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Precursors to Potential Severe Core Damage Accidents: 1984 A Status Report

Appendixes C, D, and E

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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NOTE

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APPENDIX C

OPERATIONAL EVENT LISTINGS

APPENDIX C

OPERATIONAL EVENT LISTINGS

This appendix contains listings of events that are of potential concern from a core damage standpoint; in general, however, most of the events were not selected as actual accident sequence precursors. Included are unavailabilities of RHR systems, mostly at zero-power conditions (Table C.1), and unavailabilities of single-train safety systems, such as HPCI, HPCS, RCIC, and soluble boron (Table C.2). These unavailabilities were generally not selected as accident sequence precursors.

Tables C.3 through C.6 list events reviewed in this study by docket and LER number. Table C.3 lists the events that involved a reactor trip from power or a trip that occurred during shutdown but that had no additional failures or reported unavailabilities. Table C.4 lists the 1984 trip events that were more complicated. The trips involved a core damage initiator such as LOCA, SLB, LOOP, or LOFW; or they involved additional system failures. Several of the precursors were selected from this group.

Table C.5 lists the events involving unavailabilities as well as initiators with no trips involved. Included are LOOPs and LOFWs not requiring a reactor trip, shutdown-related losses of inventory, events involving multiple failures, and unavailabilities of various plant systems required in core damage mitigation sequences.

Finally, Table C.6 lists all of the 1984 events selected for detailed review before selection of the 47 precursors.

Table C.1. RHR system unavailabilities reported in 1984

Event identifier	Plant	Event date	Event description
206/84-012	San Onofre 1	10/10/84	The CCW system was aligned to a heat exchanger that did not have saltwater flow. This configuration resulted in the inoperability of both RHR trains for ~8 h.
244/84-002	Ginna	03/03/84	The RCS suction stop valve for Loop A of the RHR system failed to open when actuated from the control room.
244/84-005	Ginna	05/14/84	The RCS suction stop valve for Loop A of the RHR system failed to open when actuated from the control room.
257/84-012	Browns Ferry 1	2/14/84	The SDC valve failed to open electrically. The RHR system was inoperable for ~9.25 h.
295/84-031	Zion 1	09/14/84	The RCS level dropped below the suction line for the RHR pump. The RHR system was unavailable for ~45 min.
311/84-002	Salem 2	02/09/84	The RHR system common suction valve inadvertently shut during testing. This rendered the RHR system inoperable for ~17 min.
316/84-014	Cook 2	05/21/84	Cavitation and air binding caused the RHR system to be out of service for ~25 min. Cavitation and air binding were caused by both pumps operating during RCS system half-loop operation.

Table C.1 (continued)

Event identifier	Plant	Event date	Event description
321/84-020	Hatch 1	12/16/84	Several events occurred (Dec. 16, 19, and 28, 1984) where primary containment isolation valves E11-F008 and E11-F009 closed, which removed the RHR system from service.
397/84-007	WNPS 2	1/27/84	RHR system was isolated due to plant trip.
324/84-014	Brunswick 2	11/27/84	RHR system was isolated due to plant trip caused by a water hammer.
325/84-001	Brunswick 1	01/19/84	RHR system inoperable for ~15 min due to air in the pump suction header. One of three pumps was out of service for scheduled maintenance.
325/84-012	Sequoyah 2	07/10/84	During surveillance testing for external-to-containment-piping leakage, both trains of the RHR system were inoperable for 2 h and 47 min.
331/84-009	Duane Arnold	01/31/84	The RHR system was inoperable for ~6 min because the discharge piping from the pumps drained. Water drained from the piping because block valves were out of position.
339/84-008	North Anna 2	10/16/84	A complete loss of the RHR system occurred when both RHR pumps were unable to operate due to the introduction of air into the RHR system. RHR was out of service for ~2 h.

Table C.1 (continued)

Event identifier	Plant	Event date	Event description
344/84-010	Trojan	05/04/84	The RHR system was inoperable for ~40 min due to air entrainment in the "A" RHR pump. The "B" RHR pump was started when water inventory in the RCS was sufficient to prevent air entrainment in the "B" RHR pump.
368/84-023	Arkansas Nuclear One 2	08/29/84	The RHR system was inoperable for ~1 h due to air entrainment in the pump suction piping, which was caused because of low RCS water levels.
370/84-001	McGuire 2	01/09/84	The RHR system was inoperable due to gas entrainment for ~43 min in one case and for ~62 min in another case. The water level in the "C" RCS loop was low.
370/84-002	McGuire 2	01/15/84	The RHR system was inoperable for ~47 min because an operator erroneously isolated the system.
373/84-062	LaSalle 1	09/30/84	The RHR system was inoperable for ~9 h due to an isolation valve that failed to shut.
374/84-062	LaSalle 2	08/27/84	The "B" train of the RHR system was inoperable due to a suction valve closure caused by a high- suction-flow signal.
387/84-020	Susquehanna 1	03/21/84	Both trains of the RHR system were inoperable for ~30 min because the inboard and outboard isolation valves closed. The isolation valves closed because of a high flow signal.

Table C.1 (continued)

Event identifier	Plant	Event date	Event description
395/84-044	Summer	10/01/84	Two fuses in the solid state protection system, which were removed for personnel safety, caused both trains of the RHR system to isolate the suction side of the train. The fuses were replaced immediately, and the operability of the RHR system was restored immediately.
395/84-045	Summer	10/18/84	Personnel erroneously deenergized a solid state protection system panel and caused the suction side of both RHR system trains to be isolated. RHR was inoperable for ~25 min.
397/84-091	WNPS 2	08/23/84	An RHR system isolation and a reactor low-water-level trip occurred while placing the RHR in the SDC mode. RHR was unavailable for ~15 min.
397/84-117	WNPS 2	11/16/84	Circuit testing, following implementation of a modification, initiated an automatic isolation of the RHR system.
416/84-002	Grand Gulf 1	01/07/84	Eight instances of RPS breaker trips resulted in an isolation of the RHR system. The RHR was restored within 1 h for each of the events.
416/84-004	Grand Gulf 1	01/14/84	While maintenance was being performed on a panel, a fuse failure occurred, which caused an SDC isolation value to close. RHR was unavailable for 58 min.

Table C.1 (continued)

Event identifier	Plant	Event date	Event description
416/84-009	Grand Gulf 1	02/18/84	A relay was inadvertently (manually) tripped, which caused loss of power to the RHR system isolation valve. The RHR system was isolated for ~10 min.
416/84-010	Grand Gulf 1	02/10/84	While power was being transferred from an alternate supply to the MG set, the MG set output breaker tripped. Both trains of the RHR system were isolated for ~10 min.
416/84-011	Grand Gulf 1	03/09/84	Arcing occurred in a 500-kV switchyard breaker as it was returned to service. The resulting electrical transient caused the RHR system to be isolated for ~19 min.
416/84-024	Grand Gulf 1	05/28/84	During startup at 4% power, RHR was removed from service due to cracks in the piping and to support deficiencies.
416/84-034	Grand Gulf 1	07/19/84	While performing a test, an electrician inadvertently bumped a breaker handle, which caused the RPS MG set output breaker to trip. The RHR system was isolated for ~15 min.

Table C.2. Unavailabilities in BWR single-train safety systems reported in 1984

Event identifier	Plant	Event date	System affected	Reactor power (%)	Event description
331/84-029	Duane Arnold	07/18/84	SBLC	100	During a test, a technician incorrectly closed the common suction valve to the two SBLC pumps.
366/84-006	Hatch 2	05/25/84	SBLC	0	While in cold shutdown, the SBLC line RV lifted at too low a pressure in a test, thereby precluding boron injection into the vessel for pressure higher than 700 psig.
374/84-014	LaSalle 2	04/03/84	HPCS	1	While in startup, the water leg pump motor failed. HPCS was made unavailable.
373/84-044	LaSalle 1	07/02/84	HPCS	97	During a test, the two check valves failed to prevent reverse flow. HPCS would have been available for ECCS injection, but it had been removed from service for valve repairs.
397/84-040	WNPS 2	05/10/84	HPCS	19	During maintenance, an operator error caused a diesel lockout relay to actuate. The HPCS diesel was disabled for 20 min.
374/84-018	LaSalle 2	05/17/84	HPCS	30	During a test, the pump electrical breaker failed to close on its power source. A switch had failed.
416/84-008	Grand Gulf 1	02/02/84	HPCS	0	While the plant was shut down, an operator error during maintenance on the DG caused control power to be lost for 30 min.
298/84-004	Cooper	04/05/84	RCIC	95	During a test, the RCIC ramp generator and signal converter in the turbine control system failed.

Table C.2 (continued)

Event identifier	Plant	Event date	System affected	Reactor power (%)	Event description
259/84-018	Browns Ferry 1	05/20/84	RCIC	96	The RCIC was removed from service to repair a steam leak from the pipe. Later, valving problems were found. RCIC was out of service for 3 d.
259/84-038	Browns Ferry 1	12/19/84	RCIC	100	During a test, the turbine failed to respond to control signals above 2100 rpm due to ramp generator and signal converter problems.
259/84-036	Browns Ferry 1	09/29/84	RCIC	84	During a test, the ramp generator and signal converter failed.
327/84-027	Brunswick 1	09/30/84	RCIC	100	The RCIC autoisolated when a steam leak caused room temperature to rise too high.
331/84-031	Arnold	09/13/84	RCIC	72	The barometric condenser vacuum pump failed. RCIC was inoperable for 3 d.
366/84-035	Hatch 2	12/13/84	RCIC	100	While at full power, RCIC isolated due to a false signal from a failed temperature sensor.
331/84-018	Hatch 2	05/07/84	RCIC	72	During a test, a technician bumped a relay and caused RCIC to isolate.
397/84-099	WNPS 2	09/28/84	RCIC	60	A spurious signal isolated RCIC.
397/84-055	WNPS 2	05/28/84	RCIC	1	In startup, during testing, an operator error caused an RCIC isolation.
416/84-056	Grand Gulf 1	12/19/84	RCIC	1	While in startup, an RCIC isolation valve closed due to a spurious signal.

Table C.2 (continued)

Event identifier	Plant	Event date	System affected	Reactor power (%)	Event description
331/84-025	Arnold	08/8/84	RCIC	93	During a test, the electrical breaker failed to stay closed due to an out-of-adjustment torque switch.
373/84-060	LaSalle 1	09/29/84	RCIC	1	The RCIC spuriously isolated.
373/84-054	LaSalle 1	09/21/84	RCIC	24	During a test, RCIC tripped on overspeed on two occasions due to dirty oil.
373/84-028	LaSalle 1	05/13/84	RCIC	100	The RCIC spuriously isolated for 12 min.
366/84-025	Hatch 2	10/25/84	RCIC	100	During an inspection, the trip and throttle valve's yoke arm was found broken due to a loose set screw.
374/84-024	LaSalle 2	05/31/84	RCIC	24	On two occasions, RCIC instrumentation power failed. The inverter had tripped off due to high battery voltage set-point drift during charging.
397/84-082	WNPS 2	08/02/84	RCIC	0	While the reactor was shut down, spurious signals caused RCIC to isolate on three occasions.
249/84-023	Dresden 3	12/24/84	HPCI	96	During a test, the pump had excessive vibration and was removed from service for repairs and maintenance.
296/84-014	Browns Ferry 3	12/06/84	HPCI	36	The steam flow control valve to the turbine was found leaking. HPCI was removed from service for repairs.
296/84-013	Browns Ferry 3	11/22/84	HPCI	0	While the reactor was shut down during a test, the outboard steam valve failed to open on demand.

Table C.2 (continued)

Event identifier	Plant	Event date	System affected	Reactor power (%)	Event description
298/84-011	Cooper	08/28/84	HPCI	89	A lube oil leak was found due to a failed diaphragm on the turbine overspeed-trip, autoreset, control-valve actuator.
265/84-008	Quad-Cities 2	07/04/84	HPCI	99	During a test, the cooling water return valve failed to open from the control room.
271/84-005	Vermont Yankee	04/20/84	HPCI	100	During a test, the oil pump trip throttle valve failed to open because a procedure step had not been followed on 04/16/84.
260/84-003	Browns Ferry 2	02/12/84	HPCI	70	During a test, the ramp generator signal converter failed, causing erratic performance and a high turbine speed.
321/84-011	Hatch 1	06/20/84	HPCI	0	While the reactor was shut down during a test, the lube oil was found contaminated with water due to leaks in the steam supply valve.
324/84-013	Brunswick 2	11/12/84	HPCI	38	During a test, the oil pump tripped off and would not re-start.
325/84-003	Brunswick 1	02/19/84	HPCI	100	During a test the turbine speed control performed erratically due to a failed governor.
331/84-010	Arnold	02/04/84	HPCI	100	The HPCI steam IV spuriously closed.
331/84-012	Arnold	02/29/84	HPCI	100	During a test, the turbine stop valve failed to open and was found to have oil leaks past the seals.

Table C.2 (continued)

Event identifier	Plant	Event date	System affected	Reactor power (%)	Event description
331/84-002	Arnold	01/3/84	HPCI	100	During a test, a technician's error with a jumper caused the steam isolation valve to close.
333/84-012	Fitzpatrick	05/18/84	HPCI	100	The HPCI steam stop valve was found to have a cracked stem and was removed from service.
333/84-015	Fitzpatrick	07/16/84	HPCI	90	During a test, the torus suction valve failed to open fully.
388/84-010	Susquehanna 2	06/27/84	HPCI	3	While in startup, HPCI was removed from service to repair a blocked strainer.
388/84-019	Susquehanna 2	09/19/84	HPCI	3	HPCI was removed from service to replace a blocked strainer.
387/84-004	Susquehanna 1	01/13/84	HPCI	0	While the reactor was shut down during a test, the two level switches at the condensate storage tanks, which transfer HPCI suction to the torus, were found frozen.
245/84-014	Millstone 1	07/09/84	IC	100	Following a test, an out-of-adjustment limit switch on the outboard condensate return valve motor caused motor failure. The redundant valve was closed while repairs were made.
245/84-018	Millstone 1	08/03/84	IC	0	While the reactor was shut down during a test, the outboard isolation valve motor failed due to an out-of-adjustment limit switch. The redundant valve was closed while repairs were made.

Table C.3. 1984 accident sequence precursor uncomplicated trip events

029-012	250-001	266-004	281-020	309-001
029-013	250-002	269-001	281-021	309-008
029-015	250-003	269-002	282-001	309-009
029-016	250-005	269-006	282-005	309-015
029-018	250-006	271-001	282-006	309-016
155-004	250-007	271-004	282-011	309-017
155-005	250-014	271-009	285-013	312-018
155-006	250-019	271-016	286-002	312-020
155-007	250-020	271-018	286-004	312-025
155-008	250-021	272-001	286-005	312-065
155-009	250-033	272-002	286-006	315-001
155-010	251-001	272-003	286-008	315-008
155-012	251-002	272-004	286-009	315-010
213-021	251-008	272-005	286-011	315-018
213-025	251-010	272-012	286-013	316-002
213-026	251-014	272-013	286-014	316-020
219-020	251-016	272-023	287-002	316-024
219-021	251-021	272-025	287-003	316-029
219-027	251-022	272-028	287-004	316-030
219-033	251-023	272-029	293-001	316-031
220-005	254-001	275-014	293-014	316-032
220-006	254-003(3)	275-015	295-001	317-002
220-008	254-009	275-021	295-007	317-004
220-010	254-010	275-022	295-008	317-009
220-011	254-011	275-030	295-009	317-013
220-017	254-013	275-031	295-010	317-015
220-018	254-015	275-032	295-011	318-003
237-009	254-016	275-033	295-012	318-008
237-012	255-001	278-005	295-015	321-001
237-013	255-015	278-011	295-038	321-006
244-001	255-016	278-014	301-004	321-007
244-007	255-021	280-001	302-003	321-012
247-003	259-004	280-002	302-010	321-015
247-017	259-011	280-003	304-001	321-016
247-018	259-014	280-008	304-002	321-021
247-019	259-016	280-015	304-003	321-026
249-001	259-024	280-016	304-007	324-004
249-002	259-026	280-020	304-010	324-008
249-004	260-002	280-025	304-016	324-010
249-007	260-004	280-026	304-017	324-011
249-010	260-006	281-001	304-018	324-012
249-011	261-001	281-002	304-032	324-014
249-012	263-032	281-003	305-002	325-002
249-015	265-001	281-005	305-008	325-025
249-016	265-002	281-009	305-009	325-026
249-017	265-004	281-010	305-010	325-034
249-020	265-007	281-012	305-014	327-006
249-021	265-009	281-018	307-079	327-007
249-022	266-003	281-019	307-095	327-013

Table C.3 (continued)

327-026	346-006(2)	370-011	395-032
327-031	346-010	370-012	395-041
327-032	348-001	370-013	395-050
327-035	348-002	370-015	395-051
327-036	348-012	370-016	397-007
327-054	361-019	370-021	397-011
327-064	361-020	370-026	397-014
328-008	361-043	370-031	397-028
328-013	361-050	370-033	397-036
328-015	362-003	370-034	397-044
328-016	362-007	373-003	397-045
328-017	362-008	373-007	397-054
328-018	362-017	373-008	397-056
328-020	362-022	373-009	397-083
328-021	362-024	373-010	397-089
331-008	362-029	373-022	397-090
331-013	362-032	373-029	397-091
331-015	362-040	373-056	397-104
331-037	364-003	374-012	397-108
331-040	364-004	374-020	397-109
331-042	364-005	374-025	397-112
333-013	364-012	374-035	397-113
333-018	366-020	374-042	397-115
333-020	366-021	374-045	397-123
333-022	366-026	374-047	397-124
333-027	366-036	374-048	397-125
334-001	366-SPR	374-050	397-129
334-002	368-001	374-052	397-131
334-003	368-003	374-071	409-001
334-004	368-004	374-085	409-002
334-012	368-004	387-013	409-006
334-017	368-005	387-028	409-007
335-003	368-007	387-029	409-014
335-005	368-008	387-031	409-016
335-006	368-011	387-033	409-018
335-007	368-013	387-034	409-019
335-009	368-014	387-035	409-021
336-002	368-019	388-017	416-011
336-011	368-020	388-018	416-024
338-001	368-021	388-021	416-027
338-003	368-024	388-U1	416-033
338-014	368-026	389-001	416-040
338-018	368-028	389-003	416-052
338-020	369-002	389-005	416-058
338-021	369-010	389-012	483-051
339-001	369-020	389-013	483-064
344-004	369-023	389-014	
344-006	370-003	389-016	
344-018	370-005	395-005	
344-020	370-006	395-008	
346-001	370-009	395-011	

Table C.4. 1984 more-complex accident sequence precursor trip events

COMPLEX TRIPS WITH INITIATORS AND/OR EQUIPMENT FAILURES	UNCOMPLICATED LOSS-OF-FEEDWATER EVENTS	
247-025	029-017	416-057
259-027	219-030	483-046
259-032	249-018	483-047
265-010	251-017	483-048
286-015	269-007	483-052
296-012	272-013	483-054
296-013	272-025	483-055
296-014	281-015	483-056
296-015	281-016	483-057
298-002	287-005	483-058
309-001	298-002	483-059
312-015	298-003	483-060
324-018	316-025	483-061
325-006	333-009	483-065
325-007	333-010	
325-014	333-023	
327-033	339-002	
331-001	339-005	
331-028	364-001	
336-012	364-016	
338-019	368-002	
344-017	370-027	
346-003	370-029	
346-013	373-002	
369-024	373-005	
370-020	373-011	
373-054	373-039	
373-056	374-017	
373-060	389-015	
373-062	395-009	
374-018	395-010	
374-020	395-024	
387-010	395-025	
388-006	395-049	
388-008	397-042	
388-013	397-043	
389-004	397-051	
409-011	397-070	
416-027	397-114	
416-030	416-045	

Table C.5. 1984 accident sequence precursor events involving initiators or unavailabilities with no trips

ALL MULTI TRAIN SYSTEM FAILURES EXCEPT RHRS	TOTAL SYSTEM UNAVAILA-BILITIES	BWR SINGLE TRAIN SYSTEM* FAILURES	RHRS UNAVAIL-ABILITES	LOFW	LOCA	LOOP	SLB/FLB
220-015	206-002	245-014	206-012	275-035	285-008	029-008	370-025
324-018	219-012	245-018	244-002	315-017		255-001	
333-002	237-010	249-023	244-005				
387-040	247-011	259-018	252-062				
	250-036	259-036	259-012				
	250-038	259-038	295-031				
	250-040	260-003	311-002				
	254-014	265-008	316-014				
	265-014	271-005	321-020				
	271-022	296-013	324-014				
	272-017	296-014	325-001				
	275-013	298-004	328-012				
	278-007	298-011	331-009				
	280-011	321-011	339-008				
	315-014	324-013	344-010				
	318-005	325-003	368-023				
	333-003	325-027	370-001				
	333-004	331-002	370-002				
	339-013	331-010	373-062				
	362-035	331-012	374-062				
		331-018	387-020				
		331-025	395-044				
		331-029	395-045				
		331-031	397-007				
		333-012	397-091				
		333-015	397-117				
		366-006	416-002				
		366-025	416-004				
		366-035	416-009				
		373-028	416-010				
		373-044	416-011				
		373-054	416-034				
		373-060					
		374-018					
		374-024					
		387-004					
		388-010					
		388-019					
*RCIC,		397-040					
HPCI,		397-055					
IC,		397-082					
SBLCS,		397-099					
CRDS,		416-008					
HPCS		416-056					

Table C.6. All 1984 accident sequence precursor events reviewed and selected for listing, documentation, or as precursors

029-008	247-025	254-016	272-012	285-013
029-012	249-001	255-001	272-013	286-002
029-013	249-002	255-015	272-017	286-004
029-015	249-004	255-016	272-023	286-005
029-016	249-007	255-021	272-025	286-006
029-017	249-010	259-004	272-028	286-008
029-018	249-011	259-011	272-029	286-009
155-004	249-012	259-012	275-013	286-011
155-005	249-015	259-014	275-014	286-013
155-006	249-016	259-016	275-015	286-014
155-007	249-017	259-018	275-021	286-015
155-008	249-018	259-024	275-022	287-002
155-009	249-020	259-026	275-030	287-003
155-010	249-021	259-027	275-031	287-004
155-012	249-022	259-032	275-032	287-005
206-002	249-023	259-036	275-033	293-001
206-012	250-001	259-038	275-035	293-014
213-021	250-002	260-002	278-005	295-001
213-025	250-003	260-003	278-007	295-007
213-026	250-005	260-004	278-011	295-008
219-012	250-006	260-006	278-014	295-009
219-020	250-007	261-001	280-001	295-010
219-021	250-014	263-032	280-002	295-011
219-027	250-019	265-001	280-003	295-012
219-030	250-020	265-002	280-008	295-015
219-033	250-021	265-004	280-011	295-031
220-005	250-033	265-007	280-015	295-038
220-006	250-036	265-008	280-016	296-012
220-008	250-038	265-009	280-020	296-013
220-010	250-040	265-010	280-025	296-014
220-011	251-001	265-014	280-026	296-015
220-015	251-002	266-003	281-001	298-002
220-017	251-008	266-004	281-002	298-003
220-018	251-010	269-001	281-003	298-004
237-009	251-014	269-002	281-005	298-011
237-010	251-016	269-006	281-009	301-004
237-012	251-017	269-007	281-010	302-003
237-013	251-021	271-001	281-012	302-010
244-001	251-022	271-004	281-015	304-001
244-002	251-023	271-005	281-016	304-002
244-005	252-062	271-009	281-018	304-003
244-007	254-001	271-016	281-019	304-007
245-014	254-003(3)	271-018	281-020	304-010
245-018	254-009	271-022	281-021	304-016
247-003	254-010	272-001	282-001	304-017
247-011	254-011	272-002	282-005	304-018
247-017	254-013	272-003	282-006	304-032
247-018	254-014	272-004	282-011	305-002
247-019	254-015	272-005	285-008	305-008

Table C.6 (continued)

305-009	324-004	331-031	346-003	368-026
305-010	324-008	331-037	346-006(2)	368-028
305-014	324-010	331-040	346-010	369-002
307-079	324-011	331-042	346-013	369-010
307-095	324-012	333-002	348-001	369-020
309-001	324-013	333-003	348-002	369-023
309-008	324-014	333-004	348-012	369-024
309-009	324-018	333-009	361-019	370-001
309-015	325-001	333-010	361-020	370-002
309-016	325-002	333-012	361-043	370-003
309-017	325-003	333-013	361-050	370-005
311-002	325-006	333-015	362-003	370-006
312-015	325-007	333-018	362-007	370-009
312-018	325-014	333-020	362-008	370-011
312-020	325-025	333-022	362-017	370-012
312-025	325-026	333-023	362-022	370-013
312-065	325-027	333-027	362-024	370-015
315-001	325-034	334-001	362-029	370-016
315-008	327-006	334-002	362-032	370-020
315-010	327-007	334-003	362-035	370-021
315-014	327-013	334-004	362-040	370-025
315-017	327-026	334-012	364-001	370-026
315-018	327-031	334-017	364-003	370-027
316-002	327-032	335-003	364-004	370-029
316-014	327-033	335-005	364-005	370-031
316-020	327-035	335-006	364-012	370-033
316-024	327-036	335-007	364-016	370-034
316-025	327-054	335-009	366-006	373-002
316-029	327-064	336-002	366-020	373-003
316-030	328-008	336-011	366-021	373-005
316-031	328-012	336-012	366-025	373-007
316-032	328-013	338-001	366-026	373-008
317-002	328-015	338-003	366-035	373-009
317-004	328-016	338-014	366-036	373-010
317-009	328-017	338-018	366-SPR	373-011
317-013	328-018	338-019	368-001	373-022
317-015	328-020	338-020	368-002	373-028
318-003	328-021	338-021	368-003	373-029
318-005	331-001	339-001	368-004	373-039
318-008	331-002	339-002	368-005	373-044
321-001	331-008	339-005	368-007	373-054
321-006	331-009	339-008	368-008	373-056
321-007	331-010	339-013	368-011	373-060
321-011	331-012	344-004	368-013	373-062
321-012	331-013	344-006	368-014	374-012
321-015	331-015	344-010	368-019	374-017
321-016	331-018	344-017	368-020	374-018
321-020	331-025	344-018	368-021	374-020
321-021	331-028	344-020	368-023	374-024
321-026	331-029	346-001	368-024	374-025

Table C.6 (continued)

374-035	395-049	416-008
374-042	395-050	416-009
374-045	395-051	416-010
374-047	397-007	416-011
374-048	397-007	416-024
374-050	397-011	416-027
374-052	397-014	416-030
374-062	397-028	416-033
374-071	397-036	416-034
374-085	397-040	416-040
387-004	397-042	416-045
387-010	397-043	416-052
387-013	397-044	416-056
387-020	397-045	416-057
387-028	397-051	416-058
387-029	397-054	483-046
387-031	397-055	483-047
387-033	397-056	483-048
387-034	397-070	483-051
387-035	397-082	483-052
387-040	397-083	483-054
388-006	397-089	483-055
388-008	397-090	483-056
388-010	397-091	483-057
388-013	397-099	483-058
388-017	397-104	483-059
388-018	397-108	483-060
388-019	397-109	483-061
388-021	397-112	483-064
388-U1	397-113	483-065
389-001	397-114	
389-003	397-115	
389-004	397-117	
389-005	397-123	
389-012	397-124	
389-013	397-125	
389-014	397-129	
389-015	397-131	
389-016	409-001	
395-005	409-002	
395-008	409-006	
395-009	409-007	
395-010	409-011	
395-011	409-014	
395-024	409-016	
395-025	409-018	
395-032	409-019	
395-041	409-021	
395-044	416-002	
395-045	416-004	

APPENDIX D

PRECURSOR DOCUMENTATION

APPENDIX D

PRECURSOR DOCUMENTATION

Reactor plant operational events for 1984 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.

A precursor description sheet and a conditional core damage calculation are included for each precursor. The 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 sequence probabilities for the more significant core damage, core vulnerability (CV), and ATWS sequences; identification of dominant sequences for each end state; and a listing of the branch probabilities and frequencies used. 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 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 system 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 B normally failing assumed to be 0.01, and the likelihood of C failing assumed to be 0.03, then the probability of sequences 1 and 2, respectively, is calculated as follows:

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

$$[0.1 \times 0.05] - [0.1 \times 0.01] = 4.9 \times 10^{-2} \quad (2)$$

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 at the different BWR and PWR plant classes defined in this report. These calculations are included following the documentation of precursors. Table D.2 lists acronym meanings for abbreviations used in the precursor descriptions. 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 number	Description of event	Plant name	Page number
206/84-002	Both diesel generators inoperable	San Onofre 1	D-10
219/84-012	Both emergency diesel generators simultaneously inoperable	Oyster Creek	D-14
220/84-015	One-half the safety-related loads become inoperable	Nine Mile Point 1	D-19
237/84-010	Inadvertent loss of feeder breaker makes LPCI unavailable	Dresden 2	D-24
247/84-025	Plant trip due to unavailability of HPI	Indian Point 2	D-29
250/84-036, -038, -040	Both diesel generators unavailable on two occasions	Turkey Point 3	D-35
254/84-014	Two LPCI injection valves fail to open	Quad-Cities 1	D-40
259/84-027	Inadvertent relief valve opening with subsequent trip	Browns Ferry 1	D-46
259/84-032	Inadvertent overpressurization and leakage from LPCS	Browns Ferry 1	D-51
265/84-010	Trip with RCIC failure	Quad-Cities 2	D-57
265/84-014	HPCI isolates with LPCI already inoperable	Quad-Cities 2	D-62
271/84-022	Diesel generator lockout trip of both generators	Vermont Yankee	D-68
272/84-017	Unavailability of high-head charging pumps	Salem 1	D-73
275/84-013	Inoperable high-head injection system	Diablo Canyon 1	D-78
280/84-011	Component cooling water isolated from charging pumps	Surry 1	D-82
286/84-015	LOOP with both a DG failure and an unavailability	Indian Point 3	D-87
296/84-012, -013, -014	Trip and HPCI failure	Browns Ferry 3	D-93
296/84-015	Trip and one condensate pump and two CRD pumps fail	Browns Ferry 3	D-99
312/84-015	Hydrogen explosion causes transient and subsequent loss of NNIX	Rancho Seco	D-104
318/84-005	Both diesel generators inoperable	Calvert Cliffs 2	D-110

Table D.1 (continued)

LER number	Description of event	Plant name	Page number
324/84-014, -018	RCIC and Train "B" LPCI/RHR unavailable	Brunswick 2	D-115
325/84-006, -007	Trip, LOFW, and HPCI isolation	Brunswick 1	D-120
325/84-014	Trip and LOFW with HPCI unavailable	Brunswick 1	D-125
327/84-033	Atmospheric dump valve opens and causes LOFW	Sequoyah 1	D-131
331/84-001	LOFW and SRV opens briefly	Duane Arnold	D-136
331/84-028	LOOP and HPCI trip	Duane Arnold	D-143
333/84-002	Engineered safety features train unavailable during postulated LOOP	Fitzpatrick	D-149
333/84-003	RCIC inoperable while HPCI is out of service	Fitzpatrick	D-154
333/84-004	RCIC and HPCI are unavailable	Fitzpatrick	D-159
336/84-012	Trip, LOFW, and AFW degraded	Millstone 2	D-164
338/84-019	Trip and one AFW train fails	North Anna 1	D-169
339/84-013	Forced shutdown due to two inoperable emergency diesel generators	North Anna 2	D-175
344/84-017	Steam generator relief valve fails open and subsequent reactor trip	Trojan	D-180
346/84-003	SFRCS initiation leads to stuck-open MSRV and trip	Davis-Besse 1	D-185
346/84-013	Trip and one atmospheric dump valve fails to close	Davis-Besse 1	D-191
362/84-035	All HPSI pumps unavailable	San Onofre 3	D-197
369/84-024	LOOP at McGuire 1 affects Unit 2	McGuire 1	D-202
373/84-054, -056, -060, -062	Scram, RCIC failures, and RHR unavailability within ±15 d	LaSalle 1	D-207
374/84-017, -018	LOFW while shutting down and HPCS fails in test within 15 d of LOFW	LaSalle 2	D-212
387/84-010	SRV failure to close following scram	Susquehanna 1	D-217
387/84-040	Diesel generators slow start and residual heat removal suppression pool unavailable	Susquehanna 1	D-222
388/84-006, -008	Trip and LOFW with "B" LPCI train unavailable	Susquehanna 2	D-228

Table D.1 (continued)

LER number	Description of event	Plant name	Page number
388/84-013	LOOP test with failure of EPS to start	Susquehanna 2	D-233
389/84-004	LOFW, failure of one AFW train and one MSRV sticks open	St. Lucie 2	D-240
389/84-011	Trip and one AFW train fails	St. Lucie 2	D-245
409/84-011	LOOP with DG failure to load and associated HPCS unavailability	LaCrosse	D-250
416/84-030	LOFW, trip, and RCIC failure	Grand Gulf 1	D-256

Table D.2. Acronyms used in Appendix D

Acronym	Definition
ADS	automatic depressurization system
AFW	auxiliary feedwater
APRM	average power range
ATTS	Analog Transmitter Trip System
ATWS	anticipated transient without scram
BIT	boron injection tank
BWR	boiling-water reactor
CC	component cooling
CCW	core cooling water
CD	core damage
CEAC	control element assembly calculator
CRD	control rod drive
CS	core spray
CSR	condensate storage tank
CV	core vulnerability
DG	diesel generator
DHR	decay heat removal
ECC	emergency core cooling
ECCS	emergency core cooling system
EDG	emergency diesel generator
EHC	electrohydraulic control
EP	emergency power
EPS	emergency power system
ERV	electromatic relief valve
ESF	engineered safety feature
ESW	emergency service water
FW	feedwater
HHIS	high-head injection system
HPCI	high-pressure coolant injection
HPCS	high-pressure core spray
HPI	high-pressure injection
HPR	high-pressure recirculation
HPSI	high-pressure safety injection
I&E	inspection and enforcement
ICS	integrated control system
LER	licensee event report
LOCA	loss-of-coolant accident
LOFW	loss of main feedwater
LOOP	loss of offsite power
LPCI	low-pressure coolant injection
LPCS	low-pressure core spray
LPI	low-pressure injection
LPR	low-pressure recirculation

Table D.2. (continued)

Acronym	Definition
MCC	motor control center
MFW	main feedwater
MFWP	main feedwater pump
M-G	motor generator
MSIV	main steam isolation valve
MSR	moisture separator reheater
MSRV	main steam-line relief valve
NNI	nonnuclear instrumentation
PCS	power conversion system
PORV	pilot-operated relief valve
PWR	pressurized-water reactor
PSRV	primary system relief valve
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCS	reactor coolant system
RFP	reactor feedwater
RHR	residual heat removal
RHRS	residual heat removal system
RPV	reactor pressure vessel
RV	relief valve
RWCS	reactor water cleanup system
RWST	refueling water storage tank
SBLC	standby liquid control
SDC	shutdown cooling
SDV	scram discharge volume
SFAS	safety features actuation signal
SFRCS	steam and feedwater rupture control system
SG	steam generator
SI	safety injection
SLDS	steam leak detection system
SPDS	safety parameter display system
SRV	safety relief valve
SSPS	solid state protection system
ST	station auxiliary transformer
SST	station service transformer
SW	service water
TBCCW	turbine building core cooling water
TBS	turbine bypass
TBV	turbine bypass valve
TG	turbine generator

PRECURSOR DESCRIPTION SHEET

LER No.: 206/84-002
Event Description: Both Diesel Generators Inoperable
Date of Event: March 9, 1984
Plant: San Onofre 1

EVENT DESCRIPTION

Sequence

During routine testing of electrical circuits, DG 2 spuriously started and tripped on overspeed; it was declared inoperable. Because DG 1 was also inoperable at this time, no operations involving core alterations or positive reactivity changes were permitted. The requirement of LCO 3.2.A(1) to maintain one charging pump or the test pump operable could not be met because no automatic emergency electrical power source was available; however, DG 2 was started manually, and no loss of safety function therefore occurred.

On March 11, at 1645 h, DG 2 was declared operable, and LCO 3.2.A(1) was satisfied. Investigation determined that the spurious start was due to a voltage transient transmitted to sequencer 2 by physical wiring discrepancies unique to DG 2.

Corrective Action

Wiring was changed to conform with design drawings.

