based on additional information, the analysis has been modified. Also, some wording changes have been made for clarification.

Comment 2: It appears that no credit was given for the availability of the TDAFWP and for the automatic valve actuation which would have alleviated the low suction pressure condition.

Response 2: Eventual automatic closure of LCV-1158 would have terminated the low suction pressure condition in the AFW suction supply. The ASP analysis made the following assumptions, however:

(1) That the 6 start/trip cycles experienced by MDAFWP 21 during the time that suction pressure was low reduced the likelihood that the pump would have automatically started and run properly on subsequent demands. Six starts of a large electric motor in quick succession exceeds desirable operating practice and can result in winding damage, breaker trip, etc.

(2) That manual action would be required to utilize the TDAFWP. LER 249/92-007 indicates that the TDAFWP was available at all times and capable of performing as required. It is unclear, then, why plant operators did not attempt to use it, as called for by procedure. In any event, the Indian Point UFSAR indicates that the TDAFWP must be manually aligned after it starts. Therefore, it should not be credited as being automatically available when demanded.

Based on information subsequently supplied by the Office of Nuclear Reactor Regulation (NRR) program manager, the low suction pressure condition which was believed to have prevented MDAFWP 23 from starting would have cleared before SG inventory was depleted, without operator intervention. Based on this, we fully credit MDAFWP 23.

The most appropriate way to apply the relatively simple ASP AFW model to this event is to assume that only the MDAFWP 23 was immediately available via automatic action to supply the SGs, and to assume a high probability of operator recovery for AFW. Page A-5 of NUREG/CR-4671, Vol. 15, indicates that when "The failure appeared recoverable in the required period from the control room and was considered routine or procedurally based", a non-recovery probability of 0.04 should be applied. Therefore, AFW was modeled with MDAFWP 21 and the TDAFWP assumed to be prevented from automatically starting and running to supply the SGs, but credited with the most reliable (lowest) non-recovery probability used in ASP analyses.

G.3 LER 251/92-007 Turkey Point 4

G.3.1 Licensee Comments

Reference: Letter from T. F. Plunkett, Florida Power and Light (FPL) to the U.S. Nuclear Regulatory Commission, dated June 23, 1993, L-93-161.

Comment 1: The licensee points out the existence of a number of systems that are present at the plant. In addition to the normal sources of MFW and AFW, a nonsafeguards Standby Steam Generator Feedwater (SSGFW) System also exists which is maintained, operated and tested under the Technical Specifications. The SSGFW system is used in place of the AFW system during normal startups and shutdowns. An emergency operating procedure (EOP) directs the operators to utilize the SSGFW if AFW is lost and MFW cannot be recovered. If the SSGFW system cannot be utilized, feed and bleed is then implemented. The SSGFW can be initiated from the control room with the exception of one local valve manipulation. Each of the two SSGFW pumps can supply the post-shutdown feedwater requirements for both units. The pumps receive nonsafeguards power from one of the following sources:

1) offsite power via individual transformers, from eight offsite power lines,
2) one of five fossil unit black start diesels,
3) crossties between units 3 and 4,
4) crossties to the fossil plant.

Response 1: The SSGFW system has been incorporated into the model quantification. The availability of emergency power supplies to the system does not affect the conditional core damage probability for this event since failure of emergency power is not postulated in the modeling of the event.

Comment 2: The event tree provided depicts an accurate plant response with the exception of the availability of the SSGFW system.

Response 2: The SSGFW system has been incorporated into the ASP model quantification.

Comment 3: The representation of the plant configuration as shown in the event tree is correct, with the exception of the SSGFW system.

Response 3: The SSGFW system has been incorporated into the ASP model quantification.

Comment 4: All safety related equipment was operable with the exception of the "B" AFW pump.

Response 4: All safety related equipment was modeled as being operable with the exception of the "B" AFW pump.

Comment 5: The modeling of the AFW system was unclear.

Response 5: The modeling of the AFW system is accomplished by representing each of the pumps as a train due to lack of clear train separation in most AFW systems. Therefore, in the case of AFW at Turkey Point, three trains are included in the model to represent the three pumps. The model utilizes the correct values for the three turbine-driven pump configuration. However, Figure B.5 on page B-25 incorrectly indicated the reference event as loss of feedwater and one MDAFWP. The reference event value was calculated by failing the first AFW pump, using nominal recovery factors for all systems and not including the SSGFW system. Therefore the modeled event and the reference event have significantly different values. The label for the reference event has been changed to indicate a loss of main feedwater (LOFW) and one TDAFWP.

Comment 6: The SSGFW pumps are normally supplied from off-site power, with emergency power being supplied by the non-safety grade diesel generators (DGs).

Response 6: The description has been modified to identify the normal power supply for the SSGFW pumps.

Comment 7: For the subject event, the use of the sequence for LOFW - recoverable, may be inappropriate, as for this event, MFW would not be recoverable so long as the diversion path exists. As a conservatism, the FPL analysis of this event assumes that MFW is not recoverable due to the flow diversion. This diversion path would not affect the availability of the SSGFW system.

Response 7: The MFW system modeling has been revised to reflect that it was not recoverable during the event.

Comment 8: In general, the Office for Analysis and Evaluation of Operational Data (AEOD) nonrecovery probabilities, and specifically the generic nonrecovery probability value of 0.34 used for this specific recovery action seem overly conservative since this specific recovery action is both routine and procedurally based.

Response 8: The system nonrecovery valves for MFW/SSGFW and high-pressure injection (HPI) feed and bleed were both modified. For MFW/SSGFW, nonrecovery was changed from 0.34 to 0.01 to reflect the routine and proceduralized nature of this evolution. However, given the use of SSGFW prior to the use of feed and bleed, the operator failure rate for this event was revised to 0.2. This is the value used by the licensee in their probabilistic risk assessment (PRA) for this sequence (see section 3.9.1.1.1, item number 9 of the Turkey Point PRA).

G.3.2 NRC Comments—Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993

Comment 1: Precursor calculation sheets were not included. SPSB would like to make comments after reviewing calculation sheets.

Response 1: Calculation sheets were provided to SPSB.

Comment 2: Was the standby feedwater system included in the model?

Response 2: It was not included in the modeling of the event in the draft report. The calculation has been revised to incorporate the SSGFW system.

G.4 LER 254/92-004 Quad Cities 1

G.4.1 Licensee Comments

Reference: Letter from Mary Beth Depuydt, Commonwealth Edison to Dr. Thomas E. Murley. Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, dated July 13, 1993.

G.4.1.1 Quad Cities PRA Group (Attachment A to Reference Letter)

Comment 1: Commonwealth Edison provided information concerning automatic depressurization system (ADS) success criteria from the licensee Modular Accident Analysis Program (MAAP) calculations (1 of 5 valves vs. 3 of 5 valves in our analysis).

Response 2. The ASP analysis was performed using the success criteria for ADS in the NUREG-1150 analysis for Peach Bottom, which is considered defensible. No revision to the analysis was considered to be necessary. Note that with consideration of reactor core isolation cooling (RCIC) and the safe shutdown makeup pump (SSMP) (see comment 2) for core cooling success with a single stuck-open relief valve, related sequences are not significant contributors to the conditional core damage probability estimate.

Comment 2: The (preliminary) ASP analysis did not consider the safe shutdown makeup system (a motor-driven HPI pump). This pump can provide core cooling success in the event of high-pressure coolant injection (HPCI) and RCIC failure.

Response 2: The analysis was revised to include consideration of the SSMP.

Comment 3: Commonwealth Edison provided information concerning the need for containment heat removal, residual heat removal (RHR) (shutdown cooling [SDC]) or RHR (suppression pool cooling [SPC]) based on MAAP analyses. The licensee proposed to ignore the requirement for containment heat removal success from certain sequences since it is not required during the first 30 h.

Response 3: The ASP models are intended to address systems and functions required to prevent core damage, even if a sequence is longer than 24 h. Arbitrarily truncating a sequence at 24 h can result in the non-identification of significant failures and underestimate the sequence conditional probability. This comment was not accepted.

G.4.1.2 Quad Cities plant personnel (Attachment B to Reference Letter)

Comment 1: Quad Cities provided information concerning the Final Safety Analysis Report (FSAR) success criteria for ADS.

Response 1: No change in the analysis was required (see comment 1, PRA Group comments).

Comment 2: Quad Cities questioned the success criteria used for RCIC/control rod drive (CRD) in the preliminary analysis.

Response 2: See Modeling Assumptions in the revised analysis.

G.4.2 NRC Comments—Region III

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Edward G. Greenman, Director, Division of Reactor Projects, Region III, June 30, 1993.

Comment 1: The event description should be revised to state that main steam isolation valve (MSIV) closure was caused by a spurious signal, not by a circuitry failure. No failed components were found.

Response 1: The event description was revised to reflect this.

Comment 2: Feedwater could have been re-established by restarting pump B and opening the isolation valves. These actions could have been performed in a short period of time.

Response 2: The analysis was performed based on the assumption that FW was not significantly impacted during the event. No changes were made to the base probability for FW failure (see Modeling Assumptions).

G.5 LER 261/92-013, -014, -017, and -018 Robinson 2

G.5.1 Licensee Comments

Reference: Letter from D. B. Waters, Carolina Power and Light Company to the U.S. Nuclear Regulatory Commission, dated June 25, 1993, RNP/93-1513.

Comment 1: The comment indicates that lack of adequate recirculation line flow for the "B" high-head safety injection (HHSI) pump will only affect its operability under small-break loss-of-coolant accident (LOCA) conditions.

Response 1: This is true. Only the LOCA initiator, and small break transient induced LOCAs have been included in the calculation.

Comment 2: The comment indicates that the three charging pumps are available for the time period that the "B" safety injection (SI) pump was inoperable.

Response 2: The Robinson charging pumps are variable speed positive displacement pumps with a capacity of 77 gpm each. Even with all three pumps running, this does not provide a viable alternative for the mitigation of a small break LOCA. This is supported by the Robinson 2 PRA which states that small break LOCAs are by definition larger than the capacity of the charging system. Table 3-19 of the PRA states the success criteria for reactor coolant system (RCS) injection phase makeup is one of two HPI pumps. As a result, they have not been included in the event modeling.

Comment 3: This comment indicates that the "B" HHSI pump may have been operable for some of the period between July 12, 1992 and August 8, 1992 as supported by test results from July 12, 1992 and performance during the manual SI on August 22, 1992.

Response 3: LER 261/92-018 states that "The blockage identified in August was thought not to be a new piece, but a residual that was too large to enter the recirculation line during July. It is speculated that subsequent use of the SI pumps eroded the material sufficiently to allow it to enter the recirculation line during August." While it is true that the pump worked during the test in July and during the manual SI in August, both of these runs were relatively short in duration when compared to the time period the pump would be needed during an actual small break LOCA event. Given the postulated failure mechanism cited by the utility, the material would be eroded early in the event and subsequently lodged in the recirculation line. This would lead to rapid failure of the pump. Therefore it is reasonable to assume that the "B" SI pump would fail during an actual event despite its success during the test and the manual SI.

