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Vol. 6

Precursors to Potential Severe Core Damage Accidents: 1986 A Status Report

Appendixes D, E, and F

Prepared by J. W. Minarick, J. D. Harris, P. N. Austin,
J. W. Cletcher, E. W. Hagen

Oak Ridge National Laboratory

Prepared for
U.S. Nuclear Regulatory
Commission

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Prepared by
J. W. Minarick*, J. D. Harris, P. N. Austin*,
J. W. Cletcher**, E. W. Hagen

Oak Ridge National Laboratory
Oak Ridge, TN 37831

*Science Applications International Corporation
**Professional Analysis, Inc.

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NOTE

This document is bound in two volumes: Volume 5 contains the main report and Appendixes A, B, and C; Volume 6 contains Appendixes D, E, and F.

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LIST OF TABLES

LIST OF ACRONYMS

AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
ATWS	anticipated transient without scram
BWR	boiling-water reactor
CC	component cooling
CCW	core cooling water
CRT	condensate return tank
CSR	condensate storage tank
CSS	core spray system
CST	condensate storage tank
CVCS	chemical and volume control system
DG	diesel generator
DHR	decay heat removal
ECC	emergency core cooling
ECCS	emergency core cooling system
ECCW	emergency condenser cooling water
EDG	emergency diesel generator
EFW	emergency feedwater
EPS	emergency power system
FSAR	final safety analysis report
HPCI	high-pressure cooling injection
HPI	high-pressure injection
HVAC	heating, ventilation, and air conditioning
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
MFW	main feedwater
MFWP	main feedwater pump
MSIV	main steam isolation valve
MSRV	main steam relief valve
NRC	Nuclear Regulatory Commission
PORV	power- or pilot-operated relief valve
PWR	pressurized-water reactor
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RHRS	residual heat removal system
RPS	reactor protection system
SDC	shutdown cooling
SG	steam generator
SI	safety injection
SLB	steam-line break
SRV	safety relief valve
SS	secondary-side

APPENDIX D

PRECURSOR DOCUMENTATION

APPENDIX D

PRECURSOR DOCUMENTATION

Reactor plant operational events for 1986 were selected for documentation as precursors to potential severe core damage based on the selection criteria described in this report. These events are documented here.

For each precursor, a precursor description sheet and a conditional core-damage calculation are included. The precursor description sheet briefly describes the event sequence, provides plant and event data pertinent to the evaluation, and documents the modeling considerations and decisions made. Included with the conditional core-damage calculations are individual sequences probabilities for the more significant core-damage (CD), core-vulnerability (CV), and anticipated-transient-without-scram (ATWS) sequences; identification of dominant sequences for each end state; and a listing of the branch probabilities and frequencies utilized. Individual sequences were listed if their probability was >0.03 times the probability of the dominant sequence for each end state.

Probabilities for sequences that reflect a decrease in conditional probability are enclosed in parentheses. A decrease in core-damage, core-vulnerability, or ATWS conditional probability for an individual sequence can occur in sequences containing success branches when an unavailability is modeled. For example, consider two sequences involving an initiator A, an observed degraded system B, plus another C. Sequence 1 includes success of B; sequence 2 includes failure of B.

A occurs, B succeeds, C fails (sequence 1)
A occurs, B fails (sequence 2)

The probability of sequence 1 is probability (A) × [1 — failure probability (B)] × failure probability (C); the probability of sequence 2 is probability (A) × failure probability (B).

In assessing the significance of an unavailable system, the likelihood of core damage calculated without any observed failures and over the same period of time is subtracted from the value calculated considering the unavailable system so as to estimate only the additional impact of the unavailability. Applying this procedure to the above sequences with the likelihood of initiator A assumed to be 0.1, the likelihood of B failing (given that it has been degraded) assumed to be 0.5, the likelihood of C failing assumed to be 0.03, the probability of sequences 1 and 2, respectively, is calculated as follows:

$$[0.1 \times (1 - 0.5) \times 0.03] - [0.1 \times (1 - 0.01) \times 0.03] = -1.47 \times 10^{-3} \quad (1)$$

$$[0.1 \times 0.5] - [0.1 \times 0.01] = 4.9 \times 10^{-2} \quad (2)$$

In this case, the differential probability for sequence 1 is negative, indicating a decrease in probability for the sequence compared with the same time period without the unavailability.

Each event is identified by its unique docket-LER number. Table D.1 provides an index to the documentation for each precursor and an index to conditional core damage calculations performed for a postulated nonspecific reactor trip and a postulated LOFW a the different BWR and PWR plant classes defined in this report. These calculations are included following the documentation of precursors. The LERs associated with each precursor event are included in Appendix E. Table E.1 in Appendix E provides an index to the corresponding LERs.

Table D.1. Index to precursor descriptions and conditional core-damage calculations

LER No.	Event title	Plant name	Page number
247/86-017	Open condenser dump valves cause trip, and one safeguards train fails to start	Indian Point 2	D-6
247/86-035	Trip, LOFW, and two AFW train failures occur	Indian Point 2	D-11
249/86-013	HPCI and one train of the core spray and LPCI systems are inoperable	Dresden 3	D-16
250/86-036	Unavailability of DGs	Turkey Point Units 3 and 4	D-21
250/86-038	AFW system is unavailable	Turkey Point Units 3 and 4	D-26
250/86-039	Trip occurs with stuck-open PORV	Turkey Point 3	D-31
261/86-005	Bus failure causes a trip followed by a LOOP with a DG unavailability	Robinson 2	D-36
269/86-001	TRIP, LOFW, and a stuck-open MSRV occur	Oconee 1	D-42
269/86-011	Emergency condenser cooling system is unavailable	Oconee Station Units 1,2, and 3	D-47
277/86-003	DG trip in test causes scram	Peach Bottom 2	D-52
280/86-029	Charging pump service-water pumps are unavailable	Surry 1	D-57
280/86-031	High-head injection system is unavailable	Surry 1	D-62
281/86-010	High-head injection system is unavailable	Surry 2	D-67
282/86-006	Emergency power system is unavailabile	Prairie Island Units 1 and 2	D-72
282/86-011	Emergency power system is unavailabile	Prairie Island Units 1 and 2	D-77
285/86-001	Trip occurs, and automatic depressurization and turbine bypass system fails to open	Ft. Calhoun	D-82
293/86-027	LOOP occurs due to winter storm	Pilgrim 1	D-87
301/86-004	MSIVs fail to close on demand	Point Beach 2	D-92
318/86-006	Trip occurs, and one atmospheric dump valve fails to close	Calvert Cliffs Unit 2	D-96
341/86-048	RCIC and HPCI are unavailable	Fermi 2	D-101
362/86-011	Saltwater and CCW systems are unavailable	San Onofre 3	D-106
366/86-035	LPCS system is unavailable	Hatch 2	D-111
370/86-006	High-head injection system is unavailable and DG A is out of service	McGuire 2	D-116
389/86-011	Emergency power system is unavailable	St. Lucie	D-121
409/86-023	LOOP occurs due to lightning strike at coal-fired unit	LaCrosse	D-126
413/86-031	Small LOCA forces plant trip	Catawba 1	D-130
414/86-028	SG PORvS open inadvertently in test, and trip when other failures occur	Catawba 2	D-135
458/86-002	Hand-held ratio causes LOOP	River Bend 1	D-140
458/86-047	Emergency power, LPCS, RHR train A, and RCIC systems are degraded twice	River Bend 1	D-146

PRECURSOR DESCRIPTION SHEET

LER No.: 247/86-017
Event Description: Open condenser dump valves cause trip, and one safeguards train fails to start
Date of Event: May 28, 1986
Plant: Indian Point 2

EVENT DESCRIPTION

Sequence

Unit 2 was operating at 30% power. The condenser steam dump control system was switched from the temperature mode to the pressure mode at 1455 h because of erratic behavior observed on temperature controller TC-412J. At 1556 h. all 12 condenser steam dump valves received an open signal as a result of faulty steam dump controller PC-404. This resulted in an increased steam flow and a reduction in reactor coolant temperature and a subsequent SI actuation.

SI train A actuated, resulting in a reactor trip and safeguards actuation; however, train B did not actuate. SI train A signal resulted in closure of the MSIVs ~2.5 s after the reactor trip, effectively ending the high steam-flow condition.

The required functions that did not fully actuate because train B did not function were containment isolation phase A, train B, and some of the required redundant valving required for SI.

SI train B was successfully actuated at 1607 h, when the control room operators reset SI. Resetting SI consists of manually locking in another SI signal and depressing SI reset buttons. This action actuates parallel contacts in both trains of the SI logic. Because train B had not been actuated by the first SI signal, the introduction of the second signal initiated a separate SI sequence. SI equipment was stripped and automatically restarted; all required redundant valves (trains A and B) then operated normally.

Event Identifier: 247/86-017

Corrective Action

The steam dump control system repairs were as follows.

1. All electrolytic capacitors and the auto/manual relays were replaced on condenser steam dump controller PC-404, and the controller was recalibrated.
2. Current-to-pneumatic converter PM-404 was replaced with a new unit and calibrated.
3. Temperature controller TC-412J was replaced with a new unit and calibrated.
4. Pressure transmitter PT-404 was calibrated.

Corrective action for the SI system actuation circuit was as follows.

1. Relays SIA-2, SL-2, TR-2, and TR-2X were replaced. The SI actuation log-in was tested and verified operational.

Plant/Event Data

Systems Involved:
Turbine bypass and HPI

Components and Failure Modes Involved:
Twelve dump valves failed to open during operation HPI, one train failed to autostart

Component Unavailability Duration: NA
Plant Operating Mode: 1 (30% power)
Discovery Method: Operational event
Reactor Age: 13.0 years
Plant Type: PWR

Comments

The event was modeled using a steam line break event tree, consistent with similar events identified in the ASP Program. Because of the limited information in the LER, HPI redundancy was assumed lost. The model assumed local operator action would be required to close the dump valves had the MSIVs failed to close. If this was not the case (i.e., the dump valves could have been closed from the room) then the core damage probability estimate would have been lower by a factor of at least three.

Event Identifier: 247/86-017

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

SLB	0.34	Steam line isolated on MSIV closure

Branches Impacted and Branch Nonrecovery Estimate

HPI	0.04	One train failed (recoverable from control room)

Plant Models Utilized

PWR plant Class F

Event Identifier: 247/86-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 247/86-017
Event Description: Open Condenser Dump Valve Causes Trip and ESF Train Fails
Event Date: 5/28/86

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

SLB	3.4E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
SLB	1.0E-04
Total	1.0E-04
ATWS	
SLB	1.0E-05
Total	1.0E-05

DOMINANT SEQUENCES

End State: CD   Conditional Probability: 9.1E-05

101 SLB -RT -REQ.SG.ISO -AFW -HPI PORV.OPEN.DUE.TO.HPI PORV.CLOSURE HPR/-HPI

End State: ATWS   Conditional Probability: 1.0E-05

112 SLB RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	SLB -RT -REQ.SG.ISO -AFW -HPI PORV.OPEN.DUE.TO.HPI PORV.CLOSURE HPR/-HPI	CD	9.1E-05 *	1.9E-01
102	SLB -RT -REQ.SG.ISO AFW -HPI(F/B) -PORV.OPEN HPR/-HPI	CD	5.0E-06	5.1E-02
104	SLB -RT -REQ.SG.ISO AFW HPI(F/B)	CD	4.2E-06	4.8E-02

Event Identifier: 247/86-017

112	SLB RT	ATWS	1.0E-05 *	4.1E-02

* dominant sequence for end state
** non-recovery credit for edited case

MODEL: c:\asp\newmodel\pwrbslb.txt
DATA:

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
SLB	1.1E-07 > 1.0E+00 ***	1.0E+00 > 3.4E-01	
Branch Model: INITOR			
Initiator Freq:	1.1E-07		
RT	2.5E-04	1.2E-01	
REQ.SG.ISO	6.4E-04	1.0E+00	
AFW	1.0E-03	2.7E-01	
HPI	1.0E-03 > 1.0E-02	5.2E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
HPI(F/B)	1.0E-03 > 1.0E-02	5.2E-01	4.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
HPR/-HPI	3.0E-03 > 3.0E-02	5.6E-01	4.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	3.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
PORV.OPEN	1.0E-02	1.0E+00	
REQ.BA.ADDITION	8.3E-04	1.0E+00	
PORV.OPEN.DUE.TO.HPI	8.0E-01	1.0E+00	
PORV.CLOSURE	6.0E-03	1.0E+00	

*** forced

Austin
09-11-1987
13:46:40

Event Identifier: 247/86-017

PRECURSOR DESCRIPTION SHEET

LER No.: 247/86-035
Event Description: Trip, LOFW, and two AFW train failures occur
Date of Event: October 20, 1986
Plant: Indian Point 2

EVENT DESCRIPTION

Sequence

At 0936 h the Unit 2 reactor tripped from 100% power when reactor trip breaker B unexpectedly opened because of loose wires in the relay racks. Breakers RT3 and 4 were deenergized. One of the reactor protection relays had also been deenergized while a monthly SI surveillance test was being performed in a nearby equipment rack.

Following the trip, SG levels dropped rapidly as expected. Both motor-driven auxiliary feed pumps started on low-low SG level. While following the emergency recovery procedure, a control room operator discovered that auxiliary feed pump 21 had tripped when its breaker tripped for an unknown reason. The pump was then successfully restarted from the control room. AFW was used to maintain the SG water levels.

The steam-driven auxiliary-feed-pump steam relief valve had also popped open following the plant trip when its steam-pressure control valve opened because its set point was out of calibration on the low side. The steam-pressure control valve received an automatic open signal on low-low steam generator level in two of the four SGs, admitting steam up to the turbine governor valve. The auxiliary-feed-pump speed changer setting was at minimum as designed, but response by the pressure control valve was too slow, which caused the relief valve to lift.

Corrective Action

Repairs were made.

Plant/Event Data

Systems Involved:
AFW, MFW

Components and Failure Modes Involved:
Two trains of AFW failed in operation

Event Identifier: 247/86-035

Component Unavailability Duration: NA
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 13.4 years
Plant Type: PWR

Comments

The FSAR states that upon SI actual signal, the MFW system will isolate. An SI actual signal actuation is not reported to have occurred. Upon RPS actuation, the MFW regulating valves should fully open, yet the LER states that the AFW pumps started as a result of low SG level and were used to maintain SG level. Therefore, MFW is assumed to have tripped, even though the LER does not appear to say so.

The event was modeled assuming that the turbine-driven AFW pump was made unavailable when its steam side relief valve opened during pump start. This, in combination with the also unavailable motor-driven train produced the calculated core damage probability estimate. It is possible that the turbine-driven AFW pump was available for steam generator cooling; if this was the case, the core damage probability estimate would be lower by a factor of ~10. However, the LER does state that steam generator inventory was maintained by one of the motor-driven AFW pumps and does not clarify that the turbine-driven pump would have been available if required.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

AFW	Base case	Two of three trains failed on demand; one train was nonrecoverable
MFW	Base case	Assumed failed in operation

Plant Models Utilized

PWR plant Class F

Event Identifier: [illegible]/86-035

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 247/86-035
Event Description: Trip, LOFW, and Two AFW Train Failures
Event Date: 10/20/86
Plant: Indian Point 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.1E-04
Total	5.1E-04
CD	
TRANS	2.9E-04
Total	2.9E-04
ATWS	
TRANS	3.4E-05
Total	3.4E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 2.3E-04

125 TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW

End State: CD Conditional Probability: 1.2E-04

126 TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW

End State: ATWS Conditional Probability: 3.4E-05

Event Identifier: 247/86-035

128 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
119	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS -COND/MFW	CV	5.2E-05	5.8E-02
120	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	2.7E-05	3.0E-02
122	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS -COND/MFW	CV	2.2E-04	5.8E-02
123	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	1.1E-04	3.0E-02
124	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	1.2E-05	8.8E-02
125	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	2.[illegible]E-04 *	4.9E-02
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	1.2E-04 *	2.5E-02
127	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	1.3E-05	7.4E-02
128	TRANS RT	ATWS	3.4E-05 *	1.2E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\indpoint.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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 > 1.0E-01	2.6E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	2.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	5.0E-02 > Failed		
Serial Component Prob:	2.8E-04		
AFW/EMERG.POWER	5.0E-02 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.0E-02 > Failed		
MFW	2.0E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Failed		

Event Identifier: 247/86-035

PORV.OR.SRV.CHALL	4.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	2.0E-02	5.0E-02	
PORV.OR.SRV.PESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	1.5E-03	8.4E-01	
HPI(F/B)	1.5E-03	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04	1.0E+00	

* branch model file
** forced

Austin
09-11-1987
14:20:03

Event Identifier: 247/86-035

PRECURSOR DESCRIPTION SHEET

LER No.: 249/86-013
Event Description: HPCI and one train of the core spray and LPCI systems are inoperable
Date of Event: August 27, 1986
Plant: Dresden 3

EVENT DESCRIPTION

Sequence

Dresden 3 was in the run mode at 19% power with the HPCI system declared inoperable for repairs (reason not stated). At 0030 h during surveillance testing, the train B CSS full-flow-test valve (3-1042-4B) was discovered to be damaged, so the valve would not close; the B core spray subsystem was also unpressurized. In addition, the LPCI system minimum-flow valve (3-1501-13A) showed a double position indication — the valve was in midposition. The 2/3 DG failed to close manually onto bus 33-1; however, the generator was able to be synchronized manually to bus 23-1 without incident. In the event of a LOCA, the DG would have closed automatically on bus 33-1. A unit shutdown was begun.

Investigation revealed that valve 3-1042-4B (the "B" pump CSS full-flow-test valve) had a fractured motor-operator housing. The torque switch failed and allowed the motor to drive the valve disk into the valve seat until the motor housing was fractured. The torque switch was incorrectly installed in the reverse direction.

Investigation revealed that the handwheel retaining-ring was disengaged and resting atop the handwheel bearing of the Limitorque motor-operator for the LPCI system minimum-flow valve (3-1501-13A). The valve was opened manually.

Investigation revealed that DG 2/3 failed to close onto bus 33-1 because a terminal block screw was loose in junction box 3TB-187. Cold shutdown was achieved at 2007 h.

Corrective Action

The torque switch on valve 3-1042-4B (CSS full-flow-test valve) was installed correctly, and the motor housing was replaced. The handwheel retaining ring for the LPCI system minimum-flow valve (3-1501-13A) was correctly installed. The loose terminal block screw in the DG 2/3 junction box 3TB-187 was tightened.

Plant/Event Data

Systems Involved:
LPCI, core spray, emergency power, and HPCI

Components and Failure Modes Involved:
Pump B CSS full-flow-test valve — failed to close in test
LPCI system minimum-flow valve — failed in midposition in test
DG 2/3 — failed to close onto bus 33-1 in manual mode operation in test
HPCI — inoperable (reason not stated)

Component Unavailability Duration: 15 d
Plant Operating Mode: 1 (19% power)
Discovery Method: Testing
Reactor Age: 15.6 years
Plant Type: BWR

Comments

Dresden station has three DGs. Each unit has one dedicated DG and the third is a swing DG (2/3) between both. One train of each unit's ECCS is supported by DG 2/3. Failure of DG 2/3 would prevent emergency power to one ECCS train. The SDC system is independent of LPCI so it was not affected.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOOP	
Postulated LOCA	

Branches Impacted and Branch Nonrecovery Estimate

HPCI	1.0	Out of service and assumed unavailable
LPCS	Base case	Assumed one of two trains fails in test
LPCI	Base case	Assumed one of two trains fails in test

Plant Models Utilized

BWR plant Class B

Event Identifier: 249/86-013

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 249/86-013
Event Description: HPCI and One Train of LPCS and LPCI Are Inoperable
Event Date: 8/27/86
Plant: Dresden 3

UNAVAILABILITY, DURATION= 360

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.1E-01
LOOP	2.0E-03
LOCA	5.9E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.4E-06
LOOP	6.1E-07
LOCA	2.5E-09
Total	2.0E-06
CD	
TRANS	6.8E-07
LOOP	1.7E-06
LOCA	3.4E-07
Total	2.7E-06
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 9.2E-07

Event Identifier: 249/86-013

130 TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS HPCI -SRV.ADS -COND/FW.PCS -SDC

End State: CD Conditional Probability: 1.3E-06

213 LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI SRV.ADS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
109	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE IS OL.COND FW/PCS.TRANS HPCI CRD SRV.ADS	CD	1.8E-07	2.4E-01
117	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI SRV.ADS	CD	4.2E-07	2.4E-01
130	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS HPCI -SRV. ADS -COND/FW.PCS -SDC	CV	9.2E-07 *	2.2E-01
134	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS HPCI -SRV. ADS COND/FW.PCS -LPCS -SDC	CV	4.6E-07	1.1E-01
147	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS HPCI SRV. ADS	CD	6.2E-08	2.4E-01
207	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE IS OL.COND HPCI CRD SRV.ADS	CD	7.9E-08	2.3E-01
212	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI -SRV.ADS LPCS LPCI FIREWTR.OR.OTHER/LPCS.LPCI/LOOP	CD	7.4E-08	7.7E-02
213	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI SRV.ADS	CD	1.3E-06 *	2.3E-01
222	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI -SRV.ADS -LPCS -SD C	CV	5.9E-07	3.1E-01
238	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE IS OL.COND HPCI	CD	8.6E-08	2.6E-01
240	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI	CD	7.2E-08	2.6E-01
309	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI SRV.ADS	CD	3.4E-07	1.2E-01

* dominant sequence for end state
** 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\newmodel\bwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\dresden.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Event Identifier: 249/86-013

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	
LOOP	1.7E-05	3.2E-01	
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
PCS/TRANS	1.7E-01	1.0E+00	
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	1.6E-02	1.0E+00	
EMERG.POWER	2.9E-03	8.0E-01	
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		
ISOL.COND	2.0E-02	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	3.7E-03	7.1E-01	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	2.0E-03 > 1.0E-01	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	2.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01		
LPCI	1.0E-03 > 1.0E-01	7.1E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01		
FIREWTR.OR.OTHER/LPCS.LPCI/TRA	1.0E+00	1.0E+00	
FIREWTR.OR.OTHER/LPCS.LPCI/LOO	1.0E+00	1.0E+00	
FIREWTR.OR.OTHER/LPCS.LPCI/LOC	1.0E+00	1.0E+00	
SDC	2.9E-03	3.4E-01	
LPCI(CC)	1.0E-03	3.4E-01	
LPCI(CC)/LPCI	1.0E+00	1.0E+00	
C.I.AND.V/LPCI	1.0E+00	3.4E-01	

* branch model file
** forced

Minarick
02-24-1988
12:02:05

Event Identifier: 249/86-013

PRECURSOR DESCRIPTION SHEET

LER No.: 250/86-036
Event Description: Unavailability of DGs
Date of Event: November 6, 1986
Plant: Turkey Point 3 and 4

EVENT DESCRIPTION

Sequence

The DG B was out of service for testing and instrument calibration. The DG A was in testing when the discovery was made that it would not shut off. It was removed from service for repairs. The DG B was restored to service in 1.5 h. Because Units 3 and 4 both share the two DGs, both units were affected.

Corrective Action

DG B was restored to service in 1.5 h. DG "A" was repaired.

Plant/Event Data

Systems Involved:
Emergency power

Components and Failure Modes Involved:
DG B — was out for maintenance
DG A — failed in test

Component Unavailability Duration: 1.5 h
Plant Operating Mode: 1 (100% power)
Discovery Method: Testing
Reactor Age: 14.1 and 13.4 years, respectively
Plant Type: PWR

Comments

Because the entire station has only two DGs, both units were affected by this unavailability.

Event Identifier: 250/86-036

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

Postulated EPS	0.34	Recoverable locally at equipment; 0.34 assumed because DG A did start but failed to stop and DG B was only out for testing

Plant Models Utilized

PWR plant Class E

Event Identifier: 250/86-036

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 250/86-036
Event Description: Unavailability of Diesel Generators
Event Date: 11/6/86
Plant: Turkey Point 3

UNAVAILABILITY, DURATION= 1.5

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	2.7E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	4.6E-09
Total	4.6E-09
CD	
LOOP	1.1E-09
Total	1.1E-09
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.5E-09

217 LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM

End State: CD Conditional Probability: 7.3E-10

216 LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT/EMERG.POWER

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 250/86-036

	Sequence	End State	Prob	N Rec**
215	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	1.8E-10	4.5E-02
216	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT/EMERG.POWER	CD	7.3E-10 *	1.3E-01
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	4.5E-09 *	4.5E-02
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	3.7E-10	3.6E-02

* dominant sequence for end state
** 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\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\turkey.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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 > 1.0E+00	8.0E-01 > 3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
AFW	1.5E-03	2.7E-01	
AFW/EMERG.POWER	1.5E-03	2.7E-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	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	

Event Identifier: 250/86-036

SS.DEPRESS	3.6E-02	1.0E+00
COND/MFW	1.0E+00	3.4E-01
LPI/HPI	1.5E-04	3.4E-01
LPR/-HPI.HPR	6.7E-01	1.0E+00
LPR/HPI	1.5E-04	1.0E+00

* branch model file
** forced

Austin
09-11-1987
11:12:03

Event Identifier: 250/86-036

PRECURSOR DESCRIPTION SHEET

LER No.: 250/86-038
Event Description: System is unavailable AFW
Date of Event: December 4, 1986
Plant: Turkey Points 3 and 4

EVENT DESCRIPTION

Sequence

During routine testing, AFW pump B of AFW train 2 unexpectedly tripped off on an overspeed trip (the set point had drifted). Because the station AFW consists of three turbine-driven pumps (pumps B and C on train 2 and pump A on train 1), pump C was placed in service. Personnel then discovered pump C's steam supply valve (MOV-3-1403) failed to open. Train A was available but could not service both Units 3 and 4.

After trains B and C were restored to service, unit 4 AFW motor valves were inspected. The alignment of the valves rendered one train inoperable.

Corrective Action

The AFW pump B trip set point was adjusted. The valve MOV-3-1403 motor was replaced.

Plant/Event Data

Systems Involved:
AFW

Components and Failure Modes Involved:
Train B — failed in testing
Train A — failed in testing

Component Unavailability Duration: 360 h
Plant Operating Mode: 1 (100% power)
Discovery Method: Testing
Reactor Age: 14.2 (Unit 3) and 13.5 years (Unit 4), respectively
Plant Type: PWR

Comments

Both units were affected by this event; however, this unavailability is a problem only if both MFW systems fail simultaneously, as in a station LOOP event. In a LOOP only one unit could be provided with sufficient AFW.

Event Identifier 250/86-038

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

AFW	1.0	Recovery impossible without repair and local troubleshooting

Plant Models Utilized

PWR plant Class E

Event Identifier: 250/86-038

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 250/86-038
Event Description: Unavailability of Auxiliary Feedwater
Event Date: 12/4/86
Plant: Turkey Point 3

UNAVAILABILITY, DURATION= 360

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	6.5E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	(7.9E-09)
Total	(7.9E-09)
CD	
LOOP	5.8E-05
Total	5.8E-05
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CD Conditional Probability: 2.6E-05

214 LOOP -RT/LOOP -EMERG.POWER AFW HPI(F/B)

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
212	LOOP -RT/LOOP -EMERG.POWER AFW -HPI(F/B) -HPR/-HPI PORV.OPEN	CD	5.9E-06	3.9E-01
213	LOOP -RT/LOOP -EMERG.POWER AFW -HPI(F/B) HPR/-HPI	CD	2.5E-05	3.9E-01

Event Identifier: 250/86-038

214	LOOP -RT/LOOP -EMERG.POWER AFW HPI(F/B)	CD	2.6E-05 *	3.3E-01
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	1.5E-06	3.1E-01

* dominant sequence for end state
** 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\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\turkey.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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 > 1.0E+00	2.7E-01 > 1.0E+00	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
AFW/EMERG.POWER	1.5E-03 > 1.0E+00	2.7E-01 > 1.0E+00	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
MFW	1.9E-01	3.4E-01	
PORV.OR.SRV.CHALL	4.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	2.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04	3.4E-01	

Event Identifier: 25J/86-038

LPR/-HPI.HPR	6.7E-01	1.0E+00
LPR/HPI	1.5E-04	1.0E+00

* branch model file
** forced

Austin
09-11-1987
11:14:36

Event Identifier: 250/86-038

PRECURSOR DESCRIPTION SHEET

LER No.: 250/86-039
Event Description: Trip occurs with stuck-open PORV
Date of Event: December 27, 1986
Plant: Turkey Point 3

EVENT DESCRIPTION

Sequence

Unit 3 was tripped manually following a loss of turbine governor oil system pressure and a subsequent rapid electrical load decrease from 730 to 0 MW(e). No automatic control rod insertion occurred. The reactor control operator, noting that the coolant temperature was increasing above the reference temperature, placed the rods under manual control, and initiated rod insertion. Concurrently, a second reactor control operator attempted to raise the oil pressure, unsuccessfully. At this time (~24 s into the transient) it became clear that the unit could not be recovered, and the unit was tripped manually. During the transient, a PORV opened but then would not fully close, necessitating closure of the associated block valve. The unit was stabilized in <5 min. The most probable cause of the drop in oil pressure was the clearing of blockage of the governor impeller orifice, resulting in the auxiliary governor dumping control oil. The control rods failed to insert automatically because of two cold solder joints in the final variable gain summator of the power mismatch circuit. The cause of the PORV failure to close was under investigation. The PORV, turbine governor impeller, and associated components were inspected; and no problems were found. The cold solder joints were repaired. The control, lube, and seal oil piping were to be cleaned.

Corrective Action

The PORV block valve was closed.

Plant/Event Data

Systems Involved:
Pressurizer relief

Components and Failure Modes Involved:
PORV — failed to open in operation

Component Unavailability Duration: NA
Plant Operating Mode: 1 (100% power)
Discovery Method: operational event
Reactor Age: 14.1 years
Plant Type: PWR

Event Identifier: 250/86-039

Comments

Manual control rod insertion occurred before any trip signal actuations.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

PORV/SRV reseat	Base case	Recoverable from the control room by closing the block valve

Plant Models Utilized

Plant Class E

Event Identifier: 250/86-039

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 250/86-039
Event Description: Trip and Stuck Open PORV
Event Date: 12/27/86
Plant: Turkey Point 3

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	6.5E-04
Total	6.5E-04
CD	
TRANS	1.4E-03
Total	1.4E-03
ATWS	
TRANS	3.4E-05
Total	3.4E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 6.4E-04

102 TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS -LPR/-HPI.HPR

End State: CD Conditional Probability: 1.3E-03

103 TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR

Event Identifier: 250/86-039

End State: ATWS   Conditional Probability: 3.4E-05

128 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rr.**
102	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS -LPR/-HPI.HPR	CV	6.4E-04 *	5.0E-02
103	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	1.3E-03 *	5.0E-02
104	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI SS.DEPRESS	CD	7.2E-05	5.0E-02
128	TRANS RT	ATWS	3.4E-05 *	1.2E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\turkey.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	2.7E-01	
AFW/EMERG.POWER	1.5E-03	2.7E-01	
MFW	1.9E-01	3.4E-01	
PORV.OR.SRV.CHALL	4.0E-02 > 1.0E+00 **	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.0E-02		
PORV.OR.SRV.RESEAT	2.0E-02 > 1.0E+00	5.0E-02	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-02 > Failed		
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02

Event Identifier: 250/86-039

HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04	1.0E+00	

* branch model file
** forced

Austin
09-11-1987
11:16:50

Event Identifier: 250/86-039

PRECURSOR DESCRIPTION SHEET

LER No.:	261/86-005
Event Description:	Bus failure causes a trip followed by a LOOP with a DG unavailability
Date of Event:	January 28, 1986
Plant:	Robinson 2

EVENT DESCRIPTION

Sequence

The plant was operating at ~80% power. EDG B had just been taken out of service to install a solid state overcurrent trip device on its output breaker. This breaker upgrade was being performed on all Westinghouse type DB safety-related breakers and had been completed on EDG A the week before. At 0917 h, the EDG B output breaker had just been "racked out" when emergency bus E-2 was lost as a result of a blown fuse. This also resulted in the loss of instrument bus 4 (IB-4), which is supplied by motor control center MCC-6. Nuclear instrumentation system power range channel N-44 (fed from IB-4) was lost, which initiated a turbine runback. The automatic-rod-control and steam-dump-control systems would not function properly. As a result, a reactor trip was received on "Hi Pressurizer Pressure" ~21 s after bus E-2 was lost.

One minute after the reactor trip, the main generator oil circuit breakers opened, and the plant auxiliaries (those powered by the auxiliary transformer during operation) shifted to the startup transformer as part of the normal turbine generator lockout feature. Approximately 1 s later, a west bus lockout occurred in the 115-kV switchyard; this deenergized the Unit 2 startup transformer, resulting in a loss of offsite ac power. EDG A started automatically and loaded emergency bus E-1. Approximately 67 s after the west bus lockout was received, an SI and MSIV signal were received. These were caused by high steam-line flow coincident with low Tave. The low Tave signal was caused by the plant cooldown as a result of the reactor trip. The high steam-line flow signal was present due to loss of bus IB-4. During the attempt to restore bus E-2, an operator accidentally disabled HPI train B.

At 1027 h power was restored to bus E-2 by manually starting and loading the B EDG.

At 1115 h after investigation, offsite ac power was restored to the plant's nonvital electrical distribution system.

Event Identifier: 261/86-005

At 1228 h, a second SI signal was received. It was caused by steam-line high differential pressure, which resulted when frozen sensing lines caused "C" SG's PORV to stick open. The "C" PORV was closed by isolating the air supply to the PORV.

Corrective Action

The investigations concluded that two major events (loss of emergency bus E-2 and the loss of offsite ac power) were separate and independent from one another. An extensive investigation of the EDG B output breaker, bus E-2 control cabinet, associated circuits, and wiring was performed. No unusual conditions were found that would have caused the blown fuse. Later, while in the process of energizing E-2 via E-1 (cross tie E-1 and E-2), degraded voltage relay actuation caused the E-2 normal supply breaker to trip open.

Plant/Event Data

Systems Involved: AFW, emergency power, HPI/recirculation, and LPI/recirculation

Components and Failure Modes Involved:
Diesel generator — unavailable due to maintenance

Component Unavailability Duration: NA
Plant Operating Mode: 1 (80% power)
Discovery Method: Operational event
Reactor Age: 15.4 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	Base case	Normal recovery assumed

Branches Impacted and Branch Nonrecovery Estimate

EPS	Base case	DG B out of service for repairs
HPI/HPR	Base case	Train B disabled by error
PI/LPR	Base case	Train B unavailable because DG B was unavailable
AFW	Base case	Motor train B unavailable because DG B was unavailable
SS release terminated	Base case	"C" PORV required local action to isolate the valve

Plant Models Utilized

PWR plant Class B

Event Identifier: 261/86-005

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 261/86-005
Event Description: Bus Failure Causes Trip and LOOP with DG Unavailable
Event Date: 1/28/86
Plant: Robinson 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.9E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	5.3E-03
Total	5.3E-03
CD	
LOOP	3.0E-04
Total	3.0E-04
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.0E-03

217 LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM

End State: CD Conditional Probability: 2.7E-04

218 LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 261/86-005

Sequence		End State	Prob	N Rec**
215	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	2.0E-04	1.0E-01
216	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT/EMERG.POWER	CD	1.8E-05	3.1E-01
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	5.0E-03 *	1.0E-01
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	2.7E-04 *	1.1E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\robinson.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	2.0E-01	3.4E-01	
PORV.OR.SRV.CHALL	4.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	3.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	3.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.5E-02 > Failed		
SS.RELEAS.TERM/-MFW	1.5E-02 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.5E-02 > Failed		

Event Identifier: 261/86-005

HPI	1.0E-03) 1.0E-02	8.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01) Unavailable		
HPI(F/B)	1.0E-03) 1.0E-02	8.4E-01	4.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01) Unavailable		
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04) 1.0E-02	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02) Unavailable		
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04) 1.0E-02	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02) Unavailable		

* branch model file
** forced

Austin
09-11-1987
11:23:11

Event Identifier: 261/86-005

PRECURSOR DESCRIPTION SHEET

LER No.: 269/86-001
Event Description: Trip, LOFW, and a stuck-open MSRV occur
Date of Event: January 31, 1986
Plant: Oconee 1

EVENT DESCRIPTION

Sequence

At 1546 h during troubleshooting, circuit breaker PCB-24 was manually closed without the reset of the generator lockout relays. When the breaker was closed, the relay logic was satisfied, causing a yellow bus lockout. Consequently, all the 230-kV yellow-bus tie breakers opened.

One of the breakers that opened was PCB-21, the generator to the yellow-bus tie breaker. When it opened, the only path for current flow from the generator to the switchyard was via PCB-20. PCB-20 faulted, undergoing an explosion, ~17 seconds after PCB-21 opened. At 1547 h the turbine/generator tripped, initiating an anticipatory reactor trip from 100% stable power conditions.

Following the reactor trip, both MFWPs tripped on high discharge pressure. A preliminary investigation showed that the MFWP speed demand did not run back as expected. All three EFW pumps started immediately to supply feedwater flow for DHR.

Following the reactor trip, one of the MSRVs (1MS-8) opened and stuck open for 11 min. It reseated when the SG pressure decreased to 975 psig, the minimum RCS pressure was 1750 psig.

Unit 1 was stabilized at hot shutdown conditions with no actuations of engineering safeguard systems or pressurizer relief valves, and no RCS leakage was induced.

Corrective Action

PCB-20 was repaired. The MFWP trip set points were reviewed. The MSRV (1MS-8) was repaired.

Plant/Event Data

Systems Involved:
MFW, main steam relief, electrical

Components and Failure Modes Involved:
MSRV — stuck open in operation
MFWPS — tripped off in operation

Component Unavailability Duration: NA
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 12.8 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

MFW	1.0	No recovery possible in the short term
SS release terminated	0.12	MSRV stuck open but closed on lower pressure

Plant Models Utilized

PWR plant Class D

Event Identifier: 269/86-001

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 269/86-001
Event Description: Trip, LOFW, and Stuck Open MSRV
Event Date: 1/31/86
Plant: Oconee 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	3.2E-05
Total	3.2E-05
CD	
TRANS	2.1E-06
Total	2.1E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 2.8E-05

109 TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI

End State: CD Conditional Probability: 1.0E-06

103 TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR

End State: ATWS Conditional Probability: 3.4E-05

Event Identifier: 269/86-001

128 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI	CV	2.4E-06	1.0E-01
103	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	1.0E-06 *	5.0E-02
104	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI SS.DEPRESS	CD	5.8E-08	5.0E-02
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	2.8E-05 *	1.0E-01
123	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	4.2E-07	3.0E-02
124	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	4.7E-08	8.8E-02
125	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	8.6E-07	4.9E-02
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	4.4E-07	2.5E-02
127	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	4.9E-08	7.4E-02
128	TRANS RT	ATWS	3.4E-05 *	1.2E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\pwrdtree.cmp
BRANCH MODEL: c:\asp\newmodel\oconee.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	2.0E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Failed		
PORV.OR.SRV.CHALL	8.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02 > 1.0E+00	3.4E-01 > 1.2E-01	

Event Identifier: 269/86-001

Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.5E-02 > Failed		
SS.RELEAS.TERM/-MFW	1.5E-02 > 1.0E+00	3.4E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.5E-02 > Failed		
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04	1.0E+00	

* branch model file
** forced

Austin
09-11-1987
11:25:59

Event Identifier: 269/86-001

PRECURSOR DESCRIPTION SHEET

LER No.: 269/86-011
Event Description: Emergency condenser cooling system is unavailable
Date of Event: October 1, 1986
Plant: Oconee 1, 2, and 3

EVENT DESCRIPTION

Sequence

The design basis of the ECCW system is to provide water to the condenser for the removal of decay heat during a loss of all ac power event (station blackout). The station blackout scenario is limiting in that CCW siphon flow through the main condenser is used to remove decay heat. Decay heat is transferred to the main condenser via the turbine bypass valves. Feedwater is delivered to the SGs via the turbine-driven EFW pumps.

During performance a load shed test on Unit 2 during refueling, the low-pressure service-water system pumps were found to have failed. A load shed of nonessential loads is initiated when emergency power is required via the underground feeder from Keowee through transformer CT-4. The load shed protects this power path from overload. When the load shed test was initiated, the condenser circulating water pumps were deenergized. Normally, this causes the gravity flow system to align automatically and to allow the flow of water from the intake structure through the condenser and discharging to the Keowee tailrace into Lake Hartwell. The elevation difference and a siphon effect are used to cause the condenser circulating water to continue to flow. For this test, the condenser gravity drain to the Keowee tailrace was blocked because it was not part of the test. The pumps had started initially on loss of load to provide condenser cooling but began to cavitate after 1 h.

CCW flow was restored by restarting a CCW pump, and the plant was restored to its normal powered condition without any plant damage or system upsets. Before the occurrence, two low-pressure service-water pumps were operating with ~13,000 gal/min per pump. The low-pressure service-water pumps are supplied from the CCW crossover header, which was being supplied from Unit 2 at the time.

Event Identifier: 269/86-011

In the evening of October 1, 1986, the test was repeated; but this time the gravity drain feature was also tested. The results were the same with the loss of low-pressure service-water flow. The U.S. Nuclear Regulatory Commission (NRC), Region II, was advised of these results late in the evening, and NRC concurred that Units 1 and 3 could continue to operate until the test data could be fully evaluated. Units 1 and 3 were at 100% power. At 0900 on October 2, 1986, evaluation of the tests revealed that the operation of this design feature (the CCW siphon flow) was questionable for Units 1 and 3 and that this resulted in inoperability of the low-pressure service-water systems for Oconee. As a result, an orderly shutdown of the two operating units was begun as required by Technical Specification 3.3.7. Both units reached cold shutdown conditions by October 3, 1986. An investigation determined that the ECCW system (gravity flow system) was not working. The lake level was lower than normal, and the low-pressure service-water pump housings were exposed. Because the housings were not qualified for this duty, air leaked in and caused pump cavitation and loss of the condenser syphon. All three units were affected.

The root cause of this incident is the inadequate design and testing of the ECCW system. This led to a failure of the ECCW system to perform its intended function as described in the FSAR under all assumed conditions. Inadequate original design evaluation of the ECCW system and the lower-than-normal lake level of Keowee are contributing factors to the cause of this incident.

Corrective Action

Numerous design and procedure changes were made (see LER pp. 4–5).

Plant/Event Data

Systems Involved:
AFW and SG emergency condenser cooling

Components and Failure Modes Involved:
CCW pumps — failed in testing

Component Unavailability Duration: Assumed 120 d
Plant Operating Mode: 1 (100% power)
Discovery Method: Testing
Reactor Age: 13.5, 12.9, and 12.1 years, respectively
Plant Type: PWR

Comments

Because the system is shared by all units at the station, all three units were affected. AFW is affected given that an EPS failure has occurred.

Event Identifier: 269/86-011

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP		Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

AFW and EPS	1.0	No recovery assumed possible in the short term

Plant Models Utilized

PWR plant Class D

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 269/86-011
Event Description: Station Emergency Condenser Cooling System is Unavailable
Event Date: 10/1/86
Plant: Oconee 1

UNAVAILABILITY, DURATION= 2880

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	5.2E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	(5.9E-08)
Total	(5.9E-08)
CD	
LOOP	1.1E-05
Total	1.1E-05
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CD Conditional Probability: 1.2E-05

218 LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER

SEQUENCE CONDITIONAL PROBABILITIES

Sequence	End State	Prob	N Rec**
218 LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	1.2E-05 *	3.1E-01

Event Identifier: 269/86-011

* dominant sequence for end state
** 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\newmodel\pwrdtree.cmp
BRANCH MODEL: c:\asp\newmodel\oconee.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
MFW	2.0E-01	3.4E-01	
PORV.OR.SRV.CHALL	8.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04	1.0E+00	

* branch model file
** forced

Austin
09-11-1987

Event Identifier: 269/86-011

PRECURSOR DESCRIPTION SHEET

LER No.: 277/86-003
Event Description: DG trip in test causes scram
Date of Event: January 24, 1986
Plant: Peach Bottom 2

EVENT DESCRIPTION

Sequence

Before the event, the DG E-2 was in service supplying the E-22 and E-23 emergency buses in preparation for a loss of power test on Unit 3.

At 0612 h, DG E-2 automatically tripped, thereby removing all power to the E-22 and E-23 buses. Loss of bus E-22 caused MSIVs AO-2-2-86B and AO-2-2-86D to close inadvertently (their solenoids deenergized). The redundant dc solenoids were later found failed. Closure of these valves resulted in a high core-flux condition, which was sufficient to initiate a full reactor scram. Immediately following the scram, reactor water level decreased to -32 in. Group II and III isolations occurred properly at the 0-in. water level. The speeds of all three reactor feed pumps automatically increased to recover reactor water level. At +45 in. the reactor feed pumps and the main turbine received trip signals indicating high reactor water level. The feed pumps and main turbine tripped properly. Both reactor recirculation pumps tripped properly during the 13.2-kV bus fast transfer. At 0634 h reactor feed pump C was reset from the high-water-level trip and placed in service to control reactor water level. Both recirculation pumps were returned to service by 0645 h.

Additionally, Group II and III outboard isolations occurred on Unit 3 as a result of this event.

Corrective Action

A review of the most recently completed surveillance test indicated that all MSIV ac and dc coils had satisfactory operating currents when tested 2 d before the event. The dc solenoids were replaced on January 25.

Plant/Event Data

Systems Involved:
Emergency power, main steam isolation, and MFW

Event Identifier: 277/86-003

Components and Failure Modes Involved:
DG — failed in test
MSIVs — failed closed during operation

Component Unavailability Duration: NA
Plant Operating Mode: 1 (95% power)
Discovery Method: Testing
Reactor Age: 12.3 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

MFW	0.04	Recoverable from control room (tripped off on high head after scram)
Emergency power system	Base case	DG train E-2 is unavailable
RHR/shutdown cooling	Base case	One train unavailable because of loss buses
RHR/SDC	Base case	One train unavailable because of loss buses
RHR service water	Base case	One train unavailable because of loss buses
SLC/rod insert	Base case	One train unavailable because of loss buses
LPCS	Base case	One train unavailable because of loss buses

Plant Models Utilized

BWR plant Class C

Event Identifier: 277/86-003

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 277/86-003
Event Descriotion: Diesel Generator Trip Test Causes Scram
Event Date: 1/24/86
Plant: Peach Bottom 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	9.0E-08
Total	9.0E-08
CD	
TRANS	8.1E-05
Total	8.1E-05
ATWS	
TRANS*	1.7E-05
Total	1.7E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.2E-08

155 TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS -COND/FW.PCS -RHR(SDC)

End State: CD Conditional Probability: 6.4E-05

101 TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE -FW/PCS.TRANS RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)

Event Identifier: 277/86-003

End State: ATWS   Conditional Probability: 1.7E-05

173 TRANS SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE -FW /PCS.TRANS RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	6.4E-05 *	1.1E-01
102	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	2.6E-06	4.6E-03
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	1.1E-05	1.7E-01
134	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	6.8E-09	1.3E-02
138	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	3.5E-09	6.6E-03
155	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	5.2E-08 *	1.6E-01
159	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	2.7E-08	8.0E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	1.7E-05 *	1.0E+00

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\bwrctree.cmp
BRANCH MODEL: c:\asp\newmodel\peach.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	
LOOP	1.7E-05	3.2E-01	
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Unavailable		
PCS/LOCA	1.0E+00	1.0E+00	

Event Identifier: 277/86-003

SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-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	2.7E-05	8.0E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 4.0E-02	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Unavailable		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	2.9E-02	7.0E-01	
RCIC/TRANS.OR.LOOP	6.0E-02	7.0E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02 > 1.0E+00	1.0E+00	4.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
SRV.ADS	3.7E-03	7.1E-01	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
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 > Unavailable		
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 > Unavailable		
RHRSW/LPCS.LPCI.TRANS	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOOP	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOCA	5.0E-01	1.0E+00	4.0E-02
RHR(SDC)	2.1E-02 > 3.0E-02	3.4E-01	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Serial Component Prob:	2.0E-02		
RHR(SDC)/-LPCI	2.0E-02	3.4E-01	
RHR(SDC)/LPCI	1.0E+00	1.0E+00	
RHR(SPCOOL)/-LPCI.RHR(SDC)	2.0E-02	1.0E+00	
RHR(SPCOOL)/LPCI.RHR(SDC)	5.2E-01	1.0E+00	
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01	

* branch model file
** forced

Minarick
02-24-1988
12:06:26

Event Identifier: 277/86-003

PRECURSOR DESCRIPTION SHEET

LER No.: 280/86-029
Event Description: Charging pump service-water pumps are unavailable
Date of Event: September 29, 1986
Plant: Surry 1

EVENT DESCRIPTION

Sequence

All service-water flow to the charging pump service-water subsystem was lost because the pump became air bound. This abnormal condition affected the heat sink for the charging pump lubricating-oil coolers and the intermediate heat sink for the charging pump mechanical seals.

Earlier in the day, one of the redundant charging pumps service-water pumps, 1-SW-P-10A, had been removed from service for replacement. Maintenance activities required that grinding be performed on a pump support prior to pump replacement. The grinding activity resulted in actuation of a smoke detector, which automatically closed a service-water fire isolation valve. Due to a leak on a strainer blowdown line in the service-water supply line, the valve closure allowed air in-leakage, which caused 1-SW-P-10B to become air bound.

The charging pumps continued to operate. The temperatures of the operating charging pump were monitored.

Corrective Action

The affected pump was vented, and the leak at the strainer blowdown line was repaired.