Plant/Event Data

Systems Involved:
Emergency power

Components and Failure Modes Involved:
DG 2 — tripped on overspeed during test
DG 1 — inoperable

Component Unavailability Duration: 8 h assumed
Plant Operating Mode: 5 (0% power)
Discovery Method: During testing
Reactor Age: 16.7 years
Plant Type: PWR

Comments

None

Event Identifier: 206/84-002

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case	

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	0.34	One DG assumed capable of being started locally

Plant Models Utilized

PWR model is unique for San Onofre LOOP.

Event Identifier: 206/84-002

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 206/84-002
Event Description: Both Diesel Generators Inoperable at San Onofre 1
Event Date: 3/9/84

UNAVAILABILITY, DURATION= 8

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	6.2E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	3.4E-07
Total	3.4E-07
CV	
LOOP	(2.8E-11)
Total	(2.8E-11)
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CD Conditional Probability: 3.4E-07

214 LOOP -RT EP AFW/EP

SEQUENCE CONDITIONAL PROBABILITIES

Sequence	End State	Prob	N Rec**
214 LOOP -RT EP AFW/EP	CD	3.4E-07 *	3.9E-02

Event Identifier: 206/84-002

* 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.

MODEL: b:\san_ono_.txt
DATA:

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
LOFW	1.6E-04	3.0E-01	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
EP	2.9E-03 > 1.0E+00	5.1E-01 > 3.4E-01	4.0E-02
Branch Model: 1.OF.2+opr			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
AFW	1.0E-03	2.7E-01	
AFW/EP	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	3.0E-02	5.0E-02	
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	2.0E-03	1.0E+00	4.0E-02
SI(MF.PUMPS)	5.0E-03	3.4E-01	
SSR/COND	1.0E+00	3.4E-01	

*** forced

Minarick
04-11-1987
13:12:28

Event Identifier: 206/84-002

PRECURSOR DESCRIPTION SHEET

LER No.: 219/84-012
Event Description: Both Diesel Generators Simultaneously Inoperable
Date of Event: June 4, 1984
Plant: Oyster Creek 1

EVENT DESCRIPTION

Sequence

The reactor was partially fueled, and the mode switch was in Refuel. EDG 2 was inoperable because maintenance was being performed on its governor. EDG 1 was started for a scheduled DG load test. Thirteen minutes later an EDG 1 "day-tank" level high/low alarm was received in the control room. Eighteen minutes after DG 1 was started, an operator informed the control room that the fuel oil day-tank had fallen to a quarter of a tank (~12 min of operation). To prevent diesel DG shutdown due to a lack of fuel, a normal shutdown of EDG 1 was initiated.

The normal shutdown sequence for an EDG includes an 11.5-min idle period (generator unloaded) to allow the diesel engine to cool. Twenty minutes after EDG 1 was started, an electrician dispatched to help find the cause of the high/low alarm found the local (EDG 1 compartment) control switch for the diesel fuel oil transfer pumps in the OFF position. This control switch was last verified to be in the ON position during a load run conducted on May 28.

Corrective Action

The immediate corrective action was to place the diesel fuel oil transfer pump control switch in the On position. The EDG-1 load test was resumed. Future corrective actions to be implemented include:

1. Incorporate a check of the transfer pump control switch position into the plant tour sheets.
2. Install keylock controls on the transfer pump control switch for each EDG to prevent repositioning without the group shift supervisor's concurrence.

Plant/Event Data

Systems Involved:
Emergency ac power system, CS system, CS and emergency SW systems, standby gas treatment system, and SBLC system

Components and Failure Modes Involved:
Diesel fuel oil transfer pump control switch — transferred off

Component Unavailability Duration: 12 h (postulated)
Plant Operating Mode: 5 (0% power)
Discovery Method: During testing
Reactor Age: 15.1 years
Plant Type: BWR

Comments

1. During power operation, Technical Specifications require that a daily load test, at a >20% rated power for at least 1 h be performed on the operable EDG when the other diesel is inoperable. Plant policy is to perform the load test at rated power. Thus the maximum time that the fuel oil transfer pump switch could be misaligned after removing one DG from service is 1 d.

2. At Oyster Creek, the fire protection system can supply water to the core even if all ECC is lost due to the shutdown of the remaining EDG. The capability to use this system in the event of emergency power system failure is not currently addressed in the LOOP core damage model.

3. This event has been modeled under the assumption that it could have occurred at power.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	0.34	Assumed recoverable locally

Plant Models Utilized

BWR plant Class A

Event Identifier: 219/84-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 219/84-012
Event Description: Both Diesel Generators Simultaneously Inoperable at San Onofre 1
Event Date: 6/4/84
Plant: Oyster Creek

UNAVAILABILITY, DURATION= 12

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	5.3E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	3.8E-07
Total	3.8E-07
CV	
LOOP	(6.7E-09)
Total	(6.7E-09)
ATWS	
LOOP	7.0E-09
Total	7.0E-09

DOMINANT SEQUENCES

End State: CD Conditional Probability: 2.2E-07

231 LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE

End State: ATWS Conditional Probability: 7.4E-09

233 LOOP EMERG.POWER SCRAM

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 219/84-012

	Sequence		End State	Prob	N Rec**
230	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE OL.COND	IS	CD	1.8E-07	1.2E-01
231	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE		CD	2.2E-07 *	1.2E-01
233	LOOP EMERG.POWER SCRAM		ATWS	7.4E-09 *	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.

MODEL: b:\bwratree.cmp
DATA: b:\ocprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	1.2E-02	1.0E+00	
EMERG.POWER	2.9E-03 > 1.0E+00	5.1E-01 > 3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
FW/PCS.TRANS	1.0E+00	1.0E+00	
FW/PCS.LOCA	1.0E+00	1.0E+00	
ISOL.COND	1.0E-02	1.0E+00	
FWCI/FW.TRANS	2.9E-01	3.4E-01	
FWCI/LOOP	1.0E+00	1.0E+00	
FWCI/FW.LOCA	1.0E-03	3.4E-01	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-04	3.4E-01	

Event Identifier: 219/84-012

FIREWTR.OR.OTHER/LPCS.TRANS	1.0E+00	1.0E+00
FIREWTR.OR.OTHER/LPCS.LOOP	1.0E+00	1.0E+00
FIREWTR.OR.OTHER/LPCS.LOCA	1.0E+00	1.0E+00
SDC	2.1E-02	3.4E-01
CC/SDC	1.0E-03	1.0E+00
C.I.AND.V	1.0E+00	3.4E-01

*** forced

Minarick
04-11-1987
13:16:36

Event Identifier: 219/84-012

PRECURSOR DESCRIPTION SHEET

LER No.: 220/84-015
Event Description: One-half the Safety-Related Loads Become Inoperable
Date of Event: July 8, 1984
Plant: Nine Mile Point 1

EVENT DESCRIPTION

Sequence

During normal operations, calibration work was being performed on the power board 103 undervoltage relays. DG 103 and its output breaker were taken out of service for this work, and power was being supplied to power board 103 from offsite power through breaker R-1013. Due to personnel error, the protective relaying was actuated, causing breaker R-1013 to open and protective relay 86-17 to trip on power board 17, deenergizing power boards 103 and 17B. This caused approximately half of the station's safety-related loads to become inoperable.

Corrective Action

Operators reestablished offsite power to the power boards 10 min after the event occurred. The calibrations were then satisfactorily completed.

Plant/Event Data

Systems Involved (one train):
- CRD system
- CS system
- EDG system
- ESW system
- Essential raw SW system
- SDC system
- SBLC system

Event Identifier: 220/84-015

Components and Failure Modes Involved:
Breaker R-1013 transferred open due to personnel error.
Because breaker R-1013 was opened by an operator; a partial list of the equipment that became inoperable follows.

battery charger 171
CRD pump 12
CS discharge isolation valves 112 and 122
CS pumps 112 and 122
CS suction isolation valves 112 and 122
DG 103 cooling raw water pump
emergency SW pump 12
feedwater isolation valve 12
liquid poison pump 12
reactor building closed-loop cooling water pump 12
reactor SDC pump suction blocking valve 12
SDC pump 12

Component Unavailability Duration: 10 min
Plant Operating Mode: 1 (97% power)
Discovery Method: Operational event
Reactor Age: 14.9 years
Plant Type: BWR

Comments

Power boards 16 and 102 (redundant power boards to power boards 17 and 103, respectively) and all redundant loads were operable.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

CRD	0.34	Unavailable but recoverable locally at equipment
LPCS	Base case	One train unavailable but recoverable locally at equipment
SDC	Base case	One train unavailable but recoverable locally at equipment

Plant Models Utilized

BWR plant Class A

Event Identifier: 220/84-015

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 220/84-015
Event Description: One-Half of Safety-Related Loads Become Inoperable
Event Date: 7/8/84
Plant: Nine Mile Point 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E-02

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
TRANS	3.3E-08
Total	3.3E-08
CV	
TRANS	6.2E-08
Total	6.2E-08
ATWS	
TRANS	2.0E-07
Total	2.0E-07

DOMINANT SEQUENCES

End State: CD Conditional Probability: 2.8E-08

108 TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE ISOL.COND FW/PCS.TRANS FWCI/FW.TRANS CRD SRV.ADS

End State: CV Conditional Probability: 4.1E-08

127 TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS FWCI/FW.TRANS -SRV.ADS -COND/FW.PCS -SDC

End State: ATWS Conditional Probability: 2.0E-07

Event Identifier: 220/84-015

141 TRANS SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
107	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE IS OL.COND FW/PCS.TRANS FWCI/FW.TRANS CRD -SRV.ADS COND/FW.PCS LPCS FIREWTR.OR.OTHER/LPCS.TRANS	CD	1.3E-09	1.3E-04
108	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE IS OL.COND FW/PCS.TRANS FWCI/FW.TRANS CRD SRV.ADS	CD	2.8E-08 *	1.2E-03
127	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS FWCI/FW.TRANS -SRV.ADS -COND/FW.PCS -SDC	CV	4.1E-08 *	2.2E-03
131	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS FWCI/FW.TRANS -SRV.ADS COND/FW.PCS -LPCS -SDC	CV	2.1E-08	1.1E-03
140	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS FWCI/FW.TRANS SRV.ADS	CD	3.0E-09	3.4E-03
141	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-07 *	1.0E-02

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

MODEL: b:\bwratree.cmp
DATA: b:\nineprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03 > 1.1E-03	1.0E+00 > 1.0E-02	
Branch Model: INITOR			
Initiator Freq:	1.1E-03		
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	1.8E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	1.0E+00	1.0E+00	
FW/PCS.LOCA	1.0E+00	1.0E+00	

Event Identifier: 220/84-015

ISOL.COND	1.0E-02	1.0E+00	
FWCI/FW.TRANS	2.9E-01	3.4E-01	
FWCI/LOOP	1.0E+00	1.0E+00	
FWCI/FW.LOCA	1.0E-03	3.4E-01	
CRD	1.0E-02 > 1.0E+00 ***	1.0E+00 > 3.4E-01	4.0E-02
Branch Model: 1.0F.1+opr			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	2.0E-03 > 2.0E-02	3.4E-01	
Branch Model: 1.0F.2			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
FIREWTR.OR.OTHER/LPCS.TRANS	1.0E+00	1.0E+00	
FIREWTR.OR.OTHER/LPCS.LOOP	1.0E+00	1.0E+00	
FIREWTR.OR.OTHER/LPCS.LOCA	1.0E+00	1.0E+00	
SDC	1.1E-02 > 1.3E-02	3.4E-01	
Branch Model: 1.0F.3+ser			
Train 1 Cond Prob:	3.0E-02		
Train 2 Cond Prob:	1.0E-01		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
Serial Component Prob:	1.0E-02		
CC/SDC	1.0E-03	3.4E-01	
C.I.AND.V	1.0E+00	3.4E-01	

*** forced

Minarick
04-11-1987
13:25:08

Event Identifier: 220/84-015

PRECURSOR DESCRIPTION SHEET

LER No.: 237/84-010
Event Description: Inadvertent Loss of Feeder Breaker Makes LPCI Unavailable
Date of Event: June 26, 1984
Plant: Dresden 2

EVENT DESCRIPTION

Sequence

During a unit startup, feeder breaker position indication in the control room was lost on the breaker at bus 29, which feeds MCC 28-7 and 29-7. The MCCs had not actually lost power. A second breaker is located at MCC 29-7, both operating off a single control switch in the control room. Following a light bulb integrity check, an operator was sent to reset the breaker at MCC 29-7. The breaker at MCC 29-7 was inadvertently tripped off, isolating MCC 28-7 and 29-7 and causing control power to the IVs to be lost. The LPCI valves are normally closed and open on demand. LPCI became unavailable for 28 min.

Two attempts at this time to energize MCC 28-7 and 29-7 failed. While preparing to use the alternate feed from bus 28, the operator placed the normal feed control switch from bus 29 in pull-to-lock. An open breaker position light appeared for the breaker at bus 29, and breaker control returned. The operator closed the control switch from bus 29 and reenergized MCC 28-7 and 29-7.

Corrective Action

A loose wire on the panel was corrected. Operator training was reviewed. Labels were placed on indicator lights.

Plant/Event Data

Systems Involved:
Electrical and LPCI

Components and Failure Modes Involved:
LPCI injection valves — rendered unavailable

Component Unavailability Duration: 28 min
Plant Operating Mode: 2 (5% power)
Discovery Method: During startup operations
Reactor Age: 14.4 years
Plant Type: BWR

Event Identifier: 237/84-010

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and LOCA	Base case	

Branches Impacted and Branch Nonrecovery Estimate

LPCI	1.0	Short-term recovery not considered likely due to failure mechanism
SDC	1.0	Short-term recovery not considered likely due to failure mechanism

Plant Models Utilized

BWR plant Class B

Event Identifier: 237/84-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 237/84-010
Event Description: Inadvertant Loss of Feeder Breaker Makes LPCI Unavailable
Event Date: 6/26/84
Plant: Dresden 2

UNAVAILABILITY, DURATION= .5

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	5.7E-04
LOOP	2.2E-06
LOCA	5.5E-07

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	(7.0E-14)
LOOP	(3.7E-14)
LOCA	(5.5E-17)
Total	(1.1E-13)
CD	
TRANS	4.1E-10
LOOP	1.1E-11
LOCA	6.3E-11
Total	4.8E-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: 1.3E-10

Event Identifier: 237/84-010

131 TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS HPCI -SRV.ADS -COND/FW.PCS SDC -LPCI(CC)

End State: CD Conditional Probability: 2.0E-10

101 TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE ISOL.COND -FW/PCS.TRANS SDC LPCI(CC) C.I.AND.V/LPCI

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
101	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE ISOL.COND -FW/PCS.TRANS SDC LPCI(CC) C.I.AND.V/LPCI	CD	2.0E-10 *	1.1E-01
102	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE ISOL.COND FW/PCS.TRANS -HPCI SDC LPCI(CC) C.I.AND.V/LPCI	CD	2.0E-11	3.8E-02
110	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE -FW/PCS.LOCA SDC LPCI(CC) C.I.AND.V/LPCI	CD	1.8E-10	1.1E-01
131	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS HPCI -SRV.ADS -COND/FW.PCS SDC -LPCI(CC)	CV	1.3E-10 *	1.3E-01
135	TRANS SCRAM -SLC.OR.RODS PCS/TRANS FW/PCS.TRANS HPCI -SRV.ADS COND/FW.PCS -LPCS SDC -LPCI(CC)	CV	6.9E-11	6.6E-02
223	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI -SRV.ADS -LPCS SDC -LPCI(CC)	CV	4.7E-11	1.9E-01
302	LOCA -SCRAM PCS/LOCA -FW/PCS.LOCA SDC LPCI(CC) C.I.AND.V/LPCI	CD	6.2E-11	3.9E-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.

MODEL: b:\bwrbtree.cmp
DATA: b:\drprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	

Event Identifier: 237/84-010

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	5.1E-01	
FW/PCS.TRANS	2.9E-01	3.4E-01	
FW/PCS.LOCA	4.0E-02	3.4E-01	
HPCI	1.0E-01	5.7E-01	
ISOL.COND	2.0E-02	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	2.0E-03	3.4E-01	
LPCI	1.0E-03 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.0F.2			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
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 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.0F.3+ser			
Train 1 Cond Prob:	3.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
Serial Component Prob:	2.0E-03		
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	

*** forced

Minarick
04-11-1987
13:31:03

Event Identifier: 237/84-010

PRECURSOR DESCRIPTION SHEET

LER No.: 247/84-025
Event Description: Plant Trip Due to Unavailability of HPI
Date of Event: December 28, 1984
Plant: Indian Point 2

EVENT DESCRIPTION

Sequence

On December 26, 1984, one SI pump (22) was run to top off the accumulator tanks. On the morning of December 28, with the reactor critical, SI pump 23 was started to top off the accumulator tanks. The pump developed a discharge head of 1100 psig and then dropped to ~700 psig, corresponding to the pressure in the accumulator tanks. The pump was secured from operation and the valve lineup verified. The pump was vented and the suction and discharge pressure taps inspected. Liquid was observed at each point with a momentary emission of gas. A second SI pump (22) was inspected and found to be solid with water. The suction pressure was satisfactory at 30 psig. SI pump 22 was started to maintain level in the accumulators. After filling two accumulators and while in the process of topping off the third, pump 22 was observed to drop in discharge pressure from 1500 to 700 psig. The pump was secured from operation. The piping to the third SI pump (21) precluded its use to top off the accumulators. An unsuccessful attempt was made to roll the pump manually.

The reactor was manually tripped and an orderly approach to cold shutdown implemented.

Precipitated boric acid is believed to have partially blocked the suction to pumps 22 and 23, causing partial suction loss. This, together with gas entrapment, resulted in the observed drop in discharge pressure when the accumulators were topped off. In the case of pump 21, the suction line was totally blocked.

Based on the analysis of a log indication of 220 gal of makeup added to the BIT during the prior week and the operating history of the SI pumps, the BIT was known to be leaking across closure valves 1822A and 1822B. This is considered to be the source of the boric acid. The boric acid is believed to have been precipitated in the pumps because they are not heat traced.

By a process of elimination, the BIT is the most likely source of the nitrogen gas vented from the pump 23. The nitrogen dissolves in the tank liquid until equilibrium is achieved at 90 psig. Either leakage or injection will cause dissolved gas to evolve in the lower pressure discharge line.

Corrective Action

Because all factors contributing to the malfunction of the SI pumps cannot be positively identified at this time, reliance has been placed on system monitoring and procedure revision to preclude further similar events. The BIT discharge line is being monitored on a daily basis and is flushed upon detection of increasing boric acid; it is maintained at a concentration no greater than 300 ppm above the RWST boron level. Similarly the pump vents are monitored for gas evolution. The emergency procedure for recovery from a spurious SI has been clarified to provide for adequate flushing of the discharge line from the BIT.

Subsequent to the events of December 28, the suction side of the pumps was flushed through the pump vents until no more gas evolved. Similar operations were performed at other points in the system. Pump 21 was replaced with a spare. All pumps were subjected successfully to a surveillance test and declared operable before reactor criticality.

Plant/Event Data

Systems Involved:
HPI

Components and Failure Modes Involved:
Two HPI pumps — failed on demand

Third HPI pump — unavailable on demand

Component Unavailability Duration: 1 d (assumed)
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 11.6 years
Plant Type: PWR

Comments

Reference: Abnormal Occurrence Reports to Congress, NUREG-0090, 7 (2), Nuclear Regulatory Commission, No. 84-18

Event Identifier: 247/84-025

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, small-break LOCA	Base case

Branches Impacted and Branch Nonrecovery Estimate

HPI	1.0	No recovery considered possible
Bleed and feed	1.0	No recovery considered possible

Plant Models Utilized

PWR plant Class B

Event Identifier: 247/84-025

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 247/84-025
Event Description: Plant Trip Due to Unavailability of HPI
Event Date: 12/28/84
Plant: Indian Point 2

UNAVAILABILITY, DURATION= 24

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	2.5E-02
LOOP	1.9E-04
LOCA	3.4E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.3E-04
LOOP	4.1E-08
LOCA	3.2E-05
Total	1.6E-04
CD	
TRANS	1.6E-07
LOOP	4.7E-08
LOCA	3.0E-07
Total	5.1E-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: 1.2E-04

Event Identifier: 247/84-025

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

End State: CD Conditional Probability: 1.2E-06

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	5.0E-06	3.4E-01
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	1.2E-04 *	3.4E-01
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	1.4E-07	3.1E-02
214	LOOP -RT/LOOP -EMERG.POWER AFW HPI(F/B)	CD	4.9E-08	9.2E-02
304	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	3.3E-05	3.4E-01
307	LOCA -RT -AFW HPI SS.DEPRESS	CD	1.2E-06 *	3.4E-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.

MODEL: b:\pwrbtree.cmp
DATA: b:\IPPROB.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	1.0E-03	2.7E-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	5.0E-02	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	1.5E-03 > 1.0E+00	5.2E-01 > 1.0E+00	

Event Identifier: 247/84-025

Branch Model: 1.0F.3+ser			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
Train 3 Cond Prob:	3.0E-01 > Failed		
Serial Component Prob:	1.2E-03		
HPI(F/B)	1.5E-03 > 1.0E+00	5.2E-01 > 1.0E+00	4.0E-02
Branch Model: 1.0F.3+ser+opr			
Train 1 Cond Prob:	1.0E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
Train 3 Cond Prob:	3.0E-01 > Failed		
Serial Component Prob:	1.2E-03		
HPR/-HPI	3.0E-03	5.6E-01	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	1.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03	1.0E+00	

*** forced

Minarick
04-11-1987
13:36:05

Event Identifier: 247/84-025

PRECURSOR DESCRIPTION SHEET

LER No.: 250/84-036, -038, -040
Event Description: Both Diesel Generators Unavailable on Two Occasions
Date of Event: December 21, 1984
Plant: Turkey Point 3

EVENT DESCRIPTION

Sequence

On December 21, 1984, during daily testing of the "B" EDG required by Technical Specifications because "A" EDG was out of service for periodic maintenance, the diesel failed to start from the control room. A local inspection of the DG revealed an overspeed alarm. When a second start was attempted, the generator revolutions per minute were observed to immediately reach the overspeed set point, and the DG locked out on overspeed. "B" EDG was declared out of service at 1127 h. At 1200 h, the governor no-load speed was adjusted too high, and it was readjusted back to normal. The generator was started locally and came up to normal speed. The DG was stopped, successfully tested, and declared back in service. During this event, both Units 3 and 4 startup transformers were available as required by Technical Specifications.

On December 22, the "B" DG was removed from service to replace a leaking section of the vent line from the engine coolant discharge to the surge tank. The "A" DG was also out of service at this time.

Corrective Action

"B" EDG governor no-load speed was readjusted back to normal. The vent line was replaced.

Plant/Event Data

Systems Involved:
Emergency power

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

Component Unavailability Duration: 4 h (assumed)
Plant Operating Mode: 5 (0% power)
Discovery Method: Testing
Reactor Age: 12.1 years
Plant Type: PWR

Event Identifier: 250/84-036, -038, -040

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case	

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	0.34	Recovery from maintenance status considered possible on "B" DG; on "A" DG, timely recovery was not considered possible (in maintenance)

Plant Models Utilized

PWR plant Class E

Event Identifier: 250/84-036, -038, -040

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 250/84-036
Event Description: Both Diesel Generators Unavailable on Two Occasions
Event Date: 12/21/84
Plant: Turkey Point 3

UNAVAILABILITY, DURATION= 4

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.1E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	5.4E-08
Total	5.4E-08
CD	
LOOP	4.3E-09
Total	4.3E-09
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.1E-08

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

End State: CD Conditional Probability: 4.3E-09

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

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 250/84-036

	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	2.1E-09	3.9E-02
216	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT/EMERG.POWER	CD	4.2E-10	5.8E-03
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	5.1E-08 *	3.9E-02
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	4.3E-09 *	3.1E-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 compared to a similar period without the existing failures.

MODEL: b:\pwrbtree.cmp
DATA: b:\turkprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 1.0E+00	5.1E-01 > 3.4E-01	
Branch Model: 1.0F.2			
Train 1 Cond Prob:	5.0E-02 > Unavailable		
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	5.0E-02	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	3.0E-04	5.2E-01	
HPI(F/B)	3.0E-04	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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	

Event Identifier: 250/84-036

LPI/HPI	1.0E-03	3.4E-01
LPR/-HPI.HPR	6.7E-01	1.0E+00
LPR/HPI	1.0E-03	1.0E+00

*** forced

Minarick
04-11-1987
13:41:44

Event Identifier: 250/84-036

PRECURSOR DESCRIPTION SHEET

LER No.: 254/84-014
Event Description: Two LPCI Injection Valves Fail to Open
Date of Event: August 8, 1984
Plant: Quad-Cities 1

EVENT DESCRIPTION

Sequence

During the cycle 7 refueling outage at 1625 h, while the operator was in the process of starting the SDC mode of the RHR system, both LPCI injection valves would not open. RHR could be accomplished using the RWCS and the RHR system with the LPCI "B" valve 25% open.

The cause of the failure was a personnel error in 1980 during modifications: a wiring design error. It went undetected.

Corrective Action

The valve stems were removed and replaced. The wiring correction was made, and the wiring diagram was corrected to reflect the change.

Plant/Event Data

Systems Involved:
LPCI

Components and Failure Modes Involved:
LPCI valves — failed to open on demand

Component Unavailability Duration: 4 years (720 h assumed for analysis; assumed failed during last surveillance test
Plant Operating Mode: 2 (0% power)
Discovery Method: In operation
Reactor Age: 12.9 years
Plant Type: BWR

Comments

The valve in the "B" LPCI train was 25% open. That percentage has been assumed to be insufficient to supply adequate flow for decay DHR.

Event Identifier: 254/84-014

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and small-break LOCA	Base

Branches Impacted and Branch Nonrecovery Estimate

LPCI	1.0	No recovery assumed possible based on event description
RHR (SDC)	1.0	No recovery assumed possible based on event description
RHR SW	Base case	No recovery assumed possible based on event description

Plant Models Utilized

BWR plant Class C

Event Identifier: 254/84-014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 254/84-014
Event Description: Two LPCI Injection Valves Fail to Open
Event Date: 8/8/84
Plant: Quad Cities 1

UNAVAILABILITY, DURATION= 720

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	8.2E-01
LOOP	3.2E-03
LOCA	8.0E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	(5.6E-11)
LOOP	(2.0E-11)
LOCA	(1.6E-12)
Total	(7.8E-11)
CD	
TRANS	6.4E-04
LOOP	2.1E-05
LOCA	5.4E-06
Total	6.7E-04
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.8E-09

Event Identifier: 254/84-014

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

End State: CD Conditional Probability: 5.7E-04

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	5.7E-04 *	3.2E-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	5.9E-05	1.1E-01
135	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS RHR(SDC) - RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	4.8E-09 *	7.3E-02
139	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) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	2.5E-09	3.8E-02
156	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS -COND/FW.PCS RHR(SDC) -RHR(SPCOO L)/-LPCI.RHR(SDC)	CV	2.9E-10	1.3E-01
160	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS COND/FW.PCS -LPCS RHR(SDC) -RHR (SPCOOL)/-LPCI.RHR(SDC)	CV	1.5E-10	6.6E-02
201	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE -HP CI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SD C).RHR(SPCOOL)	CD	2.0E-05	1.1E-01
227	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOO P -SRV.ADS -LPCS RHR(SDC) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	2.5E-09	1.1E-01
315	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS RHR(SDC) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	1.5E-10	4.3E-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.

MODEL: b:\bwrctree.cmp
DATA: b:\qcprob.cmp

No Recovery Limit

Event Identifier: 254/84-014

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	5.1E-01	
FW/PCS.TRANS	2.9E-01	3.4E-01	
FW/PCS.LOCA	4.0E-02	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.0E-03 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
RHRSW/LPCS.LPCI.TRANS	5.0E-01 > 1.0E+00	1.0E+00	4.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	5.0E-01 > Failed		
RHRSW/LPCS.LPCI.LOOP	5.0E-01 > 1.0E+00	1.0E+00	4.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	5.0E-01 > Failed		
RHRSW/LPCS.LPCI.LOCA	5.0E-01 > 1.0E+00	1.0E+00	4.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	5.0E-01 > Failed		
RHR(SDC)	2.0E-02 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	4.0E-03 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
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	

Event Identifier: 254/84-014

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

*** forced

Minarick
04-11-1987
13:47:04

Event Identifier: 254/84-014

PRECURSOR DESCRIPTION SHEET

LER No.: 259/84-027
Event Description: Inadvertent Relief Valve Opening with Subsequent Trip
Date of Event: June 27, 1984
Plant: Browns Ferry 1

EVENT DESCRIPTION

Sequence

During normal unit startup following a short unit outage, while approaching 1% power with ~400-psig reactor pressure, a main steam RV began to unseat. It continued to leak, causing the torus temperature to approach Technical Specifications' limits, and the unit was manually scrammed at 350 psig. The RV subsequently reseated at 100 psig.

Corrective Action

The valve was replaced and the unit restarted. The RV was tested at Wyle Laboratories, and it performed normally. It was then disassembled, and all internal parts were found to be normal. No reason, either electrical or mechanical, could be found to explain the premature valve actuation.

Plant/Event Data

Systems Involved:
Main steam

Components and Failure Modes Involved:
RV inadvertently opened

Component Unavailability Duration: NA
Plant Operating Mode: 2 (1% power)
Discovery Method: Operational event
Reactor Age: 10.9 years
Plant Type: BWR

Comments

It has been assumed that the RV's spurious opening could have occurred while the plant was at power.

Event Identifier: 259/84-027

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Small-break LOCA	0.1	To account for likelihood of occurring at power and likelihood that relief would have been sufficient to require LOCA mitigation

Branches Impacted and Branch Nonrecovery Estimate

None

Plant Models Utilized

BWR plant Class C

Event Identifier: 259/84-027

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 259/84-027
Event Description: Inadvertant Relief Valve Opening with Subsequent Trip
Event Date: 6/27/84
Plant: Browns Ferry 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.0E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOCA	7.2E-07
Total	7.2E-07
CD	
LOCA	9.5E-05
Total	9.5E-05
ATWS	
LOCA	2.0E-06
Total	2.0E-06

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.7E-07

314 LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)

End State: CD Conditional Probability: 9.0E-05

310 LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS

End State: ATWS Conditional Probability: 2.0E-06

332 LOCA SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
302	LOCA -SCRAM PCS/LOCA -FW/PCS.LOCA RHR(SDC) RHR(SPCOOL)/-LPC I.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	3.1E-06	7.6E-03
310	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	9.0E-05 *	1.9E-02
314	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	4.7E-07 *	1.3E-02
318	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	2.4E-07	6.6E-03
332	LOCA SCRAM SLC.OR.RODS	ATWS	2.0E-06 *	1.0E-01

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

MODEL: b:\bwrctree.cmp
DATA: b:\bfprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06 > 3.3E-06	3.4E-01 > 1.0E-01	
Branch Model: INITOR			
Initiator Freq:	3.3E-06		
SCRAM	4.1E-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	5.1E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02

Event Identifier: 259/84-027

COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-11-1987
13:51:40

Event Identifier: 259/84-027

PRECURSOR DESCRIPTION SHEET

LER No.: 259/84-032
Event Description: Inadvertent Overpressurization and Leakage from LPCS
Date of Event: August 14, 1984
Plant: Browns Ferry 1

EVENT DESCRIPTION

Sequence

While at full power, the LPCS's normally closed, motor-operated isolation valve was undergoing a surveillance test. The normal interlock preventing opening the valves simultaneously at power was bypassed. By error, 8 months previously, the testable isolation check valve's air operator had been installed backwards, thereby causing the valve to actually be open while the indicator showed closed. By a second operator error, the power to the closed motor-operated valve was not locked out during the surveillance test. The normally open motor-operated isolation valve remained open. While applying the open signal in the test, the operator caused the normally closed motor isolation valve to cycle open. The LPCS overpressurized, and the line RV discharged steam and water into the pump room. The overpressure alarm failed to sound, and the operator did not observe the change in system pressure. The pipe heated to 400°F. The seal there leaked due to backflow from the common drain that serves the seal leak line, and the clean radwaste line for the A train pump ruptured. The event lasted 13 min before the line was isolated. The workers responding to the event had their clothing contaminated by the leaking water.

Corrective Action

CS loop I was isolated and tagged, which placed the unit in a 7-d limiting condition of operation. Meanwhile, the plant manager ordered an investigation of the event. Site engineering and maintenance staffs inspected all affected components and found no damage. The extent of the pipe heating was determined by examination of paint damage on the piping. The maximum temperature experienced was estimated to be <400°F. Paint damage extended from the injection valves down to the system RV. Tennessee Valley Authority's Office of Engineering Design analyzed the system piping and supports for the transient and found that integrity for continued use was ensured. The pump A seal was removed, and no damage was observed. Also, there was no evidence that hot water entered the pump area piping, which indicates that the pump discharge check valve was holding.

Event Identifier: 259/84-032

Plant/Event Data

Systems Involved:
LPCS

Components and Failure Modes Involved:
LPCS isolation valves — inadvertently open

Component Unavailability Duration: 8 months
Plant Operating Mode: 1 (100% full power)
Discovery Method: During testing
Reactor Age: 11 years
Plant Type: BWR

Comments

Development of probability estimates related to this and other overpressurization events is addressed in An Evaluation of BWR Over-Pressure Incidents in Low Pressure Systems, J. D. Harris and J. W. Minarick, May 1985 (internal accident sequence percursor report). Based on the impact of the event on Browns Ferry Unit 1 (one train of LPCI and one train of LPCS impacted), the following modifications to probability values used in that document are required to estimate the conditional probability for the event:

p (core damage/pipe rupture and RCS depressurization) = 2E-2

p (core damage/small-break LOCA) = 1.1E-4

In addition, the probability of pipe rupture given overpressurization has been assumed to be 1E-1 (see the above document). These estimates result in an event tree/probability model for core damage associated with the events shown in the figure below. The attached calculations address sequences 15 and 17. The overall core damage likelihood is estimated using the model in the figure to be 6E-6. See also Abnormal Occurrence Reports to Congress, NUREG-00990, 7(3) for additional information on this event.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOCA	0.12	Recoverable locally at valves

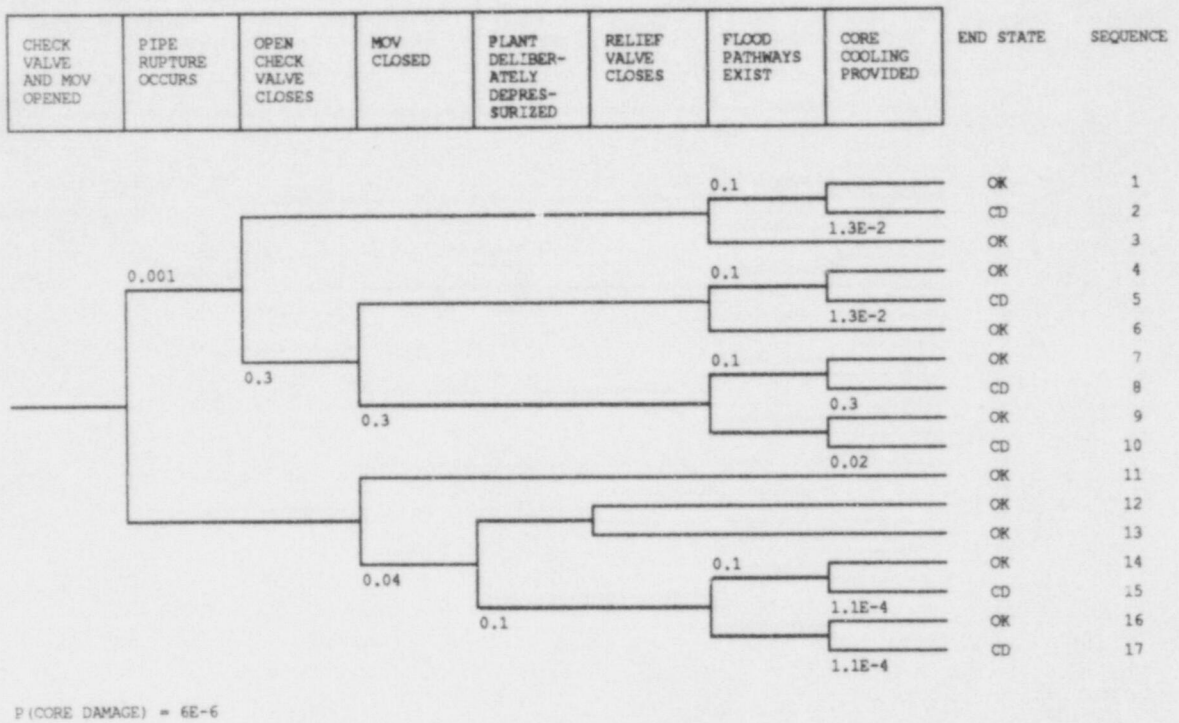
Branches Impacted and Branch Nonrecovery Estimate

LPCS	Base case
LPCI/RHR	Base case

Event Identifier: 259/84-032

Plant Models Utilized

BWR plant Class C



Core damage model for LER 259/84-032.