The current modeling reflects the inoperability of the "B" HHSI pump and the operability of the "A" HHSI pump. The modeling has been revised (by doubling the unavailability of the second pump from 1.0×10^{-2} to 2.0×10^{-2}) to reflect the potential inoperability of the "A" SI pump. Given the utility's explanation of the failure mechanism, the "A" pump could have also been susceptible to the same failure mechanism. From the location of the debris (RHR, SI, and containment spray system piping, and the refueling water storage tank [RWST]) other systems could have also been affected. However these will not be modeled as being in a degraded condition.

Comment 4: The comment indicates that there is a procedure for post-LOCA cooldown and depressurization that directs the operator to use SGs and the LPSI system for cooldown. The licensee "estimated that the core damage frequency (CDF) would be reduced by two orders of magnitude when the charging pump flow, and mitigation using secondary cooling and low pressure SI are credited for the first two events."

Response 4: Use of secondary side cooldown was evaluated and found to be a viable recovery method at this unit based on the availability of procedures, training and timing of the sequence. This method has been included in the modeling for the loss of SI pump events.

Since the charging pumps are not viable for small break LOCA mitigation, they were not included in the model, see response 2 above. Therefore this has no affect on the CDF. Inclusion of secondary cooldown and use of low-pressure injection (LPI) reduce the CDF by about one order of magnitude (factor of 0.12).

Comments 5 - 8: These four comments provide information on the dedicated shutdown diesel generator (DSDG) and indicate that it was not incorporated into the analysis of the event. The licensee states the DSDG was available throughout the event if required. The DSDG is included in the FSAR and there is a procedure for energizing plant equipment using the DSDG. Data is presented which indicates the DSDG is more reliable than emergency diesel generators (EDGs) A & B and that it has a higher availability. "...it is estimated that the CDF would be reduced by one or two orders of magnitude when the DSDG is credited."

Response 5 - 8: The information provided by the licensee has been used to modify the model to incorporate the DSDG to provide seal cooling and support a battery charger. The licensee indicated that there is a procedure for use of the DSDG, training is provided to appropriate personnel and adequate time exists during the sequence to load the DSDG. This reduces the CDF for the loop event by approximately one order of magnitude (factor of 0.15).

G.5.2 NRC Comments—Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993

Comment 1: The probability for the plant centered loss of offsite power (LOOP) at Crystal River lasting more than 4 h was assigned a probability of zero. This does not seem appropriate since the LOOP at Robinson lasted for more than 15 h.

Response 1: The comment compared the LOOP modeling for the Robinson 2 event (261/92-017) and the Crystal River LOOP (302/92-001). The Crystal River LOOP probability modeling inappropriately assigned a probability of zero to a LOOP lasting more than four h. The Crystal River modeling was modified to correct this error. See the Crystal River precursor (LER 302/92-001) for the modifications made for that event. The Robinson LOOP probabilities have also been modified (see comment 2 below).

Comment 2: SPSB assigned a value of 1.0 to the long term nonrecovery of offsite power since the SBO coping study duration of 8 h was significantly exceeded.

Response 2: NRC Inspection Report 50-261-92-025 indicates that the transformer could not have been restored earlier had the onsite power failed. Therefore, it is assumed that the offsite power was unavailable for the 15-hour period. Under these conditions, assigning a value of 1.0 to the long-term nonrecovery is appropriate. The calculation has been modified to incorporate this change.

Comment 3: This comment asks why the updated Robinson model provided by SAIC was not used in the analysis. That model incorporated the dedicated shutdown diesel (DSDG).

Response 3: The "updated" Robinson LOOP model provided by Mr. Minarick is not a standard ASP program model. Since information is not uniformly available for all emergency power supplies of this type, the current ASP models to maintain consistency between plants do not incorporate non-safeguards DGs. However, the modeling for this event has been modified to incorporate the DSDG using the current ASP model.

G.6 LER 266/92-010 Point Beach 1

Based on analysis changes resulting from comments on this event, the conditional core damage probability was revised to 1.7×10^{-7}. Since this is below the 1.0×10^{-6} precursor cutoff valve, this event is no longer considered a precursor. The documentation for this event has been moved to Appendix D.

G.6.1 Licensee Comments

Reference: Letter from Bob Link, Wisconsin Electric Power Company, to the U.S. Nuclear Regulatory Commission, dated August 26, 1993, VPNPD-93-146, NRC-93-093.

Comment 1: If high pressure SI fails, the operators are directed to cool down the RCS using AFW and the condenser or atmospheric steam dumps per EOP 1.2, Step 5, and depressurize the RCS .... This will enable the plant to use low head SI, preventing core damage.

Response 1: The potential use of secondary side depressurization, LPI and low-pressure recirculation (LPR) in the event of HPI failure has been addressed in the analysis.

Comment 2: Credit for recovery of the closed recirculation valves could be factored into the analysis.

Response 2: Recovery of the high pressure SI pumps requires operator action in a very short time period, considering the time to failure for the pumps if their recirculation valves are closed. This time period was too short to be considered in the analysis.

G.6.2 NRC Comments—Region III

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Edward G. Greenman, Director, Division of Reactor Projects, Region III, June 30, 1993.

Comment 1: The LER number for the analysis should reference both units dockets (266 and 301).

Response 1: The LER reference is correct. LER 266/92-010 reported this event for both units. LER 301/92-010 was not generated.

Comment 2: The first sentence in the Summary should be more clearly stated to read "... common to each unit's two SI pumps."

Response 2: The Summary was revised for clarity.

Comment 3: The second sentence of the Event Description should read "... isolate each unit's respective SI ..." According to information contained in the LER, ... a pump ... would begin to degrade after one minute, ...

Response 3: The Event Description was revised for clarity.

Comment 4: ... the 897 valves could possibly be reopened within approximately 2 - 3 minutes. This assumes that at event initiation, ...

Response 4: The recovery scenario described in the comment requires operator action in a very short time period, considering the time to failure for the SI pumps if their recirculation valves are closed. This time period was too short to be considered in the analysis.

Comment 5: The 897 valves are normally closed for no more than 20 min per test.

Response 5: LER 266/92-010 noted that the valves could have been closed for up to 8 h per year. However, the licensee confirmed that 10 to 20 minutes per test was the most probable value. The analysis was performed assuming 20 minutes per test.

G.7 LER 269/92-004, 005 Oconee 1

G.7.1 Licensee Comments

Reference: Letter from J. W. Hampton, Duke Power to the U.S. Nuclear Regulatory Commission, dated June 23, 1993.

Comment 1: The comment indicates that there are two typographical errors in the event description. It also notes that a previous event (LER 287/91-007, 269/91-009) involving the failure of FDW-315 was analyzed by the ASP program for the 1991 report.

Response 1: The two typographical errors have been corrected.

Comment 2: The second comment indicates that the licensee analysis of the event and the ASP analysis of the event resulted in similar dominant sequences.

Response 2: No response required.

Comment 3: The comment indicates that in a previous analysis of a similar event, the ASP analysis used a nonrecovery factor of 0.04 for the EFW system instead of the 0.12 used in the draft report.

Response 3: The previous analysis referred to by the licensee is for LERs 287/91-007, 269/91-009 found on pages B-157 through B-162 of Volume 16 of NUREG/CR-4674. The valve failure which occurred in this event in unit 1 is identical to the failure which occurred in 1991 in unit 3. The previous analysis inappropriately used a nonrecovery factor of 0.04 for the EFW valve (the standard ASP value of 0.26 was used for the EFW pumps). The current calculation should use nonrecovery factors of 0.26 for both the EFW valves and pumps. The current calculation has been revised to correct this error.

Comment 4: The comment indicates that the SSF is another source of feedwater and would have been available during this event. This should be included in the modeling for the event.

Response 4: The feedwater function of the SSF has been added to the modeling for this event.

G.7.2 NRC Comments—Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993

Comment 1: The comment points out an error in the text which describes the nonrecovery estimate for the EFW system.

Response 1: The nonrecovery value for the EFW system has been set to 0.26. The text has been changed to be consistent with the calculation.

G.8 LER 269/92-008 Oconee

G.8.1 Licensee Comments

Reference: Letter from J. W. Hampton, Duke Power to the U.S. Nuclear Regulatory Commission, dated June 24, 1993.

Comment 1: The sequence of concern, the operator actions required for recovery, and the time involved are described. The licensee concluded that the probability of operator failure to recover emergency power was ~1.0E-3.

Response 1: The event was modeled with an effective failure to recover probability for Keowee of 0.43, based on the situation which was observed subsequent to the October 19, 1992 Oconee 2 LOOP (an on-call technician had to be called to the site to recover Keowee). For plant-centered and grid-related LOOPs, the potential for ac power recovery from the Central Switchyard and the Lee combustion turbines was also considered, using the structured approach to estimating nonrecovery probabilities described in Appendix A to the yearly precursor reports. The potential recovery of the Oconee switchyard was also addressed in the analysis. For plant-centered LOOPs, the overall nonrecovery probability for ac power assumed in the analysis (exclusive of Keowee) is less than 0.001. The probability values used in the analysis are considered appropriate.

Comment 2: The licensee noted (last sentence in paragraph 3 of their letter) that their analysis assumes the Central Switchyard is lost along with the grid during a LOOP.

Response 2: This statement is correct for non-plant-centered LOOPs. The analysis and discussion of this event, LER 269/92-008, and LER 270/92-004 have been revised to separate plant-centered, grid-related, and severe weather-related LOOPs to address this condition. For plant-centered LOOPs, the Central Switchyard is assumed to be available for short-term recovery of ac power. For grid-related LOOPs, the Central Switchyard is assumed to be unavailable; however, power is assumed to be recoverable in ~1 h from the Lee combustion turbines.

G.8.2 NRC Comments--Region III

Reference: Memorandum for Gary M. Holihan, Director, Division of Safety Programs, Office of Analysis and Evaluation of Operational Data from Ellis W. Merschoff, Director, Division of Reactor Projects, July 26, 1993.

Comment 1: Credit for operation of the SSF should be included in the analysis.

Response 1: The potential use of the SSF for RCS and secondary side makeup has been addressed in the revised analysis.

G.9 LER 269/92-018 Oconee 1

G.9.1 Licensee Comments

Reference: Letter from J. W. Hampton, Duke Power, to the U.S. Nuclear Regulatory Commission, dated August 30, 1993.

Comment 1: The ASP analysis makes the assumption that, due to the "X" relay modification, the closing coils to the Keowee auxiliary bus feeder breakers would not close the breakers automatically if required. The identified problem was an insufficient voltage to the breaker closing coils that was not affected by the "X" relay modification. Both Keowee units had been black-start tested before November 24, 1992, and had never experienced the problem identified in the LER.

Response 1: The ASP analysis noted that, under the reduced dc voltage conditions that existed during the emergency start test (and would presumably exist during an actual LOOP), certain modified breakers did not close. The LER described these failures in terms of the "X" relay modification and noted that the problem was corrected by increasing the time that the closing coils were energized. In a discussion with Duke Power (L. Kachnik and G. Cruzan) on September 22, 1993, Duke noted that the auxiliary power breaker problems on Keowee 1 observed during the October 19, 1992 LOOP were potentially attributable to low dc voltage problems. The assumption that these problems existed since the "X" relay modification was completed or were made visible by the modification appears reasonable.