Plant/Event Data

Systems Involved:
HPI and chemical and volume control

Components and Failure Modes Involved:
Charging pump service water pumps — one failed in operation; another was out of service
Charging pumps — degraded operation without service water

Event Identifier: 280/86-029

Component Unavailability Duration: 1 h assumed
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 14.2 years
Plant Type: PWR

Comments

For routine charging operations the pump performance was acceptable. For transient conditions with the increased heat load associated with HPI operation, the lack of cooling is assumed to degrade performance.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOOP	Base case nonrecovery
Postulated LOCA	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

HPI	1.0	Service water for pump cooling not recoverable in the short term

Plant Models Utilized

PWR plant Class A

Event Identifier: 280/86-029

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 280/86-029
Event Description: Charging Pump Service Water Pumps Are Unavailable
Event Date: 9/29/86
Plant: Surry 1

UNAVAILABILITY, DURATION= 1

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	4.8E-04
LOOP	1.8E-06
LOCA	1.0E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	2.5E-06
LOOP	9.2E-09
LOCA	9.7E-07
Total	3.4E-06
CD	
TRANS	1.1E-09
LOOP	1.6E-10
LOCA	9.0E-09
Total	1.0E-08
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 2.3E-06

Event Identifier: 280/86-029

109 TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI

End State: CD Conditional Probability: 3.7E-08

307 LOCA -RT -AFW HPI SS.DEPRESS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI	CV	9.8E-08	3.4E-01
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	2.3E-06 *	3.4E-01
304	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	9.9E-07	4.3E-01
307	LOCA -RT -AFW HPI SS.DEPRESS	CD	3.7E-08 *	4.3E-01

* dominant sequence for end state
** 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\newmodel\pwratree.cmp
BRANCH MODEL: c:\asp\newmodel\surry.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	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	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	

Event Identifier: 280/86-029

HPI	1.5E-03 > 1.0E+00 **	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
Serial Component Prob:	1.2E-03		
HPI(F/B)	1.5E-03 > 1.0E+00 **	8.4E-01 > 1.0E+00	4.0E-02
Branch Model: 1.OF.3+ser+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
Serial Component Prob:	1.2E-03		
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
CSR	1.0E-02	1.0E+00	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04	1.0E+00	

* branch model file
** forced

Austin
09-11-1987
11:42:53

Event Identifier: 280/86-029

PRECURSOR DESCRIPTION SHEET

LER No.: 280/86-031
Event Description: High-head injection system is unavailable
Date of Event: October 30, 1986
Plant: Surry 1

EVENT DESCRIPTION

Sequence

At 0202 h with Unit 1 at 100% power and Unit 2 in a refueling shutdown, service-water flow was lost to the Unit 1 charging pump service-water subsystem. Operation without service water to the charging pump service-water system is prohibited by Technical Specification 3.14 because the water provides cooling for the lube oil coolers.

An operator was exchanging the filter elements of an in-line duplex strainer upstream of the operating Unit 1 charging pump service-water pump (1-SW-P-10A) because high differential pressure had been indicated. By failing to fill and vent the filter element, he inadvertently allowed air to enter the line. When the standby filter element was placed into service, the discharge pressure of the operating pump decreased to zero. The charging-pump service-water header's low-pressure alarm annunciated and locked in the main control room, and the standby pump (1-SW P-10B) was started but failed to clear the low-pressure alarm.

Corrective Action

The pumps were vented and returned to service.

Plant/Event Data

Systems Involved:
High-head injection, service water

Components and Failure Modes Involved:
Charging-pump service-water pumps — failed in operation
HPI pumps — degraded

Component Unavailability Duration: 19 min
Plant Operating Mode: 1 (100% power)
Discovery Method: Maintenance
Reactor Age: 14.2 years
Plant Type: PWR

Event Identifier: 280/86-031

Comments

Because of the increased high-head injection system pump heat load during a transient requiring HPI, the conservative assumption is failure of the high-head injection system. [See similar failure at Calvert Cliffs 1 in LER 317/80-027 in NUREG/CR-3591 (ORNL/NSIC-217) and at Surry 2, LER 281/86-010.]

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOOP	Base case nonrecovery
Postulated LOCA	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

HPI	1.0	Given HPI demand in a transient, pump service water could not be recoverd in time

Plant Models Utilized

PWR plant Class A

Event Identifier: 280/86-031

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 280/86-031
Event Description: High Head Injection System is Unavailable
Event Date: 10/30/86
Plant: Surry 1

UNAVAILABILITY, DURATION= .3

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.4E-04
LOOP	5.4E-07
LOCA	3.1E-07

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	7.4E-07
LOOP	2.7E-09
LOCA	2.9E-07
Total	1.0E-06
CD	
TRANS	3.4E-10
LOOP	4.8E-11
LOCA	2.7E-09
Total	3.1E-09
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV   Conditional Probability: 7.0E-07

Event Identifier: 280/86-031

109 TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI

End State: CD Conditional Probability: 1.1E-08

307 LOCA -RT -AFW HPI SS.DEPRESS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI	CV	2.9E-08	3.4E-01
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	7.0E-07 *	3.4E-01
304	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	3.0E-07	4.3E-01
307	LOCA -RT -AFW HPI SS.DEPRESS	CD	1.1E-08 *	4.3E-01

* dominant sequence for end state
** 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\newmodel\pwratree.cmp
BRANCH MODEL: c:\asp\newmodel\surry.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	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	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	

Event Identifier: 280/86-031

HPI	1.5E-03 > 1.0E+00 **	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
Serial Component Prob:	1.2E-03		
HPI(F/B)	1.5E-03 > 1.0E+00 **	8.4E-01 > 1.0E+00	4.0E-02
Branch Model: 1.OF.3+ser+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
Serial Component Prob:	1.2E-03		
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
CSR	1.0E-02	1.0E+00	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04	1.0E+00	

* branch model file
** forced

Austin
09-11-1987
11:46:21

Event Identifier: 280/86-031

PRECURSOR DESCRIPTION SHEET

LER No.: 281/86-010
Event Description: High-head injection system is unavailable
Date of Event: July 11, 1986
Plant: Surry 2

EVENT DESCRIPTION

Sequence

With Unit 2 at 100% power and Unit 1 in refueling shutdown, emergency maintenance was being performed on 2-CC-P-2A, Unit 2's A charging-pump CCW pump. At that time the redundant pump, 2-CC-P-2B, was in operation supplying cooling water to the charging-pump seal coolers. At 1518 h, while operators were attempting to return pump A to service following the maintenance, the discharge pressure of pump B dropped to zero. Both charging-pump CCW pumps were inoperable.

The charging-pump cooling-water system is a closed system consisting of two redundant cooling-water pumps, two redundant intermediate coolers (cooled by service water), a head tank, and six seal coolers (two per charging pump). Shortly after the event began, a low level was noted to exist in the head tank. Therefore, a large leak was assumed to exist in the system, and efforts were directed toward finding the leak. However, no significant leaks could be found. Thus, it is speculated that air was introduced into the system during maintenance on pump A, which caused pump B to become vapor bound, resulting in zero discharge pressure.

Corrective Action

Pump A was properly vented, makeup water was added to the system, and pump A was returned to service at 1825 h — after operability of the pump was demonstrated. Subsequently, operability of pump B was demonstrated, and that pump was also returned to service.

Plant/Event Data

Systems Involved:
High-head injection system, CCW system

Components and Failure Modes Involved:
Charging-pump CCW pumps — One was out of service, failed in testing and one failed in operation

Event Identifier: 281/86-010

Component Unavailability Duration: 3 h
Plant Operating Mode: 1 (100% power)
Discovery Method: Testing
Reactor Age: 13.3 years
Plant Type: PWR

Comments

A similar event occurred at Calvert Cliffs 1 as reported in LER 317/80-027 and evaluated in NUREG/CR-3591 (ORNL/NSIC-217). (See also LER 280/86-031 for Surry 1 in this report.)

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOCA	Base case nonrecovery
Postulated LOOP	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

HPI	1.0	Not readily recoverable (assume loss of component cooling fails HPI)

Plant Models Utilized

PWR plant Class A

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 281/86-010
Event Description: High Head Injection System is Unavailable
Event Date: 7/11/86
Plant: Surry 2

UNAVAILABILITY, DURATION= 3

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.4E-03
LOOP	5.4E-06
LOCA	3.1E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	7.4E-06
LOOP	2.8E-08
LOCA	2.9E-06
Total	1.0E-05
CD	
TRANS	3.4E-09
LOOP	4.8E-10
LOCA	2.7E-08
Total	3.1E-08
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 7.0E-06

Event Identifier: 281/86-010

109 TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI

End State: CD Conditional Probability: 1.1E-07

307 LOCA -RT -AFW HPI SS.DEPRESS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI	CV	2.9E-07	3.4E-01
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	7.0E-06 *	3.4E-01
304	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	3.0E-06	4.3E-01
307	LOCA -RT -AFW HPI SS.DEPRESS	CD	1.1E-07 *	4.3E-01

* dominant sequence for end state
** 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\newmodel\pwratree.cmp
BRANCH MODEL: c:\asp\newmodel\surry.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	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	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	

Event Identifier: 281/86-010

HPI	1.5E-03 > 1.0E+00 **	8.4E-01 > 1.0E+00	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
Serial Component Prob:	1.2E-03		
HPI(F/B)	1.5E-03 > 1.0E+00 **	8.4E-01 > 1.0E+00	4.0E-02
Branch Model: 1.OF.3+ser+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01		
Serial Component Prob:	1.2E-03		
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
CSR	1.0E-02	1.0E+00	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04	1.0E+00	

* branch model file
** forced

Austin
09-11-1987
12:16:36

Event Identifier: 281/86-010

PRECURSOR DESCRIPTION SHEET

LER No.: 282/86-006
Event Description: Emergency power system is unavailable
Date of Event: September 8, 1986
Plant: Prairie Island 1 and 2

EVENT DESCRIPTION

Sequence

Both units were at steady state power: Unit 1 at 100% and Unit 2 at 88% power. During an operability test, D-1 DG failed to start after cranking for 10 s. D-1 DG was declared inoperable. While the diesel cooling-water pump 22 was being run to prove operability of D-2 DG, a small oil line burst; the pump was shutdown and declared inoperable. With these two components inoperable, a power decrease was begun on both units. The two station DGs serve both Units 1 and 2.

The cause of the inoperability of D-1 DG was not immediately apparent, but further investigation and testing revealed that leakage through the fuel-head pressure return orifice check valve allowed the fuel oil header to drain during idle periods.

Corrective Action

The brass oil line on diesel cooling-water pump 22 was replaced with a stainless steel line. The fuel-head pressure return orifice check valve was replaced on the D-1 DG.

Plant/Event Data

Systems Involved:
Emergency power generation system and emergency-power cooling system

Components and Failure Modes Involved:
DG — failed to start on demand
Diesel cooling water pump — failed during operation

Component Unavailability Duration: 36 min
Plant Operating Mode:
1 (100% power for Unit 1); 1 (88% power for Unit 2)
Discovery Method: Testing
Reactor Age: 12.8 years for Unit 1; 11.7 years for Unit 2
Plant Type: PWR

Comments

Because of the heavy heat loads imposed on the DGs during full load conditions, the conservative assumption is that the DGs are failed in a LOOP. The DGs serve both Units 1 and 2.

Both units were affected.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

EPS	1.0	Not readily recoverable

Plant Models Utilized

PWR plant Class B

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 282/86-006
Event Description: Emergency Power is Unavailab..
Event Date: 9/8/86
Plant: Prairie Island 1

UNAVAILABILITY, DURATION= .6

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.1E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	5.3E-09
Total	5.3E-09
CD	
LOOP	1.9E-08
Total	1.9E-08
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.1E-09

217 LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM

End State: CD Conditional Probability: 1.8E-08

218 LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 282/86-006

	Sequence	End State	Prob	N Rec**
215	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	2.1E-10	1.3E-01
216	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT/EMERG.POWER	CD	8.4E-10	3.9E-01
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	5.1E-09 *	1.3E-01
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	1.8E-08 *	1.3E-01

* dominant sequence for end state
** 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\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\praislan.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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 > 1.0E+00	8.0E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
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	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	1.0E-03	8.4E-01	
HPI(F/B)	1.0E-03	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	

Event Identifier: 282/86-006

COND/MFW	1.0E+00	3.4E-01
LPI/HPI	1.5E-04	3.4E-01
LPR/-HPI.HPR	6.7E-01	1.0E+00
LPR/HPI	1.5E-04	1.0E+00

* branch model file
** forced

Austin
09-11-1987
12:18:57

Event Identifier: 282/86-006

PRECURSOR DESCRIPTION SHEET

LER No.: 282/86-011
Event Description: Emergency power system is unavailable
Date of Event: December 27, 1986
Plant: Prairie Island 1 and 2

EVENT DESCRIPTION

Sequence

While Units 1 and 2 were both at 100% power, DG 22 cooling-water pump (DCLP) was out of service for scheduled maintenance. At 0848 h during the daily test of DCLP 12, a water hose ruptured, rendering both DGs unavailable. A station shutdown was begun. At 1008 h, DG operability was restored, and the units returned to full power operation. The two DGs serve both Units 1 and 2.

Corrective Action

The hose was replaced.

Plant/Event Data

Systems Involved:
Emergency power

Components and Failure Modes Involved:
DG water hose — failed in test
DGLP — was out for maintenance

Component Unavailability Duration: 1.25 h
Plant Operating Mode: 1 (100% power)
Discovery Method: Testing
Reactor Age: 13.0 and 11.9 years, respectively
Plant Type: PWR

Comments

Both units were affected because they share the same DG. Due to the heavy heat load imposed during full-load conditions, the conservative assumption is that the EPS would be failed in a LOOP.

Event Identifier: 282/86-011

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP — Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

EPS	1.0	Not readily recoverable

Plant Models Utilized

PWR plant Class B

Event Identifier: 282/86-011

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 282/86-011
Event Description: Emergency Power System Unavailability
Event Date: 12/27/86
Plant: Prairie Island 1

UNAVAILABILITY, DURATION= 1.25

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	2.2E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	1.1E-08
Total	1.1E-08
CD	
LOOP	4.0E-08
Total	4.0E-08
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.1E-08

217 LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM

End State: CD Conditional Probability: 3.8E-08

218 LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 282/86-011

	Sequence	End State	Prob	N Rec**
215	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	4.4E-10	1.3E-01
216	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT/EMERG.POWER	CD	1.8E-09	3.9E-01
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	1.1E-08 *	1.3E-01
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	3.8E-08 *	1.3E-01

* dominant sequence for end state
** 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\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\praislan.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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 > 1.0E+00	8.0E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
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	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	1.0E-03	8.4E-01	
HPI(F/B)	1.0E-03	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	

Event Identifier: 282/86-011

COND/MFW	1.0E+00	3.4E-01
LPI/HPI	1.5E-04	3.4E-01
LPR/-HPI.HPR	6.7E-01	1.0E+00
LPR/HPI	1.5E-04	1.0E+00

* branch model file
** forced

Austin
09-11-1987
12:21:19

Event Identifier: 282/86-011

PRECURSOR DESCRIPTION SHEET

LER No.: 285/86-001
Event Description: Trip occurs, and automatic depressurization and turbine bypass sytem fails to open
Date of Event: July 2, 1986
Plant: Ft. Calhoun

EVENT DESCRIPTION

Sequence

At 0534 h, during normal operation while the reactor was at 100% power, an instrument inverter trouble alarm was received in the control room. Control room operators quickly diagnosed a failed instrument inverter feeding bus AI-40A. They dispatched an equipment operator to the switchgear room to reenergize the bus manually by closing the breaker on a bypass transformer also feeding bus AI-40A. The inverter failure placed the RPS in a half-trip condition because the RPS operates on a two-out-of-four logic and the failed inverter was one of four feeding the independent channels of the RPS. About 10 s after the inverter failure, a reactor trip occurred when a second channel trip was received on the SG B low-level trip unit.

Several unusual transients were noted in the moments following the trip:

1. RCS pressure increased to ~2400 psia for a short period of time. This caused PORVs to be actuated.
2. SG pressure increased to the set point of the secondary safety valves, causing them to be actuated.
3. Overfeeding the SG resulted in abnormally high level and subsequent overcooling of the primary system. As a result, RCS pressure decreased to a low of ~1725 psia. The overfeeding occurred because the main feed regulating valves failed to ramp down; the failure was due to loss of power to a relay when the inverter failed.
4. Steam dump and bypass valves could not be opened because the inverter power was lost to their controllers as well as to a relay that causes the dump valve to open.
5. The operating charging pump stopped, and the two backup pumps could not be started because of loss of inverter power to the relay that controls the backup pump's operations. Although the operating pump should not have stopped, for an unknown reason it did.

Within 1 min of the reactor trip, the equipment operator had reenergized the lost instrument bus, and control room operators w re soon able to restore the plant to normal shutdown condition.

A diagnosis of the information revealed the following. The deenergized instrument bus AI-40A supplies power to electrohydraulic-control panel AI-50 with no alternate power. A turbine first-stage pressure transmitter that sends a signal to the electrohydraulic-control load-control circuitry is powered from AI-50. Loss of power caused a loss of signal to the load-control unit, resulting in the turbine control valves closing without a reactor trip. This explains the high pressure seen in the primary system and the low SG level earlier in the transient.

Corrective Action

Modification was made to the bus and inverter power transfer controls to provide backup power.

Plant/Event Data

Systems Involved:
Atmospheric steam dump, turbine bypass, charging, and electrical

Components and Failure Modes Involved:
Inverter — failed in operation
Automatic depressurization and turbine bypass system — failed on demand
Charging — failed in operation

Component Unavailability Duration:
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 12.9 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

SS depressurization	0.34	Recoverable locally at the valves

Plant Models Utilized

PWR plant Class G

Event Identifier: 285/86-001

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 285/86-001
Event Description: Trip and ADS/TBS/ Fails to Open
Event Date: /2/86
Plant: Fort Calhoun

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.5E-06
Total	1.5E-06
CD	
TRANS	4.1E-05
Total	4.1E-05
ATWS	
TRANS	3.4E-05
Total	3.4E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.3E-06

101 TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI

End State: CD Conditional Probability: 4.0E-05

102 TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI

End State: ATWS Conditional Probability: 3.4E-05

121 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI	CV	1.3E-06 *	2.9E-01
102	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI	CD	4.0E-05 *	5.0E-02
115	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS -COND/MFW	CV	1.1E-07	3.9E-02
118	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	1.2E-07	3.2E-02
121	TRANS RT	ATWS	3.4E-05 *	1.2E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\pwrgtree.cmp
BRANCH MODEL: c:\asp\newmodel\calhoun.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	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 **	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.0E-02		
PORV.OR.SRV.RESEAT	2.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
SS.DEPRESS	3.6E-02 > 1.0E+00	1.0E+00 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	3.6E-02 > Failed		
COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02

Event Identifier: 285/86-001

PORV.OPEN	1.0E-02	1.0E+00
HPR/-HPI	1.5E-04	1.0E+00
CSR	2.0E-03	3.4E-01

* branch model file
** forced

Austin
09-11-1987
12:25:00

Event Identifier: 285/86-001

PRECURSOR DESCRIPTION SHEET

LER No.: 293/86-027
Event Description: LOOP occurs due to winter storm
Date of Event: November 19, 1986
Plant: Pilgrim 1

EVENT DESCRIPTION

Sequence

While the reactor was shut down for refueling, an arcing of the high-voltage lines due to locally heavy ice and snow occurred at 0819 h during a severe winter storm. A loss of offsite power occurred when both transmission lines tripped off due to near-simultaneously detected faults. All safety systems responded as designed. Offsite power was restored at 1015 h when the two lines were reenergized. By 1128 h the switchyard was restored to service.

Corrective Action

An inspection revealed no damage to any system.

Plant/Event Data

Systems Involved:
Electrical

Components and Failure Modes Involved:
Offsite power — failed in operation

Component Unavailability Duration: NA
Plant Operating Mode: 6 (0% power)
Discovery Method: Operational
Reactor Age: 14.4 years
Plant Type: BWR

Comments

Given the circumstances, this event could have occurred at full power and is analyzed on this basis.

Event Identifier: 293/86-027

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	0.12	Backup power source available

Branches Impacted and Branch Nonrecovery Estimate

None

Plant Models Utilized

BWR plant Class C

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 293/86-027
Event Description: LOOP Due to Winter Store
Event Date: 11/19/86
Plant: Pilgrim 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.2E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	3.3E-08
Total	3.3E-08
CD	
LOOP	7.7E-06
Total	7.7E-06
ATWS	
LOOP	2.2E-06
Total	2.2E-06

DOMINANT SEQUENCES

End State: CV Conditional Probability: 3.2E-08

226 LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)

End State: CD Conditional Probability: 5.6E-06

201 LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)

End State: ATWS Conditional Probability: 2.1E-06

Event Identifier: 293/86-027

240 LOOP -EMERG.POWER SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
201	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	5.6E-06 *	1.4E-02
208	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	2.1E-07	4.2E-02
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOCA SRV.ADS	CD	1.4E-06	6.0E-02
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)	CV	3.2E-08 *	5.8E-02
240	LOOP -EMERG.POWER SCRAM SLC.OR.RODS	ATWS	2.1E-06 *	1.2E-01
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP	CD	2.3E-07	4.7E-02
250	LOOP EMERG.POWER SCRAM	ATWS	9.6E-08	9.6E-02

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\bwrctree.cmp
BRANCH MODEL: c:\asp\newmodel\pilgrim.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	
LOOP	1.7E-05 > 1.7E-05	3.2E-01 > 1.2E-01	
Branch Model: INITOR			
Initiator Freq:	1.7E-05		
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
PCS/TRANS	1.7E-01	1.0E+00	
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	1.3E-02	1.0E+00	
EMERG.POWER	2.9E-03	8.0E-01	

FW/PCS.TRANS	2.9E-01	3.4E-01	
FW/PCS.LOCA	4.0E-02	3.4E-01	
HPCI	2.9E-02	7.0E-01	
RCIC/TRANS.OR.LOOP	6.0E-02	7.0E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	3.7E-03	7.1E-01	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	1.0E-03	7.1E-01	
RHRSW/LPCS.LPCI.TRANS	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOOP	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOCA	5.0E-01	1.0E+00	4.0E-02
RHR(SDC)	2.1E-02	3.4E-01	
RHR(SDC)/-LPCI	2.0E-02	3.4E-01	
RHR(SDC)/LPCI	1.0E+00	1.0E+00	
RHR(SPCOOL)/-LPCI.RHR(SDC)	2.0E-02	1.0E+00	
RHR(SPCOOL)/LPCI.RHR(SDC)	5.2E-01	1.0E+00	
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01	

* branch model file
** forced

Minarick
02-24-1988
12:08:17

Event Identifier: 293/86-027

PRECURSOR DESCRIPTION SHEET

LER No.: 301/86-004
Event Description: MSIVs fail to close on demand
Date of Event: September 28, 1986
Plant: Point Beach 2

EVENT DESCRIPTION

Sequence

The MSIVs had been in the open position since December 31, 1985. After that time, Unit 2 operated normally at full power with one runback and several power reductions requested by the power supply. The unit was shut down for refueling on September 27, 1986. On September 28, the reactor operator tried to shut the MSIVs from the control room. When the MSIVs did not shut, an operator was sent to the valves to close them manually. They were closed manually by the operator applying force to the operating arm of each valve. It should also be noted that the nonreturn valves also did not close under the no-flow conditions. The manual force needed to close the nonreturn valves was <7 ft-lb. This amount of force is minimal compared with the closing force that would have been applied to the valves if a reverse-steam-flow condition had occurred. Therefore, the conclusion is that the nonreturn valves would have closed under these circumstances.

Corrective Action

The immediate corrective action was to close the valves manually. The valves will be disassembled and inspected to determine the cause of the failure. Once the cause is determined, the valves will be repaired and tested.

Plant/Event Data

Systems Involved:
Main steam isolation system

Components and Failure Modes Involved:
MSIVs — failed to close on demand

Component Unavailability Duration: 4.5 months assumed
Plant Operating Mode: 5 (cold shutdown going to refueling)
Discovery Method: Operational event
Reactor Age: 14.3 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated SLB	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

SG isolation	1.0	Not considered recoverable in short term following the postulated SLB initiation

Plant Models Utilized

PWR plant Class E

Event Identifier: 301/86-004

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 301/86-004
Event Description: MSIVs Fail to Close on Demand
Event Date: 9/29/86

UNAVAILABILITY, DURATION= 3240

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

SLB	3.6E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
SLB	4.8E-07
Total	4.8E-07
ATWS	
SLB	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CD Conditional Probability: 3.0E-07

106 SLB -RT REQ.SG.ISO -AFW -HPI REQ.BA.ADDITION

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
105	SLB -RT REQ.SG.ISO -AFW -HPI -REQ.BA.ADDITION PORV.OPEN.DUE.TO.HPI PORV.CLOSURE HPR/-HPI	CD	7.1E-08	5.6E-01
106	SLB -RT REQ.SG.ISO -AFW -HPI REQ.BA.ADDITION	CD	3.0E-07 *	1.0E+00
107	SLB -RT REQ.SG.ISO -AFW HPI	CD	1.9E-07	5.2E-01

* dominant sequence for end state
** non-recovery credit for edited case

Event Identifier: 301/86-004

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.

MODEL: c:\asp\newmodel\pwrbaslb.txt
DATA:

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
BLB	1.1E-07	1.0E+00	
RT	2.5E-04	1.2E-01	
REQ.SG.ISO	6.4E-04 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.4E-04 > Failed		
AFW	1.0E-03	2.7E-01	
HPI	1.0E-03	5.2E-01	
HPI(F/B)	1.0E-03	5.2E-01	4.0E-02
HPR/-HPI	3.0E-03	5.6E-01	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
REQ.BA.ADDITION	8.3E-04	1.0E+00	
PORV.OPEN.DUE.TO.HPI	8.0E-01	1.0E+00	
PORV.CLOSURE	6.0E-03	1.0E+00	

*** forced

Austin
09-11-1987
13:48:35

Event Identifier: 301/86-004

PRECURSOR DESCRIPTION SHEET

LER No.: 318/86-006
Event Description: Trip occurs, and one atmospheric dump valve fails to close
Date of Event: September 5, 1986
Plant: Calvert Cliffs 2

EVENT DESCRIPTION

Sequence

While the reactor was at 100% power, a surge capacitor in the 21A RCP failed and shorted to ground. The RCP tripped off, which led to an automatic reactor trip on low flow.

The cooldown rate was faster than expected because an atmospheric steam dump valve was stuck open. It was closed manually after 22 min.

Corrective Action

The solenoid valve associated with the atmospheric dump valve was found to be leaking high-pressure air by its seats. The solenoid valve materials were replaced.

Plant/Event Data

Systems Involved:
RCS and atmospheric steam dump

Components and Failure Modes Involved:
RCP — failed in operation
Atmospheric steam dump valve — failed to close on demand

Component Unavailability Duration: NA
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 9.8 years
Plant Type: PWR

Comments

None

Event Identifier: 318/86-006

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

SS release terminated	1.0	Atmospheric dump valve failed to close from control room and is not closed locally for 22 min

Plant Models Utilized

PWR plant Class G

Event Identifier: 318/86-006

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 318/86-006
Event Description: Trip and One ASD Valve Fails to Close
Event Date: 9/5/86
Plant: Calvert Cliffs 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	2.5E-04
Total	2.5E-04
CD	
TRANS	1.8E-06
Total	1.8E-06
ATWS	
TRANS	3.4E-05
Total	3.4E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 2.4E-04

104 TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI

End State: CD Conditional Probability: 1.6E-06

102 TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI

End State: ATWS Conditional Probability: 3.4E-05

Event Identifier: 318/86-006

121 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI	CV	1.0E-05	8.4E-01
102	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT HPI HPR/-HPI	CD	1.6E-06 *	5.0E-02
104	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	2.4E-04 *	8.4E-01
116	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	8.5E-08	3.0E-02
119	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	8.9E-08	2.5E-02
121	TRANS RT	ATWS	3.4E-05 *	1.2E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\pwrgtree.cmp
BRANCH MODEL: c:\asp\newmodel\calvert.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	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	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.5E-02 > Failed		
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	

Event Identifier: 318/86-006

HPR/-HPI	1.5E-04	1.0E+00
CSR	2.0E-03	3.4E-01

* branch model file
** forced

Austin
09-11-1987
12:32:37

Event Identifier: 318/86-006

PRECURSOR DESCRIPTION SHEET

LER No.: 341/86-048
Event Description: RCIC and HPCI are unavailable
Date of Event: December 24, 1986
Plant: Fermi 2

EVENT DESCRIPTION

Sequence

At 1015 h on December 26. 1986, Fermi 2 was operating at 920 psig, 530°F, and 8% reactor power. Between 1248 h on December 24 and 1550 h on December 26, calibration activities for an RCIC system header flow instrument channel resulted in two occurrences of the RCIC system being declared inoperable. The second occurrence resulted in only slightly degraded flow capability. During these occurrences, the HPCI system was also inoperable. The HPCI system had been inoperable for a scheduled system outage since 1755 h on December 23, 1986.

Corrective Action

RCIC was recalibrated and restored to service

Plant/Event Data

Systems Involved:
RCIC and HPCI

Components and Failure Modes Involved:
RCIC — made unavailable
HPCI — made unavailable

Component Unavailability Duration: 4.5 h
Plant Operating Mode: 2 (5% power)
Discovery Method: Testing
Reactor Age: 1.5 years
Plant Type: BWR

Comments

The reason for HPCI unavailability on December 26, 1986, is not given. The assumption is that it could not be readily recovered for duty.

Event Identifier: 341/86-048

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOOP	Base case nonrecovery
Postulated LOCA	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

HPCI	1.0	No recovery assumed possible
RCIC	0.12	Recoverable in the control room

Plant Models Utilized

BWR plant Class C

Event Identifier: 341/86-048

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 341/86-048
Event Description: HPCI/RCIC Are Unavailable
Event Date: 12/24/86
Plant: Fermi 2

UNAVAILABILITY, DURATION= 4.5

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.9E-03
LOOP	2.4E-05
LOCA	7.4E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	7.2E-09
LOOP	9.3E-10
LOCA	7.8E-10
Total	8.9E-09
CD	
TRANS	4.9E-07
LOOP	5.8E-08
LOCA	1.0E-07
Total	6.5E-07
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 2.4E-09

Event Identifier: 341/86-048

134 TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS -RHR(SDC)

End State: CD   Conditional Probability: 4.6E-07

119 TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
110	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	2.5E-08	2.9E-02
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	4.6E-07 *	2.4E-01
134	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	2.4E-09 *	2.7E-02
138	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	1.2E-09	1.4E-02
155	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	2.3E-09	2.2E-01
159	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	1.2E-09	1.1E-01
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA SRV.ADS	CD	5.1E-08	2.3E-01
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOO P -SRV.ADS -LPCS -RHR(SDC)	CV	9.2E-10	3.8E-02
310	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	1.0E-07	1.2E-01
314	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	5.1E-10	1.1E-01
318	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	2.6E-10	5.7E-02

* dominant sequence for end state
** 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\newmodel\bwrctree.cmp
BRANCH MODEL: c:\asp\newmodel\fermi.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Event Identifier: 341/86-048

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	
LOOP	1.7E-05	3.2E-01	
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
PCS/TRANS	1.7E-01	1.0E+00	
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	5.0E-02	1.0E+00	
EMERG.POWER	3.0E-04	8.0E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	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		
RCIC/TRANS.OR.LOOP	6.0E-02 > 1.0E+00	7.0E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.0E-02 > Unavailable		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	3.7E-03	7.1E-01	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	1.0E-03	7.1E-01	
RHRSW/LPCS.LPCI.TRANS	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOOP	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOCA	5.0E-01	1.0E+00	4.0E-02
RHR(SDC)	2.1E-02	3.4E-01	
RHR(SDC)/-LPCI	2.0E-02	3.4E-01	
RHR(SDC)/LPCI	1.0E+00	1.0E+00	
RHR(SPCOOL)/-LPCI.RHR(SDC)	2.0E-02	1.0E+00	
RHR(SPCOOL)/LPCI.RHR(SDC)	5.2E-01	1.0E+00	
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01	

* branch model file
** forced

Minarick
02-24-1988
12:11:30

Event Identifier: 341/86-048

PRECURSOR DESCRIPTION SHEET

LER No.: 362/86-011
Event Description: Saltwater and CCW systems are unavailable
Date of Event: August 4, 1986
Plant: San Onofre 3

EVENT DESCRIPTION

Sequence

At 1550 h saltwater cooling flow through the train A CCW heat exchanger decreased as a result of fouling with marine growth. The fouling was below the postulated design-basis flow rate required for removal of CCW heat loads, and thus the exchanges was declared inoperable. At this time train B was operating with reverse saltwater cooling flow to remove similar fouling. Because there are only two saltwater cooling trains (two pumps per train), CCW water cooling flow was available. At 1605 h, operators commenced realignment of train B CCW heat-exchanger flow to the normal direction to return one train of CCW to its design configuration and thereby restore heat-removal capability of that train. Both trains of the saltwater cooling system were considered inoperable until the realignment was complete.

Corrective Action

Train B saltwater cooling system was returned to operable status at 1635 h. Operating procedures will be revised to minimize the effect of marine fouling on the operability of the SWC system.

Plant/Event Data

Systems Involved:
Essential raw cooling water system and CCW system

Components and Failure Modes Involved:
CCW heat exchangers — degraded in operation

Component Unavailability Duration: 45 min
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 3.0 years
Plant Type: PWR

Event Identifier: 362/86-011

Comments

The inoperable coding systems normally removed heat loads from the HPI, LPI, and CSR system pumps. These systems were assumed inoperable during unavailability of their cooling systems.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOOP	Base case nonrecovery
Postulated LOCA	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

HPI	0.34	One train of saltwater cooling recoverable locally with realignment
LPI	0.34	One train of saltwater cooling recoverable locally with realignment
CSR	0.34	One train of saltwater cooling recoverable locally with realignment

Plant Models Utilized

PWR plant Class G

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 362/86-011
Event Description: Salt and Component Cooling Water Systems Are Unavailable
Event Date: 8/4/86
Plant: San Onofre 3

UNAVAILABILITY, DURATION= .75

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.6E-04
LOOP	1.3E-06
LOCA	7.7E-07

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	6.2E-07
LOOP	2.3E-09
LOCA	(1.0E-12)
Total	6.3E-07
CD	
TRANS	4.7E-09
LOOP	1.8E-11
LOCA	2.5E-07
Total	2.6E-07
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 6.0E-07

Event Identifier: 362/86-011

104 TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI

End State: CD Conditional Probability: 2.6E-07

302 LOCA -RT -AFW HPI

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -RT -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI	CV	2.5E-08	1.2E-01
104	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	6.0E-07 *	1.2E-01
302	LOCA -RT -AFW HPI	CD	2.6E-07 *	1.5E-01

* dominant sequence for end state
** 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\newmodel\PWRGtree.cmp
BRANCH MODEL: c:\asp\newmodel\SANONO2.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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	1.3E-03	2.6E-01	
AFW/EMERG.POWER	5.0E-02	3.4E-01	
MFW	2.0E-01	3.4E-01	
PORV.OR.SRV.CHALL	4.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	2.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04 > 1.0E+00	8.4E-01 > 3.4E-01	

Event Identifier: 362/86-011

Branch Model: 1.OF.3			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
HPI(F/B)	3.0E-04 > 1.0E+00	8.4E-01 > 3.4E-01	4.0E-02
Branch Model: 1.OF.3+opr			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
PORV.OPEN	1.0E+00	1.0E+00	
HPR/-HPI	1.5E-04	1.0E+00	
CSR	2.0E-03 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	2.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		

* branch model file
** forced

Austin
09-11-1987
17:35:49

Event Identifier: 362/86-011

PRECURSOR DESCRIPTION SHEET

LER No.: 366/86-035
Event Description: LPCS system is unavailable
Date of Event: November 13, 1986
Plant: Hatch 2

EVENT DESCRIPTION

Sequence

At 2319 h during testing of the LPCS system, personnel found the LPCS had been isolated. The pump electrical power had been removed, and the pump suction valves had been closed (both loops). The isolation was effected to carry out a different test [the Integrated Leak Rate Test (ILRT)], but the procedure for that test was in error.

Corrective Action

The procedure was revised.

Plant/Event Data

Systems Involved:
LPCS

Components and Failure Modes Involved:
LPCS pumps — made unavailable in testing
LPCS valves — made unavailable in testing

Component Unavailability Duration: 12 h
Plant Operating Mode: 5 (0% power)
Discovery Method: Testing
Reactor Age: 8.3 years
Plant Type: BWR

Comments

None

Event Identifier: 366/86-035

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOCA	Base case nonrecovery
Postulated LOOP	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

LPCS	0.34	Recoverable locally at the equipment

Plant Models Utilized

BWR plant Class C

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 366/86-035
Event Description: LPCS Is Unavailable
Event Date: 11/13/86
Plant: Hatch 2

UNAVAILABILITY, DURATION= 12

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E-02
LOOP	6.5E-05
LOCA	2.0E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	(1.0E-14)
LOOP	(2.6E-15)
LOCA	(2.1E-15)
Total	(1.5E-14)
CD	
TRANS	3.5E-10
LOOP	7.0E-12
LOCA	6.4E-12
Total	3.6E-10
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.6E-11

Event Identifier: 366/86-035

163 TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI

End State: CD   Conditional Probability: 3.3E-10

116 TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS RHR(SDC)/LPCI RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
116	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS RHR(SDC)/LPCI RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	3.3E-10 *	9.3E-03
118	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS LPCS LPCI(RHR)/LPCS RHRSW/LPCS.LPCI.TRANS	CD	1.8E-11	2.0E-02
142	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	8.2E-12	1.9E-02
163	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	1.6E-11 *	2.7E-02
230	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	6.0E-12	5.3E-02
322	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	5.0E-12	1.4E-02

* dominant sequence for end state
** 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\newmodel\bwrctree.cmp
BRANCH MODEL: c:\asp\newmodel\hatch.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	

Event Identifier: 366/86-035

LOOP	1.7E-05	3.2E-01	
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
PCS/TRANS	1.7E-01	1.0E+00	
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-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	5.4E-04	8.0E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	2.9E-02	7.0E-01	
RCIC/TRANS.OR.LOOP	6.0E-02	7.0E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	3.7E-03	7.1E-01	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	3.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
LPCI(RHR)/LPCS	1.0E-03	7.1E-01	
RHRSW/LPCS.LPCI.TRANS	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOOP	5.0E-01	1.0E+00	4.0E-02
RHRSW/LPCS.LPCI.LOCA	5.0E-01	1.0E+00	4.0E-02
RHR(SDC)	2.1E-02	3.4E-01	
RHR(SDC)/-LPCI	2.0E-02	3.4E-01	
RHR(SDC)/LPCI	1.0E+00	1.0E+00	
RHR(SPCOOL)/-LPCI.RHR(SDC)	2.0E-02	1.0E+00	
RHR(SPCOOL)/LPCI.RHR(SDC)	5.2E-01	1.0E+00	
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01	

* branch model file
** forced

Minarick
02-24-1988
12:13:33

Event Identifier: 366/86-035

PRECURSOR DESCRIPTION SHEET

LER No.: 370/86-006
Event Description: High-head injection system is unavailable, and DG A is out of service
Date of Event: March 29, 1986
Plant: McGuire 2

EVENT DESCRIPTION

Sequence

At 0315 h on March 19, 1986, DG 2-A was declared inoperable for maintenance repairs. Charging (SI) pump 2-A was also declared inoperable because DG 2-A could not provide emergency power to the pump. On March 28, 1986, at approximately 1100 h, a station engineer requested the responsible assistant shift supervisor to rack in and operate charging pump 2-A so a retest could be performed on charging pump 2-A. The engineer made the request without realizing that DG 2-A was inoperable. The assistant shift supervisor instructed station personnel to rack out charging pump 2-B and rack in charging pump 2-A. The assistant shift supervisor did not realize that DG 2-A was inoperable and that racking out charging pump 2-B would result in a loss of boration flow path. The assistant shift supervisor did not discuss the change with the designated control room senior reactor operator to ensure Technical Specifications requirements were met.

At 1245 h, the retest on charging pump 2-A was completed.

On March 29, 1986, at 0700 h, during shift turnover, station personnel discovered that while charging pump 2-B had been racked out of service, charging pump 2-A had been racked in service without an emergency power supply. Immediately charging pump 2-A was racked out and charging pump 2-B was racked in, reestablishing compliance with Technical Specifications.

Corrective Action

Charging pump 2-B was placed in service.

Plant/Event Data

Systems Involved:
High-head injection, emergency power

Components and Failure Modes Involved:
DG 2-A — was out for maintenance
Charging pump 2-B — was removed from service

Event Identifier: 370/86-006

Component Unavailability Duration: 20 h
Plant Operating Mode: 6 (refueling)
Discovery Method: Testing
Reactor Age: 2.9 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

HPI	Base case	Both high-head injection trains would be unavailable given a LOOP
EPS	Base case	DG A was out of service
AFW	Base case	One train was unavailable because DG A was unavailable
LPI	Base case	One train was unavailable because DG A was unavailable
LPR	Base case	One train was unavailable because DG A was unavailable
HPR	Base case	One train was unavailable since DG A was unavailable

Plant Models Utilized

PWR plant Class F

Event Identifier: 370/86-006

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 370/86-006
Event Description: HHIS Is Unavailable and DG 'A' Is Out of Service
Event Date: 3/29/86
Plant: McGuire 2

UNAVAILABILITY, DURATION= 20

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.6E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	1.4E-08
Total	1.4E-08
CD	
LOOP	3.4E-08
Total	3.4E-08
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 6.5E-09

217 LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM

End State: CD Conditional Probability: 2.3E-08

218 LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 370/86-006

	Sequence	End State	Prob	N Rec**
202	LOOP -RT/LOOP -EMERG.POWER -AFW PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT SS.RELEAS.TERM HPI SS.DEPRESS	CV	2.1E-10	1.1E-01
206	LOOP -RT/LOOP -EMERG.POWER -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	1.6E-09	1.6E-02
210	LOOP -RT/LOOP -EMERG.POWER -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI -SS.DEPRESS LPI/HPI	CV	4.6E-10	3.8E-02
211	LOOP -RT/LOOP -EMERG.POWER -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI SS.DEPRESS	CV	5.1E-09	1.1E-01
214	LOOP -RT/LOOP -EMERG.POWER AFW HPI(F/B)	CD	9.6E-09	8.4E-02
215	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	2.6E-10	1.0E-01
216	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT/EMERG.POWER	CD	1.6E-09	3.1E-01
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	6.5E-09 *	1.0E-01
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	2.3E-08 *	1.1E-01

* dominant sequence for end state
** 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\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\mcguire.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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		

Event Identifier: 370/86-006

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	4.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	3.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	3.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	1.0E-03 > 1.0E+00	8.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
HPI(F/B)	1.0E-03 > 1.0E+00	8.4E-01	4.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
HPR/-HPI	1.5E-04 > 1.0E-02	1.0E+00	4.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04 > 1.0E-02	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.5E-04 > 1.0E-02	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.5E-02 > Unavailable		

* branch model file
** forced

Austin
09-11-1987
12:45:01

Event Identifier: 370/86-006

PRECURSOR DESCRIPTION SHEET

LER No.: 389/86-011
Event Description: Emergency power system is unavailable
Date of Event: July 9, 1986
Plant: St. Lucie 2

EVENT DESCRIPTION

Sequence

At 0854 h the 2-A emergency DG was started for a surveillance test conducted once every 7 d. The 2-A DG failed to meet the required generator voltage and frequency within 10 s after the start signal. One of the two engines in the 2-A DG set had failed to start. The 2-A DG was manually tripped by the operator at 0856 h.

At 0915 h the redundant 2-B DG was started. At 0917 h, 2-B DG was stopped because an operator observed 1 of the 12 cylinder cooling fan blades rubbing the cooling fan shroud.

The unit remained at 100% power throughout this event.

Corrective Action

2-B DG was repaired and returned to service at 1059 h. Troubleshooting of the 2-A DG revealed a problem in the mechanical portion of the Woodward governor. The problem was corrected, and 2-A DG was returned to service at 2010 h.

Plant/Event Data

Systems Involved:
Emergency power generation system

Components and Failure Modes Involved:
2A DG — failed in testing
2B DG — failed in testing

Component Unavailability Duration: 84 h assumed (half of the 7-d surveillance period)
Plant Operating Mode: 1 (100% power)
Discovery Method: Surveillance test
Reactor Age: 3.1 years
Plant Type: PWR

Event Identifier: 389/86-011

Comments

LER 389/86-011 states that the fan rub associated with DG 2-B was minor. If the fan rub was minor in the sense that even with the fan rub, the DG would have operated for its mission time, then the emergency power system unavailability should be based on the maintenance unavailability period (~1 3/4 hours). However, if the fan rub was minor in the sense that it was easily repaired, but with the rub the DG would not have operated for its mission time, then an emergency power system unavailability based on the surveillance period is warranted. Since it is not possible to distinguish between these two cases based on information provided in the LER, a more conservative estimate based on surveillance internal was assumed.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

EPS	1.0	Given a LOOP, recovery assumed not possible in time to mitigate the transient (see comment above)

Plant Models Utilized

PWR plant Class G

Event Identifier: 389/86-011

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 389/86-011
Event Description: Emergency Power System Is Unavailable
Event Date: 7/9/86
Plant: St Lucie 2

UNAVAILABILITY, DURATION= 84

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.5E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	7.5E-07
Total	7.5E-07
CD	
LOOP	2.6E-06
Total	2.6E-06
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 7.4E-07

211 LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM

End State: CD Conditional Probability: 2.6E-06

212 LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 389/86-011

	Sequence	End State	Prob	N Rec**
211	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	7.4E-07 *	1.3E-01
212	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	2.6E-06 *	1.3E-01

* dominant sequence for end state
** 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\newmodel\pwrgtree.cmp
BRANCH MODEL: c:\asp\newmodel\lucie.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-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 > 1.0E+00	8.0E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
AFW	3.8E-04	2.6E-01	
AFW/EMERG.POWER	5.0E-02	3.4E-01	
MFW	1.9E-01	3.4E-01	
PORV.OR.SRV.CHALL	2.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04	8.4E-01	
HPI(F/B)	3.0E-04	8.4E-01	4.0E-02
PORV.OPEN	1.0E+00	1.0E+00	
HPR/-HPI	1.5E-04	1.0E+00	
CSR	2.0E-03	3.4E-01	

* branch model file

Event Identifier: 389/86-011

** forced

Austin
09-11-1987
12:47:15

Event Identifier: 389/86-011

PRECURSOR DESCRIPTION SHEET

LER No.: 409/86-023
Event Description: LOOP occurs due to lightning strike at coal-fired unit
Date of Event: July 10, 1986
Plant: LaCrosse

EVENT DESCRIPTION

Sequence

With the plant in the cold shutdown condition, at 0630 h, the following opened: the 69-kV tie line breaker, 2NB11; the reverse transformer supply breaker, 25NB4; and the 480-V main feed breakers, 452 M1A and 452 M1B. Both EDGs started and supplied the 1-A and 1-B 480-V essential buses. The containment building also isolated. The 1-A high-pressure service-water diesel pump started when service-water pressure dropped to the low-pressure set point.

A severe thunderstorm was in progress at the time. The operations center informed the plant that the adjacent coal plant's auxiliary switchyard had been hit by lightning. The operators reset the lockout relays. At 0642 h they closed breakers 2NB11 and 25NB4; at 0645 h they shut the 480-V main feed breakers and opened the EDG's output breakers. The 480-V essential bus breakers automatically closed, completing the electrical lineup restoration. At 0659 h the 1-A high-pressure service-water DG was secured and returned to automatic. At 0702 h the EDGs were secured and returned to automatic.

An unusual event was declared due to the loss of offsite power. The plant was without offsite power for 12 min. The lightning had hit a static wire in the adjacent coal plant's auxiliary switchyard. The 69-kV tie line supplies power to LaCrosse's reserve transformer and the coal unit's reserve auxiliary transformer. When the lightning struck, the 69-kV tie line breaker and both transformers' supply breakers opened. The LaCrosse 480-V main feed breakers tripped on undervoltage. Undervoltage also started the EDGs and tripped the 480-V essential bus main feed breakers, which caused the emergency DGs' output breakers to close to supply the essential buses. If this incident had occurred while the reactor was at 100% power, a loss of load transient would have resulted. This is a design-basis transient, and the plant would still have been in a safe condition.

Corrective Action

The breakers were closed.

Event Identifier: 409/86-023

Plant/Event Data

Systems Involved:
Electrical

Components and Failure Modes Involved:
Breakers — failed open in operation

Component Unavailability Duration: NA
Plant Operating Mode: 4 (0% power)
Discovery Method: Operational event
Reactor Age: 17.6 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	Base case nonrecovery multiplied by 0.75 for occurring at power

Branches Impacted and Branch Nonrecovery Estimate

None

Plant Models Utilized

Unique BWR class

Event Identifier: 409/86-023

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 409/86-023
Event Description: LOOP Due to Lightning Strike at Coal-Fired Unit
Event Date: 7/10/86
Plant: LaCrosse

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	2.7E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.0E-05
Total	2.0E-05
CV	
LOOP	0.0E+00
Total	0.0E+00
ATWS	
LOOP	5.3E-06
Total	5.3E-06

DOMINANT SEQUENCES

End State: CD Conditional Probability: 6.7E-06

205 LOOP -EMERG.POWER -SCRAM HPCS HPSW

End State: ATWS Conditional Probability: 4.7E-06

206 LOOP -EMERG.POWER SCRAM -HPCS SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 409/86-023

	Sequence	End State	Prob	N Rec**
202	LOOP -EMERG.POWER -SCRAM HPCS -HPSW -SRV.CLOSE SHUTDOWN.CONDENSER MANUAL.DEPRESS	CD	1.6E-06	2.7E-01
204	LOOP -EMERG.POWER -SCRAM HPCS -HPSW SRV.CLOSE MANUAL.DEPRESS	CD	1.6E-06	2.7E-01
205	LOOP -EMERG.POWER -SCRAM HPCS HPSW	CD	6.7E-06 *	2.7E-01
206	LOOP -EMERG.POWER SCRAM -HPCS SLC.OR.RODS	ATWS	4.7E-06 *	2.7E-01
207	LOOP -EMERG.POWER SCRAM HPCS	ATWS	4.7E-07	2.7E-01
209	LOOP EMERG.POWER -SCRAM -HPSW -SRV.CLOSE SHUTDOWN.CONDENSER MANUAL.DEPRESS	CD	7.3E-07	2.2E-01
210	LOOP EMERG.POWER -SCRAM -HPSW SRV.CLOSE	CD	6.1E-06	2.2E-01
211	LOOP EMERG.POWER -SCRAM HPSW	CD	3.1E-06	2.2E-01
212	LOOP EMERG.POWER SCRAM	ATWS	2.2E-07	2.2E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\lactree.cmp
BRANCH MODEL: c:\asp\newmodel\lacrosse.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	
LOOP	2.0E-05 > 2.0E-05	3.6E-01 > 2.7E-01	
Branch Model: INITOR			
Initiator Freq:	2.0E-05		
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
EMERG.POWER	2.9E-03	8.0E-01	
FW	1.0E-01	3.4E-01	
HPSW	5.0E-03	1.0E+00	
SHUTDOWN.CONDENSER	1.0E-02	1.0E+00	
HPCS	5.0E-03	1.0E+00	
LPCS	1.0E-03	1.0E+00	
SRV.CLOSE	1.0E-02	1.0E+00	
DH	1.0E-02	1.0E+00	
MANUAL.DEPRESS	1.2E-01	1.0E+00	

* branch model file
** forced

Event Identifier: 409/86-023

PRECURSOR DESCRIPTION SHEET

LER No.: 413/86-031
Event Description: Small LOCA forces plant trip
Date of Event: June 13, 1986
Plant: Catawba 1

EVENT DESCRIPTION

Sequence

The unit was at 48% power with the variable letdown orifice valve 1NV849 in service to reduce letdown flow to 30 gal/min. A leak (>1 gal/min) had been detected at the CCW/CVCS junction at the letdown heat exchanger. The fixed orifice flow paths were isolated. At 1100 h a leak of >1.5 gal/min was detected. At 1500 h an unusual event was declared. At 1542 h, alarms occurred indicating the loss of motor control center 1MXD, which affected control power to valve 1NV849 and the generator hydrogen-cooler-temperature valve. The former failed open, and the latter failed closed.