Event Identifier: 259/84-032

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 259/84-032
Event Description: Inadvertant Overpressurization and Leakage from LPCS
Event Date: 8/14/84
Plant: Browns Ferry 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	1.2E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOCA	8.6E-07
Total	8.6E-07
CD	
LOCA	1.1E-04
Total	1.1E-04
ATWS	
LOCA	2.4E-06
Total	2.4E-06

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.7E-07

314 LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)

End State: CD Conditional Probability: 1.1E-04

310 LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS

End State: ATWS Conditional Probability: 2.4E-06

332 LOCA SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
302	LOCA -SCRAM PCS/LOCA -FW/PCS.LOCA RHR(SDC) RHR(SPCOOL)/-LPC I.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	3.7E-06	9.2E-03
310	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	1.1E-04 *	2.3E-02
314	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	5.7E-07 *	1.5E-02
318	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	2.9E-07	7.8E-03
332	LOCA SCRAM SLC.OR.RODS	ATWS	2.4E-06 *	1.2E-01

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

MODEL: b:\bwrctree.cmp
DATA: b:\bfprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06 > 3.3E-06	3.4E-01 > 1.2E-01	
Branch Model: INITOR			
Initiator Freq:	3.3E-06		
SCRAM	4.1E-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	5.1E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02

Event Identifier: 259/84-032

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 > Failed		
LPCI(RHR)/LPCS	4.0E-04 > 4.0E-03	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.0E-03		
Train 2 Cond Prob:	1.0E-01 > Failed		
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)	2.0E-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	

*** forced

Minarick
04-11-1987
13:56:22

Event Identifier: 259/84-032

PRECURSOR DESCRIPTION SHEET

LER No.: 265/84-010
Event Description: Trip with RCIC Failure
Date of Event: October 25, 1984
Plant: Quad-Cities 2

EVENT DESCRIPTION

Sequence

On October 25, 1984, Unit 2 was proceeding to hot standby. At 0546 h, the procedure was partially completed, and all outboard MSIVs were closed. Once the outboard MSIVs were closed, reactor pressure started to increase. In an attempt to control pressure, additional control rods were inserted into the core. Because the reactor was already subcritical, the insertion of additional rods had no effect on the increasing pressure. A second attempt was made to control pressure by starting the RCIC system. RCIC tripped on overspeed and had to be manually and locally reset at the turbine. Concurrently, the HPCI system was started by another operator, but the reactor scrammed from a high pressure of 1044 psig at 0641 h.

When the reactor scrammed, rod K-13 remained at position 48. Control rod K-13 was successfully inserted from the individual rod scram back-panel at 0712 h.

An inspection of the hydraulic control unit 38-51, which drives control rod K-13, revealed that the scram discharge riser valve EP 305-112 was closed, preventing the drive from venting properly when the scram took place. A thorough investigation to determine the root cause of the manual valve 112 being closed was conducted by reexamining Work Requests, Out-of-Service requests subsequent to the refueling outage, the September 18 hot scram timing surveillance tests, accumulator alarms logged in the unit operator's log book subsequent to the September 18 hot scram surveillance tests, and work performed on CRD modules in the vicinity of that for the K-13 hydraulic control unit (on both units). Despite all of the above measures, the reason for valve EP 305-112 being in the improper position could not be determined.

Corrective Action

The LER stated that the procedure for placing the plant in hot standby from full power would be revised. The hydraulic control unit valve positions were checked. The RCIC problem was being investigated at the time of the report.

Event Identifier: 265/84-010

Plant/Event Data

Systems Involved:
RCIC

Components and Failure Modes Involved:
RCIC — tripped on demand

Component Unavailability Duration: NA
Plant Operating Mode: 3 (0% power)
Discovery Method: Operational event
Reactor Age: 12.5 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

RCIC	0.34	Recoverable locally at pump

Plant Models Utilized

BWR plant Class C

Event Identifier: 265/84-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 265/84-010
Event Description: Trip with RCIC Failure
Event Date: 10/25/84
Plant: Quad Cities 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.2E-07
Total	1.2E-07
CD	
TRANS	8.9E-06
Total	8.9E-06
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 7.8E-08

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: 7.1E-06

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: 265/84-010

End State: ATWS Conditional Probability: 2.0E-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	7.1E-06 *	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	7.3E-07	3.8E-02
110	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	7.4E-07	6.6E-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	7.8E-08 *	4.3E-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	4.0E-08	2.2E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\qcprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	5.1E-01	
FW/PCS.TRANS	2.9E-01	3.4E-01	

Event Identifier: 265/84-010

FW/PCS.LOCA	4.0E-02	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02 > 1.0E+00	5.7E-01 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.7E-02 > Failed		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-11-1987
14:15:07

Event Identifier: 265/84-010

PRECURSOR DESCRIPTION SHEET

LER No.: 265/84-014
Event Description: HPCI Isolates with LPCI Already Inoperable
Date of Event: September 19, 1984
Plant: Quad-Cities 2

EVENT DESCRIPTION

Sequence

An HPCI system isolation occurred while the system was being run at low speed during turbine warming. This event was caused by a small intermittent leak from a steam seal on the HPCI turbine. The HPCI isolation was reset, but valve MO 2-2301-4 failed to open from the control room. This rendered HPCI inoperable. Because the LPCI mode of the RHR system was also inoperable for preventative maintenance, the decision was made to shut down. The shutdown was never initiated because Electrical Maintenance opened the valve 5 min after deciding to shut down and prior to initiating a load drop.

Corrective Action

Limit switches were readjusted.

Plant/Event Data

Systems Involved:
HPCI and LPCI (RHR mode)

Components and Failure Modes Involved:
HPCI — failed in operation

LPCI — unavailable because of maintenance

Component Unavailability Duration: 25 min
Plant Operating Mode: 1 (99% power)
Discovery Method: While operating
Reactor Age: 12.4 years
Plant Type: BWR

Comments

None

Event Identifier: 265/84-014

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and LOCA	Base case

Branches Impacted and Branch Nonrecovery Estimate

HPCI	0.34	Potential recovery at the component
LPCI	1.0	No recovery assumed because of maintenance unavailability
RHR (SDC)	1.0	No recovery assumed because of maintenance unavailability
RHR SW	1.0	No recovery assumed because of maintenance unavailability

Plant Models Utilized

BWR plant Class C

Event Identifier: 265/84-014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 265/84-014
Event Description: HPCI Isolates with LPCI Already Inoperable
Event Date: 9/19/84
Plant: Quad Cities 2

UNAVAILABILITY, DURATION= .49

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	5.6E-04
LOOP	2.2E-06
LOCA	5.4E-07

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	3.9E-11
LOOP	8.7E-12
LOCA	7.8E-13
Total	4.9E-11
CD	
TRANS	2.2E-07
LOOP	5.5E-09
LOCA	1.3E-09
Total	2.2E-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: 1.4E-11

Event Identifier: 265/84-014

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: 1.9E-07

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	1.9E-07 *	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	1.4E-08	2.6E-02
103	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW/PCS.TRANS HPCI -RCIC/TRANS.OR.LOOP RHR(SDC RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	6.9E-09	1.3E-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	1.4E-11 *	2.9E-02
135	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS RHR(SDC) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	9.8E-12	1.5E-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	7.5E-12	1.5E-02
139	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) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	5.0E-12	7.6E-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	8.8E-13	5.0E-02
156	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS -COND/FW.PCS RHR(SDC) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	5.9E-13	2.6E-02
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	4.5E-13	2.6E-02
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)	CV	5.2E-12	4.3E-02
227	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS RHR(SDC) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	3.5E-12	2.2E-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: 265/84-014

compared to a similar period without the existing failures.

MODEL: b:\bwrctree.cmp
DATA: b:\qcprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	5.1E-01	
FW/PCS.TRANS	2.9E-01	3.4E-01	
FW/PCS.LOCA	4.0E-02	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Failed		
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.0E-03 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
RHRSW/LPCS.LPCI.TRANS	5.0E-01 > 1.0E+00	1.0E+00	4.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	5.0E-01 > Unavailable		
RHRSW/LPCS.LPCI.LOOP	5.0E-01 > 1.0E+00	1.0E+00	4.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	5.0E-01 > Unavailable		
RHRSW/LPCS.LPCI.LOCA	5.0E-01 > 1.0E+00	1.0E+00	4.0E-02
Branch Model: 1.OF.1+opr			
Train 1 Cond Prob:	5.0E-01 > Unavailable		
RHR(SDC)	2.0E-02 > 1.0E+00	3.4E-01	

Event Identifier: 265/84-014

Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	4.0E-03	> Unavailable	
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

*** forced

Minarick
04-11-1987
14:20:53

Event Identifier: 265/84-014

PRECURSOR DESCRIPTION SHEET

LER No.: 271/84-022
Event Description: Diesel Generator Lockout Trip of Both Generators
Date of Event: October 23, 1984
Plant: Vermont Yankee

EVENT DESCRIPTION

Sequence

On October 22, 1984, at 1335 h EST, DG 1-1-A experienced a generator lockout trip caused by a differential relay trip resulting from a zener diode failure in the relay. At 0140 h EST on October 23, 1984, control room personnel noted a loss of DG 1-1-B, also resulting from generator lockout trip caused by differential relay trip due to the same cause. Because both DGs were unavailable, a reactor shutdown was begun.

On October 23, 1984 at 1730 h EST and on October 24, 1984 at 2000 h EST, the relays for DGs 1-1-B and 1-1-A, respectively, were repaired; and the diesels were declared operable.

Corrective Action

Corrective action will consist of installing the newer version of the Westinghouse SA-1 relay that is designated for Class 1E applications and no longer uses the Zener diode across the output SCR.

Plant/Event Data

Systems Involved:
Emergency Power

Components and Failure Modes Involved:
EPS — rendered unavailable

Component Unavailability Duration: 16 h
Plant Operating Mode: 1 (100% power)
Discovery Method: Observation
Reactor Age: 12.7 years
Plant Type: BWR

Comments

None

Event Identifier: 271/84-022

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case	

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	1.0	No recovery assumed possible

Plant Models Utilized

BWR plant Class C

Event Identifier: 271/84-022

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 271/84-022
Event Description: Diesel Generator Lockout Trip of Both Generators
Event Date: 10/23/84
Plant: Vermont Yankee

UNAVAILABILITY, DURATION= 16

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	7.1E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	(5.7E-11)
Total	(5.7E-11)
CD	
LOOP	1.8E-07
Total	1.8E-07
ATWS	
LOOP	2.8E-08
Total	2.8E-08

DOMINANT SEQUENCES

End State: CD Conditional Probability: 1.1E-07

249 LOOP EMERG.POWER -SCRAM -SRV.CHALL/LOOP.-SCRAM HPCI RCIC/TRANS.OR.LOOP

End State: ATWS Conditional Probability: 2.9E-08

250 LOOP EMERG.POWER SCRAM

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 271/84-022

	Sequence	End State	Prob	N Rec**
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI RCIC/TRANS.OR.LOOP	CD	4.5E-08	1.1E-01
246	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA	CD	2.4E-08	1.9E-01
249	LOOP EMERG.POWER -SCRAM -SRV.CHALL/LOOP.-SCRAM HPCI RCIC/TRANS.OR.LOOP	CD	1.1E-07 *	1.1E-01
250	LOOP EMERG.POWER SCRAM	ATWS	2.9E-08 *	3.4E-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.

MODEL: b:\BWRCTREE.CMP
DATA: b:\VTYANPRO.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	3.0E-01	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	3.0E-01	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	2.0E-02	1.0E+00	
EMERG.POWER	2.9E-03 > 1.0E+00	5.1E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Failed		
FW/PCS.TRANS	2.9E-01	3.4E-01	
FW/PCS.LOCA	4.0E-02	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02

Event Identifier: 271/84-022

COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-12-1987
16:41:15

Event Identifier: 271/84-022

PRECURSOR DESCRIPTION SHEET

LER No.: 272/84-017
Event Description: Unavailability of High-Head Charging Pumps
Date of Event: July 16, 1984
Plant: Salem 1

EVENT DESCRIPTION

Sequence

While performing surveillance testing of charging pump 12, the pump seized after running for ~30 s. Charging pump 12 was declared inoperable; the redundant charging pumps remained operable. Upon disassembly of the pump, a small amount of resin particles and metal filings were discovered in the pump casing. As a result of these findings, an investigation ensued to determine the source and extent of the problem. Similar material was found in the common suction line of all charging pumps.

It has been assumed (because of the extremely close internal tolerances in the centrifugal charging pumps) that the other charging pumps would also have failed as a result of the metal filings.

Corrective Action

Replaced rotating element in the charging pump. Suction lines were cleaned and temporary strainers installed.

Plant/Event Data

Systems Involved:
HHIS

Components and Failure Modes Involved:
Charging pump 12 — failed on demand
Remaining charging pumps — potentially failed on demand

Component Unavailability Duration: 360 h (postulated)
Plant Operating Mode: 6 (0% power)
Discovery Method: During testing
Reactor Age: 3.9 years
Plant Type: PWR

Comments

This unavailability possibly could have been discovered during startup checks; however, it is being conservatively modeled as if it could have rendered HPI unavailable at power.

Event Identifier: 272/84-017

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and LOCA	Base case

Branches Impacted and Branch Nonrecovery Estimate

HPI	1.0	No recovery is assumed possible
Bleed and feed	1.0	No recovery is assumed possible

Plant Models Utilized

PWR plant Class B

Event Identifier: 272/84-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 272/84-017
Event Description: Unavailability of High-Head Charging Pumps
Event Date: 7/16/84
Plant: Salem 1

UNAVAILABILITY, DURATION= 360

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.7E-01
LOOP	2.8E-03
LOCA	5.1E-04

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.6E-03
LOOP	6.2E-07
LOCA	4.8E-04
Total	2.1E-03
CD	
TRANS	2.0E-06
LOOP	7.0E-07
LOCA	4.5E-06
Total	7.3E-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: 1.5E-03

Event Identifier: 272/84-017

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

End State: CD Conditional Probability: 1.8E-05

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	6.3E-05	3.4E-01
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	1.5E-03 *	3.4E-01
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	1.8E-06	3.1E-02
214	LOOP -RT/LOOP -EMERG.POWER AFW HPI(F/B)	CD	7.3E-07	9.2E-02
304	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	4.9E-04	3.4E-01
307	LOCA -RT -AFW HPI SS.DEPRESS	CD	1.8E-05 *	3.4E-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.

MODEL: b:\pwrbtree.cmp
DATA: b:\salempro.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	5.4E-04	5.1E-01	
AFW	1.0E-03	2.7E-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	5.0E-02	
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	5.2E-01 > 1.0E+00	

Event Identifier: 272/84-017

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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03	1.0E+00	

*** forced

Minarick
04-11-1987
14:26:35

Event Identifier: 272/84-017

PRECURSOR DESCRIPTION SHEET

LER No.: 275/84-013
Event Description: Inoperable High-Head Injection System
Date of Event: April 7, 1984
Plant: Diablo Canyon 1

EVENT DESCRIPTION

Sequence

The plant experienced an anticipated safety injection (SI) as part of SG safety valve startup testing. The SI resulted in the discharge of the contents of the BIT into the RCS. To recharge the BIT, licensed operators — using approved procedures — inhibited the automatic opening feature of the BIT inlet and outlet valves during the recharging operation. This practice prevents problems that might occur due to an inadvertent SI signal while the BIT is being drained prior to recharging with boric acid. With the BIT inlet and outlet valves disabled, there is no flowpath from the charging pumps through the BIT to the RCS.

Corrective Action

Applicable operating procedures were revised.

Plant/Event Data

Systems Involved:
HHIS

Components and Failure Modes Involved:
BIT inlet and outlet automatic valve actuation — rendered unavailable

Component Unavailability Duration: 14.3 h
Plant Operating Mode: 3 (0% power)
Discovery Method: Following testing
Reactor Age: 0.1 year
Plant Type: PWR

Comments

None

Event Identifier: 275/84-013

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated MSLB	Base case

Branches Impacted and Branch Nonrecovery Estimate

Boric acid addition	0.12	Local recovery assumed; higher recovery probability because operators were cognizant of the configuration following the test

Plant Models Utilized

PWR plant Class B

Event Identifier: 275/84-013

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 275/84-013
Event Description: Inoperable High-Head Injection System
Event Date: 4/7/84

UNAVAILABILITY, DURATION= 14.3

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

SLB	1.6E-06

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
SLB	1.2E-10
Total	1.2E-10
ATWS	
SLB	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CD Conditional Probability: 1.2E-10

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

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
106	SLB -RT REQ.SG.ISO -AFW -HPI REQ.BA.ADDITION	CD	1.2E-10 *	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.

Event Identifier: 275/84-013

MODEL: C:\ASP\pwrbaslb.txt
DATA:

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
SLB	1.1E-07	1.0E+00	
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	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	1.0E+00 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	8.3E-04 > Failed		
PORV.OPEN.DUE.TO.HPI	8.0E-01	1.0E+00	
PORV.CLOSURE	6.0E-03	1.0E+00	

*** forced

Minarick
04-14-1987
08:07:37

Event Identifier: 275/84-013

PRECURSOR DESCRIPTION SHEET

LER No.: 280/84-011
Event Description: Component Cooling Water Isolated from Charging Pumps
Date of Event: May 18, 1984
Plant: Surry 1

EVENT DESCRIPTION

Sequence

On May 18, 1984, with the unit at full power, operations personnel performing a system walkdown discovered that charging/SI pump CCW was isolated from the intermediate seal cooler 1-SW-E-1B and that SW was isolated from the intermediate seal cooler 1-SW-E-1A. This alignment isolated the charging system's intended heat sink.

A review of plant logs and operator interviews confirmed that both intermediate seal coolers were isolated during two separate events. The first event started May 16, 1984, at 2045 h, when the "B" cooler was improperly placed in service and "A" cooler was removed from service until 2125 h. The second event started at 2140 h on the same day when the "A" cooler was again removed from service with the "B" cooler remaining improperly valved-in. Both coolers were isolated for a total of 40 min during the first event and 32 h for the second event.

Corrective Action

The "B" intermediate seal cooler was placed in service; the "A" cooler, in standby.

Following this event, specific maintenance operating procedures were written to ensure control of removal and return to service of the intermediate seal coolers. Proper valve alignment will be verified weekly by inclusion on the engineered safeguards valve alignment checklist.

Plant/Event Data

Systems Involved:

CVCS, CCW system, and SW system

Components and Failure Modes Involved:
Charging pump coolers 1-SW-E-1A and 1-SW-E-1B isolated.

Component Unavailability Duration: One, 40 min; two, 32 h
Plant Operating Mode: 1 (100% power)
Discovery Method: system walkdown
Reactor Age: 11.9 years
Plant Type: PWR

Comments

See LER 280/83-052 (November 18, 1983) for a similar event.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and small-break LOCA	Base case

Branches Impacted and Branch Nonrecovery Estimate

HPI	0.34	Recoverable with realignment of several valves
Bleed and feed	0.34	Recoverable with realignment of several valves

Plant Models Utilized

PWR plant Class A

Event Identifier: 280/84-011

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 280/84-011
Event Description: Component Cooling Water Isolated from Charging Pumps
Event Date: 5/18/84
Plant: Surry 1

UNAVAILABILITY, DURATION= 32.67

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.4E-02
LOOP	2.5E-04
LOCA	4.6E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.7E-05
LOOP	4.4E-07
LOCA	3.8E-06
Total	6.2E-05
CD	
TRANS	3.7E-07
LOOP	2.4E-08
LOCA	1.1E-05
Total	1.1E-05
ATWS	
TRANS	0.0E+00
LOOP	0.0E+00
LOCA	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.5E-05

Event Identifier: 280/84-011

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

End State: CD Conditional Probability: 1.0E-05

308 LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI LPR/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	2.3E-06	1.2E-01
112	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	5.5E-05 *	1.2E-01
307	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI -LPR/HPI	CV	5.0E-06	1.2E-01
308	LOCA -RT -AFW HPI -SS.DEPRESS -LPI/HPI LPR/HPI	CD	1.0E-05 *	1.2E-01
310	LOCA -RT -AFW HPI SS.DEPRESS	CD	5.6E-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.

MODEL: b:\pwratree.cmp
DATA: b:\surrprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EP	5.4E-04	5.1E-01	
AFW	1.0E-03	2.7E-01	
AFW/EP	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	
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	2.3E-03 > 1.0E+00	5.2E-01 > 3.4E-01	

Event Identifier: 280/84-011

Branch Model: 1.0F.3+ser			
Train 1 Cond Prob:	1.0E-02 > Unavailable		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
Train 3 Cond Prob:	3.0E-01 > Unavailable		
Serial Component Prob:	2.0E-03		
HPI(F/B)	2.3E-03 > 1.0E+00	5.2E-01 > 3.4E-01	4.0E-02
Branch Model: 1.0F.3+ser+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		
Serial Component Prob:	2.0E-03		
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	3.0E-03	5.6E-01	4.0E-02
CSR	3.0E-03	3.4E-01	4.0E-02
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI	2.0E-03	1.0E+00	
LPR/HPI	6.7E-01	1.0E+00	

*** forced

Minarick
04-12-1987
17:13:08

Event Identifier: 280/84-011

PRECURSOR DESCRIPTION SHEET

LER No.: 286/84-015
Event Description: LOOP with Both a DG Failure and an Unavailability
Date of Event: November 16, 1984
Plant: Indian Point 3

EVENT DESCRIPTION

Sequence

On November 16, 1984, the reactor was at cold shutdown for a scheduled maintenance and inspection outage. RCS temperature was ~115°F with RHR pump 32 providing core cooling. All plant electrical loads were being supplied from offsite 13.8-kV sources through the station auxiliary transformer (ST); 6.9-kV buses 5 and 6 were energized from the station auxiliary transformer via breakers ST-5 and ST-6. All other inservice 6.9-kV buses were energized via tie breakers to buses 5 and 6. EDG 31 was out of service for scheduled maintenance. SWPs 31 through 36 were out of service to provide protection for divers cleaning the suction to the pumps on the intake structure. SWPs 38 and 39 and CCW pumps 31 and 32 were operating.

At 1242 h on November 16, breakers ST-5 and ST-6 were tripped open via fault detection circuitry. A phase-to-phase fault had occurred as a piece of metal was blown onto the 138-kV primary-side A and B phase station auxiliary transformer buswork from an adjacent building roof. As breakers ST-5 and ST-6 opened, normal offsite power to the plant was lost. DGs 32 and 33 started automatically due to the undervoltage condition on their respective 480-V buses (6A and 5A) and achieved normal operating voltage. DG 33 successfully reenergized bus 5A, automatically starting CCW pump 31. The output breaker, 52-EG2, for DG 32 did not close, leaving bus 6A deenergized.

The control room operators closed breakers GT-35 and GT-36 at 1256 h to reenergize 6.9-kV buses 5 and 6 from the 13.8-kV offsite sources. Four-hundred-eighty-volt buses 2A and 3A were then manually energized via normal supply and tie breakers. RHR pump 31 was started manually to reestablish core cooling. Attempts to energize 480-V bus 6A by closing the station service transformer (SST) supply breaker SST-6 were unsuccessful due to an apparent loss of dc control power to the breaker. The operators then attempted to energize bus 6A from bus 3A by closing tie breaker 3AT6A. This breaker also failed to close. SW pump 38 was started manually to supply essential header cooling water. Both

operating DGs were secured because offsite power had been successfully restored. After replacing failed control fuses, breaker SST-6 was closed, reenergizing 480-V bus 6A. All equipment was then returned to original status with the exception that outside power was being supplied by the 13.8-kV source instead of the normal 138-kV source. RCS temperature increased ~3°F during the time RHR was interrupted.

The total time that power was unavailable to the RHR system was 14 min. Because the reactor had been in the cold shutdown condition for over a month and Tavg was significantly below the 200°F limit for cold shutdown at the time of the event, the plant operators voluntarily chose to proceed cautiously and deliberately in restoring power. This was in light of the amount of equipment out of service at the time.

Corrective Action

Investigation into the series of breaker failures associated with bus 6A has yielded the following results: (1) Breaker 52-EG2, the output breaker for DG 32, operated in accordance with design even though it did not close. Logic circuitry for the plant's electrical distribution system prevents any 480-V vital bus from being tied to two separate power supplies simultaneously. The bus 6A normal feed breaker, 52/6A, failed to open when offsite power was lost due to failed control power fuses. The logic circuitry therefore prevented breaker 52-EG2 from closing because two supply breakers to bus 6A would have been closed. (2) Breaker SST-6, the SST supply breaker for bus 6A, opened as required on the LOOP. The control power fuses for this breaker are believed to have failed the previous time that the breaker was closed. The operators were unable to close SST-6 until the fuses were replaced. (3) No cause for the failure of breaker 3A-6A was determined. The breaker worked properly the following day during testing.

On November 17, 1984, the events of the previous day were simulated to check the operation of all undervoltage associated equipment. As previously mentioned, new power supply fuses had been installed in breakers SST-6 and 52/6A. All equipment operated correctly. The roof from which the metal had fallen was inspected, and all remaining loose material was removed.

Plant/Event Data

Systems Involved:
Emergency power

Components and Failure Modes Involved:
One DG — unavailable due to routine maintenance

One DG breaker — could not close on demand (logic failure)

Event Identifier: 286/84-015

Component Unavailability Duration: 1 d (assumed)
Plant Operating Mode: 5 (0% power)
Discovery Method: Operational event
Reactor Age: 8.6 years
Plant Type: PWR

Comments

A bounding estimate was developed for this event. It assumes that the LOOP occurred while at power and that one DG was undergoing maintenance.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	Base case

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	Base case	Degraded, two of three DGs unavailable
AFW	Base case	Degraded, one train unavailable
HPI	Base case	Degraded, one train unavailable
HPR	Base case	Degraded, one train unavailable
LPI	Base case	Degraded, one train unavailable
LPR	Base case	Degraded, one train unavailable

Plant Models Utilized

PWR plant Class B

Event Identifier: 286/84-015

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 286/84-015
Event Description: LOOP with both a DG Failure and an Unavailability
Event Date: 11/16/84
Plant: Indian Point 3

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.4E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	5.0E-05
Total	5.0E-05
CD	
LOOP	1.9E-04
Total	1.9E-04
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.8E-05

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

End State: CD Conditional Probability: 1.7E-04

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

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 286/84-015

	Sequence	End State	Prob	N Rec**
213	LOOP -RT/LOOP -EMERG.POWER AFW -HPI(F/B) HPR/-HPI	CD	9.2E-06	5.1E-02
214	LOOP -RT/LOOP -EMERG.POWER AFW HPI(F/B)	CD	7.0E-06	4.7E-02
215	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	2.0E-06	5.8E-02
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	4.8E-05 *	5.8E-02
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	1.7E-04 *	5.9E-02

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

MODEL: b:\pwrbtree.cmp
DATA: b:\IPPROB.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.3E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 5.7E-02	5.1E-01	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02		
Train 3 Cond Prob:	1.9E-01 > Unavailable		
AFW	1.0E-03 > 1.9E-03	2.7E-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:	9.2E-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	2.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	2.0E-02	5.0E-02	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	
HPI	1.5E-03 > 2.2E-03	5.2E-01	
Branch Model: 1.OF.3+ser			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01		

Event Identifier: 286/84-015

Train 3 Cond Prob:	3.0E-01 > Unavailable		
Serial Component Prob:	1.2E-03		
HPI(F/B)	1.5E-03 > 2.2E-03	5.2E-01	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 > Unavailable		
Serial Component Prob:	1.2E-03		
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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.0E-03 > 1.0E-02	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03 > 1.0E-02	1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	1.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		

*** forced

Minarick
04-11-1987
14:59:46

Event Identifier: 286/84-015

PRECURSOR DESCRIPTION SHEET

LER No.: 296/84-012, -013, -014
Event Description: Trip and HPCI Failure
Date of Event: November 20, 22 and December 6, 1984
Plant: Browns Ferry 3

EVENT DESCRIPTION

Sequence

On November 20, 1984, Unit 3 was in startup at 4.5% power. During preparation for performance of RV functional surveillance testing, the licensed reactor operator manually scrammed the unit. In preparation for the test, the pressure set-point controller was lowered to 270 psig, thereby opening ~1.5 bypass valves. The RPV water level began decreasing due to the increased steam flow through the bypass valves. The operator attempted without success to place condensate boosters 3B and 3C in service to increase feedwater flow. The pumps' local start switches were found to be set in the Safe/Stop position. Plant procedures did not have a check-off verification for proper position for the start switches. The operating procedures did not allow for insertion of reactor control rods, and the operator felt that raising the pressure set point by closing the bypass valves would cause a pressure spike and drive the reactor water level lower.

When the RPV level indication in the control room level instruments decreased below +11 in. without an automatic scram, the shift engineer directed the unit operator to scram the reactor manually. (Due to the fact that the reactor was not operating at rated conditions, the level indication in the control room was subsequently determined to be low. The actual level was determined to be +12 in.)

On November 22, 1984, at 2130 h, the HPCI system was being realigned to the standby readiness condition after reaching a pressure consistent with reset of the HPCI low-pressure isolation. HPCI outboard flow control valve FCV-73-3 could not be opened electrically, and the HPCI system was declared inoperable.

The limitorque valve operator for valve FCV-73-3 was disassembled and visually inspected for damage. Inspection determined that the motor pinion gear had been installed backwards during previous maintenance work. Also, the cable from the power supply to motor shunt field was found to be open.

Event Identifier: 296/84-012

Corrective Action

Necessary procedures for startup were revised. The motor pinion gear and mating worm gears on the flow control valve were replaced with new gears in the proper direction. The power cable was repaired.

A 20% random sample of all accessible ECCS valves were inspected on all units. A total of 36 valves were inspected and all of the valves' motor pinion gears were found to be installed in the proper arrangement.

Plant/Event Data

Systems Involved:
HPCI, condensate system

Components and Failure Modes Involved:
HPCI isolation valve — failed to open on demand
Two condensate booster pumps — failed to start on demand (due to improperly positioned start switches)

Component Unavailability Duration: NA
Plant Operating Mode: 2 (5% power)
Discovery Method: Operational event
Reactor Age: 8.3 years
Plant Type: BWR

Comments

The event has been modeled as if it had occurred from power. Because of the condensate pump switch positioning. In reality, the event could not have occurred above ~50% power.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOCA	1×10^{-3}	Turbine bypass valve open is modeled as LOCA with nonrecovery equal to typical MSIV failure to close probability
Transient	1.0	No recovery assumed

Event Identifier: 296/84-012

Branches Impacted and Branch Nonrecovery Estimate

HPCI	1.0	No recovery assumed possible
CON	Base case	Note that base-case failure probability is considered equal to one with base-case nonrecovery estimate equal to 0.34, reflecting nonroutine alignment and or local actuation at the pumps

Plant Models Utilized

BWR plant Class C

Event Identifier: 296/84-012, -013, -014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 296/84-012
Event Description: Trip and HPCI Failure
Event Date: 11/20/84
Plant: Browns Ferry 3

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00
LOCA	1.0E-03

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.1E-06
LOCA	1.3E-07
Total	1.3E-06
CD	
TRANS	1.1E-04
LOCA	1.6E-05
Total	1.2E-04
ATWS	
TRANS	2.0E-05
LOCA	2.0E-08
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.1E-07

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: 9.7E-05

Event Identifier: 296/84-012

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

End State: ATWS Conditional Probability: 2.0E-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	6.5E-06	1.0E-01
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	9.7E-05 *	3.4E-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-07	1.3E-01
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-07	6.6E-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	5.1E-07 *	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	2.6E-07	1.1E-01
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00
310	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	1.6E-05	3.4E-04
314	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	8.3E-08	2.2E-04
318	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	4.3E-08	1.1E-04

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

MODEL: b:\bwrctree.cmp
DATA: b:\bfprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06 > 3.3E-06	3.4E-01 > 1.0E-03	
Branch Model: INITOR			
Initiator Freq:	3.3E-06		

Event Identifier: 296/84-012

SCRAM	4.1E-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	5.1E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Failed		
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-11-1987
14:43:27

Event Identifier: 296/84-012

PRECURSOR DESCRIPTION SHEET

LER No.: 296/84-015
Event Description: Trip and One Condensate Pump and Two CRD Pumps Fail
Date of Event: December 9, 1984
Plant: Browns Ferry 3

EVENT DESCRIPTION

Sequence

During normal operation, Unit 3 was operating at 36% power. The feeder breaker for condensate pump motor 3A failed to trip when the motor shorted to ground. A burned-up trip coil prevented the breaker from operating. The effect was that the normal feeder breaker for the unit board tripped when one of its overcurrent relays operated. This also locked out the alternate feeder breaker and deenergized the loads connected to the unit board.

The safety loads supplied by the unit board then automatically transferred to their alternate sources as designed. DGs 3A and 3B started but were not required. The unit was manually scrammed following loss of CRD pump 3B, which tripped due to loss of board voltage. CRD pump 3A was out of service for maintenance. In anticipation of a low-water-level scram and to determine as quickly as possible that all rods were fully inserted, the licensed unit operator scrammed the reactor.

Corrective Action

The condensate breaker and motor were repaired. There was no other apparent damage. The safety-related equipment operated as designed during this event.

Plant/Event Data

Systems Involved:
Condensate and CRD

Event Identifier: 296/84-015

Components and Failure Modes Involved:
Condensate pump — failed in operation

CRD pumps — rendered unavailable

Component Unavailability Duration: N/A
Plant Operating Mode: 1 (36% power)
Discovery Method: Operational event
Reactor Age: 8.3 years
Plant Type: BWR

Comments

It has been assumed that because the unit was operating at 36% power, only the failed condensate pump was operating. Because of this assumption, an LOFW has been assumed to have occurred.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

CRD	1.0	Unavailable due to maintenance on 3A pump (two pumps are required for cooling using CRD pumps)
MFW	0.34	Assumed failed
PCS	1.0	Failed because of MFW unavailability

Plant Models Utilized

PWR plant Class C

Event Identifier: 296/84-015

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 296/84-015
Event Description: Trip and One Condensate Pump and Two CRD Pumps Unavailable
Event Date: 12/9/84
Plant: Browns Ferry 3

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.3E-07
Total	5.3E-07
CD	
TRANS	1.1E-04
Total	1.1E-04
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.7E-07

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: 3.3E-05

110 TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS

End State: ATWS Conditional Probability: 2.0E-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	3.0E-05	7.6E-02
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	1.5E-05	3.8E-02
110	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	3.3E-05 *	1.1E-01
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	1.1E-06	7.6E-02
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	3.3E-05	1.9E-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	1.7E-07 *	7.3E-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	8.9E-08	3.7E-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	1.7E-07	1.3E-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	8.8E-08	6.6E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\bfprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02

Event Identifier: 296/84-015

PCS/TRANS	1.7E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.7E-01 > Failed		
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	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Failed		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-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	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-11-1987
14:48:08

Event Identifier: 296/84-015

PRECURSOR DESCRIPTION SHEET

LER No.: 312/84-015
Event Description: Hydrogen Explosion Causes Transient and Subsequent Loss of NNIX
Date of Event: March 19, 1984
Plant: Rancho Seco

EVENT DESCRIPTION

Sequence

Rancho Seco was operating at 92% power when MCC 2E1 bus became deenergized when its supply breaker from the 3E bus tripped. This supply breaker could not be reclosed. The loss of MCC 2E1 was due to a ground fault on a gland steam exhaust motor and resulted in a loss of the hydrogen-side seal oil pump that is powered from that MCC. The plant procedures allow full-load operation with the hydrogen-side pump shut down. Seal oil problems eventually resulted in the escape of hydrogen from the generator and subsequent explosions.