Comment 2: Keowee 1 was functionally tested by the October 19, 1992 LOOP. This event occurred after the "X" relay modification associated with Keowee 1. ... It is also noteworthy that, during the emergency start test, the auxiliary power breakers for Keowee 1, and the field breakers for both Keowee units, did not indicate any problems. The assumption is being made that Keowee 1 was inoperable in spite of two successful trials after the "X" relay modification.

Response 2: It is acknowledged that Keowee 1 operated correctly during the emergency start test. However, problems with Keowee 1 auxiliary power breaker ACB-7 and with the field breakers on both units were subsequently found. This type of event, in which component inoperability is potentially a function of specific voltage levels, is very difficult to address in PRA. In lieu of a component-specific assessment, which would not have been practical, a potentially conservative bounding analysis was performed in which it was assumed that both Keowee units would be unavailable following a postulated LOOP. See the response to comment 1a regarding Keowee 1 performance during the October 19, 1992 LOOP.

Comment 3: For the above reasons, the period of unavailability for both Keowee units assumed in the (preliminary) ASP evaluation (360 h) is too large. This period should have been about 22 h.

Response 3: The unavailability period assumed in the analysis is considered appropriate, considering the nature of the observed failures. Both Keowee units were clearly inoperable during the 22 h period discussed in the comment. However, during most of this period, the standby buses were energized from the Lee steam station. As noted in Modeling Assumptions, this period of time was not of concern in the ASP analysis, since the risk was believed to be relatively small once Lee was powering the standby buses.

Comment 4: LER 269/92-018 does describe a period when both Keowee units were functionally inoperable.... This is a period of 21 h 35 min. ...

Response 4: As noted in the response to comment 1c, the 21 h 35 min period is less of a concern to the ASP program since the standby buses were energized from the Lee steam station during most of this period. Both the Keowee and Oconee operators were aware of the problems with Keowee during this time period. The period of concern is when the potential inoperability was unknown.

Comment 5: The preliminary ASP evaluation says that "the use of CT-5 is described in procedures but the need for manual load shedding is not addressed," however, main feeder buses would automatically load shed....

Response 5: The description of the potential use of the Central Switchyard and the Lee gas turbines for recovery of offsite power via transformer CT-5 has been revised to better characterize, from an ASP standpoint, the issues involved.

Comment 6: The backup emergency power through CT-5 (for the plant-centered case) should be considered more reliable than assumed in this analysis.... A value of 1.0E-03, ... would be appropriate.

Response 6: The nonrecovery probability for this action is still assumed to be 0.12, based on the criteria included in Appendix A to the yearly precursor reports. However, the ASP model also addresses LOOP recovery in the short term via the Oconee switchyard and in the long term (prior to battery depletion). The overall probability assumed in the analysis of not recovering ac power for the plant-centered LOOP case is approximately 0.001 (exclusive of Keowee).

Comment 7: Improvements made since the October 19, 1992 LOOP, the implementation of procedure AP/0/A/2000/002, "Keowee Hydro Station - Emergency Start," and enhanced communications systems make the action to restore power to the Keowee auxiliary buses more reliable. A value of 0.05 for the failure to recover Keowee power in the short term can be justified.

Response 7: As noted in Modeling Assumptions, the revised analysis is a bounding analysis that addresses the potential impact if multiple breakers were to concurrently fail during a postulated LOOP. As a result of the multiple postulated breaker failures, it was assumed that the on-call technician would be required to recover Keowee except during the day shift. During the vulnerability period associated with this event, the on-call technicians were contacted by phone and would then have to drive to Keowee to address the problem, unless it could be handled by phone or radio (telephone conversation with L. Kachnik and G. Cruzan, Duke Power, September 22, 1993). While it is possible that the breaker problems could have been corrected by a phone call, this was not assumed in the analysis.

G.9.2 NRC Comments

No NRC comments were received.

G.10 LER 270/92-004 Oconee 2

G.10.1 Licensee Comments

Reference: Letter from J. W. Hampton, Duke Power to the U.S. Nuclear Regulatory Commission, dated March 10, 1993.

G.10.1.1 Comments contained in the referenced letter

(Duke Power comments have been paraphrased.)

Comment 1: The purpose of the ASP evaluation is to estimate the core melt probability margin of operational events of significance. The analysis appears to utilize conservative and pessimistic assumptions concerning manually operated equipment. The Duke Power estimate of the conditional probability for the event is ~1.0E-5, compared with the (preliminary) ASP estimate of 3.0E-3. While both the ASP program and Duke Power consider the event to be a precursor, there is considerable difference in the numerical results and corresponding significance.

Response 1: The analysis has been revised to incorporate information provided in comments from a number of organizations. The analysis now recognizes the potential for short-term recovery of ac power via the Central Switchyard following a plant-centered LOOP, consistent with the analyses of LER 269/92-008 and LER 269/92-018. The approach used to assign a nonrecovery probability for this action is described in Appendix A to the yearly precursor reports. The assumptions concerning the likelihood of recovering Keowee are considered valid, considering the recovery actions required during the event.

Comment 2: The sixth paragraph of the ASP event description inaccurately describes the Keowee auxiliary power supplies (specific concerns were not identified). This paragraph should be revised to be consistent with the Augmented Inspection Team (AIT) report on the event.

Response 2: The paragraph has been revised to reflect information on the Keowee auxiliary power supplies included in the AIT report.

G.10.1.2 Comments contained in the attachment to the reference letter

Comment 1a: Recovery of Keowee auxiliary power is not dependent on operation of Oconee 1, as described in the preliminary ASP event description. Alternate sources of auxiliary power are identified.

Response 1a: The analysis was revised to remove the requirement for Oconee 1 operation for Keowee auxiliary power recovery.

Comment 1b: The Central Switchyard was available during the event and could have been used to energize transformer CT-5. This action is considered highly reliable.

Response 1b: The analysis has been revised to address the potential for short-term recovery of ac power from the Central Switchyard.

Comment 1c: The potential existed for short-term recovery of ac power through restoration of the switchyard and startup buses.

Response 1c: This was addressed in the analysis (LOOP nonrecovery).

Comment 2: The use of a generic failure probability for the turbine-driven emergency feedwater pump (TDEFWP) results in conservative sequence probabilities compared to those which would be calculated using the much lower Oconee-specific EFW failure probability. These sequence probabilities are also conservative because of the safe shutdown facility (SSF) was not addressed as an alternate source of secondary side cooling.

Response 2: Considering other associated basic events addressed in the licensee's analysis results in an overall EFW pump failure probability consistent with that used in the ASP analysis. The EFW pump failure probability used in the ASP analysis is considered appropriate. The use of the SSF has been addressed in the revised analysis.

Comment 3: The assumption in the (preliminary) ASP analysis that the loss of instrument air (IA) pressure came close to tripping Unit 1 is speculative.

Response 3: The primary IA compressor was lost when 230 kV switchyard isolated. The diesel-driven air compressor was manually started to recover IA pressure. It is acknowledged that estimating a probability of Unit 1 trip due to loss of IA following the LOOP is difficult and involves substantial uncertainty. It is also acknowledged that a possible Unit 1 trip had little impact on the core damage probability estimated for Unit 2, based on the preliminary ASP analysis. Because of this, the potential for Unit 1 trip has been removed from the base analysis. It is still considered as a sensitivity analysis, however.

Comment 4: The ASP analysis did not consider the SSF.

Response 4: The potential for use of the SSF has been addressed in the revised analysis.

Comment 5: It is believed that the major difference between the conditional core damage probability in the ORNL/ASP evaluation and the Duke analysis arises from the lack of credit for SSF capability and the conservatively low reliability assumed for the 100 kV standby source of power in the ORNL/ASP evaluation.

Response 5: Analysis differences regarding recovery of ac power from the 100 kV standby source and the potential use of the SSF have a large impact on the core damage probability estimated for the event. Consideration of the potential for short-term ac power recovery via the Central Switchyard and the potential use of the SSF in the revised ASP analysis resulted in a reduction in the difference between it and the Duke Power analysis by about an order of magnitude.

G.10.2 NRC Comments--Region III

Reference 1: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ellis W. Merschoff, Director, Division of Reactor Projects, Region II, July 26, 1993.

Reference 2: Memorandum for Edward L. Jordan, director, Office for Analysis and Evaluation of Operational Data from Stewart D. Ebneter, Regional Administrator, Region II, March 8, 1993.

Comment 1: It is unclear why the nominal LOOP value used in the (preliminary) ASP analysis differs from previous ASP evaluations for Oconee.

Response 1: The value developed in the preliminary analysis was based on Keowee data developed by the licensee. That data was not used in the final ASP analysis of the Oconee LOOP. However, since the LOOP model was revised from that used in previous analyses, the nominal LOOP core damage probability is still inconsistent with values reported in earlier ASP reports.

Comment 2: The results of SARA model simulations indicate a conditional core damage probability in the range of 2.0E-04 to 4.0E-04. These simulations used similar assumptions to those of the ASP study, but included consideration of the SSF.

Response 2: The revised ASP analysis addressed the potential use of the SSF. The revised conditional probability is within this range.

Comment 3: The (preliminary) ASP analysis used a nonrecovery probability of 0.12 for failure to recover power via the Lee Steam Station. However, during the event, transformer CT5 remained energized via 100 kV power from the Central Switchyard. ... An estimate of nonrecovery via 100 kV sources of approximately 4.0E-02 would be more appropriate.

Response 3: The ASP model for the event has been revised to address recovery of ac power via transformer CT5 from the Central Switchyard for plant-centered LOOPs. The nonrecovery probability for this action is still assumed to be 0.12, based on the criteria included in Appendix A to the yearly precursor reports. However, the ASP model also addresses LOOP recovery in the short term via the Oconee switchyard and in the long term (prior to battery depletion). The overall probability assumed in the analysis of not recovering ac power is 0.001 (exclusive of Keowee).

Comment 4: The licensee's evaluation of the event yielded a conditional probability estimate in the range of 1.0E-05 to 2.0E-05.... However, the licensee used (an optimistic probability) for failing to recover power via 100 kV sources. If the cutsets containing the 100 kV recovery actions are modified such that a nonrecovery probability of 0.04 is used instead, then a rough approximation of the licensee's conditional core damage probability range would be 6.0E-05 to 4.0E-04. This value is consistent with simulations using the SARA model. It should be noted that the licensee's evaluation also included credit for the SSF although the SSF was considered to be degraded.

Response 4: See the response to comment 3 above.

Comment 5: The (preliminary) ASP analysis did not allow credit for the SSF. Even though the SSF may have been degraded during the event, it was available for accident mitigation. The analysis should consider SSF recovery.

Response 5: The revised ASP analysis addressed the potential use of the SSF for RCS makeup and secondary side cooling.

Comment 6: The assumption (in the preliminary analysis) that the loss of control air would lead to a trip of Oconee Units 1 and 3 may not be warranted. The Oconee units have a backup source via the Service Air System.... The probability of 1.0E-01 assigned to the likelihood of a trip to Unit 1 may be overly conservative.