Charging flow suddenly increased to 130 gal/min, and pressurizer level began to fall. The letdown line had suffered a guillotine rupture at valve 1NV849's downstream outlet flange as a result of vibration-induced fatigue. At 1550 h the main-generator hydrogen temperature began to rise. At 1551 h the letdown orifice valve was closed, but pressurizer level continued to decrease. Hydrogen temperature continued to increase. Sump high-level alarms were actuated, and at 1610 h reactor power and turbine load were reduced. Maximum charging was maintaining pressurizer level, and additional letdown isolation valves were closed. The leak was contained by 1641 h. Hot standby was entered at 1700 h. Cold shutdown was entered at 0257 h the next day.

Corrective Action

Repairs were made to the letdown line. The MCC failure was due to a name plate that became unglued and caused a short circuit when it fell.

Plant/Event Data

Systems Involved:
Electrical and chemical volume and control

Components and Failure Modes Involved:
Motor control center transformer — failed in operation
CVCS pipe — ruptured in operation

Event Identifier: 413/86-031

Component Unavailability Duration: NA
Plant Operating Mode: 1 (48% power)
Discovery Method: Operational event
Reactor Age: 1.4 years
Plant Type: PWR

Comments

We are assuming a 130 gpm SBLOCA since CP's were able to maintain pressurizer level with this flowrate

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

SBLOCA	0.12	Flow isolable via letdown isolation valves

Branches Impacted and Branch Nonrecovery Estimate

None

Plant Models Utilized

PWR plant Class F

Event Identifier: 413/86-031

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 413/86-031
Event Description: Small LOCA Forces Plant Trip
Event Date: 6/13/86
Plant: Catawba 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.2E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOCA	1.6E-03
Total	1.6E-03
CD	
LOCA	3.3E-03
Total	3.3E-03
ATWS	
LOCA	4.0E-06
Total	4.0E-06

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.5E-03

301 LOCA -RT -AFW -HPI HPR/-HPI -SS.DEPRESS -LPR/-HPI.HPR

End State: CD Conditional Probability: 3.1E-03

302 LOCA -RT -AFW -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR

End State: ATWS Conditional Probability: 4.0E-06

Event Identifier: 413/86-031

326 LOCA RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
301	LOCA -RT -AFW -HPI HPR/-HPI -SS.DEPRESS -LPR/-HPI.HPR	CV	1.5E-03 *	1.2E-01
302	LOCA -RT -AFW -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	3.1E-03 *	1.2E-01
303	LOCA -RT -AFW -HPI HPR/-HPI SS.DEPRESS	CD	1.7E-04	1.2E-01
304	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	9.7E-05	1.0E-01
326	LOCA RT	ATWS	4.0E-06 *	1.4E-02

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\pwrbtree.cmp
BRANCH MODEL: c:\asp\newmodel\cataw.txt
PROBABILITY FILE: c:\asp\newmodel\pwr_b.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	4.8E-04	1.0E+00	
LOOP	4.6E-06	3.9E-01	
LOCA	2.4E-06 > 2.4E-06	4.3E-01 > 1.2E-01	
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	8.0E-01	
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	3.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	3.0E-02	1.0E+00	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	1.0E-03	8.4E-01	
HPI(F/B)	1.0E-03	8.4E-01	4.0E-02
HPR/-HPI	1.5E-04	1.0E+00	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.5E-04	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	

Event Identifier: 413/86-031

LPR/HPI	1.5E-04	1.0E+00

* branch model file
** forced

Austin
09-11-1987
12:58:13

Event Identifier: 413/86-031

PRECURSOR DESCRIPTION SHEET

LER No.: 414/86-028
Event Description: SG PORVs open inadvertently in test, and trip with other failures occurs
Date of Event: June 27, 1986
Plant: Catawba 2

EVENT DESCRIPTION

Sequence

During a loss of control room function test from 24% power, an unexpected plant transient, SG depressurization, and reactor trip occurred as a result of test procedure errors. The procedure provides reactor guidelines to demonstrate, principally

1. that the plant can be brought to hot standby-conditions from a moderate power level (10—25%) using only the auxiliary shutdown panel controls,
2. that the plant can be maintained at hot standby conditions for 30 min from the auxiliary shutdown panels, and
3. that the RCS can be cooled down at least 50°F from a steady state hot standby condition while being operated from the auxiliary shutdown panel controls.

In accordance with the test procedure, the reactor was manually tripped at the reactor trip switchgear at 0942 h. MFW isolation and the autostart of both motor-driven AFW pumps occurred 12 s later. Low-low levels subsequently occurred in all four SGs. The AFW pump turbine automatically started on low-low level in two out of four SGs. MFW pump 2-B later tripped at 0942:42 h on low suction flow.

Unit control was transferred from the control room to the auxiliary shutdown panel at 0942:49 h. The letdown pressure control valve, 2NV-148A, unexpectedly failed open when the transfer occurred. Letdown flow indication began to oscillate rapidly. Charging flow spiked to a maximum of 178 gal/min at approximately 0946:30 h. Letdown was manually isolated after pressurizer level dropped to <20%. Letdown flow dropped to ~15 gal/min by 0947:30 h.

At 0946:59 h, the SG PORV breakers at the AFW turbine control panel were closed in accordance with the procedure. When the breakers were energized, SG A, B, C, and D PORVs opened to 75%. This was a result of the SG PORV manual loaders being initially set to what was thought to be the 1125 psig opening set point. A design change had modified the SG PORV controls, but the modification had not been adequately understood.

The SG PORV opening caused a rapid depressurization of the secondary side with an accompanying cooldown of the primary side. Personnel observed the decreasing steam pressure and attempted to increase the set point for SG PORV opening, but they actually opened the PORVs further. Personnel in the control room observed the actual SG PORV positions go Open, but did not immediately communicate this to personnel at the auxiliary shutdown panel because of the nature of the test. SG levels responded to the SG PORV openings by first swelling and then dropping rapidly off the narrow range scale. The auxiliary shutdown panel operators were observing wide range indication. The AFW turbine had been secured at 0945:45 h. For ~4.5 min the SGs were blowing down through the SG PORVs, with AFW flow being provided to SG D.

Pressurizer pressure dropped off scale (<1700 psig) ~2 min after the SG PORVs opened. SI condition on low pressurizer pressure (1845 psig) occurred at 0949:46 h. SI condition on low steam-line pressure loop D (725 psig) occurred at 0950:08 h. However, SI was partially blocked at that time because control had been transferred to the auxiliary shutdown panel operators. Several containment isolation valves closed automatically, and charging suction was automatically aligned to the refueling water storage tank when the SI conditions were satisfied.

As pressurizer level continued to decrease, personnel at the auxiliary shutdown panel manually started centrifugal charging pump 2-B. However, because of valve controller labeling problems, operators as the auxiliary shutdown panel reduced charging flow rather than increasing it while adjusting the manual loader for 2NV-294, charging pumps flow control valve.

At approximately 0953:30 h, the decision was made to terminate the test and return control to the control room. At 0953:14 h, the senior reactor operator directed personnel to swap control back to the control room. When this was done, SI was immediately actuated due to the unblocking of the still-present actuation signal. Both DGs actuated on LOCA condition. The SG PORVs reclosed on transfer of controls. The SI signal started the RHR pumps, SI pumps, and the AFW turbine pump and opened volume-control-pump discharge to cold-leg isolation valves 2NI-9A and 2NI-10B and associated AFW valves. Valve 2NV-148A reclosed following the transfer.

Both DG load sequencers completed accelerated sequencing within ~21 s. SI flow restored pressurizer level to 33% and pressure to 1250 psig within ~5.5 min.

At 0958 h, SI was reset, the cold-leg-injection isolation valves were closed, and the SI system and RHR pumps were secured. The SI had further reduced steam-line pressure to ~480 psig and primary coolant temperature to ~468°F. The AFW was secured at 1000 h.

Corrective Action

A review of all design changes and construction department shutdown requests implemented after hot functional testing and before fuel load was performed prior to the unit reentering Mode 2, startup.

Event Identifier: 414/86-028

A review of both units' auxiliary shutdown panels and AFW pump turbine control panels was performed, and numerous unit differences and labeling problems were identified. Labeling problems were corrected. Revisions were made to operating and abnormal procedures. Also added were instructions to manually initiate SI, containment spray, and annulus ventilation if required following a loss of control room incident.

Plant/Event Data

Systems Involved:
SG atmospheric dump system

Components and Failure Modes Involved:
PORVs — failed open in test

Component Unavailability Duration: NA
Plant Operating Mode: 1 (24% power)
Discovery Method: Testing
Reactor Age: 0.1 year
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

SLB	0.12	No recovery assumed possible because of the test criteria; leak isolable from the control room when the test was terminated

Branches Impacted and Branch Nonrecovery Estimate

SS release terminated	1.0	Recoverable from control room but recovery was delayed due to numerous procedure and operator errors
HPI	1.0	Valve labeling errors resulted in the inability to provide sufficient HPI flow during the test

Plant Models Utilized

PWR plant Class F

Event Identifier: 414/86-028

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 414/86-028
Event Description: SG PORVs Open with Plant Trip and Other Failures at Catawba
Event Date: 6/27/86

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

SLB	1.2E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
SLB	1.1E-04
Total	1.1E-04
ATWS	
SLB	3.6E-06
Total	3.6E-06

DOMINANT SEQUENCES

End State: CD Conditional Probability: 7.7E-05

107 SLB -RT REQ.SG.ISO -AFW HPI

End State: ATWS Conditional Probability: 3.6E-06

112 SLB RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
104	SLB -RT -REQ.SG.ISO AFW HPI(F/B)	CD	3.3E-05	3.2E-02
107	SLB -RT REQ.SG.ISO -AFW HPI	CD	7.7E-05 *	1.2E-01
112	SLB RT	ATWS	3.6E-06 *	1.4E-02

Event Identifier: 414/86-028

* dominant sequence for end state
** non-recovery credit for edited case

MODEL: c:\asp\newmodel\pwrbslb.txt
DATA:

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
SLB	1.1E-07 > 1.1E-07	1.0E+00 > 1.2E-01	
Branch Model: INITOR			
Initiator Freq:	1.1E-07		
RT	2.5E-04	1.2E-01	
REQ.SB.ISO	6.4E-04	1.0E+00	
AFW	1.0E-03	2.7E-01	
HPI	1.0E-03 > 1.0E+00	5.2E-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	5.2E-01 > 1.0E+00	4.0E-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	3.0E-03	5.6E-01	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
REQ.BA.ADDITION	8.3E-04	1.0E+00	
PORV.OPEN.DUE.TO.HPI	8.0E-01	1.0E+00	
PORV.CLOSURE	6.0E-03	1.0E+00	

*** forced

Austin
09-11-1987
13:53:04

Event Identifier: 414/86-028

PRECURSOR DESCRIPTION SHEET

LER No.: 458/86-002
Event Description: Hand-held radio causes LOOP
Date of Event: January 1, 1986
Plant: River Bend 1

EVENT DESCRIPTION

Sequence

At 0941 h with the unit in hot shutdown and cooling down from a eactor trip that had occurred ~6 h earlier (see LER 458/86-001) preferred station transformers A and C tripped. Recirculation pump A tripped, the operating condensate pump tripped, and the reactor water cleanup system isolated. RPS bus A deenergized, initiating a half scram and partial isolation of the nuclear steam supply shutoff system. The partial NSSSS isolation caused an instrument air isolation to the reactor building, which caused the scram valves to leak, thereby causing the scram discharge volume to fill. This filling subsequently resulted in an RPS actuation on high scram-discharge-volume level at 0957 h. Upon the preferred station transformer trips, division I and III DGs started, division I emergency ventilation systems autostarted, and standby service-water pumps A, B, C, and D load sequenced. Normal service-water pump B and circulating-water pump B were still running but without any bearing cooling water because bearing-cooling-water pump A had lost power. At 1001 h the MSIV automatically isolated due to decreasing condenser vacuum.

At 1003 h operators were dispatched, and they attempted to recover deenergized load centers. At 1031 h, RPS bus A was reset. Later, an electrical panel was discovered deenergized because of a blown fuse in a transformer. This loss had caused several control building HVAC and fuel building HVAC dampers to close, which then caused the division I control building chiller to trip. Subsequent attempts to restore operation of chillers B and D were also unsuccessful. The partial NSSSS isolation remained sealed in because of the deenergized electrical panel.

The RPS actuation was reset at 1042 h. At 1044 h, ~1 h after the initiating event, preferred station transformers B and D tripped. The station was now in a complete LOOP. The division II DG started and sequenced properly. An unusual event was immediately declared, and abnormal operating procedures were initiated. Reactor water level was +80 in. on the shutdown range, and pressure was at 240 psig.

At 1114 h the half RPS actuation was reset, and power to RPS bus B was restored. At 1124 h the preferred station transformers were energized, but the supply breakers to the plant could not be closed. It was determined that breaker closure was locked out by the tone-relaying transfer trip (fiber-optic) system, which could not be reset. At 1130 h this backup system was disabled and the breakers were closed. All in-house loads were restored, and the unusual event ended after 1 h and 10 min.

An investigation of the protective relaying revealed that no protective relaying targets had been initiated. Further, the trip signals sent to the lockout relays could only have been initiated by a spurious signal in the backup pilot wire or tone-relaying transfer trip circuits. Functional and diagnostic testing of both the pilot wire and tone-relaying circuits showed that both systems were operating as designed at the time of testing. Two items were noted: (1) spurious trips could be generated on the tone-relaying system with hand-held radios in close proximity (within approximately a 10- to 12-ft radius) of the transmitters/receivers and (2) some of the tone-relaying keying and rack power were supplied from two separate battery sources. Although no spurious trips could be simulated by testing, this type of connection could result in transients within the tone-relaying equipment. It was decided to correct the wiring in the field such that keying power and rack power were supplied by the same battery source.

Two types of hand-held radios were tested. They are commonly used on site by security and operations personnel. Both of these radios were keyed to transmit inside the control building of the Fancy Point switchyard, and both caused spurious trips on the tone-relaying system. Careful consideration led to the conclusion that it was highly probable that the LOOP was caused by radio frequency interference.

Also investigated was the difficulty in resetting the lockout relays. Because of the complexity of the tone-relaying and pilot-wire-tripping circuitry, the resetting of the lockout relays must be performed in the proper sequence. Operations procedures were determined to have addressed the required sequence.

Corrective Action

As a result of this event, several corrective actions have been completed or are in progress. These corrective actions in part include

1. installation of shielding on the tone-relaying equipment in the Fancy Point switchyard,
2. rewiring the tone equipment such that both channels are required for tripping,

Event Identifier: 458/86-002

3. changing dc power supplies to tone-relaying equipment such that the keying and rack power are both supplied from the same dc source,
4. installation of sequence of event recorders in the switchyard and at the generator/transformers protective relaying panel,
5. installation of additional drainage reactors at the plant end of the pilot wire shielding, and
6. installation of supervisory control and data acquisition (SCADA) system alarms to provide annunciation in the main control room and at the Government Street transmission and distribution control center for loss of channel signals on tone-relaying equipment.

Plant/Event Data

Systems Involved:
Power system (ac), pilot-wire relay system, tone-relaying transfer trip system, plant communications system

Components and Failure Modes Involved:
Hand-held radios — gave false signals to tone-relaying transfer trip system
Power relay (ac) — transferred open
Main feedwater — failed in operation

Component Unavailability Duration: NA
Plant Operating Mode: 3 (0% power)
Discovery Method: Operational event
Reactor Age: 0.2 year
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	1.0	Nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

None

Plant Models Utilized

BWR plant Class C

Event Identifier: 458/86-002

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 458/86-002
Event Description: Hand Held Radio Causes LOOP
Event Date: 1/1/86
Plant: River Bend 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	9.0E-08
Total	9.0E-08
CD	
LOOP	7.0E-05
Total	7.0E-05
ATWS	
LOOP	1.9E-05
Total	1.9E-05

DOMINANT SEQUENCES

End State: CV   Conditional Probability: 8.9E-08

226 LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)

End State: CD   Conditional Probability: 4.5E-05

201 LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)

End State: ATWS   Conditional Probability: 1.7E-05

Event Identifier: 458/86-002

240 LOOP -EMERG.POWER SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
201	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	4.5E-05 *	1.1E-01
209	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	2.8E-06	1.1E-01
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOCA SRV.ADS	CD	1.7E-05	2.4E-01
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)	CV	8.9E-08 *	2.4E-01
240	LOOP -EMERG.POWER SCRAM SLC.OR.RODS	ATWS	1.7E-05 *	1.0E+00
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP	CD	1.6E-06	1.9E-01
246	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOCA	CD	2.4E-06	2.7E-01
250	LOOP EMERG.POWER SCRAM	ATWS	2.1E-06	8.0E-01

* dominant sequence for end state
** non-recovery credit for edited case

SEQUENCE MODEL: c:\asp\newmodel\bwrctree.cmp
BRANCH MODEL: c:\asp\newmodel\riverbnd.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	
LOOP	1.7E-05 > 1.7E-05	3.2E-01 > 1.0E+00	
Branch Model: INITOR			
Initiator Freq:	1.7E-05		
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
PCS/TRANS	1.7E-01	1.0E+00	
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	1.0E+00	1.0E+00	

Event Identifier: 458/86-002

SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	5.9E-02	1.0E+00	
EMERG.POWER	7.5E-03	8.0E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	2.0E-02	3.4E-01	
RCIC/TRANS.OR.LOOP	6.0E-02	7.0E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	3.7E-03	7.1E-01	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	2.0E-02	3.4E-01	
LPCI(RHR)/LPCS	6.0E-04	7.1E-01	
RHRSW/LPCS.LPCI.TRANS	1.0E+00	1.0E+00	
RHRSW/LPCS.LPCI.LOOP	1.0E+00	1.0E+00	
RHRSW/LPCS.LPCI.LOCA	1.0E+00	1.0E+00	
RHR(SDC)	2.1E-02	3.4E-01	
RHR(SDC)/-LPCI	2.0E-02	3.4E-01	
RHR(SDC)/LPCI	1.0E+00	1.0E+00	
RHR(SPCOOL)/-LPCI.RHR(SDC)	2.0E-02	1.0E+00	
RHR(SPCOOL)/LPCI.RHR(SDC)	5.2E-01	1.0E+00	
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01	

* branch model file
** forced

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02-24-1988
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Event Identifier: 458/86-002

PRECURSOR DESCRIPTION SHEET

LER No.: 458/86-047
Event Description: Emergency power, LPCS, RHR train A, and RCIC systems are degraded twice
Date of Event: July 31, 1986
Plant: River Bend 1

EVENT DESCRIPTION

Sequence

At 0243 h on July 31, 1986, and at 0637 h on August 2, 1986, containment unit cooler 1-A feeder breaker (1EJS*ACB36) and the switchgear tripped at the same time. The loss of the switchgear resulted in the automatic start of both trains of the following systems: (1) annulus mixing, (2) standby gas treatment, and (3) fuel building filtration. Additionally, power was lost to the division 1 DG fuel-oil transfer pump along with power to several valves on the LPCS, RHR train A, RCIC systems, and various drywell and unit coolers. Unit cooler operation was checked and found to be normal.

Feeder breaker 1EJS*ACB36 is equipped with an overcurrent timer relay, which initiates a trip of breaker 1EJS*ACB38 in the event ACB36 fails to clear a fault in sufficient time. The manufacturer has determined that the output transistor on the overcurrent timer relay was defective and caused the trip.

In neither event were redundant trains affected.

Corrective Action

The overcurrent timer relay was replaced. The manufacturer has recommended that the output transistor be replaced with a different type transistor, one that has higher voltage and lower leakage characteristics. The output transistors for all affected relays are being replaced.

Plant/Event Data

Systems Involved:
Containment heating and ventilation, emergency power, low-pressure core spray, RHR, and RCIC systems.

Event Identifier: 458/86-047

Components and Failure Modes Involved:
Containment unit 1-A cooler feeder breaker — tripped in operation
Switchgear feeder breaker — tripped in operation

Component Unavailability Duration: 2 h assumed (1 h per breaker trip)
Plant Operating Mode: 1 (94%/99% power)
Discovery Method: Operational event
Reactor Age: 0.75 year
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	Base case nonrecovery
Postulated LOOP	Base case nonrecovery
Postulated LOCA	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

RCIC	Base case	Unavailable due to loss of switch gear
LPCS	Base case	One train unavailable due to loss of switch gear

Plant Models Utilized

BWR plant Class C

Event Identifier: 458/86-047

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 458/86-047
Event Description: One Train EPS, RHR, RCIC and LPCS Are Unavailable
Event Date: 7/31/86
Plant: River Bend 1

UNAVAILABILITY, DURATION= 2

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.7E-03
LOOP	1.1E-05
LOCA	3.3E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	6.1E-11
LOOP	1.5E-11
LOCA	(1.6E-16)
Total	7.7E-11
CD	
TRANS	6.4E-09
LOOP	5.9E-10
LOCA	6.8E-11
Total	7.1E-09
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.0E-11

Event Identifier: 458/86-047

134 TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS -RHR(SDC)

End State: CD Conditional Probability: 4.7E-09

101 TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE -FW/PCS.TRANS RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE -FW /PCS.TRANS RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	4.7E-09 *	1.0E-01
102	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	8.7E-10	3.9E-02
110	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	4.1E-10	5.7E-02
111	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE -FW /PCS.LOCA RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V /RHR(SDC).RHR(SPCOOL)	CD	2.3E-10	7.6E-02
134	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	4.0E-11 *	5.3E-02
138	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	1.3E-11	1.8E-02
142	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	7.5E-12	9.3E-03
163	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	1.4E-12	1.3E-02
201	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	2.1E-10	3.7E-02
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)	CV	9.7E-12	5.0E-02
230	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	5.5E-12	2.6E-02
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP	CD	2.7E-10	6.1E-02

* dominant sequence for end state

** 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

Event Identifier: 458/86-047

compared to a similar period without the existing failures.

SEQUENCE MODEL: c:\asp\newmodel\bwrctree.cmp
BRANCH MODEL: c:\asp\newmodel\riverbnd.txt
PROBABILITY FILE: c:\asp\newmodel\bwr_c.pro

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	8.6E-04	1.0E+00	
LOOP	1.7E-05	3.2E-01	
LOCA	3.3E-06	5.0E-01	
SCRAM	3.5E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
PCS/TRANS	1.7E-01	1.0E+00	
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	5.9E-02	1.0E+00	
EMERG.POWER	7.5E-03	8.0E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	2.0E-02	3.4E-01	
RCIC/TRANS.OR.LOOP	6.0E-02 > 1.0E+00	7.0E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.0E-02 > Unavailable		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	3.7E-03	7.1E-01	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	2.0E-02 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-02 > Unavailable		
LPCI(RHR)/LPCS	6.0E-04	7.1E-01	
RHRSW/LPCS.LPCI.TRANS	1.0E+00	1.0E+00	
RHRSW/LPCS.LPCI.LOOP	1.0E+00	1.0E+00	
RHRSW/LPCS.LPCI.LOCA	1.0E+00	1.0E+00	
RHR(SDC)	2.1E-02 > 3.0E-02	3.4E-01	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Serial Component Prob:	2.0E-02		
RHR(SDC)/-LPCI	2.0E-02	3.4E-01	
RHR(SDC)/LPCI	1.0E+00	1.0E+00	

Event Identifier: 458/86-047

RHR(SPCOOL)/-LPCI.RHR(SDC)	2.0E-02	1.0E+00
RHR(SPCOOL)/LPCI.RHR(SDC)	5.2E-01	1.0E+00
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01

* branch model file
** forced

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02-24-1988
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Event Identifier: 458/86-047

APPENDIX E

LICENSEE EVENT REPORTS ASSOCIATED WITH PRECURSORS

APPENDIX E

LICENSEE EVENT REPORTS ASSOCIATED WITH PRECURSORS

This appendix contains copies of licensee event reports (LERs) associated with precursors documented in Appendix D. A table of contents, Table E.1, is also provided.

Note that copies of LERs utilized in the Accident Sequence Precursor Program are also used in other Oak Ridge National Laboratory programs and may contain markings made during abstracting and coding in these programs.

Table E.1. Index of precursor licensee event reports

LER No.	Event title	Plant name	Page number
247/86-017	Open condenser dump valves cause trip, and one safeguards train fails to start	Indian Point 2	E-6
247/86-035	Trip, LOFW, and two AFW train failures occur	Indian Point 2	E-10
249/86-013	HPCI and one train of the core spray and LPCI systems are inoperable	Dresden 3	E-14
250/86-036	Unavailability of DGs	Turkey Point Units 3 and 4	E-17
250/86-038	AFW system is unavailable	Turkey Point Units 3 and 4	E-20
250/86-039	Trip occurs with stuck-open PORV	Turkey Point 3	E-24
261/86-005	Bus failure causes a trip followed by a LOOP with a DG unavailability	Robinson 2	E-28
269/86-001	TRIP, LOFW, and a stuck-open MSRV occur	Oconee 1	E-38
269/86-011	Emergency condenser cooling system is unavailable	Oconee Station Units 1,2, and 3	E-43
277/86-003	DG trip in test causes scram	Peach Bottom 2	E-49
280/86-029	Charging pump service-water pumps are unavailable	Surry 1	E-53
280/86-031	High-head injection system is unavailable	Surry 1	E-56
281/86-010	High-head injection system is unavailable	Surry 2	E-59
282/86-006	Emergency power system is unavailabile	Prairie Island Units 1 and 2	E-62
282/86-011	Emergency power system is unavailabil	Prairie Island Units 1 and 2	E-66
285/86-001	Trip occurs, and automatic depressurization and turbine bypass system fails to open	Ft. Calhoun	E-68
293/86-027	LOOP occurs due to winter storm	Pilgrim 1	E-71
301/86-004	MSIVs fail to close on demand	Point Beach 2	E-75
318/86-006	Trip occurs and one atmospheric dump valve fails to close	Calvert Cliffs Unit 2	E-90
341/86-045	Condensate storage tank is lost	Fermi 2	E-95
341/86-048	RCIC and HPCI are unavailable	Fermi 2	E-106
362/86-011	Saltwater and CCW systems are unavailable	San Onofre 3	E-112
366/86-035	LPCS system is unavailable	Hatch 2	E-115

Table E.1 (continued)

LER No.	Event title	Plant name	Page number
370/86-006	High-head injection system is unavailable and DG A is out of service	McGuire 2	E-121
389/86-011	Emergency power system is unavailable	St. Lucie 2	E-125
409/86-023	LOOP occurs due to lightning strike at coal-fired unit	LaCrosse	E-131
413/86-031	Small LOCA forces plant trip	Catawba 1	E-133
414/86-028	SG PORVS open inadvertently in test, and trip when other failures occur	Catawba 2	E-137
458/86-002	Hand-held ratio causes LOOP	River Bend 1	E-143
458/86-047	Emergency power, LPCS, RHR train A, and RCIC systems are degraded twice	River Bend 1	E-151

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	Indian Point Unit #2
DOCKET NUMBER (2)	0 5 0 0 0 2 4 7
PAGE (3)	1 OF 0 1
TITLE (4)	Reactor Trip Due to Steam Dump Valves Opening

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	2 8	8 6	8 6	0 1 7	0 0	0 7	0 1	8 6		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N
POWER LEVEL (10)	0 3 0
THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (11)	X 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Ray Sutton, Failure Analysis Engineer	9 1 4 5 2 6 5 6 9 7 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
B	S B	P I 1 K	F 1 1 8 0	Y						
X	J E	R L 1 Y	W 1 1 2 0	Y						

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

ABSTRACT (16)

On May 28, 1986 at 1556, while operating at 30% power, the condenser steam dump valves opened, creating a high steam flow condition coincident with a low reactor coolant system average temperature (T-AVG < 541 F). This resulted in a safety injection actuation and a reactor trip. Safety injection Train A actuated, however Train B did not initially actuate. Train B was subsequently actuated when an operator manually locked-in the safety injection signal as part of the recovery procedure. The health and safety of the public were not affected.

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PDR ADOCK 05000247
S PDR

NRC Form 366

Plant and System Description:

Westinghouse 4-loop pressurized water reactor.

Identification of Occurrence:

Reactor trip due to safety injection (High steam flow with low reactor T-AVG) and failure to actuate one of two engineered safeguards trains.

Event Date:

May 28, 1986

Report Due Date:

June 27, 1986

Reference:

Significant Occurrence Report (SOR) 86-177

Past Similar Occurrence:

None

Description of Occurrence:

On May 28, 1986, Unit 2 was operating at 30% power. The condenser steam dump control system was switched from the "temperature" mode to the "pressure" mode at 1455 due to erratic behavior observed on temperature controller TC-412J. At 1556, all twelve (12) condenser steam dump valves received an open signal due to a faulty steam dump controller PC-404 (Foxboro Model 62H5E). This resulted in an increased steam flow and a reduction in reactor coolant temperature, and a subsequent safety injection actuation.

Safety injection Train A actuated resulting in a reactor trip and safeguards actuation, however, Train B did not actuate. Safety injection Train A signal resulted in closure of the main steam isolation valves approximately 2½ seconds after the reactor trip. This effectively ended the high steam flow condition.

The required functions which did not fully actuate due to Train B not functioning were containment isolation phase A ("T" signal) Train B, and some of the required redundant valving required for safety injection.

Safety injection Train B was successfully actuated at 1607 when the control room operators reset safety injection per Optimal Recovery Procedure ES-1.1. Resetting safety injection consists of manually locking in another safety injection signal and depressing safety injection reset buttons. This action actuates parallel contacts in both trains of the safety injection logic. Because Train B had not been actuated by the first safety injection signal, the introduction of the second signal initiated a separate safety injection sequence. Safety injection equipment was stripped and automatically restarted and all required redundant valves (Train A and Train B) operated normally.

Analysis of Occurrence:

This occurrence is a reportable event because it resulted in completion of Engineered Safeguards logic and actuated the Reactor Protection System.

One of two trains of safety injection and containment isolation is sufficient to mitigate the consequences of an accident. Safety injection was not required, and no water was injected during this event. There was no effect on the health and safety of the public as a result of this event.

Cause of Occurrence:

Investigation of the steam dump control circuit revealed that steam dump controller PC-404 output was erratic, with output signal going high off-scale with minor variations in input. A high output signal from PC-404 causes current to pneumatic controller PM-404 to increase its output signal to the steam dump valves, causing them to open.

The safety injection circuit was examined to determine the cause of Train B not actuating on the initial signal. The high steam flow with low T-AVG actuates relays SL1 and SL2, which actuate safety injection relays SIA-1 and SIA-2 for Trains A and B respectively. Analysis of the Train B circuitry indicated that either the safety injection relay SIA-2 (Westinghouse type MG-6) did not actuate, or relay SL2 contacts (Westinghouse type BFD) did not close to allow SIA-2 to actuate. The circuit was checked and the relays were tested repeatedly with no subsequent malfunctions.

The cause of failure of pressure controller PC-404 was suspected to be failed capacitors based on previous experience and manufacturers data.

The cause of failure of the safety injection Train B is suspected to be dirt or foreign material in the relays.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)	PAGE (3)
Indian Point Unit #2	0 5 0 0 0 2 4 7	8 6 - 0 1 7 - 0 0	0 4 OF 0 4

Corrective Action:

The steam dump control system repairs were as follows:

1. All electrolytic capacitors and the auto/manual relay were replaced on condenser steam dump controller PC-404 and the controller was recalibrated. The controller functioned normally following the repair.

2. Current to pneumatic converter PM-404 was replaced with a new unit and calibrated.

3. Temperature controller TC-412J was replaced with a new unit and calibrated.

4. Pressure transmitter PT-404 was calibrated.

Corrective action for the Safety Injection System Actuation circuit was as follows:

1. Relays SIA-2, SL-2, T[illegible] 2 and TR-2X were replaced. The Safety Injection Actuation Log in was tested and verified operational.

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)	Indian Point Unit No. 2
DOCKET NUMBER (2)	0 5 0 0 0 2 4 7
PAGE (3)	1 OF 0 1
TITLE (4)	Reactor Trip Due To Reactor Trip Relay De- Energizing

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)
1 0	2 0	8 6	8 6	– 0 3 5	– 0 0	1 1	1 9	8 6		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 § (11)	X 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)	
Ray Sutton, Failure Analysis Engineer	9 1 4	5 2 6 - 5 6 2 7

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	J E	R L Y	W 1 2 0	N
B	B A	P C V	C 6 3 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)

Unit 2 Reactor tripped from 100% power when reactor trip breaker (BKR) "B" opened. One of the reactor protection (AA) relays (RLY) deenergized while a monthly safety injection surveillance test was being performed in a nearby equipment rack. Several loose connections in the associated circuitry were discovered during the subsequent troubleshooting. Safeguards equipment functioned normally except for portions of the auxiliary feedwater system.

Feedwater was maintained by one of the motor driven auxiliary feed pumps (P). The other motor driven auxiliary feed pump (P) tripped after starting and was subsequently restarted successfully by the control room operator. In addition, the relief valve (RV) on the turbine driven auxiliary feed pump (P) lifted when its steam control valve (PCV) opened.

The relay rack terminals were checked for loose connections, the auxiliary feed pump circuit breaker trip point was readjusted, and the auxiliary feedwater system (BA) was retested and restored to operable condition.

The health and safety of the public were not affected.

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Plant and System Identification:
Westinghouse 4-loop pressurized water reactor - 900 MWE.

Identification of Occurrence:
Reactor trip breaker B opened when an associated trip relay deenergized. The most probable cause of the relay deenergizing was loose wiring.

Event Date: October 20, 1986

Reference: Indian Point 2 Significant Occurrence Report 86-453

Past Similar Occurrence: None

Description of Occurrence:
At 0936 on October 20, 1986, Unit 2 reactor (RCT) tripped from 100% power when reactor trip breaker (BKR) "B" unexpectedly opened. One of the reactor protection relays (RLY) deenergized while a monthly safety injection surveillance test was being performed in a nearby equipment rack (RK).

Following the trip, steam generator (SG) levels dropped rapidly as expected. Both motor (MO) driven auxiliary feed pumps (P) started on low-low steam generator level. While following the emergency recovery procedure, a control room operator discovered that #21 Auxiliary Feed Pump (P) was tripped. The pump (P) was then successfully restarted from the control room.

The steam driven auxiliary feed pump steam relief valve (RV) had also popped opened following the plant trip. The steam pressure control valve (PCV) receives an automatic open signal on low-low steam generator level in two of the four steam generators, admitting steam up to the turbine governor valve (SCV). The auxiliary feed pump speed changer setting was at minimum as designed, and the pressure control valve (PCV) response was too slow which caused the relief valve (RV) to lift.

All other plant response was normal.

Analysis of Occurrence:

The opening of reactor trip breaker "B" tripped the reactor as designed. This is one of two redundant trip breakers provided to assure this happens even assuming a single failure of one trip breaker to function.

With regard to the auxiliary feedwater system, one motor driven auxiliary feedwater pump is sufficient to satisfy system requirements following a loss of normal feedwater event. Thus, even with the failure of one motor-driven pump to continue to run following its automatic start, the remaining motor driven pump provided adequate auxiliary feedwater flow.

Cause of Occurrence:

The opening of the reactor trip breaker is attributed to loose wires in the associated relay racks. Reactor trip relays RT3 and RT4 were found de-energized, as was relay SIAM 1-X. Several loose connections were subsequently discovered between relay SIAM 1-X and SI-13X which is the circuit which controls SIAM 1-X. A safety injection logic test was being performed on the other side of the relay cabinet at the time of the trip, and this activity apparently disturbed the relay circuitry. It was noted that the above listed relays could be actuated by moving the wiring bundles in the same cabinet during the subsequent troubleshooting operations.

The cause of the #21 Auxiliary Boiler Feed Pump circuit breaker tripping following initial pump start could not be positively determined. The circuit breaker is a Westinghouse DB-50 with amptector tripping devices. Both the instantaneous and time delay trip indicators were found actuated at the circuit breaker, however the indicators cannot be considered to be a reliable indication of circuit breaker actuation. The time delay trip actuation indicator was discovered to be in the "operated" position on the day following the circuit breaker trip as well. This indication was known to be false since the indicator had been reset previously, the circuit breaker was closed and the motor was operating at the time of discovery and the breaker was known to have not tripped during this time interval.

The auxiliary feed pumps were retested using an automatic start signal in order to simulate the actual pump conditions and challenge the equipment to the extent practical. Both motor driven auxiliary feed pumps were started simultaneously with reduced bus voltage to determine if system transients could be duplicated and pinpoint the cause of the trip. During the test, higher than expected motor current was measured. The higher current was due to higher than expected flow from the pump because of an improperly set auxiliary feedwater control valve to steam generator #21. Although the circuit breaker did not trip during subsequent testing, the effect of increased current due to the motor characteristics and the high auxiliary feedwater flow was close enough to the circuit breaker minimum setpoint to represent a challenge to the amptector setting. Since the low suction pressure and the instantaneous overcurrent trip signal did not reach a value near their setpoints, the time/overcurrent setting must be considered the most probable cause of tripping.

The relief valve in the steam line to the turbine driven auxiliary feed pump was tested and found to open at 665 psi vs a nominal set point of 700 psi. The actuation of the relief valve was probably due to pressure hunting down stream of the control valve because of controller low proportional band setting problems and the high differential pressure across the valve.

Corrective Action:
Since several loose connections were discovered in the relay rack, a program was instituted to check and tighten all accessible connections in the racks. The terminals are being checked individually and marked on a drawing to verify which terminals were checked and/or tightened.

Over 10,000 screws were checked for tightness in the associated relay racks. Approximately 1/4 of 1% of the terminals required greater than a half-turn to tighten the screws.

Although the relays which were deenergized appeared to be functioning normally, those which could have been a contributing factor, even if only slightly, were replaced. These relays, SIAM 1-X, SIAM 1-Y, and SI-13X, are Westinghouse BFD delays and are being replaced with like kind. The removed relays will be examined further for evidence of any malfunction.

Auxiliary Boiler Feed Pump #21 circuit breaker was retested by means of an automatic start signal with reduced bus voltage to simulate actual start conditions and challenge the equipment as much as possible to ensure operability. Suction header conditions were also monitored to reverify that the low pressure suction switches will not cause either pump to inadvertently trip. As a result of this testing, the circuit breaker time delay trip setpoint was raised from a nominal value of 600 amperes to 660 amperes. In addition, the auxiliary feedwater flow control valve setting to the steam generators were re-established to limit the flow to the proper value and keep total auxiliary feedwater flow within the proper limits.

In an attempt to prevent subsequent relief valve lifting, the speed changer setting on the turbine driven auxiliary feed pump was left at the 20% position (from 0%) to provide an additional steam demand to the turbine on automatic auxiliary feed system actuation. The pump was given a start signal several times following this adjustment to demonstrate that the relief valve would not open when the steam control valve receives its open signal. The turbine rotated under these conditions during several subsequent tests without actuating the relief valve.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Dresden Nuclear Power Station, Unit 3	0 5 0 0 0 2 4 9	1 OF 0 3

TITLE (4) Unit Shutdown Due to Exceeding Limiting Conditions for Operations on Emergency Core Cooling Systems

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 7	8 6	8 6	0 1 3	0 0	0 9	2 5	8 6	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 1 9

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)

X 50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Jerry Lizalek, Technical Staff Engineer X-421	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	MANUFAC-TURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS
X	B M	V	L 2 0 0	Y					

SUPPLEMENTAL REPORT EXPECTED (14): X NO

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On August 27, 1986 at 0030 hours, with Unit 3 in the run mode at 19 percent rated power, with the HPCI system declared inoperable, while performing core spray surveillances required per T.S. 4.5.C.2 it was found that the 3-1402-4B valve was damaged so that the valve would not close. A normal unit shutdown was initiated and an Unusual Event was declared. The "B" core spray system was declared inoperable. It was discovered that the 2/3 diesel generator failed to close into bus 33-1. The diesel closed on bus 23-1 without incident. Also while performing DOS 1500-1 the 1501-13A valve showed a double position indication. It was discovered that the valve was in mid-position. The unit shutdown was achieved at 2007 hours.

Subsequent investigation of the 3-1402-4B valve revealed that the motor housing was cracked. This was a result of high torque generated by an inoperable torque switch. The valve was repaired and declared operable. This failure was possibly due to an installation error. A review of the 2/3 diesel generator failure revealed that a terminal block screw was loose in junction box 3TB-187. The screw was tightened and the diesel operated properly. A review of the 3-1501-13A valve revealed that the handwheel retaining ring had disengaged. It was replaced and the open/close limits were reset. It is not believed that the disengaged retaining ring prevented the operator from electrically cycling. The direct cause can not be determined. To avoid this event from recurring, all ECCS valve operability surveillances will be performed on Unit 3 prior to startup and for one month after. This action began on 9/8/86.

This event was of minimal safety significance. The "A" core spray, "B" LPCI, isolation condenser and automatic depressurization systems were operable and available to mitigate the consequences of a LOCA. Also the 2/3 diesel was still available in the automatic initiation mode. Last occurrence was reported by DVR #12-3-82-045.

NRC Form 366 (9-83)

NRC Form 366A (9-83)

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)
Dresden Nuclear Power Station, Unit 3	0 5 0 0 0 2 4 9	8 6	— 0 1 3	— 0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

On August 27, 1986 at 0030 hours, with Unit 3 in the run mode at 19 percent rated power, with the high pressure coolant injection (HPCI) (EIIS System Code BJ) system declared inoperable (see DVR 12-3-86-52), while performing core spray surveillances required per Technical Specification 4.5.C.2 it was discovered that the "B" core spray subsystem (EIIS System Code BM) was not pressurized. Further examination revealed that the 3-1402-4B valve core spray "B" pump full flow test valve was damaged so that the valve would not close adequately. A normal unit shutdown was initiated per Technical Specification 3.5.C.3 and an Unusual Event was declared. Upon discovering the "B" core spray subsystem inoperable, all applicable Technical Specification surveillances required per Technical Specification 4.5.A.2 were being performed in anticipation of the repair of HPCI or core spray. During the performance of Dresden Operating Surveillance (DOS) 6600-1 "Diesel Generator Surveillance Test", it was discovered that the 2/3 diesel generator (EIIS System Code EK) failed to close on to bus 33-1. However, the 2/3 diesel generator was synchronized to bus 23-1 without incident. Also, while performing DOS 1500-1, "Low Pressure Coolant Injection (LPCI) (EIIS System Code BM) System Valve Operability Test" the 1501-13A, LPCI minimum flow valve, showed a double position indication. An investigation of the event revealed the valve was in mid-position. The valve was manually opened and successfully cycled three times. The unit shutdown continued and cold shutdown completed by 2007 hours on August 27, 1986.

Subsequent investigation of the 3-1402-4B, "B" pump full flow test valve, under work request #57254 revealed that the motor operator housing was fractured. This fracture was a result of an inoperable Limitorque torque switch. The torque switch was removed and it was discovered that the pinion gear located on the torque switch shaft was free spinning as a result of a sheared roll pin. The roll pin attaches the pinion gear to the shaft. With the torque switch inoperable, the motor did not de-energize on high torque once the valve reached the closed position. As a result, the motor continued to drive the valve disc into the valve seat until the forces created fractured the motor operator housing. The limitorque operator was reassembled, filled with grease, and installed on the valve. DOS 1400-2, "Core Spray Valve Operability" was performed at 2112 hours on 8/28/86 and the "B" core spray loop declared operable. The Limitorque Corporation was contacted about this failure and replied that this is not a design deficiency but rather an installation error. If the torque switch was installed in the reverse direction and torque was applied, the shaft and pinion gear would not have rotational movement and therefore be subjected to high torsional forces. The torsional forces subsequently caused the roll pin to shear. Presently, Dresden's Maintenance Procedures (DMP) for Limitorque operators state that the torque switch assembly must be replaced exactly as it was removed. An Electrical Maintenance tailgate of this event will be presented to the Electrical work group. The tailgate will further emphasize the importance of installing the torque switch correctly.

A subsequent investigation of the 2/3 diesel generator failure to close on to bus 33-1 was conducted under work request #57277 and it was revealed that a terminal block screw was loose in junction box 3TB-187. This junction box was located above a cable pan on the 517' elevation near the Unit 3 reactor feed pump room. The screw on terminal 5 of TB3 was approximately a half-turn from full in. This wire is connected to the HACR relay synchro check permissive contact which allows the diesel generator breaker to close in if it is in phase with bus 33-1.

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NRC Form 366A (9-83)

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)
Dresden Nuclear Power Station, Unit 3	0 5 0 0 0 2 4 9	8 6	— 0 1 3 —	0 0	0 3 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The screw was tightened and the diesel generator operated properly when closed on to bus 33-1. A review revealed that no maintenance was performed on junction box 3TB-187 during the Unit 3 maintenance outage. No further corrective action is required. DOS 6600-1 is performed monthly and would identify any malfunctions.

Following the declaration of operability for the 3-1501-13A valve by cycling three times on August 27, 1986 at 1800 hours, work request #57278 was written to further investigate and repair as necessary. It was discovered that the handwheel retaining ring was disengaged and resting atop the handwheel bearing of the SMB-000 Limitorque motor-operator. The retaining ring was reinstalled and the open/close limits were reset. It is not believed that the disengaged retaining ring prevented the operator from electrically cycling. The direct cause can not be determined. A current/voltage signature was taken to verify that the limits were set properly. DOS 1500-1, "LPCI System Valve Operability Test" was performed on 9/16/86 to declare the valve operable after maintenance.

In order to avoid the recurrence of this event, all emergency core cooling system valve operability surveillances will be performed on Unit 3 prior to startup and weekly for one month after Unit 3 startup. The surveillances began as of 9/8/86. This event was of minimal safety significance since in the unlikely event of a loss of coolant accident (LOCA) the "A" core spray system, "B" LPCI system, isolation condenser and automatic depressurization system were available to mitigate the consequences. Additionally, in the event of a loss of off-site power the 2/3 diesel generator would have closed on to bus 33-1 regardless of the loose terminal screw since the loose wire only affected the manual closing of the 2/3 diesel generator on to bus 33-1 and this part of the logic is bypassed in an automatic initiation.

The last occurrence of this type at Dresden, in which equipment failure caused a plant shutdown, was reported by DVR #12-3-82-045.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	1 OF 0 3

TITLE (4)
Both Emergency Diesel Generators Out of Service

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)
1 1	0 6	8 6	8 6	— 0 3 6 —	0 0	1 2	0 8	8 6	Turkey Point Unit 4	0 5 0 0 0 2 5 1
									N/A	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)	1 0 0	[ ] 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	
Randall D. Hart, Licensing Engineer	3 0 5	2 4 6 - 1 3 0 0

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	E K	F S V	W 2 9 0	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)

EVENT:
On November 6, 1986, while Unit 3 and Unit 4 were at 100% power, the requirements of Technical Specification (TS) 3.7 were exceeded when both emergency diesel generators (EDGs) were declared out of service. On November 6, 1986, the A EDG was tested for operability. This was being done because the B EDG was out of service to perform instrument calibrations in preparation for the eight (8) hour test run required by TS 4.8.1.c.6. TS 3.7.2 requires that if one EDG is out of service the remaining EDG must be tested daily. After the A EDG satisfactorily completed its test, the EDG would not stop during the shutdown sequence of the test and the operators had to use an alternate method to stop the EDG. The A EDG was declared out of service and since the B EDG was also out of service the requirements of TS 3.7 were exceeded and both units were placed under TS 3.0.1 requiring the units to be in Mode 3 (Hot Standby) within seven (7) hours. Preparations were begun to test the B EDG for operability. The B EDG was started for its operability test and satisfactorily completed the test within a hour and a half. This placed both units out of TS 3.0.1. The cause of the A EDG not stopping was that the governor solenoid was out of adjustment. The governor solenoid was adjusted and the A EDG satisfactorily tested on November 7, 1986.

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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)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	8 6	0 3 6	0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT:
On November 6, 1986, while Unit 3 and Unit 4 were at 100% power, the requirements of Technical Specification (TS) 3.7 were exceeded when both emergency diesel generators (EDGs) were declared out of service. At 0039 on November 6, 1986, the A EDG was started for its operability run as per Operating Procedure (OP) 4304.1, Emergency Diesel Generator - Periodic Test Load on 4 KV Bus. This was being done because the B EDG was out of service to perform instrument calibrations in preparation for the eight (8) hour test run required by TS 4.8.1.c.6. TS 3.7.2 allows one EDG to be out of service as long as the remaining EDG is tested daily and its associated engineered safety features are operable and either start-up transformer is operable. After satisfactorily completing the test on the A EDG, the A EDG would not stop during the cooldown cycle as designed. The operators stopped the A EDG by pulling the manual governor control lever full out. The A EDG was declared out of service at 0225. Since the B EDG was also out of service the requirements of TS 3.7 were exceeded and both units were placed under TS 3.0.1 requiring the units to be in Mode 3 (Hot Standby) within seven (7) hours. Preparations were begun to test the B EDG for operability. At 0325 the B EDG was started for its operability test as per OP 4304.1. The B EDG satisfactorily passed its operability test at 0447 and was declared back in service. This took the units out of TS 3.0.1.