When the hydrogen-side seal-oil pump is off, hydrogen-side seal oil is supplied by the air-side pump. The oil that flows to the hydrogen seals ends up in the drain regulator tank and is rejected to the suction of the air-side pump. Prior to the loss of the hydrogen-side pump, swing shift logs were taken, and defoaming tank levels were normal. Shortly after the pump stopped, the defoaming tank levels were found high, and generator moisture detector level switches were dry. The operator was instructed to operate the drain tank level control valves manually to reduce defoaming tank level. He overrode the automatic level control valves on the drain regulator tank, observed a slow level decrease, and then left the area to find another operator to control tank level while he checked defoaming tank levels. Before the second operator reached the drain regulator tank (~2 min) the regulator tank emptied, which allowed hydrogen to enter the suction of the air-side seal-oil pump. This caused reduction in seal oil pressures and allowed hydrogen and seal oil to blow out of the generator seals. Hydrogen escaped for several minutes before it exploded.

A reduction in power to 85% was initiated at a maximum rate of 99 MW/min. Shortly after, a second and larger explosion occurred. The generator remained on the line: No automatic trip signals were received because the explosion did not damage the generator or exciter. The shift supervisor was notified that the exciter was on fire. He immediately tripped the turbine, which then tripped the reactor.

The reactor trip was normal except that a TBV stuck open and was closed within 6 min. The RCS cooled to 505°F (40°F below the nominal posttrip temperature). The pressurizer level remained on scale, and RCS pressure reached a minimum of 1794 psig (~50 psig below nominal posttrip minimum). Operators manually started both HPI pumps and opened one of four HPI valves to help control RCS pressure and pressurizer level.

About an hour after the reactor trip nonnuclear instrumentation train X(NNIX) ±24 V dc was lost for ~4 min because of drift in the overvoltage trip relay set point that resulted in a false trip signal. In initiating the SFAS manually by procedure for loss of NNI, full HPI flow increased RCS pressure. A pressurizer code safety valve lifted 140 psi below its 2500-psi set point to relieve pressure.

When NNIX dc power was lost, it was incorrectly diagnosed as a total loss of NNI based on control room indications, and the applicable casualty procedure was then followed. This procedure required, among other things, manual initiation of SFAS channels 1A and 1B. This resulted in both the "A" and "B" HPI pumps starting and the HPI valves opening. Due to HPI injection, RCS pressure began to increase. At a pressure of ~2350 psig, pressurizer code safety valve PSV-21507 lifted prematurely, blew down RCS pressure 100 psig, and then reseated. Pressure began to increase again, and the code safety again lifted and then reseated. During the second lifting of the code safety valve, the HPI injection valves were being throttled based on pressure and temperature indications on instrumentation that was unaffected by the loss of NNIX. HPI was manually controlled per procedure and RCS pressure and pressurizer level restored to normal valves. An atmosphere dump valve that opened due to loss of NNIX was immediately recognized and closed from the control room.

Corrective Action

Hydrogen Seal Oil. A recommendation regarding on-line testing of panel alarms will be prepared. Also, a determination will be made of what preventive maintenance, if any, should be performed on the alarm panel.

An investigation of the need for additional instrumentation in the seal oil system, to allow better monitoring of system performance, will also be performed. In addition, a review will be done on the seal-oil installation for conformance to the manufacturer's recommendations, particularly in regard to component elevations and piping configuration.

Also, the seal-oil-system casualty procedures will be revised. Modifications to level gages will consist of interim markings until permanent dial face changes can be made if necessary. Finally, appropriate prestartup tests, as recommended by the manufacturer to ensure proper system operation, will be performed.

Event Identifier: 312/84-015

Carbon Dioxide Tank. The instructions in the operating procedure regarding manual termination of automatic carbon dioxide discharge will be verified and revised, if necessary, to ensure that it is applicable to all carbon dioxide zones.

NNI. All of the NNIX and ±24-V power supplies overvoltage and undervoltage trip set points will be calibrated and set to the manufacturer's recommended setting. Also, the problem with the ±24-V power supply's failure to trip on overvoltage will be resolved prior to startup.

Pressurizer Code Safety Valve. The pressurizer code safety valve PSV-21507 will be reset during plant heatup.

Plant/Event Data

Systems Involved:
main generator, NNI, turbine bypass, and pressurizer relief

Components and Failure Modes Involved:
NNI — failed in operation
TBS/ASD -- failed in operation
Primary-system RV — lifted early but reclosed

Component Unavailability Duration: NA
Plant Operating Mode: 1 (85% power)
Discovery Method: Operational event
Reactor Age: 7.5 years
Plant Type: PWR

Comments

Reference: Abnormal Occurrence Reports to Congress, NUREG-0090, 7(2), 24 and 32.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

Secondary side relief terminated	0.12	Atmospheric dump valve was closed from control room

Plant Models Utilized

PWR plant Class D

Event Identifier: 312/84-015

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 312/84-015
Event Description: Hydrogen Explosion Causes Transient and Subsequent Loss of NNI-X
Event Date: 3/19/84
Plant: Rancho Seco

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	2.1E-05
Total	2.1E-05
CD	
TRANS	2.2E-06
Total	2.2E-06
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.7E-05

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

End State: CD Conditional Probability: 1.1E-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: 3.0E-05

Event Identifier: 312/84-015

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	1.5E-06	6.2E-02
102	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS -LPR/-HPI.HPR	CV	5.3E-07	2.8E-02
103	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	1.1E-06 *	2.8E-02
104	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI SS.DEPRESS	CD	6.0E-08	2.8E-02
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	1.7E-05 *	6.2E-02
122	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS -COND/MFW	CV	9.0E-07	3.4E-02
123	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	4.6E-07	1.7E-02
124	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	5.1E-08	5.1E-02
125	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	9.0E-07	3.2E-02
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	4.6E-07	1.6E-02
127	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	5.1E-08	4.8E-02
128	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\pwrdtree.cmp
DATA: b:\ranchpro.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	1.9E-03	2.7E-01	
AFW/EMERG.POWER	5.0E-02	3.4E-01	
MFW	2.0E-01	3.4E-01	
PORV.OR.SRV.CHALL	8.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	5.0E-02	
SS.RELEAS.TERM	1.5E-02 > 1.0E+00	3.4E-01 > 1.2E-01	

Branch Model: 1.0F.1

Event Identifier: 312/84-015

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: 1.0F.1			
Train 1 Cond Prob:	1.5E-02 > Failed		
HPI	3.0E-04	5.2E-01	
HPI(F/B)	3.0E-04	5.2E-01	4.0E-02
HPR/-HPI	3.0E-03	5.6E-01	4.0E-02
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	2.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03	1.0E+00	

*** forced

Minarick
04-11-1987
16:07:40

Event Identifier: 312/84-015

PRECURSOR DESCRIPTION SHEET

LER No.: 318/84-005
Event Description: Both Diesel Generators Inoperable
Date of Event: April 26, 1984
Plant: Calvert Cliffs 2

EVENT DESCRIPTION

Sequence

The 24A 480-V ac safety bus was removed from service for preventive maintenance. To maximize DG 21 availability, DG 21 auxiliaries normally supplied from 24A 480-V ac bus via MCC 204R, were kept energized by powering MCC 204R from MCC 214R via a tie breaker. This lineup allowed DG 12 to power DG 21 auxiliaries but in turn removed the independence between the two DGs. DG 21 was declared out of service but not logged as such. If the unit had been in a higher mode, less severe consequences would likely have occurred because the log entry concerning entry into a Technical Specifications action statement should have prevented DG 12 from being taken out of service. At 0625 h on April 26, 1984, licensed personnel on the next shift failed to recognize the dependence of DG 21 on DG 12 and placed DG 12 out of service so preventive maintenance could be performed.

Corrective Action

A senior licensed operator noted that both DGs 12 and 21 were inoperable and that containment integrity had not been established as required by Technical Specification 4.8.2.2. Restoration of DG 12 to operability was in progress at the time and was continued. At 2105 h, DG 12 was declared operable, terminating the event.

Plant/Event Data

Systems Involved:
Emergency power

Components and Failure Modes Involved:
DGs — removed from service for preventive maintenance

Component Unavailability Duration: 15 h
Plant Operating Mode: 6 (0% power)
Discovery Method: Operator observation
Reactor Age: 7.4 years
Plant Type: PWR

Event Identifier: 318/84-005

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	0.034	Base case nonrecovery x 0.1 (assumed likelihood of occurring at power)

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	1.0	No recovery assumed possible

Plant Models Utilized

PWR plant Class G

Event Identifier: 318/84-005

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 318/84-005
Event Description: Both Diesel Generators Unavailable
Event Date: 4/26/84
Plant: Calvert Cliffs 2

UNAVAILABILITY, DURATION= 15

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.4E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	6.8E-08
Total	6.8E-08
CD	
LOOP	2.3E-07
Total	2.3E-07
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 6.6E-08

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

End State: CD Conditional Probability: 2.3E-07

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

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 318/84-005

	Sequence	End State	Prob	N Rec**
209	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	2.7E-09	1.3E-02
211	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	6.6E-08 *	1.3E-02
212	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	2.3E-07 *	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.

MODEL: b:\pwrgtree.cmp
DATA: b:\calvprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05 > 2.3E-05	3.4E-01 > 4.0E-02	
Branch Model: INITOR			
Initiator Freq:	2.3E-05		
LOCA	2.6E-02	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	5.4E-04 > 1.0E+00	5.1E-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	1.0E-03	2.7E-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	5.0E-02	
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	5.2E-01	
HPI(F/B)	3.0E-04	5.2E-01	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	1.0E-03	1.0E+00	

Event Identifier: 318/84-005

CSR	2.0E-03	3.4E-01

*** forced

Minarick
04-11-1987
16:51:13

Event Identifier: 318/84-005

PRECURSOR DESCRIPTION SHEET

LER No.: 324/84-014, -018
Event Description: RCIC and Train "B" LPCI/RHR Unavailable
Date of Event: November 27, 1984
Plant: Brunswick 2

EVENT DESCRIPTION

Sequence

At 1023 h on November 27, 1984, a main turbine trip and stop valve closure caused a main turbine moisture separator-reheater (MSR) high-level trip signal. An automatic reactor scram of Unit 2 resulted. The LPCI train B was inoperable due to excessive seat leakage past the inboard primary containment IV, 2-E11-F015B. This leakage also rendered RHR train B inoperable. In addition, the RCIC system was inoperable due to failure to meet the in-service test requirement for pump-developed pressure as a function of pump flow criteria. Later, while the unit was being placed in shutdown cooling mode, RHR loop A experienced a water hammer in the steam condensing piping, which rendered the loop inoperable. The main condenser was then utilized for shutdown cooling. After supports and snubbers were repaired, RHR was restored to service.

Corrective Action

The MSR high-level actuation switch, 2-MD-LSH-MS-2, was cleaned and tested for proper operation. An inspection revealed that the instrument float plunger was loose. The float plunger was tightened, and the instrument was returned to service.

Plant/Event Data

Systems Involved:
LPCI, RCIC, and secondary-side instrumentation.

Components and Failure Modes Involved:
MSR high-level actuation switch — failed high
LPCI train B — unavailable
RCIC — unavailable

Component Unavailability Duration: NA
Plant Operating Mode: 1 (98% power)
Discovery Method: Operational event
Reactor Age: 9.7 years
Plant Type: BWR

Event Identifier: 324/84-014, -018

MODELING CONSIDERATIONS AND DECISIONS

Comments

Due to lack of information, RCIC unavailability is assumed.

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Non-Recovery Estimate

LPCI	Base case	Degraded (train 2 unavailable)
RCIC	1.0	Failed, not recoverable to full operability in required time frame
RHR (SDC)	0.12	Failed (but operator could open the containment isolation valves from the control room)

Plant Models Utilized

BWR plant Class C

Event Identifier: 324/84-014, -018

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 324/84-014
Event Description: RCIC and Train "B" LPCI/RHR Unavailable
Event Date: 11/27/84
Plant: Brunswick 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.8E-07
Total	5.8E-07
CD	
TRANS	1.4E-04
Total	1.4E-04
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 3.2E-07

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: 8.2E-05

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

End State: ATWS Conditional Probability: 2.0E-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	3.4E-05	3.6E-02
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	6.0E-06	1.4E-02
120	TRANS -SCRAM PCS/TRANS -SRV.CHALL/TRANS.-SCRAM -FW/PCS.TRANS RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).R HR(SPCOOL)	CD	8.2E-05 *	3.6E-02
124	TRANS -SCRAM PCS/TRANS -SRV.CHALL/TRANS.-SCRAM FW/PCS.TRANS -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR (SDC).RHR(SPCOOL)	CD	1.4E-05	1.4E-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	3.2E-07 *	1.1E-01
135	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS RHR(SDC) - RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	4.3E-08	1.5E-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	1.6E-07	5.8E-02
139	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) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	2.2E-08	7.9E-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	1.9E-08	1.1E-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	9.9E-09	5.8E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\brunprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch System Non-Recov Opr Fail

Event Identifier: 324/84-014

TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	3.0E-01	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	3.0E-01	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	2.7E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02 > 1.0E+00	5.7E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.7E-02 > Failed		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04 > 4.0E-03	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.0E-03		
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)	2.0E-02 > 1.0E+00	3.4E-01 > 1.2E-01	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	4.0E-03 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
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	

*** forced

Minarick
04-11-1987
16:57:59

Event Identifier: 324/84-014

PRECURSOR DESCRIPTION SHEET

LER No.:	325/84-006, -007
Event Description:	Trip, LOFW, and HPCI Isolation
Date of Event:	March 31, 1984
Plant:	Brunswick 1

EVENT DESCRIPTION

Sequence

On March 31, 1984, at 2308 h, the Unit 1 reactor scrammed due to a low RPV level caused by an error made while operators were working on the instrument air system. The MFW system tripped off. Following the scram, the RV level decreased to the low-level No. 2 set point, and the HPCI system automatically initiated. Shortly thereafter, the HPCI system isolated due to isolation channel B logic, and the HPCI system turbine tripped concurrent with the receipt of the HPCI system steamline flow differential pressure alarm. The isolation cleared, and the HPCI system turbine trip was reset. The HPCI turbine was manually restarted; the HPCI system channel B logic isolation, along with a HPCI system turbine trip, occurred once again. The isolation cleared, the turbine trip was reset, and the HPCI turbine was manually started. However, the turbine speed indication did not function; and the HPCI system was shut down, manually isolated, and declared inoperable.

The RCIC system, which also received an automatic initiation on RPV low-level No. 2, was utilized to restore and maintain RPV level following the reactor scram and throughout the scram recovery.

If Unit 2 had also been operating at the time of this event, it would have experienced the same LOFW and reactor low-level scram because both units' condensate filter demineralizers are supplied by Radwaste Building instrument air.

Corrective Action

An investigation revealed that the HPCI isolations resulted from a lack of HPCI system turbine-speed control feedback. A wire in the HPCI system's turbine-speed magnetic pickup amphenol connector was broken. This caused failure of the turbine-speed controller and the turbine-speed indication in the control room. The HPCI turbine-speed control circuit thus demanded maximum turbine speed and fully opened HPCI turbine throttle valve E41-V9. When V9 fully opened, an HPCI system turbine high-steam-flow differential pressure resulted, which was followed by the HPCI system isolation.

Event Identifier: 325/84-006

Following the repair of the HPCI system speed control amphenol wire, an investigation was conducted to determine why each incurred HPCI system isolation was initiated from the B isolation logic. The instrument slave trip unit of HPCI system steam-line-flow high channel A logic instrument, E41-PDT-N004, was found actuating out of specified tolerance by 0.05 in. of water applied in the conservative direction. Based on the results of the response time findings, it is reasonable to expect a channel B HPCI system isolation to occur before a channel A logic isolation.

Plant/Event Data

Systems Involved:
HPCI, MFW

Components and Failure Modes Involved:
HPCI — failed to initiate on demand

MFW — tripped following reactor trip

Component Unavailability Duration: NA
Plant Operating Mode: 3 (0% power)
Discovery Method: Operational event
Reactor Age: 7.4 years
Plant Type: BWR

Comments

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

PCS	1.0	Unavailable due to feedwater isolation
HPCI	1.0	No recovery assumed possible
MFW	1.0	No recovery assumed

Plant Models Utilized

BWR plant Class C

Event Identifier: 325/84-006, -007

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 325/84-006
Event Description: Trip with LOFW and HPCI Isolation
Event Date: 3/31/84
Plant: Brunswick 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.7E-05
Total	1.7E-05
CD	
TRANS	2.6E-04
Total	2.6E-04
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 9.0E-06

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: 1.3E-04

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

End State: ATWS Conditional Probability: 2.0E-05

Event Identifier: 325/84-006

173 TRANS SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
103	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI -RCIC/TRANS.OR.LOOP RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	1.3E-05	1.1E-01
110	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	2.6E-05	5.7E-01
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	1.3E-04 *	3.4E-01
122	TRANS -SCRAM PCS/TRANS -SRV.CHALL/TRANS.-SCRAM FW/PCS.TRANS HPCI -RCIC/TRANS.OR.LOOP RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	3.2E-05	1.1E-01
129	TRANS -SCRAM PCS/TRANS -SRV.CHALL/TRANS.-SCRAM FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	6.2E-05	5.7E-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	9.0E-06 *	3.7E-01
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	4.7E-06	1.9E-01
155	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	2.2E-06	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-06	1.1E-01
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\brunprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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: 1.0F.1

Event Identifier: 325/84-006

Train 1 Cond Prob:	1.7E-01 > Failed		
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	3.0E-01	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	3.0E-01	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	2.7E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Failed		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Failed		
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

forced

Minarick
04-11-1987
17:03:10

Event Identifier: 325/84-006

PRECURSOR DESCRIPTION SHEET

LER No.: 325/84-014
Event Description: Trip and LOFW with HPCI Unavailable
Date of Event: August 1, 1984
Plant: Brunswick 1

EVENT DESCRIPTION

Sequence

At 1417 h while the reactor was at 95% power, an instrument upscale trip of the reactor average power range monitor (APRM) system caused the reactor protection system to automatically initiate a reactor scram. In addition, the HPCI system was out of service, pending periodic testing.

A scram recovery was carried out. Reactor level, with the lowest recorded value of 142.8 in., was controlled through the RCIC system. A Group 1 isolation occurred, as per design, when the reactor pressure decreased to the low-pressure set point while the mode switch was in mode 1. Reactor pressure, which peaked at 997 psig, was controlled by manual opening of the unit reactor SRVs A, B, E, and J. Following the isolation, the control operator discovered that inboard MSIV 1-B21-F022A did not automatically close. An attempt to close the valve manually proved unsuccessful. The MSIV failed when its ac/dc, three-way, air-operated solenoid valve failed.

The subject APRM system upscale trip resulted from the reactor's recirculation-loop-flow instrumentation's receiving erroneous input signals. These signals caused the instruments to sense simultaneous decreasing flow spikes in each reactor recirculation loop (A and B). This resulted in an automatic reduction of the APRM system high-reactor-power scram set point to less than the actual reactor power, thereby causing the APRM system upscale trip. The cause of the erroneous input signals to the recirculation-loop-flow instrumentation was electronic keying of two-way radios in use in the immediate vicinity of the subject instrumentation in the unit reactor building. Plant auxiliary operators were using the two-way radios in the performance of an annual periodic test of the reactor building fire protection sprinkler systems.

Corrective Action

The F022A three-way ac/dc solenoid pilot valve was replaced, and the removed component was subsequently bench tested. No evident signs of failure were noted during testing of the three-way solenoid pilot valve.

As a result of this event, various types of communication radios utilized in both units will be electronically keyed in the vicinity of the Unit 2 instrumentation racks in the reactor building to determine if control room instrumentation is adversely affected. This testing of plant communication radios was planned to be complete by September 14, 1984. Following this testing, signs prohibiting the use of plant communication radios within specific identified plant areas were to be appropriately posted in those areas. In addition, plant Engineering was to be requested to evaluate the apparent failure of the MSIV F022A solenoid pilot valve to determine applicable corrective action.

Plant/Event Data

Systems Involved:
HPCI

Components and Failure Modes Involved:
HPCI -- out of service for testing
MFW — failed by Group I isolation

Component Unavailability Duration: NA
Plant Operating Mode: 1 (94% power)
Discovery Method: Operational event
Reactor Age: 7.8 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Event Identifier: 325/84-014

Branches Impacted and Branch Nonrecovery Estimate

PCS	1.0	Unavailable following Group I isolation
HPCI	0.34	Assume potential recovery from testing status
MFW	1.0	Unavailable following Group I isolation

Plant Models Utilized

BWR plant Class C

Event Identifier: 325/84-014

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 325/84-014
Event Description: Trip and LOFW with HPCI Unavailable
Event Date: 8/1/84
Plant: Brunswick 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.9E-06
Total	5.9E-06
CD	
TRANS	1.2E-04
Total	1.2E-04
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 3.1E-06

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: 4.3E-05

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

End State: ATWS Conditional Probability: 2.0E-05

Event Identifier: 325/84-014

173 TRANS SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
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	9.1E-06	7.6E-02
103	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI -RCIC/TRANS.OR.LOOP RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	4.5E-06	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	8.7E-06	1.9E-01
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	4.3E-05 *	1.2E-01
121	TRANS -SCRAM PCS/TRANS -SRV.CHALL/TRANS.-SCRAM FW/PCS.TRANS -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR (SDC).RHR(SPCOOL)	CD	2.2E-05	7.6E-02
122	TRANS -SCRAM PCS/TRANS -SRV.CHALL/TRANS.-SCRAM FW/PCS.TRANS HPCI -RCIC/TRANS.OR.LOOP RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	1.1E-05	3.9E-02
129	TRANS -SCRAM PCS/TRANS -SRV.CHALL/TRANS.-SCRAM FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	2.1E-05	1.9E-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	3.1E-06 *	1.3E-01
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	1.6E-06	6.6E-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	7.6E-07	7.6E-02
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	3.9E-07	3.9E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\brunprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	

Event Identifier: 325/84-014

LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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 > Failed		
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	3.0E-01	1.0E+00	
SRV.CHALL/TRANS.SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.-SCRAM	3.0E-01	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	2.7E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Unavailable		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Failed		
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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)	5.0E-01	1.0E+00	
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01	

*** forced

Minarick
04-11-1987
17:12:32

Event Identifier: 325/84-014

PRECURSOR DESCRIPTION SHEET

LER No.: 327/84-033
Event Description: Atmospheric Dump Valve Opens and Causes LOFW
Date of Event: May 11, 1984
Plant: Sequoyah 1

EVENT DESCRIPTION

Sequence

During a normal reactor startup on May 11, 1984, following a reactor trip on May 10, Unit 1 experienced another reactor trip. Just prior to the event that occurred at 1400 h CST, Unit 1 was in mode 1 (554°F, 2235 psig) at 21% reactor power with SG level controls in manual.

Atmospheric steam dump valve 1-FCV-1-107 spuriously opened, causing a swell of SG levels. This action resulted in a high-high level in SG 3 that caused a turbine trip and MFW isolation to all four SGs. The transient then resulted in shrink of SG levels, causing a reactor trip on low-low level in SG 2. All equipment and personnel responded as expected, and the unit stabilized at 547°F.

Corrective Action

Inspection revealed a broken repositioning linkage on atmospheric dump valve 1-FCV-1-107, allowing the valve to cycle erratically. The repositioning linkage was replaced, and the valve was returned to service.

Plant/Event Data

Systems Involved:
Atmospheric dump valve and MFW isolation

Components and Failure Modes Involved:
Atmospheric dump valve — opened spuriously in operation
MFW — isolated on demand

Component Unavailability Duration: NA
Plant Operating Mode: 1 (21% power)
Discovery Method: Operational event
Reactor Age: 3.9 years
Plant Type: PWR

Comments

None

Event Identifier: 327/84-033

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

MFW	0.34	Recovery assumed locally at equipment
Secondary-side release terminated	1.0	No recovery assumed because of damaged valve linkage

Plant Models Utilized

PWR plant Class F

Event Identifier: 327/84-033

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 327/84-033
Event Description: ASD Valve Opens and Causes LOFW
Event Date: 5/11/84
Plant: Sequoyah 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.3E-04
Total	5.3E-04
CD	
TRANS	4.8E-06
Total	4.8E-06
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.0E-04

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

End State: CD Conditional Probability: 1.6E-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: 3.0E-05

Event Identifier: 327/84-033

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	2.1E-05	5.2E-01
103	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	1.6E-06 *	2.8E-02
104	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI SS.DEPRESS	CD	9.0E-08	2.8E-02
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	5.0E-04 *	5.2E-01
120	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	2.8E-07	3.1E-02
123	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	1.2E-06	1.7E-02
124	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	1.3E-07	5.1E-02
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	1.2E-06	1.6E-02
127	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	1.4E-07	4.8E-02
128	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\PWRBTREE.CMP
DATA: b:\SEQUOPRO.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	1.0E-03	2.7E-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 > Unavailable		
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	5.0E-02	
SS.RELEAS.TERM	1.5E-02 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			

Event Identifier: 327/84-033

Train 1 Cond Prob:	1.5E-02 > Failed		
SS.RELEAS.TERM/-MFW	1.5E-02 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.0F.1			
Train 1 Cond Prob:	1.5E-02 > Failed		
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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03	1.0E+00	

*** forced

Minarick
04-12-1987
16:35:46

Event Identifier: 327/84-033

PRECURSOR DESCRIPTION SHEET

LER No.: 331/84-001
Event Description: LOFW and SRV Opens Briefly
Date of Event: June 7, 1984
Plant: Duane Arnold

EVENT DESCRIPTION

Sequence

At 08:08:26 (T = 0), while the reactor was at 99.8% power, feedwater recirculation valve B (SJ-FCV-1611) failed open because of a broken air supply line fitting. As a result, a portion of "B" reactor feedwater flow was returned to the condenser, and the vessel level immediately began to drop. While operators were diagnosing and compensating for the decrease in vessel level, a technician's error caused the "B" feedwater pump to trip on low suction pressure and one of two SRVs (SB-RV-4401) utilizing low-low set logic to cycle open at T + 43 s. After the RV opened, a momentary upswing in vessel level was experienced, followed by a rapid decrease in level to the low-level trip set point (170 in.) and an automatic scram initiation at T + 44 s. At T + 57 s, the "B" feedwater pump breaker was reset. At T + 66 s, both feedwater pumps tripped on low suction pressure (due to condensate pumps being unable to match RFP flow with the high vessel demand and return flow to the condenser). During this time, the vessel level was continuing to fall until the low-low level HPCI/RCIC initiation set point of 119.5 in. was reached at T + 73 s. At this point, HPCI and RCIC initiated per design, and the level began to rise. As the vessel level momentarily fell to the low-low level set point, HPCI initiated but did not inject at any time in the event. HPCI control logic requires low-low level signal to remain present for the duration of the IV initiating time (~15 s) to have HPCI actually inject. At T + 112 s, the "B" reactor feedwater pump breaker was again closed to provide additional make-up, and it remained closed with no further trips. After operator action, the open SRV was reseated at T + 118 s and remained closed. As RCIC was injecting and the "B" feedwater pump was functioning, the level quickly recovered to normal operating level (maximum level reached was 204.4 in. at T + 4 min and 30 s). After the level had recovered, RCIC secured at T + 3 min 50 s, and HPCI was secured at T + 4 min and 30 s. At this point, the vessel level and pressure were stable at 194 in. and 810 psig, respectively. All systems necessary for remaining in a safe shutdown condition were operable, and no further system perturbations were experienced.

Main steam SRV valve (SB-RV-4401) is one of two non-ADS SRVs that are utilized in the low-low set logic. Following an event that has opened one of the six SRVs, the low-low set logic established a lower opening pressure (lifting pressure: 1020 to 1025 psig, reseating pressure: 900 to 905 psig, respectively). Investigation revealed that the lifting of the SRV was totally unrelated to the failure of the feedwater recirculation valve. Prior to the recirculation valve failure, a low-low set instrument functional test had commenced. While performing the routine surveillance procedure, the instrument technician erroneously placed an ohmmeter across the high-pressure switch contacts too early in the procedure. As a result, the SRV actuation solenoid relay was falsely energized with a high-pressure test signal that, in conjunction with the procedure step to push the test button, caused the valve to cycle open (~40 s after the recirculation valve failure). Approximately 75 s after the SRV had opened, the operators reset the low-low SRV logic, thereby disarming the solenoid and cycling the valve closed. It was later theorized that the relatively low internal impedance of the ohmmeter caused the meter to act as a jumper and to bypass the contacts. It is noteworthy that prompt identification of the cause of the SRV actuation was greatly aided by the technician volunteering that he had indeed committed an error. This theory was confirmed prior to startup after a special test procedure was run. This procedure recreated the applicable sequence of test steps leading up to the opening of the SRV and revealed that the connection of an ohmmeter across the contacts, in conjunction with pressing the test button, does in fact energize the SRV solenoid.

Corrective Action

The following causes and determinations can be made as to the exact component failures and related events leading up to, and after, the scram.

The feedwater recirculation valve (SJ-FCV-1611) is an air-actuated, fail-open control valve, Control Components model No. PDA964-96BW. Investigation revealed that a flexible air-supply line fitting broke due to fatigue. When the air supply was lost, the valve cycled open. Prior to startup, the broken air line on the "B" recirculation valve was repaired. As an additional precaution, the identical airline on the "A" recirculation valve (SJ-FCV-1569) was inspected and found satisfactory. As a long-term corrective action, a maintenance action request has been generated to replace the fittings subject to fatigue with higher strength fittings.

Event Identifier: 331/84-001

To preclude recurrence of similar SRV opening situations, all instrument technicians were assembled and shown the exact cause of the event during a step-by-step reconstruction. The importance of procedural compliance without deviating from the prescribed testing sequence was impressed upon them. To reduce the margin for personnel error, the surveillance test procedure has been revised to utilize a volt meter in lieu of an ohmmeter. This revision will eliminate the possibility of the meter acting as a jumper in a circuit under test, regardless of when it is inserted. As a long-term corrective action, selected surveillance test procedures are continuing to be revised to simplify and clarify the testing sequence, thereby reducing the possibility of personnel error. In addition to this, a joint management and union task force is being formed to determine and implement methods of maintaining a heightened awareness of the importance of minimizing personnel errors.

Prior to startup, all systems initiated during the scram and subsequent evolutions were reviewed to determine whether they had functioned per design and Technical Specifications. At the 170-in. reactor water level, the reactor scrammed; valve groups 2, 3, 4, and 5 isolated; and both trains of the standby gas treatment system initiated per design. At the 119.5 in. reactor water level valve group 8 isolated, LPCI logic tripped both recirculation pumps, loop-select logic initiated and performed its function, and HPCI/RCIC initiated per design. During and after the transient, the operators observed a normal SRV tail-pipe temperature response. As an additional precaution, a walkdown was performed on the tailpipe of the opened SRV. The piping and restraints were inspected and found satisfactory.

Plant/Event Data

Systems Involved:
Steam relief

Components and Failure Modes Involved:
MFW — failed in operation
Steam RVs — failed to close in operation

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

Comments

None

Event Identifier: 331/84-001

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Small-break LOCA	0.34	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

PCS	1.0	Unavailable
MFW	0.12	Failed but recoverable

Plant Models Utilized

BWR plant Class C

Event Identifier: 331/84-001

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 331/84-001
Event Description: LOFW and SRV Opens Briefly
Event Date: 6/7/84
Plant: Duane Arnold

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOCA	3.4E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOCA	8.6E-07
Total	8.6E-07
CD	
LOCA	1.2E-04
Total	1.2E-04
ATWS	
LOCA	6.9E-06
Total	6.9E-06

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.7E-07

314 LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)

End State: CD Conditional Probability: 1.1E-04

310 LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS

End State: ATWS Conditional Probability: 6.9E-06

Event Identifier: 331/84-001

332 LOCA SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
302	LOCA -SCRAM PCS/LOCA -FW/PCS.LOCA RHR(SDC) RHR(SPCOOL)/-LPC I.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	1.4E-05	3.5E-02
310	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	1.1E-04 *	2.3E-02
314	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	5.7E-07 *	1.5E-02
318	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS COND/FW.PCS -LPCS -RHR(SDC)	CV	2.9E-07	7.9E-03
332	LOCA SCRAM SLC.OR.RODS	ATWS	6.9E-06 *	3.4E-01

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

MODEL: b:\BWRCTREE.CMP
DATA: b:\ARNOLPRO.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	
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	2.6E-02	1.0E+00	
EMERG.POWER	2.9E-03	3.1E-01	
FW/PCS.TRANS	2.9E-01 > 1.0E+00	3.4E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.9E-01 > Unavailable		
FW/PCS.LOCA	4.0E-02 > 1.0E+00	3.4E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.0E-02 > Failed		
HPCI	1.0E-01	5.7E-01	

Event Identifier: 331/84-001

RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-12-1987
16:28:08

Event Identifier: 331/84-001

PRECURSOR DESCRIPTION SHEET

LER No.: 331/84-028
Event Description: LOOP and HPCI Trip
Date of Event: July 14, 1984
Plant: Duane Arnold

EVENT DESCRIPTION

Sequence

On July 14, 1984 at 1524 h, with the reactor at 0% thermal power, in the startup mode at 176 psig, the essential buses were automatically transferred from offsite to onsite power because of degraded offsite grid voltage. As per design, the reactor protection system was de-energized, resulting in a scram. The two essential and two nonessential 4160-kV buses were receiving offsite power via the startup transformer when the essential bus's undervoltage protection instrumentation sensed grid voltage <92.3% of nominal for +8 s. Consequently, the essential bus breakers tripped, as per design. The nonessential buses remained energized, and no load shedding occurred because grid voltage did not drop below 65% of nominal. Both DGs auto started upon loss of power to the essential buses and within 10 s had assumed the essential bus's loads. The degraded voltage was caused by the accidental motoring of a 650-MW(e) generator for over 20 s at the Louisa Generating Station.

The HPCI inboard steam supply valve (BJ-ISV-2238) closed following the scram. Although this was not per design, if necessary the valve could have been opened within a short time by manual operation after resetting the HPCI logic. This was done later at 1810 h after Operations personnel had returned other systems to normal. The false isolation signal due to the power loss was received from the SLDS. The isolation may have been due to a spurious signal from one or both SLDS temperature switches.

The reactor scram was reset at 1556 h, following the restarting of the reactor protection system M-G sets. All required systems were returned to normal by 1600 h. At 1620 h after the Iowa Electric system control center had advised the plant that recurrence of the grid voltage excursion was unlikely, the essential buses were transferred back to the startup transformer, and both diesels were unloaded. The diesels were secured at 1642 h. After a postevent review determined the operability of all safety-related systems and concluded that there had been no effect upon safe plant operation, startup of the reactor was commenced at 1901 h.

Event Identifier: 331/84-028

Corrective Action

On October 15, 1984, a special test procedure was run on the "A" logic of the HPCI SLDS. The reactor was in the shutdown mode for a planned maintenance outage, with RV pressure below that at which Technical Specifications requires HPCI to be operable. A review of the isolation logic for the HPCI inboard steam supply valve indicated that the spurious isolation of this valve following the LOOP on July 14, 1984, most likely originated in the HPCI SLDS isolation logic (temperature switches).

Three trials of the test procedure were performed. On the first and third trials, the suspected temperature switches (TS-2261A and TDS-2260A) closed and quickly reopened upon restoration of power. The result was an isolation signal of short duration that was sealed into the HPCI isolation logic. The second test produced no isolation signal. Test results proved that a random signal could be expected from the two suspect instruments upon reenergizing after LOOP.

After review, a minor design change was instituted to eliminate the random HPCI ac power dependency that results from powering up the HPCI SLDS logic. The design change implemented in both the "A" and "B" logic trains was to introduce a short time delay of ~1 s on restoration of ac power.

Plant/Event Data

Systems Involved:
HPCI and electrical power

Components and Failure Modes Involved:
HPCI isolation valve — spurious operation
Essential buses — transferred to onsite power

Component Unavailability Duration: NA
Plant Operating Mode: 2 (0% power)
Discovery Method: Operational event
Reactor Age: 10.3 years
Plant Type: BWR

Comments

The assumption for this analysis is that the Louisa station generator motoring, which initiated the event, could have occurred while Duane Arnold was at power.