Response 6: The revised ASP analysis addresses the potential for trip of Oconee 1 only as a sensitivity analysis. See the response to licensee comment 3 above.

G.10.3 NRC Comments

G.10.3.1 Office of Nuclear Reactor Regulation and Project Directorate II-3

Reference: Note to Jack E. Rosenthal, Chief, Reactor Operations Analysis Branch, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Alfred E. Chaffee, Chief, Events Assessment Branch, Division of Operation Reactor Support, Office of Nuclear Reactor Regulation, February 12, 1993.

Reference: Note to A. Chaffee, DEAB, NRR from D. Matthews, PD II-3/NRR, no date indicated.

Comment 1: No credit is given in the preliminary analysis for manual cross-connection of EFW from another unit.

Response 1: Potential recovery of EFW by cross-connecting to another unit was not addressed in the analysis. Sequences involving EFW failure are not dominant, and hence consideration of alternate recovery strategies for EFW would not affect overall analysis results. The licensee's analysis of this event also did not credit EFW cross-connect from another unit.

Comment 2: No credit was given to the use of the SSF....

Response 2: The potential use of the SSF is addressed in the revised analysis.

Comment 3: The ASP analysis assigns a probability of failure to energize the standby buses from Lee of 0.12. This value does not appear to consider that CT5 ... is normally energized at all times from the Central Switchyard, ...

Response 3: The modeling assumptions have been revised to more clearly describe the assumptions made concerning recovery of offsite power. Recovery via the Central Switchyard is now addressed. A failure probability of 0.12 is still applied to this action. However, this action is but one of three actions related to recovery of offsite power included in the analysis. The overall probability of failing to recover offsite power (exclusive of Keowee recovery) is 0.001.

Comment 4: The (preliminary) ASP analysis includes a trip of Oconee Unit 1 due to a loss of IA. Although a decrease in IA pressure did occur as described in the analysis, the impact would probably not be as described....

Response 4: The revised base-case analysis does not consider the potential for Oconee 1 trip due to the loss of IA. This is now considered in a sensitivity analysis. See the response to licensee comment 3 (above).

Comment 5: It is unclear whether the analysis takes into account that, during the first 40 - 60 min, Keowee was available for emergency power, and thus the motor-driven emergency feedwater pumps (MDEFWPs) would have been available. Later, when the possibility of the loss of auxiliary power may have resulted in a loss of all ac, the problems with the TDEFWP had been resolved, and thus the usual failure probabilities for the TDEFWP should have been used.

Response 5: The analysis addresses both emergency power success and failure in the ASP model. The increased likelihood of TDEFWP failure, because of the water in the steam line, is applicable to both cases. Note that the potential for recovery of the TDEFWP, had it failed, is addressed in the model.

Comment 6: The licensee has conducted an analysis using an approach similar to the ASP method. ... the licensee core damage probability estimate is 2.1E-05....

Response 6: The licensee analysis has been reviewed as a part of the comment resolution process. The revised ASP analysis includes consideration of the SSF and the use of the Central Switchyard for ac power recovery. This revised analysis estimates a core damage probability of 2.1E-04.

G.10.3.2 Electrical Engineering Branch

Reference: Memorandum for Alfred E. Chaffee, Chief, Events Assessment Branch, Division of Operating Reactor support from Carl H. Berlinger, Chief, Electrical Engineering Branch, Division of Engineering, no date indicated.

Comment 1: The summary should be revised to also note that two component failures, in addition to the operator error, prevented the automatic transfer of the auxiliary power buses, greatly compounding the operator misjudgment.

Response 1: The summary has been revised to reflect this comment.

Comment 2: The event description states that Oconee 1 and Oconee 3 would not have had a source of offsite power available if they had tripped. ... Power was recoverable from the Central Switchyard and from the Lee gas turbines.

Response 2: The text has been revised to note the potential for manual recovery of offsite power.

Comment 3: The eighth paragraph of "Additional Event-Related Information" should be rewritten along the lines of the first paragraph under "Event Description."

Response 4: The intent of paragraph eight is to describe allowed alignments, not to describe the precise alignment at the time of the event. No change to the text was considered necessary.

Comment 4: In the first paragraph under "Modeling Assumptions," the term "failed emergency power" is used. Does this mean that both Keowee units were assumed to be failed?... Transformer CT5 was available throughout the event for ac power recovery.

Response 4: Both Keowee units were assumed to be failed unless auxiliary power was recovered prior to loss of the hydraulic oil used for wicket gate control. The potential use of transformer CT5 for recovery of ac power was addressed in the analysis.

Comment 5: The third paragraph of "Modeling Assumptions" may need to address the fact that ac power was available manually via transformer CT5.

Response 5: The paragraph of "Modeling Assumptions" has been revised and addresses the potential use of transformer CT5 for offsite power recovery.

Comment 6: In the fifth paragraph of "Modeling Assumptions," the assumption that the failure of Keowee is not recoverable....

Response 6: The analysis has been revised to remove the previously assumed requirement that Oconee 1 be available for Keowee recovery.

G.10.3.3 Probabilistic Safety Assessment Branch (SPSB)

Reference: To enf from Stacy L. Rosenberg, February 10, 1993.

Comment 1: Probability of failing to recover auxiliary power to Keowee prior to loss of hydraulic control oil (p=0.5) seems reasonable given that the technician had to drive to the site, diagnose the problem, deal with numerous breaker abnormalities, and restore power to the aux buses within a short time period.

Response 1: No response required.

G.11 LER 285/92-023 Fort Calhoun 1

G.11.1 Licensee Comments

No licensee comments were received on this LER.

G.11.2 NRC Comments

Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993.

Comment 1: The comment points out an error in the relative significance diagram.

Response 1: The error will be corrected.

Comment 2: The comment asks why cooldown using RHR as an alternative to high-pressure recirculation (HPR) was not incorporated into the modeling even though this is not part of the dominant sequence.

Response 2: Of the two dominant sequences for this event, only one involves the failure of HPR. As a result, RCS cooldown and depressurization using the secondary side would only affect one of the two dominant sequences. HPI will initially be successful. Cooldown and depressurization of the RCS using the secondary side is then performed. RHR is initiated when conditions are established. If this fails, then HPR can still be initiated. This recovery action is presently not addressed in the ASP modeling. The current models have been modified to incorporate this possible sequence of events.

G.12 LER 286/92-011 Indian Point 3

G.12.1 Licensee Comments

Reference: Letter from Ralph E. Beedle, New York Power Authority to the U.S. Nuclear Regulatory Commission, dated June 25, 1993.

Comment 1: A clear description of event tree headings should be made. There are no references to the sources used for initiating event probabilities nor component unavailabilities.

Response 1: This information is in the ASP annual reports and associated documentation. See, for example, Volume 17 of this report.

Comment 2: There is no reference for the probability of reactor coolant pump (RCP) seal LOCA. If WCAP 10541 was used to derive this value, a lower value than 0.21 should be considered given lower RCS pressure at the onset of seal failure. IP-3 EOP ECA 0.0, "Loss of All AC Power," directs operators in step 21 to immediately depressurize SGs to effectively cool down and depressurize the RCS. At lower RCS pressure, WCAP 10541 shows a seal LOCA probability of 0.108.

Response 2: For further information regarding modeling of seal LOCA, see Volume 17 of this report and technical letter report ORNL/NRC/LTR-89/11, *Revised LOOP Recovery and PWR Seal LOCA Models*, August 1989. Limited information has been obtained concerning plant thermal hydraulics, reactor physics, operator reliability, and other issues relating to depressurization, so it was assumed that substantial time would be required to depressurize under blackout conditions.

Comment 3: In sequence 53, the probability of non-recovery of ac power should consider non-recovery of the Appendix R diesel generator and the Buchanan substation gas turbines.

Response 3: The contribution of the Buchanan substation to ac power system reliability was considered in the evaluation of ac power recovery probability.

The Appendix R diesel generator was credited in the following way:

The Appendix R EDG is not normally connected to feed safety loads; operators must perform a number of steps to connect it. The ASP program assumes an operator non-recovery likelihood of 0.34 in a circumstance when "[t]he failure appeared recoverable in the required period at the failed equipment, and the equipment was accessible; recovery from control room did not appear possible". If it is assumed that the EDG can be aligned in the short term and that the likelihood of its failure is small compared with the operator non-recovery term, then the Appendix R diesel can be credited by reducing the emergency power non-recovery value by a factor of 0.34. It is also assumed that one EDG is sufficient to supply emergency power.

Comment 4: Sequence 51, failure of HPR (given successful high head injection), assumes that one EDG is restored after a seal LOCA condition has occurred. It is not clear how the probability of loss of HPR was derived. This sequence probability may be much lower considering the facts below:

Response 4: See Volume 17 of this report and supporting documentation for additional information on derivation of branch probabilities.

Comment 5: In section B.13.3 of the report, the FSAR success criteria of two-out-of-three EDGs required to power the minimum service and component cooling water (CCW) pumps was used. However, in reality, operators are directed by the EOPs to close non-essential service water (SW) header valves FCV-1111 and FCV-1112 to prevent SW pump runout during one pump operation. CCW will be available for decay heat removal (DHR) under these conditions. Recirculation failure probability determination would have to include failure to perform this action as well.

Response 5: The ASP program primarily relies on information contained in the FSAR, however it was assumed for this analysis that one EDG is sufficient (also, see the response to Comment 3) for success.

Comment 6: Operators are directed by the EOPs,if only one EDG can be restored, to start and load the Appendix R diesel generator which will make an additional service and CCW pump available. This sequence models high head injection as successful. If the restored 480-V ac bus does not have an associated recirculation pump (as in buses 2A/3A), RHR pump 31 along with high head injection pump 32 can be used together in external recirculation mode.

Response 6: The ASP program places primary reliance on information contained in the FSAR, however in this analysis one EDG is assumed to be sufficient. Also, the available information in contradictory regarding this assumption, see response 3 above.

G.12.2 NRC Comments

G.12.2.1 Reactor Projects I/II

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Robert A. Capra, Director, Division of Reactor Projects - I/II, June 30, 1993.

Comment 1: This event needs to be reassessed for inclusion as an ASP. The event description in B.13.2 and the modeling assumptions in B.13.4 are not correct. Specifically, the facility had been shut down for about 2 months at the time the event occurred. Although two of the three EDGs may have been inoperable for a maximum of 3 days, the facility was in cold shutdown (with minimal decay heat) during the entire period. The draft ASP assumes the plant was at power with two EDGs inoperable.

Response 1: The ASP program analyzes events which occur at shutdown, but which could have occurred at power, as if they occurred at power. It is possible that, during power operations, one EDG could be removed from service while another was simultaneously inoperable due to an unknown failure; therefore this event is modeled as if it occurred at power.

Comment 2: Figure B.27 (Dominant Core Damage Sequence) is illegible.

Response 2: This figure has been reprinted.

G.12.2.2 Division of Operating Reactor Support

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Brian K. Grimes, Director, Division of Operating Reactor Support, Office of Nuclear Reactor Regulation, June 25, 1993.