CAUSE OF EVENT:
An investigation into the cause of the event determined that the governor solenoid was out of adjustment.

ANALYSIS OF EVENT:
The B EDG had been taken out of service for instrument calibration by valving out the air start supply to the B EDG. The instrument calibrations would not have prevented the B EDG from starting. The B EDG could have been manually started by valving the air start supply if it had been necessary within a few minutes. In addition, the A EDG had just satisfactorily completed its daily run and during the shutdown sequence of the test, the EDG could not be stopped in its normal fashion. Based on the above, the health and safety of the public were not affected.

CORRECTIVE ACTIONS:

1) An Event Response Team was formed to address the failure of the A EDG to stop after its daily operability test. The team utilized Administrative Procedure 0-ADM-011, Short Notice Outage Work (SNOW) Response Organization. They determined that the governor solenoid was out of adjustment.

2) The governor solenoid was properly adjusted and the A EDG was satisfactorily tested at 0045 on November 7, 1986, and declared back in service.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	8 6	0 3 6	0 0	0 3 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

3) Preventative Maintenance Procedure 0-PMI-23.1, Emergency Diesel Generator Instrumentation Calibrations, will be revised to include the governor solenoid adjustment.

ADDITIONAL DETAILS:
OP 4304.1 has been cancelled and the information contained in that procedure is now included in Operating Surveillance Procedure 0-08P-023.1, Diesel Generator Operability Test. The two (2) EDGs used at Turkey Point were supplied by A. G. Schoonmaker Company, Inc. The engine was manufactured by General Motors, Electro Motive Division, Model No. 20-645E4. The governor was supplied by Woodward Governor Company, Model number UG8. The solenoid type is de-energize to shutdown. Similar Occurences: LERS 251-85-015, 250-85-043, 250-86-014, and 250-86-022.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	0 1 OF 0 4

TITLE (4)

Auxiliary Feedwater Steam Supply Valve Out of Service While Other Train is Out of Service

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
1 2	0 4	8 6	8 6	— 0 3 8	— 0 0	0 1	0 5	8 7	N/A	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 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	
Randall D. Hart, Licensing Engineer	3 0 5	2 4 6 - 1 3 0 0

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)

EVENT:

On December 4, 1986, during the Operability Verification of Auxiliary Feedwater Train 2, the valve position indication for MOV-3-1403 was lost and the valve was declared out of service. At this time the B auxiliary feedwater (AFW) pump was out of service because of overspeed problems. This condition did not meet the definition of an operable AFW train, as described in the AFW System operating procedure, so the requirements of Technical Specification (TS) 3.8.5 were exceeded and Unit 3 entered TS 3.0.1 requiring the unit to be in hot standby within 7 hours. Evaluations were begun to determine the acceptability of aligning AFW pump C and MOV-4-1404 to AFW train 2. An evaluation by our Engineering Department determining the alignment of the C AFW pump and MOV-4-1404 to AFW train 2 to be aceptable was completed. The evaluation was then reviewed and concurred with by the Plant Nuclear Safety Committee (PNSC). Unit 3 was taken out of TS 3.0.1 and back into TS 3.8.5. The Cause of MOV-3-1403 being out of service was burned motor leads on the valve actuator. Similar valve actuators were inspected and no similar conditions were found. The cause of the B AFW pump being out of service was drift on the electronic overspeed trip setpoint. The setpoint was readjusted and the pump was satisfactorily tested.

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U.S. NUCLEAR REGULATORY COMMISSION

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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)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	8 6	— 0 3 8	— 0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT:

On December 4, 1986, at 0550, while Unit 3 and Unit 4 were at 100% power, Operating Surveillance Procedure (OSP) 3-OSP-075.2, Auxiliary Feedwater Train 2 Operability Verification, was initiated to verify the operability of steam supply motor operated valve, MOV-3-1403, and flow transmitter (FT) FT-3-1458B in auxiliary feedwater (AFW) train 2. Procedure 3-OSP-075.2 was satisfactorily completed at 0620, however, during the shutdown sequence of the B AFW pump, the pump tripped on electronic overspeed. The B AFW pump was declared out of service and both units were placed in a 12 hour limiting condition for operation (LCO) as per Technical Specification (TS) 3.8.5.d. At 0730 the B AFW pump was tested to try and repeat the previous electronic overspeed trip but the trip could not be duplicated. The pump was kept out of service to continue troubleshooting the problem.

The AFW system at Turkey Point consists of 3 turbine driven pumps of which two pumps are normally aligned to train 1 and one pump is aligned to train 2. Steam can be supplied to the pump turbines from either or both units through redundant steam headers. Two D. C. MOVs (MOV-*-1403 and MOV-*-1405) and one A.C. MOV (MOV-*-1404) on each unit isolate the 3 main steam lines from these headers

At 0745, Operations began aligning the C AFW pump to train 2, as a result of the overspeed problem. At 0930, 3-OSP-075.2 was commenced to test the C AFW pump to train 2. At 0953, during the performance of 3-OSP-075-.2, the valve position indication for MOV-3-1403 was lost. The valve was declared out of service and because operating procedure (OP) 3-OP-075, Auxiliary Feedwater System, describes AFW train 2 as consisting of MOV-3-1403 and AFW pump B during dual unit operation, Unit 3 exceeded the requirements of TS 3.8.5 and entered TS 3.0.1 requiring the unit to be in hot standby within (7) hours. Evaluations were begun to determine the acceptability of aligning AFW pump C and MOV-4-1404 to AFW train 2. At 1300, 3-OSP-075.2 was completed with the C AFW pump and MOV-4-1404 aligned to train 2. At 1345, 4-OSP-075.2 was completed with the C AFW pump aligned to train 2 on Unit 4. At 1435, an evaluation by our Engineering Department of the C AFW pump and MOV-4-1404 aligned to AFW train 2 was reviewed by the Plant Nuclear Safety Committee (PNSC) along with an on-the-spot-change (OTSC) to 3-OP-075 and the PNSC concurred with the evaluation. Unit 3 was taken out of TS 3.0.1 and back into TS 3.8.5.

An investigation into the overspeed trip of the B AFW pump found that the electronic overspeed trip setpoint had drifted low. The setpoint was readjusted and satisfactorily tested as per 0-OSP-075.9, AFW Overspeed Test, at 0340 on December 5, 1986. 3-OSP-075.2 was satisfactorily completed at 0715 and the B AFW pump was declared back in service and both units were out of TS 3.8.5.

NRC FORM 366A

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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EXPIRES: 8/31/88

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Turkey Point Unit 3	0 5 0 0 0 2 5 0	8 6	— 0 3 8 —	0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

An inspection of the motor for MOV-3-1403 revealed burnt motor leads. Plant management decided to inspect similar motors to see if any other problems existed. At the time the inspections were begun Unit 4 was in mode 2 (start- up) for a scheduled mainte- ce outage. Beginning at 1627 on December 6, 1986, MOV-4-1403, MOV-4-1405, MOV-6459A, MOV-6459B, and MOV-6459C were taken out of service one valve at a time for inspections. MOVs 6459A, 6459B, and 6459C are the throttle and trip valves for the AFW pumps. These valves automatically trip closed to protect the turbine from an overspeed condition. TS 3.8.4.b requires two independent AFW trains and a third AFW pump to be operable whenever both units are above mode 4 (hot shutdown). While these valves were out of service, the requirements of TS 3.8.4.b were exceeded which placed Unit 4 under the requirements of TS 3.0.1.

At 0325 on December 7, 1986, MOV-6459C was taken out of service for inspections. At 0345, AFW flow indicator HIC-3-1457B was declared out of service due to indicating flow when a no flow condition was present. This resulted in declaring AFW train 2 out of service to Unit 3. Since the C AFW pump was out of service, this placed AFW train 1 out of service which exceeded the requirements of TS 3.8.5 and placed Unit 3 in TS 3.0.1. The C AFW pump was declared back in service at 0346 which placed Unit 3 back in TS 3.8.4.5.

CAUSE OF EVENT:

The cause of the electronic overspeed trip of the B AFW pump was due to setpoint drift. The cause of the problems with MOV-3-1403 was burnt motor leads. The cause of the problems with the flow transmitters was air in the sense lines.

ANALYSIS OF EVENT:

During the event, on December 4, 1986, both the A and C AFW pumps were operable and capable of supplying feedwater to the Unit 3 and Unit 4 steam generators. Also at least two steam supply MOVs on Unit 3 and 3 steam supply MOVs on Unit 4 were operable and capable of supplying steam to the AFW pumps. During the inspections of the MOVs only one valve was out of service at a time, therefore, at least one train of AFW was available to each unit. During the time that HIC-3-1457B was out of service, train 2 was technically declared out of service, however, the train would have been able to deliver feedwater to the steam generators if the need had arisen. Based on the above the health and safety of the public was not affected.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	8 6	— 0 3 8	— 0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTIONS:

1) An evaluation was done by our Engineering Department to assess the acceptability of two unit power operation with MOV-3-1403 and AFW pump B out of service simultaneously. Engineering concluded that dual unit operation may continue for 72 hours (TS 3.8.5.b) provided that AFW pump C is aligned to train 2. This was done and an OTSC was written to 3-OP-075 to reflect this new alignment. The evaluation and OTSC were reviewed and concurred with by the PNSC.

2) An inspection of MOV-3-1403 revealed burned motor leads. The motor was replaced, and the defective motor was sent off-site for an external root-cause analysis.

3) Due to concerns over Limitorque DC operators, as indentified at another plant, MOV's with similar operators were inspected. The inspections did not reveal any similar problems.

4) The B AFW pump electronic overspeed trip setpoint was found to have drifted low. The setpoint was readjusted and the electronic overspeed trip setpoint satisfactorily tested.

5) The flow transmitter for HIC-3-1457B was vented and satisfactorily tested for operability as per 3-OSP-075.2 at 2000 on December 7, 1986.

ADDITIONAL DETAILS:

The AFW pumps at Turkey Point are steam driven turbine pumps, type Terry 254, manufactured by the Terry Corporation, which is subsidiary of Ingersoll Rand. MOV-3-1403 and MOV-3-1405 are 3 inch Walworth gate valves with Limitorque SMB-00 actuators. MOV-4-1403 and MOV-4-1405 are 4 inch Velan Globe valves with Limitorque SMB-00 actuators. MOV-6459A, MOV-6459B, and MOV-6459C are 3 inch Gimpel Corporation Globe valves with Limitorque SMB-000 actuators. Similar Occurrences: LERs 250-85-037 and 250-86-016

NRC Form 366

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	1 OF 0 4

TITLE (4) Manual Reactor Trip Following Loss of Plant Electrical Load Due to Failed Turbine Governor

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	2 7	8 6	8 6	0 3 9	0 0	0 1	2 6	8 7	N/A	0 5 0 0 0
									N/A	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)

X 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Gabe Salamon, Compliance Engineer	3 0 5 2 4 6 - 1 3 0 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
X	T G	6 5	W 1 2 0	N	A	J D	A M P	H 1 0 5	Y
X	A B	R V	C 6 3 5	Y					

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)

EVENT:

On December 27, 1986, Unit 3 was tripped manually following a loss of turbine governor oil system pressure and a subsequent rapid electrical load decrease from 730 MWe to 0 MWe. No automatic control rod insertion occurred. The Reactor Control Operator (RCO), noting that the coolant temperature was increasing above the reference temperature, placed the rods under manual control, and initiated rod insertion. Concurrently, a second RCO attempted to raise the oil pressure, unsuccessfully. At this time, (about 24 seconds into the transient) it became clear that the unit could not be recovered, and it was manually tripped. During the transient, a PORV opened, then would not fully close, necessitating closure of the associated block valve. The unit was then stabilized, in less than 5 minutes. The most probable cause of the drop in oil pressure was the clearing of blockage of the governor impeller orifice, resulting in the auxiliary governor dumping control oil. The control rods failed to automatically insert due to two cold solder joints in the final variable gain summator of the power mismatch circuit. The cause of the PORV failure to close is still under investigation. The PORV, and turbine governor impeller and associated components were inspected, and no problems were found. The cold solder joints were repaired. The control, lube, and seal oil piping will be cleaned.

IE22 1/1

NRC Form 366

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	8 6	0 3 9	0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT

On December 27, 1987, at 0941, Unit 3 was tripped manually following a loss of turbine governor oil system pressure and a subsequent rapid electrical load decrease from 730 MWe to 0 MWe. The initial indications of a transient were several steam generator (SG) related alarms annunciating. The SG feedwater flow control valves were verified to be operating properly, in the "auto" mode, and were fully open. At 0940, the indicated turbine electrical load and turbine governor oil pressure began to decrease rapidly, without any decrease in reactor power. Automatic control rod insertion did not occur. The Unit 3 Reactor Control Operator (RCO), noting that the reactor coolant average temperature (Tave) was increasing above the coolant reference temperature (Tref), placed the control rods under manual control, and initiated manual insertion. Concurrently a second RCO attempted to raise the governor oil pressure, without success. Starting from the fully withdrawn position, (step 228), the manual rod insertion continued until step 214 was reached. At this time, (approximately 24 seconds into the transient) it became clear that the unit could not be recovered, as:

a) the reactor was still generating significant power
b) the turbine electrical load was at 0 MWe, and the turbine governor oil pressure was not responding to the RCO's actions
c) the SG safety valves were lifting, and
d) the steam dumps were fully open.

With the unit in the above conditions, at the request of the Assistant Plant Supervisor-Nuclear, a second RCO manually tripped the reactor at 0941.

During the transient, the Reactor Coolant System (RCS) pressure was increasing, until Power Operated Relief Valve (PORV) PCV-3-456 opened. The maximum RCS pressure reached was 2330 psig, just prior to the opening of the PORV. Approximately 26 seconds after the trip, the Low Pressurizer Pressure Safety Injection Block alarmed, indicating that pressurizer pressure had decreased below 2000 psig. Following the alarm, the RCO's noted that the pressure was continuing to decrease. The pressurizer spray valve controller demand signal was verified to be zero (the demand signal for closed spray valves) and a check of the PORVs revealed that PCV-3-456 had dual position indication, suggesting that it had not closed fully. The RCO then attempted to close it manually. After the PORV failed to close under manual control, at 0942 the RCO manually closed block valve MOV-3-535, which is the block valve associated with PCV-3-456, halting the pressurizer pressure decrease. PCV-3-456 also closed at about this time, without any additional operator intervention. The minimum RCS pressure reached was 1760 psig. No Safety Injection (SI) occurred, as the set point for SI is 1723 psig. The unit was stablized, with pressurizer pressure increasing, in less than 5 minutes.

Investigations were initiated into the causes of the PORV malfunction, automatic rod control failure to insert, and the governor control oil pressure loss. At the conclusion of the investigations, required maintenance, PNSC approval of the Post Trip Review, and after receiving Plant Manager approval, the reactor returned to criticality on January 4, 1987.

NRC Form 366A

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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TEXT (If more space is required, use additional NRC Form 366A's) (17)

CAUSE OF EVENT

The immediate cause of the manual reactor trip was loss of turbine electrical load, due to a loss of turbine governor control oil pressure. A gradual decrease in impeller oil pressure was noted in the days prior to the event. The pressure just prior to the event was 24 psig. The most likely cause of the pressure decrease was a blockage of the impeller orifice caused by a gradual accumulation of dirt. The most probable cause of the loss of control oil pressure was a sequence of events initiated by a sudden clearing of the blockage. Upon the blockage clearing, impeller oil pressure would have suddenly increased about 12% to approximately its pre-blockage pressure (over 27 psig). The auxiliary governor interprets oil control pressure increases greater that 3% per second as excessively swift increase in turbine speed, and the result is that the auxiliary governor starts dumping control oil. The loss of control oil is followed by automatic closure of the governor and steam intercept valves.

The absence of any automatic control rod insertion was due to two reasons:

1) The Tave - Tref circuits functioned as designed. Even on a sudden, complete load rejection, it takes approximately 15 seconds for this portion of the control circuit to initiate rod motion. This is consistent with the time constants in the circuit lead/lag units. During this event the load rejection was gradual and the time for total load rejection was approximately 15-20 seconds. This circuit would have eventually initiated inward rod motion, but with a time delay that would not have prevented this transient.

2) The power mismatch circuit should have initiated prompt rod motion on the loss of turbine load. Troubleshooting identified two cold solder joints, resulting in no output, on the final variable gain summator. This would have prevented the circuit from functioning. Testing performed after repair of the cold solder joints showed that the nonlinear gain unit would break down to zero output during rapid load changes. Bench testing of the unit revealed normal responses to static load conditions. A new function generator was installed and calibrated. Normal system response was obtained during subsequent testing.

The cause of the PORV failure to fully close is under investigation. Extensive troubleshooting, including dissembly, bench testing, and operation with flow through the valve, failed to identify any malfunctions, or any reason for the earlier failure to fully close.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	8 6	— 0 3 9	— 0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

ANALYSIS OF EVENT

A post trip review was performed to assess the proper operation of safety related equipment. The post-trip review established that the transient behavior of pertinent plant parameters for the RCS and SGs responded as expected for a reactor trip of this kind. The pressure decrease due to the PORV failure to close fully and the automatic rod insertion failure was addressed by the post trip review and no unexpected causes or responses were found. Specifically, the RCS pressures and temperatures were determined to have followed an expected pattern, based on the conditions leading up to and during the transient. The Plant Nuclear Safety Committee reviewed and approved the post-trip review. Prompt operator actions, in that the operators assumed manual control of the control rods, manually tripped the reactor, then manually closed block valve MOV-3-535, precluded the need for safety injection, and prevented the transient from resulting in additional degradation of plant conditions. Based on the above, the health and safety of the public were not affected.

CORRECTIVE ACTIONS

1) The turbine control oil, lube oil, and seal oil piping will be cleaned during the next refueling outages for each unit.

2) The turbine control oil system was inspected, and no indications of any inoperable or malfunctioning components were found. During unit startup, with the turbine at 1800 rpm, impeller oil pressure was measured and found to be 28 psig. This pressure is acceptable and confirms the hypothesis that the sudden clearing of a blockage of the impeller orifice caused the loss of governor control oil pressure. The impeller orifice was adjusted to raise the pressure to 29.5 psig.

3) PORV PCV-3-456 was inspected. The plug and cage were removed and replaced with new parts even though no problems with them were found. The valve and actuator were repeatedly tested, without a recurrence of the problem. The PORV was also stroked with the unit in hot standby (Mode 3) and full pressure conditions, with the block valve closed, in order to demonstrate operability.

4) The PORV manufacturer (Copes-Vulcan) will be requested to review FPL's findings.

5) The circuits associated with the auto rod control system were repaired and operationally tested.

6) The two cold solder joints in the summator were repaired.

7) Surveillance procedures will be updated to periodically check the operation of the auto rod control system during Power Range Nuclear Instrumentation Testing.

ADDITIONAL DETAILS

PORV Manufacturer: Copes-Vulcan. Model No.: D-100-160-2.5
Power Mismatch Summator Manufacturer: Hagan Controls/Westinghouse. Dwg. No: 1111084-L.
Turbine Governor Manufacturer: Westinghouse, Serial 13-A-2893.

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
H. B. Robinson Unit 2	0 5 0 0 0 2 6 1	1 OF 1 0

TITLE (4): Loss of Offsite AC Event

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 1	2 8	8 6	8 6	— 0 0 5 —	0 2					0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9):
POWER LEVEL (10): 8 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)	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)
Don Sayre	8 0 3 3 8 3 - 4 5 2 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
B	E K	X C T	W 1 2 0	Y					
B	E K	F U B	W 1 2 0	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 January 28, 1986, with Unit 2 at 80% power, Emergency Buss E-2 was lost, resulting in a high pressurizer pressure reactor trip. Unit auxiliaries then shifted to the startup (S/U) transformer but a West 115 kV Buss Lockout de-energized the transformer, causing loss of offsite AC power. Emergency Buss E-1 was energized. SI and MSIV closure signals were received from a high steam line flow coincident with low Tave, and an Unusual Event was declared. Power was restored to E-2 but a second SI signal was received from a steam line high differential pressure. Offsite AC power was then restored and the Unusual Event was terminated.

On March 6, 1986, during refueling shutdown, two Station Service Transformers were taken out-of-service for maintenance on their common supply breaker. While energizing E-2 from Emergency Buss E-1, the supply breaker opened due to degraded voltage relay actuation.

Investigation found the loss of E-2 and loss of offsite AC power apparently resulted from two separate, independent conditions - susceptibility of the S/U Transformer primary side Current Transformers (CTs) to DC saturation and vulnerability to a random blown fuse in the Emergency Buss Undervoltage Relays. Hardware changes have been made, and installation of an improved fuse holder design has been planned.

On August 7, 1986, susceptibility of the 4 kV side CTs to DC saturation was confirmed. An interim solution was installed, with complete replacement of the CTs planned.

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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)

EVENT DESCRIPTION

On January 28, 1986, the Plant was operating at approximately 80% power. Emergency Diesel Generator (EDG) "B" had just been taken out-of-service to install a solid state overcurrent trip device (amptector) on the EDG "B" output breaker. This breaker upgrade was being performed on all Westinghouse tie DB safety-related breakers and was completed on EDG "A" the week before. At 0917 hours, the EDG "B" output breaker had just been "racked out" when the Emergency Bus "E-2" was lost. This also resulted in the loss of Instrument Bus 4 (IB-4) which is supplied by Motor Control Center "MCC-6". Nuclear Instrumentation System Power Range Channel N-44 (fed from IB-4) was lost, which initiated a turbine runback (rod drop feature). The automatic rod control system (input from N-44) and the steam dump control system (powered from IB-4) could not function properly. As a result, a reactor trip was received on "Hi Pressurizer Pressure" approximately twenty-one seconds after "E-2" was lost.

One minute after the reactor trip, the main generator oil circuit breakers (OCBs) opened and the Plant Auxiliaries (those powered by the Auxiliary Transformer during operation) shifted to the Startup Transformer as part of the normal Turbine Generator Lockout feature. Approximately one second later, a West Bus Lockout occurred in the 115 KV switchyard which de-energized the Unit No. 2 Startup Transformer (See Figure 1). This resulted in a loss of offsite AC power. EDG "A" started automatically and loaded Emergency Bus "E-1". Approximately sixty-seven seconds after the West Bus Lockout was received, a Safety Injection (SI) and Main Steam Isolation Valve (MSIV) signal were received. These were caused by High Steam Line Flow coincident with Low Tave. The Low Tave siganl was caused by the Plant cooldown as a result of the Reactor Trip. The High Steam Line Flow signal was present due to loss of IB-4. When the loss of offsite AC power occurred, all three Reactor Coolant Pumps coasted down and the Plant was cooled by natural circulation flow. The Plant was stabilized at Hot Shutdown conditions with Reactor Coolant System (RCS) temperature being controlled with the Steam Generator (S/G) PORVs. An Unusual Event was declared at 0935.

At 1027 hours, power was restored to "E-2" by manually starting and loading EDG "B".

At 1115 hours, after investigation revealed no faulted condition on the Startup Transformer and its associated circuits, offsite AC power was restored to the Plant non-vital Electrical Distribution System.

At 1228 hours, a second SI signal was received. This was caused by "C" Steam Line High Differential Pressure which resulted when frozen sensing lines caused "C" S/G PORV to stick open. The "C" PORV was closed by isolating the air supply to the PORV, thus, correcting the situation. The freezing condition resulted when power was lost to freeze protection circuits.

Throughout the event, RCS pressure remained above the shutoff head of the SI pumps; therefore, no SI flow entered the RCS. At no time did RCS temperature and pressure approach saturation. Offsite AC power was restored to the entire Plant Electrical Distribution System at 1601 hours and the Unusual Event was terminated at 1634 hours.

NRC FORM 366A
(9-83)

NRC Form 366A (9-83)

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)
H. B. Robinson	0 5 0 0 0 2 6 1	8 6	— 0 0 5	— 0 2	0 3 OF 1 0

TEXT (If more space is required, use additional NRC Form 366A's) (17)

During the Loss of Offsite Power, other conditions resulted as follows:

1. The Control Room Ventilation System failed to automatically align to the Emergency Recirculation Mode when the initial SI signal was received. This was caused by the loss of power to "MCC-6" (supplied by "E-2"). This event was corrected when the power was restored to "E-2" and "MCC-6". This potential failure mode, including corrective action, was addressed in CP&L's response to the Control Room Habitability issue (NUREG-0737, Item No. III.D.3.4).

2. During the event (from 0918 to 1105 hours), the Fire Water Supply to the Containment Vessel (CV) was isolated when the Phase "A" Isolation Signal accompanying the initial SI signal closed the Fire Water CV Isolation Valves FP-256 and FP-248. Technical Specification 3.14.4.2 requires that if a hose station in the CV is out-of-service, back-up protection must be provided within one (1) hour. Although the Phase "A" Isolation Signal was reset at 0936 hours, reopening these valves (a remote operation) was intentionally postponed to allow the Operators to concentrate on the actions being taken to restore offsite power. If required, these valves could have been reopened with little delay.

3. During the initial attempt to restore power to "E-2" from EDG "B", breaker cycling on "E-2" was observed. An operator was directed to remove all control power fuses from breakers on "E-2" to prevent breaker damage. The Operator pulled all the control power fuses; however, SI Pump "B" fuses were also pulled. SI Pump "B" is supplied from the "E-1" and "E-2" Tie Bus, but its breaker is physically located on the "E-2" Bus. The pump had already been stopped in accordance with End Path Procedure, EPP-7, SI Termination. Since "E-1" was available, SI Pump "B" power via the tie bus was being supplied from "E-1".

   Since the control power fuses had been pulled, only SI Pump "A" was available for automatic start or manual start for approximately 40 minutes. SI Pumps were not required at the time. SI Pump "B" could have been started by locally closing the breaker or installing the control power fuses. The control power fuses for the "E-2" Bus loads (including SI Pump "B") were replaced after the "E-2" Undervoltage (UV) Relay Fuse was replaced. This action restored the affected components to the fully operable status.

During this event, there was no threat to public safety since one EDG started and supplied needed power to one of two redundant Emergency Busses. The Dedicated Shutdown Diesel was available if needed. In addition, appropriate provisions are available in the Emergency Operating Procedures (EOPs) to control the Plant for an extended period of time without any AC power until some form of AC power is restored (i.e., offsite power, Emergency Diesels, or the Dedicated Shutdown Diesel).

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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CAUSE/CORRECTIVE ACTION

Extensive investigations have been performed to identify the cause of the event. As a result of these investigations, it has been concluded that two major events (loss of Emergency Bus "E-2" and the loss of offsite AC power) were separate and independent from one another.

LOSS OF EMERGENCY BUS "E-2"

One potential cause of the loss of Emergency Bus "E-2" is attributed to a blown fuse on the secondary side of the Potential Transformer (PT) supplying the "E-2" bus UV relay. This would have caused a false undervoltage trip condition on the "E-2" bus, thereby, disabling the bus until the fuse was replaced. The "E-2" Bus UV relays initiate the bus loss of power sequence which "sheds" the motor loads off the bus by opening the load breakers, opens the normal (offsite power) supply breaker, starts EDG "B" and closes EDG "B" output breaker. However, since EDG "B" was out-of-service, it could not start nor could its output breaker close until the blown fuse was replaced during the event. An extensive investigation of the EDG "B" output breaker, "E-2" Bus control cabinet, associated circuits, and wiring was performed. No unusual conditions were found that would have caused the blown fuse. The blown fuse was a typical nonrenewable type 6 amp fuse. Inspection of the blown fuse also showed no unusual condition. The blown fuse could have been a random failure that cannot be related to the removal of EDG "B" from service.

The second potential cause of the loss of "E-2" was discovered on March 6, 1986, while the Plant was shutdown for refueling. The Station Service Transformers (SSTs) 2C and 2G were being taken out-of-service for maintenance on the common supply breaker for these SSTs. While in process of energizing "E-2" via "E-1" (cross tie "E-1" and "E-2"), the "E-2" normal supply breaker tripped open due to degraded voltage relay actuation.

The degraded voltage relays protect the Emergency Buses from low voltage and high current conditions by opening the normal (offsite power) supply breaker to the affected Emergency Bus should bus voltage become less than 415 volts for approximately 10 seconds.

Subsequent reviews and inspections revealed that the cause of the degraded voltage relay actuation was a loose fuse holder on the degraded voltage Emergency Bus "E-2", DC control circuit. When the cross-tie breaker was closed during the occurrence, it apparently caused the fuse holder connection to open.

The fuses and fuse holders on Buses "E-1" and "E-2" were inspected and eleven (11) of twenty-eight (28) additional DC control power fuse holders (3 on "E-1" and 8 on "E-2") were found to be loose to some degree and were replaced. An evaluation is underway to determine a better method to fuse these circuits on a long-term basis to prevent the loose fuse holder problem.

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Subsequent investigation after the March 6, 1986, occurrence revealed that the loose fuse holder could have caused the loss of "E-2" on January 28, 1986. In this case, the operator racking out the EDG "B" output breaker for maintenance could have caused sufficient vibration to open the connection in the fuse holder.

If the loose fuse holder did initiate the loss of "E-2", then the UV relay fuse addressed earlier could have blown when the "E-2" Bus was reenergized. Because of the events that had occurred, it would have not been easily discernable which was the actual initiating event.

Both the UV and degraded voltage relays were determined to be susceptible to random PT fuse failures. A modification has been performed to these circuits for both emergency buses to increase the rating of the PT primary side fuses and to eliminate fuse protection on the PT secondary side to the relays. This modification provides sufficient circuit protection while minimizing the vulnerability to a random fuse failure. Should a PT fail, the higher rated primary fuses would still clear a fault from the Emergency Bus. The modification was performed to both Emergency Buses and was completed prior to startup from the recent refueling outage.

LOSS OF OFFSITE POWER

Extensive investigation was performed to determine the cause of the loss of the offsite power. The Plant trip caused a normal transfer of the Auxiliary Transformer load to the Startup Transformer. Coincident with the transfer of the load, however, a "C" phase Differential Relay operated on the Startup Transformer. This relay tripped the 115 kV West Bus Lockout Relay, which in turn opened all source and load supply circuit breakers associated with the 115 kV West Bus and the Unit No. 2 Startup Transformer (See Figure 1).

Subsequent to the event, equipment and possible conditions that could have resulted in a tripping of the Startup Transformer due to a "C" phase Differential Relay operation were systematically examined. Some of the tests and inspections that were performed included oil samples from the Startup Transformer, setpoint checks and bench testing of the transformers relays Onsite and at Westinghouse, inspection of associated circuit breakers and related buses, and breaker coordination testing of the auxiliary transfer system. Westinghouse was consulted for independent analysis and recommendations. During the course of the investigation, all aspects of equipment, equipment inputs, and actual conditions present were analyzed. None of the inspections or tests identified any faulted conditions or component failures which could have contributed to the event. However, data collected during breaker coordination testing revealed a condition as described below.

Calculations based on information collected on the installed equipment revealed that the the three (3) current transformers (CT) on the primary side of the Startup Transformer are susceptible to DC saturation. These CTs provide the primary (115 KV) side input to the three (3) Differential Relays. If a primary CT were in saturation, the Differential Relay could sense a sufficient differential current (30% - 35%) across the Startup Transformer and operate, leading to a protective action (115 KV West Bus Lockout). The secondary side CTs are not susceptible to this condition.

The condition (DC saturation) results from a DC component of the AC in-rush current during loading of the Startup Transformer at the time Plant auxiliaries are transferred. The susceptibility to this saturation is a function of voltage rating of the CT, the current present under the in-rush condition, and the resistance of the CT circuit (CT, wiring, relay, etc.). Although this susceptibility is a function of circuit design and may have been present during the operating history of Robinson, conditions in the past apparently had not caused CT saturation to the extent and current in-rush to a magnitude that operated a Differential Relay. Specifically, a West Bus Lockout had not occurred during the operating history of Unit No. 2.

Conditions present on January 28, 1986, that apparently contributed to the saturation of the "C" phase CT follow:

1. CP&L system voltage profile had been increased in November, 1985. Additionally, the Robinson Fossil Unit was operating at full load that morning. This resulted in a "stiffer" system (lower system impedance) which would tend to make in-rush current effects more predominant.

2. Auxiliary load on Unit 2 was slightly higher due to freeze protection circuits being energized and the running of other equipment as a result of the cold weather.

3. The freeze protection circuits creating a higher than usual resistive load tends to slow down motors (inductive loads) more during the dead bus period at transfer. The transfer of auxiliary power uses a "break-before-make" scheme resulting in a 6-7 cycle (approximately) dead bus time. As the resistive load slows the motors down, the phase angle increases between the "residual" motor load and the system. This will further increase the magnitude of the current in-rush and its DC component.

4. Auxiliary load at Robinson has slowly increased over the years due to backfit modifications.

It is believed that the combination of these conditions on that morning, each representing an incremental change, resulted in the DC saturation of the "C" phase primary CT with an in-rush current of sufficient magnitude to operate the "C" phase Differential Relay. It should be noted that bench testing of the "C" phase Differential Relay revealed it to be the most likely of the three relays to operate under this condition.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

The susceptibility of the DC saturation is eliminated by a modification which essentially increases the rating of each CT (increased turn ratio) and connects a second CT in parallel. This modification was performed on all three phases of the primary side of the Startup Transformer and was completed prior to startup from the refueling outage. This modification is based on recommendations from Westinghouse. CP&L believes that its systematic and detailed review of the affected portions of the Plant's Electrical Distribution System and the identified corrective actions above will preclude this event from occurring again.

ADDENDUM

During the week of February 17, 1986, the 115/4 kV S/U Transformer differential relay input CTs were evaluated for operational susceptibility to DC saturation during transfer of unit auxiliary load from the Auxiliary Transformer. Based on best-estimate data available at the time, the differential input 4000/5 amp CTs on the 4 kV side were determined not to be susceptible. Calculations performed for the 115 kV side CTs did reveal susceptibility and subsequent corrective action focused on these.

Follow-up review of all data de[illegible] during the initial investigations included refinement of original calc[illegible] account for a hypothetical worst case scenario. CT nameplate data [illegible] provided to the manufacturer with a request for a specific CT characteristic cu[illegible] curve was obtained on August 5, 1986.

Key parameters determined from the curve indicated that the preliminary calculations may have been in error. Specifically, the new calculations indicated the 4 kV side CTs were also susceptible to DC saturation. To assure correct input data was being used, the 4 kV side CTs were tested using equipment not available in February. These tests confirmed the accuracy of the CT characteristic curve, and susceptibility of the 4 kV side CTs to DC saturation was confirmed August 7.

It was recognized at that time the best permanent solution would involve installation of improved characteristic CTs. These CTs, however, would require special design and construction, involving a lead time of several months. In order to provide an interim solution, a 10-cycle time delay in the trip path from the S/U Transformer differential relay output contacts to the West 115 kV Buss Lockout Relay was installed. This would ensure that if DC saturation were to occur, sufficient time (approximately 5 cycles) would be allowed for saturation decay. Since the relay differential scheme provides non-nuclear safety-related functions, a 10-cycle delay in the differential protection logic creates no safety concern.

The installation of the 10-cycle time delay to eliminate susceptibility to DC saturation was accomplished August 8, 1986. Replacement of the 4000/5 CTs to eliminate the potential for DC saturation is currently planned for 1987.

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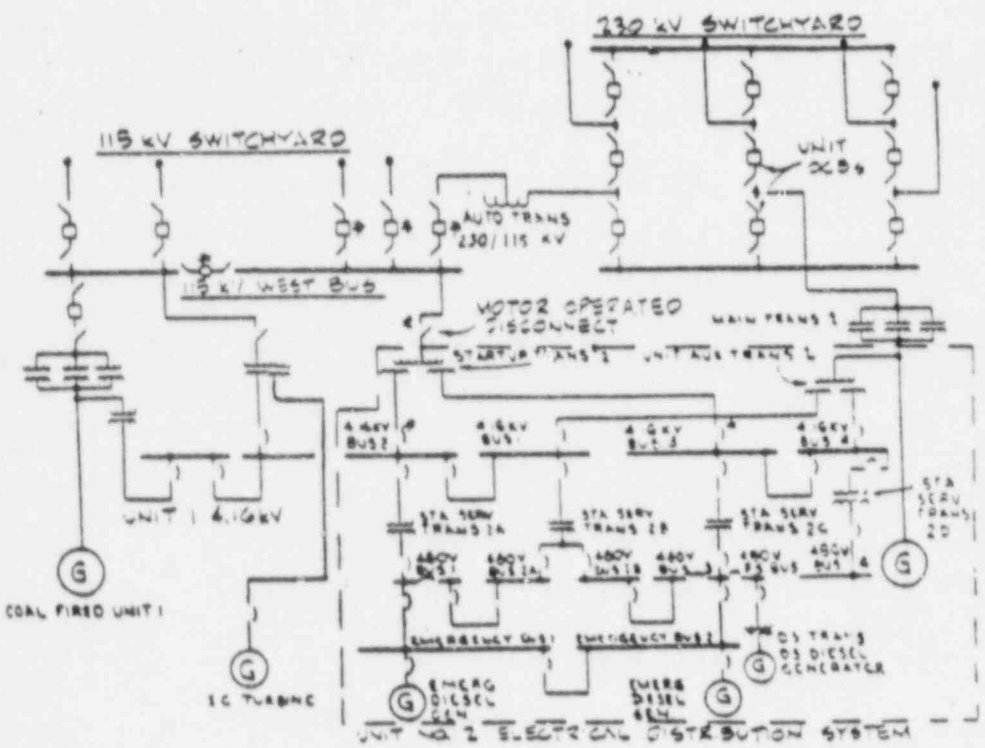
TEXT (If more space is required, use additional NRC Form 366A's) (17)

FIGURE 1

H.B. ROBINSON ELECTRICAL DISTRIBUTION SYSTEM



* BREAKERS THAT OPEN ON WEST BUS LOCKOUT

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

JANUARY 28, 1986, SEQUENCE OF EVENTS

APPROX. TIME (HR/MIN/SEC)		EVENT DESCRIPTION
Initial Condition	-	Plant at 80% power
	-	Plant coasting down for refueling.
0915:00	-	EDG "B" output breaker racked out for breaker upgrade.
0917:15	-	Loss of Emergency Bus E-2, Motor Control Center MCC-6, Instrument Bus IB-4, and all loads supplied by these buses.
	-	Initiation of Turbine Runback.
0917:36	-	Reactor Trip - "High Pressurizer Pressure".
0918:36	-	Turbine Generator Lockout (unit OCBs opened and Auxiliary Transformer loads shifted to Startup Transformer).
0918:37	-	Loss of offsite power (Startup Transformer) due to 115 kV West Bus Lockout.
	-	EDG "A" Auto Start.
	-	All three Reactor Coolant Pumps coasted down (Natural Circulation initiated).
0919:44	-	SI and MSIV closure signal - "High Steamline Flow coincident with low Tave".
0935:00	-	Declared Unusual Event.
0936:00	-	Reset SI, Phase "A", and Feedwater Isolation.
0941:00	-	EDG "B" Local Start - Attempted to start loads on Emergency Bus E-2 but prevented due to the false undervoltage signal. Investigation found blown fuse in the secondary side of the Potential Transformer supplying the E-2 UV relays.
1027:00	-	Bus E-2 loaded.
1058:00	-	Energized Startup Transformer.
1115:00	-	Restored offsite power from Startup Transformer to 4 kV Busses 1 and 2 (Non-vital load).

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

JANUARY 28, 1986, SEQUENCE OF EVENTS

APPROX. TIME (HR/MIN/SEC)		EVENT DESCRIPTION
1226:00	-	"C" S/G PORV stuck open (due to frozen sensing lines).
1228:00	-	Second SI signal - "Steam Line "C" High Differential Pressure".
1230:00	-	"C" S/G PORV closed by isolating air supply to the PORV.
1237:00	-	Reset second SI, Phase "A", and Feedwater Isolation.
1255:00	-	E-1 placed on offsite power, secured EDG "A".
1304:00	-	Restored offsite power from Startup Transformer to 4 kV Busses 3 and 4.
1601:00	-	E-2 placed on offsite power, secured EDG "B".
	-	Plant Power Distribution restoration to normal complete.
1634:00	-	Terminated Unusual Event.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Oconee Nuclear Station, Unit 1

DOCKET NUMBER (2): 0 5 0 0 0 2 6 9

PAGE (3): 1 OF 0 5

TITLE (4): Generator/Reactor Trip Due to Failure of PCB-20 in 230 kv Switchyard

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	3 1	8 6	8 6	— 0 0 1	— 0 0	0 3	0 3	8 6		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9):

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)(iv)

X OTHER (Specify in Abstract below and in Text, NRC Form 366A): 50.72(b)(2)(ii)

LICENSEE CONTACT FOR THIS LER (12)

NAME: M. A. Haghi, Licensing

TELEPHONE NUMBER: AREA CODE 7 0 4 — 3 7 3 - 4 0 6 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
X	B U	P	D 0 5 5	Y		B	E A	B R K	I 2 0 2	N
X	S B	V	C 7 1 0	Y						

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE) NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On January 31 1986, at 1547 hours, Unit 1 Reactor tripped from 100% power because of a RPS Generator/Turbine Anticipatory Reactor trip signal. The anticipatory Turbine/Reactor trip was initiated when a 230 kv switchyard power circuit breaker (PCB-20) failed following a 230 kv yellow bus lockout.

When the yellow bus lockout occurred the Unit 1 generator yellow bus tie breaker (PCB-21) opened. Immediately afterwards the parallel generator breaker (PCB-20), which was subjected to the entire generator output, exploded causing the Turbine/Generator to trip on under-voltage. The failure of PCB-20 was apparently caused by degraded breaker contacts.

Following the reactor trip, both Main Feedwater Pumps (MFWP) failed to runback and tripped on high discharge pressure. All three emergency feedwater pumps started immediately and remained in service for about 38 minutes. A preliminary investigation has revealed the MFWP speed demands did not run back as expected.

The immediate corrective action was to stabilize the unit at hot shutdown. The supplemental corrective action assured that PCB-20 was isolated and Unit 1 was allowed to restart.

The health and safety of the public was not affected by this incident

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Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	8 6	— 0 0 1 —	0 0	0 2 OF 0 5

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BACKGROUND

When power is not available from the unit's generator through the auxiliary transformer, power is supplied to the unit through its startup transformer fed from either or both of the buses in the 230 kv switching station. Power to the startup transformer can flow through the 230 kv switching station from any one of fourteen supplies. These include eight 230 kv transmission circuits, two nuclear generating units if operating, two hydroelectric units and the 500 kv switching station. When the 230 kv switchyard yellow bus became locked out the power circuit breaker (PCB-20) became the only flow path from Unit 1 Generator to the 230 kv Switchyard and the Duke System.

DESCRIPTION OF OCCURRENCE

On January 31, 1986 during the process of troubleshooting for microwave problems experienced earlier, PCBs 22, 23 and 24 were opened and isolated from both the red and yellow 230 kv switchyard buses. When PCB-22 and -23 were checked an unbalance condition was found on PCB-23 as a result of high constant resistance on PCB-22.

At 1546 hours, the circuit breaker PCB-24 was manually closed without the reset of the generator lockout relays. When this breaker was closed the relay logic was satisfied to cause a yellow bus lockout. Consequently all the 230 kv yellow bus tie breakers opened.

One of the breakers that opened on the yellow bus lockout was PCB-21, the Unit 1 generator to yellow bus tie breaker. When it opened the only path for current flow from Unit 1 Generator to the Switchyard was via PCB-20. PCB-20 faulted, undergoing an explosion, approximately 17 seconds after PCB-21 opened. At 1547 hours the turbine/generator tripped initiating an anticipatory reactor trip from 100% stable power conditions. PCB-20 is an ITE Model 230-GA-20-30 power circuit breaker and is not reportable to NPRDS. There were no personnel injuries as result of this explosion.

Following the reactor trip, both Main Feedwater Pumps (MFWP) tripped on high discharge pressure. A preliminary investigation has shown the MFWP speed demand did not run back as expected. All three emergency feedwater pumps started immediately to supply feedwater flow for decay heat removal. Emergency feedwater remained in service for about 38 minutes.

At the time of the reactor trip a steam generator tube leak existed on the unit. On the day of the incident, the calculated steam generator tube leak was .016 gallon per minutes. Following the reactor trip one of the main steam relief valves (1MS-8) opened for 11 minutes.

Unit 1 was stabilized at hot shutdown conditions with no actuations of engineered safeguard (ES) systems or pressurizer relief valves and no reactor coolant system (RCS) leakage was induced.

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CAUSE OF OCCURRENCE

A discussion with the personnel involved in this incident indicates the procedure they were using to trouble shoot is very general. There is however a Maintenance Procedure that gives more specific details concerning breaker maintenance work in the 230 kv Switchyard. This breaker maintenance procedure has in it a safety consideration statement indicating the failure to notify the Shift Supervisor to reset the lockout may result in a switchyard isolation. However, due to misunderstanding and lack of a clear definition of responsibility for verifying the Unit 2 generator lockout reset, PCB-24 was closed without the generator lockout reset. This set up a relaying fault condition and consequently locking out the yellow bus.

The failure of PCB-20, however, has been evaluated as the root cause of this incident. The cause for the PCB-20 fault was attributed to failures of the breaker contacts. Under normal circumstances, a yellow bus lockout is not expected to cause a unit trip. In this case PCB-20 failed when PCB-21 opened, causing a turbine/generator trip. PCB-20 is rated to carry the full output from the generator. This is the first incident at Oconee in which following a yellow bus lockout, the alternate generator breaker faulted; therefore, this failure is considered an isolated case.

The failure of the MFWP to run back, as expected, was due to a mechanical problem on one of the MFWPs. During steady state full power operation, when the integrated control system (ICS) demanded a certain speed, the mechanical linkage on the 1A MFWP that converts an electrical signal to an appropriate valve position did not operate properly. As a result, the pump speed was below the normal speed. Consequently, the ΔP across the feedwater valve was below the setpoint of 35 psi. Over a period of time a setpoint error built in the ICS 1A MFWP speed integral which caused it to saturate high. When the reactor tripped, the MFWP did not run back as expected because the saturated integral was still at a position calling for the pump speed to increase. The feedwater valves had gone closed, consequently feedwater discharge pressure increased until it reached approximately 1155 psig at which point both main feedwater pumps tripped.

There have been four incidents in the last 24 months where a unit has lost main feedwater pumps, however, the causes were unrelated to what occurred during this event; therefore, this loss of feedwater is considered an isolated case.

CORRECTIVE ACTION

The immediate corrective action was to stabilize the unit at hot shutdown conditions. Supplementary corrective actions identified the failure of PCB-20 as the cause of the reactor trip. PCB-20 was isolated from the remainder of the switchyard, repaired and then returned to service. Actions were also taken to investigate the trip setpoint calibrations for 1A and 1B feedwater pumps and to investigate and repair as necessary Main Steam relief 1MS-8.

Planned corrective actions will include the following:

-A Safety Consideration statement similar to the one found in the Maintenance Procedure will be added to the Troubleshooting Procedure.

-Signs will be posted on equipment in the 230 kv Switchyard to inform personnel working on a breaker that a yellow bus lockout may occur if specific relays are not properly set.

-Implement changes as necessary to ensure relaying requirements are met during future equipment isolations.

-Safety related equipment in the switchyard will be appropriately identified as safety related.

-The main feedwater pumps will be worked on during the upcoming refueling outage and adjustments will be made as necessary to correct misalignments in the mechanical linkage.

ANALYSIS OF OCCURRENCE

This event was a loss of load transient with a subsequent loss of main feedwater. The criteria for plant protection during this event are that the minimum DNBR will not be less than 1.3, and the system pressure will not exceed code limits (see FSAR Chapter 15.8).

After the lockout of the yellow bus, power to unit 1 and 2 startup transformers was supplied from unit 3 main generator via the red bus. Emergency power situation did not occur and was not required.

Had the red bus been lost during this period of time emergency power would have been actuated and power to the unit 1 and 2 4160 volt engineered safeguard switchgear would have been supplied from Keowee hydro via the underground line. The yellow bus was returned to operation within 72 hours as required by the Technical Specification.

The reactor tripped on 2 out of 4 anticipatory signals following Turbine/Generator trip. All control rod drive (CRD) breakers opened within specified time, with a maximum delay time of 51 msec. Minimum subcooling margin was approximately 40 degrees F.

Four seconds after the reactor trip both main feedwater pumps tripped on high discharge pressure. All three emergency feedwater pumps started as designed and supplied feedwater to both steam generators for approximately 38 minutes. The minimum level maintained in both steam generators was 25 inches. The consequences of the loss of main feedwater were within safety limits.

Reactor coolant temperature and pressure were within normal limits. Maximum reactor coolant system temperature was 504 degrees F prior to the trip. Minimum RCS temperature was approximately 548 degrees F. The maximum cooldown rate of 100 degrees F was not violated. Maximum RCS pressure was 2200 psig, well below the code limits. The minimum RCS pressure was approximately 1750 psig, well above the setpoint for emergency core cooling system (ECCS) actuation.

Reactor coolant inventory was control led within normal limits, between a minimum pressurizer level of 40 inches and a maximum of 260 inches.

Minimum steam generator pressure was approximately 900 psig, prior to the trip. The steam pressure peaked at 1125 psig immediately following the turbine trip. One main steam relief valve (MSRV) 1MS-8 remained open for approximately 11 minutes after the trip. It was reseated by lowering the steam pressure to 975 psig.

When Unit 1 tripped, a steam generator tube leak existed on the unit. At 1533, on the day of the incident, the calculated tube leak size was .016 GPM. Conservative estimate of Gamma and Beta doses to the public indicated the dose rates were well below the limits of Technical Specifications.

In conclusion, all safety criteria were met during this event. ECCS and Emergency Power systems were not actuated. The health and safety of the public were not affected.