Event Identifier: 331/84-028

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	0.34	Potential grid recovery considered possible within 30 min

Branches Impacted and Branch Non-Recovery Estimate

HPCI	0.12	Recovery possible from control room after HPCI logic reset

Plant Models Utilized

BWR plant Class C

Event Identifier: 331/84-028

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 331/84-028
Event Description: LOOP and HPCI Trip
Event Date: 7/14/84
Plant: Duane Arnold

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.4E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	5.8E-07
Total	5.8E-07
CD	
LOOP	7.3E-05
Total	7.3E-05
ATWS	
LOOP	7.1E-06
Total	7.1E-06

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.7E-07

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

End State: CD Conditional Probability: 5.0E-05

215 LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOC SRV.ADS

End State: ATWS Conditional Probability: 6.9E-06

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 -HP CI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	1.4E-05	3.5E-02
202	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI -RCIC/TRANS.OR.LOOP RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	1.8E-06	4.6E-03
208	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	3.5E-06	2.3E-02
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA SRV.ADS	CD	5.0E-05 *	4.1E-02
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)	CV	5.7E-07 *	2.3E-02
240	LOOP -EMERG.POWER SCRAM SLC.OR.RODS	ATWS	6.9E-06 *	3.4E-01
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI RCIC/TRANS.OR.LOOP	CD	2.2E-06	1.2E-02
246	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA	CD	1.6E-06	2.1E-02

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

MODEL: b:\BWRCTREE.CMP
DATA: b:\ARNOLPRO.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	2.6E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	

Event Identifier: 331/84-028

FW/PCS.TRANS	2.9E-01	3.4E-01	
FW/PCS.LOCA	4.0E-02	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 1.2E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Failed		
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-12-1987
16:32:12

Event Identifier: 331/84-028

PRECURSOR DESCRIPTION SHEET

LER No.: 333/84-002
Event Description: Engineered Safety Features Train Unavailable During Postulated LOOP
Date of Event: January 30, 1984
Plant: Fitzpatrick

EVENT DESCRIPTION

Sequence

On January 30, 1984, at 1051 h, while performing the required surveillance testing for an inoperative "C" RHR system SW pump the "B" ESW pump breaker tripped as it was starting. The overcurrent trip device set points were out of tolerance.

The "C" RHR SW pump provides 50% of the cooling flow to "A" RHR heat exchanger for the CC and shutdown modes. The "B" ESW pump provides cooling to the "B" EDG.

On February 7, 1984 at 0537 h, the HPCI turbine was removed from service to perform scheduled preventive and minor corrective maintenance and make a modification to the overspeed trip mechanism. The planned outage duration was 2 to 3 d. On February 8, 1984, at 0420 h during a routine surveillance test of EDG, the "B" ESW pump failed to start. The overcurrent trip set points were incorrect, and the pump clearances were 10 mils under those required to prevent rubbing between impeller and the wear ring.

Corrective Action

Overcurrent trip set points were recalibrated, and the ESW pump clearances were adjusted to within tolerance.

Plant/Event Data

Systems Involved:
ESW system, HPCI, train B of EDGs, and RHR SW system.

Event Identifier: 333/84-002

Components and Failure Modes Involved:

Component Unavailability Duration: 13.5 h
Plant Operating Mode: 1 (100% power)
Discovery Method: During surveillance test
Reactor Age: 9.2 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	0.34	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

HPCI	1.0	Not considered recoverable because down for extended maintenance
EPS	Base case	Degraded, one train failed

Plant Models Utilized

BWR plant Class C

Event Identifier: 333/84-002

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 333/84-002
Event Description: Engineered Safety Features Train Unavailable
Event Date: 1/30/84
Plant: Fitzpatrick

UNAVAILABILITY, DURATION= 13.5

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	6.0E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	7.8E-10
Total	7.8E-10
CD	
LOOP	2.8E-07
Total	2.8E-07
ATWS	
LOOP	6.4E-10
Total	6.4E-10

DOMINANT SEQUENCES

End State: CV Conditional Probability: 7.6E-10

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

End State: CD Conditional Probability: 1.0E-07

208 LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS

End State: ATWS Conditional Probability: 6.8E-10

Event Identifier: 333/84-002

250 LOOP EMERG.POWER SCRAM

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
208	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	1.0E-07 *	1.9E-01
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA SRV.ADS	CD	6.9E-08	3.4E-01
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)	CV	7.6E-10 *	1.9E-01
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI RCIC/TRANS.OR.LOOP	CD	6.4E-08	9.9E-02
246	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA	CD	4.7E-08	1.7E-01
250	LOOP EMERG.POWER SCRAM	ATWS	6.8E-10 *	1.7E-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.

MODEL: b:\bwrctree.cmp
DATA: b:\fitzprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	2.7E-02	1.0E+00	
EMERG.POWER	2.9E-03 > 5.7E-02	5.1E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		

Event Identifier: 333/84-002

Train 2 Cond Prob:	5.7E-02		
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Unavailable		
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-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	6.7E-03	1.0E+00	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	4.0E-04 > 4.0E-03	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.0E-03		
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)	2.0E-02 > 2.4E-02	3.4E-01	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	4.0E-03		
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	

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Minarick
04-11-1987
17:25:11

Event Identifier: 333/84-002

PRECURSOR DESCRIPTION SHEET

LER No.: 333/84-003
Event Description: RCIC Inoperable While HPCI Is Out of Service
Date of Event: February 7, 1984
Plant: Fitzpatrick

EVENT DESCRIPTION

Sequence

During normal full-power operation the HPCI system was intentionally removed from service to permit maintenance and modification. Before its removal, completion of surveillance required by Technical Specifications had demonstrated the ADS, RCIC, LPCI, and both CS systems to be operable. While the HPCI system was out of service, the RCIC system was made inoperable by a personnel error.

Corrective Action

Corrective action to reduce the probability of recurrence includes disciplinary action for the persons involved, implementation of a program to verify that employees are knowledgeable of the equipment they work on, continuation of plant-specific BWR technology/training, and labeling of certain plant equipment.

Plant/Event Data

Systems Involved:
HPCI, RCIC

Components and Failure Modes Involved:
RCIC — made inoperable

HPCI — out for maintenance

Component Unavailability Duration: 10 h
Plant Operating Mode: 1 (100% power)
Discovery Method: During maintenance
Reactor Age: 10.2 years
Plant Type: BWR

Event Identifier: 333/84-003

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and small-break LOCA	Base case

Branches Impacted and Branch Nonrecovery Estimate

HPCI	1.0	No potential recovery assumed
RCIC	0.34	Assumed recoverable locally at equipment

Plant Models Utilized

BWR plant Class C

Event Identifier: 333/84-003

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 333/84-003
Event Description: RCIC Inoperable While HPCI Is Out of Service
Event Date: 2/7/84
Plant: Fitzpatrick

UNAVAILABILITY, DURATION= 10

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.1E-02
LOOP	4.4E-05
LOCA	1.1E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	4.3E-08
LOOP	5.6E-09
LOCA	1.3E-09
Total	5.0E-08
CD	
TRANS	1.0E-06
LOOP	1.1E-07
LOCA	1.6E-07
Total	1.3E-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: 2.4E-08

Event Identifier: 333/84-003

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: 7.8E-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	2.3E-07	1.2E-01
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	7.8E-07 *	3.4E-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-08 *	7.6E-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-08	3.9E-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	4.1E-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	2.1E-09	1.1E-01
208	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	3.4E-08	1.2E-01
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA SRV.ADS	CD	5.2E-08	3.4E-01
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOO P -SRV.ADS -LPCS -RHR(SDC)	CV	5.5E-09	1.1E-01
310	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	1.6E-07	1.2E-01
314	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	8.6E-10	7.6E-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.

MODEL: b:\bwrctree.cmp
DATA: b:\fitzprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail

Event Identifier: 333/84-003

TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	2.7E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Unavailable		
RCIC/TRANS.OR.LOOP	6.7E-02 > 1.0E+00	5.7E-01 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.7E-02 > Unavailable		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-11-1987
17:28:17

Event Identifier: 333/84-003

PRECURSOR DESCRIPTION SHEET

LER No.: 333/84-004
Event Description: RCIC and HPCI Are Unavailable
Date of Event: February 10, 1984
Plant: Fitzpatrick

EVENT DESCRIPTION

Sequence

With the HPCI system out of service for scheduled maintenance, a dc ground occurred on the "A" station battery. During the performance of the ground isolation procedure, the dc control power to the RCIC inverter was momentarily interrupted. The momentary loss of dc power to the RCIC inverter required a manual reset to repower the inverter. The ground isolation procedure did not inform the operator that a manual reset was required. The loss of both HPCI and RCIC placed the plant on a 24-h limiting condition for operation. The operator, after determining that the inverter would not reset automatically, performed a manual reset. Surveillance testing for RCIC operability was immediately conducted and RCIC was declared operable.

Corrective Action

A change to the ground isolation procedure was incorporated to instruct the operator to manually reset the RCIC inverter.

Plant/Event Data

Systems Involved:
RCIC, HPCI, electrical

Components and Failure Modes Involved:
"A" station battery — ground detected during operation
HPCI — out for maintenance
RCIC inverter — deenergized during ground detection procedure

Component Unavailability Duration: 30 min
Plant Operating Mode: 1 (100% power)
Discovery Method: During maintenance
Reactor Age: 10.2 years
Plant Type: BWR

Event Identifier: 333/84-004

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and small-break LOCA	Base case	

Branches Impacted and Branch Nonrecovery Estimate

RCIC	0.34	Nonroutine recovery requiring manual reset
HPCI	1.0	Out for maintenance

Plant Models Utilized

BWR plant Class C

Event Identifier: 333/84-004

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 333/84-004
Event Description: RCIC and HPCI Are Unavailable
Event Date: 2/10/84
Plant: Fitzpatrick

UNAVAILABILITY, DURATION= .5

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	5.7E-04
LOOP	2.2E-06
LOCA	5.5E-07

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	2.2E-09
LOOP	2.8E-10
LOCA	6.5E-11
Total	2.5E-09
CD	
TRANS	5.1E-08
LOOP	5.5E-09
LOCA	8.1E-09
Total	6.4E-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: 1.2E-09

Event Identifier: 333/84-004

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: 3.9E-08

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	1.1E-08	1.2E-01
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	3.9E-08 *	3.4E-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	1.2E-09 *	7.6E-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	6.3E-10	3.9E-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	2.0E-10	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	1.1E-10	1.1E-01
208	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HP CI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	1.7E-09	1.2E-01
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HP CI RCIC/LOCA SRV.ADS	CD	2.6E-09	3.4E-01
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOO P -SRV.ADS -LPCS -RHR(SDC)	CV	2.8E-10	1.1E-01
310	LOCA -SCRAM PCS/LOCA FW/PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	8.1E-09	1.2E-01
314	LOCA SCRAM -SLC.OR.RODS PCS/LOCA FW/PCS.LOCA HPCI -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	4.3E-11	7.6E-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.

MODEL: b:\bwrctree.cmp
DATA: b:\fitzprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch System Non-Recov Opr Fail

Event Identifier: 333/84-004

TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	2.7E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01 > 1.0E+00	5.7E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.0E-01 > Unavailable		
RCIC/TRANS.OR.LOOP	6.7E-02 > 1.0E+00	5.7E-01 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.7E-02 > Unavailable		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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)	5.0E-01	1.0E+00	
C.I.AND.V/RHR(SDC).RHR(SPCOOL)	1.0E+00	3.4E-01	

*** forced

Minarick
04-11-1987
17:33:18

Event Identifier: 333/84-004

PRECURSOR DESCRIPTION SHEET

LER No.: 336/84-012
Event Description: Trip, LOFW, and AFW Degraded
Date of Event: November 28, 1984
Plant: Millstone 2

EVENT DESCRIPTION

Sequence

The unit had been operating at 100% power when a tube leak was detected in feedwater heater 5A. An orderly shutdown of the unit had been under way for some time when a steady rise in the level in the feedwater heater 5A was noted. The reactor was then tripped to protect the turbine from water intrusion. At the time of the trip, the unit was operating at 62% power.

Following the trip, standard posttrip actions were carried out. In addition, trip recovery procedures were also followed. When the "B" steam generator feed pump was taken to minimum speed, the level in both SGs started decreasing. The "B" SG feed pump was secured due to low discharge pressure, and AFW flow was initiated. The level in the SG 1 increased while the level in SG 2 continued to decrease. AFW flow to SG 2 was increased with no effect on the level decrease in SG 2. Operations personnel noted steam escaping from the "B" SG feed pump. It was theorized that the MFW check valve to the SG 2 (2-FW-5B) failed to seat, thus resulting in a backflow of AFW to the "B" SG feed pump. At this time, the feed-regulating valves, the feed-regulating block valves, and the SG feed pump discharge valves were shut. Level in SG 2 was brought on scale and returned to normal.

The unit was placed in hot standby (mode 3). The tubes in the feedwater heater 5A were inspected and plugged as required. An inspection of the malfunctioning check valve, 2-FW-5B, determined that the valve stem had bound up slightly, not allowing the valve to seat. Adjustments were made to the valve, and its operability was evaluated through in-service test T84-36. The valve was deemed operable before the unit was returned to 100% power operation.

Corrective Action

Check valves 2-FW-5A and 2-FW-5B were inspected and reworked during the 1985 refueling outage. The rework consisted of machining a spacer ring internal to the valves to eliminate binding. The valve vendor concurred with this modification.

Event Identifier: 336/84-012

Plant/Event Data

Systems Involved:
AFW, MFW

Components and Failure Modes Involved:
MFW check valve — failed in operation
MFW pump — failed in operation
AFW train flow — degraded

Component Unavailability Duration: NA
Plant Operating Mode: 1 (62% power)
Discovery Method: Operational event
Reactor Age: 9.1 years
Plant Type: PWR

Comments

For information concerning a similar event, see: J. W. Minarick and J. D. Harris, Analysis of the November 21, 1985, San Onofre 1 Transient from the Standpoint of Potential Severe Core Damage, ORNL Letter Report from J. R. Buchanan to F. J. Hebdon, Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, January 17, 1986.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery (manual trip)

Branches Impacted and Branch Nonrecovery Estimate

AFW	Base case	Degraded flow, one train failed
MFW	1.0	No recovery assumed

Plant Models Utilized

PWR plant Class G

Event Identifier: 336/84-012

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 336/84-012
Event Description: Trip With LOFW and AFW Degraded
Event Date: 11/28/84
Plant: Millstone 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.3E-05
Total	5.3E-05
CD	
TRANS	3.0E-05
Total	3.0E-05
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.1E-05

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

End State: CD Conditional Probability: 2.1E-05

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

End State: ATWS Conditional Probability: 3.0E-05

Event Identifier: 336/84-012

121 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
112	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS -COND/MFW	CV	9.7E-06	1.8E-01
113	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	5.0E-06	9.2E-02
118	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	4.1E-05 *	9.3E-02
119	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	2.1E-05 *	4.8E-02
120	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	2.3E-06	1.4E-01
121	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\PWRGTREE.CMP
DATA: b:\MILL2PRO.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	5.4E-04	5.1E-01	
AFW	1.0E-03 > 5.9E-03	2.7E-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		
Serial Coaponent Prob:	9.2E-04		
AFW/EMERG.POWER	5.3E-02	3.4E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Failed		
PORV.OR.SRV.CHALL	2.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	1.2E-01	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	1.2E-01	
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	

Event Identifier: 336/84-012

COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04	5.2E-01	
HPI(F/B)	3.0E-04	5.2E-01	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	1.0E-03	1.0E+00	
CSR	2.0E-03	3.4E-01	

*** forced

Minarick
04-12-1987
16:23:05

Event Identifier: 336/84-012

PRECURSOR DESCRIPTION SHEET

LER No.: 338/84-019
Event Description: Trip and One AFW Train Fails
Date of Event: November 14, 1984
Plant: North Anna 1

EVENT DESCRIPTION

Sequence

At 0640 h a vital bus inverter failure caused Unit 1 to trip from 100% power. The inverter was supplying power to the 125-V ac vital bus 1-III. The inverter failure caused this bus and its associated equipment to become deenergized. Loss of power to the relay that senses "C" RCP breaker position caused the reactor trip on loss of RCS flow coincident with reactor power >30%. The "C" RCP never stopped running during this event.

Vital bus 1-III was deenergized for <2 min. The inverter had damaged SCRs and a blown fuse which prevented it from being reenergized. The bus was subsequently powered from its backup regulating transformer. All equipment power from vital bus 1-III responded as expected during loss and restoration of the bus. The most significant equipment response involved "B" SG. The "B" main feed valve (FCV-1488) and "B" feed bypass valve (FCV-1489) both failed closed. "B" wide-range SG level indication (LI-1487) failed low. The AFW pump (1-FW-P-3B) that supplies "B" SG failed to autostart and was manually started by the control room operator. These actions caused "B" SG level to drop below the narrow range indication while no-wide range level indication was available. Level was restored to "B" SG within a few minutes.

Loss of vital bus 1-III also deenergized all four water boxes' vacuum breakers, which caused all circulating water pumps to trip. This has been assumed to have resulted in an LOFW.

Vital bus 1-III also supplies power to many containment isolation trip valves, including CC to the RCPs. Other significant equipment powered from the 1-III vital bus included 1 power range detector (N43), 26 incore thermocouples, SSPS channel III inputs, SSPS train B output relays, train B RV-level instrumentation, radiation monitor cabinet 1-2, and other equipment.

One of the blowdown-containment isolation trip valves did not close automatically and would not close manually during this event. A solenoid-operated valve for this trip valve would not change position. Maintenance personnel agitated the solenoid valve, and the trip valve was subsequently cycled satisfactorily. Blowdown containment isolation trip valves are cycled every three months during a periodic test to verify valve-stroke time.

The source range excore detectors had to be manually reinstated because one intermediate-range detector was undercompensated. This detector had its compensation voltage adjusted before the reactor was taken critical.

The unit was placed in mode 2 on November 17, 1984, and returned to 100% power on November 19, 1984.

Corrective Action

Repairs were made.

Plant/Event Data

Systems Involved:
AFW, electrical

Components and Failure Modes Involved:
AFW pump — failed on demand

Component Unavailability Duration: NA
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 6.6 years
Plant Type: PWR

Comments

None

Event Identifier: 338/84-019

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Not recoverable

Branches Impacted and Branch Nonrecovery Estimate

AFW	Base case	One train unavailable
MFW	0.34	Assumed recoverable locally at the equipment

Plant Models Utilized

PWR plant Class A

Event Identifier: 338/84-019

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 338/84-019
Event Description: Trip and One AFW Train Fails
Event Date: 11/14/84
Plant: North Anna 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	2.1E-05
Total	2.1E-05
CD	
TRANS	1.0E-05
Total	1.0E-05
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.9E-06

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

End State: CD Conditional Probability: 2.4E-06

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

End State: ATWS Conditional Probability: 3.0E-05

Event Identifier: 338/84-019

137 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-07	1.8E-01
102	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI -HPR/-HPI CSR -SS.DEPRESS -LPR/-HPI	CV	5.0E-07	1.7E-02
103	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI -HPR/-HPI CSR -SS.DEPRESS LPR/-HPI	CD	1.0E-06	1.7E-02
105	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS -LPR/-HPI	CV	5.3E-07	2.8E-02
106	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI	CD	1.1E-06	2.8E-02
112	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	5.9E-06 *	1.8E-01
125	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI -CSR PORV.OPEN -SS.DEPRESS -COND/MFW	CV	9.9E-07	6.0E-02
126	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI -CSR PORV.OPEN -SS.DEPRESS COND/MFW	CD	5.1E-07	3.1E-02
128	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI CSR -SS.DEPRESS -COND/MFW	CV	4.2E-06	2.1E-02
129	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI CSR -SS.DEPRESS COND/MFW	CD	2.2E-06	1.1E-02
130	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI CSR SS.DEPRESS	CD	2.4E-07	3.1E-02
131	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS -COND/MFW	CV	4.5E-06	3.4E-02
132	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	2.3E-06	1.7E-02
133	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	2.5E-07	5.1E-02
134	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	4.6E-06	3.2E-02
135	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	2.4E-06 *	1.6E-02
136	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	2.6E-07	4.8E-02
137	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\PWRATREE.CMP
DATA: b:\NANNAPRO.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	

Event Identifier: 338/84-019

RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EP	2.9E-03	5.1E-01	
AFW	1.0E-03 > 1.9E-03	2.7E-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:	9.2E-04		
AFW/EP	5.0E-02	3.4E-01	
MFW	1.9E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.9E-01 > Unavailable		
PORV.OR.SRV.CHALL	4.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	2.0E-02	5.0E-02	
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	2.3E-03	5.2E-01	
HPI(F/B)	2.3E-03	5.2E-01	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	3.0E-03	5.6E-01	4.0E-02
CSR	3.0E-03	3.4E-01	4.0E-02
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI	6.7E-01	1.0E+00	
LPR/HPI	2.0E-03	1.0E+00	

*** forced

Minarick
04-12-1987
10:25:50

Event Identifier: 338/84-019

PRECURSOR DESCRIPTION SHEET

LER No.: 339/84-013
Event Description: Forced Shutdown Due to Two Inoperable Emergency Diesel Generators
Date of Event: December 9, 1984
Plant: North Anna 2

EVENT DESCRIPTION

Sequence

At 1215 h the "2J" EDG was started to determine operability, while the "2H" EDG was tagged out for the maintenance. At 1321 h the "2J" EDG tripped on high crankcase pressure. Preventive maintenance was immediately stopped on the "2H" EDG. The "2H" EDG was started, loaded, and determined operable at 1605 h pursuant to testing requirements. The "2H" EDG was placed on an 8-h surveillance testing schedule as required. At 0637 h on December 9, 1984, the "2H" EDG was started for surveillance testing. At 0652 h the "2H" EDG tripped on high crankcase pressure and was declared inoperable.

As a result of having two inoperable EDGs, a plant shutdown was initiated.

Corrective Action

Maintenance personnel and technical representatives from the Fairbanks Morse, EDG manufacturer, investigated the causes of the EDG trips and performed corrective maintenance. The Nos. 2, 3, and 11 upper pistons and the D11 liner were replaced because of possible leaks on the "2J" EDG. As a result of the failures, a root cause was sought. It is believed to be due to a fault in the Technical Specifications surveillance requirement.

Plant/Event Data

Systems Involved:
Emergency power

Components and Failure Modes Involved:
DG 2H — failed in test
DG 2J — failed in test

Component Unavailability Duration: First time 2.5 h; second time; 53 h; 9 h assumed for analysis
Plant Operating Mode: 1 (100% power)
Discovery Method: During testing
Reactor Age: 4.5 years
Plant Type: PWR

Event Identifier: 339/84-013

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	Base case	

Branches Impacted and Branch Nonrecovery Estimate

EPS	1.0	No recovery assumed possible

Plant Models Utilized

PWR plant Class A

Event Identifier: 339/84-013

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 339/84-013
Event Description: Forced Shutdown Due to Two Inoperable Diesel Generators
Event Date: 12/9/84
Plant: North Anna 2

UNAVAILABILITY, DURATION= 9

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	7.0E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	3.5E-07
Total	3.5E-07
CD	
LOOP	1.2E-06
Total	1.2E-06
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 3.4E-07

219 LOOP -RT/LOOP EP -AFW/EP -PORV.OR.SRV.CHALL SS.RELEAS.TERM

End State: CD Conditional Probability: 1.2E-06

220 LOOP -RT/LOOP EP AFW/EP

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 339/84-013

	Sequence	End State	Prob	N Rec**
217	LOOP -RT/LOOP EP -AFW/EP PORV.OR.SRV.CHALL -PORV.OR.SRV.RESE AT SS.RELEAS.TERM	CV	1.4E-08	1.1E-01
219	LOOP -RT/LOOP EP -AFW/EP -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	3.4E-07 *	1.1E-01
220	LOOP -RT/LOOP EP AFW/EP	CD	1.2E-06 *	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.

MODEL: b:\PWRATREE.CMP
DATA: b:\NANNAPRO.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EP	2.9E-03 > 1.0E+00	5.1E-01 > 1.0E+00	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Failed		
AFW	1.0E-03	2.7E-01	
AFW/EP	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	
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	2.3E-03	5.2E-01	
HPI(F/B)	2.3E-03	5.2E-01	4.0E-02
PORV.OPEN	1.0E-02	1.0E+00	
HPR/-HPI	3.0E-03	5.6E-01	4.0E-02
CSR	3.0E-03	3.4E-01	4.0E-02
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI	6.7E-01	1.0E+00	
LPR/HPI	2.0E-03	1.0E+00	

Event Identifier: 339/84-013

*** forced

Minarick
04-12-1987
10:29:45

Event Identifier: 339/84-013

PRECURSOR DESCRIPTION SHEET

LER No.: 344/84-017
Event Description: Steam Generator Safety Valve Fails Open and Subsequent Reactor Trip
Date of Event: September 26, 1984
Plant: Trojan

EVENT DESCRIPTION

Sequence

The event began on September 26, 1984, just after a power distribution flux map had been taken at power [~500 MW(e)]. The control rods were in manual mode to facilitate rod repositioning to compensate for boron dilution and to achieve varying axial flux differences for the Cycle 7 physics testing program. At 2208 h a plant computer alarm indicated low suction pressure (caused by a cracked bourdon tube in the suction pressure transmitter) on the only operating MFWP pump. When the control room personnel first started reducing turbine load by manually closing the control valves, they noticed the mismatch between turbine demand and reactor power, which caused the RCS average temperature (T_{ave}) to increase. They attributed this mismatch to the load runback. The control room personnel failed to realize that RCS T_{ave} was not decreasing because the control rods were in manual. In addition, SG pressure increased from ~970 psig to the set point of the first set of safety valves (1170 psig) on all four SGs. At 2230 h, the oncoming crew informed the control room personnel that the safety valves were open. It was also noticed that the "A" steam-line PORV was open 30% and that the steam pressure was ~1130 psig in the SGs. The PORV was later determined to have been set to relieve at 1260 psig instead of 1125 psig.

The PORV was closed and reactor temperature and pressure were reduced so that the SRVs could close. The "D" SRV remained open. At about 2310 h, the shift maintenance mechanics tried unsuccessfully to force the "D" safety valve closed. Reduction in reactor and turbine power was continued, and the turbine generator was taken off line at 2326 h. Level control problems in the "D" SG resulted in a reactor trip at 2329 h due to low-low level. At 2335 h, the "D" safety valve reseated when the SG pressure reached ~890 psig.

Corrective Action

The immediate corrective action was to reduce steam pressure to reseat the stuck-open steam-line safety valve. Additional corrective actions were developed later and reported to NRC in separate correspondence.

Plant/Event Data

Systems Involved:
Nonnuclear instrumentation system, secondary-side relief system

Components and Failure Modes Involved:
SG SRV — failed to close

Component Unavailability Duration: NA
Plant Operating Mode: 1 (50% power)
Discovery Method: Operational event
Reactor Age: 8.8 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

Secondary-side release terminated given MFW success	1.0	SRV could not be closed
Secondary-side release terminated given MFW failure	1.0	SRV could not be closed

Plant Models Utilized

PWR plant Class C

Event Identifier: 344/84-017

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 344/84-017
Event Description: SG Relief Valve Fails Open and Subsequent Reactor Trip
Event Date: 9/26/84
Plant: Trojan

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.4E-04
Total	5.4E-04
CD	
TRANS	1.1E-05
Total	1.1E-05
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.0E-04

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

End State: CD Conditional Probability: 3.8E-06

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

End State: ATWS Conditional Probability: 3.0E-05

Event Identifier: 344/84-017

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	2.1E-05	5.2E-01
103	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	1.1E-06	2.8E-02
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	5.0E-04 *	5.2E-01
120	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	8.7E-07	3.9E-02
123	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	3.8E-06	2.2E-02
124	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	4.2E-07	6.5E-02
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	3.8E-06 *	2.0E-02
127	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	4.2E-07	6.0E-02
128	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\pwrbtree.cmp
DATA: b:\trojprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	2.5E-03	3.4E-01	
AFW/EMERG.POWER	5.0E-02	3.4E-01	
MFW	1.0E+00	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	5.0E-02	
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 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.5E-02 > Failed		

Event Identifier: 344/84-017

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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03	1.0E+00	

*** forced

Minarick
04-12-1987
10:34:26

Event Identifier: 344/84-017

PRECURSOR DESCRIPTION SHEET

LER No.: 346/84-003
Event Description: SFRCS Initiation Leads to Stuck-Open MSRV and Trip
Date of Event: March 28, 1984
Plant: Davis-Besse 1

EVENT DESCRIPTION

Sequence

At 1220 h on March 2, Davis-Besse 1 was operating at ~99% of full power. The plant was in full automatic control. During periodic steam and feedwater rupture control system (SFRCS) surveillance testing, a previously undetected SFRCS channel failure resulted in closure of the loop 2 MSIV. This caused an increase in feedwater to the other SG, which overcooled that side of the reactor. Flux increased because of the negative moderator coefficient. The reactor tripped on high flux ~13 s after MSIV 2 closed.

The cause of the MSIV closure was a failed optical isolator in a relay driver card for a relay in SFRCS Channel 4. This failure, undetected and in conjunction with normal testing on another channel, resulted in a close signal to MSIV 2. During troubleshooting, a wiring anomaly was found in the circuitry for MSIV 2. This anomaly, due to a circuit modification made in 1979, was the reason that the failed relay driver card had not been detected. Both an equipment failure and an installation and construction error were associated with the MSIV closure.

Following the reactor trip, steam pressure on SG 2 did not stabilize as would normally be expected. Local observation determined that main steam SRV, SP17A4, with a set pressure of 1070 psig, had not fully closed on the No. 2 steam line.

Subsequent investigation by the licensee determined that the cause of the valve sticking open was the failure of a cotter pin holding a nut in place on the valve stem. The nut rotated when the valve opened and prevented the safety valve from closing.

Manual actuation of SFRCS isolated SG 2. After AFW isolation, SG 2 boiled dry and depressurized to atmospheric pressure in ~5 min. This excessive depressurization rate caused the RCS to exceed the normal cooldown limits for a short time. Plant cooldown was conducted with SG 1, which was unaffected. At ~340°F RCS temperature, the failed MSRV was replaced. When operators attempted to restore level in SG 2, the AFW valve (AF599) failed to open. It was opened manually, and SG 2 level was restored to operable status. The plant was then cooled down to cold shutdown.

Event Identifier: 346/84-003

It was determined later that an additional MSRV (SP17A1) on the No. 2 steam line had failed to open when it should have.

Corrective Action

MSRV SP17A4 was replaced. The cotter pins in all other MSRVs were replaced with stainless steel pins, and maintenance procedures were modified to ensure new pins are used after any maintenance or testing in the future.

MSRV SP17A1 was declared inoperable and gagged. It was to be repaired or replaced during the next refueling outage. The cause of its failure to lift was still unknown at the time. The RPS high-flux trips must be set <99.69% of rated thermal power with this safety inoperable.

The effects of the SG No. 2 boiling dry were analyzed, and it was concluded that the transient was within SG design limits. The effects of high main steam flow from SG 1 when MSIV 2 closed was analyzed. It was concluded that some (~100) tubes may have been unstable for a period of seconds. As corrective action, the suspect tubes were to be eddy-current tested during the next refueling outage.

The AFW valve AF599 problem was investigated. The motor operator torque switch settings were changed from 1.5 open and close to 1.0 close and 1.5 open. This was to prevent the valve disk from being jammed into its seat. This change was also made to AF608, the AFW valve for SG 1.

The faulty relay driver board in SFRCS Channel 4 was replaced. The wiring anomaly was corrected and verified not to exist in the circuitry for MSIV 1.

Plant/Event Data

Systems Involved:
Steam and feedwater rupture control, main steam relief, AFW

Components and Failure Modes Involved:
SFRCS Channel 4 relay card — failed in test
MSRV — failed to close in operation
AFW regulating valve — failed to open on demand

Component Unavailability Duration: NA
Plant Operating Mode: 1 (99% power)
Discovery Method: During testing
Reactor Age: 6.6 years
Plant Type: PWR

Event Identifier: 346/84-003

Comments

Reference: Abnormal Occurrence Reports to Congress, NUREG-0090, 1(1), 36.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	No recovery

Branches Impacted and Branch Nonrecovery Estimate

MFW	Base case	Unavailable due to SFRCS trip
AFW	Base case	Degraded (one train unavailable)

Plant Models Utilized

PWR plant Class B (because it has low-head HPI, it is grouped with Class B and not Class D)

Event Identifier: 346/84-003

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 346/84-003
Event Description: SFRCS Initiation Leads to Stuck Open MSRV and Trip
Event Date: 3/28/84
Plant: Davis-Besse

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	2.6E-04
Total	2.6E-04
CD	
TRANS	1.5E-04
Total	1.5E-04
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.2E-04

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

End State: CD Conditional Probability: 6.1E-05

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

End State: ATWS Conditional Probability: 3.0E-05

128 TRANS RT

SEQUENCE COND.TIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
119	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS -COND/MFW	CV	2.7E-05	6.1E-02
120	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	1.4E-05	3.1E-02
122	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS -COND/MFW	CV	1.2E-04	3.4E-02
123	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	6.0E-05	1.7E-02
124	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	6.6E-06	5.1E-02
125	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	1.2E-04 *	3.2E-02
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	6.1E-05 *	1.6E-02
127	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	6.7E-06	4.8E-02
128	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\pwrbtree.cmp
DATA: b:\davispro.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	5.0E-03 > 5.0E-02	2.7E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		
AFW/EMERG.POWER	5.0E-03	2.7E-01	
MFW	2.0E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-01 > Unavailable		
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	5.0E-02	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-01	

Event Identifier: 346/84-003

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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03	1.0E+00	

*** forced

Minarick
04-12-1987
10:44:10

Event Identifier: 346/84-003

PRECURSOR DESCRIPTION SHEET

LER No.: 346/84-013
Event Description: Trip and One Atmospheric Dump Valve Fails to Close
Date of Event: September 11, 1984
Plant: Davis-Besse 1

EVENT DESCRIPTION

Sequence

At 1235 h on September 11, 1984, Davis-Besse experienced a turbine trip from 70% full power, and the turbine trip initiated an anticipatory reactor trip. The posttrip response was normal for a trip from 70% full power. Pressurizer level remained on scale, and minimum RCS pressure was ~1880 psig. The PORV was not operated. Adequate subcooling margin existed at all times. The No. 1 atmospheric vent valve did not fully reseat on its own, and operators had to lower steam header pressure to get it to reseat.

Because the unit was in the outage burnup window, it was decided to begin the refueling outage. A plant cooldown was initiated.

Later in the cooldown, in mode 3, with one RCP shut down, operators had difficulty balancing pressure in the two OTSGs. At 0109 h on September 12, the station received a SFRCS trip from low pressure in once-through SG 1. This initiated another anticipatory trip of the reactor.

The cause of the trip was an error by personnel who positioned a rotor-lifting beam on the turbine deck in preparation for the refueling outage turbine work. A timber was inadvertently placed into the piping that supports the moisture separator reheater, high-water-level switch. The bump caused the switch to actuate. The switch is intended to cause the turbine to be isolated when the water level gets too high in the moisture separator reheater. This is to protect the turbine from damage that would occur if water hit the blades. The switch caused the turbine to trip, which initiated a reactor trip.

The cause of the No. 1 atmospheric vent valve's not fully reseating was determined to be in the valve control circuit, specifically the air control solenoids that are in need of replacement or refurbishment.

The cause of the SFRCS trip on September 12, 1984, was that the plant shutdown and cooldown procedure did not adequately cover an RCS cooldown using the turbine-driven main feed pumps. Use of this pump is necessitated by the inavailability of the startup feedpump due to pipe-break concerns.

Corrective Action

The maintenance workers who actuated the switch were counseled on being more careful around operating equipment.

Permanent guardrails were to be installed around the MSR high-level switches. A two-out-of-three trip scheme for the MSR high-level trip was to be provided by adding two additional level switches to the existing sensing leg, with guardrails around these additional level switches.

The atmospheric vent air-control solenoid valves were replaced during the 1984 refueling outage.

The plant shutdown and cooldown procedure was modified to provide guidance for an RCS cooldown using the turbine-driven main feed pump.