Comment 1: The preliminary analysis for LER 286/92-011, regarding multiple EDGs being simultaneously inoperable at Indian Point 3, included a postulated 84 h unavailability of two trains of emergency power with the plant at power. However, the LER indicates that the plant was at cold shutdown for the entire duration of the event. Therefore, the preliminary ASP analysis for this event appears to be inconsistent with the associated LER with respect to the power level which existed at the time of the event. DORS has no comments on any of the other preliminary ASP analyses.

Response 1: The ASP program analyzes events which occur at shutdown, but which could have occurred at power, as if they occurred at power. It is possible that, during power operations, one EDG could be removed from service while another was simultaneously inoperable due to an unknown failure; therefore this event is modeled as if it occurred at power.

G.13 LER 301/92-003 Point Beach 2

G.13.1 Licensee Comments

Reference: Letter from Bob Link, Wisconsin Electric Power Company, to the U.S. Nuclear Regulatory Commission, dated June 29, 1993, VPNPD-93-122, NRC-93-080.

Comment 1: The event summary implies that the inoperability of the containment spray (CS) system resulted in the calculated conditional core damage probability. However, as stated in the event description, the calculated conditional core damage probability is based on the loss of the SI system, not loss of the CS system. Revise the event summary to clarify this.

Response 1: The event summary has been revised to clarify this point.

Comment 2: Two of the reference events in the "Relative Significance" diagram are not defined in the section of the draft NUREG that was reviewed by the licensee. These should be defined.

Response 2: A table has been added in the front of Appendix B to explain the events that are indicated on the "Relative Significance" diagram.

Comment 3: The event is appropriately characterized in the draft NUREG. The conditional core damage probability documented by the NRC, 7.3×10^{-5}, correlates well with the preliminary results of the PBNP probabilistic safety analysis.

Response 3: No response required.

G.13.2 NRC Comments

G.13.2.1 Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993

Comment 1: Analysis does not incorporate low pressure SI as an alternative to HPR. Why not, since this is part of the dominant sequence?

Response 1: In this case, HPI will initially be successful. Then, cooldown and depressurization of the RCS using the secondary side is performed. RHR is initiated when conditions are established. If this fails, but the RHR pumps are still operable, then HPR can be initiated. This is presently not addressed in the modeling. The current models were modified to incorporate this sequence of events.

G.13.2.2 Region III

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Edward G. Greenman, Director, Division of Reactor Projects, Region III, June 30, 1993.

Comment 1: It should be noted that containment spray is not needed after entering the recirculation phase.

Response 1: This has been noted.

G.14 LER 302/92-001 Crystal River 3

G.14.1 Licensee Comments

Reference: Letter from P. M. Beard, Jr., Florida Power Corporation to the U.S. Nuclear Regulatory Commission, dated June 22, 1993, 3F0693-12.

Comment 1: The comment indicates that the wording of the present summary does not imply that EDG 3B ran for 2.5 h before being declared inoperable.

Response 1: The summary states that the EDG was declared inoperable after the partial restoration of emergency power. As stated in the text, partial restoration occurred after 2.5 h. Therefore, the summary provides a brief and accurate description of the event.

Comment 2: The licensee states the length of time between the shutdown of the 3B EDG and the time when it was declared inoperable was inappropriately rounded.

Response 2: The licensee method of rounding values is unclear. 2330 hours - 1538 hours = 7 h and 52 minutes. It does not seem appropriate to round this value to 7 h. The description was modified to state the length of time in hours and minutes (7 hrs and 52 min) rather than the approximate value of 8 h.

Comment 3: The licensee states that they have run three cases which they believe are similar to the three cases shown in the ASP report (see table below for a comparison of ASP and licensee conditional core damage probability values). They state the ASP and licensee values for the best estimate (from the DRAFT report) and upper bound cases are "roughly comparable." However, for the lower bound the licensee calculates a value "approximately an order of magnitude less." They believe this lower bound is "the most representative of the CR-3 transient" and that upper bound is "exceedingly conservative" and "has little relevance." The point estimate in the draft report "is only slightly conservative as the 'B' diesel generator was operating in a somewhat degraded condition with problems in the jacket water cooling system." Finally, the licensee states that subsequent to this event, an additional transformer was installed. If it had been installed at the time of this event, it would "reduce the conditional core damage probabilities in the table (below) even more."

Conditional Core Damage Probability			Description/ Assumptions
ASP Value		Licensee Value	
Draft	Final		
1.2×10^{-4}	1.7×10^{-5}	4.6×10^{-5}	ASP Point Estimate.
1.3×10^{-5}	1.3×10^{-5}	1.8×10^{-6}	ASP Lower bound. Assumes EDG 3B and B train equipment operable throughout the LOOP event.
2.6×10^{-4}	2.6×10^{-4}	2.2×10^{-4}	ASP Upper bound. Assumes EDG 3B and B train equipment out of service for entire LOOP recovery.

Response 3: The upper bound is conservative since the 3B EDG did run for the first 2.5 h of the event, although it was degraded. The lower bound is nonconservative, as identified by the licensee, since the EDG was degraded. The licensee states that the event is most appropriately modeled with the "B" EDG operable, "B" train equipment operable, and the "C" inverter operable. However, due to the degraded condition of the "B" EDG this is not the most appropriate modeling.

As recognized by the licensee, the 3B EDG was operating in a degraded condition during the period that offsite power was lost to its associated bus. LER 302/92-002 states the following:

> "Prior to the reactor trip, EDG 3B had a one gph leak from the jacket coolant pump (DJP-2). The leakage was being made up regularly."

Following the LOOP and the starting of EDG 3B, "...leakage from the seal of DJP-2 had increased to approximately 2−3 gpm with the diesel running and make up to account for the increased leakage was difficult. At this point the operability of EDG 3B was questioned." This occurred during the time when offsite power to the associated bus was unavailable.

> "After the diesel was shutdown, ...the leakage had decreased although the volume of the leak was higher than before the trip."

> "...following the automatic start of EDG 3B on loss of the OPT, the leakage had increased to the point where makeup for the leak was no longer practical and the Nuclear Shift Supervisor determined the EDG was not operable."

Seven h and 52 minutes after the EDG was shutdown, it was declared inoperable after discussions between the engineer responsible for the EDG system, the On-Duty STA, and management personnel.

A point estimate calculation should incorporate the degraded condition of the 3B EDG. The point estimate in the DRAFT report was overly conservative in that it assumed that the "B" EDG was inoperable. The point estimate in the final report was developed assuming that the "B" EDG would operate for the first 2.5 hour of the event and then subsequently fail. This decreased the point estimate for the event to a value close to the original lower bound.

G.14.2 NRC Comments

G.14.2.1 Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993.

Comment 1: The comment points out an error in the event tree event labeling.

Response 1: The event tree event label was corrected. This was a typographical error and does not affect the analysis of the event.

Comment 2: What is the basis for setting the probability of a plant-centered LOOP to zero?

Response 2: This was an error in the analysis in the DRAFT report. The probability of a plant-centered LOOP lasting more than 4 h is greater than zero as reflected in the NUREG-1022 estimates. The LOOP probability was revised to correct this error.

Comment 3: What is the basis for modeling the 3B EDG as inoperable?

Response 3: The 3B EDG was operating in a degraded condition during the period that offsite power was lost to its associated bus. The point estimate case presented in the draft report is conservative since the 3B EDG did run for the first 2.5 h of the event, although it was degraded. The point estimate calculation was revised to incorporate the degraded condition of the 3B EDG. It was assumed that the EDG would operate for the first 2.5 h of the event and subsequently fail.

G.14.2.2 Region II

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for analysis and Evaluation of Operational Data, from Ellis W. Merschoff, Director, Division of Reactor Projects, July 26,1993.

Comment 1: The event tree used in the analysis is not consistent with that used in Appendix A of the report. Specifically, the emergency power branch is depicted as RT (Reactor Trip).

Response 1: The event tree event label was corrected. This was a typographical error and does not affect the analysis of the event.

Comment 2: The treatment of the 3B EDG as inoperable is overly conservative. The sensitivity analysis shows that the results are sensitive to this assumption. A more realistic approach would be to assume a degraded EDG. This will yield a result between the as analyzed value of 1.2×10^{-4} and the sensitivity calculation value of 1.3×10^{-5}.

Response 2: The 3B EDG was operating in a degraded condition during the period that offsite power was lost to its associated bus. The point estimate case presented in the draft report is conservative since the 3B EDG did run for the first 2.5 h of the event, although it was degraded. The point estimate calculation was revised to incorporate the degraded condition of the 3B EDG. It was assumed that the EDG would operate for the first 2.5 h of the event and subsequently fail.

G.15 LER 306/92-002 Prairie Island

Based on analysis changes resulting from comments on this event, the conditional core damage probability was revised to 6.3E-07. Since this is below the 1.0E-06 precursor cutoff value, this event is no longer considered a precursor. It's documentation has been moved to Appendix D.

G.15.1 Licensee Comments

Reference: Telecopy from Jack Leveille, Northern States Power Company to Fred Manning, NRC, AEOD, dated June 30, 1993.

Comment 1: In the event description, clarification was provided of the intent of step 5.3.4.g of procedure D2.

Response 1: The parenthetical statement that this comment refers to is no longer considered relevant and has been deleted.

Comment 2: In the second paragraph of the event summary, there were no "initially failed" systems.

Response 2: The wording of this paragraph has been revised for clarity.

Comment 3: This comment is similar to comment 1.

Response 3: See the response to comment 1.

Comment 4: The licensee provided information concerning the cross-connect status of the RHR system at the time of the event.

Response 4: The first paragraph of Additional Event-Related Information has been revised to state that the RHR system was not cross connected at the time of the event. The preliminary analysis was performed with this understanding.

Comment 5: With regard to the next-to-the-last sentence of paragraph 3 of Additional Event-Related Information, the licensee stated that the potential use of the SGs for DHR during shutdown was addressed during operator training.

Response 5: Paragraph 3 has been revised to reflect this.

Comment 6: The licensee stated that Prairie Island 2 never left Cold Shutdown (as indicated in Table B.4 of the preliminary analysis) during the event. Average reactor vessel temperature was always less than 200F.

Response 6: Table B.4 has been revised to reflect this.

Comment 7: Two of three charging pumps are inadequate to refill the RCS and remove decay heat (success criteria for RCS makeup in Modeling Assumptions assumed two charging pumps were adequate as indicated in step 8 of EOP 2×10^{-4}).

Response 7: The ASP analysis has been revised to reflect this.

Comment 8: Both SGs were available for DHR (only one SG was assumed to be available in the preliminary ASP analysis).

Response 8: The analysis has been revised to address the availability of both SGs.

Comment 9: The preliminary ASP analysis estimated that 70 minutes were available for RHR recovery before the RHR suction valve interlock pressure was reached, if little water existed in the SGs. The licensee noted that a much longer time was available, and hence the non-recovery probability assumed for RHR (0.34) was too conservative.