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LICENSEE EVENT REPORT (LER)

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TITLE (4)
Inoperability of the Emergency Condenser Circulating Water System

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)
1 0	0 1	8 6	8 6	— 0 1 1	— 0 0	1 2	1 2	8 6	Oconee, Unit 2	0 5 0 0 0 2 7 0
									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)	[ ] 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)	50.72(b)(1)(ii)
[ ] 20.405(a)(1)(iv)	[X] 50.73(a)(2)(ii)	[ ] 50.73(a)(2)(viii)(B)	50.72(b)(2)(iii)
[ ] 20.405(a)(1)(v)	[ ] 50.73(a)(2)(iii)	[ ] 50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Paul F. Guill, Licensing	AREA CODE 7 0 4 — 3 7 3 - 2 8 4 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
B	S D	P		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 Wednesday, October 1, 1986, with Units 1 and 3 at 100% full power, and Unit 2 shutdown for refueling, a Load Shed Test on Unit 2 was performed. Suction to the Low Pressure Service Water (LPSW) Pump was lost about one hour into the test. The Loss of prime in the Condenser Circulating Water (CCW) Siphon Flow (or Emergency CCW) system was the cause for the loss of the LPSW pumps. The Emergency Condenser Circulating Cooling Water (ECCW) System is required to provide water through the Main Condenser for decay heat removal during a Loss of All AC Power event (Station Blackout).

The immediate corrective action was to analyze the failures that occurred during the Load Shed Test, and shut down Oconee Units 1 and 3. Subsequent corrective actions included redesign of the CCW pump flanges and determination of the design basis of the ECCW system.

The root cause of this event is the inadequate design and testing of the ECCW system. This led to a failure of the ECCW system to perform the intended function as described in the Final Safety Analysis Report (FSAR).

There is sufficient condensate available to provide decay heat removal following a blackout without the operation of the ECCW system. The diverse and reliable sources of AC power make the probability of a complete Loss of AC Power or a load shed coincident with a LOCA very low. A CCW pump can be restarted to supply LPSW suction following a LOCA event with a load shed, if the siphon flow system was inoperable. As such, the health and safety of the public were not affected by this incident.

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NRC Form 366 (9-83)

*U.S.GPO:1984-0-454-461/18790

NRC Form 366A

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	8 6	— 0 1 1	— 0 0	0 2 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Background:

The design basis of the Emergency Condenser Cooling Water (ECCW) System is to provide water to the condenser for the removal of decay heat during a Loss of all AC Power event (Station Blackout). The Station Blackout scenario is limiting, in that Condenser Cooling Water (CCW) siphon flow through the main condenser is used to remove decay heat. Decay heat is transferred to the main condenser via the Turbine Bypass Valves. Feedwater is delivered to the steam generators via the Turbine Driven Emergency Feedwater Pumps (TDEFWP).

For the Station Blackout event, the following systems must operate:

1) Continuous Vacuum Priming (CVP) System - Using the Main Steam (MS) supplied Emergency Air Ejector.
2) Condenser Vacuum (V) System - The Condensate Steam Air Ejector (CSAE) must operate off MS and maintain condenser vacuum.
3) Emergency Condenser Cooling Water (ECCW) System - The gravity flow siphon must be established and function with the appropriate design flow for decay heat removal for all three units.
4) Emergency Feedwater (EFW) System - The turbine driven emergency feedwater pump must function while being cooled by High Pressure Service Water (HPSW) from the Elevated Water Storage Tank (EWST). The TDEFWP is powered by Main Steam (MS).
5) Turbine Bypass valves (TBV) - The TBV must relieve steam to the condenser in order to reclaim the condensate for EFW. These valves are air operated with diesel air compressor as a backup.
6) Elevated Water Storage Tank - The EWST must be available to provide cooling for the TDEFWP and sealing for the CCW pumps with High Pressure Service Water (HPSW).

The Initial testing of the CCW System Gravity and Recirculation Flow function was performed on Unit 1 on January 10, 1972, on Unit 2 on March 18, 1973, and on Unit 3 on February 7, 1974. The acceptance criteria for the initial test were:

1. All valves necessary to perform this function were in the proper position.
2. Gravity flow to the Keowee tailrace was visually verified.

DESCRIPTION OF OCCURRENCE:

On Wednesday, October 1, 1986, while Unit 2 was in a refueling outage, the Unit 2 load shed test was performed. At Oconee, a load shed of non-essential loads is initiated when emergency power is required via the underground feeder from Keowee through transformer CT-4. The load shed protects this power path from overload.

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NRC Form 366A

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)
Oconee Nuclear Station, Unit 1	0 5 0 0 0 2 6 9	8 6	— 0 1 1	— 0 0	0 3 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

When the load shed test was initiated, the condenser circulating water pumps were deenergized. Normally, this causes the gravity flow system to automatically align and to allow the flow of water from the intake structure through the condenser and discharging to the Keowee tailrace into Lake Hartwell. The elevation difference and a siphon effect are used to cause the condenser circulating water to continue to flow. For this test, the condenser gravity drain to the Keowee tailrace was blocked because this was not part of the test.

After about an hour, the Low Pressure Service Water (LPSW) pumps began to cavitate and stop pumping. One LPSW pump was stopped by the Control Room operator, and a second LPSW pump was observed to have low discharge pressure and cycling amps. Various high temperature alarms for the components cooled by LPSW were received in the Control Room. CCW flow was restored by restarting a CCW pump and the plant was restored to its normal powered condition without any plant damage or system upsets. Prior to the occurrence, two LPSW pumps were operating with approximately 13,000 gpm/pump. The LPSW pumps are supplied from the CCW crossover header which was being supplied from Unit 2 at the time.

In the evening of October 1, 1986, the test was repeated, but this time the gravity drain feature was also tested. The results were the same with the loss of LPSW flow. The NRC/Region II was advised of these results late in the evening, and concurred that units 1 and 3 could continue to operate until the test data could be fully evaluated. Units 1 and 3 were at 100% power. At 0900 on October 2, 1986, evaluation of the tests revealed that the operation of this design feature (the CCW Siphon flow) was questionable for Units 1 and 3, and that this resulted in inoperability of the LPSW systems for Oconee. As a result, an orderly shutdown of the two operating units was begun as required by Technical Specification 3.3.7. Both units reached Cold Shutdown conditions by October 3, 1986.

The subsequent investigation of this incident by Duke Personnel indicated that the flange on the CCW Pumps, which was exposed due to the low lake level, was noted to be leaking water when the pumps were running. Initial thoughts were that when the siphon was required air was sucked into the pumps, destroying the siphon. To confirm this suspecion, a temporary repair was made to a pump with a polyurethane drape and a test of the gravity drain feature was run overnight. In this case, the siphon flow appeared to improve, and, the cause for failure of the ECCW system to maintain flow was postulated to be the leaking flange which allowed air to enter the CCW piping and collect in the high point of the piping, thus terminating CCW siphon flow.

On October 3, 1986, plans were made to pull all of the CCW pumps and repair the flange. This would prevent air in-leakage and would enable the siphon to be maintained. Two pumps and three motors had been pulled by the morning of October 4, 1986, when it was discovered that the intended fix would probably not work. The design of the pump and casing relied on a very thin lip to support the pump. The pump had never been designed to be leak tight in this joint inasmuch as it was not critical to the design of the pump for normal lake levels.

NRC FORM 366A

NRC Form 366A (9-83)

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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)

To resolve this apparent problem another fix was proposed. The design of this particular fix included building a rubber boot about the pump casing and pump barrel and venting the space under water to allow water to flow out but not to allow air to flow in. As a test case a pair of CCW pumps were modified and a test of the ECCW system was performed. The results of the test indicated that the proposed fix did resolve the problem and that flow through the CCW piping could be maintained for an extended period of time (greater than 8 hours) by the ECCW system. Repairs were begun on the other CCW pumps and were completed by October 11, 1986.

In addition to the above, each Continuous Vacuum Priming (CVP) line at the CCW intake was inspected for blockage. Unit 3 lines were clear and vacuum was established on Unit 3 intake high point vents. Unit 1 and Unit 2 lines were found blanked off with blind flanges which prevented the CVP pumps from developing adequate vacuum on the CCW intake high point vents to overcome air inleakage at the pumps. These flanges had apparently not been removed at the completion of the original system hydro testing. The flanges were removed and a vacuum was established on Units 1 and 2 intake high point vents.

Successful testing was also performed on the CSAE, the Turbine Bypass Valves, and the siphon effect. By October 23, 1986 all three units were returned to service.

CAUSE OF OCCURRENCE:

The root cause of this incident is the inadequate design and testing of the Emergency Condenser Cooling Water (ECCW) System. This led to a failure of the ECCW System to perform its intended function as described in the FSAR under all assumed conditions. Inadequate original design evaluation of the ECCW System and the lower than normal lake level of Keowee are contributing factors to the cause of this incident.

CORRECTIVE ACTION:

The following is a listing of the corrective actions that were taken as a result of this incident:

1) Evaluation of the test data associated with the load shed test to determine reasons for failue of the LPSW pumps.
2) Bringing Units 1 and 3 to cold shutdown in accordance with Technical Specification 3.3.7
3) Modification of the leaking flange on the CCW pump casings
4) Determination of the design basis of the gravity flow function
5) Removal of blank flanges from Units 1 and 2 continuous vacuum priming lines and the inspection of the lines on Unit 3

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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)

6) Set up of a 1000 CFM diesel air compressor and hard piping into the service air header
7) The procedure for loss of power was changed to include:
   a. Verification of flow through CCW-8.
   b. Monitoring of Elevated Water Storage Tank (EWST) level.
   c. Isolating steam to all first stage Condensate Steam Air Ejector (CSAEs), thereby allowing the system to maintain condenser vacuum.
   d. Aligning the Condensate side of the CSAEs to provide an emergency cooling flow path from the UST to the Hotwell.
   e. Prompt alignment of the Turbine Driven EFW pump suction to the Hotwell to allow more UST water for cooling the CSAEs.
   f. Opening of the CCW cross-connects to supply LPSW suction from any unit with operating CCW pumps.
   g. Loading of the HPSW jockey pump onto CT-4 following a Load Shed Reset.
8) Changing the procedure for the compressed air system to reflect the modification which had piped the diesel air compressor into the Service Air System
9) Changing the procedure for the instrument air system to instruct the operators to start the diesel air compressors and open the service air to instrument air cross-connect, upon loss of instrument air
10) Satisfactory performance of the following tests:
   a. Siphon Flow Test without continuous priming on all units.
   b. Diesel air compressor test to hold both the Service Air and Instrument Air header at a pressure greater than 75 psig with the Instrument and Service Air Compressors off.
   c. Test of the Condenser Vacuum response after Condensate flow was removed from the CSAEs.
   d. Siphon Flow Test without HPSW flow to CCW bearing injection connections.
11) Repair the CCW discharge high point vent valves
12) Requirements to store CCW pump motor cable and replacement breaker for damage control measures for use after an Appendix R fire has been added to the Appendix R requirement list.

The Planned Corrective Actions in response to this incident are as follows:

1) Review and analysis of the seismicity of the CCW system.
2) The development of a program to include CCW piping in a routine inspection
3) A review of the validity of the testing program to ensure that systems and components are tested adequately.
4) A review of Technical Specifications will be performed to determine if any revisions are necessary.

ANALYSIS OF OCCURRENCE:

Section 15.8.3 of the Oconee Final Safety Analysis Report (FSAR) assumes operability of the Emergency Condenser Circulating Water (ECCW) System in the event of a loss of all AC power to the station (blackout). Included in this is the ability to maintain siphon flow of condenser circulating water through the

Condenser of each operating unit. Also included is operability of the Turbine Bypass Valves and the Turbine Driven Emergency Feedwater Pumps such that feedwater can be recirculated through the Condenser to remove decay heat. However, immediate operation of the ECCW System and the Turbine Bypass Valves is not of a critical nature following a station blackout event based on the inventory of feedwater maintained and the ability to release decay heat by steaming directly to the atmosphere through the Main Steam Relief Valves.

With the TDEFWP available but the ECCW System unavailable following a blackout event, approximately 6.2 hours are available before exhausting the minimum 72,000 gallon supply of stored condensate required by Technical Specifications. The normal amount of condensate available to the emergency feedwater pumps following blackout is approximately twice the Technical Specification minimum, so extended decay heat removal would be possible. Based on the redundancy designed into the Oconee AC power distribution system, it can be assumed that AC power would be restored within 4 hours of a station blackout event; therefore, the normal CCW and EFW systems could be restored to service well before depleting the condensate supply needed to remove decay heat. During the Station blackout scenario, the Elevated Water Storage Tank will supply cooling water to the TDEFWP for 5 to 11 hours.

The Loss of Coolant Accident (LOCA) assumes a loss of offsite power and a worst case single failure. In Section 15.14 of the FSAR the worst single failure is the failure of one bus of emergency power which results in the loss of one train of Low Pressure Injection and one train of High Pressure Injection.

In this situation the overhead emergency power supply path from Keowee is available; accordingly, the CCW pumps would still have power to operate and provide flow through the CCW system during the event. As such, the gravity flow capability provided by the ECCW system is not required . However, if it is also assumed that the overhead line is lost as the single failure and the ECCW system was unable to perform its design function, station loads would then be supplied by the underground feeder (the second train of emergency AC power) through transformer CT-4, which would constitute a load shed situation in which the CCW pumps would be load shed. Operators would then manually load the CCW pumps onto the emergency bus immediately following the load shed. Thus, the CCW pumps could be restarted after the initial load shed to provide water for the Low Pressure Service Water System and gravity flow would not be required. (Reference Section 8.3.1.2 and Table 8.1-1 of the FSAR.)

The diverse and reliable sources of AC power available to Oconee make the probability of a complete loss of AC power or a load shed coincident with a LOCA very low. Sufficient condensate is available to provide decay heat removal following blackout without the operation of the ECCW System, which would allow recirculation of condensate. A CCW pump can be restarted to supply LPSW suction following LOCA with a load shed if the siphon flow system is inoperable. Therefore, the inoperability of the ECCW System did not adversely affect the health and safety of the public.

LICENSEE EVENT REPORT (LER)

Facility Name (1)	Docket Number (2)	Page (3)
Peach Bottom Atomic Power Station - Unit 2	0 5 0 0 0 2 7 7	1 of 0 1

Title (4): Reactor Scram Due to Failure of E-2 Diesel Generator

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	2 4	8 6	8 6	0 0 3	0 0	0 2	2 4	8 6		0 5 0 0 0
										0 5 0 0 0

Operating Mode (9): N

Power Level (10): 0 9 5

This report is submitted pursuant to the requirements of 10 CFR §: X 50.73(a)(2)(iv)

Licensee Contact for this LER (12)

Name	Telephone Number
W. C. Birely, Senior Engineer - Licensing Section	2 1 5 8 4 1 - 5 0 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
X	E K	B L O	C 4 7 0		X	S B	F S V	A 6 1 3	
X	S B	F S V	A 6 1 0						

Supplemental Report Expected (14): X No

Expected Submission Date (15):

Abstract: 2-86-03

On January 24, 1986, with Unit 2 at 95% power, the Reactor Protection System (RPS) initiated a full reactor scram. The scram occurred as a result of high core flux caused by the inadvertent closure of outboard Main Steam Isolation Valves (MSIVs) AO-2-2-86B and AO-2-2-86D. The MSIVs failed closed as a result of loss of AC power to bus E-22 in conjunction with the failure of two redundant DC solenoids which are designed to allow the MSIVs to stay open during such a loss of AC power condition. Loss of power to E-22 occurred as a result of E-2 diesel generator failure. The diesel generator air intake blower failed which caused the diesel to trip. Additionally, Group II and Group III outboard isolations occurred on Unit 3, which is shutdown for refueling, as a result of loss of power to E-23 bus load center. The Unit 3 outboard isolation logic relays are normally powered via the E-23 bus. The air blower was replaced and E-2 diesel generator was satisfactorily tested and returned to service by February 3, 1986.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

Unit Conditions Prior to Event

Unit 2 was operating at 95% power level with E-2 diesel generator supplying buses E-22 and E-23 in preparation for a loss of power test on Unit 3.

Description of the Event:

On January 24, 1986, at 0612 hours, E-2 diesel generator automatically tripped thereby removing all power to E-22 and E-23 buses. Main steam isolation valves (MSIVs) AO-2-2-86B and AO-2-2-86D inadvertently closed following the diesel trip. Closure of these valves resulted in a high core flux condition which was sufficient to initiate a full reactor scram. Immediately following the scram, reactor water level decreased to -32 inches. Group II and Group III isolations occurred properly at zero inches water level. The speeds of all three reactor feedpumps automatically increased to recover reactor water level. At +45 inches the reactor feedpumps and the main turbine received high reactor water level trip signals. The feedpumps and main turbine tripped properly. Both reactor recirculation pumps tripped properly during the 13.2 KV bus fast transfer. At 0634 hours the 'C' reactor feedpump was reset from the high water level trip and placed in service to control reactor water level. Both recirculation pumps were returned to service by 0645 hours.

Additionally, Group II and Group III outboard isolations occurred on Unit 3 as a result of this event.

Cause of the Event:

Prior to the event, E-2 diesel generator was in service supplying E-22 and E-23 emergency buses in preparation for a loss of power test on Unit 3. At 0612 hours E-2 diesel generator tripped, thereby removing all power to E-22 and E-23 buses. Removal of power from E-22 bus de-energized the AC solenoids of all four outboard MSIVs. By design, a redundant DC solenoid remains energized to allow the MSIV to stay open during such a condition. Subsequent to the event, the DC solenoids for MSIVs AO-86B and AO-86D were found to be failed. These failed DC solenoids, in

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Peach Bottom Atomic Power Station - Unit 2	0 5 0 0 0 2 7 7	8 6	— 0 0 3	— 0 0	0 3 OF 0 4

conjunction with the loss of power to the AC solenoids, caused MSIVs AO-86B and AO-86D to fail closed thereby isolating two of the four main steam lines. Isolation of these lines produced a 13 PSI pressure spike in the reactor which, turn, produced a 20% flux spike as detected by the in-core flux monitors. The flux spike was sufficient for the RPS to initiate the full scram.

Additionally, Group II and Group III outboard isolations occurred on Unit 3 as a result of loss of power to E-23 bus because the outboard isolation logic relays are powered via the E-23 bus load center.

The E-2 diesel generator had been in operation for approximately 51 hours prior to the event. The diesel was run at relatively low loads during that period (nominally 550 KW, although rated at 2600 KW). At low loads, all combustion air to the diesel is supplied by the diesel's air intake blower. When the air blower failed, the diesel became air starved and tripped.

Consequences of the Event:

All isolations occurred properly. No Emergency Core Cooling System initiations were necessary as a result of this event (nor did any occur) due to the effective operation of the reactor feedpumps. With the exception of E-2 diesel, all systems were promptly returned to normal after the event.

Corrective Actions:

RT-15.6 titled "MSIV Pilot Valve Solenoid Continuity Test" is performed on a monthly basis for the purpose of verifying MSIV solenoid coil continuity. A review of the most recently completed RT-15.6 indicated that all MSIV AC and DC coils had satifactory operating currents when tested on January 22, 1986, just two days prior to the event. The AO-86B and AO-86D DC solenoids were replaced on January 25, 1986. One of the failed solenoids has been sent to PECo Electrical Engineering Division for failure analysis.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Peach Bottom Atomic Power Station - Unit 2	0 5 0 0 0 2 7 7	8 6	— 0 0 3	— 0 0	0 4 OF 0 4

The E-2 Diesel air blower was replaced and E-2 diesel was satisfactorily tested and returned to service by February 3, 1986. The failed diesel air blower has been sent to Colt/Fairbanks Morse for failure analysis and rebuilding.

Previous Similar Occurrences:

None.

POW 28-06-01

NRC Form 366

U.S. NUCLEAR REGULATORY COMMISSION
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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	Surry Power Station, Unit 1
DOCKET NUMBER (2)	0 5 0 0 0 2 8 0
PAGE (3)	1 OF 0 3
TITLE (4)	Loss of Charging Pump Service Water Pumps

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	2 9	8 6	8 6	— 0 2 9 —	0 0	1 0	2 8	8 6		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 § (11)	X 50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
R. F. Saunders, Station Manager	8 0 4 3 5 7 - 3 1 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

SUPPLEMENTAL REPORT EXPECTED (14)

YES (If yes, complete EXPECTED SUBMISSION DATE)   X NO

EXPECTED SUBMISSION DATE (15): MONTH | DAY | YEAR

ABSTRACT (16)

On September 29, 1986 with Surry Units 1 and Unit 2 at 100% power, all service water flow to the Unit 1 Charging Pump Service Water Subsystem was lost due to the pump becoming air bound. This abnormal condition affected the heat sink for the charging pump lubricating oil coolers and the intermediate heat sink for the charging pump mechanical seals.

Immediate attention was provided to return a flowpath to service. The affected Unit 1 pump was subsequently vented. Following verification of proper operation, the Unit 1 subsystem was returned to normal status.

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NRC Form 366

POW 28-06-01

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
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Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	8 6	— 0 2 9 —	0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

1.0 Description of the Event

On September 29, 1986 with Surry Units 1 and 2 at 100% power, Service Water (SW) flow to the Unit 1 Charging Pump Service Water (ChgPSW) subsystem was lost. The approximate time of the event was 1445 hours.

Earlier in the day, one of the redundant Unit 1 ChgPSW pumps (EIIS-P), 1-SW-P-10A, had been removed from service for replacement. Maintenance activities in the 1-SW-P-10A room required that grinding be performed on a pump support prior to pump replacement. The grinding activity resulted in actuation of a smoke detector which automatically closed a SW fire isolation valve. Due to a leak on a strainer blow down line in the SW supply line, closure of the SW fire isolation valve allowed air in-leakage which caused 1-SW-P-10B to become air bound.

2.0 Safety Consequences and Implications

During normal operation, the charging pumps are used as part of the Reactor Coolant Chemical and Volume Control System (CVCS) and take suction from the Volume Control Tank (VCT) (EIIS-CB). During accident conditions, with Safety Injection (SI) actuated, the charging pumps (EIIS-P) are used as High Head Safety Injection Pumps and take suction from the Refueling Water Storage Tank (RWST) (EIIS-BQ).

The ChgPSW pumps provide a heat sink for the charging pump lube oil coolers and the component cooling water subsystem (which is the heat sink for the charging pump mechanical seal coolers) (EIIS-CLR). Recent analyses and communications with the vendor indicate that no heat sink for the mechanical seal coolers is required. The effect of loss of heat sink to the charging pump lubricating oil coolers was monitored by the reactor operator on the plant computer. The highest bearing temperature observed during the event was approximately 160°F. Subsequent operating evaluation has revealed no pump degradation due to the short term lube oil temperature increase. Public health and safety were not affected during the event.

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3.0 Cause

The cause of the event was introduction of air into the Charging Pump SW supply line. Grinding activities in the cubicle that houses ChgPSW pumps 1-SW-P-10A and 2-SW-P-10A actuated the smoke detector and closed the SW isolation valve.
A leak on the blowdown line for the in-line strainer (EIIS-STR) in the SW supply line provided an air in-leakage path into the system.

4.0 Immediate Corrective Action

Operators were dispatched to locate the source of the problem and return the pumps to normal. The temperatures of the operating charging pump were monitored.

5.0 Subsequent Corrective Action

The leak at the in-line strainer was repaired. The Maintenance Predictive Analysis Group subsequently monitored the Unit 1 charging pump that had been in operation during the event and found its operating parameters to be normal.

6.0 Actions Taken to Prevent Recurrence

This is considered an isolated event, therefore, no additional actions were taken.

7.0 Generic Implications

None.

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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)
Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	1 OF 0 3

TITLE (4) Loss of Charging Pump Service Water System Caused by Failing to Vent A Service Water Strainer.

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)
1 0	3 0	8 6	8 6	— 0 3 1 —	0 0	1 1	2 6	8 6		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	
R. F. Saunders, Station Manager	8 0 4	3 5 7 - 3 1 8 4

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 October 30, 1986 with Surry Unit 1 at 100% power and Unit 2 at refueling shutdown and the reactor defueled, service water flow to the Unit 1 Charging Pump Service Water Subsystem was lost due to the pumps becoming air bound when a service water strainer was placed in service without being vented. This abnormal condition affected the heat sink for the charging pump lubricating oil coolers and the intermediate heat sink for the charging pump mechanical seals. Operation without service water to the charging pump service water system is prohibited by Technical Specification 3.14.

Immediate attention was provided by operators to return a flowpath to service. The affected Unit 1 pumps were subsequently vented. Following verification of proper operation, the Unit 1 subsystem was returned to normal status. The system was out of service for approximately 19 minutes. This report is submitted pursuant to 10CFR50.73(a)(2)(i).

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NRC Form 366 (9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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)
Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	8 6	— 0 3 1	— 0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

1.0 Description of the Event

On October 30, 1986 at 0202 hours, with Surry Unit 1 at 100% power and Unit 2 at refueling shutdown, with the reactor defueled, service water (SW) flow to the Unit 1 Charging Pump Service Water subsystem (EIIS-BI) was lost. Operation without service water to the charging pump service water system is prohibited by Technical Specification 3.14.

An operator was swapping the filter elements of an in-line duplex strainer (EIIS-STR) upstream of the operating Unit 1 ChgPsw pump (1-SW-P-10A) (EIIS-P) due to an indicated high differential pressure. When the standby filter element was placed into service, the discharge pressure of the operating pump decreased to zero. The ChgPsw header low pressure alarm annunciated and locked-in in the main control room and the standby pump (1-SW-P-10B) auto-started but failed to clear the low pressure alarm.

2.0 Safety Consequences and Implications

The ChgPSW pumps provide a heat sink for the charging pump lube oil coolers and the component cooling water subsystem (which is the heat sink for the charging pump mechanical seal coolers) (EIIS-CLR). Recent analyses and communications with the vendor indicate that no heat sink for the mechanical seal coolers is required. The effect of loss of heat sink to the charging pump lubricating oil coolers was monitored by the reactor operator on the plant computer. The highest bearing temperature observed during the event was approximately 143 degrees fahrenheit. This is an acceptable value and will not degrade the equipment. The public health and safety were not affected during the event.

3.0 Cause

The cause of the event was introduction of air into the ChgPSW pump supply line. When the standby filter element was placed into service, it was not filled and vented which resulted in the operating pump becoming air bound. It has not been determined why the standby pump failed to clear the low header pressure condition.

NRC FORM 366A (9-83)

NRC Form 366A
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)
Surry Power Station, Unit 1	0 5 0 0 0 2 8 0	8 6	— 0 3 1 —	0 0	0 3 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Subsequent investigation of the event revealed an accumulation of marine growth in the Unit 2 Service Water supply line to the ChgPSW pump and control/relay room area chiller subsystems. This growth reduced the interior pipe size of the supply line and increased system losses. The increase in suction side losses is believed to be a contributor to the loss of SW events.

4.0 Immediate Corrective Action

Operations personnel were dispatched to identify and correct the problem and return the pumps to service. The control room operator monitored the temperatures of the operating charging pump on the plant computer.

5.0 Additional Corrective Actions

The affected Unit 1 pumps were successfully vented and were returned to service at approximately 0224 hours. The system was out of service for approximately 19 minutes.

6.0 Actions Taken to Prevent Recurrence

Operators have been instructed to ensure in-line strainers are filled and vented prior to placing them into service. The marine growth was cleaned from the Unit 1 and 2 service water supply lines.

7.0 Similar Events

Unit 1 LER 86-024.
Unit 1 LER 86-030.

8.0 Manufacturer/Model Number

Not required.

NRC FORM 366A

NRC Form 366

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)
Surry Power Station, Unit 2	0 5 0 0 0	1 OF 0 3

TITLE (4): Inoperable Charging Pump Component Cooling Water Pumps

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	1 1	8 6	8 6	— 0 1 0 —	0 0	0 7	2 9	8 6		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): N

POWER LEVEL (10): 1 0 0

X 50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
R. F. Saunders, Station Manager	804 357-3184

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	CC	P	G 2 0 0	Y					
X	CC	P	G 2 0 0	Y					

SUPPLEMENTAL REPORT EXPECTED (14): YES (If yes, complete EXPECTED SUBMISSION DATE) [ ] NO [X]

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On 7/11/86 with Unit 1 in refueling shutdown and Unit 2 at 100% power, operators were attempting to return the 'A' charging pump component cooling water pump to service following emergency maintenance. At 1518 hours, the redundant 'B' pump, which had been supplying cooling water to the charging pump seal coolers, lost discharge pressure. This resulted in both pumps being inoperable. It is assumed that air introduced into the system during maintenance on the 'A' pump caused the 'B' pump to become vapor bound. The 'A' pump was vented, water was added to the system, and the pump was returned to service at 1825 hours. Subsequently, operability of the 'B' pump was demonstrated, and it was also returned to service.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Surry Power Station, Unit 2	0 5 0 0 0 2 8 1	8 6	— 0 1 0	— 0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Inoperable Charging Pump Component Cooling Water Pumps

1) Description of Event

On July 11, 1986, with Unit 2 at 100% power and Unit 1 in refueling shutdown, emergency maintenance was being performed on 2-CC-P-2A, the Unit 2 'A' charging pump component cooling water pump (EIIS CC). At that time the redundant pump, 2-CC-P-2B, was in operation supplying cooling water to the charging pump seal coolers. At 1518 hours, while attempting to return the 'A' pump to service following the maintenance, the 'B' pump's discharge pressure dropped to zero. This resulted in both charging pump component cooling water pumps being inoperable. This event is contrary to Technical Specification 3.3.A.7.

2) Safety Consequences and Implications

During normal operation, the charging pumps are used as part of the Reactor Coolant Chemical and Volume Control System (CVCS) and take suction from the Volume Control Tank (VCT) (EIIS CB). During accident conditions, with Safety Injection (SI) actuated, the charging pumps are used as the Hi Head SI pumps and take suction from the Refueling Water Storage Tank (RWST) (EIIS BQ). The charging pump component cooling water pumps provide cooling water for the charging pump seals through a seal cooler. The normal maximum temperature of the VCT is 115 F and the maximum allowed temperature of the RWST is 45 F. The vendor has indicated that no seal cooling is required for the charging pumps as long as the pumped fluid is below 115 F. Therefore, the loss of the charging pump cooling water pumps did not create an unreviewed safety question, and the health and safety of the public were not affected.

3) Cause

The charging pump cooling water system is a closed system consisting of two redundant cooling water pumps, two redundant intermediate coolers (cooled by service water (EIIS BI)), a head tank and 6 seal coolers (2 pr [illegible] harging pump). Shortly, following the initiation of the event, [illegible] was noted that a low level existed in the head tank. It was therefore assumed a large leak existed in the system and efforts were directed toward finding the leak. However, no significant leaks could be found. Therefore, it is speculated that air was introduced into the system du[illegible]ing maintenance on the 'A' pump which caused the 'B' pump to [illegible] vapor bound resulting in zero discharge pressure.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO 3150-0104
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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Surry Power Station, Unit 2	0 5 0 0 0 2 8 1	8 6	— 0 1 0	— 0 0	0 3 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

4) Immediate Corrective Action

Operators were dispatched to locate the source of the problem and return the pumps to operation. The temperatures of the operating charging pump were monitored and trended during the period the cooling water pumps were inoperable and no increase in temperatures were observed. Also, a Technical Specification Limiting Condition of Operation was entered and preparations were made to ramp the unit down if required.

5) Additional Corrective Action

The 'A' pump was properly vented and make-up water was added to the system and the 'A' pump was returned to service at 1825 hours after operability of the pump was demonstrated. Subsequently, operability of the 'B' pump was demonstrated and that pump was also returned to service.

6) Actions Taken to Prevent Recurrence

This is considered to be an isolated event, therefore, no additional actions were taken.

7) Generic Implications

None.

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(9-83)

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Prairie Island Unit 1	0 5 0 0 0 2 8 2	1 OF 0 4

TITLE (4) Simultaneous Inoperability of One Diesel Generator and One Diesel Cooling Water Pump Resulting From Component Failures During Testing

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 9	0 8	8 6	8 6	— 0 0 6 —	0 0	1 0	0 8	8 6	Prairie Island Unit 2	0 5 0 0 0 3 0 6
										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)	[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)		
[ ]	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)
Arne A. Hunstad, Staff Engineer	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
X	E K	D G	F 0 1 0	Y					
B	B I	T B G	X 9 9 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)

On September 7, 1986, both units were at steady-state power, Unit 1 at 100% and Unit 2 at 88% power. At 2355, during an operability test, D1 Diesel Generator failed to start after cranking for ten seconds. D1 was declared inoperable. At 0330, while running No. 22 Diesel Cooling Water Pump to prove operability per Technical Specification 3.7.B.2, a small oil line burst; the pump was shut down and declared inoperable. With these two components inoperable, a power decrease was begun on both units. Repair of the oil leak on No. 22 Diesel Cooling Water Pump was completed and at 0406 the pump was restarted and proven operable. The power decrease was halted and both units were returned to normal operation.

Cause of the inoperability of No. 22 Diesel Cooling Water Pump was the rupture of brass tubing, which was replaced with stainless steel.

Cause of the inoperability of D1 Diesel Generator was not immediately apparent but further investigation and testing revealed that leakage through the fuel header pressure return orifice check valve allowed the fuel oil header to drain during idle periods. The check valve was replaced.

This event is being reported voluntarily for information purposes. Health and safety of the public were not affected since offsite power sources were intact throughout the event. Operator actions were judicious and timely.

One previous instance of inoperability of one diesel generator and one diesel cooling water pump was reported as RO 80-06.

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NRC Form 366
(9-83)

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Prairie Island Unit 1	0 5 0 0 0 2 8 2	8 6	— 0 0 6	— 0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

On September 7, 1986, both units were at steady-state power, Unit 1 at 100% and Unit 2 at 88% power. An operability test of D1 Diesel Generator (DG) was to be done in preparation for taking No. 22 Diesel Cooling Water Pump (DCLP) (P) out of service for preventive maintenance. At 2355 D1 Diesel generator failed to start after cranking for ten seconds, and the Start Failure annunciator (ANN) and 86 Lockout were received. D1 was declared inoperable.

With D1 inoperable, testing in accordance with Technical Specification 3.7.B.2.(a) was begun. At 0028 on September 8, D2 DG was started to prove operability. After D2 was proven operable, No. 22 DCLP was started to prove operability. At 0330, after running a short time, tubing (TBG) to the lube oil low pressure alarm switch (PS) ruptured. Operators at the scene took local control and shut down the pump. At 0334, with D1 DG inoperable and No. 22 DCLP inoperable, a power decrease was begun on both units. Rather than test any more equipment, manpower was allocated to repair the oil leak on No. 22 DCLP. Repair of the oil leak was completed and at 0406 the pump was restarted and proven operable. The power decrease was halted and both units were shortly returned to normal operation.

CAUSE

Cause of the inoperability of No. 22 Diesel Cooling Water Pump was the rupture of brass tubing on which a pressure switch was mounted in a cantilever fashion. Engine vibration caused work-hardening of the brass tubing and eventual brittle fracture.

Cause of the inoperability of D1 Diesel Generator was not immediately apparent. Further investigation and testing was done as follows:

At 0138 on September 8, the 86 Lockout was reset so that it could be determined if the governor shutdown solenoid plunger was stuck in the shutdown position. The plunger was found to be in the proper position. At 0150, D1 was started from the control room. During this start, it was noted that D1 took an abnormally long time to start. It was suspected at this time that the failure of D1 to start was due to a fuel system problem. At 0726, D1 was again started; this time no problems were observed.

At approximately 0810, work was begun to investigate potential problems with the fuel system. Leakage tests were performed on the fuel oil pump discharge check valve (V) and the fuel oil pump suction piping back to the foot valve (V) in the day tank. These tests revealed no problems. The packing of the fuel oil hand priming pump (P) was replaced. The fuel oil pump discharge relief valve (RV) was removed and tested. The investigative work uncovered no problems which could have caused the failure of D1 to start.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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)
Prairie Island Unit 1	0 5 0 0 0 2 8 2	8 6	— 0 0 6 —	0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

On the morning of September 9, D1 was successfully started three times from the diesel generator room, while in local control. Prior to the second of these starts, the air supply to the governor oil booster was disconnected and capped to determine if this would adversely affect the ability of the diesel to start. It was found that without the oil boost, the governor was shower to respond, but the diesel still started within ten seconds. At 1203, D1 was started per its normal surveillance procedure to prove operability. At 1501, D1 was declared operable.

A schedule was developed for increased testing and further investigation of D1 to assure its reliability since the cause of its failure to start had not been determined. D1 was started successfully on the following days: September 9 through 12, September 15, and September 18. A special test was developed to determine if the fuel oil header was draining down excessively between starts. The fuel header pressure was monitored immediately following the operation of the fuel oil hand priming pump. This revealed that the pressure decay rate was dependent on the amount of time the diesel was idle.

On the morning of September 19, D1 was removed from service and the fuel header pressure return orifice check valve (V) was removed for inspection. The testing and inspection of the check valve revealed seat leakage which was caused by a nick in the rubber O-ring seat. The valve was replaced, and at 1115 D1 was started again and at 1224 D1 was declared operable.

The apparent cause of the D1 inoperability was leakage through the fuel header pressure return orifice check valve, which allowed the fuel oil header to drain during idle periods. The purpose of this spring check valve is to allow excess fuel oil to return to the day tank (TK) while the engine is operating and to prevent the fuel header from draining down while the engine is idle. Air is allowed to enter the fuel header from the clean fuel return line vents through the bodies of the injection pumps. This source of air, along with the leaky check valve, caused the fuel header to drain down.

Time between diesel starts was a factor. The typical interval between starts is two to three weeks; on this occasion the interval was 25 days. This apparently allowed draining to continue to the point that it affected diesel operation.

SAFETY CONSIDERATIONS

This event is being reported voluntarily for information purposes. Health and safety of the public were not affected since offsite power sources were intact throughout the event. Operator actions were judicious and timely.

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NRC Form 366A (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

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 1	0 5 0 0 0 2 8 2	8 6	— 0 0 6	— 0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTIONS

A temporary repair to the ruptured oil line on No. 22 Diesel Cooling Water Pump was made quickly. The oil line was permanently repaired by replacing the brass tubing with stainless steel tubing. This repair will also be done on No. 12 Diesel Cooling Water Pump.

The leaky check valve in the fuel system for D1 Diesel Generator was replaced. The similar check valve installed on D2 Diesel Generator will be inspected at the next scheduled preventive maintenance. In the interim, the hand priming pump is being operated daily to assure that the fuel oil header remains filled.

FAILED COMPONENT IDENTIFICATION

The leaking valve is a spring check valve supplied with the Model 38TD8-1/8 diesel generator made by Fairbanks-Morse.

SIMILAR PREVIOUS EVENTS

One previous instance of inoperability of one diesel generator and one diesel cooling water pump was reported as RO 80-06.

NRC FORM 366A (9-83)

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)
PRAIRIE ISLAND NUCLEAR GENERATING PLANT	0 5 0 0 0 2 8 2	1 OF 0 2

TITLE (4) Hose Failure During Testing Caused Inoperability of Second Diesel Cooling Water Pump With One Pump Already Out of Service

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)
1 2	2 7	8 6	8 6	— 0 1 1 —	0 0	0 1	2 1	8 7	Prairie Island Unit 2	0 5 0 0 0 3 0 6
										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): 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)	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 Report
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
Arne A. Hunstad, Staff Engineer	AREA CODE 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
X	B I		A 1 0 0	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 December 27, 1986, both units were at 100% power. No. 22 Diesel Cooling Water Pump (DCLP)(P) was out of service for planned maintenance. During the daily operability run of No. 12 DCLP (required by Technical Specifications when one Diesel Cooling Water Pump is out of service), a jacket water hose ruptured. The No. 12 DCLP was immediately shutdown and declared inoperable at 0848. At 0947, a load decrease was begun on both units since both diesel cooling water pumps were inoperable. A Notification of Unusual Event (NUE) was declared. Replacement of the jacket water hose on No. 12 DCLP was accomplished quickly; at 1008 the pump was declared operable and the load decrease was stopped. The NUE was terminated and a load increase to full power was begun.

Cause of the event was failure of a flexible hose made by Aeroquip Corp. Preliminary investigation indicates that expected service life of this hose is about 5 years; the hose had been installed in early 1980.

This event is being reported voluntarily for information purposes. Health and safety of the public were unaffected since offsite power sources were available throughout the event.

All the flexible hoses on No. 12 DCLP were replaced with hoses of a higher temperature rating. Hoses on No. 22 DCLP were replaced with hoses of higher rating last year. The hose replacement program is being reviewed for adequacy.

There have been no previous similar events.

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NRC Form 366
(9-83)

NRC Form 366A (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
PRAIRIE ISLAND NUCLEAR GENERATING PLT	0 5 0 0 0 2 8 2	8 6	— 0 1 1	— 0 0	0 2 OF 0 2

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

On December 27, 1986, both units were at 100% power. No. 22 Diesel Cooling Water Pump (DCLP)(P) was out of service for planned maintenance. During the daily operability run of No. 12 DCLP (required by Technical Specifications when one Diesel Cooling Water Pump is out of service), a jacket water hose ruptured. The No. 12 DCLP was immediately shutdown and declared inoperable at 0848. At 0947, a load decrease was begun on both units since both diesel cooling water pumps were inoperable. A Notification of Unusual Event (NUE) was declared. Replacement of the jacket water hose on No. 12 DCLP was accomplished quickly; at 1008 the pump was declared operable and the load decrease was stopped. The NUE was terminated and a load increase to full power was begun.

CAUSE

Cause of the event was failure of a flexible hose made by Aeroquip Corp. Preliminary investigation indicates that expected service life of this hose is about 5 years; the hose had been installed in early 1980.

SAFETY CONSIDERATIONS

This event is being reported voluntarily for information purposes. Health and safety of the public were unaffected since offsite power sources were available throughout the event.

CORRECTIVE ACTIONS

All the flexible hoses on No. 12 DCLP were replaced with hoses of a higher temperature rating. Hoses on No. 22 DCLP were replaced with hoses of higher rating last year. The hose replacement program is being reviewed for adequacy.

PREVIOUS SIMILAR EVENTS

There have been no previous similar events.

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NRC Form 366 (9-83)

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EXPIRES 8/31/85

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 0 3

TITLE (4)
Reactor Trip Caused by Instrument Inverter Failure

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 7	0 2	8 6	8 6	- 0 0 1 -	0 0	0 8	0 2	8 6	N	0 5 0 0 0
									N	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)

X 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE	
John C. Adams, Nuclear Production Engineer Fort Calhoun Station, Unit No. 1	4 0 2	4 2 6 - 4 0 1 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
B	E F	I N V T	E 2 0 9	Y					

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 2, 1986, at 0534, while the plant was operating at 100% power, the reactor and turbine generator were automatically tripped on low steam generator level after the failure of a safety related instrument inverter. The trip was initiated by a closure of the turbine control valves which was caused by the loss of 120 VAC instrument power to the electrohydraulic control unit. Other consequences of the loss of power included inoperability of the steam dump and bypass valves and failure of the feedwater valve rampdown circuitry. These failures combined to cause an abnormal post-trip pressure transient in the reactor coolant system. Alternate power was quickly restored to the failed instrument bus and, within a few minutes, the plant was placed in a normal hot shutdown condition.

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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)
Fort Calhoun Station, Unit No. 1	0 5 0 0 0 2 8 5	8 6	0 0 1	0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

During normal operation at 100% power, an instrument inverter trouble alarm was received in the control room at 0534 on July 2, 1986. Control room operators quickly diagnosed a failed instrument inverter feeding bus AI-40A and dispatched an equipment operator to the switchgear room to manually reenergize the bus by closing the breaker on a bypass transformer also feeding bus AI-40A. The inverter failure placed the Reactor Protective System (RPS) in a half-trip condition since the RPS operates on a two-out-of-four logic and the failed inverter was one of four feeding the independent channels of the RPS. About ten seconds after the inverter failure, a reactor trip occurred when a second channel trip was received on the steam generator B low level trip unit.

Several unusual transients were noted in the moments following the trip:

1. Reactor Coolant System pressure increased to approximately 2400 psia for a short period of time. This caused PORV's to be actuated.

2. Steam generator pressure increased to the setpoint of the secondary safety valves causing them to be actuated.

3. Overfeeding the steam generators resulted in abnormally high level and subsequent overcooling of the primary system. As a result, RCS pressure decreased to a low of about 1725 psia

4. Steam dump and bypass valves could not be opened.

5. The operating charging pump stopped and the two backup pumps could not be started.

Within a minute of the reactor trip, the equipment operator had reenergized the lost instrument bus and control room operators were soon able to restore the plant to normal shutdown condition.

A diagnosis of computer and recorder information revealed the following explanation for transients seen after the inverter failure. The deenergized instrument bus AI-40A supplies power to EHC panel AI-50 with no alternate power. A turbine first stage pressure transmitter which sends a signal to the EHC load control circuitry is powered from AI-50. Loss of power caused a loss of signal to the load control unit. This ultimately resulted in the turbine control valves going closed without a reactor trip. The load rejection before reactor trip explains the high pressure seen in the primary system and the low steam generator level earlier in the transient. The high steam generator pressure was due to the loss of a heat removal path that occurred when inverter power was lost to the steam dump and bypass controllers. Also, a relay which energizes to open the steam dump valves on a turbine trip receives its power from AI-40A. These valves again became operable when power was restored to the bus.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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EXPIRES 8/31/85

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	8 6	— 0 0 1	— 0 0	0 3 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The overfeeding of the steam generators after the trip occurred because the main feedwater regulating valves did not rampdown as they normally would. A relay which energizes after a trip to initiate the rampdown is powered from AI-40A and therefore did not perform its function when the reactor tripped. Operator action was required to restore steam generator level to normal once the overfeeding was discovered.

The loss of the inverter also caused deenerization of relays which control the operation of backup charging pumps. The loss of these relays would have shutdown the backup charging pumps if they had been operating (they were not). The operating pump should have kept running unless the charging pump selector switch was not in its normal position. When AI-40A was reenergized, all charging pumps regained operability. Investigation of this problem is continuing.

The loss of a safety related inverter does not put the plant in an unsafe condition. There are four such inverters which supply power to the four channels of the Reactor Protective System and to the Engineered Safety Features logic. Loss of a single inverter cannot prevent these systems from performing their functions. It is apparent, however, that the failure of inverter A led to several undesirable consequences. Several steps were taken to reduce the probability of this incident being repeated. These steps are summarized below.

An emergency modification was performed to transfer the power supply for AI-50 from bus AI-40A to bus AI-42B which is supplied by an inverter which has automatic transfer to alternate power. This reduces the probability that the initiating scenario will be repeated on the loss of an inverter. This modification was completed before the plant was returned to power. An Engineering Evaluation Assistance Request has been initiated to study the desirability of redistributing the loads on AI-40A so that the loss of a single inverter would not have all the consequences as described above.

The failure of an inverter due to a problem on the DC-DC converter has been seen before in other instrument inverters at Fort Calhoun Station, but this is the first time that such a failure has caused a reactor trip or any other kind of adverse consequence. Consultation with the vendor has been taking place to determine how to improve the reliability of the inverters.

The loss of load aspect of this event was compared to the loss of load analysis in the Updated Safety Analysis Report (USAR). The values of critical parameters during the transient were, in all cases, more conservative than those predicted in the USAR.

A similar loss of load trip occurred on May 28, 1976, in which the turbine control valves partially closed while the plant was operating at 100% power. That event was not caused by a loss of inverter power.

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APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Pilgrim Nuclear Power Station - Unit No. 1	0 5 0 0 0 2 9 3	1 OF 0 4

TITLE (4)
Loss of Offsite Power Due to Severe Winter Storm

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)
1 1	1 9	8 6	8 6	— 0 2 7 —	0 1	0 5	0 7	8 7		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): N

POWER LEVEL (10): 0 0 0

X 50.73(a)(2)(iv)

OTHER (Specify in Abstract below and in Text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Brian P. Lunn - Plant Engineer, Ext. 8241	6 1 7 7 4 6 - 7 9 0 0

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)

At about 0800 hours on November 19, 1986, Pilgrim Nuclear Power Station was in a cold condition/refuel mode when it experienced a loss of preferred offsite power during a severe winter storm. The emergency diesel generators started and loaded, supplying power to the emergency buses. The secondary offsite 23KV power supply also was available during this event except for a period of approximately three minutes. The safety systems responded as expected for the existing plant configuration.

Power was restored to the plant systems by approximately 1238 hours. Investigation and inspection determined the most probable cause for the loss of offsite power to have been the ice and snow associated with the storm in progress. No further corrective actions are planned. This event did not effect the health and safety of the public.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	8 6	— 0 2 7 —	0 1	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

At approximately 0800 hours on November 19, 1986, the Pilgrim Nuclear Power Station (PNPS) was in a cold condition with the mode switch in the "Refuel" position, when a severe winter storm caused a loss of preferred offsite power (LOP). In response to the LOP, both emergency diesel generators (EIIS Code EK) automatically started and loaded, supplying power to the emergency buses. The other engineered safety features also responded as expected for the existing plant configuration including appropriate portions of the Primary and Secondary Containment Isolation Systems (EIIS Code JM) and the Reactor Protection System (EIIS Code JC).

The operations staff responded as required by plant procedures, verifying and maintaining the reactor in a safe condition. The NRC Emergency Operations Center was notified of the event at approximately 0852 hours.

The Pilgrim Station preferred offsite power distribution system consists of an onsite 345 KV ring bus which connects the main and startup auxiliary transformers to two 345 KV transmission lines. At the time of the LOP, both transmission lines tripped as designed due to near simultaneous, detected faults. The plant can also be supplied with power from the local 23 KV grid. This backup offsite power supply was available during this event, except for a period of approximately three minutes, at about 0830 hours.

Investigative efforts were coordinated with the regional power transmission control center. Onsite efforts focused on the switchyard, with interviews and inspections conducted to verify proper operation during the LOP and to attempt to locate the source of the fault. Interviews with personnel in the switchyard area verified that no unusual or unexplained noise or responses were observed. Simultaneously the transmission center dispatched personnel to check the distribution lines.

In order to attempt to locate the detected fault, at about 0900 one 345 KV offsite transmission line was re-energized, and at approximately 1015 the other 345 KV line was re-energized, each with the respective disconnect switches open in the plant switchyard. Neither line indicated a continuing fault, and observers in the switchyard witnessed no problem. At approximately 1106, the plant switchyard was partially re-energized to verify its ability to operate. Again no faults or problems were indicated, and at about 1128 the balance of the switchyard and remaining transmission line were re-energized. At about 1133 normal power restoration was begun with full restoration completed at approximately 1238.