Plant/Event Data

Systems Involved:
Secondary-side relief

Components and Failure Modes Involved:
Atmospheric vent valve — failed to close on demand

Component Unavailability Duration: NA
Plant Operating Mode: 1 (70% power)
Discovery Method: Operational event
Reactor Age: 7.1 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Not recoverable following reactor trip

Event Identifier: 346/84-013

Branches Impacted and Branch Nonrecovery Estimate

Secondary-side release terminated	0.12	Nonroutine recovery from control room by operators lowering steam header pressure
Secondary-side release terminated given MFW success	0.12	Nonroutine recovery from control room by operators lowering steam header pressure

Plant Models Utilized

PWR plant Class B

Event Identifier: 346/84-013

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 346/84-013
Event Description: Trip and One Atmospheric Dump Valve Fails to Close
Event Date: 9/11/84
Plant: Davis-Besse

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	6.8E-05
Total	6.8E-05
CD	
TRANS	4.1E-06
Total	4.1E-06
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 5.7E-05

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

End State: CD Conditional Probability: 1.2E-06

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

End State: ATWS Conditional Probability: 3.0E-05

Event Identifier: 346/84-013

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	5.0E-06	6.2E-02
103	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	1.1E-06	2.8E-02
104	TRANS -RT -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI SS.DEPRESS	CD	6.0E-08	2.8E-02
109	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	5.7E-05 *	6.2E-02
120	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	2.8E-07	3.1E-02
122	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS -COND/MFW	CV	2.3E-06	3.4E-02
123	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI -SS.DEPRESS COND/MFW	CD	1.2E-06	1.7E-02
124	TRANS -RT AFW MFW -HPI(F/B) HPR/-HPI SS.DEPRESS	CD	1.3E-07	5.1E-02
125	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	2.4E-06	3.2E-02
126	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	1.2E-06 *	1.6E-02
127	TRANS -RT AFW MFW HPI(F/B) SS.DEPRESS	CD	1.3E-07	4.8E-02
128	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\pwrbtree.cmp
DATA: b:\davispro.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	5.0E-03	2.7E-01	
AFW/EMERG.POWER	5.0E-03	2.7E-01	
MFW	2.0E-01	3.4E-01	
PORV.OR.SRV.CHALL	8.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	5.0E-02	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	5.0E-02	
SS.RELEAS.TERM	1.5E-02 > 1.0E+00	3.4E-01 > 1.2E-01	

Branch Model: 1.0F.1

Event Identifier: 346/84-013

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	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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	
LPR/HPI	1.0E-03	1.0E+00	

*** forced

Minarick
04-12-1987
10:47:38

Event Identifier: 346/84-013

PRECURSOR DESCRIPTION SHEET

LER No.: 362/84-035
Event Description: All HPSI Pumps Unavailable
Date of Event: August 21, 1984
Plant: San Onofre 3

EVENT DESCRIPTION

Sequence

Train-B CCW heat exchanger was removed from service for cleaning. Train-B ESF components cooled by CCW, including the train-B HPSI pump, were therefore inoperable (see table below). Later the train-A HPSI bypass valves were opened in accordance with the approved surveillance procedure for conducting train-A subgroup relay testing. Opening the train-A HPSI bypass valves rendered train-A HPSI inoperable. The loss of both trains of HPSI while operating at 100% power constitutes operation outside Limiting Condition for Operation. However, the miniflow bypass valves were shut within 18 min, restoring the Train A HPSI pumps to an operable status.

Safety-related components[a]

Component	No. of components
HPSI pump and the shared standby HPSI pump	1
Low-pressure SI pump	1
CS pump	1
Shutdown heat exchanger	1

[a]Each of two CCW loops supplies water to the listed safety-related components (partial listing).

Corrective Action

In addition to disciplinary action taken against operators involved, corrective action has included an in-depth review of this event by station management. In conjunction with an overall review of action that being taken to implement guidance provided in I&E Notice 84-51 and Item I.C.6 of NUREG-0737, operator training was enhanced. Training will emphasize the importance of the senior reactor function of authorizing

removal of equipment from service, the importance of the manipulation of locked valves, and the importance of again reviewing procedure precautions and prerequisites prior to recommencing activity begun on a previous shift.

Plant/Event Data

Systems Involved:
HPSI, CCW

Components and Failure Modes Involved:
"B" CCW heat exchanger — unavailable due to maintenance
"A" HPSI train — unavailable due to open bypass valves

Component Unavailability Duration: 18 min
Plant Operating Mode: 1 (100% power)
Discovery Method: During maintenance
Reactor Age: 1.0 years
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated transient, LOOP, and small-break LOCA	1.0, 0.34, 0.34	Base case nonrecoveries

Branches Impacted and Branch Nonrecovery Estimate

HPI (feed and bleed)	0.34	Recoverable locally at the pump
HPI	0.34	Same as above
Emergency power	Base case	One train unavailable
CSR	Base case	One train unavailable

Plant Models Utilized

PWR plant Class G

Event Identifier: 362/84-035

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 362/84-035
Event Description: All HPSI Pumps Unavailable
Event Date: 8/21/84
Plant: San Onofre 3

UNAVAILABILITY, DURATION= .3

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	3.1E-04
LOOP	2.3E-06
LOCA	4.3E-07

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.4E-07
LOOP	4.2E-09
LOCA	(1.8E-12)
Total	5.4E-07
CD	
TRANS	4.2E-09
LOOP	9.6E-10
LOCA	1.4E-07
Total	1.5E-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: 5.1E-07

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

End State: CD Conditional Probability: 1.4E-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	2.1E-08	1.2E-01
104	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	5.1E-07 *	1.2E-01
302	LOCA -RT -AFW HPI	CD	1.4E-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.

MODEL: C:\ASP\PWRGTREE.CMP
DATA: C:\ASP\SANONO2.CMP

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03 > 5.0E-02	5.1E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02 > Unavailable		
AFW	1.9E-03	2.7E-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	5.0E-02	
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	

Event Identifier: 362/84-035

COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04 > 1.0E+00	5.2E-01 > 3.4E-01	
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	5.2E-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	1.0E-03	1.0E+00	
CSR	2.0E-03 > 2.0E-02	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	2.0E-02		
Train 2 Cond Prob:	1.0E-01 > Unavailable		

*** forced

Minarick
04-14-1987
09:14:43

Event Identifier: 362/84-035

PRECURSOR DESCRIPTION SHEET

LER No.: 369/84-024
Event Description: LOOP at McGuire 1 Affects Unit 2
Date of Event: August 21, 1984
Plant: McGuire 1

EVENT DESCRIPTION

Sequence

At ~2400 h on August 20, 1984, the McGuire switchyard computer was reported inoperable. On August 21, computer and inverter maintenance personnel performed corrective maintenance on the switchyard computer and static inverter. At 2114 h, the switchyard computer was restarted, checked for operability, and returned to service. At 2148 h, when the switchyard operator reenabled the computer control outputs, 30 power circuit breakers and associated disconnects opened, resulting in McGuire Unit 1 reactor trip and turbine trip, loss of Unit 1 offsite ac power, and startup of Unit 1 DGs A and B.

Unit 1 was in mode 1 at 100% power at the time and supplying steam to the Unit 2 MFWP turbines. Unit 2 was in startup at 0% power. The trip at Unit 1 also caused a loss of MFWP turbine steam at Unit 2.

This incident was classified as a component malfunction/failure because the control circuits were changed to an undesirable state without a command from the computer, apparently during computer and inverter maintenance. A design deficiency also contributed because the computer program did not include a function to reset the computer-output control circuits to a predetermined state when the computer was restarted.

Corrective Action

Corrective action was not stated in the LER.

Plant/Event Data

Systems Involved:
Electrical and computer

Components and Failure Modes Involved:
LOOP during operation

Component Unavailability Duration: NA
Plant Operating Mode: Unit 1, mode 1 (100% power); Unit 2, mode 2 (0% power)
Discovery Method: Maintenance
Reactor Age: Unit 1, 3 years; Unit 2, 2.2 years
Plant Type: PWR

Comments

Reference LER 370/84-020

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP Base case

Branches Impacted and Branch Nonrecovery Estimate

None

Plant Models Utilized

PWR plant Class F

Event Identifier: 369/84-024

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 369/84-024
Event Description: LOOP at McGuire 1 Affects Unit 2
Event Date: 8/21/84
Plant: McGuire 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.4E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	2.8E-06
Total	2.8E-06
CD	
LOOP	1.7E-05
Total	1.7E-05
ATWS	
LOOP	0.0E+00
Total	0.0E+00

DOMINANT SEQUENCES

End State: CV Conditional Probability: 2.4E-06

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

End State: CD Conditional Probability: 8.4E-06

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

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 369/84-024

	Sequence	End State	Prob	N Rec**
203	LOOP -RT/LOOP -EMERG.POWER -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS -LPR/-HPI.HPR	CV	2.7E-07	9.5E-03
204	LOOP -RT/LOOP -EMERG.POWER -AFW PORV.OR.SRV.CHALL PORV.OR.SRV.RESEAT -HPI HPR/-HPI -SS.DEPRESS LPR/-HPI.HPR	CD	5.5E-07	9.5E-03
212	LOOP -RT/LOOP -EMERG.POWER AFW -HPI(F/B) -HPR/-HPI PORV.OPEN	CD	8.6E-07	9.2E-02
213	LOOP -RT/LOOP -EMERG.POWER AFW -HPI(F/B) HPR/-HPI	CD	3.7E-06	5.1E-02
214	LOOP -RT/LOOP -EMERG.POWER AFW HPI(F/B)	CD	3.8E-06	4.8E-02
215	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER PORV.OR.SRV.CHALL -PORV.OR.SRV.RESEAT/EMERG.POWER SS.RELEAS.TERM	CV	9.9E-08	5.8E-02
217	LOOP -RT/LOOP EMERG.POWER -AFW/EMERG.POWER -PORV.OR.SRV.CHALL SS.RELEAS.TERM	CV	2.4E-06 *	5.8E-02
218	LOOP -RT/LOOP EMERG.POWER AFW/EMERG.POWER	CD	8.4E-06 *	5.9E-02

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

MODEL: b:\pwrbtree.cmp
DATA: b:\mcgurpro.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	4.2E-06	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	1.0E-03	2.7E-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	5.0E-02	
SS.RELEAS.TERM	1.5E-02	3.4E-01	
SS.RELEAS.TERM/-MFW	1.5E-02	3.4E-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	
SS.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
LPI/HPI	1.0E-03	3.4E-01	
LPR/-HPI.HPR	6.7E-01	1.0E+00	

Event Identifier: 369/84-024

LPR/HPI	1.0E-03	1.0E+00

*** forced

Minarick
04-12-1987
10:53:42

Event Identifier: 369/84-024

PRECURSOR DESCRIPTION SHEET

LER No.: 373/84-054, -056, -060, -062
Event Description: Scram, RCIC Failures, and RHR Unavailability Within ±15 d
Date of Event: September 21, 29, and 30, 1984
Plant: LaSalle 1

EVENT DESCRIPTION

Sequence

While the reactor was at 23% power on September 21, 1984, operator error caused a reactor scram and MSIV closure. This caused a Group I isolation during the performance of an MSIV isolation calibration and functional test. Later, on the same day, RCIC was found failed during a test; again on September 29, RCIC isolated on high steam flow when an attempt was made to open the RCIC outboard isolation valve. On September 30, with the unit in hot shutdown, the RHR inboard suction isolation valve failed to open on demand, rendering RHR unavailable for almost 9 h. Due to the nature of the events, RCIC and RHR may have been unavailable simultaneously with the scram.

Corrective Action

Following the September 21 trip, a warning sign was posted to prevent bumping of the instrument rack that caused the trip. The first RCIC failure was corrected by flushing the RCIC oil system and replacing clogged oil filters. The second RCIC failure only required resetting of the outboard isolation valve. The RHR suction valve inoperability was investigated, and a training procedure for declutching motor operators was issued.

Plant/Event Data

Systems Involved:
RCIC, RHR

Components and Failure Modes Involved:
RCIC pump — isolated during test
RCIC pump — tripped during test
RHR suction valve — failed on demand

Event Identifier: 373/84-054

Component Unavailability Duration: NA
Plant Operating Mode: 24%, 1%, 23%, and 0%
Discovery Method: See sequence description
Reactor Age: 2.2 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

RCIC	1.0	Nonrecoverable in required time; pump-governor oil system required flushing
RHR (SDC)	0.34	Recovered within 9 h, SDC is not required in the short term
PCS	1.0	Unavailable due to MSIV closure
MFW	1.0	Unavailable due to MSIV closure; considered nonrecoverable

Plant Models Utilized

BWR plant Class C

Event Identifier: 373/84-054

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 373/84-054
Event Description: Scram with RCIC Failure and RHR Unavailability (+/-15 days)
Event Date: 9/21/84
Plant: LaSalle 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	2.4E-06
Total	2.4E-06
CD	
TRANS	2.3E-03
Total	2.3E-03
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.0E-06

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: 2.2E-03

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)

End State: ATWS Conditional Probability: 2.0E-05

173 TRANS SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
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	2.2E-03 *	1.2E-01
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	9.2E-05	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	1.0E-06 *	1.5E-01
135	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS RHR(SDC) - RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	5.2E-07	7.6E-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	5.3E-07	7.6E-02
139	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) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	2.7E-07	3.9E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\lasiprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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: 1.0F.1			
Train 1 Cond Prob:	1.7E-01 > Failed		
PCS/LOCA	1.0E+00	1.0E+00	
SRV.CHALL/TRANS.-SCRAM	1.0E+00	1.0E+00	

Event Identifier: 373/84-054

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	6.0E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Failed		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	2.0E-02	3.4E-01	
RCIC/TRANS.OR.LOOP	6.7E-02 > 1.0E+00	5.7E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.7E-02 > Failed		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	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	3.4E-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 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	1.1E-02 > Failed		
Train 2 Cond Prob:	1.0E-01 > Failed		
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	

*** forced

Minarick
04-12-1987
11:14:55

Event Identifier: 373/84-054

PRECURSOR DESCRIPTION SHEET

LER No.: 374/84-017, -018
Event Description: LOFW While Shutting Down and HPCS Fails in Test Within ±15 d of LOFW
Date of Event: May 3 and 17, 1984
Plant: LaSalle 2

EVENT DESCRIPTION

Sequence

On May 3, 1984, while the reactor was at 10% power and shutting down, it was scrammed manually following failure to restart the motor-driven FW pump. The pump had tripped due to a clogged strainer following a valving error. The turbine-driven FW pumps had been valved out due to the shutdown in progress. On May 17, with the reactor at 30% power, the HPCS system failed in testing when the HPCS pump breaker failed to close and start the pump. Faulty position switch contacts were found, and certain breaker/switch components had not been installed. Due to the nature of these events, HPCS may have been unavailable during the May 3 LOFW.

Corrective Action

The motor-driven FW pump was repaired and steps were taken to prevent a similar valving error from recurring. The breaker position switch that caused the HPCS breaker failure was replaced. In addition, all of the Division III 4160-V switchgear were inspected and cleaned before being returned to service.

Plant/Event Data

Systems Involved:
MFW, HPCS

Components and Failure Modes Involved:
Motor-driven FW pump — tripped due to operator error
HPCS pump — failed to start on demand (breaker failure)

Component Unavailability Duration: NA
Plant Operating Mode: 10%, 30% power
Discovery Method: See sequence description
Reactor Age: 0.2 year
Plant Type: BWR

Event Identifier: 374/84-017, -018

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

PCS	1.0	Failed due to LOFW
Main feed-water	0.34	Motor-driven train was not recoverable; possible recovery through use of turbine-driven feed pump
HPCS	0.34	Potential recovery at breaker

Plant Models Utilized

BWR plant Class C

Event Identifier: 374/84-017, -018

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 374/84-017
Event Description: LOFW While Shutting Down and HPCS Fails in Test (+/-15 days)
Event Date: 5/3/84
Plant: LaSalle 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	4.1E-06
Total	4.1E-06
CD	
TRANS	3.8E-04
Total	3.8E-04
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.7E-06

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: 3.2E-04

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

End State: ATWS Conditional Probability: 2.0E-05

Event Identifier: 374/84-017

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	3.0E-05	7.6E-02
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	1.0E-05	2.6E-02
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	3.2E-04 *	1.2E-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	1.0E-06	4.3E-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	5.2E-07	2.2E-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	1.7E-06 *	7.6E-02
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	8.6E-07	3.9E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\laslprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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 > Failed		
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	

Event Identifier: 374/84-017

SRV.CHALL/LOOP.-SCRAM	1.0E+00	1.0E+00	
SRV.CHALL/LOOP.SCRAM	1.0E+00	1.0E+00	
SRV.CLOSE	6.0E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Failed		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	2.0E-02 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	2.0E-02 > Failed		
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	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	3.4E-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	

*** forced

Minarick
04-12-1987
12:02:46

Event Identifier: 374/84-017

PRECURSOR DESCRIPTION SHEET

LER No.: 387/84-010
Event Description: SRV Failure to Close Following Scram
Date of Event: February 25, 1984
Plant: Susquehanna 1

EVENT DESCRIPTION

Sequence

On February 25, 1984, at 1848 h, Unit 1 was in mode 1 at 54% power when it was manually scrammed during preplanned testing of the ADS Susquehanna 1 utilizes 16 SRVs; 6 of these valves also function as ADS valves. A preplanned test requirement was in progress to verify operability of the ADS valves wherein each ADS valve was to be manually and sequentially cycled. During the test sequence, the "M" SRV failed to close; in accordance with the test procedure, a manual scram was initiated because attempts to close the SRV were unsuccessful.

Each of the ADS SRVs has three independent solenoid-operated control valves. During testing of the "B" solenoid on the "M" SRV, the solenoid valve stuck open, and the instrument gas pressure kept the SRV open. After 2 min of attempting to close the SRV by a procedure especially written for this activity, the reactor was manually scrammed. At 1 min and 20 s after scram, the inboard MSIVs were closed to reduce vessel depressurization. Vessel pressure dropped from 946 to 682 psig during the transient. Several minutes later, the "M" SRV closed due to internal spring energy when the instrument gas header isolated for the test dropped to 60 psig.

Corrective Action

The "B" solenoid and air valve on the "M" SRV were replaced, and the new solenoid was tested successfully. Investigation has found this to be a nonrecurring event. The vendor will inspect the valves to determine the cause of the failure. The test was continued, and the other SRVs and solenoid valves operated properly.

Plant/Event Data

Systems Involved:
Steam relief

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

Component Unavailability Duration: NA
Plant Operating Mode: 1 (54% power)
Discovery Method: Testing
Reactor Age: 1.4 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

SRV	0.1	Assumed recoverable because of isolated gas header
PCS	1.0	Unavailable because of MSIV closure
MFW	1.0	Unavailable because of MSIV closure

Plant Models Utilized

BWR plant Class C

Event Identifier: 387/84-010

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 387/84-010
Event Description: SRV Failure to Close Following Scram
Event Date: 2/25/84
Plant: Susquehanna 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.4E-06
Total	1.4E-06
CD	
TRANS	1.4E-04
Total	1.4E-04
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.8E-07

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: 9.0E-05

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

End State: ATWS Conditional Probability: 2.0E-05

Event Identifier: 387/84-010

173 TRANS SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
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	4.0E-05	1.0E-01
110	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	4.5E-06	2.9E-01
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	3.1E-06	7.6E-03
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	9.0E-05 *	1.9E-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	4.8E-07 *	1.9E-01
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	2.5E-07	9.9E-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	4.7E-07	1.3E-02
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	2.4E-07	6.6E-03
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\susqprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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: 387/84-010

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	5.3E-02 > 1.0E+00	1.0E+00 > 1.0E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.3E-02 > Failed		
EMERG.POWER	5.4E-04	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Unavailable		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-12-1987
12:14:04

Event Identifier: 387/84-010

PRECURSOR DESCRIPTION SHEET

LER No.:	387/84-040
Event Description:	Diesel Generators Slow Start and Residual Heat Removal Suppression Pool Unavailable
Date of Event:	September 10, 1984
Plant:	Susquehanna 1

EVENT DESCRIPTION

Sequence

On September 10, 1984, the "D" DG tripped on high turbocharger vibration. The radial bearing was found failed; a replacement turbocharger was installed. Technical Specification 3.8.1.1 require the remaining diesels to be started within 4 h and at least once per 8 h thereafter while one DG is unavailable.

On September 11, 1984, at 0750 h, the RHR suppression-pool cooling full-flow test valve 1F024A was declared inoperable when its circuit breaker tripped. The key that holds the motor pinion to the motor shaft fell out. The missing key was found in the actuator grease box and reinstalled, and the motor shaft was peened. The test valve 1F024A was out of service for 6 h and 15 min.

On September 11, 1984, at 0215 h, the "B" DG failed to start and could not be started unitl 23 min later.

On September 11, 1984, at 1721, the "B" DG failed to start. Another start attempt 34 min later resulted in a slow start of 11.2 s vs a start time of <10 s as required. At 1812 h on September 11, 1984, a successful start was achieved.

On September 12, 1984, at 0850 h, the "B" DG was declared inoperable for troubleshooting. At 0930 h, it was declared operable.

On September 12, 1984, at 1040 h, the "B" DG was removed from service for further testing and investigation of intermittent starting problems. Thus, two DGs were inoperable. This requires that three DGs be operable within 2 h or that the unit be in a hot shutdown condition within the next 12 h. At 2045 h on September 12, 1984, the "D" DG was declared operable. This restored three of four station DGs (2%), to an operable status.

Event Identifier: 387/84-040

On September 12, 1984, at 1620 h, the "B" DG was started for troubleshooting. The start time was in excess of the required 10 s. At 0427 h on September 13, 1984, the "B" DG was started successfully for a postmaintenance run. The "B" DG was declared operable at 0730 h on September 13, 1984.

On September 13, 1984, at 2148 h, the "B" DG was started, but it required 11.9 s to attain rated speed. The fuel-oil booster pump and check valves were replaced. An investigation found loose suction flanges from the day tank to the booster pump. These loose suction flanges allowed air to enter the fuel oil system, which caused a slow start.

On September 24, 1984, at 0620 h, while the "D" DG was out of service to correct the deficiencies noted above on the "B" DG, the "B" DG was declared out of service due to a trip during a starting attempt. The "D" diesel was placed into service at 1545 h. A troubleshooting start on the "B" DG was attempted at 1945 h, and the DG tripped after 12.5 s. The fuel racks on the "B" DG did not open for 6 to 7 s. This was caused by the safety-trip fuel-oil control cylinder's (USC-7) not venting. The venting problem was traced back to the sluggish response of the safety-trip control valve (USV-9).

Corrective Action

The correction of the fuel oil pressure response problem and the fuel rack response time problem has restored the reliability of the "B" DG.

Plant/Event Data

Systems Involved:

EDG system, CS, and RHR system.

Components and Failure Modes Involved:

"D" EDG — failed to start in test (failed bearing)
"B" EDG — failed to start in test

Component Unavailability Duration: 6.25 h for EDG "B" and EDG "D"; RHR suppression pool full-flow test valve failure had no impact on Cd models.
Plant Operating Mode: 1 (100% power)
Discovery Method: Surveillance test
Reactor Age: 2.0 years
Plant Type: BWR

Event Identifier: 387/84-040

Comments

The RHR test valve failure does not affect suppression pool cooling.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Postulated LOOP	0.34	Base case nonrecovery

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	Base case nonrecovery	Degraded, two DGs failed
CS	Base case nonrecovery	Degraded, one train unavailable
LPCI	Base case nonrecovery	Degraded, one train unavailable
RHR (SDC)	Base case nonrecovery	Degraded, one train unavailable
RHR (SDC)/-LPCI	Base case nonrecovery	Degraded, one train unavailable
CRD	1.0	Unavailable

Plant Models Utilized

BWR plant Class C

Event Identifier: 387/84-040

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 387/84-040
Event Description: DG Slow Start and RHR Suppression Pool Valve Unavailable
Event Date: 9/10/84
Plant: Susquehanna 1

UNAVAILABILITY, DURATION= 6.25

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	2.8E-05

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	(2.2E-12)
Total	(2.2E-12)
CD	
LOOP	1.6E-08
Total	1.6E-08
ATWS	
LOOP	1.0E-09
Total	1.0E-09

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.8E-13

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

End State: CD Conditional Probability: 8.1E-09

246 LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP,-SCRAM SRV.CLOSE HPCI RCIC/LOCA

End State: ATWS Conditional Probability: 1.1E-09

Event Identifier: 387/84-040

250 LOOP EMERG.POWER SCRAM

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
208	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP CRD SRV.ADS	CD	2.3E-09	1.0E-01
227	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS RHR(SDC) -RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	7.6E-15	3.5E-02
230	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS LPCS -LPCI(RHR)/LPCS -RHR(SDC)/-LPCI	CV	1.8E-13 *	3.5E-02
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP	CD	5.5E-09	5.6E-02
246	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOCA	CD	8.1E-09 *	9.9E-02
250	LOOP EMERG.POWER SCRAM	ATWS	1.1E-09 *	1.7E-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.

MODEL: b:\bwrctree.cmp
DATA: b:\susqprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	5.3E-02	1.0E+00	
EMERG.POWER	5.4E-04 > 1.9E-01	5.1E-01	
Branch Model: 1.OF.3			

Event Identifier: 387/84-040

Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Failed		
Train 3 Cond Prob:	1.9E-01		
FW/PCS.TRANS	4.6E-01	3.4E-01	
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-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	6.7E-03	1.0E+00	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	4.0E-04 > 4.0E-03	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.0E-03		
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)	2.0E-02 > 2.4E-02	3.4E-01	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	4.0E-03		
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	

*** forced

Minarick
04-12-1987
12:20:58

Event Identifier: 387/84-040

PRECURSOR DESCRIPTION SHEET

LER No.: 388/84-006, -008
Event Description: Trip and LOFW with "B" LPCI Train Unavailable
Date of Event: May 27, 1984
Plant: Susquehanna 2

EVENT DESCRIPTION

Sequence

At 0530 h, on May 27, 1984, shutdown of the reactor commenced from low-power testing due to the inoperability of the "B" Loop of the LPCI system, which had occurred 7 d earlier. The shutdown was being accomplished by inserting control rods individually into the reactor's core by utilizing the rod pull sheet until all of the control rods were at the full-in position. Shutdown proceeded normally until at 0605 h, when it was observed that TBV 1 would not close below the 18% open position. Shutdown of the Unit 2 reactor was halted, and control rods in Group 5 were pulled sequentially to maintain reactor pressure with the TBV 1 controlling at a position slightly greater than 18%.

Instrumentation and Control and Mechanical Maintenance personnel were sent to investigate the valve's failure to close. These investigations determined that TBV 1 could not be closed below 18%. It was then determined that the best means available for shutting down the reactor would be with an reactor protection system manual scram. At 1346 h, the Unit 2 reactor was manually scrammed, and at RV pressure of 700 psig all inboard MSIVs were closed, thus isolating the TBV.

Subsequent investigations of the EHC pressure control and TBV control logic indicated that all control functions were operating normally. Investigation of TBV 1 revealed that a chipping hammer was wedged between the valve seat and the valve disk, preventing TBV 1 from fully closing.

Although a sizeable portion of the handle and the head of the hammer itself remained intact, a spring portion, small in comparison to the overall dimensions of the hammer, is believed to have been severed from the handle. This severed portion would most likely be deposited in the TBS's sparger into the main condenser, posing no threat to components in other parts of the system.

Corrective Action

Disassembly of TBV 1 showed small dents on the disk and the seat of the valve. The valve's seat was machined to remove the dents, the disk was replaced due to the difficulties in removing the old disk, and the valve was returned to service.

Event Identifier: 388/84-006, -008

A review of unit work documents indicates TBV system was one of the last systems worked on prior to startup for preoperational testing. Based on this review and the fact that system flushes are performed as part of the Preoperational Test Program, it is concluded that the occurrence of this loose tool in the unit's piping is an isolated event.

Plant/Event Data

Systems Involved:
LPCI, TBV

Components and Failure Modes Involved:
LPCI injection valve — failed during operation
TBV — stuck open in operation

Component Unavailability Duration: NA
Plant Operating Mode: 2 (2% power)
Discovery Method: Operational event
Reactor Age: 0.1 year
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

PCS	1.0	Unavailable because of MSIV closure
MFW	1.0	Unavailable because of MSIV closure
LPCI	Base case	Degraded; one train failed
RHR (SDC)	Base case	Degraded; one train failed

Plant Models Utilized

BWR plant Class C

Event Identifier: 388/84-006, -008

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 388/84-006
Event Description: Trip and LOFW With "B" LPCI Train Unavailable
Event Date: 5/27/84
Plant: Susquehanna 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	1.1E-06
Total	1.1E-06
CD	
TRANS	3.3E-04
Total	3.3E-04
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 4.9E-07

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: 2.4E-04

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)

Event Identifier: 388/84-006

End State: ATWS Conditional Probability: 2.0E-05

173 TRANS SCRAM SLC.OR.RODS

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
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	2.4E-04 *	1.1E-01
103	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM -SRV.CLOSE FW /PCS.TRANS HPCI -RCIC/TRANS.OR.LOOP RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I.AND.V/RHR(SDC).RHR(SPCOOL)	CD	1.4E-05	6.5E-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	9.5E-06	7.6E-02
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	4.8E-05	1.9E-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	4.9E-07 *	2.1E-01
135	TRANS SCRAM -SLC.OR.RODS PCS/TRANS -SRV.CLOSE FW/PCS.TRANS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -COND/FW.PCS RHR(SDC) - RHR(SPCOOL)/-LPCI.RHR(SDC)	CV	2.0E-08	7.3E-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	2.5E-07	1.1E-01
155	TRANS SCRAM -SLC.OR.RODS PCS/TRANS SRV.CLOSE FW/PCS.LOCA HPCI RCIC/LOCA -SRV.ADS -COND/FW.PCS -RHR(SDC)	CV	2.4E-07	1.2E-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-07	6.4E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\susqprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-04	1.0E+00	

Event Identifier: 388/84-006

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	
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	5.3E-02	1.0E+00	
EMERG.POWER	5.4E-04	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Unavailable		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04 > 1.0E-01	3.4E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	4.0E-03 > Failed		
Train 2 Cond Prob:	1.0E-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)	2.0E-02 > 1.2E-01	3.4E-01	
Branch Model: 1.OF.2+ser			
Train 1 Cond Prob:	4.0E-03 > Failed		
Train 2 Cond Prob:	1.0E-01		
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	

*** forced

Minarick
04-12-1987
12:26:50

Event Identifier: 388/84-006

PRECURSOR DESCRIPTION SHEET

LER No.: 388/84-013
Event Description: LOOP Test with Failure of EPS to Start
Date of Event: July 26, 1984
Plant: Susquehanna 2

EVENT DESCRIPTION

Sequence

On July 26, 1984, Operations personnel were performing plant alignment in accordance with loss of TG and LOOP startup test. Included in the lineup was racking out the four feeder breakers that supply power to the Unit 2 4.16-kV buses from the Unit 1 T10 ESS transformer.

The normal operating practice for racking out a 4-kV breaker is to ensure that the breaker is open, open the dc knife switch to the dc control power for the breaker, and then to rack out the breaker. The T10 ESS transformer feeder breakers 2A20101, 2A20201, and 2A20401 are all in the 01 cubicles of the 4-kV ESS buses. The 01 cubicle has two dc knife switches, whereas all other breakers in the switchgear bus have only one dc knife switch that provides dc control power to the breaker. The additional dc knife switch in the 01 cubicle provides dc power to the logic circuitry for the bus and DG autostart. Prior to physically racking out the breaker, the operator opened the dc knife switch to the bus logic rather than the dc knife switch to the 01 breaker control circuit. The two dc knife switches in the Unit 2 4-kV ESS bus 01 cubicle were labeled as follows:

BREAKER AND CONTROL SWITCH AND TRIP CIRCUIT FUSES

D.C. CONTROL

The dc knife switch on the left supplies dc power to the 01 breaker. The dc knife switch on the right (the one operator opened) supplies dc control power to the bus logic. When the operator opened the first 01 cubicle door, he called the control room personnel, informed them that he was at the breaker, and requested confirmation that the breaker be racked out and the dc opened. The operator subsequently opened the dc control knife switch and racked out the breaker. This action was repeated at each 4-kV 01 breaker.

At 0137 h on July 26, 1984, with Unit 2 operating at 30% power, a loss of TG and LOOP startup test was initiated from the control room by opening the Unit 2 main generator 500-kV output breakers 2T and 4T and the startup transformer T20 to bus 20 breaker 0A10401. This resulted in a reactor scram due to turbine control valve fast closure; the deenergization of the 13.8-kV buses 20, 12A, and 12B; and the deenergization of 4.16-kV buses 2A, 2B, 2C, and 2D. These were expected actions and were indicated in Technical Specification 31.1.

Following the initiation of the test, the operator located at electrical panel 0C653 noted that the four EDGs did not start. When the 4.16-kV buses were deenergized, he noted that the feeder breakers from the bus 20 ESS transformers 201 and 211 to the 4.16-kV ESS buses were closed. Because the 4.16-kV bus was deenergized, these four feeder breakers should have opened.

The failure of the DGs to start initially was due to the T20 ESS transformer feeder breakers being closed in on the dead ESS bus. The T20 ESS transformer feeder breakers did not open because the open dc knife switch to the bus control logic prevented the bus undervoltage relay from energizing and giving a trip signal to the feeder breakers. When the operator manually opened the T20 ESS transformer feeder breakers, the DGs again did not start because the open dc knife switch removed power to the bus 62A timers, which must energize for the DGs to start.

The operator knew that the feeder breakers had to be open for the DGs to automatically start. He manually opened the feeder breakers, and the DGs still did not start. He then manually started the four DGs. The "D" DG tripped on overvoltage; the "B" DG tripped on overvoltage and underfrequency. The "A" and "C" DGs idled but did not close into their associated 4.16-kV Bus. The "A" DG exhibited frequency oscillations and was manually tripped by the operator. The operator then tried to manually close the "C" DG onto the 4.16-kV, bus but the breaker would not close. The operator then reenergized bus 20 by closing 0A10401 and reenergized ESS transformers 201 and 211 by closing 0A10406 and 0A10412. He then attempted to close the feeder breakers from the ESS transformer to the 4.16-kV buses. The feeder breakers would not close. The 4.16-kV buses were still deenergized. The unit supervisor then instructed the reactor building plant operator to rack in the feeder breakers and close the dc knife switch. As the feeder breakers from the T10 ESS transformer were racked in and the dc knife switches closed, the preferred feeder breaker to the ESS bus closed, reenergizing the bus. Power was restored to the first bus 11 min into the transient and to the last bus 17 min into the transient. When power was restored to all four ESS buses, the operator noted that "A," "B," and "D" DGs had high-priority alarms, so he manually shut them down. The operator in the DG building reset the high-priority alarm on the "A" DG but could not reset the high-priority alarm on the "B" and "D" DGs.

Event Identifier 388/84-013

When the DGs failed to start and initial attempts at reenergizing the 4-kV ESS buses did not succeed, the shift supervisor entered the emergency plan and declared an unusual event at 0150 h. Once power was fully restored, the unusual event was terminated at 0230 h.

Corrective Action

The labeling of the dc knife switches on the Units 1 and 2 4-kV ESS buses was found to be misleading. The labels were changed to be more clearly descriptive. The label on the dc control power for the 2A20101 breaker now reads in black letters on a white background:

BKR 2A20101
CONTROL AND TRIP
D.C. POWER

The label for the dc control power to the bus logic circuits reads in white letters on a red background:

BUS/DIESEL GEN A
AUX RELAY CONTROL
D.C. POWER

In addition, the handle for the dc knife switch for the bus logic circuits has been painted red, and a caution label has been added that reads in white letters on a red background:

CAUTION
OPENING THIS SWITCH
DISABLES O/G AND BUS
TRANSFER

With the "C" DG running and the 2C bus deenergized, the "C" DG breaker did not close in on the dead bus, nor could the operator manually close the breaker from the control room panel. That the breaker did not close automatically is explained by the open dc knife switch that removed power to the bus undervoltage relay, which must energize for the DG breaker to autoclose. For the operator to close the breaker manually, he must turn the keylocked synchronization switch to the "On" position and place the DG breaker control switch to the "Close" position. Additional permissives in the closing circuit are auxiliary relay V1, which deenergizes on loss of bus power (and should have been deenergized), and auxiliary relay V2, which energizes when DG voltage is present (and should have been energized). A retest has been performed to demonstrate that the DG breaker can be closed manually on to a dead bus from the control room.