Response 9: The time for RHR recovery was re-estimated based on information provided in comments 4 and 7 from Region III. The time for RHR recovery is now estimated to be greater than 200 min. The probability of not recovering RHR in this time period has been estimated to be 0.03. See Modeling Assumptions for the impact of this revised value on the event analysis.

Comment 10: The analysis is overly conservative due to the reasons described in comment 10.

Response 10: The analysis has been revised. See the response to comment 10.

G.15.2 NRC Comments—Region III

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Edward G. Greenman, Director, Division of Reactor Projects, Region III, June 30, 1993.

Comment 1: Provided wording changes to the Analysis Summary to more accurately characterize the temperature increase during the event.

Response 1: The summary has been revised to clarify the which temperatures were measured during the event.

Comment 2: Recommended a sentence be added to the summary describing why the core damage probability estimated for the event was low.

Response 2: The analysis summaries briefly describe the event and identify the major equipment failures which were observed. They have not included general statements concerning the availability of multiple systems to provide protection against core damage, as was proposed. The documentation has not been revised.

Comment 3: A parenthetical statement in the event description concerning actions to be taken in the event the Emergency Response Computer System (ERCS) becomes inoperable should be deleted, since the ERCS was never determined to be inoperable.

Response 3: The parenthetical statement has been deleted. The wording in the preliminary analysis event description summarized a requirement in the operating procedure that was not viewed by the Region (or the licensee) as applicable, considering the specifics of the event.

Comment 4: Recommended wording changes to characterize the RCS average temperature change (25F) observed during the event.

Response 4: The event description has been revised to more specifically describe the RCS temperature increase observed during the event.

Comment 5: The status of the second SG (available, but not dedicated for DHR) should be clarified in the Modeling Assumptions.

Response 5: Modeling assumptions have been revised to consider both SGs available for DHR. The preliminary analysis considered only the "dedicated" SG to be available.

Comment 6: Information was provided concerning the actual sequence of events prior to entry into EOP 2E-4, "Core Cooling Following Loss of RHR Flow."

Response 6: The Modeling Assumptions have been revised to delete the parenthetical statement concerning the use of the RHR pumps for RCS makeup. The preliminary wording summarized a requirement in EOP 2E-4. However, EOP 2E-4 was not entered until after RCS makeup was provided during the actual event.

Comment 7: The RCS was vented to the pressurizer relief tank (PRT) via the power-operated relief valves (PORVs) during the event. Once the PRT pressure reached the rupture disc failure point, the disc would fail and vent the RCS to the containment. Therefore, the RCS could not repressurize to the RHR suction valve interlock setpoint.

Response 7: The preliminary analysis assumed the RCS could repressurize if DHR was not recovered before the onset of core boiling. With the RCS vented to the PRT throughout the event, the RHR suction valve interlock setpoint would not be exceeded. However, such a vent path is not expected to be sufficient to consider the RCS to be "open" as described in the first paragraph of Modeling Assumptions. Based on this comment, the time to core uncovery was recalculated and the probability of failing to recover RHR was revised (see licensee comment 10).

Comment 8: The RHR suction valves can be operated manually.

Response 8: The preliminary analysis assumed the RHR pump suction valves can be manually operated. The last sentence in Analysis Results notes that if this is not the case and the valves must be operated using the motor operators, then a higher core damage probability would be estimated. The final sentence of Analysis Results has been deleted.

G.16 LER 317/92-008 Calvert Cliffs 1

After further evaluation of this LER, it was determined that this event could be rejected on low probability. The AFW pumps had been incorrectly modeled as two motor-driven and one turbine-driven when they should have been modeled as one motor-driven and two turbine-driven.

Re-analysis of this event with the correct modeling assumptions resulted in the conditional core damage probability being below the ASP cutoff level. As such the event has been deleted from the NUREG.

G.17 LER 327/92-027 Sequoyah 1 and 2

G.17.1 Licensee Comments

Reference: Letter from Robert A. Fenech of the Tennessee Valley Authority to the U.S. Nuclear Regulatory Commission, dated June 25, 1993.

Comment 1: The comment indicates there is a discrepancy between the summary description for the precursor and the LER.

Response 1: The Summary description has been reworded to clarify the sequence of events.

G.17.2 NRC Comments

G.17.2.1 Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993.

Comment 1: The post-trip complications for unit 2 are significant enough that the modeling for the Unit 1 and Unit 2 events should be done separately.

Response 1: Any increase in personnel stress due to minimum control room staffing is not currently reflected in the nonrecovery values in the ASP models. Although the sequence of events for the two units were not identical, from the ASP modeling standpoint they were essentially the same. The event description has been modified to indicate that there was limited staffing for Unit 2.

Comment 2: The 21-second loss of RCP cooling should be reflected in the separate Unit 2 analysis.

Response 2: The centrifugal charging pumps (CCPs) continued to operate throughout the event. This supplied flow to the RCP seals at a reduced rate throughout the 21 seconds when the CCPs and the Thermal Barrier Booster Pumps (TBBP) were tripped off. In addition, the RCP itself has low temperature coolant inventory contained within it. Therefore there was no immediate threat to the RCP seal integrity. This is supported by the lack of a low flow alarm on the discharge of the TBBP outlet (set at < 100 gpm to all four RCPs) and the lack of high temperature alarms on the RCP bearings and seal leakoff lines (set at 180 degrees F) during the event. The NRC inspection report concluded that no seal damage occurred during the event. Had the degraded seal cooling condition existed for an extended period of time, this could have affected the integrity of the seals. However, the operations personnel were aware of the status of seal cooling and quickly took appropriate steps to return seal cooling to the normal mode. Given that the seal cooling was only degraded, and not lost during the event, and that the operators were aware of the conditions and rapidly took corrective action, the model was not modified to incorporate seal LOCAs while the pumps were running. A description of this aspect of the event has been added to the event description.

Comment 3: The small break LOCA event should be used to account for the potential of seal LOCA development.

Response 3: The LOOP tree already incorporates a seal LOCA event due to insufficient cooling following the LOOP. Since the event involved a degradation of seal cooling and not a loss of seal cooling, the model was not modified to include the potential for a seal LOCA caused by insufficient cooling while the pump was running.

G.17.2.2 Region II

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office of Analysis and Evaluation of Operational Data from Ellis W. Merschoff, Director, division of Reactor Projects, July 26,1993.

Comment 1: The challenge to the RCP seals is not addressed in the analysis. Inspection report 50-327/93-02 documents this challenge. The region also conducted a special team inspection in January 1993. One of the significant findings was that both RCP seal injection and thermal barrier cooling had been simultaneously lost to the unit two RCPs. Subsequent calculations revealed that the safety significance of the event was on the order of 2.0×10^{-4}, which agrees with the AEOD estimate of 1.8×10^{-4}. However, the AEOD estimate highlighted the event as a plant centered LOOP. The actual sequence of events were somewhat more complex in that the LOOP was the initiator and subsequent operator errors and component failures were seen which complicated the overall plant recovery. Region II agrees with the overall estimate of the conditional core damage probability associated with this event. However, the event could be more accurately characterized by highlighting the issues associated with RCP seal cooling.

Response 1: The CCW pumps continued to operate throughout the event. This supplied flow to the RCP seals at a reduced rate throughout the 21 seconds when the CCPs and the TBBPs were tripped off. In addition, the RCP itself has low temperature coolant inventory contained within it. Therefore there was no immediate threat to the RCP seal integrity. This is supported by the lack of a low flow alarm on the discharge of the TBBP outlet (set at < 100 gpm to all four RCPs) and the lack of high temperature alarms on the RCP bearings and seal leakoff lines (set at 180 degrees F) during the event. Had the degraded seal cooling condition existed for an extended period of time, this could have affected the integrity of the seals. However, the operations personnel were aware of the status of seal cooling and quickly took appropriate steps to return seal cooling to the normal mode. The NRC inspection report stated that "Current industry guidance indicates that the RCPs can operate for only very short periods of time without both seal injection and the thermal barrier cooling.... from an accident initiation standpoint, the events .... were a significant precursor to a RCP seal LOCA scenario." However it also stated that "Subsequent investigation by the licensee indicated that no discernable RCP seal degradation had occurred in this particular scenario." Given that the seal cooling was only degraded, and not lost during the event, and that the operators were aware of the conditions and rapidly took corrective action, the model was not modified to incorporate seal LOCAs while the RCPs were running. A description of this aspect of the event has been added to the event description.

G.18 LER 328/92-010 Sequoyah 2

G.18.1 Licensee Comments

Reference: Letter from Robert A. Fenech of the Tennessee Valley Authority to the U.S. Nuclear Regulatory Commission, dated June 25, 1993.

Comment 1: Only two of the three calculations described in the text were included in the report. The missing calculation is for the unavailability of the CCPs and the RHR pump.

Response 1: The calculation for the CCP and RHR pump unavailabilities that was missing from the draft report was removed from the final report. In general, the ASP program has not modeled events with only the CCPs and one train of safety related equipment inoperable. Therefore, for consistency between the calculations in the report, the calculation for the CCP/RHR unavailability was removed. The text of the analysis has been changed to mention that the six-hour CCP unavailability/RHR pump failure was not modeled.

Comment 2: The model allows no credit for the SI pumps for use as HPI.

Response 2: The calculation involving the inoperability of the CCP and the RHR pump was removed from the report as noted above. For the remaining calculation, the HPI pumps and the CCPs were included in the HPI system. The Modeling Assumptions section of the event analysis provides a complete description of how the CCPs were incorporated.

G.18.2 NRC Comments—Probabilistic Safety Assessment Branch (SPSB)

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from Ashok C. Thadani, Director, Division of Systems Safety and Analysis, Office of Nuclear Reactor Regulation, July 1, 1993.

Comment 1: One of the calculation sheets was not provided.

Response 1: The ASP models do not explicitly model the CCPs. As a result the original calculation for the unavailability of the CCP and the RHR pump for six h was performed by failing the entire HPI/CCP train. In general, the ASP program has not modeled events with only the CCPs and one train of safety related equipment inoperable. Therefore, for consistency between the calculations in the report, the calculation for the CCP/RHR unavailability has been removed. In addition, only the LOOP initiator is normally run when an EDG and only one other train of equipment is inoperable since for the transient and LOCA initiators only the RHR inoperability affects the calculation. This means that there is only one calculation for this precursor which models the inoperability of the RHR pump and the EDG for

17 h. The text of the analysis has been modified to mention that the six-hour CCP unavailability/RHR pump failure was not modeled.

The modeling for the remaining calculation involving the RHR pump and the EDG has been revised to incorporate the CCPs. This marginally decreases the conditional core damage probability.

G.19 LER 344/92-020 TROJAN

G.19.1 Licensee Comments

Reference: Letter from James E. Cross, Portland General Electric Company to the U.S. Nuclear Regulatory Commission, dated June 28, 1993.