A follow up inspection of the transmission lines was performed with a helicopter as soon as the local weather would permit. No physical degradation or failure was observed.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	8 6	— 0 2 7	— 0 1	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Based on the inspections and investigation results, and the severity of the storm, it was concluded that the LOP was attributable to arcing of the high voltage lines due to locally heavy ice and snow.

In response to this event, the emergency diesel generators started and loaded automatically, supplying power to the emergency buses. The other emergency safety features responded as expected for the existing plant conditions. Though not used, the backup offsite power supply provided an additional margin of safety. This event had no effect on the health and safety of the public. No further corrective actions are planned.

A somewhat similar event was reported in LER's 77-021T and 78-003X.

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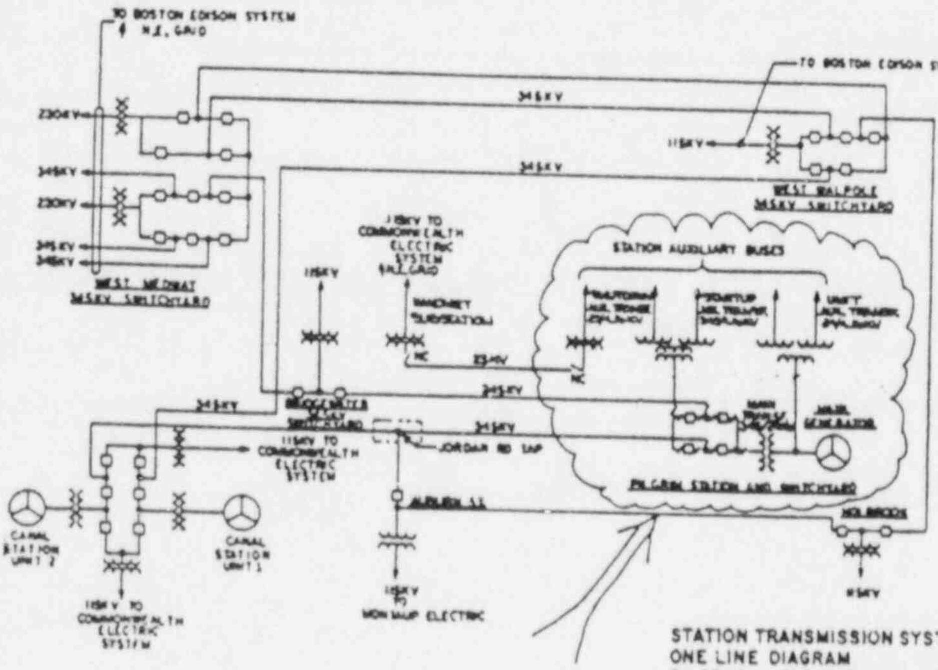
LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Pilgrim Nuclear Power Station	0 5 0 0 0 2 9 3	8 6	— 0 2 7	— 0 1	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)



STATION TRANSMISSION SYSTEM
ONE LINE DIAGRAM
PILGRIM NUCLEAR POWER STATION

NRC FORM 366A

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U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Point Beach Nuclear Plant

DOCKET NUMBER (2): 0 5 0 0 0 3 0 1

PAGE (3): 1 OF 1 4

TITLE (4): Failure of Unit 2 Main Steam Isolation Valves to Close upon Demand

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 9	2 8	8 6	8 6	0 0 4	0 1	0 3	1 0	8 7	None	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9):

POWER LEVEL (10): 1 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)(v)

LICENSEE CONTACT FOR THIS LER (12)

NAME: C. W. Fay, Vice President-Nuclear Power

TELEPHONE NUMBER: AREA CODE 4 1 4 2 2 1 - 2 8 0 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
B	S B	I S V	A 5 8 5						

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)

At 0250 hours on September 28, 1986 during a scheduled Unit 2 shutdown for refueling the main steam isolation valves 2CV-2017 and 2CV-2018 failed to close upon demand from the manual pushbuttons in the control room. The valves did close when operations personnel applied force to the operating arm of each valve. The valves were disassembled and inspected to determine the failure mode. The failure appears to have been due to excess packing friction in both valves with additional friction in one valve's operating cylinder. Once the failure mode was identified the valves were repaired and reassembled. Both valves were tested as required by Technical Specifications for a closure time of less than 5 seconds.

On January 17, 1987, during testing 2CV-2017, the disc stop broke and the disc stuck open. The disc stop was subsequently repaired and 2CV-2017 was returned to service

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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)
Point Beach Nuclear Plant	0 5 0 0 0 3 0 1	8 6	0 0 4	0 1	0 2 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

The main steam isolation valves (MSIVs) had been in the open position since December 31, 1985. Unit 2 was shut down for Refueling 12 on September 27, 1986. At 0250 hours on September 28, 1986, the Unit 2 reactor operator tried to shut the MSIVs from the control room as required by OP-3C, "Hot Shutdown to Cold Shutdown." The secondary side steam generator pressure at the time was approximately 300 psig with essentially no steam flow in the main steam lines. When the MSIVs did not shut (i.e., position indication lights did not change), an operator was sent to the valves to manually close the valves. The valves were manually closed by the operator applying force to the operating arm of each valve. It should also be noted that the non-return valves also did not close under the no flow conditions. The manual force needed to close the non-return valves was less than 7 ft-lbs. This amount of force is minimal compared to the large amount of force which would have been applied if a reverse flow condition would have occurred. Therefore, it is concluded that the non-return valves would have closed under these circumstances.

PLANT AND SYSTEM RESPONSES

Other systems operated as expected during the September 28 shutdown sequence.

SYSTEM DESCRIPTIONS

Point Beach is a two-loop pressurized water reactor with a main steam isolation valve (MSIV) located in each main steam line just outside containment. A non-return check valve is installed in the turbine hall down stream of each MSIV. MSIV 2CV-2017 and non-return valve 2017A are associated with the "B" steam generator. MSIV 2CV-2018 and non-return valve 2018A are associated with the "A" steam generator. The non-return check valves are installed to prevent the blowdown of the non-faulted steam generator in the event of a steam line break. For example, referencing the attached print, if a steam line break occurred between 2CV-2017 and 2017A assuming MSIV 2CV-2017 did not close, the "B" steam generator would blow down through the break until 2CV-2017 was closed. If 2CV-2017 failed to shut, the "B" steam generator would continue to blow down through the break until dry and 2017A would prevent the "A" steam generator from blowing down through the break. CV-2018 can also be closed manually from the control room to prevent blowdown of both steam generators. It should also be noted that each steam generator has a

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flow limiting orifice immediately down stream of the steam generator outlet. As can be seen from the above discussion, for the failure of both MSIVs in conjunction with a steam line break between an MSIV and a non-return valve the cool down of the reactor coolant system is limited by the non-return valves and the steam generator flow orifices.

The MSIVs at Point Beach are 30-inch self aligning, swinging disc, inclined seat, check valves manufactured by Atwood & Morrill Co. of Salem, Massachusetts. The drawing number for the valve is 20735-H. The valves are straight-through type having a swinging disc rotating on a heavy shaft with bushed bearings. Each of the valves has an external air operated cylinder which requires 80-100 psig to hold the valve open. Two series solenoid valves control the supply air which maintains the valves in an open configuration during operation. These series solenoid valves are closed upon receipt of a main steam isolation signal. An accumulator maintains air pressure in the cylinder if the supply air is lost. Two normally closed, energize to latch open, solenoid valves are provided for venting the air upon receipt of an isolation signal. When the air is vented, the MSIV closes assisted initially by a spring and then by steam flow impinging on the back of the disc.

The energy industry identification system component function identifier and system name of MSIVs are as follows:

Component function identifier: ISV
System name identifier: SB

GENERIC IMPLICATIONS

The Unit 1 MSIVs are the same type of valve as the Unit 2 MSIVs. It is possible that the Unit 1 valves have a similar problem with packing adjustment as discussed in this LER. The Unit 1 MSIVs will be inspected, and if necessary, repaired, tested and returned to service during the Unit 1 spring 1987 refueling/maintenance outage.

REPORTABILITY

This event is reported pursuant to 10 CFR 50.73.a.2.v.D, "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."

CAUSE

In order to determine the cause of the valve failing to close and provide for appropriate corrective action, a systematic approach for diagnosing the problem was developed. This approach consisted of step-by-step disassembly of each valve, while observing any signs that might have contributed to the valve hanging up. Special maintenance procedure (SMP) #754 was prepared to control the work activity and document the data and results obtained. In addition, a representative from the manufacturer witnessed the disassembly and assisted in problem assessment. Parameters measured included pressure in the operating cylinder required to start the valve opening, pressure needed to start the valve shutting, and pressure required to fully shut the valve. The following was found during the testing activity:

a. Adequate clearance was observed or demonstrated between the stuffing box bushings and the disc arms in both valves.

b. The shaft-to-stuffing box bushing clearances were within specified values for both valves.

c. There were no signs of galling on the shaft in bushing area, or in the bushings of either valve.

d. There were some signs of galling on the shaft in the gland pusher area and in the gland pusher. This galling was determined to not be recent, and was not considered to be a potential contributor to the current problem.

e. A slight misalignment was noted between the vertical planes of the air cylinder shaft and the valve operating arm. There were no signs of galling or rubbing in the linkage and there appeared to be sufficient margin to accommodate the misalignment.

f. Each stuffing box had about 12-13 rings of packing and the packing was tightly compressed to the bottom of the stuffing box.

g. The air cylinder of 2CV-2017 operated smoothly, requiring only about 1 psi pressure change to reverse it. The cylinder for 2CV-2018 operated in a jerky motion. This was considered to be abnormal and turned out to be a misalignment between the lower cylinder bushing and the bushing oil seal in the dashpot. Since the dashpot is no longer used, the bushing oil seal was removed under an approved modification in the interest of reducing all potential contributors to friction in the valve and operating system. The dashpot remains only as a protective can for the cylinder shaft outside the cylinder and limits downward travel of the cylinder when not attached to the valve.

h. Some play existed in the operator linkage which allows the air cylinder shaft and the valve shaft operating arm to move slightly when air pressure is released without actually moving the valve disc. This issue was discussed with the auxiliary operator who initially reported the valve had closed about 5-10% and it was concluded that the valve had not, in fact, moved at all during its test.

i. The packing in the valves was circumferentially wound with die-formed graphite ribbon, whereas the packing originally had been axially-laminated graphite. The wound graphite does a better job of sealing than the original material and is the presently-recommended packing; however, it will provide a higher radial load with the same axial load in comparison to the laminated packing. This may increase the friction on the MSIV shaft.

CONCLUSIONS

The following conclusions were reached as a result of the testing performed:

a. The reason that 2CV-2017 failed to close was solely excessive packing friction.

b. Valve 2CV-2017 did stick fully open during testing. It did not close 5-10% as previously thought.

c. The failure of 2CV-2018 to close was due to a combination of packing friction and excessive friction in the operating cylinder. It is believed that if the operating cylinder had been working correctly, the valve would have closed.

d. The reason for the change in friction load after the valves had acceptably passed IT-285 (Technical Specification required test for closing time) cannot be explained. A number of theories exist, but none can be substantiated.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Point Beach Nuclear Plant	0 5 0 0 0 3 0 1	8 6	— 0 0 4	— 0 1	0 6 OF 1 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

One theory is that the friction load may have been just below the load required to prevent initial motion of the valve during the test and as the valve sat in the open position the static or break-away friction increased slightly due to flow of the packing into the valve shaft irregularities. If the static friction is not overcome, the static-to-dynamic friction load reduction and valve momentum forces would not be realized. Both of these would affect valve closure during test performance.

e. A definitive statement that the valve would have closed during a steam line break accident with steam flow cannot be made. However, since we have had problems in the past with holding the valve in the full open position when flow is present in the line, this would indicate that there is a force which attempts to pull the disc down in the flow stream.

CORRECTIVE ACTIONS

The following corrective actions have been implemented:

a. Spacers have been installed in the stuffing box bottom to reduce the number of packing rings from 12-13 to 8-9. This task was accomplished through an approved modification request and in accordance with discussions with the manufacturer.

b. Prior to the Unit 1 refueling/maintenance outage in April 1987, modifications will be made to change the air system to facilitate testing of the valves. The inservice test will be modified to collect more data than a simple pass/fail of the Technical Specification limit for the closing time. These modifications will be done on Unit 2 by the start of the 1987 fall refueling/maintenance outage.

c. Even though we have not experienced a problem with the Unit 1 MSIVs, they will be modified to reduce the number of packing rings similar to Unit 2 during the spring 1987 outage.

d. The details of this event will be disseminated to operating and maintenance personnel with special emphasis being placed upon the importance of not tightening valve packing without subsequent post maintenance testing to verify valve operability. Post-maintenance testing is required by PBNP 3.1.3, "Maintenance Work Request."

e. A modified IT-285 valve stroke test was performed upon completion of the maintenance of the subject valves. Results indicated that 2CV-2017 closed within 1.5 seconds and 2CV-2018 closed in 2.5 seconds. These results are well within the Technical Specification required stroke time of 5 seconds.

SAFETY ASSESSMENT

Failure of both MSIVs to shut upon demand could have an effect on a steam line break event. Failure of the MSIV to close would result in the faulted steam generator blowing down completely. This result is the same as the result of the steam line break happening upstream of the MSIV. It should be noted that Point Beach is analyzed for a steamline break which involves blowdown of one steam generator. As discussed above, a steam line break upstream of the non-return valve in one steam line will not result in the blowdown of the non-faulted steam generator due to the function of the non-return valve.

The worst case steam line break conditions concurrent with the failure of both MSIVs to shut would be a steam line break down stream of the non-return valves. This accident would result in a rapid cooldown of the reactor coolant system until both steam generators were dry or the MSIVs were shut. Emergency Contingency Action Procedure ECA 2.1 addresses operator actions in these circumstances. Note that 2017A and 2018A and downstream piping are located in the turbine hall. It is, therefore, possible to reach and manually close these valves (if necessary) without exposure to hot steam from a break in this area. Manual closing of the MSIVs under these conditions would result in regaining control of the reactor coolant system cooldown rate. The flow limiting feature of the flow orifices at the outlet of each of the steam generators will limit the initial cooldown rate until the MSIVs are shut.

The overall conclusion is that the MSIVs would have closed manually resulting in the ultimate ability to control reactor coolant pressure and decay heat removal using auxiliary feedwater flow and dumping steam through atmospheric steam dumps.

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SIMILAR OCCURRENCES

December 31, 1985, after a trip on Unit 2, 2CV-2017 failed to close when the operator in the control room tried to close the valve manually. During a post-trip investigation a valve packing was adjusted and the valve passed the stroke test required by Technical Specifications. The test was performed three times with all three test times being less than three seconds. Refer to LER 85-005-00, "Reactor Trip Due to Loss of Load" for further details on this event.

On January 17, 1987 during an inservice test (IT-285) 2CV-2017 failed to close completely within the Technical Specification required time of 5 seconds. The valve was tested 4 times, each with relatively the same results. In each instance, the valve closed easily to within 85 to 90% closed within approximately 2-3 seconds. The valve was tested a fifth time and the operating air cylinder which normally holds the valve open during operation was bled down to 0 psig. The valve again closed to 85% closed. The torque to close the valve completely was measured at less than 50 ft-lbs. The valve was again reopened and tripped closed. The valve closed to a 90% closed position. Since it was suspected that there may have been a different pressure in the "B" steam generator, the "A" atmospheric dump valve was opened and the "B" MSIV 2CV-2017 closed easily from the 90% closed position.

The packing of the valve was subsequently loosened and retorqued to determine if the packing was a contributing factor to the closing difficulties. The valve was then closed completely three times. Each closure required less than 2.5 seconds. After the last closure, one more test was to be run to determine if the three good closures were due to a differential pressure between the two steam generators because of opening of the "A" atmospheric dump valve. When the valve operating air cylinder was bled completely, 2CV-2017 remained in the fully open position. The valve appeared to be further open than normal and it was theorized that the valve open stop had broken. The valve body was opened, the stop was found to be broken and repaired, and the valve returned to service. Further details can be found in attachment "A."

ATTACHMENT "A"

MSIV 2CV-2017 FAILURE TO CLOSE

Unit 2 was placed in a hot shutdown condition on January 17, 1987 to repair a packing leak on a reactor coolant system loop flow transmitter root isolation valve. Following the repair of the transmitter, a test of the Unit 2 main steam isolation valves (MSIVs) was performed to verify the continued operability of these MSIVs which had stuck open during the last outage. A temporary change to IT-285 was initiated to test the MSIVs at hot shutdown and to include measurement of the pressures in the air-operating cylinders required to stroke the valves.

The testing was performed on the morning of January 17, 1987. All steam loads were minimized including drawing steam from the Unit 1 for part of the Unit 2 gland steam system. Testing of the "A" valve was performed first with valve closure times in the three tests of 1.80, 1.47, and 1.35 seconds. It should be noted that no stroking of the valve had occurred prior to the first IT-285 test trip.

Part of the changes to IT-285 included the measurement of the pressure in the air operating cylinder during definable positions of the valve after valve closure testing.

The test results along with reference as left data from the fall 1986 refueling outage are as follows:

Valve position	"A" MSIV (2CV-2018) As found press. Test #: 1	2	3	As left press. 1986
Starts to close	33	34	33	34
Reaches 80% closed	17	16	16	19
Starts open from 20%	59	59	59	57
Just reaches 100% open	83	84	84	81

These pressures indicate essentially no change from the performance of the valve at the end of the outage in the fall of 1986. The slight increase (approximately 9%) in pressure to open the valve could indicate an increase in the friction of the shaft against the packing in the valve.

The "B" MSIV (2CV-2017) was then trip tested with the following results. Again it should be noted that no prior stroke had been done.

Valve stroked to 85% closed position in 3.07 sec.
Valve stroked to 85% closed position in 2.27 sec.
Valve stroked to 90% closed position in 3.03 sec.
Valve stroked to 90% closed position in 2.70 sec.

In each case the valve disc appeared to drop to the 85-90% closed position rather rapidly then hit a cushion. The control room was contacted to see if there was any difference in steam generator pressures and that both reactor coolant pumps were operating. Both pumps were running and there was no discernable difference in pressure between the steam generators. A plant process computer printout of the steam generator pressures obtained after the event confirmed the lack of an indicated pressure difference. Instrument & Control personnel however believe that a small pressure differential could exist even without indication in the control room due to the allowable inaccuracies in the instrumentation.

Following is the pressure data similar to the "A" MSIV for the air operating cylinder:

Valve position	"B" MSIV (2CV-2017) As found press. Test #: 1	2	3	As left press. 1986
Starts to close	13	14	13	16
Reaches 80% closed	3	3	3	6
Starts open from 20%	29	30	29	31
Just reaches 100% open	41	43	43	43

Essentially all the pressures are slightly lower than the as left pressures and would tend to indicate a difference in the pressure gauges rather than a difference in the valve. There was a slight increase in the pressure difference required to change the direction of the valve; about 5% on the average. This could be caused by a slight increase in the friction of the valve. In general, the valve performed as expected and the pressure results appeared to be essentially the same as left after the refueling outage.

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The pressure in the air operating cylinder was bled to zero after the final pressure test and the valve stopped at 85% closed. The torque required to fully close the valve was less than 50 ft-lb. The valve was reopened and tripped shut with the valve stopping at about 90% closed. The "A" steam generator atmospheric dump valve was opened to drop that generator's pressure slightly to make sure it was less than that in the "B" steam generator. This would ensure that there was no pressure differential between the "A" and "B" steam generator holding the "B" MSIV open. As soon as the "A" atmospheric dump valve was opened, the "B" MSIV closed fully. Therefore, it is felt that the valve would have gone completely shut if a small reverse pressure differential condition had not existed during the initial tests.

To evaluate the packing torque contribution to the closing resistance of the valve, the packing on the "B" MSIV was loosened and retorqued to 65 ft-lbs (the same as left in November 1986). A reduction in the packing torque was not considered desirable because a slight amount of steam leakage existed with the current torquing. The valve was then tripped and the valve closed completely with times of 2.09, 2.25, and 2.21 seconds. The reason the valve did not completely close instantly was due to friction from the packing or a small differential pressure between steam generators. The MSIV was opened one more time and the work was started to take pressure readings on the operating air cylinders during operation of the valve. When the air was being bled off, the valve remained in the fully open position. Attempts to close the valve by applying torque to the valve shaft were unsuccessful. The valve appeared to be further open than normal and it was theorized that the valve disc stop may have broken. The decision was therefore made to place the unit in the cold shutdown condition and open the valve body for inspection.

ASME Code Section VIII was reviewed for guidance to determine what would be required if welding would be required to repair the valve. In addition, the valve manufacturer was contacted for any additional guidance. It was determined the welding would be acceptable.

CAUSE

When the valve was opened the valve stop was lying on top of the valve disc and the disc had traveled further into the valve bonnet area and hung up on some of the remaining weld material which had held the valve stop to the valve body. One rap of a large hammer on the valve disc at the point of hang-up closed the valve. It does not appear that a significant loading had been applied to the valve shaft by the as-found condition.

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A good portion of the weld fracture on the valve stop was old. It appears to have initiated on the corner of the stop where the stop had been cut back several years ago to allow for additional disc travel. The original horizontal cut on the stop had been made by a grinding wheel and the arc from the cutting wheel extended into the piece left in the valve. This appears to have been the most likely location for the initiation of the point of fracture. It should also be noted that the old weld was a fillet which had indication of areas of poor fusion.

GENERIC IMPLICATIONS

The design of the disc stop on three other valves (1CV-2018, 1CV-2017, and 2CV-2018) of this type at Point Beach is the same. However, we do not believe that the other valves are as susceptible to cracking of the fillet welds as experienced in 2CV-2017. 2CV-2017 has a larger valve operator air cylinder than the other three valves. Often, when the valves are opened, there is a differential steam pressure across the valve which requires a much larger operating air cylinder pressure to move the valve from its closed seat. At times the steam pressure differential is adequate to prevent the opening of the valve, thus requiring the opening of the atmospheric dump valve to reduce pressure in the effected steam generator. When the atmospheric dump valve is opened, the MSIV opens very quickly and in the case of 2CV-2017, the valve slams against its disc stop. Because 2CV-2017 has a much larger air operating cylinder, the pressure to open the valve is usually in the 40 psig range, whereas the other valves at Point Beach usually require at least 80 psig. Thus, if the pressure in the air cylinder for 2CV-2017 builds up to near instrument air pressure (100 psig) before the valve opens, there can be enough stored energy to quickly take the valve all the way open to the disc stop. In addition, the vent hole on the nonpressurized side of the air cylinder piston for 2CV-2017 is 1 inch line whereas for the remainder of the valves this line is 1/8 inch in diameter. The 1 inch vent is large enough to prevent the buildup of air pressure on the back side of the operating piston during fast movement. In the case of the other valves, the small vent line allows the buildup of a back pressure on the piston during quick movement of the valve which cushions the movement of the valve into the stop.

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CONCLUSIONS

Based on the facts presented here, we believe the valve can be considered operable at the time of the initial testing. It is felt that the differential pressure between the two steam generators accounts for the behavior of 2CV-2017 during the initial testing. It is also believed there is no reason for immediate concern about the integrity of the disc stops in the other MSIVs because of the differences in the air cylinders. We will, however, issue maintenance work requests to inspect the disc stops on the three remaining MSIVs when convenient.

REPORTABILITY

Although subsequent evaluation determined the broken disc stop was not reportable, a courtesy emergency notification system call was made at 1244 hours on January 17, 1987.

CORRECTIVE ACTIONS

The valve body was cleaned up and the area subjected to an informational die penetrant test (PT) to make sure no cracks had propagated into the valve body. The old disc stop piece was beveled, cleaned, and welded back in. The piece was reinstalled with a groove and fillet weld and an informational PT was done on the final weld surface.

After the valve disc stop was reinstalled the valve was stroked prior to reinstallation of the cover to verify free movement of the valve. The pressures required to stroke the valve were measured as follows:

Valve position	As found press. (psig) Test 1	Test 2
Start valve open	22	22
Valve full open	39	39
Valve starts shut	19	19
Valve full shut	2	1

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These values are comparable to the values taken hot and to those taken during the testing performed during the last refueling outage. Full open and full closed indication was also verified. Finally, the valve was tripped from a fully open position and it fully closed.

When the valve was reassembled and the unit was returned to operating temperature, IT-285 was again performed. The result of this testing was acceptable. It should be noted that the leakage of steam through the packing has increased.

We are considering the installation of an orifice plug in the vent port of the air cylinder for 2CV-2017 when opening the valve. Some testing would be done to determine the impact this installation would have on the valve closing time. If there is little or no impact, the plug could be permanently installed.

SAFETY ASSESSMENT

The safety assessment for the supplemental report is the same as the original report.

SIMILAR OCCURRENCES

This is the first case of a broken stop found in an MSIV.

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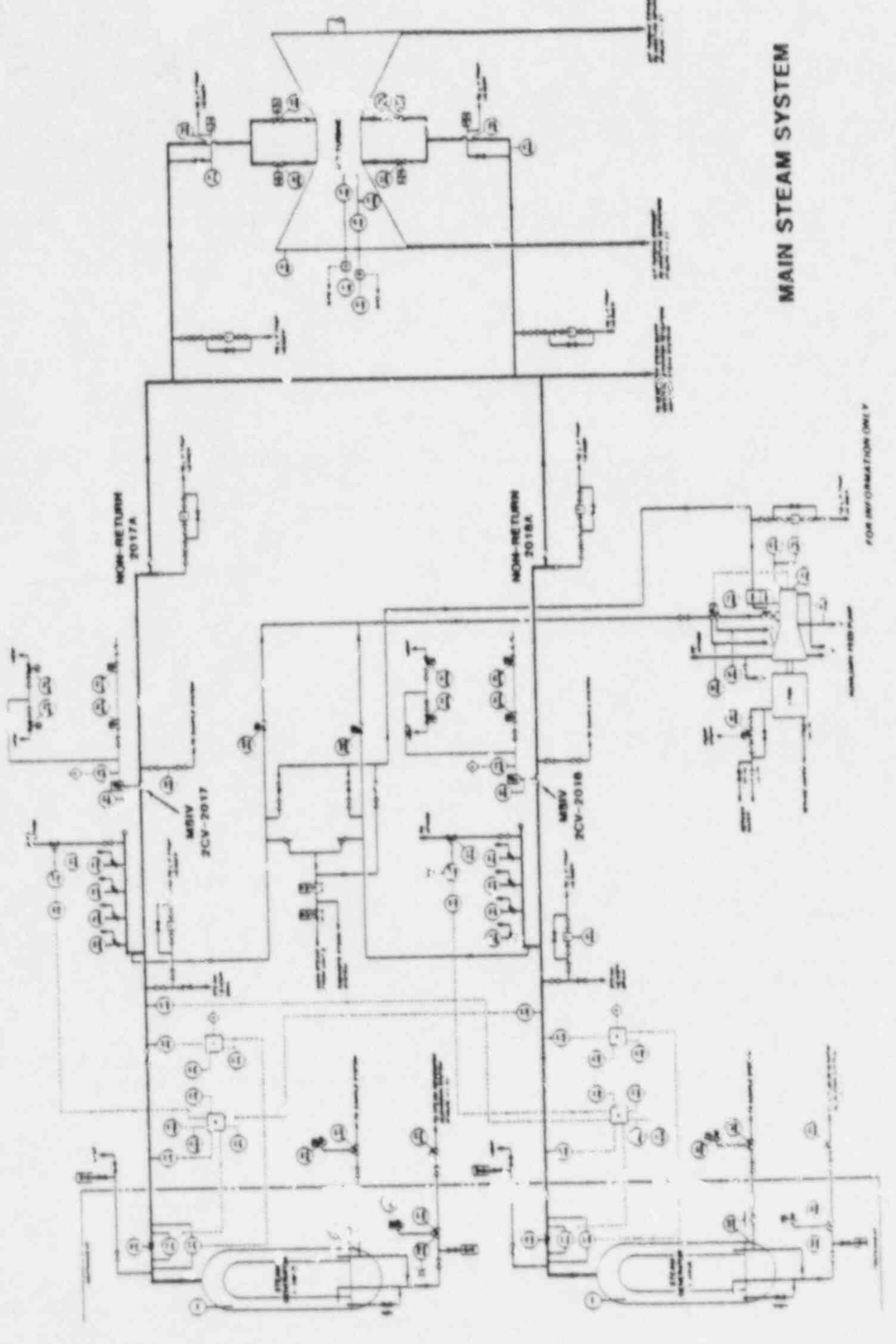
MAIN STEAM SYSTEM
NON-RETURN 2017A
NON-RETURN 2018A
MSIV 2CV-2017
MSIV 2CV-2018
FOR INFORMATION ONLY

NRC Form 366 (9-83)

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LICENSEE EVENT REPORT (LER)

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DOCKET NUMBER (2)	0 5 0 0 0 3 1 8
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TITLE (4)	Reactor Trip Caused by Reactor Pump Surge Capacitor Failure

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	0 5	8 6	8 6	– 0 0 6 –	0 1	0 2	0 5	8 7		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)	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	
L. S. Larragoite, Licensing Engineer	3 0 1	2 6 0 - 4 9 5 3

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	A B	C A P	W 1 2 0	Y					
E	S B	F S V	A 6 1 0	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)

At 2358 on September 5, 1986, while operating in MODE 1 at 100% power, the Calvert Cliffs Unit 2 reactor automatically tripped on a low reactor coolant flow trip signal initiated by Reactor Coolant Pump (RCP) 21A breaker tripping open. The atmospheric steam dump valve for 22 Steam Generator (SG) failed to reseat following the trip causing additional primary cooldown and was manually isolated. At 0010 on September 6, 1986 an Auxiliary Feedwater Actuation Signal was generated due to a temporary low level in SG 22. The low level occurred while manually controlling SG levels to limit the primary cooldown rate. Troubleshooting determined the RCP breaker trip was due to a failed surge capacitor. The surge capacitor was replaced and the pump was returned to service at 0825 on September 6, 1986. The atmospheric steam dump failed to reseat due to its associated steam dump solenoid valve leaking air by its seats and maintaining pressure on the actuator. The solenoid valve internals were replaced.

The corrective action is to replace RCP surge capacitors with inductors located at the RCP breaker switchgear. Additionally, the atmospheric steam dump valve positioner's technical manual was changed (upon recommendation by the manufacturer) to include a shimming procedure for the positioner's linkage.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

On September 5, 1986, at 2358, while Calvert Cliffs Unit 2 was operating in MODE 1 at 100% power, the reactor (EIIS AC-RCT) was automatically tripped on a Low Reactor Coolant Flow Trip signal resulting from Reactor Coolant Pump (RCP) (EIIS AB-P) 21A breaker (EIIS AB-BKR) tripping open. Emergency Operating Procedure (EOP)-0 (Post Trip Immediate Actions) and EOP-1 (Reactor Trip) were properly carried out.

Following the trip, the primary cooldown rate was faster than expected and the atmospheric steam dump valve (EIIS SB-PCV) for 22 Steam Generator (SG) (EIIS SB-SG) was noted to still be open. The dump valve was manually isolated at 0010 on September 6, 1986. While manually controlling SG level to limit the primary cooldown rate, an Auxiliary Feedwater Actuation Signal (EIIS JB) was generated at 0010 when 22 SG level passed through the actuation setpoint (-170 inches) and reached a level of -175 inches. The motor driven Auxiliary Feedwater Pump (EIIS SJ-P) started automatically as expected and was secured when SG level was promptly restored.

Post trip review data showed the reactor protection system (EIIS-JC) functioned properly and no Technical Specification limits were exceeded. There are no safety consequences since this event was much less severe than the Loss of Coolant Flow Analysis in the Final Safety Analysis Report, Section 14.9. Also, the reactor was at 100% power, so the event would not have been more severe under alternative circumstances.

Investigation revealed high pressure air was leaking by the seat of the steam dump solenoid valve (EIIS SB-FSV). This valve applies high pressure air directly to the atmospheric steam dump valve actuator to allow quick opening. The valve internals of the steam dump solenoid were replaced. Although not believed to be related, the atmospheric steam dump's positioner (EIIS SB-CPOS) was also replaced due to signs of rubbing wear on the linkage. Upon completion of repairs the atmospheric steam dump was stroke tested in the normal and quick actuation modes.

Further inspection of the atmospheric steam dump's positioner showed the cause of the rubbing wear was due to the linkage being improperly aligned within the positioner's box. Upon recommendation by the manufacturer, the Technical Manual for the positioner was changed to include a shimming procedure (using flat washers at the joints) for the linkage.

Both the differential and ground overcurrent relays were found tripped on 21A RCP breaker. Investigation determined the root cause to be a RCP surge capacitor (EIIS AB-CAP) internally shorted to ground. There are three surge capacitors (one for each phase) installed for each RCP motor. Although not needed while the pump is operating, these surge capacitors were installed to provide protection to the stator insulation from the initial voltage surge seen by the windings when the feeder breaker is closed. The protection provided decreases as the surge capacitors distance from the motor increases. Consequently, the surge capacitors are mounted directly on the RCP motor.

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The manufacturer has provided recommended maximum operating conditions for these surge capacitors which are: less than 100 rads/hr, 70 psig external pressure, 10% above nameplate rated voltage, 149 degrees Fahrenheit ambient temperature and a vibration of 0.2 g. Of these, both temperature and vibration appear to be exceeded during operation. Although RCP bays are approximately 120 degrees Fahrenheit, containment cooling air does not reach inside the capacitor enclosures. Temperature dots installed on RCP surge capacitor porcelain housings indicate that at one time during a 15 month period, the temperature was 180 degrees Fahrenheit but 190 degrees Fahrenheit. The measured vibration on the RCP motor casing is less than the manufacturer's recommended maximum vibration. However, measurements taken on the surge capacitor terminal boxes for Unit 1 RCPs (during the fall 1986 refueling outage) showed maximum peak g vibration levels ranging from 0.28 to 2.40.

As noted in LER 86-04 for the Unit 1 trip on July 20, 1986, BG&E has reviewed both the effectiveness of surge capacitors in providing protection to winding insulation and an alternate system which can provide the same protection. The electrical system from breaker to RCP motor has been modeled by computer to show the voltage surge seen by the stator windings without any protection, with surge capacitors, and with inductors located at the RCP breaker switchgear. Additionally, our spare RCP motor has been used with an equivalent length of cabling and a pulse generator to experimentally obtain data to compare to the computer model. The model and experimental data compare favorably, show that surge capacitors do provide some reduction in the voltage surge, and that inductors are a viable alternative to surge capacitors. Additionally, since the RCP breaker switchgear is outside the containment, the potential problems associated with the environment of the containment are removed. Finally, inductors have an inherently greater reliability than capacitors.

BG&E has met with the RCP motor vendor. The above test data and computer model were reviewed and their surge protection expert concurs that inductors can provide the necessary protection to the RCP motor stator insulation. Therefore, Calvert Cliffs will replace RCP motor surge capacitors with approximately 100 uH inductors mounted at the RCP breaker switchgear.

Each surge capacitor consists of 54 capacitor "packets" electrically connected and stacked in series. Each "packet" is made of two thin metallic foil sheets, separated by a mylar dielectric, and wrapped in two more sheets of mylar. These are all enclosed in an insulating sheath (made of a glass filled polyester material) and housed in an airtight, helium filled porcelain container with a metal base plate.

All Unit 2 RCP surge capacitors were checked. Three surge capacitors were replaced due to a 3% increase in measured capacitance (from baseline data). This indicated a failure in at least two of the fifty-four surge capacitor packets with an associated decrease in voltage rating. Two surge capacitors had loose terminal lugs (EIIS E-CON). Although electrical continuity was present and no degradation in capacitance material was found, these surge capacitors were also replaced.

The reason for the loose terminal lugs on the surge capacitors is unknown. There are several possible causes: vibration, thermal expansion and contraction, manufacturing or design deficiencies, or mishandling. The surge capacitors are heavy (70 pounds), bulky (26 inches long and 8 inches in diameter) and the terminal lugs provide an easy surface to grab when handling. Additionally, lockwashers or equivalent devices are not used in the surge capacitor.

Calvert Cliffs Unit 1 has experienced similar events on April 2, 1976; October 24, 1977; October 26, 1977; June 6, 1983; and July 20, 1986. Unit 2 has had similar events on September 7, 1979 and April 15, 1984. In each case, a low Reactor Coolant Flow Trip resulted from a RCP breaker opening due to a shorted surge capacitor. BG&E has noted several deficiencies in the design of surge capacitors and several improvements have been made by the manufacturer in their structural design. Surge capacitors presently used are the third modification to this style surge capacitor. Until the July 20, 1986 Unit 1 trip, all previous failures were occurring at the edge of the capacitor "packets" at the capacitor/insulating sheath junction. This mode of failure was the basis for previous modifications to reduce the possibility of abrasion to the mylar from the insulating boards rough interior.

As noted in LER 86-04 for the Unit 1 trip on July 20, 1986, an analysis was done on the failed capacitor material. Unlike the previous failures, this failure appeared to be the result of an arc tracking along the mylar dielectric from one foil strip to the other foil strip on the other side of the mylar dielectric. Although moisture could be one possible cause, a series of high temperature (up to 100 degrees Celsius) and high humidity environment tests on a good surge capacitor were inconclusive. Examination of the surge capacitors, removed from the September 5, 1986 Unit 2 trip, showed evidence of both external arc tracking along the packets' exterior as well as internal shorting within some packets through the dielectric material.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

FAILURE DATA:

Surge Capacitor	Westinghouse Electric Corporation Radiation Resistant Surge Capacitor (.05 uf) Style # 634A269A02
Steam Dump Solenoid Valve	Automatic Switch Company (ASCO) Solenoid Valve Model #8300C64
Atmospheric Steam Dump Positioner	Moore Products Co. Mode # 72G315

The contact for this event is L. S. Larragoite (301-260-4983.)

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DOCKET NUMBER (2): 0 5 0 0 0 3 4 1

PAGE (3): 1 OF 0 6

TITLE (4): HPCI/RCIC Inop Requires Entry into Tech Spec 3.0.3 Caused by Personnel Error During RCIC System Troubleshooting and Testing

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)
1 2	2 4	8 6	8 6	0 4 8	0 1	0 4	0 7	8 7	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): 2

POWER LEVEL (10): 0 0 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(a)(1)(i)
- [ ] 20.405(a)(1)(ii)
- [ ] 20.405(a)(1)(iii)
- [ ] 20.405(a)(1)(iv)
- [ ] 20.405(a)(1)(v)
- [ ] 20.405(c)
- [ ] 50.36(c)(1)
- [ ] 50.36(c)(2)
- [X] 50.73(a)(2)(i)
- [ ] 50.73(a)(2)(ii)
- [ ] 50.73(a)(2)(iii)
- [ ] 50.73(a)(2)(iv)
- [ ] 50.73(a)(2)(v)
- [ ] 50.73(a)(2)(vii)
- [ ] 50.73(a)(2)(viii)(A)
- [ ] 50.73(a)(2)(viii)(B)
- [ ] 50.73(a)(2)(x)
- [ ] 73.71(b)
- [ ] 73.71(c)
- [ ] OTHER (Specify in Abstract below and in Text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Lewis P. Bregni, Compliance Engineer

TELEPHONE NUMBER: AREA CODE 3 1 3 586-1617

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)

At 1015 hours on December 26, 1986 Fermi 2 was in OPERATIONAL CONDITION 2 (STARTUP), operating at 920 psig, 530 degrees Fahrenheit, and 8 percent reactor power. During calibration of an instrument channel, two occurrences of Reactor Core Isolation Cooling (RCIC) and High Pressure Coolant Injection (HPCI) being inoperable resulted. Entry into Technical Specification 3.0.3 was required following each event.

This event was caused by a personnel error which resulted from not recognizing that the calibration procedure for the RCIC flow channel causes RCIC to become inoperable. Contributing to the event was inadequate communication between Operations personnel and the persons performing the test, and a personnel error during restoration of the RCIC pump flow controller setpoint. As corrective actions, training will be provided on Technical Specification 3.0.3, the personnel involved in this event were counseled, and required reading related to independent verification was provided to licensed operators. Additionally, instrument surveillance procedures will be revised to clarify plant operations impacts, and training will be provided regarding the RCIC pump flow control circuit interface with HPCI. This event did not involve any failed components or systems.

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NRC Form 366
(9-83)

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NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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)
Fermi 2	0 5 0 0 0 3 4 1	8 6	— 0 4 8	— 0 1	0 2 OF 0 5

TEXT (If more space is required, use additional NRC Form 366A's) (17)

At 1015 hours on December 26, 1986 Fermi 2 was in OPERATIONAL CONDITION 2 (STARTUP), operating at 920 psig, 530 degrees Fahrenheit, and 8 percent reactor power. Between 1248 hours on December 24 and 1550 hours on December 26, calibration activities for a Reactor Core Isolation Cooling (RCIC)(BN) System header flow instrument channel resulted in two occurrences of the RCIC System being inoperable. During these occurrences, the High Pressure Coolant Injection (HPCI)(BJ) System was also inoperable.

In OPERATIONAL CONDITIONS 1 (POWER OPERATION), through 3 (HOT SHUTDOWN), operability of both HPCI and RCIC is required when steam dome pressure is above 150 psig. When both HPCI and RCIC are required, but inoperable, entry into Technical Specification 3.0.3, and initiation of a plant shutdown within one hour is required. The HPCI System had been inoperable for a scheduled system outage since 1755 hours on December 23, 1986.

During a routine performance of the CHANNEL CHECK procedure for the Remote Shutdown Panel (RSP) instrumentation, at 0230 hours on December 24 Operations personnel (non-licensed, utility) noted that the RCIC header flow indicator (FI) located at the Remote Shutdown Panel was reading 100 gpm. This was not expected since the RCIC System was not in operation at the time, and the RCIC flow indicator located in the main control room was reading 0 gpm.

Subsequently, a work order was issued to investigate the discrepancy, and recalibrate the RCIC pump flow indicator located at the RSP if necessary. In order to facilitate the investigation, at approximately 1215 hours Maintenance personnel (non-licensed, utility) were directed by their foreman to perform a calibration surveillance of the RCIC flow indicator at the Remote Shutdown Panel.

Prior to initiating work on the flow channel, the surveillance procedure was reviewed by the Maintenance personnel who were going to perform the surveillance. The procedure was then presented to the Nuclear Assistant Shift Supervisor (NASS)(licensed, utility) for review and work authorization. The procedure was reviewed by the NASS without comment and released to the field for execution.

NRC FORM 366A (9-83)

*U.S. GPO 1984-0-624-538/455

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fermi 2	0 5 0 0 0 3 4 1	8 6	— 0 4 8	— 0 1	0 3 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Surveillance activities involving the flow channel were initiated at approximately 1250 hours. During performance of the surveillance the output readings from the RSP flow indicator loop were found to be out-of-tolerance. Further investigation indicated that the flow indicator was within the calibration range, and that the out-of-tolerance flow readings were originating in either the RCIC flow loop transmitter (FT) or the associated flow loop square root signal converter.

The Maintenance personnel who were performing the calibration were only authorized to perform the calibration surveillance and recalibrate the RSP flow indicator. As a result of their limited work scope authorization, at 1720 hours it was determined that any further work on the flow loop would have to be performed under a more specific work package and the surveillance was exited. The RCIC flow loop was restored to the as-found configuration at this time.

The prerequisites for the calibration procedure state that performance of the procedure will cause the RCIC flow controller to be inoperative. However, when the procedure was reviewed by the NASS he did not take notice of the precaution. Although the Maintenance personnel noticed the precaution they neglected to ensure that the NASS was also aware that RCIC would be inoperable. As a result, performance of the calibration procedure resulted in both HPCI and RCIC being inoperable simultaneously.

Additionally, when the Maintenance personnel exited the surveillance they did not notify the Nuclear Shift Supervisor (NSS)(licensed, utility) that either the square root converter or the flow transmitter was not functioning properly, as required by procedure. As a result, it was not recognized that RCIC was potentially inoperable as a result of the flow loop being out-of-tolerance. In each case, as a result of inadequate communications proper actions were not taken to prevent or respond to this event.

The NSS on the next shift recognized that either the square root converter or the flow transmitter was not functioning properly. This was the first time that the problem was recognized by a member of the Operations staff.

NRC Form 366A (9-83)

U.S. NUCLEAR REGULATORY COMMISSION

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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)
Fermi 2	0 5 0 0 0 3 4 1	8 6	— 0 4 8	— 0 1	0 4 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The NSS identified the problem when a Maintenance worker delivered the revised work package for troubleshooting and recalibration of the RCIC flow loop for work authorization at 1015 hours on December 26, 1986. At this time it was also realized that the execution of the surveillance procedure would cause RCIC to be inoperable. Upon discovery, RCIC was immediately declared inoperable and Technical Specification 3.0.3 was entered. Shutdown of the plant was initiated at 1103 hours.

The calibration surveillance was re-entered immediately at approximately 1015 hours. At this time the RSP and main control room flow indicators were still reading 100 gpm and 0 gpm, respectively. At approximately this time an operator tapped on the cover of the main control room flow indicator. After tapping on the meter the control room indicator also read 100 gpm.

Based on this observation and the fact that the RSP flow indicator had been calibrated only two days earlier, troubleshooting of the flow transmitter and the square root converter was initiated. When the as-found transmitter output at various simulated levels was measured it was found to be uniformly out-of-tolerance by approximately 1 millivolt DC.

Subsequently, the flow transmitter was re-calibrated, and the flow loop surveillance test was performed satisfactorily. The RCIC System was returned to OPERABLE status at 1310 hours, Technical Specification 3.0.3 was exited, and the plant shutdown was terminated.

At 1550 hours on December 26, 1986 it was discovered that the RCIC pump flow controller located at the main control room panel was incorrectly set to 505 gpm. The correct flow controller setpoint is 605 gpm. The flow controller setpoint was immediately reset to 605 gpm by a control room operator (licensed, utility).

It is believed that the flow controller setpoint was incorrectly positioned by an operator (licensed, utility) during the flow controller calibration and troubleshooting activities which were performed on December 26. Technical Specification 3.0.3 was entered immediately upon discovery of the incorrect flow control setpoint, and exited upon resolution.

The incorrect RCIC pump flow controller setpoint resulted in both RCIC and HPCI being inoperable between 1310 hours and the time that the setpoint error was discovered. Since the incorrect RCIC pump flow setpoint was not detected until 1550 hours the plant was operated for approximately 2.5 hours in a condition which required entry into Technical Specification 3.0.3 without the recognition of the requirement.

NRC FORM 366A (9-83)

*U.S. GPO: 1986-0-824-538/455

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fermi 2	0 5 0 0 0 3 4 1	8 6	— 0 4 8	— 0 1	0 5 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The flow transmitter which supplies the RCIC flow indicator at the RSP also provides input to the RCIC flow indicator located in the main control room and the automatic RCIC flow controller. Availability of the RCIC pump flow controller and establishment of the proper flow control setpoint are required by Technical Specifications in order to establish operability of the RCIC System.

Evaluation of the out-of-tolerance condition for the RCIC flow transmitter has demonstrated that this condition would not have resulted in controlled RCIC flow below the 600 gpm required by Technical Specifications. As a result the out-of-tolerance condition for the flow transmitter did not cause RCIC to be inoperable, or require entry into Technical Specification 3.0.3.

The incorrect RCIC pump flow controller setpoint did cause RCIC to be inoperable since it would have prevented the system from automatically providing the minimum required flowrate. However, the incorrect flow controller setpoint would not have prevented RCIC from being able to provide flow, or be manually controlled from the main control room.

Calibration and testing activities for the RCIC flow loop and the incorrect RCIC pump flow setting resulted in HPCI and RCIC being simultaneously inoperable between 1250 hours and 1720 hours (4.5 hours) on December 24, 1986, and 1015 hours and 1550 hours (5.5 hours) on December 26, 1986. The existence of plant conditions which required entry into Technical Specification 3.0.3 was recognized, and the appropriate actions were taken, between 1015 hours and 1310 hours (3.0 hours) on December 26, 1986, and at 1550 hours on December 26, 1986.

This event was initiated when the NASS did not recognize that performance of the calibration procedure for the RCIC flow channel would cause RCIC to become inoperable. The event was caused by this cognitive personnel error. Contributing causes to the event were: two instances of inadequate communications involving the Maintenance personnel who were performing the calibration and the NASS, and an operator error involving restoration of the pump flow controller setpoint following testing.

The event was also contributed to by inoperability of the HPCI system prior to and during the event. If HPCI had been operable during this event, entry into Technical Specification 3.0.3 would not have been required. This event did not involve any other inoperable or failed components, structures, or systems, and did not involve an error in a procedure.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Fermi 2	0 5 0 0 0 3 4 1	8 6	— 0 4 8	— 0 1	0 6 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

As corrective action, the following actions will be or have been taken:

1) Licensed operators will receive supplemental training on the requirements of Technical Specification 3.0.3.

2) The Operations and Maintenance personnel involved in this event have been counseled, and required reading on performing independent verification has been provided for licensed operators.

3) Instrument surveillance procedures (44.XXX.XX series) will be revised under a procedures improvement program to include clearer statements regarding plant operations impact.

4) Training will be provided regarding the signifigance of the RCIC pump flow control circuit interface between HPCI and RCIC, and the control circuit effects on system operablity.

Completion of corrective actions listed in items 1 and 4 are scheduled to be completed by June 1, 1987. The corrective actions listed in item 3 are scheduled to be completed by December 31, 1987.

During the periods when HPCI and RCIC were simultaneously inoperable during this event plant conditions did not necessitate initiation of the function associated with these systems. Had plant conditions existed which required initiation of the function associated with these systems, the Standby Feedwater System, the Automatic Depressurization System (ADS) and the ability to manually control the RCIC pump were available continuously throughout this event. As a result, this event did not affect the safe operation of the plant, or the safety of the public.

Events which required entry into Technical Specification 3.0.3 because of concurrent inoperability of HPCI and RCIC have been reported in Licensee Event Reports 86-037, and 85-038.