Event Identifier: 388/84-013

Plant/Event Data

Systems Involved:
Emergency power and electrical

Components and Failure Modes Involved:
All DGs — failed to start on demand

Component Unavailability Duration: NA
Plant Operating Mode: 1 (30% power)
Discovery Method: During testing
Reactor Age: 0.2 year
Plant Type: BWR

Comments

A station blackout actually occurred for an hour. Reference: Abnormal Occurrence Reports to Congress, NUREG-0090, 1(3), 14.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	0.12	Assumed recoverable, although not procedurally based

Branches Impacted and Branch Nonrecovery Estimate

EPS	0.34	Assumed potentially recoverable in 20- to 30-min time period

Plant Models Utilized

BWR plant Class C

Event Identifier: 388/84-013

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 388/84-013
Event Description: LOOP Test With Failure of EPS to Start
Event Date: 7/26/84
Plant: Susquehanna 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.2E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
LOOP	6.4E-08
Total	6.4E-08
CD	
LOOP	2.2E-04
Total	2.2E-04
ATWS	
LOOP	1.8E-05
Total	1.8E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 6.4E-08

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

End State: CD Conditional Probability: 1.2E-04

246 LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOCA

End State: ATWS Conditional Probability: 1.7E-05

Event Identifier: 388/84-013

250 LOOP EMERG.POWER SCRAM

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
215	LOOP -EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOCA SRV.ADS	CD	1.1E-05	4.5E-02
226	LOOP -EMERG.POWER SCRAM -SLC.OR.RODS HPCI RCIC/TRANS.OR.LOOP -SRV.ADS -LPCS -RHR(SDC)	CV	6.4E-08 *	2.6E-02
240	LOOP -EMERG.POWER SCRAM SLC.OR.RODS	ATWS	1.6E-06	7.9E-02
243	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM -SRV.CLOSE HPCI RCIC/TRANS.OR.LOOP	CD	8.4E-05	1.3E-02
246	LOOP EMERG.POWER -SCRAM SRV.CHALL/LOOP.-SCRAM SRV.CLOSE HPCI RCIC/LOCA	CD	1.2E-04 *	2.3E-02
250	LOOP EMERG.POWER SCRAM	ATWS	1.7E-05 *	4.1E-02

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

MODEL: b:\bwrctree.cmp
DATA: b:\susqprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Cur Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05 > 1.3E-05	3.4E-01 > 1.2E-01	
Branch Model: INITOR			
Initiator Freq:	1.3E-05		
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	5.3E-02	1.0E+00	
EMERG.POWER	5.4E-04 > 1.0E+00	5.1E-01 > 3.4E-01	
Branch Model: 1.OF.3			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02 > Failed		
Train 3 Cond Prob:	1.9E-01 > Failed		
FW/PCS.TRANS	4.6E-01	3.4E-01	

Event Identifier: 388/84-013

FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	1.0E-01	5.7E-01	
RCIC/TRANS.OR.LOOP	6.7E-02	5.7E-01	
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	4.0E-02
COND/FW.PCS	1.0E+00	3.4E-01	
LPCS	3.0E-03	3.4E-01	
LPCI(RHR)/LPCS	4.0E-04	3.4E-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)	2.0E-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	

*** forced

Minarick
04-12-1987
12:30:25

Event Identifier: 388/84-013

PRECURSOR DESCRIPTION SHEET

LER No.:	389/84-004
Event Description:	LOFW, Failure of One AFW Train, and One MSRV Sticks Open
Date of Event:	February 9, 1984
Plant:	St. Lucie 2

EVENT DESCRIPTION

Sequence

While the reactor was at 100% power, the MFWPs tripped due to low suction pressure. The reactor subsequently tripped on low SG level. Following the trip, the 2C AFW pump started and then tripped on overspeed. A main steam SRV on the "A" SG also stuck partially open following the trip. Approximately 40 min was required to reseat the safety valve. Cooldown from the open safety valve was successfully controlled.

Corrective Action

The cause of the low suction pressure to the MFWPs was not positively determined. Condensate pump vent-line design probably contributed. The design is being changed to allow proper venting during strainer cleaning.

The 2C AFW pump tripped because of transients on a power supply during AFW actuation. The cause was not immediately known. However, repeated testing over a period of 6 d revealed the problem. A modification has been completed to eliminate this problem.

The SRV stuck open because a cotter pin was missing from a spindle nut. When the safety valve opened (as expected), the nut vibrated down and held the valve partially open. The nut pin was replaced, and all safeties were checked.

Plant/Event Data

Systems Involved:
AFW and SG steam relief

Components and Failure Modes Involved:
AFW pump — failed on demand
MSRV — failed open in operation
MFW — tripped during operation

Event Identifier: 389/84-004

Component Unavailability Duration: NA
Plant Operating Mode: 1 (100% power)
Discovery Method: Operational event
Reactor Age: 0.7 year
Plant Type: PWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

MFW	0.34	Recovery assumed locally at equipment
AFW	Base case	Degraded; one train failed
Secondary-side release terminated	1.0	No recovery assumed
Secondary-side release terminated given MFW success	1.0	No recovery assumed

Plant Models Utilized

PWR plant Class G

Event Identifier: 389/84-004

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 389/84-004
Event Description: LOFW With Failure of One AFW Train and Stuck-Open MSRV
Event Date: 2/9/84
Plant: St Lucie 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	5.0E-04
Total	5.0E-04
CD	
TRANS	2.0E-04
Total	2.0E-04
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 3.3E-04

112 TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS -COND/MFW

End State: CD Conditional Probability: 1.7E-04

113 TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW

End State: ATWS Conditional Probability: 3.0E-05

Event Identifier: 389/84-004

121 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

	Sequence	End State	Prob	N Rec**
104	TRANS -RT -AFW -PORV.OR.SRV.CHALL SS.RELEAS.TERM HPI	CV	1.5E-04	5.2E-01
112	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS -COND/MFW	CV	3.3E-04 *	6.1E-02
113	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	1.7E-04 *	3.1E-02
114	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN SS.DEPRESS	CD	1.9E-05	9.2E-02
118	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	1.4E-05	3.2E-02
119	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	7.1E-06	1.6E-02
121	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\pwrgtree.cmp
DATA: b:\luciepro.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	2.6E-02	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	1.0E-03 > 5.9E-03	2.7E-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		
Serial Component Prob:	9.2E-04		
AFW/EMERG.POWER	5.0E-02	3.4E-01	
MFW	1.9E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.9E-01 > Failed		
PORV.OR.SRV.CHALL	2.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	1.2E-01	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	1.2E-01	
SS.RELEAS.TERM	1.5E-02 > 1.0E+00	3.4E-01 > 1.0E+00	
Branch Model: 1.OF.1			

Event Identifier: 389/84-004

Train 1 Cond Prob:	1.5E-02 > Failed		
SS.RELEAS.TERM/-MFW	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.DEPRESS	3.6E-02	1.0E+00	
COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04	5.2E-0'	
HPI(F/B)	3.0E-04	5.2E-01	4.0E-02
PORV.OPEN	1.0E+00	1.0E+00	
HPR/-HPI	1.0E-03	1.0E+00	
CSR	2.0E-03	3.4E-01	

*** forced

Minarick
04-12-1987
12:36:57

Event Identifier: 389/84-004

PRECURSOR DESCRIPTION SHEET

LER No.: 389/84-011
Event Description: Trip and One AFW Train Fails
Date of Event: November 21, 1984
Plant: St. Lucie 2

EVENT DESCRIPTION

Sequence

At 0927 h on November 21, 1984, the reactor was automatically tripped from 68% power due to loss of load. The loss of load was due to a generator exciter field failure. All automatic functions performed as designed with the exception of the "C" auxiliary feed pump that received its start signal, attempted to start, and tripped on overspeed as a result of steam leakage, causing the pump to spin. The "B" auxiliary feed pump functioned properly and provided the needed feed flow to the SGs. The cause of the overspeed trip was the pump spinning as a result of steam leakage. The leakage was corrected, and the pump spinning stopped.

The cause of the loss of field excitation was determined to be failure of the exciter bearing, which allowed the rotor to drop slightly and rub the permanent magnet generator.

Corrective Action

The bearing and the permanent magnet generator were replaced. Alignment and other checks were performed. No cause for the failure of the bearing was able to be determined. The AFW leakage was repaired.

Plant/Event Data

Systems Involved:
AFW

Components and Failure Modes Involved:
One AFW pump — failed on demand

Component Unavailability Duration: NA
Plant Operating Mode: 1 (68% power)
Discovery Method: Operational event
Reactor Age: 1.4 years
Plant Type: PWR

Comments

None

Event Identifier: 389/84-011

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

MFW	0.34	Assumed failed
AFW	0.27	Degraded; one train failed

Plant Models Utilized

PWR plant Class G

Event Identifier: 389/84-011

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 389/84-011
Event Description: Trip and One AFW Train Fails
Event Date: 11/21/84
Plant: St Lucie 2

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	3.5E-04
Total	3.5E-04
CD	
TRANS	2.0E-04
Total	2.0E-04
ATWS	
TRANS	3.0E-05
Total	3.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 3.3E-04

112 TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS -COND/MFW

End State: CD Conditional Probability: 1.7E-04

113 TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW

End State: ATWS Conditional Probability: 3.0E-05

Event Identifier: 389/84-011

121 TRANS RT

SEQUENCE CONDITIONAL PROBABILITIES

Sequence		End State	Prob	N Rec**
112	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS -COND/MFW	CV	3.3E-04 *	6.1E-02
113	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN -SS.DEPRESS COND/MFW	CD	1.7E-04 *	3.1E-02
114	TRANS -RT AFW MFW -HPI(F/B) -HPR/-HPI PORV.OPEN SS.DEPRESS	CD	1.9E-05	9.2E-02
118	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS -COND/MFW	CV	1.4E-05	3.2E-02
119	TRANS -RT AFW MFW HPI(F/B) -SS.DEPRESS COND/MFW	CD	7.1E-06	1.6E-02
121	TRANS RT	ATWS	3.0E-05 *	1.2E-01

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

MODEL: b:\pwrgtree.cmp
DATA: b:\luciepro.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.0E-03	1.0E+00	
LOOP	2.3E-05	3.4E-01	
LOCA	2.6E-02	3.4E-01	
RT	2.5E-04	1.2E-01	
RT/LOOP	0.0E+00	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
AFW	1.0E-03 > 5.9E-03	2.7E-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		
Serial Component Prob:	9.2E-04		
AFW/EMERG.POWER	5.0E-02	3.4E-01	
MFW	1.9E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.9E-01 > Failed		
PORV.OR.SRV.CHALL	2.0E-02	1.0E+00	
PORV.OR.SRV.RESEAT	1.0E-02	1.2E-01	
PORV.OR.SRV.RESEAT/EMERG.POWER	1.0E-02	1.2E-01	
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	

Event Identifier: 389/84-011

COND/MFW	1.0E+00	3.4E-01	
HPI	3.0E-04	5.2E-01	
HPI(F/B)	3.0E-04	5.2E-01	4.0E-02
PORV.OPEN	1.0E+00	1.0E+00	
HPR/-HPI	1.0E-03	1.0E+00	
CSR	2.0E-03	3.4E-01	

*** forced

Minarick
04-12-1987
12:39:29

Event Identifier: 389/84-011

PRECURSOR DESCRIPTION SHEET

LER No.:	409/84-011
Event Description:	LOOP with DG Failure to Load and Associated HPCS Unavailability
Date of Event:	July 16, 1984
Plant:	LaCrosse

EVENT DESCRIPTION

Sequence

At 1750 h while in hot shutdown, the potential transformer in the switchyard shorted out during a storm, causing breakers to open and resulting in an LOOP. Although both EDGs started, the 1B EDG output breaker, 452 EGB, did not close, leaving the 1B essential bus without power. The breaker could not be closed using the control switch in the control room.

When offsite power was regained at 1810 h, the 1B essential bus could not be energized. A successful attempt was made to close the 1B EDG output breaker locally, which reenergized the 1B essential bus. The normal alignment was then tried with 452-52B, the normal feed breaker, closed and 452 EGB open. This also worked. The 1B EDG was then returned to "auto." Breaker 452-52B immediately tripped open, leaving the bus deenergized again. Breaker 452 EGB did not close. Only placing the 1B EDG control switch to Off allowed breaker 452-52B to be closed, reenergizing the bus. This action was completed at ~1915 h.

At 1920 h the operating crew attempted to start HPCS Pump 1B but could not. The 1A HPCS pump, which was tagged out, was checked to see if maintenance were in progress. Because the pump appeared intact, the tags were cleared at 2000 h, and the 1A HPCS pump started.

At ~0350 h a static inverter annunciated because of decreased input voltage. The input breaker to the diesel building battery charger was open and probably had been since the power transient. An overvoltage trip probably actuated during the electrical transient before the protective devices operated. The breaker was closed.

Corrective Action

Troubleshooting was conducted on the 1B EDG output breaker. A blown fuse was found in the control power circuit for 452 EGB. The breaker's spring release coil, which allows the breaker to close, was found burnt out. This could have caused the fuse to blow. The coil and fuse were replaced. Further troubleshooting led to the discovery that two of four primary fuses for the undervoltage potential transformer on 1B essential bus were also blown. The breaker was bench tested; and the toggle rollnut, which knocks the latch off center during the closing cycle, was lubricated.

At 1801 h on July 17, a successful breaker test, which checked the diesel starting and 1B essential bus loading on an undervoltage condition, was performed. Following additional successful tests of the system on July 18, it was determined that during the loss of power, the 1B EDG output breaker received a closing signal but did not close. The spring release coil burnt out because of the sustained closure signal, which, in turn, caused the control power circuit fuse to blow. The two undervoltage fuses on the 1B essential bus blew during the electrical transient. These fuses did not affect the closing ability of the 1B EDG output breaker but did simulate the existence of an undervoltage condition on the bus.

Bus undervoltage logic prevents HPCS pump starting if an undervoltage condition exists, or existed, on the essential bus until after the EDG output breaker closes, which clears the undervoltage signal. The blown undervoltage fuses continued to simulate an undervoltage condition on the bus after power was restored, precluding closure of the HPLCS pump breaker.

A generator plant 125-V-dc ground alarm had annunciated during LOOP and had not cleared when power was restored. The ground was traced to the closing circuit of breaker 452 M1B, the 1B 480-V bus main feed breaker. While offsite power was disconnected on July 18, this breaker and its circuitry were examined; no problems were identified. The ground did not return when the circuit was reenergized.

Plant/Event Data

Systems Involved:
Emergency power, SI

Event Identifier: 409/84-011

Components and Failure Modes Involved:
"1B" DG breaker — failed to close on demand
"1A" SI pump — failed on demand

Component Unavailability Duration: NA
Plant Operating Mode: 3 (0% power)
Discovery Method: Operational event
Reactor Age: 17 years
Plant Type: BWR

Comments

The LaCrosse high-pressure safety injection system consists of two trains of high-pressure core spray pumps driven by two trains of dedicated power supplies.

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

LOOP	Base case	

Branches Impacted and Branch Nonrecovery Estimate

Emergency power	Base case	Degraded; one train failed
HPCS	Base case	The train in maintenance was assumed recoverable locally

Plant Models Utilized

Specialized model for LOOP at LaCrosse

Event Identifier: 409/84-011

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 409/84-011
Event Description: LOOP and DG Failure to Load and Associated HPCS Unavailability
Event Date: 7/16/84
Plant: LaCrosse

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	3.4E-01

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	9.9E-04
Total	9.9E-04
CV	
LOOP	0.0E+00
Total	0.0E+00
ATWS	
LOOP	5.5E-05
Total	5.5E-05

DOMINANT SEQUENCES

End State: CD Conditional Probability: 5.6E-04

205 LOOP -EMERG.POWER -SCRAM HPCS HPSW

End State: ATWS Conditional Probability: 4.6E-05

207 LOOP -EMERG.POWER SCRAM HPCS

SEQUENCE CONDITIONAL PROBABILITIES

Event Identifier: 409/84-011

	Sequence	End State	Prob	N Rec**
202	LOOP -EMERG.POWER -SCRAM HPCS -HPSW -SRV.CLOSE SHUTDOWN.CONDENSER MANUAL.DEPRESS	CD	1.3E-04	1.1E-01
204	LOOP -EMERG.POWER -SCRAM HPCS -HPSW SRV.CLOSE MANUAL.DEPRESS	CD	1.3E-04	1.1E-01
205	LOOP -EMERG.POWER -SCRAM HPCS HPSW	CD	5.6E-04 *	1.1E-01
206	LOOP -EMERG.POWER SCRAM -HPCS SLC.OR.RODS	ATWS	4.4E-06	2.2E-01
207	LOOP -EMERG.POWER SCRAM HPCS	ATWS	4.6E-05 *	1.1E-01
210	LOOP EMERG.POWER -SCRAM -HPSW SRV.CLOSE	CD	9.8E-05	1.7E-01
211	LOOP EMERG.POWER -SCRAM HPSW	CD	4.9E-05	1.7E-01
212	LOOP EMERG.POWER SCRAM	ATWS	4.1E-06	1.7E-01

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

MODEL: b:\lactree.cmp
DATA: b:\lacprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	
LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-04	1.0E+00	
SLC.OR.RODS	1.0E-02	1.0E+00	4.0E-02
EMERG.POWER	2.9E-03 > 5.7E-02	5.1E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02 > Failed		
Train 2 Cond Prob:	5.7E-02		
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	1.0E+00 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	5.0E-03 > Unavailable		
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	

*** forced

Event Identifier: 409/84-011

Minarick
04-12-1987
12:46:30

Event Identifier: 409/84-011

PRECURSOR DESCRIPTION SHEET

LER No.: 416/84-030
Event Description: LOFW, Trip, and RCIC Failure
Date of Event: May 25, 1984
Plant: Grand Gulf 1

EVENT DESCRIPTION

Sequence

At ~0915 h during startup, a reactor scram occurred at low water level number 3, 11 in. above instrument zero. The low level was due to a trip of the condensate pump, condensate booster pump, and feedwater pump and the inability to start RCIC manually to restore level.

Maintenance personnel had previously begun to investigate the cause of a dual indication on valve N19F504, the condensate minimum-flow control valve. The cause was determined to be a high-voltage output on the controller, which was then adjusted. As the technician touched the positioner arm linkage to check for tightness, a noise was heard inside the positioner, and the valve moved to full open. A later investigation revealed a broken linkage and a bent valve stem positioner bracket, which occurred at an unknown time.

With the valve full open, a path bypassing the booster pumps was created to the condenser. The running condensate and condensate booster pump and feedwater pump tripped immediately on low suction at 0910 h. The reactor was operating at ~4% thermal power, 540°F, and 920 psig. Operators attempted to restart the condensate system, but the condensate pumps again tripped. The reactor water level began to decrease from 38 in. above instrument zero. Operators tried twice to start RCIC manually, but both times the RCIC turbine tripped. When initially started, RCIC operated properly and momentarily stabilized water level at ~27 in. before tripping on overspeed. It was reset and again tripped on overspeed. The turbine evidently oversped on initial startup, but the trip valve did not close instantaneously, which allowed RCIC to operate for a short time. A reactor scram occurred on a low level 3 signal at 0915 h. By 0927 h all main steam inboard isolation valves were manually closed by hand switch. RCIC was restarted and began feeding the vessel at 0928 h with the vessel level at 10 in. below instrument zero. The normal RCIC automatic initiation is at 41.6 in. below instrument zero at which time HPCS, which was available, would also start. By 0934 h the condensate system was made available by isolating the recirculation flow path. RCIC was then secured with the water level at ~37 in. above instrument zero.

Corrective Action

The N19F504 valve positioner arm was replaced, and the valve was restored to service by 1640 h the same day. A modification was made to the RCIC turbine governor valve to restrict it from full opening and causing a turbine overspeed trip. The turbine trip valve was lubricated and retested satisfactorily. Startup recommenced at 0420 h on May 26.

Plant/Event Data

Systems Involved:
Condensate and RCIC

Components and Failure Modes Involved:
Condensate system — failed in operation
RCIC — failed on demand

Component Unavailability Duration: NA
Plant Operating Mode: 2 (4% startup)
Discovery Method: Operational event
Reactor Age: 1.7 years
Plant Type: BWR

Comments

None

MODELING CONSIDERATIONS AND DECISIONS

Initiators Modeled and Initiator Nonrecovery Estimate

Transient	1.0	Nonrecoverable

Branches Impacted and Branch Nonrecovery Estimate

MFW	1.0	No recovery assumed possible (MSIVs closed)
RCIC	0.34	Recoverable locally at turbine controls

Plant Models Utilized

BWR plant Class C

Event Identifier: 416/84-030

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 416/84-030
Event Description: LOFW and RCIC Failure
Event Date: 5/25/84
Plant: Grand Gulf 1

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

TRANS	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CV	
TRANS	3.3E-07
Total	3.3E-07
CD	
TRANS	5.8E-05
Total	5.8E-05
ATWS	
TRANS	2.0E-05
Total	2.0E-05

DOMINANT SEQUENCES

End State: CV Conditional Probability: 1.8E-07

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: 3.0E-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)

End State: ATWS Conditional Probability: 2.0E-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	3.0E-05 *	7.6E-02
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	1.5E-05	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	1.7E-06	3.9E-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	2.1E-06	7.6E-02
112	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA -HPCI RHR(SDC) RHR(SPCOOL)/-LPCI.RHR(SDC) C.I .AND.V/RHR(SDC).RHR(SPCOOL)	CD	1.1E-06	3.9E-02
119	TRANS -SCRAM PCS/TRANS SRV.CHALL/TRANS.-SCRAM SRV.CLOSE FW /PCS.LOCA HPCI RCIC/LOCA SRV.ADS	CD	7.1E-06	1.2E-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	1.8E-07 *	2.6E-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	9.1E-08	1.3E-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	3.7E-08	7.6E-02
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	1.9E-08	3.9E-02
173	TRANS SCRAM SLC.OR.RODS	ATWS	2.0E-05 *	1.0E+00

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

MODEL: b:\bwrctree.cmp
DATA: b:\gulfprob.cmp

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
TRANS	1.1E-03	1.0E+00	
LOOP	1.3E-05	3.4E-01	

Event Identifier: 416/84-030

LOCA	3.3E-06	3.4E-01	
SCRAM	4.1E-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	
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	6.6E-02	1.0E+00	
EMERG.POWER	2.9E-03	5.1E-01	
FW/PCS.TRANS	4.6E-01 > 1.0E+00	3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	4.6E-01 > Failed		
FW/PCS.LOCA	1.0E+00	3.4E-01	
HPCI	2.0E-02	3.4E-01	
RCIC/TRANS.OR.LOOP	6.7E-02 > 1.0E+00	5.7E-01 > 3.4E-01	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	6.7E-02 > Failed		
RCIC/LOCA	1.0E+00	1.0E+00	
CRD	1.0E-02	1.0E+00	4.0E-02
SRV.ADS	6.7E-03	1.0E+00	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	3.4E-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	

*** forced

Minarick
04-12-1987
12:52:55

Event Identifier: 416/84-030

APPENDIX E

LICENSEE EVENT REPORTS ASSOCIATED WITH PRECURSORS

APPENDIX E

LICENSEE EVENT REPORTS ASSOCIATED WITH PRECURSORS

This appendix contains copies of 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 ASP Program are also used in other ORNL programs and may contain markings made during abstracting and coding in these programs.

Table E.1 Index of precursor licensee event reports

LER number	Description of event	Plant name	Page number
206/84-002	Both diesel generators inoperable	San Onofre 1	E-7
219/84-012	Both emergency diesel generators simultaneously inoperable	Oyster Creek	E-8
220/84-015	One-half the safety-related loads become inoperable	Nine Mile Point 1	E-13
237/84-010	Inadvertent loss of feeder breaker makes LPCI unavailable	Dresden 2	E-16
247/84-025	Plant trip due to unavailability of HPI	Indian Point 2	E-19
250/84-036, -038, -040	Both diesel generators unavailable on two occasions	Turkey Point 3	E-23
254/84-014	Two LPCI injection valves fail to open	Quad-Cities 1	E-28
259/84-027	Inadvertent relief valve opening with subsequent trip	Browns Ferry 1	E-31
259/84-032	Inadvertent overpressurization and leakage from LPCS	Browns Ferry 1	E-33
265/84-010	Trip with RCIC failure	Quad-Cities 2	E-37
265/84-014	HPCI isolates with LPCI already inoperable	Quad-Cities 2	E-42
271/84-022	Diesel generator lockout trip of both generators	Vermont Yankee	E-45
272/84-017	Unavailability of high-head charging pumps	Salem 1	E-48
275/84-013	Inoperable high-head injection system	Diablo Canyon 1	E-52
280/84-011	Component cooling water isolated from charging pumps	Surry 1	E-55
286/84-015	LOOP with both a DG failure and an unavailability	Indian Point 3	E-58
296/84-012, -013, -014	Trip and HPCI failure	Browns Ferry 3	E-61
296/84-015	Trip and one condensate pump and two CRD pumps fail	Browns Ferry 3	E-73
312/84-015	Hydrogen explosion causes transient and subsequent loss of NNIX	Rancho Seco	E-75
318/84-005	Both diesel generators inoperable	Calvert Cliffs 2	E-80

Table E.1 (continued)

LER number	Description of event	Plant name	Page number
324/84-014, -018	RCIC and Train "B" LPCI/RHR unavailable	Brunswick 2	E-85
325/84-006, -007	Trip, LOFW, and HPCI isolation	Brunswick 1	E-91
325/84-014	Trip and LOFW with HPCI unavailable	Brunswick 1	E-97
327/84-033	Atmospheric dump valve opens and causes LOFW	Sequoyah 1	E-100
331/84-001	LOFW and SRV opens briefly	Duane Arnold	E-102
331/84-028	LOOP and HPCI trip	Duane Arnold	E-106
333/84-002	Engineered safety features train unavailable during postulated LOOP	Fitzpatrick	E-112
333/84-003	RCIC inoperable while HPCI is out of service	Fitzpatrick	E-115
333/84-004	RCIC and HPCI are unavailable	Fitzpatrick	E-119
336/84-012	Trip, LOFW, and AFW degraded	Millstone 2	E-120
338/84-019	Trip and one AFW train fails	North Anna 1	E-122
339/84-013	Forced shutdown due to two inoperable emergency diesel generators	North Anna 2	E-124
344/84-017	Steam generator relief valve fails open and subsequent reactor trip	Trojan	E-126
346/84-003	SFRCS initiation leads to stuck-open MSRV and trip	Davis-Besse 1	E-130
346/84-013	Trip and one atmospheric dump valve fails to close	Davis-Besse 1	E-134
362/84-035	All HPSI pumps unavailable	San Onofre 3	E-137
369/84-024	LOOP at McGuire 1 affects Unit 2	McGuire 1	E-140
373/84-054, -056, 060, -062	Scram, RCIC failures, and RHR unavailability within $\pm$15 d	LaSalle 1	E-146
374/84-017, -018	LOFW while shutting down and HPCS fails in test within 15 d of LOFW	LaSalle 2	E-157
387/84-010	SRV failure to close following scram	Susquehanna 1	E-164
387/84-040	Diesel generators slow start and residual heat removal suppression pool unavailable	Susquehanna 1	E-166
388/84-006, -008	Trip and LOFW with "B" LPCI train unavailable	Susquehanna 2	E-170

Table E.1 (continued)

LER number	Description of event	Plant name	Page number
388/84-013	LOOP test with failure of EPS to start	Susquehanna 2	E-177
389/84-004	LOFW, failure of one AFW train and one MSRV sticks open	St. Lucie 2	E-243
389/84-011	Trip and one AFW train fails	St. Lucie 2	E-244
409/84-011	LOOP with DG failure to load and associated HPCS unavailability	LaCrosse	E-245
416/84-030	LOFW, trip, and RCIC failure	Grand Gulf 1	E-249

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(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 1	0 5 0 0 0 2 0 6	1 OF 0 1

TITLE (4)
SPURIOUS STARTING OF NO. 2 DIESEL GENERATOR

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQ NUMBER	REV NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
					Rev. 0,1 on file					0 5 0 0 0
0 3	0 9	8 4	8 4	– 0 0 2	– 0 2	0 9	1 4	8 4		0 5 0 0 0

OPERATING MODE (9)	5	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)					
POWER LEVEL (10)	0 0 0	20.402(b)		20.405(c)	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)	X	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	X	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)		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
J. G. HAYNES, STATION MANAGER	7 1 4 4 9 2 - 7 7 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	

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 3/9/84, at 1003, ~~with~~ Unit 1 was in an extended Mode 5 outage, during routine testing of electrical circuits, the No. 2 Diesel Generator (DG) spuriously started, tripped on overspeed, and was declared inoperable. Since No. 1 DG was also inoperable at this time, in accordance with LCO 3.7.II(2), no operations involving core alterations or positive reactivity changes were permitted. The requirement of LCO 3.2.A(1) to maintain one charging pump or the test pump operable could not be met since no automatic emergency electrical power source was available, however, DG No. 2 could be started manually and, therefore, there was no loss of safety function.

On 3/11/84, at 1645, No. 2 DG was declared operable and LCO 3.2.A(1) was satisfied. Investigation determined the spurious start was due to a voltage transient transmitted to the No. 2 sequencer by physical wiring discrepancies unique to No. 2 DG. The voltage transient was caused by testing of relays in the Auxiliary Transformer "C" Loss of Voltage circuit.

We have completed our investigation, and no engineering documentation has been found to account for the discrepant physical wiring configuration. As corrective action, the wiring was changed to conform with design drawings. The relay testing was repeated. The spurious start did not recur. No further corrective action is planned.

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S PDR

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(9-83)

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(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)
Oyster Creek, Unit 1	0 5 0 0 0 2 1 1 9	1 OF 0 5

TITLE (4)

Both Emergency Diesel Generators Simultaneously 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 6	0 4	8 4	8 4	— 0 1 2	— 0 0	0 6	2 9	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 1 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	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
Michael H. Allen, Operations Engineer	6 0 9 — 9 7 1 - 4 6 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

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-spaced typewritten lines) (16)

During a scheduled load test on Emergency Diesel Generator No. 1 (EDG-1), a diesel fuel oil day tank low level alarm for unit one was received in the Control Room. Subsequent investigation revealed that the diesel fuel oil transfer pump control switch for EDG-1 was in the OFF position. In the OFF position, fuel oil is not automatically transferred to the diesel day tank from the main fuel storage tank. This resulted in EDG-1 being considered inoperable. Since EDG-2 was out of service for governor repairs, both Emergency Diesel Generators were simultaneously inoperable. A violation of the Technical Specifications resulted, which require that at least one EDG be operable in order for the Standby Gas Treatment, Core Spray and the Standby Liquid Control Systems to be considered operable. EDG-1 was returned to service by placing the diesel fuel transfer pump control switch to the ON position. The control switch was last demonstrated to be in the ON position during a load run conducted on May 28, 1984. Requirements for checking the control switch will be added to plant tour sheets.

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S PDR

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(9-83)

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

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

DATE OF OCCURRENCE

The event occurred on June 4, 1984 at approximately 1112 hours.

IDENTIFICATION OF OCCURRENCE

Both Emergency Diesel Generators were inoperable at the same time, resulting in a violation of the Technical Specifications sections 3.7.C, 3.5.B.2, and 3.2.C.

This event is considered to be a reportable event as defined in 10 CFR 50.73(a)(2)(i)(B), and 10 CFR 50.73(a)(2)(v).

CONDITIONS PRIOR TO OCCURRENCE

The reactor was partially fueled and the mode switch was in REFUEL.

DESCRIPTION OF OCCURRENCE

At 1059 hours on June 4, 1984, Emergency Diesel Generator No. 1 (EDG-1) was started for a scheduled diesel generator load test. Thirteen minutes later, at 1112 hours, the EDG-1 Day Tank Level Hi/Lo Alarm was received in the Control Room. The equipment operator at the EDG was informed and began investigating the problem. The Group Shift Supervisor (GSS) dispatched an electrician to assist the operator in finding the cause of the day tank alarm. At 1117 hours the GSS was informed by the EDG operator that diesel fuel oil day tank level had fallen to a quarter of a tank. To prevent diesel generator shutdown due to a lack of fuel, the GSS ordered a normal shutdown of EDG-1.

At 1119 hours the electrician that had been previously dispatched entered the Emergency Diesel Generator compartment and found the control switch for the diesel fuel oil transfer pumps in the OFF position. With the switch in this position, power is not available to the two fuel oil transfer pumps for EDG-2 which deliver fuel oil from the main diesel generator fuel tank to the diesel fuel oil day tank for EDG-1. Since no makeup to the diesel day tank was available, and because EDG-1 is supplied directly from this day tank, level in the day tank would have eventually reached zero with no operator action. This would have resulted in a shutdown of EDG-1 due to a lack of fuel. Because EDG-2 was already inoperable (due to governor maintenance) and EDG-1 was rendered inoperable due to loss of its fuel oil transfer system, both Emergency Diesel Generators were simultaneously inoperable.

The fuel oil transfer pump control switch was immediately placed in the ON position, which energized the fuel transfer pumps. Diesel day tank level rose sufficiently to clear the Control Room alarm, and at 1127 hours the load test on EDG-1 was resumed. During the period from commencement of a normal EDG shutdown to resumption of the load test the diesel had continued to operate since a normal shutdown sequence involves an 11.5 minute idle period (generator unloaded) to allow diesel engine cooldown. Realizing that a violation of the Technical Specifications had occurred, the GSS notified the NRC and submitted a Plant Deviation Report.

APPARENT CAUSE OF OCCURRENCE

The apparent cause of the occurrence is attributed to the following:

a. Inadequate procedural controls for the diesel fuel oil transfer pump control switch.

b. Inadequate protection of the control switch from being repositioned. The control switch is a toggle switch located on the face of the engine control cabinet. Although labelled, it has no protective cover or enclosure allowing for the switch to be easily repositioned.

ANALYSIS OF OCCURRENCE and SAFETY ASSESSMENT

The two Emergency Diesel Generators (EDGs) represent a source of electrical power which is self contained within the plant and not dependent on outside sources. Each EDG can supply sufficient power for the operation of the required engineered safety features following an accident or emergency condition. The engineered safety systems supplied by the EDGs (in the event of a loss of offsite power) include independent trains for the following systems:

a. Core Spray System
b. Containment Spray and Emergency Service Water Systems
c. Standby Gas Treatment System
d. Standby Liquid Control System

These systems are designed to mitigate the consequences of several postulated accidents described in the Plant's Facility Description and Safety Analysis Report.

Plant conditions at the time of the occurrence were such that at least one train of the Core Spray, the Standby Gas Treatment, and the Standby Liquid Control Systems were required to be operable. Since both Emergency Diesel Generators were inoperable, the Technical Specifications definition of operability requires that these safety systems also be declared inoperable. It should be noted, however, that the elapsed time between commencement of EDG-1 shutdown from a loaded condition and the repositioning of the fuel oil transfer pump control switch (which made EDG-1 operable again) was only two minutes. If a loss of offsite power had occurred requiring the use of EDG-1, sufficient fuel remained in the day tank to allow full loading of the generator during this time period. Thus, EDG-1 was capable of suppying emergency loads even though its fuel transfer switch was in the OFF position. Furthermore, plant conditions at the time of the occurrence were such that an event requiring initiation of the Core Spray, Standby Gas Treatment, or Standby Liquid Control Systems would be highly unlikely.

The safety significance of this event would have been greater had it occurred during power operation. The consequences of both Emergency Diesel Generators being inoperable would be most severe during the design basis Loss of Coolant Accident (LOCA) with simultaneous loss of offsite power. During this postulated accident, the Core Spray, Containment Spray, Emergency Service Water and Standby Gas Treatment Systems are required to perform their safety functions. The Standby Liquid Control System may be required to shutdown the Reactor depending on plant conditions after initiation of the event. Normally, power for these loads would still be available to the plant through the startup transformer banks. However, in the worst case analysis a simultaneous loss of offsite power occurs requiring startup of the Emergency Diesel Generators. Since EDG-2 is inoperable, EDG-1 would fast start and begin supplying vital loads to the safety systems of concern within 35 seconds. Assuming that the diesel fuel oil day tank for EDG-1 is just above the low level alarm setpoint at the start of the event, the day tank hi/lo alarm for EDG-1 would be received in the control room shortly after the fast start of EDG-1. Conservative calculations using diesel fuel oil consumption at maximum electrical loading indicate that approximately twelve (12) minutes are available from receipt of the day tank alarm to loss of fuel oil to the EDG (zero level in the day tank). This is sufficient time to dispatch an operator to the EDG compartment and carry out the Plant Alarm Response procedure for this alarm, which includes checking the diesel fuel oil transfer pump control switch as an immediate corrective action. Although the consequences of this design basis accident would be more severe if both diesels were lost, the following mitigating conditions must be considered:

a. As described above, Plant emergency procedures combined with the operator action would have prevented the loss of the remaining Emergency Diesel Generator.

b. During power operation, the Technical Specifications require that a daily load test, at greater than 20 percent rated power for at least one hour, be performed on the operable EDG when the other diesel is inoperable. Plant policy is to perform the load test at rated power of the EDG. Diesel fuel oil consumption at rated power is such that a day tank low level alarm would be received before the daily test was completed if the EDG-1 fuel oil transfer pumps were de-energized. Thus, the maximum time that the fuel oil transfer pump switch could be misaligned is one day. The probability of the unlikely accident described above occurring at the same time that both Emergency Diesel Generators are inoperable, within the maximum allowed one day period, is extremely remote.

c. The fire protection system can supply water to the core even if all emergency core cooling is lost due to the shutdown of the remaining EDG.

d. Sufficient time would be available for primary and secondary containment isolation before EDG-1 would run out of fuel.