Comment 1: The preliminary analysis modeling assumptions (Item B.20.4) describes this event as a reactor trip with loss of feedwater and one AFW pump unavailable. The non-safety related AFW pump was assumed capable of providing SG cooling following a manual start. However, the analysis also assumed that no procedures were available for this action. This assumption is incorrect. Operator response to a loss of feedwater event, including the failure of the AFW pumps to start, is specified in Functional Restoration Instruction (FR-H.1), "Response to Loss of Secondary Heat Sink" and Emergency Instructions (EI-0), "Reactor Trip, Safety Injection, and Diagnosis". Off-Normal Instruction (ONI) 55, "Operation of Electric Auxiliary Feedwater Pump Supplied by Emergency Diesel Generator" was also available to provide procedural steps necessary to start the electric AFW pump if offsite power was not available during the performance of FR-H.1. Copies of the appropriate sections of the procedures are attached for your review. Trojan's Nuclear Plant Operators are also trained for various loss of feedwater events in both classroom lecture and the plant simulator. It is important this information be considered in the final report modeling assumptions.

Response 1: It was assumed in the analysis and the procedures subsequently confirmed that the non-safety AFW pump would be available. Availability of appropriate procedures was also assumed. The text of the analysis report has been corrected to reflect this.

G.19.2 NRC Comments—Region V

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data from K. E. Perkins, Jr., Director, Division of Reactor Safety and Projects, June 30, 1993.

Comment 1: The ASP analysis reasonably represented the configuration and capabilities of plant equipment at the time of the event. However, we found that the ASP report may not have accurately characterized the plant's response to further possible plant system failures in that it did not account for some mitigating actions contained in the licensee's procedures.

Paragraph B.20.4 of the ASP report noted that the analysis assumed that the licensee did not have procedures to use the non-safety-related AFW pump to supply emergency cooling to the SGs. The Trojan resident inspector found that the licensee's EOPs included directions for the use of the MDAFWP in response to a loss of feedwater event. The EOPs also included steps to provide the MDAFWP with safety-related power in the event its normal, non-safety-related power supply is disabled. The resident inspector has observed licensed operators successfully implement these steps during simulator exercises. In addition, the EOPs included steps to reduce main steam pressure using the main steam line PORVs and supply the SGs with the condensate pumps. Operators would have attempted this after attempting primary side feed-and-bleed operations.

Response 1: The model credits the non-safety-related AFW pump. The analysis text has been revised to incorporate the comment concerning use of EOPs.

Limited information has been obtained concerning the plant thermal hydraulic behavior and operator performance during rapid secondary side depressurization and cooldown. A human factors specialist who was consulted on this issue believes that the nonrecovery probability should be quite high in this scenario, since time would be short and stresses would be great after failure of feed-and-bleed, and operators would be required to perform actions outside the control room. Nevertheless, since the EOPs exist and training is conducted on these EOPs, it was determined that this was a viable alternative. The impact of using this process was calculated by adjusting the AFW nonrecovery probability from 0.34 to 0.12.

G.20 LER 374/92-012 LaSalle County 2

G.20.1 Licensee Comments

Reference: Letter from Mary Beth Depuydt, Commonwealth Edison to Thomas E. Murley, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, dated July 13, 1993.

G.20.1.1 PRA Group Comments (Attachment A of reference letter)

Comment 1: No basis for the nonrecovery probabilities used for RCIC and FW is provided. These values appear quite high compared to values used in other studies.

Response 1: The basis for assigning nonrecovery probabilities is described in Appendix A to the yearly precursor report. Some nonrecovery values may be conservative compared to those used in other studies.

Comments 2 and 3 were editorial in nature and were incorporated.

G.20.1.2 LaSalle Comments (Attachment C of reference letter)

Comments 1 - 4 were editorial in nature and were incorporated.

Comment 5 was an editorial comment on the electronic version of the LER that was included with the analysis in the draft report. Electronic versions of LERs were not used in the final version of the precursor report.

G.20.2 NRC Comments

No comments received.

G.21 LER 388/92-001 Susquehanna

G.21.1 Licensee Comments

Reference: Letter from R. G. Byram, Pennsylvania Power and Light Company to Director of Nuclear Reactor Regulation, Attention: Mr. C. L. Miller, Project Director, Project Directorate I-2, Division of Reactor Projects, U.S. Nuclear Regulatory Commission, dated June 30, 1993, PLA-3994

Comment 1: The durations for DG unavailability cited in the NRC letter appear to be inaccurate. DG "B" would have been immediately available had we manually switched to the intact generator field rectifier bridge 2 diode after bridge 1 diode failed. We elected to repair DG "B" instead. Therefore, no DG was available to cover the "B" bus from 0831 on March 18, 1992, when DG "B" tripped, until 0750 on March 19, 1992, when DG "E" was placed in service (data from Unit Log - PCO Log). If it had become necessary, either DG "B" or DG "E" could have been made available for the B bus within 2 h. The 72 h referenced in the NRC letter refers only to the LCO time as stated in Technical Specifications. DG "C" was never unavailable. DG "C" was running in the emergency mode, ready and fully capable for use. Channel 2C bus only was unavailable. The 2C bus could have been energized immediately, however the decision was to proceed slowly and purposefully on the cause of the problem and bus/relay integrity.

NRC estimates the conditional probability of core damage given the equipment failure combination that occurred on March 18, 1992 to be in the range of 3.6E-06 to 1.7E-07 per reactor year. The range in core damage frequency is a result of the values used to estimate the probability of ac power recovery used by the analysts who prepared the analysis. Based upon our understanding of the data and model used to analyze the SCRAM of 3/18/92, we believe that the conditional probability of core damage for SSES for this event falls orders of magnitude below the threshold value of 1.0E-06. In the report, the NRC is emphatic that "the conditional probabilities determined for each precursor cannot be directly associated with the probability of severe core damage resulting from the specific event at the specific reactor plant at which it occurred." However, PPL is sensitive to misinterpretations or misapplications of the "high" values of calculated core damage frequency ascribed to an event at SSES.

Response 2: In agreement with specific comment 2 below, the modeling of the event was modified to represent it as a transient with an engineered safety feature (ESF) bus unavailable. Accordingly, the comments regarding EDG availability and reliability are no longer applicable. Regarding the restoration time for ESF bus C: many utilities procedurally require that the cause of a bus lockout be determined before restoring the affected bus to service. Based on the performance during the event, it seems that a substantial delay would likely occur before the bus could realistically be restored to service.

Comment 2: The title of the event, "Three of Five EDGs Unavailable for Eleven Hours", is not indicative of what occurred and does not represent SSES emergency DG power requirements. Functionally, only one diesel failed. The DG "C" was running and could have been loaded onto the bus after resetting the lockout. In addition the spare DG "E" was always available for tie in which requires less than 2 h. The SSES design is 3 of 4 emergency DGs with a spare that can be manually substituted for any of the four EDGs.

Response 2: The title has been changed to, "Reactor trip with EDG and vital bus unavailable." The focus of the analysis has been similarly shifted.

Comment 3: This event was modeled as a transient initiator, 'Loss of an ac bus' in the Susquehanna Individual Plant Examination (IPE). The ac bus loss precipitates a MSIV closure through the loss of containment instrument gas. The NRC instead chose to treat it as a LOOP probably due to the loss of DG "B" and the C 4160V ac bus. (Note that MSIVs will also close on LOOP)

Response 3: The event is now modeled as a transient with one ESF bus unavailable.

Comment 4: Given the NRC modeling of the event, we were unable to reproduce the calculated conditional core damage probabilities. When applying an ac non-recovery factor of 0.8 we calculate a conditional core damage probability of 1.8E-06 instead of 3.8E-06. If we presume the LOOP exposure is about 2 to 3 h, the NRC frequency can be reproduced. However, the actual event included a reactor trip so the choice of 2 to 3 h is arbitrary on our part and does not reflect the risk reduction due to SCRAM and reduced decay heat at 3 h.

Response 4: See the response to Comment 2. Since the event is now modeled as a transient with one ESF bus unavailable, this comment is no longer applicable.

Comment 5: The LOOP frequency used by the NRC is 1.6E-05/hr (0.14/year) compared with a Susquehanna specific value of 6.4E-06/hr (0.057/year). The NRC value is on the high side for Susquehanna which has not experienced a LOOP during 11 site years of operation, but probably reasonable when considering the entire reactor population.

Response 5: Agreed.

Comment 6: The NRC presumes three DGs failed when in fact only one DG failed. DG "C" started and ran, but was not loaded onto the bus due to the bus lockout. The DG "E" was in stand-by and was started and loaded onto the B ESS bus. This affects the treatment of subsequent diesel failures. With only DG "B" diesel failed, the probability of failing the remaining diesels, A, D & E, using the emergency power branch model should be;

$$P(ep) = 0.057 \times 0.190 \times 0.500 = 0.0054$$

instead of;

$$P(ep) = 0.190 \times 0.500 = 0.095$$

which was used in the precursor analysis. This adjustment results in the conditional core damage probability of 3.8E-06 becoming 2.2E-07. This value is below the precursor cut off probability of 1.0E-06.

PP&L has included DG "E" in the evaluation of onsite ac power recovery above because since this diesel can be connected into any of the four 4 kV busses. Without consideration of DG "E" we recommend that a value of 0.01 (0.057 × 0.190), be used for the failure probability of emergency power when using the NRC diesel failure model. However, statistical analysis of Susquehanna diesel failure data indicates that multiple diesel failures occur at a rate consistent with what would be expected as the result of independent failures. Therefore, using Susquehanna specific data, a value of 0.0025 (0.05)**2 is recommended for the failure probability of emergency power.

Response 6: See the response to Comment 2. As the event is now modeled as a transient with one ESF bus unavailable, this comment no longer is applicable.

Comment 7: It appears from the information provided, that long term station blackout is the dominant contributor to core damage for this event. Core damage occurs in this event because ac independent safety systems become unavailable when dc control power is lost due to battery discharge. Core damage is prevented by ac power recovery. It is presumed from the information in NUREG/CR-4674 that battery depletion occurs between 2 and 4 h following the station blackout. Therefore, ac power must be recovered within this time frame to avoid core damage. The precursor analysis accounts for ac power recovery. The NRC used three values for failure to recover ac power; 0.8, 0.34 and 0.04 with the 0.04 being considered the best choice for calculating core damage frequency. These values were compared with those representative of Susquehanna.

Ac power recovery data from the Susquehanna IPE was obtained. Susquehanna is committed to cope with station blackout for at least 4 h. Battery discharge calculations demonstrate that the limiting time is actually 6 h. Susquehanna also has a standby diesel that can be tied into any of the four 4 kV busses. Additionally, we have placed a 100 kw diesel generator at Susquehanna to provide ac power to the battery chargers. This diesel has a 24 hour fuel supply that can be replenished from the 1E diesel fuel source. Therefore, if this diesel is operable, dc control power will not be limiting at Susquehanna. Using this information, an ac power recovery table has been constructed for Susquehanna as shown below. This data was derived from NUREG-1032 and Pennsylvania New Jersey Maryland (PJM) power pool data for offsite power recovery, Susquehanna diesel maintenance records through 1989 for diesel repair and DG "E" logs through 1989 for DG "E" availability and tie in time.