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)
SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3	0 5 0 0 0 3 6 2	1 OF 0 3

TITLE (4)
SALTWATER COOLING LOOPS 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 8	0 4	8 6	8 6	0 1 1	0 0	0 9	0 3	8 6		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)	X 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)
H. E. MORGAN, STATION MANAGER	7 1 4 3 6 8 - 6 2 4 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)

AT 1550 on August 4, 1986, Saltwater Cooling (SWC) flow through Train A Component Cooling Water (CCW) Heat Exchanger (CCWHX) decreased, due to fouling with marine growth, to below the postulated design basis flow rate required for removal of CCW heat loads (critical CCW loop), and was therefore declared inoperable. At this time Train B CCWHX was operating with reverse SWC flow to remove similar fouling which had previously taken place. At 1605, operators commenced realignment of Train B CCWHX SWC flow to the normal direction in order to return one train of CCW to its design configuration and thereby increase heat removal capability of that train. During the realignment, both trains of the SWC system were considered to be inoperable contrary to Technical Specification Limiting Condition for Operation (LCO) 3.7.4, and LCO 3.0.3 was entered.

Train B SWC system was returned to operable status within thirty minutes, and at 1635, LCO 3.0.3 was exited.

As corrective action, operating procedures will be revised to minimize the effect of marine fouling on the operability of the SWC system.

Neither the health and safety of plant personnel nor the health and safety of the public was affected by this event.

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NRC Form 366
(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3	0 5 0 0 0 3 6 2	8 6	0 1 1	0 0	0 2 OF 0 3

TEXT (If more space is required, use additional NRC Form 366A's) (17)

At 2201 on August 3, 1986, Saltwater Cooling (SWC) (EIIS System Code BS) flow through the Train B Component Cooling Water (CCW) (EIIS System Code BI) Heat Exchanger (CCWHX) (EIIS Component Code HX) decreased below the flow rate at which the heat exchanger would support removal of the postulated design basis accident heat load (critical CCW loop). This decrease in flow was due to unusually high deposits of marine growth and debris. In accordance with operating procedures the SWC flow through the Train B CCWHX was reversed using recently installed provisions to enable Operators to remove such flow restrictions. With reverse SWC flow, the heat removal capability of the CCWHX is reduced, but remains sufficient for removal of critical loop heat loads and is, therefore, considered operable pursuant to Technical Specifications. At this time, there was minor fouling of the Train A CCWHX, as well, but SWC flow remained sufficient to remove the critical CCW heat loads, and this train was therefore operable.

At 0201, on August 4, 1986, surveillance testing of a Low Pressure Safety Injection (LPSI) valve was commenced, which resulted in placing the Train A LPSI in an inoperable status. As this surveillance progressed, during graveyard and day shift, the Train A SWC flow was monitored by operations and it was anticipated that the marine fouling would not reduce the SWC flow below the rate required for CCWHX operability prior to completion of the LPSI valve test. It was intended to return the Train B SWC from reverse flow to its normal configuration after completion of the valve test on Train A LPSI, thereby avoiding a simultaneous Train B (CCW) and Train A (LPSI) inoperable condition. However, the Train A SWC flow deteriorated more quickly than anticipated.

At 1550 on August 4, 1986, increased fouling resulted in a reduction of SWC flow through the Train A CCWHX to a level where the heat exchanger would have been incapable of removing post accident (critical CCW loop) component heat loads. It was therefore declared inoperable pursuant to Technical Specifications.

At 1605, operators commenced realignment of Train B CCWHX SWC flow to the normal direction in order to return one train of CCW to its design configuration and thereby increase heat removal capability of that train. During the realignment, both trains of the SWC system were considered to be inoperable contrary to Technical Specification Limiting Condition for Operation (LCO) 3.7.4, and LCO 3.0.3 was entered. SWC was restored to the Train B CCWHX, in the normal flow direction, at 1635, at which time LCO 3.0.3 was exited.

Before proceeding to re-align Train B SWCS, Operations had considered increasing Train A CCWHX capability by reversing SWC flow. However, this would have created a thermal transient in the CCW system, which, in turn, would have accelerated degradation of Reactor Coolant Pump (RCP) seals. Operators had also considered transferring the RCP seal and other non-critical loop CCW heat loads to the Train B CCWHX before reversing the flow in the Train A SWC system. This would have resulted in defouling the Train A CCWHX prior to realigning Train B SWC system. Operating procedures, however, did not provide for transferring of such heat loads to a CCWHX operating with reverse SWC flow.

TEXT (If more space is required, use additional NRC Form 366A's) (17)

SCE has recognized the significant impact marine fouling of the CCWHX can have on plant operation. As a result, the capability to reverse the SWC system flow was provided by a recently completed plant design change. This has yielded considerable operational flexibility resulting in a substantial increase in availability of the SWC system.

The following corrective actions will be taken:

1. Operating proc dures will be revised to provide for transferring non-critical loads to a CCWHX with reverse flowing SWC;

2. RCP seal design change, already completed on Unit 2, will be completed on Unit 3 during the next refueling outage. This new seal arrangement is less sensitive to thermal transients and permits reversal of SWC flow in CCWHXs without detrimental effect on the seals.

Neither the health and safety of plant personnel nor the health and safety of the public was affected by this 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)
EDWIN I. HATCH, UNIT 2	0 5 0 0 0 3 6 6	1 OF 0 6

TITLE (4)

PERSONNEL ERROR DURING CLEARANCE DEVELOPMENT MAKES CORE SPRAY 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)
1 1	1 3	8 6	8 6	0 3 5	0 0	1 2	1 5	8 6		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 5

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)	[X]	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)
Raymond D. Baker, Nuclear Licensing Manager - Hatch	4 0 4 5 2 6 - 7 0 2 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)

[ ] 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 11/13/86 at approximately 2319 CST, Unit 2 was at 0 percent of rated thermal power and the mode switch was in the refuel position. At that time, plant personnel found, while performing a plant procedure, that both loops of core spray (CS) were incapable of performing their intended function.

The root cause of the event was personnel error in developing a clearance and the Integrated Leak Rate Test (ILRT) procedure. The plant ILRT procedure called for both loops of CS to have the suction valves closed and power removed from the pumps.

Corrective actions include: 1) returning the CS system to operable status, 2) performing a management critique of the defective clearance and procedure, 3) making personnel aware of the event and steps leading to it, and 4) incorporating the event into the operator training program. The last two actions will be performed in conjunction with the corrective actions for LER 50-321/1986-036.

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NRC Form 366 (9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
EDWIN I. HATCH, UNIT 2	0 5 0 0 0 3 6 6	8 6	— 0 3 5	— 0 0	0 2 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

A. REQUIREMENT FOR REPORT

This report is required per 10 CFR 50.73 (a)(2)(v), because both trains of the Core Spray (CS) system were incapable of performing their safety function and 10 CFR 50.73 (a)(2)(vii) because a condition caused 2 independent trains to become inoperable in a single system designed to remove residual heat and maintain the reactor in a safe shutdown condition.

B. UNIT(S) STATUS AT TIME OF EVENT

Unit 2 was at an approximate power level of 0 percent of rated thermal power. The reactor mode switch was in the refuel position. One loop of Residual Heat Removal (RHR) system was tagged out for maintenance and the other loop was in the Shutdown Cooling (SDC) mode of operation.

C. DESCRIPTION OF EVENT

On 11/13/86 at approximately 2319 CST, during the performance of "Emergency Core Cooling Systems Operability Status Checks" procedure 34GO-OPS-033-2S on Unit 2, plant personnel found both loops of the Core Spray (CS) system were inoperable. The inoperability occurred because both the suction valves (one for each subsystem) were closed and the electrical power for both of the CS pumps (one pump in each subsystem) was removed.

An investigation of the event showed that plant personnel were aligning plant systems in order to perform the Integrated Leak Rate Test (ILRT). The system alignment occurred sometime after 1446 CST on 11/13/86. Plant personnel were manipulating plant equipment in accordance with a completed equipment clearance sheet. The clearance sheet was used because plant personnel wanted to place hold tags on selected plant equipment to prevent changing the condition of the equipment while the ILRT was in progress.

One of the documents used to develop the clearance was the ILRT procedure. This procedure, however, contained an error that resulted in both subsystems of the CS system being inoperable as described above. At the time of the event, CS was required to be operable per Technical Specifications 3.5.3.1, since the reactor vessel head was in place and being tensioned.

The Unit 2 Technical Specifications section 3.5.3.1.b.2 states that with both CS subsystems inoperable, operation may continue provided that at least one Low Pressure Coolant Injection (LPCI) subsystem is operable and both LPCI subsystems are operable within 4 hours. Otherwise, suspend all operations that have a potential for draining the reactor vessel and verify that at least one LPCI subsystem is operable within 4 hours. With the RHR system in the SDC mode of operation, the RHR system can not automatically come out of the SDC mode to align itself to the LPCI mode of operation were a LPCI initiation signal to occur.

The event was discovered at 2319 CST on 11/13/86. The event was documented on a deficiency report at 0100 CST on 11/14/86. There were no activities in progress, or planned in the plant, that had the potential for draining the reactor pressure vessel. Both trains of CS were returned to service on 11/14/86 at 0232 CST. By returning both subsystems of CS to operable status, the action statement of the Limiting Condition for Operations (LCO) was satisfied.

D. CAUSE OF EVENT

The intermediate cause was personnel error in the drafting, review, and implementation of clearance sheet number 2-86-1758. Major contributing factors leading to this personnel error are as follows: length of the clearance sheet (3,000 to 3,500 items), restricted time schedule to draft, review and implement, and staffing insufficient to meet restricted time schedule.

The root cause was personnel error in the initial drafting of the Unit 2 ILRT procedure. Then when engineering personnel changed the old procedure to its present format, numerous improvements were made to the new procedure. However, the technical error in the old procedure (that required the closure of the suction valves and removal of supply power to both CS pumps) was not discovered and remained in the new procedure. When the new procedure was used as a basis for the clearance, the technical error was transmitted to the clearance and ultimately implemented in the field.

It is to be noted that the ILRT procedure had its format changed. However, the procedure had not been through the full Procedures Upgrade Program (PUP) verification program.

E. ANALYSIS OF EVENT

The basis for requiring CS when the reactor is in the refueling mode of operation is to provide inventory (water) makeup should an event occur which could drain the reactor pressure vessel. At the time of this event, there were no on-going plant activities which had the potential for draining the reactor pressure vessel. Additionally, there are no postulated accidents in the Unit 2 FSAR, in the refueling mode, which could drain the vessel. While the RHR system could not automatically come out of the SDC mode and enter the LPCI mode, plant operators could have manually aligned the RHR system well within the 4 hour LCO action time frame, had LPCI been required. Other circumstances which mitigate the safety significance of this event are: 1) the decay heat load in the reactor was minimal because one-third of the core was composed of new unirradiated fuel, and 2) all control rods were fully inserted.

Based on the above information, it is concluded that this event had no impact on safety.

F. CORRECTIVE ACTIONS

On identification of this incident, both Core Spray loops were returned to service on 11/14/86 at approximately 0230 CST.

All of the ILRT procedure and clearance activities were ceased until completion of a management critique. The critique was held on 11/14/86 at approximately 0630 CST. During the critique, the ILRT procedure and the clearance that caused the isolation of the CS system were reviewed against the requirements of the Technical Specifications. No additional discrepancies were noted.

Plant personnel performed a temporary procedure modification to the ILRT procedure which brought the procedure into compliance with the Technical Specifications requirements. The defective clearance was also corrected to reflect the newly corrected procedure.

Engineering personnel are aware of the event and the steps leading to it. Engineering management emphasized the need for personnel involved in procedure revisions to insure that the procedure meets current Technical Specifications requirements before and after revisions.

Involved operations personnel fully understand this incident and the consequences thereof. Thus, no other corrective action for these personnel is anticipated.

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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)
EDWIN I. HATCH, UNIT 2	0 5 0 0 0 3 6 6	8 6	— 0 3 5	— 0 0	0 5 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Shift personnel will be made aware of this event and steps leading to it. Operations Department management will emphasize the need for personnel involved in the clearance preparation process to do detailed reviews when performing electrical clearances on plant components. These personnel will be instructed to get further assistance if needed to ascertain the results of isolating these electrical circuits. Corrective action for this LER will be completed in conjunction with the corrective action in LER's 50-321/1986-036 and 50-366/1986-034. This corrective action is scheduled to be completed on approximately 1/19/87.

This event and associated information will be provided to the Training Department to incorporate this operating experience into initial and requalification training. This is scheduled to be completed on approximately 6/19/87.

G. ADDITIONAL INFORMATION

1. FAILED COMPONENT(S) IDENTIFICATION

No components failed in this event.

2. PREVIOUS SIMILAR EVENTS

Previous LERs have reported events where inadvertent ESF actuations occurred in conjunction with the performance of a clearance. These LERs are: 50-321/1986-036 (dated 10/20/86) and 50-366/1986-034 (dated 11/5/86).

LER 50-321/1986-036 described an event where plant personnel did not perform an adequate review of some logic prints. The inadequate review resulted in a defective clearance, that when performed, caused actuations of ESFs.

LER 50-366/1986-034 described an event where plant personnel did not perform an adequate review of some logic prints and an inadvertent start of a diesel generator resulted.

NRC FORM 366A (9-83)

NRC Form 366A

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)
EDWIN I. HATCH, UNIT 2	0 5 0 0 0 3 6 6	8 6	0 3 5	0 0	0 6 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

The corrective actions for these events included: 1) securing affected systems, 2) counseling of personnel, 3) informing other shift personnel of th events and the consequences of the events, and 4) incorporating the experiences into the operator training programs. Items numbers 3 and 4 were the long term corrective actions to prevent recurrence of these types of events. These corrective actions are scheduled for completion on approximately 1/19/87 and 6/19/87 respectively.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
McGuire Nuclear Station - Unit 2	0 5 0 0 0 3 7 0	1 OF 0 4

TITLE (4)
Failure to Maintain Required Boration Flow Path Due to a Personnel Error

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 9	8 6	8 6	0 0 6	0 0	0 4	3 0	8 6		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 6
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)

X 50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Julio G. Torre, Licensing	7 0 4 3 7 3 - 8 0 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

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 29, 1986, at 0700, it was discov[illegible] Chemical and Volume Control (NV) charging pump 2B had been racked ou[illegible] while NV charging pump 2A had been racked in service without havi[illegible]cy power supply. Technically, this resulted in no opera[illegible] low path or operable NV charging pump as required by Techni[illegible] 3.1.2.1 and 3.1.2.3 for approximately twenty hours.

Immediately upon discovery, N[illegible] NV charging pump 2B was rac[illegible] [illegible]ked out of service, and

Unit 2 was in Mode 6, [illegible], at [illegible] [illegible]ident.

This incident has [illegible]ibuted t[illegible] [illegible]ecause the responsible Assistant Shift [illegible]r failed t[illegible] [illegible]arging pump 2A did not have availab[illegible]y power supp[illegible]

There wer[illegible] [illegible]or core alterati[illegible] [illegible]ity changes while both NV chargin[illegible]s were technically [illegible]

ILLEGIBLE ORIGINAL

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NRC Form 366 (9-83)

NRC Form 366A

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)
McGuire Nuclear Station - Unit 2	0 5 0 0 0 3 7 0	8 6	— 0 0 6 —	0 0	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

On March [illegible]9, 1986, at 0700, it was discovered that Chemical and Volume Control (NV) [EIIS:CB] charging pump 2B had been racked out of service while NV charging pump 2A had been racked in service without having an emergency power supply. Technically, this resulted in no operable boration flow path or operable NV charging pump as required by Technical Specifications 3.1.2.1 and 3.1.2.3 for approximately twenty hours.

Immediately upon discovery, NV charging pump 2A was racked out of service, and NV charging pump 2B was racked in service.

Unit 2 was in Mode 6, Refueling, at the time of this incident.

BACKGROUND:

The NV system is designed to provide several services to the Reactor Coolant (NC) [EIIS:CB] system. One service is to control the soluble chemical neutron absorber (boric acid) concentration and makeup. During normal operating conditions, one NV charging pump takes suction from the Volume Control Tank (VCT) which uses an automatic makeup system to maintain its borated water level. In an event requiring emergency boration and makeup, both NV charging pumps take suction from the VCT or the Refueling Water Storage Tank (RWST). The Boric Acid Tank can also be aligned to supply borated water to the [illegible]ion of the NV charging pumps. During a loss of coolant accident, bot[illegible] [illegible]harging pumps [illegible] operate automatically as part of the Safety Injection [illegible] [illegible]IS:BP] system and take suction from the RWST and injects borated water [illegible] [illegible]C system.

T.S. 3.1.2.1 and 3.1.2.3 specify a minimum of one bo[illegible] [illegible]on flow path must be operable and capable of being powered from an em[illegible] [illegible] source, while in Modes 5 and 6. Without an operable NV charging [illegible] [illegible]f being powered from an emergency power source, ope[illegible] [illegible] involvi[illegible] [illegible] alterations or positive reactivity changes must [illegible] [illegible]ed. T.[illegible] [illegible]tes that only one NV charging pump can be ope[illegible] [illegible]ng Modes [illegible] [illegible] other NV charging pump must be demonst[illegible] [illegible]erable to [illegible] [illegible]tion pressure [illegible]ansient in the NC system [illegible]ieved by on[illegible] [illegible] operated [illegible]lief valve.

[illegible]en an NV charging [illegible] [illegible]oved from service [illegible] [illegible]nd 6, the [illegible]rcuit breaker fo[illegible] [illegible] is racked out. Th[illegible] [illegible] [illegible]mp [illegible]erable as pe[illegible] [illegible].2.3.2. To restore t[illegible] pump to [illegible] [illegible]e circuit [illegible]er has to [illegible] in.

[illegible]rpos[illegible] [illegible]esidual Heat Removal (ND) [illegible]IIS:BP] syst[illegible] [illegible] [illegible]emove heat [illegible]he re[illegible] [illegible]ore and the NC system during [illegible] coo[illegible]down and re[illegible]eling [illegible]ions. [illegible] ND system is placed in servic[illegible] when the NC system [illegible]erature an[illegible] [illegible]essure are reduced to approximately 350 [illegible] F and 385 pou[illegible] [illegible] per [illegible] inch gauge (psig).

ILLEGIBLE ORIGINAL

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
McGuire Nuclear Station - Unit 2	0 5 0 0 0 3 7 0	8 6	— 0 0 6	— 0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

DESCRIPTION OF EVENT:

On March 19, 1986, at 0315, diesel generator 2A was declared inoperable for maintenance repairs. NV charging pump 2A was also declared inoperable because diesel generator 2A could not provide emergency power to the pump. On March 28, 1986, at approximately 1100, a Station Engineer requested the responsible Assistant Shift Supervisor to rack in and operate NV charging pump 2A so a retest could be performed on NV charging pump 2A. The Engineer made the request without realizing diesel generator 2A was inoperable. The Assistant Shift Supervisor instructed Station personnel to rack out NV charging pump 2B and rack in NV charging pump 2A. The Assistant Shift Supervisor did not realize diesel generator 2A was inoperable and that racking out NV charging pump 2B would result in a loss of boration flowpath as defined by Technical Specifications 3.1.2.1 and 3.1.2.3. The Assistant Shift Supervisor did not make a Technical Specification Action Item Logbook (TSAIL) entry or discuss the change with the designated control room Senior Reactor Operator (SRO) to ensure Technical Specification requirements were met.

At 1245 the retest on NV charging pump 2A was completed.

On March 29, 1986, at 0700, during shift turnover, station personnel discovered that while NV charging pump 2B had been racked out of service, NV charging pump 2A had been racked in service without an emergency power supply. Immediately NV charging pump 2A was racked out and NV charging pump 2B was racked in reestablishing compliance with Technical Specifications.

CONCLUSION:

According to Duke Power Management it is the responsibility of [illegible] ant Shift Supervisor (designated unit supervisor) to be aware of wh[illegible] re in the TSAIL. It is accepted practice for the unit supervisor to [illegible] nical Specification equipment status changes with the designated con[illegible] to ensure Technical Specification requiremen[illegible]e met and the a[illegible] entr[illegible] made.

When [illegible]ect Assistant Shift [illegible] received the requ[illegible] char[illegible] 2A in service he [illegible]rming a Unit 2 contai[illegible] per[illegible] He stated [illegible] time his attention wa[illegible] concentrated [illegible] this [illegible] did not [illegible]ut diesel generator 2A bei[illegible] inoperable.

Thi[illegible] bee[illegible]ed to a Personnel Error because [illegible] Assistant [illegible] Sup[illegible] for knowing the status of the eq[illegible]pment [illegible] TS[illegible]fication requirements were not met b[illegible] having NV [illegible] pu[illegible] B [illegible]f service, and having NV charging pump [illegible] racked in [illegible] wh[illegible]ency power supply. The Assistant Shift S[illegible] c[illegible] make any entries in the TSAIL and did no[illegible] e[illegible]hanges with the designated control room SRO [illegible] S[illegible]irements were met.

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NRC Form 366A

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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McGuire Nuclear Station - Unit 2	0 5 0 0 0 3 7 0	8 6	0 0 6	0 0	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

A Limiting Conditions Operational Monitor (LIMCOM) computer program has been developed and will be made available to appropriate personnel in the control room. The use of the LIMCOM computer program along with the TSAIL will identify limiting operational conditions. Appropriate personnel will be able to use this system to aid in avoiding similar incidents.

A review of past incidents indicates this incident is an isolated event.

There were no personnel injuries, radiation overexposures, or releases of radioactive materials as a result of this incident.

CORRECTIVE ACTIONS:

Immediate: NV charging pump 2A was racked out of service and NV charging pump 2B was racked in service.

Subsequent: Appropriate TSAIL entries were made, and station personnel ensured no reactor core alterations or positive reactivity changes were being made.

Planned:

1) This incident will be reviewed during staff meeting by all appropriate Duke Power personnel.

2) Duke Power management will ensure that appropriate personnel are familiar with the availability of the LIMCOM computer program and are trained in the use of the system.

SAFETY ANALYSIS:

The ND system was operating while both NV ch[illegible]ging pumps were inoperable. If a loss of coolant accident had occurred, NV [illegible]ng pump 2A would have operated as long as offsite power was not interr[illegible] would have been used along w[illegible] the ND system to [illegible] the reactor cor[illegible] and cooled.

Had a loss of c[illegible]ccident or [illegible] accompanied by an offsite power failure, diesel [illegible]or 2B w[illegible] supplied emergency power to train B [illegible] the ND system w[illegible] ha[illegible] the core covered and cooled using 2000 [illegible] borated water [illegible]ionally, NV charging pump 2B could have racked in and [illegible] makeup.

There were no [illegible]lterations or positive reactivity changes whil[illegible] NV charging [illegible]erable.

The health a[illegible] public were not affected by this incident.

ILLEGIBLE ORIGINAL

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
St. Lucie, Unit 2	0 5 0 0 0 3 8 9	1 OF 0 6

TITLE (4) Both Diesel Generators Simultaneously Out of Service Due to One Personnel Error And One Component Failure

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	8 6	8 6	0 1 1	0 0	0 8	0 8	8 6	N/A	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)

X 50.73(a)(2)(iv)

X OTHER (Specify in Abstract below and in Text, NRC Form 366A) Special Report

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Mark S. Dryden, Shift Technical Advisor	AREA CODE 3 0 5 465-3550

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
A	E K	6 5	W 2 9 0	Y						
B	E K	F A N	X 9 9 9	Y						

SUPPLEMENTAL REPORT EXPECTED (14)

X YES (If yes, complete EXPECTED SUBMISSION DATE) ☐ NO

EXPECTED SUBMISSION DATE (15): MONTH 1 2 DAY 3 1 YEAR 8 6

ABSTRACT (Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines) (16)

On July 9, while Unit 2 was at full power, the 2A Emergency Diesel Generator (D/G) was taken out of service due to failure to meet its required start time. The redundant 2B D/G was started to satisfy the redundant D/G operability. The 2B D/G came up to voltage and frequency within the required start time. Upon completing the surveillance run the 2B D/G was stopped due to observation of one of its cooling fans rubbing its shroud. A determination was made to declare the 2B D/G out of service. Repairs on the 2B D/G were completed and the 2B D/G set was returned to operable status within the Technical Specification time limit. The intermediate cause of the 2B D/G cooling fan event was due to vibration within the cooling unit, thereby, causing the set screws in the fan hub to loosen. The root cause of the vibration within the cooling units is associated with the fan drive belt flapping. A continuing effort is underway to correct the belt flapping. The failure of the 2A D/G was caused by overtightening of a friction clutch locknut. An immediate inspection of torque values of the friction clutch locknuts in the remaining St. Lucie diesel generators was made. D/G maintenance personnel have been instructed to make every attempt to contact the vendors, particularly in the area where information may not be provided or discussed in the technical manual.

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NRC Form 366

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
St. Lucie, Unit 2	0 5 0 0 0 3 8 9	8 6	0 1 1	0 0	0 2 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION:

At 0854 hours on July 9, 1986, St. Lucie Unit 2 was operating at 100%. The Unit remained at 100% throughout the event.

At 0855 hours on July 9, 1986, the 2A Emergency Diesel Generator (D/G) (EIIS:EK) was started for a once per seven (7) days surveillance test (once per 7 days based on three (3) valid failures within the last 100 valid starts). The 2A D/G failed to meet the required generator voltage and frequency of 4160±420 volts and 60±1.2Hz within 10 seconds after the start signal. An alarm was recieved which indicated that one of the engines in the 2A D/G set had failed to start. The engine fail to start alarm is actuated by high differential temperature between the turbo charger exhausts of the engines in the D/G set. The power unit consists of two (2) EMD diesel engines, a 12 cylinder-645E4 and a 16 cylinder-645E4, driving one (1) Electric Products generator coupled with EMD tandem couplings, forming a diesel-generator assembly. The 2A D/G was maually tripped by the operator at 0856 hours.

At 0915 hours on July 9, 1986, the redundant 2B D/G was started to satisfy Technical Specification ACTION (a) of Limiting Condition of Operation (LCO) 3.8.1.1, i.e. the performance of Surveillance Requirement 4.8.1.1.2a.4 (redundant D/G operability check) within one (1) hour and at least once per eight (8) hours thereafter. This surveillance was performed since the 2A D/G came up to voltage frequency within ten (10) seconds, therefore, meeting the Surveillance Requirement; 4.8.1.1.2a.4. At 0917 hours the 2B D/G was stopped due to an operator observation of one (1) of the 12-cylinder cooling fan blades rubbing the cooling fan shroud.

A decision was made to take the 2B D/G out of service to evaluate the seriousness of the rub. In accordance with ACTION (e) of LCO 3.8.1.1, operability of offsite power sources was verified and immediate actions were taken to repair both the 2A and 2B Diesel Generators.

The 2B D/G rub was determined to be minor and at 1048 hours repairs were completed on the 12-cylinder engine cooling fan. The 2B D/G was started for an operational check and met the required start time. The 2B D/G was declared back in service at 1059 hours. With the 2B D/G back in service ACTION (a) of LCO 3.8.1.1 was maintained.

Trouble shooting of the 2A D/G revealed a problem in the mechanical portion of the Woodward governor. The problem was corrected and the 2A D/G was returned to service at 2010 hours on July 9, 1986.

NRC FORM 366A (9-83)

CAUSE OF EVENT:

2B Diesel Generator Set

The intermediate cause of the 2B D/G 12-cylinder engine cooling fan event was vibration within the 12-cylinder engine Vertical Cooler Unit (ES-165), thereby, causing the set screws in the fan hub to loosen. With the loosening of the fan hub set screws, the fan shifted and began rubbing the shroud. The root cause of the vibration within the Cooler Unit is a design problem associated with fan drive belt flapping. A continuing engineering effort is underway to correct the belt flapping and thus reduce the resulting vibration.

2A Diesel Generator Set

The intermediate cause of the 2A2 diesel failing to start was the failure of a roll pin (Ref. No. 82340-44) in the mechanical section of the Woodward EGB-13P engine governor. This governor consists of an electrical section which operates at or near rated engine speed, and a mechanical section which is mainly used during engine startup and shutdown. During startup, a small speed setting motor is used to run up the mechanical governor to allow the engine to reach rated speed where the electrical governor assumes control of engine speed. This speed setting motor operates on the linkage of the mechanical governor by a friction clutch.

Investigations revealed a roll pin which holds the intermediate gear on the pinion shaft of the speed setting controls had broken. This gear arrangement drives the dial stop gear which actuates the upper and lower stops of the speed setting motor. With the failure of the roll pin the speed setting motor caused excessive wear on the friction clutch which, in turn, allowed excessive slippage of the friction drive shaft and prevented the mechanical governor from demanding sufficient fuel flow to pick up load on the 12-cylinder engine and allowing the electric portion of the governor from taking control at the designated engine speed.

The root cause of the roll pin failure was the result of friction clutch adjustments made on the 2A 12-cylinder D/G mechanical governor as described in LER 389-86-006 (see previous similar events section). The root cause of LER 389-86-006 was determined to be a loose locknut in the friction clutch. This allowed excessive slippage and prevented the mechanical governor from demanding sufficient fuel flow to pick up load on the 2A 12-cylinder engine. The corrective action was to tighten the loose locknut on the clutch. The friction clutches are supplied as assembled units and are not required to be disassembled and inspected as part of the vendor's recommended preventative maintenance program.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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EXPIRES: 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
St. Lucie, Unit 2	0 5 0 0 0 3 8 9	8 6	— 0 1 1	— 0 0	0 4 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

Previous to tightening the loose locknut, a review of the technical manual was completed to determine the torque value for the locknut. A torque value was not supplied in the technical manual. A self-determined adjustment was made and the engine was retested with positive results. Upon later conversations with the vendor it was learned that the locknut and the clutch of the 2A 12-cylinder D/G mechanical governor had been tightened beyond the vendor prescribed torque value. The overtightened locknut provided the stress necessary for the roll pin in the speed setting control to break. Thus, the root cause of this component failure was a cognitive personnel error by utility maintenance personnel.

EVENT ANALYSIS

The event is reportable under 10 CFR 50.73(a)(2)(v) as neither diesel generator set was operable between the time the 2A D/G failed and the 2B D/G was returned to service. This condition is allowed for a period not to exceed two (2) hours by LCO 3.8.1.1, provided both offsite power sources are available. Both offsite power sources were operable throughout this event and the time both D/G sets were out of service was less than two (2) hours (1 hour 44 minutes). Also, as per Surveillance Requirement 4.8.1.1.3, all diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.9.1.

The 2A D/G governor component failure was readily detected during routine surveillance testing. The event was determined to be a valid failure in accordance with Regulatory Guide 1.108.

The 2B D/G 12-cylinder cooling fan event was observed while satisfying ACTION (a) of LCO 3.8.1.1. The effect of the cooling fan rubbing the shroud did not inhibit the 2B D/G set from coming up to voltage and frequency within ten (10) seconds. During troubleshooting, it was determined that had it been necessary for the 2B D/G to perform its saftey function the 12-cylinder cooling fan would have worn the point of contact on the shroud to where no further rubbing would have occured. The 2B D/G was taken out of service strictly as a precautionary measure and based on the above observation it was determined that the event would not be considered a valid failure per Regulatory Guide 1.108.

In the unlikely event of a complete loss of AC power (onsite and offsite) for St. Lucie 2 and, for the benefit of a conservative analysis, the simultaneous loss of offsite power and one diesel generator at St. Lucie 1, the remaining diesel generator in St. Lucie 1 is able to operate the minimum safeguard loads such that both Units are maintained in a safe, hot stand-by condition. The present St. Lucie design does have the capability of electrically connecting the two units (Reference: St. Lucie 2 UFSAR, Updated Final Safety Analysis Report, Section 8.3.1.1.2,Pg.8.3-19d).

This was the fourth valid failure in the last 100 valid tests. Thus, the current surveillance interval is once per (3) days. This surveillance interval is in conformance with the schedule of regulatory position c.2.d of Regulatory Guide 1.108.

NRC FORM 366A (9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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)
St. Lucie, Unit 2	0 5 0 0 0 3 8 9	8 6	— 0 1 1	— 0 0	0 5 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

CORRECTIVE ACTIONS

2B D/G SET

The 2/B D/G cooling fan shroud was removed and the fan was repositioned in order to provide sufficient clearance between the fan blade tips and the fan shroud. Upon completion of the re-positioning, the fan hub set screws were securely tightened. Corrective actions resulting from this event are:

A. A list of instructions has been developed describing steps to be taken for preventative maintenance inspections of the D/G vertical cooling fan units. The purpose of these instructions is to check for loose bolts and to insure fan drive integrity.

B. In the intermediate to long term, investigation and testing is underway to locate the source of excessive vibration. Evaluation of the testing results will be used to modify the St. Lucie Unit 2 D/G sets and, thereby, reduce and or eliminate the excessive vibration.

2A D/G SET

The 2A2 D/G governor roll pin was replaced by replacing the dial panel assembly in total; this included both the roll pin and the friction clutch. Adjustments to the stop cams had to be made and a test run was performed with satisfactory results. Corrective actions resulting from this event are:

A. An immediate inspection of torque values of the like component, i.e., friction clutch locknuts, in the remaining St. Lucie Plant D/G's was made.

B. D/G maintenance personnel have been instructed to make every attempt to contact the appropriate vendor should component adjustments be necessary, particulary, in the area where information may not be provided or discussed in the technical manual.

ADDITIONAL INFORMATION

FAILED COMPONENT INFORMATION

The failure of each D/G set was unrelated. The 2A D/G governor is a Woodward Model EGB-13P. The roll pin (broken component in governor) Reference No. is 82340-44. The 2B D/G cooling fan is part of an ES-165 Vertical Cooler Assembly designed by the O&M Manufacturing Company.

NRC FORM 366A (9-83)

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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)
St. Lucie, Unit 2	0 5 0 0 0 3 8 9	8 6	— 0 1 1	— 0 0	0 6 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

PREVIOUS SIMILAR EVENTS

LER 389-86-6 reported a previous event where both diesel generators were simultaneously out of service for the following related causes:

On March 10, 1986, the 2B Emergency Diesel Generator (D/G) was taken out of service to repair an idler pulley wheel on the belt-driven engine cooling fan. On March 12, while performing a required operability surveillance on the redundant 2A D/G, one of the two engines in the diesel generator set failed to start. Repairs on the 2B D/G were completed and the unit was returned to operable status within the time limit allowed by the applicable Technical Specification. The damage to the idler pulley is believed to be related to the belt flapping problem which has been observed on the 12 Cylinder engines in the D/G set. The failure of the 2A D/G was caused by a loose locknut in the friction clutch assembly which operates the mechnical governor used for engine start-up. Corrective actions were to repair both diesels and inspect the remaining idler pulley wheels on the diesels for similar failures. The friction clutches on the remaining engine governors were inspected during the Unit 2 refueling outage, April 1986.

SUPPLEMENTAL REPORT

Upon completion of the engineering effort to correct the belt flapping in the D/G set cooling units, a supplemental report describing the cause and correction will be submitted.

NRC FORM 366A (9-83)

NRC Form 366

LICENSEE EVENT REPORT (LER)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104

FACILITY NAME (1): La Crosse Boiling Water Reactor (LACBWR)

DOCKET NUMBER (2): 0 5 0 0 0 4 0 9 — PAGE (3): 1 OF 0 2

TITLE (4): Loss of Offsite Power due to Lightning While Shutdown

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	1 9	8 6	8 6	0 2 3	0 0	0 8	0 6	8 6		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 §: X 50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Lynne S. Goodman, LACBWR Operations Engineer

TELEPHONE NUMBER: 6 0 8 6 8 9 - 2 3 3 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): X NO

EXPECTED SUBMISSION DATE (15): MONTH DAY YEAR

ABSTRACT (16)

LACBWR experienced a loss of offsite power while in the cold shutdown condition due to a lightning strike at the adjacent coal plant's auxiliary switchyard which caused switchyard and plant breakers to open. The Emergency Diesel Generators started and supplied the essential busses. Offsite power was restored 12 minutes later.

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NRC Form 366

NRC Form 366A (9-83)

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

U.S. NUCLEAR REGULATORY COMMISSION
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EXPIRES 8/31/88

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
La Crosse Boiling Water Reactor (LACBWR)	0 5 0 0 0 4 0 9	8 6	— 0 2 3	— 0 0	0 2 OF 0 2

TEXT (If more space is required, use additional NRC Form 366A's) (17)

On July 19, 1986, the plant was in the cold shutdown condition. At 0630, the 69 kv Tie Line (FK) Breaker (BKR), 2NB11, the Reserve Transformer (XFMR) Supply Breaker, 25NB4, and the 480V Main Feed (EC) Breakers, 452 M1A and 452 M1B, opened. Both Emergency Diesel Generators (EK)(DG) started and supplied the 1A and 1B 480V Essential Busses (ED). Containment Building (NH)(JM) isolated. The 1A High Pressure Service Water (KG) Diesel Pump (P) started when High Pressure Service Water (HPSW) Pressure dropped to the low pressure setpoint.

A severe thunderstorm was in progress at the time. Dairyland Power Cooperative's Systems Operations Center informed LACBWR that the adjacent coal plant's auxiliary switchyard had been hit by lightning. The operators reset the lockout relays (86). At 0642, they closed Breakers 2NB11 and 25NB4. At 0645, they shut the 480V Main Feed Breakers and opened the Emergency Diesel Generators' output breakers. The 480V Essential Bus Breakers automatically closed, completing the electrical lineup restoration. At 0659, the 1A HPSW Diesel was secured and returned to auto. At 0702, the Emergency Diesel Generators were secured and returned to auto.

An unusual event was declared due to the loss of offsite power. The plant was without offsite power for 12 minutes. The lightning had hit a static wire in the adjacent coal plant's auxiliary switchyard. The 69 kv Tie Line supplies power to both LACBWR's Reserve Transformer and the coal unit's Reserve Auxiliary Transformer. When the lightning struck, the 69 kv Tie Line Breaker and both transformers' supply breakers opened. The LACBWR 480V Main Feed Breakers tripped on undervoltage. Undervoltage also started the Emergency Diesel Generators and tripped the 480V Essential Bus Main Feed Breakers, which caused the Emergency Diesel Generators' output breakers to close to supply the essential busses. If this incident had occurred while the reactor was at 100% power, a loss of load transient would have resulted. This is a design basis transient and the plant would still have been in a safe condition.

WP6.20.3

NRC FORM 366A (9-83)

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)
Catawba Nuclear Station, Unit 1	0 5 0 0 0 4 1 3	1 OF 0 4

TITLE (4): Forced Shutdown Caused by Excessive Leakage Due to Weld Failure

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 6	1 3	8 6	8 6	0 3 1	0 2	1 0	0 1	8 6	N/A	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 4 8

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: [X] 50.73(a)(2)(i)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Roger H. Ouellette - Associate Engineer, Licensing	7 0 4 3 7 3 - 7 5 3 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 June 13, 1986, at approximately 1600 hours, a weld break on Letdown piping resulted in excessive Reactor Coolant System leakage causing a forced shutdown. A loss of power to a Motor Control Center caused a loss of control power to the Variable Letdown Orifice. The orifice failed in the opened position. During the resulting transient, a 1 inch pipe weld on the discharge of the orifice broke. The unit was at 48% power at the time of this incident.

This incident is assigned Cause Code B, Design, Manufacturing, Construction/Installation deficiency. A weld on the outlet flange on the variable Letdown Orifice failed due to fatigue resulting from cavitation induced vibration.

This incident is reportable pursuant to 10 CFR 50.73, Section (a)(2)(i)(A).

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NRC Form 366 (9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Catawba Nuclear Station, Unit 1	0 5 0 0 0 4 1 3	8 6	— 0 3 1	— 0 2	0 2 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND

One of the functions of the Chemical and Volume Control (NV) System (EIIS:CB) is to maintain a programmed water level in the pressurizer and a required water inventory in the Reactor Coolant (NC) System (EIIS:AB). This is achieved by means of charging and letdown, which is a continuous feed and bleed process. The charging rate is automatically controlled by Pressurizer level. The letdown rate can be chosen to suit various plant operational requirements by selecting the proper combination of letdown orifices. Three parallel lines are provided to reduce the pressure and control the flow of reactor coolant leaving the NC System. Two of the lines incorporate fixed letdown orifices. The third line utilizes a valve as a variable orifice. An alternate (excess) letdown path is provided in the event that the normal letdown path is inoperable. The excess letdown can also be used to maintain normal heatup rate of the unit, by providing additional letdown capability during heatup.

Technical Specification (Tech Spec) 3.4.5.2 states that NC leakage shall be limited to 1 gpm of unidentified leakage. With unidentified leakage greater than 1 gpm, the leakage rate must be reduced to within limits within 4 hours or be in at least Hot Standby within the next 6 hours and in Cold Shutdown within the following 30 hours.

DESCRIPTION OF INCIDENT

On June 13, 1986, the Unit was at 48% power. The Variable Letdown Orifice, 1NV849, was in service and throttled to approximately 30 gpm to reduce pressure due to a NV to Component Cooling System (EIIS:CC) leak at the Letdown Heat Exchanger. The fixed orifices flowpaths were isolated.

At 1100 hours, the Unit entered the action statement of Tech Spec 3.4.5.2 due to unidentified NC leakage of 1.486 gpm. At 1500 hours, an Unusual Event was declared due to unidentified NC leakage of greater than 1.0 gpm. At approximately 1542 hours, alarms were received indicating the loss of Motor Control Center (MCC) 1MXD. This resulted in the loss of control power to 1NV849 and 1RL138, Hydrogen Cooler Temperature control valve, causing the valves to fail open and closed, respectively. Charging flow suddenly increased to approximately 130 gpm and Pressurizer level began decreasing. This gave the indication of a probable NC leak. At 1550:11 hours, an alarm was received indicating an increasing Hydrogen temperature on the Generator. At 1551:02 hours, 1NV849 was isolated, but the Pressurizer level continued to decrease. The hydrogen temperature on the Generator also continued to increase. The Containment Floor and Equipment Sump B High Level alarm was received at 1601:13 hours, confirming NC leakage.

At approximately 1610 hours, Reactor power and Turbine load were decreased due to high Generator hydrogen temperature and NC leakage. Pressurizer level was being maintained by maximum charging. At 1638:34 hours, the Main Turbine was manually tripped and the Unit entered Mode 2, Startup. At 1638:46 hours, valves 1NV1A and 1NV2B, NC Letdown to Regeneration Heat Exchanger Isolation valves, were manually closed in an attempt to isolate the NC leak. Excess Letdown was established at 1641:28 hours. Pressurizer level returned to normal. At approximately 1700 hours, the Unit entered Mode 3, Hot Standby. A Work Request was initiated to investigate and repair MCC 1MXD. At 2105 hours, the Unit entered Mode 4, Hot Shutdown. On June 15, 1986, at 0257 hours, the Unit entered Mode 5, Cold Shutdown. The Work Request was completed on June 18, 1986.

CONCLUSION

This incident is assigned Cause Code B, Design Manufacturing, Construction/ Installation deficiency. Upon shutdown of the unit, an investigation revealed a 360 degree circumferential weld failure on the outlet flange of 1NV849. The preliminary conclusion is that the weld failed due to fatigue resulting from cavitation induced vibration of 1NV849. This can be attributed to long term utilization of the valve throttled at low flow. 1NV849 had been used for approximately one month to reduce pressure due to the Letdown Heat Exchanger leak. A formal failure analysis is being performed by Westinghouse. The interim resolutions are to replace the failed weld and limit operation of 1NV849 to a short period of time, 5 to 10 minutes, at low flow when re-establishing letdown to minimize shock on the piping. Vibration in the vicinity of the letdown orifices will be monitored to verify acceptable operations. The weld has been repaired. Upon receipt of the Westinghouse report of the failure analysis, Duke will review the data and make recommendations for a permanent resolution.

A contributing cause to this incident is loss of power on MCC 1MXD. Investigation revealed that the nameplate on a control transformer in compartment R04A of MCC 1MXD became unglued. The nameplate fell against a terminal strip and caused an overload. The overload tripped the normal feeder breaker to the MCC and prevented the alternate feeder breaker from closing in. The failure of MCC 1MXD caused a loss of control power to 1NV849 and 1RL138. The breaker in 1MXD R04A was replaced and the work completed on June 18, 1986. On May 15, 1986, a Work Request was initiated to remove the nameplates from all control transformers in all Unit 1 and shared Nelson 600V MCCs. The work request was completed on June 16, 1986. The removal of all control transformer nameplates from Unit 2 Nelson 600V MCC was done in 1985 per Significant Deficiency No. 414/85-09. At that time, an inspection of Unit 1 revealed a low percentage of fallen nameplates. A decision was made to remove the Unit 1 nameplates during the first refueling outage.

An exact value of the leakrate was found to be difficult to determine. Personnel employed various calculation methods in an attempt to quantify the NC leakage. The method which was chosen as the most accurate was the Radwaste inventory method. This data covered the entire span of the incident, and the Radwaste input before and after the incident was constant. Therefore, using the Radwaste generation base as the most reliable indication, the average leakrate was determined to be 87 gpm.

A post shutdown inspection for NC leakage revealed a leak on the manway of the Pressurizer. The leak has been repaired.

Post incident vibration monitoring of the associated Unit 2 piping revealed no unusually high vibrations on the variable letdown orifice flowpath.

NRC Form 366A (9-83)

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)
Catawba Nuclear Station, Unit 1	0 5 0 0 0 4 1 3	8 6	— 0 3 1	— 0 2	0 4 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

A review of NPRDS indicated there are no reported failures of this type involving Nelson MCC.

There were two previous incidents of a Unit Shutdown due to unidentified leakage at Catawba (see LER's 413/85-59 and 413/85-61).

CORRECTIVE ACTION

(1) Reactor power and Turbine load were decreased.

(2) Valves 1NV1A and 1NV2B were closed.

(3) A Work Request to repair MCC 1MXD R04A, was initiated and completed.

(4) A Work Request to remove all remaining control transformer nameplates from Unit 1 MCCs, was completed.

(5) Procedure changes to OP/1/A/6100/01, Controlling Procedure for Unit Startup and OP/1/A/6200/01, Chemical and Volume Control System, were implemented to add operational limitations for 1NV849.

(6) The weld failure was repaired.

(7) A followup surveillance will be performed based on the proposed action as stated in the final resolution of the weld failure cause.

(8) An accurate determination of the NC leakrate during this incident has been completed.

SAFETY ANALYSIS

All NC System leakage from the failed weld went to the Containment Floor and Equipment Sump. The water was pumped to the Waste Evaporator Feed Tank, Floor Drain Tank, and the Steam Generator Drain Tank. All water was eventually processed, sampled, and discharged through the Liquid Radwaste System. NC System inventory was maintained by the Centrifugal Charging Pumps and the Fueling Water Storage Tank. There were no unexpected exposure problems during the cleanup of the Containment Building.

During the Unit Shutdown, NC System cooldown rates did not exceed 100 degrees F in any 1 hour period. Pressurizer pressure did not decrease below 2050 psi and the Pressurizer level did not decrease below 19%. Average temperature decreased to 530 degrees F post shutdown, but stabilized at 551 degrees F after 30 minutes. The Steam Generator levels decreased to a minimum of 35% narrow range but quickly stabilized at approximately 50% post shutdown.

The health and safety of the public were not affected by this incident.

NRC FORM 366A (9-83)

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Catawba Nuclear Station, Unit 2	0 5 0 0 0 4 1 4	1 OF 0 6

TITLE (4)

Safety Injection During Loss of Control Room Test 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)
0 6	2 7	8 6	8 6	— 0 2 8 —	0 0	0 7	2 5	8 6	N/A	0 5 0 0 0
										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)	[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)	[X] OTHER (Specify in Abstract below and in Text, NRC Form 366A) 50.72(b)(1)(iv)
[ ] 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	
Roger W. Ouellette, Associate Engineer - Licensing	7 0 4	3 7 3 - 7 5 3 0

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 June 27, 1986, at 0953:14 hours, Safety Injection was actuated on low Pressurizer and Main Steam Line pressure. Pressurizer and Steam Line pressure had decreased during the Loss of Control Room Test due to inadvertent opening of the Steam Generator (S/G) Power Operated Relief Valves (PORVs). The ensuing decrease in Pressurizer and Steam Line pressure was sufficient to cause Safety Injection to be actuated when unit control was transferred back to the Control Room. The unit was in Mode 3, Hot Standby, at the time of the Safety Injection.

The incident is assigned Cause Code B, Design, Manufacturing, Construction/Installation Deficiency, and Cause Code D, Defective Procedure. The S/G PORV controls were changed since initial installation, but PORV control device legends located on the Auxiliary Shutdown Panels (ASPs) were not revised accordingly so that personnel could accurately position the PORVs. Procedures which specify the manner in which to adjust the PORV controls were not revised following the implementation of the design change, so that the operators were unaware of the change to S/G PORV controls on the ASPs.

This incident is reportable pursuant to 10 CFR 50.72, Section (b)(1)(iv) and 10 CFR 50.73, Section (a)(2)(iv).

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
Catawba Nuclear Station, Unit 2	0 5 0 0 0 4 1 4	8 6	— 0 2 8	— 0 0	0 2 OF 0 6

TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND

Procedure TP/2/A/2650/03, Loss of Control Room Functional Test, provides guidelines to demonstrate:

(1) That the plant can be brought to Hot Standby conditions from a moderate power level (10-25%) using Auxiliary Shutdown Panel (ASP) controls and following procedure AP/2/A/5500/17 (Loss of Control Room).
(2) That the plant can be maintained at Hot Standby conditions for 30 minutes from the Auxiliary Shutdown Panels.
(3) That the plant can be brought to Hot Standby and maintained in that condition with the minimum shift requirements of Technical Specifications.
(4) That the Reactor Coolant System (EIIS:AB) can be cooled down at least 50 degrees F from a steady state Hot Standby condition while being operated from the ASPs.

A Safety Injection (S/I) signal is initiated on several conditions, among those being Pressurizer Pressure less than 1845 psig, or Main Steam Line Pressure less than 725 psig.

A S/I signal is blocked to the Diesel Generator load sequencers and sequenced loads when controls are transferred to the Auxiliary Shutdown Panels. In the event that initiating conditions are present, these components will be actuated if control is transferred back to the Control Room. A S/I signal also initiates a Phase A Containment Isolation. A Phase A Isolation isolates all Containment penetrations which are non-essential to Reactor/Containment safety or cooling.

DESCRIPTION OF INCIDENT

On June 27, 1986, the Loss of Control Room Functional Test was begun with the unit at 24% power. In accordance with the test procedure, the Reactor was manually tripped at the Reactor Trip Switchgear at 0942:20:855 hours. Main Feedwater (CF) (EIIS:SJ) Isolation and the autostart of both Motor Driven Auxiliary Feedwater (CA) (EIIS:BA) Pumps occurred at 0942:32 hours. Low-Low levels subsequently occurred in all 4 Steam Generators (S/Gs). The CA Pump Turbine (CAPT) automatically started on low-low level in 2 out of 4 S/Gs. CF Pump 2B later tripped at 0942:42 hours on low suction flow.

Unit control was transferred from the Control Room to Auxiliary Shutdown Panels at 0942:49 hours. Letdown Pressure Control Valve, 2NV-148A unexpectedly failed open when the transfer occurred. Letdown flow indication oscillated rapidly for approximately 3 minutes. Charging flow during this time was approximately 38 gpm. Letdown flow then spiked high to a maximum off 177.8 gpm at approximately 0946:30 hours. Letdown was manually isolated after Pressurizer level dropped to below 20%. Letdown flow dropped to approximately 15 gpm by 0947:30 hours.

At 0946:59 hours, the PORV breakers at the Auxiliary Feedwater Pump Turbine Control Panel (AFWPTCP) were closed in accordance with the procedure. When the breakers were energized, S/G A, B, C, and D Power Operated Relief Valves (PORVs) opened to 75%. This was due to the PORV manual loaders on the AFWPTCP being initially set per procedure to what was thought to be a setpoint for opening at 1125 psig. A Design Change had modified the PORV controls, but the impact on the function of the ASP PORV controls had not been adequately communicated/understood.

Therefore, the changes had not been incorporated into all applicable procedures, nor had manual loader legends/scales been changed to accurately indicate the PORV positions on the ASP. The S/G PORV opening caused a rapid depressurization of the secondary side with an accompanying cooldown of the primary side. Personnel at the AFWPTCP observed the decreasing steam pressure and attempted to increase the setpoint for PORV opening, but actually opened the PORVs further. Personnel in the Control Room observed actual PORV position go OPEN after energizing the AFWPTCP, but did not immediately communicate this to ASP personnel due to the nature of the test. S/G levels responded to the PORV openings by first swelling and then dropping rapidly off the narrow range scale. The ASP Operators were observing wide range indication. The CAPT had been secured at 0945:45 hours. For approximately 4.5 minutes, the S/Gs were blowing down through the PORVs with CA flow being provided to S/G D.

Pressurizer Pressure dropped off scale (less than 1700 psig) approximately 2 minutes after the S/G PORVs opened. Safety Injection (S/I) condition on Low Pressurizer Pressure (1845 psig) occurred at 0949:46:179 hours. S/I condition on Low Steam Line Pressure Loop D (725 psig) occurred at 0950:08:107 hours. However, S/I was partially blocked at that time due to control being transferred to the ASPs. Several containment isolation valves closed automatically and Charging suction was automatically aligned to the Refueling Water Storage Tank when the S/I conditions were satisfied.

As Pressurizer level continued to decrease and fall off scale, personnel at the ASP manually started Centrifugal Charging (NV) Pump 2B. However due to valve controller labeling problems, ASP Operators reduced Charging flow rather than increasing it while adjusting the manual loader for 2NV-294, Charging Pumps Flow Control Valve.

At approximately 0953:30 hours, the decision was made to terminate the test and return control to the Control Room. At 0953:14 hours, the Senior Reactor Operator directed personnel to swap control back to the Control Room. When this was done, S/I was immediately actuated due to the unblocking of the still-present actuation signal. Both Diesel Generators (D/G) actuated on LOCA condition. The S/G PORVs reclosed on transfer of controls to the Control Room. The S/I signal started the Residual Heat Removal (ND) Pumps, Safety Injection (NI) Pumps, the CAPT, and opened 2NI-9A, and 2NI-10B, NV Pumps Discharge to Cold Leg Isolation Valves, and associated CA valves. 2NV-148A reclosed following the transfer back to the Control Room.

Both D/G load sequencers completed accelerated sequencing within approximately 21 seconds. Containment isolation valves not repositioned previously were positioned on the Phase A Isolation signal. S/I flow restored Pressurizer level to 33%, and pressure to 1250 psig within approximately 5.5 minutes.

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TEXT (If more space is required, use additional NRC Form 366A's) (17)

At 0958 hours, S/I was reset, the Cold Leg Injection Isolation Valves were closed and the NI and ND Pumps were secured. The S/I had further reduced Steam Line pressure to approximately 480 psig and primary coolant temperature to approximately 468 degrees F. The CAPT was secured at 1000 hours.

After the NV Pumps suction was automatically swapped to the Refueling Water Storage Tank (FWST), Volume Control Tank (VCT) level began increasing due to NV Pump recirculation flow. The VCT was realigned to the suction of the NV Pumps and the FWST Suction Valves were closed at 1007 hours, completing the realignment of normal charging.

CONCLUSION

In January 1985, a Design Change Authorization (DCA) was originated and approved. This DCA upgraded the S/G PORVs to safety-related per NUREG-0954, Supplement No. 2. Within this DCA, the function of the ASP S/G PORV manual loaders was changed so that the PORVs open in direct response to any position dialed-in on the loader. Previously, the loader provided a setpoint selection so that the PORVs open fully when the setpoint was exceeded. This DCA was implemented after Hot Functional Testing (HFT) was completed in October 1985.

While changing the Manual Loader functions for this DCA, the legends on the loaders were not revised. Since the manual loaders appeared physically the same as during HFT, the ASP Operators attempted to close the PORVs by increasing the setpoint, but in actuality opened the PORVs further. Therefore, this incident is assigned Cause Code B, Design, Manufacturing, Construction/Installation Deficiency.

This incident is also assigned Cause Code D, Defective Procedure. On several occasions during December 1985, January 1986, and February 1986, responsible personnel discussed the DCA, but the effects on ASP operation were not understood, and therefore procedures and training were not modified.

During the transient, several deficiencies were identified:

(1) D/G Load Sequencer A Load Group 7 was 0.1 second late. The timer has been recalibrated.
(2) The ASP controller for the Charging Pumps Flow Control Valves, 2NV-294, was labeled incorrectly. The label was corrected.
(3) Event Recorder (ER) times were 4 hours late. The timer was reset.
(4) Intermediate Range Channel N-35 was undercompensated. The voltage was adjusted from -10V to -16V.
(5) 2NV-13A, Letdown Orifice 2A Outlet Containment Isolation valve, could not be closed during the transient. The valve was found to be stuck open. The valve was freed and successfully retested. 2NV-13A is a 2 inch Borg Warner Gate Valve. Per NPRDS, there are no reported failures of 2 inch Borg Warner valves in which the valve became stuck in the open position.
(6) ER416, CF Pump B Suction Pressure Emergency Lo Trip, registered with an adequate suction pressure present. A Work Request was issued to investigate/repair the point. This point is actually indicating suction flow. A Station Problem Report was submitted to correct the point ID.

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(7) Several additional problems were identified with Operator Aid Computer indication. The problems are being investigated.

(8) Personnel had difficulty controlling Reactor Coolant Pump Seal flow. Additional labeling on the ASPs was added to clarify control requirements for 2NV-309. The appropriate operations procedures were also revised to clarify use of the valve.

(9) 2NV-148A, Letdown Pressure Control Valve, failed open following transfer to the ASP. A poor electrical connection in the control circuitry was found and corrected. The control circuit for the valve had maintenance performed on it in January 1986. It is not certain if the poor connection was the result of this previous maintenance activity.

(10) Difficulty was encountered in resetting the Main Steam Isolation Bypass Valves. The problem could not be recreated during investigation. The associated Monthly Surveillance Test was performed successfully.

None of the identified Equipment Malfunctions are reportable to NPRDS.

This incident is considered to be an isolated occurrence. The Nuclear Station Modification program currently in use provides more stringent controls on modifications than the Design Change program.

This is the first actuation of Safety Injection on Unit 2.

CORRECTIVE ACTION

(1) In light of degrading conditions, the Loss of Control Room Test was terminated and control was transferred back to the Control Room. Safety Injection was actuated at this time.

(2) A review of all Design Changes and Construction Department Shutdown Requests implemented after Hot Functional Testing and prior to Fuel load was performed prior to the unit re-entering Mode 2, Startup.

(3) A review of both units Auxiliary Shutdown Panels and Auxiliary Feedwater Pump Turbine Control Panels was performed to identify all differences between units and all Human Engineering Deficiencies (HEDs). Numerous unit differences and labeling problems were identified. Labeling problems were corrected.

(4) Revisions were made to Operating and Abnormal Procedures to reflect changes required as a result of Corrective Action (3). Also added were instructions to manually initiate Safety Injection, Containment Spray, and Annulus Ventilation if required following a Loss of Control Room Incident. Test termination criteria was also clarified in the test procedure.

(5) TT/2/A/9100/03, ASP and Auxiliary Feedwater Pump Turbine Control Panel Supplemental Test, was originated and performed prior to Loss of Control Room Retest on July 11, 1986. This test verified proper function of various valves while controlling at the ASPs.

(6) TP/2/A/2100/01, Controlling Procedure for Power Escalation, was revised to include more thorough pre-transient test preparation and walk throughs. This will include reviews of previous test results, Operating Procedures, Abnormal Procedures, and Emergency Procedures.

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

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APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

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(7) Training was provided to appropriate personnel on this incident, procedural changes made to Operating and Abnormal Procedures, labeling and surface changes made to the ASPs as a result of the post incident analysis, and Unit 1/Unit 2 control differences.

(8) Completion of ASP surface enhancements not requiring hardware modifications, control board cutting, or a system shutdown are to be identified. The remaining items will be implemented during the first refueling.

SAFETY ANALYSIS

Following the manual Reactor Trip in accordance with the Loss of Control Room Test, power immediately decreased to zero. S/G narrow range levels decreased to approximately 15% and were being restored by both Motor Driven Auxiliary Feedwater Pumps and the Auxiliary Feedwater Pump Turbine. Pressurizer Pressure was at approximately 2235 psig at the time of the trip and Pressurizer level was at approximately 29%. Both parameters began slowly decreasing following the trip. Reactor Coolant (NC) Highest average temperature was 560.9 degrees F and S/G Steam Pressure was approximately 1030 psig at the time of the trip.

When unit control was transferred to the Auxiliary Shutdown Panels, Letdown flow increased to 177.8 gpm before being manually isolated. An unsuccessful attempt was made to increase charging flow, due to controller legend problems. The inadvertent opening of the S/G PORVs resulted in a rapid decrease in Main Steam pressure. S/G narrow range level increased and then rapidly decreased and dropped off scale. Wide range level did not decrease below 54.4% indicated, which is approximately 63% actual level in the S/Gs throughout the incident. The top of the S/G tube bundle is at approximately 59%. While the PORVs were open, Pressurizer level was lost completely in approximately 2 minutes, and NC wide range pressure decreased to 702 psig. After Pressurizer level was lost, approximately 400-500 cubic feet of voiding occurred in the NC System. This is based on the rate of level recovery following initiation of Safety Injection. Personnel and the Safety Parameter Display System did not detect any significant drop in Reactor Vessel Level Instrumentation readings.

When unit control was transferred back to the Control Room, S/I was initiated automatically as Pressurizer Pressure and Steam Pressure were low. The S/G PORVs closed automatically. Cold Leg Injection was initiated with the Safety Injection Pumps and Centrifugal Charging Pumps. All S/I equipment functioned satisfactorily.

Following the initiation of S/I, NC pressure and level began increasing. Pressurizer pressure was restored to approximately 1250 psig and Pressurizer level was restored to 33% after approximately 5.5 minutes. The maximum cooldown rate of NC System during this incident was 95.5 degrees F/hour.

Based on Health Physics sampling of Main Feedwater activity, there were no radioactive releases during this incident.

The health and safety of the public were not affected by this incident.

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LICENSEE EVENT REPORT (LER)

Facility Name (1): River Bend Station

Docket Number (2): 0|5|0|0|0|4|5|8

Page (3): 1 OF 0|1

Title (4): Hand Held Radio Causes Loss of Offsite Power

Event Date (5) Month	Day	Year	LER Number (6) Year	Sequential Number	Revision Number	Report Date (7) Month	Day	Year
0 1	0 1	8 6	8 6	0 0 2	0 0	0 2	0 4	8 6

Other Facilities Involved (8): Docket Number(s) 0|5|0|0|0 ; 0|5|0|0|0

Operating Mode (9): 3

Power Level (10): 0 0 0

Licensee Contact for This LER (12):

Name: C. Alan Bysfield - Senior Systems Engineer

Telephone Number: 5|0|4 6|3|5|-|6|0|9|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
B	F J	T M RC	G 0 8 0	N					
D	F J	T M RC	G 0 8 0	N					

Supplemental Report Expected (14): X NO

Abstract (16):

On 01/01/86 at approximately 0941, preferred station transformers A and C tripped off the line. One hour later, at approximately 1044 preferred station transformers B and D also tripped prior to A and C being restored. This resulted in a total loss of offsite power (LOP) to the station. An Unusual Event was declared at 1045 and operations entered into appropriate Abnormal Operating Procedures. The plant was shutdown at the time of the LOP due to a reactor scram that had occurred approximately six hours earlier. Upon investigation it was determined that hand held radios most likely caused spurious signals in the tone relaying transfer trip receivers of the preferred station transformers. Corrective action is being taken in an effort to minimize the probability of recurrence. This event did not affect the public safety and welfare.

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1/1

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River Bend Station	0 5 0 0 0 4 5 8	8 6	— 0 0 2	— 0 0	0 2 OF 0 8

Sequence of Events:

On 01/01/86 at 0941 with the unit in operational condition 3 (hot shutdown) and cooling down from a reactor trip which occurred approximately six hours earlier (reference LER 86-001), preferred station transformers 'A' and 'C' tripped. Recirculation pump 'A' tripped, the operating condensate pump tripped, and the Reactor Water Cleanup (RWCU) system isolated. Reactor Protection System (RPS) bus 'A' de-energized initiating a half scram and partial Nuclear Steam Supply Shutoff System (NSSSS) isolation. The partial NSSSS isolation caused an instrument air isolation to the Reactor Building which caused the scram valves to leak filling the Scram Discharge Volume (SDV). This subsequently resulted in an RPS actuation on high SDV level at 0957. Upon the preferred station transformer trips Division I and III diesel generators started, Division I emergency ventilation systems autostarted, and standby service water pumps 1SWP*P2A, B, C, and D load sequenced. Normal service water pump SWP-P1B and circulating water pump CWS-P1B were still running but without bearing cooling water since bearing cooling water pump BCS-P1A had lost power. At 1001 the Main Steam Isolation Valves (MSIVs) automatically isolated due to decreasing condenser vacuum.

At 1003 operators were dispatched and attempted to recover de-energized load centers. At 1031 RPS bus 'A' was reset. Later, panel 1SCM*PNL01A was discovered de-energized due to a blown fuse in transformer 1SCM*XRC14A1. This caused several Control Building HVAC (HVC) and Fuel Building HVAC (HVF) dampers to close which caused the Division I Control Building chiller (HVK) to trip. Subsequent attempts to restore operation of HVK chillers 'B' and 'D' were also unsuccessful. The partial NSSSS isolation remained sealed in because of de-energized panel 1SCM*PNL01A.

The RPS actuation was reset at 1042. At 1044, approximately one hour after the initiating event, preferred station transformers 'B' and 'D' tripped. The station was now in a complete loss of offsite power (LOP). The Division II diesel generator started and sequenced properly. An Unusual Event was immediately declared and Abnormal Operating Procedures (AOP) 004, 005, 0010 and 0042 were initiated. Reactor Water level was +80 inches on the shutdown range and pressure was at 240 psig.

At 1114 the half RPS actuation was reset and power to RPS bus 'B' was restored. At 1124 the preferred station transformers were energized, but the supply breakers to the plant could not be closed. It was determined that breaker closure was locked out by the tone relaying transfer trip (fiber optic) system which could not be reset. At 1130 this backup system was disabled and the breakers were closed. All in house loads were restored and the Unusual Event ended after an hour and ten minute duration. The plant was stabilized.

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
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Investigation:

In an effort to determine the cause of the transformer trips an investigation of the protective relaying was conducted and revealed that no protective relaying targets were initiated. It was further determined that the trip signals sent to the lockout relays could only have been initiated by a spurious signal in the backup pilot wire or tone relaying transfer trip circuits. Functional and diagnostic testing of both the pilot wire and tone relaying circuits showed that both systems were operating as designed at the time of testing.

As a result of this testing two items were noted. First, spurious trips could be generated on the tone relaying system with hand held radios in close proximity (within approximately a 10-12 foot radius) of the transmitters/receivers. Second, some of the tone relaying keying and rack power were supplied from two separate battery sources. Although no spurious trips could be simulated by testing, this type of connection could result in transients within the tone relaying equipment. It was decided to correct the wiring in the field such that keying and rack power were supplied by the same battery source.

The two types of hand held radios tested were the 4 watt, 150 MHz Motorola and 5 watt, 450 MHz Motorola. Both are commonly used on site by security and operations personnel. Both of these radios were keyed to transmit inside the control building of the Fancy Point switchyard and both caused spurious trips on the tone relaying system. Also

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tested were 100 watt, 50 MHz and 150 MHz Motorola mobile radios from just outside the switchyard control building with the doors open. The mobile radios did not initiate either a trip or a loss of guard signal in the tone relaying system. After careful consideration it was concluded with high probability that the LOP was caused by radio frequency interference.

Also investigated was the difficulty in resetting the lockout relays. Because of the complexity of the tone relaying and pilot wire tripping circuitry, the resetting of the lockout relays must be performed in the proper sequence. It was determined that operations procedures did not address the required sequence.

Corrective Actions:

As a result of this event several corrective actions have been completed or are in progress. These corrective actions include:

1. Installation of shielding on the tone relaying equipment in the Fancy Point switchyard. Shielding of the equipment in the plant is not required because the equipment is enclosed in a reinforced concrete room with locked doors and a sign restricting the use of radios on each door. This activity is presently scheduled for completion by 02/12/86.
2. Rewiring the tone equipment such that both channels are required for tripping. At the time of the event if one channel had a loss

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River Bend Station	0 5 0 0 0 4 5 8	8 6	— 0 0 2	— 0 0	0 6 OF 0 8

of guard and the other channel had a trip signal the transfer trip would have been initiated. This wiring change provides increased reliability to help prevent spurious tripping. Temporary Alterations were installed. This design change (MR 86-0081) is scheduled for completion prior to the planned 35 percent power scram at the conclusion of test condition 2.

3. Changing DC power supplies to tone relaying equipment such that the keying and rack power are both supplied from the same DC source. Temporary Alterations were installed. The design change (MR 86-0026) is scheduled for completion prior to the planned 35 percent scram at the conclusion of test condition 2.
4. Installation of sequence of event recorders in the switchyard and at the generator/transformers protective relaying panel. This requires the completion of two design modifications (MR 86-0027 and MR 86-0098). The final installation of these recorders is to be completed during an outage just after the planned 35 percent power scram.
5. Installation of additional drainage reactors at the plant end of the pilot wire shielding. This design change (MR 86-0093) is scheduled for completion prior to the planned 35 percent scram at the conclusion of test condition 2.
6. Installation of Supervisory Control and Data Acquisition (SCADA) system alarms to provide annunciation in the main control room and

at the Government Street transmission and distribution control center for loss of channel signals on tone relaying equipment. This is scheduled for completion on 02/05/86. Additional capabilities for monitoring trip and loss of guard signals will be added (MR 86-0094) upon receipt of alarm cards by approximately 04/18/86.

7. Training personnel on the restricted use of radios. Signs have been posted in the Fancy Point switchyard prohibiting the use of radios in the control building. Signs have also been posted on the doors of the room in the turbine building which houses the tone relaying equipment. Letters have been sent to Security, Operations, Maintenance, and Transmission and Distribution personnel informing them of the radio use restrictions. This action is complete.
8. Training operations personnel on the resetting of lockouts, including necessary procedural changes and the posting of operator aids. Operator aids have been posted. Operators are presently undergoing requalification and will be trained on protective relaying, tone relaying, and pilot wire relaying including the proper resetting of the lockout relays. This process is presently scheduled to be completed on or before 03/28/86.
9. A procedure for the periodic testing of the tone relaying equipment and the proper operation of the sequence of event

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recorders is being written and is scheduled to be completed prior to the planned 35 percent scram at the conclusion of test condition 2.

Safety Assessment:

There were no safety consequences to the public as a result of this event. The safety implications of a loss of offsite power are however, clearly recognized and it is for this reason that the above corrective actions are being taken.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): RIVER BEND STATION

DOCKET NUMBER (2): 0 5 0 0 0 4 5 8

PAGE (3): 1 OF 0 3

TITLE (4): Trip of EJS*SWG2A Due To a Faulty Output Transistor

EVENT DATE (5) MONTH	DAY	YEAR	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	REPORT DATE (7) MONTH	DAY	YEAR
0 7	3 1	8 6	8 6	0 4 7	0 1	1 0	2 0	8 6

OPERATING MODE (9): 1

POWER LEVEL (10): 0 9 6

LICENSEE CONTACT FOR THIS LER (12)

NAME: E.R. Grant - Director-Nuclear Licensing

TELEPHONE NUMBER: 5 0 4 6 3 5 - 6 0 9 5

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE DESCRIBED IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	E C	1 5 1	X 9 9 9	Y

SUPPLEMENTAL REPORT EXPECTED (14): X NO

ABSTRACT

On 7/31/86 with the unit at 94% rated power and again on 8/2/86 with the unit at 99% rated power 1EJS*SWG2A feeder breaker tripped causing the automatic start of both divisions of Annulus Mixing, Standby Gas Treatment and Fuel Building Ventilation Systems. Additionally, various drywell and containment unit coolers as well as the Division I diesel generator fuel oil transfer pump were lost. A defective protective relay in the feeder breaker to the 1A containment Unit Cooler was found to be the cause of the trip. During the 7/31/86 event the Technical Specification surveillance 4.8.1.1.1.a was not completed within one hour as required by Action 3.8.1.1.b. There were no adverse affects on the health and safety of the public as a result of these events since the start of these Engineered Safety Features placed the unit in a more conservative condition by filtering any radioactivity from the air prior to releasing it to the environment.

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At 0243 on 7/31/86 with the unit at 94% rated power containment unit cooler 1A feeder breaker 1EJS*ACB36 tripped concurrent with the switchgear 1EJS*SWG2A feeder breaker 1EJS*ACB38 tripping. The 1EJS*ACB36 targets indicated an overload. The loss of the switchgear resulted in the automatic start of both trains of the following Engineered Safety Feature (ESF) systems: Annulus Mixing, Standby Gas Treatment, and Fuel Building Filtration. Additionally, power was lost to the Division 1 diesel generator fuel oil transfer pump along with power to several valves on the Low Pressure Core Spray (LPCS), Residual Heat Removal (RHR) train A and Reactor Core Isolation Cooling (RCIC) systems, and various drywell and unit coolers. Reactor power was immediately reduced to approximately 55% to maintain area temperatures, due to the loss of area coolers.

Testing of feeder breakers ACB36 and ACB38 was performed and no problems were identified. Unit Cooler operation was checked and found to be normal. Drawings, design modifications, and as built wiring were reviewed for correctness and no abnormalities impacting this problem were found. Feeder breaker ACB36 is equipped with an overcurrent timer relay (type ITE 50D) which initiates a trip of breaker ACB38 in the event ACB36 fails to clear a fault in sufficient time. This circuitry and relay were tested and found to function correctly. Unit Cooler 1A was placed into service and functioned properly. At the conclusion of these investigations the unit was returned to service but Unit Cooler 1A was left in standby as a precaution.

Technical Specification Action 3.8.1.1.b required surveillance 4.8.1.1.1.a to be performed within one hour (due to the loss of the DG fuel oil transfer pump). This surveillance was satisfactorily completed at 0900, beyond the allowed time interval. This is an isolated case of a missed Technical Specification Action and is not indicative of a generic problem.

On 8/2/86 at 0637 with the unit at 99% rated power, feeder breaker ACB38 again tripped on apparent overload of Unit Cooler 1A with all events and actions occurring as described in the 7/31/86 event above, with the exception that Unit Cooler 1A was not inservice at the time.

With the overload indication having been reported on Cooler UC1A, maintenance tested the ITE 50D relay in place. The relay tested normal except that it's pushbutton test circuit and target indicators would not work, indicating some malfunction. Since the ambient temperature was very close to the equipment qualification temperature of 114 degrees F it was felt that this relay may be heat sensitive. The relay was removed from service and placed in an oven at 120 degrees with dc power connected and the trip circuit monitored. At one hour and 10 minutes, the ITE 50D relay failed with a continuous trip output. The malfunction of this relay caused the overload indication and trip of feeder breaker ACB38. The relay was replaced with a new unit.

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The defective relay (ITE 50D) was returned to its manufacturer, Brown Bovari. GSU asked the manufacturer to determine the failure mode of the relay. GSU suspected that the transistor had failed and asked the manufacturer to determine if the output transistor is located too close to a 10 watt resistor on the circuit board. Under the circumstances, GSU initiated a Modification Request (MR 86-1316) to replace the trip function of this and two other similar (ITE 50D) relays with electro-mechanical time overcurrent trip devices. Additionally, there are two ITE 46D relays that provide trip functions on the recirculation pumps and 26 other ITE 50D relays that provide only overload indication in use at River Bend Station.

MR 86-1316 has subsequently been cancelled because the manufacturer has satisfactorily determined that the output transistor only was defective and caused the trip. The preliminary investigation by the manufacturer has determined that the transistor developed high leakage over time and is indicative of a batch problem rather than a generic one. The manufacturer has recommended this transistor, identified as Q3 by the vandor on his circuit board, be replaced with a different type transistor which has higher voltage and lower leakage characteristics. The transistors that are being removed will be sent back to the manufacturer for further analysis. GSU is now replacing the output transistors in all the affected relays via MR 86-1577. The replacement of the transistors in the relays with a trip function is expected to be complete by 11/11/86 and by 12/31/86 for the relays with only an indication function.

This failure resulted in a partial loss of Division I power. In neither event were redundant trains affected and all actions, both automatic and manual, resulted in system performance as designed. At no time was the health and safety of the public affected.

APPENDIX F

OPERATIONAL EVENT LISTINGS

APPENDIX F

OPERATIONAL EVENT LISTINGS

This appendix contains listings of events that are of potential concern from a core damage standpoint but most of which were not, in general, selected as actual accident sequence precursors. Included are unavailabilities of RHR systems, mostly at zero-power conditions (Table F.1), and unavailabilities of single-train safety systems, such as HPCI, HPCS, RCIC, and soluble boron (Table F.2). These were not, in general, selected as accident sequence precursors.

Table F.3 through F.6 list events reviewed in this study by docket and LER number. Table F.3 provides a listing of the events involving a reactor trip from power or a trip that occurred during shutdown but with no additional failures or reported unavailabilities. Table F.4 lists the 1984 trip events that were more complicated, including events involving a core-damage initiator such as LOCA, SLB, LOOP, or LOFW or trips involving additional system failures. Several of the precursors were selected from this group.

Table F.5 provides a listing of the events involving a trip followed by an LOFW and no additional unavailabilities. Table F.6 lists LOFWs not requiring a trip and those that initiated a trip. Table F.7 lists events involving multiple failure or unavailabilities of various plant systems required in core-damage mitigation sequences.

Finally, Table F.6 lists all of the 1986 events selected for detailed review before selection of the 36 precursors.

Table F.1. Residual heat removal system unavailabilities reported in 1986

Event identifier	Plant name	Event date	Reactor power (%)	Event description
275/86-012	Diablo Canyon 1	09/08/86	0	A technician inadvertently grounded a power supply while performing maintenance, isolating the RHRS
280/86-017	Surry 1	05/24/86	0	A spurious signal during maintenance activities caused the RHRS to trip
302/86-002	Crystal River 3	01/10/86	0	The RHRS was disabled when the service-water system was shut off to recover two divers who died while working in the sea pump systems
302/86-003	Crystal River 3	02/02/86	0	RHRS was unavailable for 24 min when the pump A shaft failed; pump B isolation valve failed closed
312/86-016	Rancho Seco	10/03/86	0	A maintenance error caused a short circuit, which isolated RHR for 13 min
312/86-024	Rancho Seco	11/15/86	0	The RHRS isolated when a false signal was generated during inverter fuse replacement
312/86-030	Rancho Seco	12/08/86	0	The RHRS isolated due to a maintenance error committed while an employee was working on a transformer
317/86-002	Calvert Cliffs 1	03/22/86	0	During a test, a maintenance procedure error caused the RHRS to trip off
323/86-002	Diablo Canyon 2	01/17/86	0	An unlicensed operator inadvertently transferred power to the wrong panel, causing a valve to close and forcing an RHRS trip
352/86-025	Limerick 1	05/13/86	0	During a test, a personnel error caused the RHRS to isolate

Table F.1 (continued)

Event identifier	Plant name	Event date	Reactor power (%)	Event description
354/86-093	Hope Creek 1	12/09/86	0	During instrument maintenance, an error caused a false signal to isolate the RHRS
361/86-007	San Onofre 2	03/26/86	0	During shutdown for repairs, instrument error led to the RCS being drained too far, which caused the RHRS to isolate
366/86-027	Hatch 2	09/21/86	0	A procedure error in testing caused the RHRS isolation valve to close
373/86-022	Las..lle 1	06/12/86	0	An operator error during maintenance tripped the wrong switch and isolated RHRS for 2 min
373/86-022	Lasalle 1	06/12/86	0	The RHRS was isolated for 2 min when an operator activated the wrong key switch during testing
373/86-039	Lasalle 1	10/16/86	90	A personnel error in testing caused the high-pressure switch to be look-wired closed
388/86-015	Susquehanna 2	10/12/86	0	The outboard suction isolation valve closed on a spurious signal when switching "B" and "D" RHR pumps
388/86-015	Susquehanna 2	10/12/86	0	The RHRS isolated twice because of false signals; a waterhammer occurred the second time.
397/86-021	WNPS 2	06/20/86	75	Leakage from the loop B SDC return-line isolation valve was detected; the plant was shut down
413/86-044	Catawba 1	08/15/86	0	The RHRS was isolated for 15 min when a fuse blew during maintenance, causing several valves to close

Table F.1 (continued)

Event identifier	Plant name	Event date	Reactor power (%)	Event description
416/86-034	Grand Gulf 1	10/14/86	0	A personnel error committed in maintenance caused an electrical ground, which closed the isolation valves
440/86-032	Perry 1	07/05/86	0	Several RHRS isolations (16 min each) occurred as a result of communication failures among personnel
440/86-048	Perry 1	08/19/86	0	Several RHRS isolations of several minutes' duration occurred because of procedural errors during testing
440/86-088	Perry 1	12/09/86	0	During a test, an operator error caused the RHRS to become isolated
458/86-024	River Bend 1	03/25/86	0	RPS bus B tripped off spuriously, causing operating RHR train A to isolate
458/86-025	River Bend 1	03/26/86	0	During testing, a technician's error caused a short and an RHRS isolation
458/86-064	River Bend 1	10/31/86	0	An operator performing maintenance accidently grounded a power supply, isolating the RHRS

Table F.2. Unavailabilities in BWR single-train safety systems reported in 1986

Event identifier	Plant name	Event date	Reactor power (%)	Event description
249/86-014	Dresden 3	08/26/86	18	HPCI was found to be degraded for 6.5 d because of a condenser hotwell drain failure
254/86-034	Quad-Cities 1	11/17/86	70	HPCI was removed from service to repair a leaking steam supply valve
263/86-002	Monticello	01/07/86	97	The pump flow controller failed in auto mode because of bad contacts during routine testing
265/86-004	Quad-Cities 2	03/14/86	95	The HPCI turbine exhaust pressure switch failed, causing HPCI to isolate
277/86-016	Peach Bottom 2	07/09/86	100	During a test, the turbine control valve would not open beyond 75% of full open
298/86-017	Cooper	08/18/86	93	HPCI was made unavailable for 3 min due because of a personnel maintenance error in closing a valve
324/86-023	Brunswick 2	10/09/86	100	HPCI was inadvertently isolated as a result of electrical problems that occurr during reactor-water-cleanup system testing
331/86-022	Duane Arnold	10/22/86	87	In annual testing, the torus supply stop valve motor was found failed, making causing HPCI unavailable
331/86-024	Duane Arnold	11/21/86	94	A false signal caused by an electrical short circuit isolated HPCI
333/86-021	Fitzpatrick	12/23/86	82	A fire line valve cracked, spraying water onto breakers and the battery motor control center, causing the HPCI unavailability
341/86-029	Fermi 2	08/23/86		While the reactor was at 4% power, HPCI was found to have been essentially unavailable for 7 d because of sensor problems

Table F.2 (continued)

Event identifier	Plant name	Event date	Reactor power (%)	Event description
341/86-041	Fermi 2	07/22/86	2	During maintenance activities, HPCI was made unavailable when an error caused lube oil cooling to be lost
352/86-050	Limerick 1	10/17/86	100	The steam supply outboard isolation valve was found with a packing failure, making HPCI unavailable
352/86-052	Limerick 1	11/10/86	100	The inboard steam isolation valve closed on a false signal caused by an instrument technician
354/86-051	Hope Creek 1	10/23/86	70	HPCI had a degraded start-up time in testing caused by hydraulic system problems
366/86-014	Hatch 2	07/17/86	84	The HPCI flow was found to have been degraded for an indefinite time (<30 d)
388/86-002	Susquehanna 2	01/22/86	66	HPCI was removed from service to repair a ruptured (5-gal/min) lube oil cooler water pressure-control valve
245/86-010	Millstone 1	03/26/86	100	During a test, the isolation condenser condensate return valve was found to be closed for 48 h
254/86-023	Quad-Cities 1	05/05/86	96	RCIC turbine tripped on overspeed as a result of mechanical problems with the trip linkage
254/86-027	Quad-Cities 1	09/05/86	1	RCIC was made unavailable for 10 min when the pump isolation valve failed to open on demand
254/86-028	Quad-Cities 1	10/03/86	79	RCIC turbine trip throttle valve spuriously closed for 20 min
278/86-024	Peach Bottom 3	11/08/86	45	A loose wire caused a false signal, resulting in RCIC isolation
331/86-007	Duane Arnold	03/15/86	0	A spurious signal isolated RCIC for a very brief time

Table F.2 (continued)

Event identifier	Plant name	Event date	Reactor power (%)	Event description
331/86-023	Duane Arnold	11/04/86	98	During a test, the pump flow meter failed, thus requiring RCIC removal from service for repairs
333/86-005	Fitzpatrick	04/04/86	100	A false signal caused RCIC to momentarily isolate and its turbine to trip
333/86-015	Fitzpatrick	09/04/86	100	RCIC isolated on a spurious high steam flow signal
341/86-048	Fermi 2	12/26/86	5	Maintenance personnel failed to notify the control room when removing RCIC from service
354/86-082	Hope Creek 1	10/28/86	70	RCIC was taken out of service for valve packing repairs
354/86-082	Hope Creek 1	10/28/86	70	RCIC was removed from service to repack a leaking valve
366/86-017	Hatch 2	09/15/86	87	The RCIC inboard primary isolation valve closed on a spurious signal
374/86-002	LaSalle 2	02/06/86	99	A loose torque switch caused the steam-line outboard isolation valve to behave erratically
397/86-031	WNPS 2	09/10/86	100	Technicians input a signal to the wrong circuit, causing the RCIC inboard steam valve to close
440/86-066	Perry 1	10/06/86	2	The RCIC isolated on a spurious signal for 25 min
458/86-016	River Bend 1	01/30/86	23	The steam-line isolation valve closed on a false signal
458/86-018	River Bend 1	02/07/86	34	A false signal caused RCIC to isolate
458/86-067	River Bend 1	12/10/86	100	During a test, an instrument error caused the RCIC/RHR steam-supply line to isolate
458/86-068	River Bend 1	12/23/86	100	The steam line high flow transmitter failed, causing RCIC isolation

Table F.3. 1986 accident sequence precursor uncomplicated trip events reviewed (docket/LER)

029/86-012	265/86-012	298/86-022	323/86-021	362/86-013
155/86-005	266/86-003	301/86-001	323/86-023	364/86-007
206/86-008	266/86-005	302/86-001	323/86-spr	366/86-009
213/86-027	269/86-008	304/86-011	324/86-017	366/86-010
213/86-041	270/86-001	304/86-016	324/86-020	366/86-022
213/86-044	270/86-002	305/86-007	325/86-009	366/86-023
219/86-004	270/86-004	305/86-008	325/86-010	368/86-001
237/86-001	270/86-005	306/86-001	325/86-021	368/86-004
237/86-009	272/86-001	306/86-002	325/86-024	368/86-007
237/86-017	272/86-003	306/86-003	325/86-029	368/86-011
237/86-019	272/86-012	309/86-001	333/86-010	369/86-002
244/86-004	272/86-013	309/86-002	333/86-013	369/86-007
244/86-005	272/86-016	309/86-003	334/86-001	370/86-001
244/86-008	275/86-010	309/86-005	334/86-012	370/86-016
244/86-011	276/86-006	309/86-006	335/86-002	370/86-017
244/86-018	277/86-001	309/86-007	335/86-004	370/86-021
244/86-SPR1	277/86-013	309-spr	335/86-009	373/86-043
244/86-SPR2	277/86-014	311/86-002	336/86-002	374/86-004
245/86-005	277/86-022	311/86-004	336/86-004	374/86-008
245/86-027	278/86-012	311/86-006	336/86-005	382/86-001
247/86-001	278/86-016	311/86-007	336/86-006	382/86-002
247/86-021	278/86-018	311/86-009	336/86-022	382/86-009
247/86-024	278/86-019	311/86-014	338/86-002	382/86-013
247/86-027	278/86-020	313/86-004	338/86-006	382/86-019
247/86-031	278/86-022	313/86-008	338/86-008	382/86-023
247/86-036	280/86-001	315/86-012	338/86-009	388/86-004
247/86-037	280/86-002	315/86-015	338/86-015	388/86-010
249/86-012	280/86-003	315/86-017	339/86-005	389/86-001
249/86-016	280/86-005	315/86-023	339/86-008	389/86-002
249/86-019	280/86-025	316/86-005	339/86-009	389/86-013
249/86-021	281/86-003	316/86-024	341/86-035	395/86-006
249/86-025	281/86-005	317/86-001	344/86-007	395/86-009
250/86-006	281/86-007	317/86-004	344/86-008	395/86-011
250/86-021	282/86-010	317/86-006	344/86-011	395/86-014
250/86-030	285/86-004	318/86-004	346/86-001	397/86-003
250/86-032	286/86-001	318/86-005	346/86-043	397/86-020
250/86-034	286/86-003	318/86-006	348/86-004	397/86-023
251/86-019	286/86-005	318/86-007	348/86-007	397/86-025
251/86-023	286/86-006	318-spr	348/86-008	397/86-026
251/86-025	286/86-010	321/86-018	352/86-011	397/86-030
254/86-026	286/86-011	321/86-023	354/86-065	409/86-001
255/86-015	286/86-012	321/86-030	354/86-080	409/86-006
261/86-002	287/86-001	321/86-043	354/86-085	409/86-018
261/86-003	289/86-002	323/86-001	361/86-015	409/86-019
261/86-004	289/86-006	323/86-005	361/86-018	409/86-020
261/86-011	289/86-011	323/86-007	361/86-019	409/86-021
261/86-012	293/86-002	323/86-008	361/86-022	409/86-029
261/86-013	293/86-009	323/86-011	361/86-027	409/86-036
261/86-014	295/86-012	323/86-012	361/86-029	413/86-006
263/86-025	298/86-006	323/86-016	362/86-001	413/86-022
265/86-001	298/86-016	323/86-020	362/86-005	413/86-025

Table F.3. (continued)

413/86-026	423/86-048	458/86-035	483/86-018	528/86-047
413/86-030	423/86-049	458/86-037	483/86-019	528/86-053
413/86-040	423/86-051	458/86-039	483/86-022	528/86-056
413/86-042	454/86-001	458/86-041	483/86-027	528/86-063
414/86-015	454/86-003	458/86-044	483/86-029	528/86-spr
414/86-030	454/86-008	458/86-045	528/86-003	529/86-017
416/86-003	454/86-027	458/86-055	528/86-018	529/86-026
416/86-004	456/86-004	458/86-056	528/86-024	529/86-027
416/86-011	458/86-007	458/86-069	528/86-033	529/86-033
416/86-025	458/86-019	458/86-SPR	528/86-042	529/86-034
416/86-028	458/86-022	458/86-SPR	528/86-044	529/86-047
423/86-035	458/86-032	482/86-018	528/86-045	529/86-049
423/86-041	458/86-033			

Table F.4. 1986 accident sequence precursor trip events reviewed involving initiators or additional system failures (docket/LER)

247/86-017
247/86-035
250/86-039
261/86-005
269/86-001
277/86-003
285/86-001
293/86-027
318/86-006
409/86-023
413/86-031
414/86-028
458/86-002

Table F.5. 1986 accident sequence precursor trip events followed by an uncomplicated LOFW (docket/LER)

029/86-004
247/86-019
249/86-017
254/86-030
263/86-024
270/86-006
272/86-010
281/86-020
281/86-026
304/86-014
341/86-040
361/86-004
362/86-010
364/86-001
366/86-012
369/86-018*
370/86-020*
395/86-002
397/86-038
409/86-035
414/86-014
414/86-034
414/86-051
414/86-053
423/86-012*
423/86-015
458/86-001
482/86-038
482/86-069
482/86-070*

*LOFW without trip, generally from very low power.

Table F.6. 1986 accident sequence precursor uncomplicated LOFW* and LOFW events followed by a trip (docket/LER)

249/86-013
250/86-036
250/86-038
269/86-011
280/86-029
280/86-031
281/86-010
282/86-006
282/86-011
301/86-004
341/86-045
341/86-048
362/86-011
366/86-035
370/86-006
389/86-011
458/86-047

*LOFW without trip, generally from very low power.

Table F.7. 1986 accident sequence precursor unavailability events not involving a trip (docket/LER)

287/86-002
318/86-002
344/86-001
346/86-043
348/86-015
369/86-018
370/86-012
413/86-008
482/86-007
482/86-037
483/86-013
483/86-022
483/86-030
528/86-020
528/86-061
529/86-023

Table F.8. All 1986 accident sequence precursor events reviewed* for selection as precursors (docket/LER)

029/86-004	251/86-025	280/86-005	309/86-003	325/86-029
029/86-012	254/86-026	280/86-025	309/86-005	333/86-010
155/86-005	254/86-030	280/86-029	309/86-006	333/86-013
206/86-008	255/86-015	280/86-031	309/86-007	334/86-001
213/86-027	261/86-002	281/86-003	311/86-002	334/86-012
213/86-041	261/86-003	281/86-005	311/86-004	335/86-002
213/86-044	261/86-004	281/86-007	311/86-006	335/86-004
219/86-004	261/86-005	281/86-010	311/86-007	335/86-009
237/86-001	261/86-011	281/86-020	311/86-009	336/86-002
237/86-009	261/86-012	281/86-026	311/86-014	336/86-004
237/86-017	261/86-013	282/86-006	313/86-004	336/86-005
237/86-019	261/86-014	282/86-010	313/86-008	336/86-006
244/86-004	263/86-024	282/86-011	315/86-012	336/86-022
244/86-005	263/86-025	285/86-001	315/86-015	338/86-002
244/86-008	265/86-001	285/86-004	315/86-017	338/86-006
244/86-011	265/86-012	286/86-001	315/86-023	338/86-008
244/86-018	266/86-003	286/86-003	316/86-005	338/86-009
244/86-SPR1	266/86-005	286/86-005	316/86-024	338/86-015
244/86-SPR2	269/86-001	286/86-006	317/86-001	339/86-005
245/86-005	269/86-008	286/86-010	317/86-004	339/86-008
245/86-027	269/86-011	286/86-011	317/86-006	339/86-009
247/86-001	270/86-001	286/86-012	318-spr	341/86-035
247/86-017	270/86-002	287/86-001	318/86-002	341/86-040
247/86-019	270/86-004	287/86-002	318/86-004	341/86-045
247/86-021	270/86-005	289/86-002	318/86-005	341/86-048
247/86-024	270/86-006	289/86-006	318/86-006	344/86-001
247/86-027	272/86-001	289/86-011	318/86-007	344/86-007
247/86-031	272/86-003	293/86-002	321/86-018	344/86-008
247/86-035	272/86-010	293/86-009	321/86-023	344/86-011
247/86-036	272/86-012	293/86-027	321/86-030	346/86-001
247/86-037	272/86-013	295/86-012	321/86-043	346/86-043
249/86-012	272/86-016	298/86-006	323/86-001	348/86-004
249/86-013	275/86-010	298/86-016	323/86-005	348/86-007
249/86-016	276/86-006	298/86-022	323/86-007	348/86-008
249/86-017	277/86-001	301/86-001	323/86-008	348/86-015
249/86-019	277/86-003	301/86-004	323/86-011	352/86-011
249/86-021	277/86-013	302/86-001	323/86-012	354/86-065
249/86-025	277/86-014	304/86-011	323/86-016	354/86-080
250/86-006	277/86-022	304/86-014	323/86-020	354/86-085
250/86-021	278/86-012	304/86-016	323/86-021	361/86-004
250/86-030	278/86-016	305/86-007	323/86-023	361/86-015
250/86-032	278/86-018	305/86-008	323/86-spr	361/86-018
250/86-034	278/86-019	306/86-001	324/86-017	361/86-019
250/86-036	278/86-020	306/86-002	324/86-020	361/86-022
250/86-038	278/86-022	306/86-003	325/86-009	361/86-027
250/86-039	280/86-001	309-spr	325/86-010	361/86-029
251/86-019	280/86-002	309/86-001	325/86-021	362/86-001
251/86-023	280/86-003	309/86-002	325/86-024	362/86-005

*Detailed review.

Table F.8. (continued)

362/86-010	397/86-023	458/86-001	529/86-026
362/86-011	397/86-025	458/86-002	529/86-027
362/86-013	397/86-026	458/86-007	529/86-033
364/86-001	397/86-030	458/86-019	529/86-034
364/86-007	397/86-038	458/86-022	529/86-047
366/86-009	409/86-001	458/86-032	529/86-049
366/86-010	409/86-006	458/86-033	
366/86-012	409/86-018	458/86-035	
366/86-022	409/86-019	458/86-037	
366/86-023	409/86-020	458/86-039	
366/86-035	409/86-021	458/86-041	
368/86-001	409/86-023	458/86-044	
368/86-004	409/86-029	458/86-045	
368/86-007	409/86-035	458/86-047	
368/86-011	409/86-036	458/86-055	
369/86-002	413/86-006	458/86-056	
369/86-007	413/86-008	458/86-069	
369/86-018	413/86-022	458/86-SPR	
369/86-018	413/86-025	482/86-007	
370/86-001	413/86-026	482/86-018	
370/86-006	413/86-030	482/86-037	
370/86-012	413/86-031	482/86-038	
370/86-016	413/86-040	482/86-069	
370/86-017	413/86-042	482/86-070	
370/86-020	414/86-014	483/86-013	
370/86-021	414/86-015	483/86-018	
373/86-043	414/86-028	483/86-019	
374/86-004	414/86-030	483/86-022	
374/86-008	414/86-034	483/86-022	
382/86-001	414/86-051	483/86-027	
382/86-002	414/86-053	483/86-029	
382/86-009	416/86-003	483/86-030	
382/86-013	416/86-004	528/86-003	
382/86-019	416/86-011	528/86-018	
382/86-023	416/86-025	528/86-020	
388/86-004	416/86-028	528/86-024	
388/86-010	423/86-012	528/86-033	
389/86-001	423/86-015	528/86-042	
389/86-002	423/86-035	528/86-044	
389/86-011	423/86-041	528/86-045	
389/86-013	423/86-048	528/86-047	
395/86-002	423/86-049	528/86-053	
395/86-006	423/86-051	528/86-056	
395/86-009	454/86-001	528/86-061	
395/86-011	454/86-003	528/86-063	
395/86-014	454/86-008	528/86-spr	
397/86-003	454/86-027	529/86-017	
397/86-020	456/86-004	529/86-023	

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Internal Distribution

1. P. N. Austin (Consultant)
2. J. R. Buchanan
3. J. D. Cletcher (Consultant)
4. J. C. Cleveland
5. J. A. Getsi
6. E. W. Hagen
7. J. D. Harris
8. S. E. Hughes
9. A. P. Malinauskas
10. G. T. Mays
11. J. R. Merriman
12. J. W. Minarick (Consultant)
13. D. L. Moses
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51. I. Wall, Nuclear Safety Analysis Center, Electric Power Research Institute, P. O. Box 10412, Palo Alto, CA 94303

52. Institute of Nuclear Power Operations, 1100 Circle 75 Parkway, Suite 1500, Atlanta, GA 30339

53. G. M. Ballard, Head, Reliability Technology Section, Systems Reliability Service, United Kingdom Atomic Energy Authority, Culcheth, Warrington, WA3 4NE, United Kingdom

54. J. R. Fragola, Science Applications International Corporation, 274 Madison Avenue, Suite 1501, New York, NY 10016

55-79. F. M. Manning, Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, Washington, DC 20555

80. Office of Assistant Manager for Energy Research and Development, Department of Energy, Oak Ridge Operations Office, Oak Ridge, TN 37830

81-82. Office of Scientific and Technical Information, Department of Energy, P. O. Box 62, Oak Ridge, TN 37831

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J. W. Minarick, J. D. Harris, P. N. Austin,
J. W. Cletcher, E. W. Hagen

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13. ABSTRACT (200 words or less)

Thirty-five operational events, reported in licensee event reports and occuring at commercial LWRs during 1986, are considered to be precursors to potential severe core damage. These are described along with associated significance estimates, categorization, and subsequent analyses. This study is a continuation of earlier work, which evaluated the 1969-1981 and 1984-1985 events. 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 initial conclusions from the assessment of 1986 events and from the collective assessment of 1984-1986 events.

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