Susquehanna Specific Non-Recovery Data

Recovery Time	Offsite Power	Offsite Power & DG Repair	Offsite Power, DG Repair & DG "E" Tie-in
3-h battery discharge and 1-h reactor pressure vessel (RPV) water level boil-down	0.087	0.046	0.015
4-h battery depletion and 2-h RPV water Level boil-down	0.060	0.022	0.007
Credit for charger diesel, core damage postulated at 24 h	0.0056	0.0012	0.0004

If DG "E" diesel is included in the Event Tree Top Event emergency power, then the third column should be used for assessing ac power recovery. If the DG "E" is the Event Tree Top Event "LOOP REC (LONG)", then the fourth column should be used for ac power recovery. The NRC recovery value of 0.04 seems to correspond to a 3 hour coping time. This implies that no credit was given for station blackout rule compliance or station blackout enhancements such as the charger diesel. We recommend that the NRC use a value of 0.0004 in conjunction with the emergency power failure probability given in comment 5 when assessing the probability of ac power recovery. This value accounts for those improvements made to comply with the station blackout rule and other plant enhancements installed by PP&L to reduce the risk from station blackout.

Response 7: See the response to Comment 2. As the event is now modeled as a transient with an ESF bus available, this comment is no longer applicable.

Comment 8: The event tree model gives no credit for RCIC operation given a stuck-open relief valve. PP&L calculations performed with the ORNL BWRSAR code demonstrate that the RCIC system will remain operable with a stuck-open relief valve. The HPCI system on the other hand will trip on low steam pressure.

Response 8: The model for the event has been modified to credit RCIC.

G.21.2 NRC Comments

No NRC comments were received.

G.22 LER 483/92-011 Callaway

G.22.1 Licensee Comments

Reference: Letter from A. C. Passwater, Union Electric to the U.S. Nuclear Regulatory Commission, dated August 26, 1993, ULNRC-2845.

Comment 1: ... Changes to the generic model should include the reason behind the change .... because often the changes made to the base model are due to a condition which existed during the Annunciator event and were not a result of the event itself. This will help the reader differentiate causes and effects when reviewing the document.

Response 1: The analysis has been revised to clarify the reasoning behind the changes to the base model. The key to this event was that after the initial annunciator repairs, a significant number of alarms remained unavailable, unlit, and this condition was unknown to the operators. The effect was that the operators continued with normal operations (e. g., rad waste processing, turbine valve testing and switchyard breaker testing); had they known that the annunciators were unavailable the activities would have been suspended until the annunciators were repaired. In addition to the normal plant model that accounts for equipment faults, the ASP model was adjusted to include errors in performing the on going tasks that could trigger initiating events, or leave a system in an unavailable state. Also, it was assumed that the operator responses to a variety of event sequences would be degraded because of the lack of annunciators. Thus, adjustments to the ASP model include primarily effects of the event rather than the causes of the annunciator tile unavailability. The adjustments were included within the constraints of the ASP logic model. The models were adjusted from a base probability to include human reliability changes. In no case were values changed to a failure probability of 1.0, because diverse instruments were assumed to be available in the control room.

Comment 2: The contractor has increased the probability that the HPI system will not perform its intended function (by eight times for train A). Because Callaway's HPI systems are fully independent of the annunciator system, we believe that HPI train A unavailability should not increase.

Response 2: It is true that the systems are independent from a hardware viewpoint, however, the change in system unavailability was not a result of potential problems with the auto-start function, but with control of injection flow later in an event. This includes the potential for securing the HPI systems prematurely, since annunciators (which have direct sensor interface to the plant) would provide an inaccurate picture of the plant condition. For example, unlit annunciators that might cue operators to prematurely secure HPI are PZR SFTY VLV OPEN (A35), PORV OPEN (B35), PZR SFTY DISCH TEMP HI (C35), CHG LINE FLOW HILO (A42), CHARGING PMP TROUBLE (E42), ACC TK A LEV HILO (A43), SI PMP TROUBLE (A49), RCS SATURATE (A56), and RCS < 50 SUBCOOL (B56). This assessment is reasonable for a degraded instrument condition that was unknown to the operators.

Comment 3: Changes to nonrecovery probabilities are possible assuming degraded annunciators; however, we feel the increase in (some) nonrecovery probabilities ... is extreme. If AFW was lost during an accident, the operator would be alerted by the ESFs status panels. In addition, the SPDS and EOP FR-H.1 would direct the operator to take the necessary actions, including AFW restoration, based upon reading control board indications. The control room indicators and ESF status panels (SA066X, SA066Y and SA066Z) were not impacted by the loss of annunciators...

Response 3: It is acknowledged that some of the assessments may be conservative in reducing the crew reliability estimates and incorporating the result into the ASP model. This is due to a lack of information on the ability of crews to dynamically interact with the plant equipment under conditions with degraded instruments. For example, if the automatic AFW start fails (as considered in the basic ASP model) and if the annunciator tiles SG level Lo Lo (A85), No AFP start (B129), and AFW suct switch to Con (C127) did not light (as would be the case according to the LER), the crew could assume initially that AFW was running when it was not. Use of the ESF status panels and SPDS to trigger the use of EOP FR-H.1 might be delayed as the crew verifies conflicting instrument status. It was assumed that the crews give highest priority to the hardwired annunciators rather than the computer generated signals from the plant computer. Note that only a small change was made to the AFW nonrecovery probability to reflect the fact that failures that would normally be quickly recovered in the control room could be delayed. In the case of the PORV failure to reseat, credit for recovery was given in the basic ASP model. However, loss of annunciator [PORV open (B35)] would provide operators with misinformation in certain sequences. To account for this conflicting information actions in the ASP model, the PORV reset nonrecovery probability was increased from 1.1E-2 to 4.2E-1, primarily due to a slow response. This was one of the few recovery actions that was adjusted to a significant degree. Demonstration of the crew reliability for PORV control with degraded instruments in the simulator could be used to reduce this factor.

Comment 4: With respect to a postulated LOOP, breaker V85 was closed when the largest number of annunciators was lost. At all times two offsite power circuits were available.

Response 4: The basis for the assessment was that the likelihood of a LOOP increases when maintenance activities are performed in the switchyard. The error modes that could trigger a LOOP could be improper isolation, selecting the wrong breaker, and inadvertent triggering. These error modes can affect operating lines as well as those out for maintenance. Of 37 LOOP events from 1965 to 1990, 18 were initiated by errors associated with maintenance activities. The revised frequency for LOOP is considered appropriate.

Comment 5: With respect to a postulated LOCA, the Discharge Monitor Tank A in the Radwaste system (that was involved in a discharge at the time of the event) is not connected to the RCS. In addition, no abnormal leakage from the RCS was noted during the annunciator event.

Response 5: The preliminary assessment was based on the potential need during rad waste processing to perform let down from the RCS to transfer radioactive primary coolant into the waste processing system. The increase in LOCA initiator frequency was then based on incorrect valve operations that could allow high pressure systems to connect with low pressure systems. Since there was no connection between the radwaste system and the RCS at the time of the event, the analysis was revised to use the base-case LOCA frequency.

Comment 6: ..the analysis uses 18.5 h for the event, while the actual time when the most annunciators were unavailable was 56 minutes. During the remaining time, only 164 and 136 annunciators were unavailable. Also, compensatory alarms and non-alarm indicators were available. These are the ESF status panels, SPDS, Digital Rod Position indicators, partial trip status, Permissive/interlock status panel, Radiological Release Information System, main control board analog indications of power, pressure, temperature, level, flow, valve positions, etc. that assist operators in controlling plant systems. In addition, the plant computer CRT displays and alarms for approximately 2836 input computer points were available.

Response 6: The modifications to the base risk model addressed the 136 annunciators that were out for the duration of the event. The basis for changes to the data depend on the activities that were in progress during the event period, not the event duration. The on-going task error probabilities were averaged over the event duration to estimate changes to frequencies. Thus, changing the duration of the event would have little effect on the frequency of the initiating events or changes to the recovery actions. If other activities are on-going, such as turbine valve testing, breaker tag outs in the switchyard, normal I&C testing, etc., the crews attention may be focused on completing the testing and surveillance tasks, including communication with plant technicians. Hence, greater reliance is placed on the audible alarms associated with the annunciators. The assumption was made that diverse instrumentation was available to the operators. It was also assumed that alarmed annunciators provide positive detection capability during multiple task operations, and that crews give highest priority to the annunciator systems, and second priority to the plant computer controlled systems which, until recently, have been sources of lower information reliability.

Comment 7: With regard to the unavailability and nonrecovery associated with the pressurizer PORVs and safeties... TMI upgrades provide independent verification of reactor pressure on a digital readout. Response to a decrease in reactor pressure, indicative of an open PORV or safety valve, is stressed during operator training. Operators use the limit switch indications to identify the affected valve and take corrective actions.

Response 7: In the ASP assessment, the key contributor was a slow response caused by conflicting information. While a decrease in the reactor pressure is a symptom of an open PORV, it is also a signal for a SGTR, a LOCA, or other primary system breach. Based on a review of the information provided in the reference letter, a reduction in the error probability could be justified, if simulator data were available. The crew response time data from simulations on this or similar events could be used to modify the assessment by verifying the way the event is identified (considering other failure modes the lower limit for this event would be about 4.0E-2 from a current value of 4.0E-1). See also the response to comment 3.

Comment 8: ...procedure EOP FR-H.1 is used to restore feedwater to SGs or initiate feed and bleed cooling. This procedure is initiated by the critical safety function monitored by the SPDS. Use of the procedure does not rely on the annunciators...

Response 8: It is agreed that the initiation of feed and bleed can be accomplished without the use of annunciators, however down-stream control and verification of PORV positions, injection tank levels etc. would be enhanced during the control phases of a feed and bleed operation. Also, conflicting information might cause the crew to delay this action during the critical time near SG dryout [lack of signal SG Lo Lo (A85)]. The ASP assessment increased the feed and bleed failure probability from .01 to .07. The representative failure modes, made more likely by the loss of annunciators, were slow response, an undetected fault condition, and selecting the wrong action. The current assessment appears reasonable. See also the response to comment 3.

G.22.2 NRC Comments--Region III

Reference: Memorandum for Gary M. Holahan, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data Edward G. Greenman, Director, Division of Reactor Projects Region III, no date indicated.

Comment 1: The summary states that 76 MCB annunciator windows were disabled. While 76 annunciator windows failed in the "on" condition, a total of 198 annunciator windows were actually inoperable.

Response 1: The summary wording has been revised to reflect this information.

Comment 2: The total number of blown fuses was 14, not 10 ...

Response 2: The number of fuses reported failed is different in the LER, AIT report, and in the referenced memorandum. The summary and event description have been revised to more qualitatively describe the fuse failures in cases where inconsistent information exists.

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11. ABSTRACT (200 words or less)

Twenty-seven operational events with conditional probabilities of subsequent severe core damage of 1.0 x 10E-06 or higher occurring at commerical light-water reactors during 1992 are considered to be precursors to potential core damage. These are described along with associated significance estimates, categorization, and subsequent analyses. The report discusses (1) the general rationale for this study, (2) the selection and documentation of events as precursors, (3) the estimation and use of conditional probabilities of subsequent severe core damage to rank precursor events, and (4) the plant models used in the analysis process.

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