CORRECTIVE ACTION

The immediate corrective action was to place the diesel fuel oil transfer pump control switch in the ON position. The Emergency Diesel Generator Load Test was then resumed. Future solutions to be implemented include:

a. Incorporate a check of the transfer pump control switch position into the plant tour sheets.

b. Install keylock controls on the transfer pump control switch for each Emergency Diesel Generator to prevent repositioning without the Group Shift Supervisor's concurrence.

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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)	DOCKET NUMBER (2)	PAGE (3)
Nine Mile Point Unit #1	0 5 0 0 0 2 2 0	1 OF 0 3

TITLE (4) ~~Inadvertent~~ A Loss of Power to ~~two~~ A Power Boards ~~#103 and Power Board #17B~~

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 7	8 4	8 4	— 0 1 5	— 0 0	0 9	0 7	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 9 7	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)	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)(ix)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Robert Randall, Supervisor, Technical Support	AREA CODE 3 1 5 3 4 9 - 2 4 4 5

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

ABSTRACT

During normal operations on August 7, 1984, calibration work was being performed on the Power Board #103 Undervoltage relays. Diesel Generator #103 and its output breaker were taken out of service for this work, and power was being supplied to Power Board #103 from offsite power through breaker R-1013. Calibration work was then performed on the relays, one at a time, per procedure N1-IMP-52, "Procedure For Calibration and Functional Test of meters and Protective Relay Systems." Due to personnel error, the protective relaying was actuated, causing breaker R-1013 to open, and protective relay 86-17 to trip on Power Board #17, de-energizing Power Boards #103 and #17B. This caused approximately half of the station's safety-related loads to become inoperable. Operators re-established offsite power to the powerboards approximately 10 minutes after the event occu red. The calibrations were then satisfactorily completed. To prevent recurrences of this type in the future, procedural changes will be implemented, and engr ed nameplates indicating the proper test switch operating sequence will be attached at each test switch assembly on Power Boards #102 and #103.

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S PDR

NRC Form 366 (9-83)

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

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

TEXT

During normal operations on August 7, 1984, Meter and Test personnel were scheduled to perform calibration work on the Power Board #103 ITE Undervoltage Relays (27-1A, 27-2A, and 27-3A). To allow this work to be performed, Diesel Generator #103 and Diesel Generator Output Breaker R-1032 were taken out of service in compliance with Technical Specifications. Power was supplied from offsite power to Power Board #103 via breaker R-1013, which is the normal alignment. Test personnel then began their calibrating work per Instrument and Maintenance procedure N1-IMP-52, "Procedure for Calibration and Functional Test of Meters and Protective Relay Systems." Relay 27-1A was removed from service, calibrated, and returned to service. Then, relay 27-2A was removed from service. Due to personnel error, the test power supply was hooked up to 27-1A rather than 27-2A, causing the potential transformer's secondary fuse feeding relay 27-1A to blow. The technicians completed the calibration of relay 27-2A and returned it to service. When relay 27-2A was returned to service, a restoring sequence error was made by the technician, causing this relay to indicate low voltage. The combination of 27-1A with a blown fuse and 27-2A reading instantaneous low voltage made up the 2 out of 3 logic. As a result, at approximately 1050 hrs., breaker R-1013 opened, and protective relay 86-17 tripped on Power Board #17, resulting in a loss of power to Power Boards #103 and #17B. As a direct result of this, the following equipment became inoperable:

Core Spray Pumps #112 and #122; Core Spray Topping Pumps #112 and #122; Containment Spray Pumps #121 and #122; Containment Spray Raw Water Pumps #121 and #122; Reactor Building Closed Loop Cooling Water Pump #12; Shutdown Cooling Pump #12; Liquid Poison Pump #12; Emergency Service Water Pump #12; Control Rod Drive Pump #12; Battery Charger #171; Nitrogen Supply #12 Heater; Containment Monitoring Sample Pump #12; Emergency Vent Exhaust Fan #12; Emergency Exhaust Duct #12 Heater; Diesel Generator #103 Cooling Raw Water Pump; Diesel Generator #103 Air Compressors #1 and #2; Condensate transfer Pump #12; Diesel Generator #103 Roof Exhaust Fans #3 and #4; Diesel Room #103 Motor Operated Door; Core Spray Suction Isolation Valves #112 and #122; Core Spray Discharge Isolation Valves #112 and #122; Containment Spray Suction Isolation Valves #121 and #122; Containment Spray Raw Water Pump Discharge Valves #121 and #122; Reactor Shutdown Cooling Pump Suction Blocking Valve #12; Reactor Vent Valves #11 and #12; Emergency Condenser Steam Isolation Valve #121; Main Steam Isolation Valve #121; Feedwater Isolation Valve #12; Containment Spray Raw Water/Containment Spray Intertie Valve #121; Core Spray High Point Vent Valve; and Containment Spray Raw Water/Core Spray Intertie Valve #122.

ASSESSMENT OF POTENTIAL SAFETY CONSEQUENCES

As a direct result of this event occurring, components in the core spray and containment spray systems were not operable for approximately 10 minutes. The core spray and containment spray systems are designed to be used during loss of coolant accident conditions. During the time period that these systems were inoperable, the plant did not experience a loss of coolant accident, and no transients or other events occurred that could have caused the plant to degrade into an accident condition. Additionally, during the course of this event, Power Board #16 and #102 (redundant power boards to Power Boards #17 and #103, respectively) and all redundant loads were operable. Therefore, the overall potential consequences arising out of this event were minimal.

CORRECTIVE ACTION

Operators reduced the load on the generating unit to 300Mwe due to the loss of Power Board #17B loads, which included the #12 Reactor Building Closed Loop Cooling (RBCLC) Pump. Operators also contacted the test personnel to find out what they had done, and to verify that breaker R-1013 could be reclosed. The blown potential transformer fuse was replaced on undervoltage relay 27-1A, and the contacts were reset on undervoltage relay 27-2A. Operators then reclosed breaker R-1013, which re-energized Power Boards #103 and #17B. The calibrations were then satisfactorily completed. To prevent recurrences of this type in the future, procedural changes will be implemented, and an engraved nameplate will be attached at each test switch assembly associated with relays 27-1A, 27-2A, and 27-3A at Power Boards #102 and #103. The nameplate will indicate the proper test switch operating sequence (ie-when testing, open trip switches first and restore last).

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(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)
Dresden Nuclear Power Station Unit 2	0 5 0 0 0 2 3 7	1 OF 0 2

TITLE (4)

Loss of Feeder Breaker Position Indication From Bus 29 to Bus 29-7

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 6	8 4	8 4	— 0 1 6	— 0 0	0 7	2 4	8 4		0 5 0 0 0 _ _ _
										0 5 0 0 0 _ _ _

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 1 5	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)	X 50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	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
Gerald W. Bergan (X-529)	AREA CODE 8 1 5 9 4 2 - 2 9 2 0

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	E D	I H S	G 0 8 0	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)

During a unit start-up, feeder breaker position indication in the control room was lost on the breaker at Bus 29 which feeds MCC 28-7 and 29-7. A second breaker is located at MCC 29-7; both operate off a single control switch in the control room. Following a light bulb integrity check, an operator was sent to reset the breaker at MCC 29-7. This seemed to be the correct choice based on the control room layout of breaker indication. The breaker at MCC 29-7 was inadvertantly tripped, isolating MCC 28-7 and 29-7 and causing LPCI to be inoperable. A GSEP unusual event was declared. Two attempts at this time to energize MCC 28-7 and 29-7 failed. It was now evident that the breaker with no indication was at Bus 29. While preparing to use the alternate feed from Bus 28, the normal feed control switch from Bus 29 was placed in pull-to-lock. An open breaker position light appeared for the breaker at Bus 29 and breaker control returned. The NSO closed the control switch from Bus 29 and re-energized MCC 28-7 and 29-7. All breaker indications appeared normal. Subsequent investigation revealed a loose wire on the breaker control switch at the 902-8 panel causing an intermittent loss of breaker indication and breaker control. The total elapsed time for this event was approximately 28 minutes.

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S PDR

NRC Form 366
(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Dresden Nuclear Power Station	0 5 0 0 0 2 3 7	8 4	— 0 1 0	— 0 0	0 2 OF 0 3

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

At approximately 2040 hours on June 26, 1984, with Unit 2 in the startup mode and critical, the Unit 2 NSO noticed that the position indicating lights for what he believed to be the MCC 29-7 feedbreaker from Bus 29 was not illuminated on Control Room panel 902-8. There are dual feedbreakers from Bus 29 to MCC 29-7 from a single control switch on panel 902-8 in the Control Room. The NSO immediately verified that the problem was not in the lamp, as the light bulbs were replaced. An Equipment Attendant (EA) was immediately dispatched to MCC 29-7 with instructions to reset the feedbreaker at approximately 2045. The EA mistakenly pushed the trip button on the breaker which resulted in a breaker trip. It should be noted that up to this point, despite the loss of feedbreaker indication in the Control Room, MCC's 28-7 and 29-7 had not lost power. A GSEP Unusual Event was declared because control power was lost to both LPCI injection valves (MO 2-1501-21 A & B) causing LPCI to become inoperable.

When the MCC 29-7 feedbreaker was manually tripped, MCC's 28-7/29-7 de-energized. The NSO immediately tried to reclose the breaker from Bus 29 to MCC 29-7 but could not. An attempt was also made to close in the alternate feed from Bus 28 to MCC 28-7. The breakers would not close. At this point in time, MCC's 28-7/29-7 were dead and could not be re-energized by either the normal Bus 29 or the alternate Bus 28. The only breaker closed was the breaker at Bus 29. It was now evident that the breaker with no indication was at Bus 29, and that the EA had been sent to the wrong breaker.

While preparing for a second attempt to close the alternate feedbreakers, the normal feedbreaker from Bus 29 was put into the pull-to-lock position. The NSO noted that the open breaker position light appeared for the breaker at Bus 29 and that breaker control returned from Bus 29 to MCC 29-7. The NSO immediately closed the control switch from Bus 29 and re-energized MCC 29-7/28-7 at 2108 hours. Breaker indication for Bus 29 to MCC 29-7 was observed closed.

Upon investigation, a loose wire was found on the breaker control switch at the 902-8 panel which caused intermittent loss of breaker indication at Bus 29 and loss of breaker control. Operations personnel assumed that the feed-breaker at MCC 29-7 tripped, based on the fact that schematically on the 902-8 panel, the breaker position closest to MCC 29-7 had no indication; breaker position indicating lights on panel 902-8 were not labeled. As a result, the EA was sent to the wrong breaker. He then proceeded to inadvertently trip the breaker at MCC 29-7 which previously was indicating closed on panel 902-8. One breaker control switch controls the operation of both breakers and has separate indication for both breakers.

Another factor contributing to this event was the control logic for the feedbreaker pair from Bus 28 and Bus 29. As designed, there is an interlock such that if the Bus 29 or 28 feedbreaker trips, it will trip the associated MCC feedbreaker. The logic also provides that if the Bus 28 or 29 feedbreaker is closed and the associated MCC feedbreaker is opened, as in this event, the alternate supply breaker will not close on to the dead bus.

(Cont'd)

MCC's 28-7/29-7 are normally powered from Bus 29. Only upon loss of voltage on Bus 29 (Div. II) would the MCC's automatically transfer to Bus 28 (Div. I). The auto throwover requires operation of two breakers in series. This interlock is provided to prevent automatic bus transfer in the event of a single failure. This breaker logic is arranged to prevent closing in the alternate feed to a faulted motor control center.

This logic was reviewed and found acceptable under SEP Topic VI-7 C.1, Appendix K per D.M. Crutchfield to L. DelGeorge letter dated February 5, 1982, Section V-B.8.

Corrective actions as a result of this event consist of the following:

1. An investigation as to the cause of the event by the Electrical Maintenance Department found a loose wire on the 902-8 panel. This problem was corrected.

2. Operator training is being conducted to ensure all Operations personnel understand fully the breaker logic and limitations.

3. The indication lights on the 902-8 panel have been labeled to eliminate the confusion as to which light represents which breaker.

4. A warning sign will be placed on the incoming feedbreaker for each of the MCC's involved to warn personnel that tripping the MCC feedbreakers without tripping the bus feedbreaker first will result in a loss of the MCC's.

NRC Form 366 (9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
INDIAN POINT, UNIT 2	0 5 0 0 0 2 4 7	1 OF 0 4

TITLE (4) Main (Turbine) FIRE AT S.I. PUMPS MALFUNCTION

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	1 9	8 4	8 4	— 0 2 5	— 0 0	0 1	1 8	8 5		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10) 1 0 0	50.73(a)(2)(iv) X	73.71(b)		
	50.73(a)(2)(v) X	73.71(c)		
		OTHER (Specify in Abstract below and in Text, NRC Form 366A)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER AREA CODE
	9 1 4 5 2 6 - 5 1 8 2

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
D	B P	P P	0 2 5	N							
X	B P	S H V	A 2 0 0	N							

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	NO				

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

On the evening of December 19, 1984, with the unit at full power, a fire occurred at the generator exciter end seal due to seal failure and hydrogen leakage. During operator-initiated shutdown, the reactor tripped on low steam generator level and safety injection occurred on a High Steam Flow signal (coincident with a low average temperature of the Reactor Coolant System) due to actuation of the steam dump valves. The Boron Injection Tank injected its contents into the Safety Injection System. There was no injection of borated water into the Reactor Coolant System since the Reactor Coolant System was at a pressure greater than the Safety Injection System shutoff head.

During the subsequent week, repairs were made to the generator and the reactor brought critical. On the morning of December 28, 1984 two Safety Injection Pumps were declared inoperable after they malfunctioned in an attempt to top off the ECCs Accumulators; the third Safety Injection Pump would not manually turnover. The reactor was manually tripped and an orderly cooldown commenced. By January 1, 1985, the three Safety Injection Pumps were verified to be operable and the reactor brought critical. (S.I.)

The cause of the malfunction of the Safety Injection Pumps is attributed to a combination of solidified boric acid preventing suction flow and gas binding of the pumps. Flushing procedures have been modified to ensure better flushing of lines where the potential exists for high boric acid concentration, and the function of associated equipment is being monitored to preclude further similar events.

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S PDR

NRC Form 366 (9-83)

On December 19, 1984 at 8:00 p.m. a previously observed oil leak under the main generator intensified. The source of the oil leak was traced to the Generator Exciter End. An interim oil catcher, fabricated from aluminum flashing, inadvertently touched the generator shaft and produced a spark, igniting leaking hydrogen. The resulting fire was extinguished in 30 seconds. Steps were then taken to eliminate the hydrogen leak by isolating the hydrogen supply to the generator and adjusting the seal oil pressure. Following the latter adjustment, the hydrogen side seal oil pressure rose and oil started leaking from the outboard and inboard generator seals. A loud noise was heard and a second fire was seen in the generator outboard bearing. This occurred at approximately 10:00 p.m and an operator-initiated rapid shutdown was implemented. At 10:02 the unit tripped on a low steam generator level, and safety injection actuation occurred due to high steam flow coincident with low average temperature of the Reactor Coolant System.

The second fire was extinguished in approximately thirty minutes. Due to the Safety Injection signal, the Safety Injection Pumps ran in the recirculation mode prior to being secured from operation. The Boron Injection Tank performed as designed and delivered approximately 1500 gallons of concentrated (nominally 13%) boric acid to the Safety Injection System. The Boron Injection Tank valves opened automatically on Safety Injection and closed on a low Boron Injection Tank level signal as designed.

The plant remained in a hot shutdown condition following the generator fire while repairs were in progress to the Exciter End Hydrogen Seal. An electrical short circuit which caused the seal failure was corrected and therefore the hydrogen and seal oil leak was eliminated. On December 26, 1984 one safety Injection Pump, #22 was run to top off the Accumulator Tanks. On the morning of December 28, 1984 with the reactor critical, #23 Safety Injection Pump was started to top off the Accumulator Tanks. The pump developed a discharge head of 1100 psig and then dropped to approximately 700 psig corresponding to the pressure in the Accumulator Tanks. The pump was secured from operation and the valve lineup verified. The pump was vented and the suction and discharge pressure taps inspected. Liquid was observed at each point with a momentary emission of gas. A second Safety Injection Pump, #22, was inspected and found to be solid with water. The suction pressure was satisfactory at 30 psig. #22 Safety Injection Pump was started to maintain level in the Accumulators. After filling two Accumulators and while in the process of topping off the third, #22 pump was observed to drop in discharge pressure from 1500 to 700 psig. The pump was secured from operation. The piping to the third Safety Injection Pump, #21, precluded its use to top off the Accumulators. An unsuccessful attempt was made to manually roll the pump.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
INDIAN POINT, UNIT 2	0 5 0 0 0 2 4 7	8 4	— 0 2 5	— 0 0	0 3 OF 0 4

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

The reactor was manually tripped and an orderly approach to cold shutdown implemented.

An investigation of the status of the Safety Injection System was commenced. #22 pump was vented and a continuous flow of gas and water were observed. At the same time #23 pump was vented with only water flow observed. #21 pump was vented and only gas was observed; otherwise the pump internals were dry. An analysis of a gas sample from #21 pump indicated the major constituent to be nitrogen (97%).

Other points in the system were also opened. Water and gas were observed in the suction line from the RWST and in the discharge line from the Boron Injection Tank. Venting of pump #22 continued for a few hours until gas evolution ceased. Further investigation of pump #21 identified the suction line immediately upstream of the pump to be completely plugged with boric acid.

It is believed that precipitated boric acid had partially blocked the suction to pumps #22 and #23 causing partial suction loss. This, together with gas entrapment resulted in the observed drop in discharge pressure when the accumulators were topped off. In the case of pump #21 total blockage of the suction line occurred.

An evaluation program was initiated to identify the sources of boric acid and gas. Samples were taken from the piping downstream of the Boron Injection Tank, the discharge side of pump #21, the Refueling Water Storage Tank and the Accumulators. Based on the analysis of the samples, a log indication of the 220 gallons of make up added to the Boron Injection Tank during the prior week and the operating history of the Safety Injection Pumps, it is known that the Boron Injection Tank was leaking across closure valves 1822 A and 1822 B. This is considered to be the source of the boric acid. It is believed that the boric acid precipitated in the pumps since they are not heat traced.

Potential sources of the nitrogen in the system were the Accumulators, nitrogen used for the post-LOCA sealing of two isolation valves in the Safety Injection System and the Boron Injection Tank (which operates under a nitrogen cover gas but at a lower pressure than the Accumulators). Nitrogen from the sealing system was eliminated from further consideration through test isolation of the nitrogen source to that system branch which serves the two isolation valves. No pressure loss was observed. The Accumulators were eliminated as a suspected source after a test simulating conditions of backleakage across the check valves on the pump discharge failed to produce detectable nitrogen on the pump suction side. By a process of elimination the Boron Injection Tank is the most likely source of the nitrogen. The nitrogen dissolves in the tank liquid until equilibrium is achieved at 90 psig. Due to either leakage or injection, dissolved gas will evolve in the lower pressure discharge line.

Since all factors contributing to the malfunction of the Safety Injection pumps cannot be positively identified at this time, reliance has been placed on system monitoring and procedure revision to preclude further similar events. The Boron Injection Tank discharge line is being monitored on a daily basis and is flushed upon detection of increasing boric acid; it is maintained at a concentration no greater than 300 ppm above the RWST boron level. Similarly the pump vents are monitored for gas evolution. The emergency procedure for recovery from a spurious safety injection has been clarified to provide for adequate flushing of the discharge line from the Boron Injection Tank.

Subsequent to the events of December 28, 1984, the suction side of the pumps was flushed through the pump vents until no more gas evolution occurred. Similar operations were performed at other points in the system. Pump #21 was replaced with a spare pump. All pumps were subjected successfully to a surveillance test and declared operable before reactor criticality.

Since the Safety Injection System would have performed its function as designed on the date of the generator fire no actual safety hazard was involved. On the date of the malfunction of the Safety Injection Pumps, they were not called upon to perform their safety function.

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)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	1 OF 0 1

TITLE (4)
Emergency Diesel Generator Overspeed Trips On

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 1	8 4	8 4	0 3 6	0 0	0 1	2 1	8 5	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
R. L. Teuteberg, Regulation and Compliance Engineer	3 0 5 2 4 5 - 2 9 1 0

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		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 21, 1984, at 11:27 a.m., during daily testing of the "B" Emergency Diesel Generator (OP 4304.1), required by Technical Specifications because "A" Emergency Diesel Generator was out of service for periodic maintenance, the diesel failed to start from the control room. A local inspection of the diesel generator revealed an overspeed alarm lit. A second start was attempted and generator RPM was observed to immediately reach the overspeed setpoint and the diesel generator locked out on overspeed. "B" Emergency Diesel Generator was declared out of service at 11:27 a.m. At 12:00 noon, it was observed that the governor no load speed was adjusted too high, and was readjusted back to normal. The generator was started locally and came up to normal speed. After stopping the diesel generator, it was successfully tested via OP 4304.1 at 12:10 p.m., and declared back in service. During this event, both Unit 3 and Unit 4 start-up transformers were available as required by Technical Specifications.

Cause of Event:
The cause of this event was the result of a no load governor speed adjustment on the diesel generator which had been set higher than the overspeed protection setpoint. The root cause appears to have been a personnel oversight in misadjustment of the diesel no load speed while the diesel was not running.

Corrective Actions:
"B" Emergency Diesel Generator governor no load speed was readjusted back to normal. A training brief concerning emergency diesel generator governor operation was implemented. Information tags were placed on local and remote control switches for the governor, and night orders concerning operator awareness of the emergency diesel generator control system were written.

The USNRC was notified of a Significant to 10CFR50.72(b)(2)(iii)(d) via the ENS at 11:27 a.m. ~~The health and safety of t~~ ~~not affected.~~ Similar occurrences: LERs 250-83-025, 250-83-003 and 250-82-006.

NRC Form 366
(9-83)

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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)
Turkey Point Unit 3

DOCKET NUMBER (2) 0 5 0 0 0 2 5 0

PAGE (3) 0 1 OF

TITLE (4)
"B" Emergency Diesel Generator Coolant Leak

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
1 2	2 2	8 4	8 4	— 0 3 8	— 0 0	0 1	2 1	8 5	N/A	0 5 0 0 0
									N/A	0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 0 0 0

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

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME: R. L. Teuteberg, Regulation and Compliance Engineer

TELEPHONE NUMBER: AREA CODE 3 0 5 2 4 5 - 2 9 1 0

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

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

Event:
On December 22, 1984, at 3:00 p.m., the "B" Emergency Diesel Generator was declared out of service to replace an approximately 12-inch long section of vent line from the engine coolant discharge to the surge tank. The vent line was discovered to be leaking during daily operability testing of the "B" Emergency Diesel Generator (OP 4304.1). "A" Emergency Diesel Generator had been taken out of service earlier. The vent line was replaced by 3:03 p.m., and the "B" Emergency Diesel Generator was declared back in service at 4:15 p.m., after checking the line for leaks and successful completion of periodic test per OP 4304.1.

Cause of Event:
The vent line was leaking because the vibration of the engine coolant discharge line during diesel operation caused the crown holding the vent line in the coolant line to break.

Corrective Actions:
The approximately 12-inch section of leaking vent line and crown were replaced. A Plant Change/Modification (PC/M 85-05) was requested and implemented to replace the solid copper vent line with flexible piping to eliminate the vibration effects on the crown.

The USNRC was notified of a Significant Event pursuant to 10CFR50.72(b)(2)(ii)(d) via the ENS at 3:04 p.m. ~~The health and safety of the public were not affected.~~ Similar occurrences: LERs 250-84-036, 250-83-025, 250-83-003, and 250-82-006.

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NRC Form 366
(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)
Turkey Point Unit 3	0 5 0 0 0 2 5 0	1 OF 0 3

TITLE (4)
Emergency Diesel Generator ~~Surveillance Performance~~ Experience Voltage Spike

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	2 2	8 4	8 4	— 0 4 0	— 0 0	0 1	2 2	8 5	N/A	0 5 0 0 0

OPERATING MODE (9)		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
	N	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)	0 0 0	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	Voluntary
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
J. Arias, Jr., Regulation and Compliance Supervisor	3 0 5 2 4 5 - 2 9 1 0

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		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)

~~Voluntary Report~~

This report is being submitted as a means of documenting problems encountered and evaluations performed as a result of EDG testing in accordance with OP 4304.3. This report does not fall under the 10CFR50.73 reportability criteria but it is submitted as the result of agreements between NRC Region II and Turkey Point Plant Manager. ~~The results of evaluations, as described in the text portion of this report support the fact that th~~ ~~ealth and safety of the~~ public were not affected.

Inserts (see next page)

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S PDR

NRC Form 366
(9-83)

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

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

Voluntary Report

On December 22, 1984, with Unit 3 in a repair shutdown and Unit 4 at 100% power, the "A" Emergency Diesel Generator (EDG) was started for the eight hour full load and load rejection tests in accordance with Operating Procedure 4304.3. The results of this testing revealed that a short duration spike of approximately 5000 volts (maximum of 5170 volts) occurred during the initial second of the rejection.

Following the initial test performed, the recorder calibration was checked. This recorder was installed in order to obtain more accurate readings during the load rejection test. When difficulty was encountered in obtaining transducer calibration data, the test voltage and frequency transducers were recalibrated. The test was then rerun using a Temporary Operating Procedure (TOP). The results of the second test confirmed the results from the first test. Further evaluations by the Electrical Maintenance and Technical Departments concluded that:

1) The voltage regulator was already adjusted for optimum performance, therefore, the regulator settings were returned to their original values and a final test was performed.

2) From the test data and the voltage regulator Technical Manual, the voltage regulator was not capable of maintaining the generator transient voltage within the Technical Specification limits.

3) Based on the above, evaluations were initiated in the areas of: a) Technical aspects, b) Technical Specification compliance and interpretation, and c) design/performance aspects.

4) Similar testing was performed on the "B" EDG on January 4, 1985, and the results reflect identical conditions as those encountered on "A" EDG.

The results of the evaluations are as follow:

1) No hazardous condition was posed to plant equipment as a result of the voltage spike.

2) The vendor concurred that, based on test results, the regulator was performing as designed.

3) The PNSC reviewed the above referenced test data and concurred that the EDG full load rejection acceptance criteria should be based on steady state values instead of transient values.

4) Engineering evaluation concluded that the voltage and speed transients experienced during the full load rejection tests are acceptable, all equipment operated as designed and that no equipment degradation occurred. In addition, it was determined that Regulatory Guides 1.9 and 1.108 were not included in the design basis of the EDGs since they were manufactured prior to issuance of the Regulatory Guides. A copy of this evaluation is enclosed as an attachment to this report.

Corrective Actions:

1) FPL has committed to revising the EDG Technical Specifications by April 1, 1985. This is in response to Generic Letter 84-15. It is our intention to evaluate the EDG testing and acceptance criteria and any necessary changes will be included as part of this proposed amendment.

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

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

Evaluation of Emergency Diesel Generator Load Rejection

Tests of December 22 and 23, 1984

Purpose:

This evaluation has been conducted to determine if the transients obtained during the subject test exceeded any equipment design limits.

Scope:

The scope of this evaluation consists of analyzing the equipment which experienced the voltage transient to determine if any equipment design limits were exceeded, analyzing the increase in speed experienced to determine if it is within acceptable limits and analyzing the voltage regulator performance to determine if it is degraded from original design. Additionally, the applicability of Regulatory Guide 1.9 and 1.108 with respect to the design of the emergency diesel generators will be determined.

Discussion:

The maximum voltage transient experienced during the full load (2500 KW) rejection tests was in excess of 5000 volts (maximum of 5170 volts) for approximately one second. The following analysis shows that the voltage transient is within the voltage ratings of the affected equipment.

Per the manufacturer's data, the diesel generator breaker, potential and current transformers are designed to pass an applied A.C. potential test for one minute at 19 kV and to withstand an impulse of 60 kV. The diesel generator cables were designed and tested in accordance with IPCEA S-10-81 which states that this size cable shall withstand without failure a 13 kV A.C. voltage for five minutes. Per the manufacturer's instruction manual, the diesel generator stator was designed to pass a high potential test of 4.8 kV phase to ground (8.3 kV phase to phase) for one minute. As can be seen above, the applied potential tests for the affected equipment envelope the voltage transient experienced and, therefore, no equipment degradation is expected.

The engine speed transient also experienced during the full load rejection test was determined to be inherent to the system design, and to be within acceptable limits. Regulatory Guide 1.9 states that "the transient following the complete loss of load should not cause the speed of the unit to attain the overspeed trip setpoint". Based on this and the fact that the manufacturer's recommended trip setpoint was not reached, we conclude that the overspeed experienced is normal and resulted in no equipment degradation.

The voltage transient was also determined to be inherent to the system design. By comparison of the original factory load rejection test results with the subject test results, we have determined that the voltage regulator performance is not degraded.

Conclusion:

We conclude that the voltage and speed transients experienced during the full load rejection tests are acceptable, all equipment operated as designed and that no equipment degradation occurred as a result of these transients. In addition, we have determined that Regulatory Guide 1.9 and 1.108 were not included in the design basis of the emergency diesel generators since they were manufactured prior to issuance of the Regulatory Guides.

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)
Quad-Cities Nuclear Power Station, Unit 1	0 5 0 0 0 2 5 4	1 OF 0 3

TITLE (4) Two Low Pressure Coolant Injection Valves Fail to Open ~~MO 1-1001-29A and 1-1001-29B Failure~~

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)		
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR
0 8	0 8	8 4	8 4	0 1 4	0 0	0 8	1 4	8 4

OTHER FACILITIES INVOLVED (8)	
FACILITY NAMES	DOCKET NUMBER(S)
None	0 5 0 0 0
	0 5 0 0 0

OPERATING MODE (9)	2
POWER LEVEL (10)	0 1 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)
	20.405(a)(1)(i)		50.36(c)(1)	X	50.73(a)(2)(v)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)
	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)
	73.71(b)				
	73.71(c)				
	OTHER (Specify in Abstract below and in Text, NRC Form 366A)				

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
David B. Cook	3 0 9 6 5 4 - 2 2 4 1

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	

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)

During the Cycle 7 Refueling Outage, on August 8, 1984, at 4:25 p.m., it was discovered that both the 1-1001-29A and 1-1001-29B Low Pressure Coolant Injection Valves would not open. This was discovered as the Operator was in the process of starting the Shutdown Cooling mode of the Residual Heat Removal System. The Core Spray and Feedwater Systems were available to maintain level. Residual Heat Removal could be accomplished using the Reactor Water Clean-up System and the Residual Heat Removal System with the 1-1001-29B valve still 25 percent open.

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S PDR

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(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Quad-Cities Nuclear Power Station, Unit 1	0 5 0 0 0 2 5 4	8 4	— 0 1 4	— 0 0	0 2 OF 0 3

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

Event Description

During the Cycle 7 Refueling Outage, on August 8, 1984, at 4:25 p.m., while the Operator was in the process of starting the Shutdown Cooling mode of the Residual Heat Removal System (BO) (RHRS), it was discovered that both the 1-1001-29A and 1-1001-29B Low Pressure Coolant Injection (BO) (LPCI) valves would not open. The Core Spray (BM), Feedwater (SJ), and Control Rod Drive (AA) systems were all available to maintain level, and therefore the consequences of this event were minimal. Residual Heat Removal could be accomplished using the Reactor Water Clean-up System and the RHRS with the 1-1001-29B valve 25 percent open. This report is being submitted as required by the Code of Federal Regulations 10 CFR 50.73(a)(2)(v).

Cause

The cause of this deviation was personnel error. In 1980, Modification M-4-1-73-76 was installed. This modification consisted of a change in the logic circuits of the 1-1001-29A and 1-1001-29B valves in order to prevent them from hammering. Hammering is a condition where the motor continues to drive the valve closed until a high torque signal stops the motor. When the motor is stopped, the valve relaxes and the high torque signal is removed. With a close signal still present, the motor then again tries to drive the valve closed, until high torque is experienced. This chattering continues until the breaker is tripped or the close signal is removed.

The logic design was originated from the Station Nuclear Engineering Department (SNED). The Station was sent schematic diagrams of the designs and the wiring diagrams were then originated here at the Station. A mistake was made when the wiring diagrams were drawn. In 1980, these logic circuits were installed as per the faulty wiring diagrams and thus, the possibility of hammering still existed. No problems were experienced with these two valves after the installation of the modification however, because the motor operators present on the valves at that time were equipped with brakes. The intended purpose of the brakes is to stop the momentum of the valve at the desired valve position. An additional feature of the brakes is that the brakes also stopped the valve at the end of its closed stroke and thus, prevented the hammering condition. During the past refueling outage these motor operators were replaced with Environmentally Qualified motors. Brakes cannot be qualified for Environmentally Qualified motors and these valve operators were analyzed as not requiring brakes.

When these valves experienced a continuous closed signal, as from a control switch held in the closed position, or a LPCI Loop Select signal during surveillance testing, they continuously tried to close and both valve stems were damaged. The damage was such that the valves would no longer fully open.

Cause (continued)

They were visually inspected immediately and the 29B valve was found to be 25 percent open and the 29A valve was found fully closed. The wiring diagram problem affected only the anti-hammer circuit of the 29A and 29B valves and did not affect their LPCI Loop Select logic.

Corrective Action

The valve stems were removed and are being replaced. The wiring correction has been done and the wiring diagram has been corrected to reflect that change. With our new modification program, there is no longer the possibility of a personnel error of this type. Drawings that are now sent to the Station from SNED, schematics and wiring diagrams are now both drawn by them, receive a Technical Review by Engineers on the Station Technical Staff before the modification can be implemented. The Station has investigated all circuits modified under M-4-1-73-76 and, also M-4-2-73-76 performed on Unit 2. The Unit 2 1001-29A and B were found to have the same mistake and were corrected. Additionally, all motor operators and motors that were replaced to comply with Bulletin 79-018, Environmental Qualifications, were checked to determine if the wiring diagrams and schematics were functionally the same. This investigation revealed that the High Pressure Coolant Injection (BJ) (HPCI) valve 1-2301-3 did not have the anti-hammering circuit installed. The anti-hammering circuit will be installed under Modification M-4-1-84-24. No other discrepancies were found. The Station feels no further corrective action is deemed necessary.

NRC Form 366 (9-83)

UPDATE REPORT - PREVIOUS REPORT DATE 7/24/84

LICENSEE EVENT REPORT (LER)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Browns Ferry - Unit 1	0 5 0 0 0 2 5 9	1 OF 0 2

TITLE (4): ~~Reactor Manual Scram due to~~ Update on Main Steam Relief Valve Lifting

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 NAME	DOCKET NUMBER(S)
0 6	2 7	8 4	8 4	- 0 2 7	- 0 1	0 8	2 8	8 4	on file	0 5 0 0 0
					No Rev. 0					0 5 0 0 0

OPERATING MODE (9)	POWER LEVEL (10)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
N	0 0 1	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
D. L. Smith	2 0 5 7 2 9 - 0 8 6 5

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

		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)

During normal unit startup following a short unit outage, while approaching 1 percent power with approximately 400 psig reactor pressure, a main steam relief valve began to unseat. It continued to leak causing the torus temperature to approach technical specification limits and the unit was manually scrammed at 350 psig. The relief valve subsequently reseated at 100 psig. No unusual occurrences followed.

The valve was replaced and the unit restarted. The relief valve was tested at Wyle Laboratories; it performed normally. It was then disassembled and all internal parts were found to be normal. No reason, either electrical or mechanical, could be found to explain the premature valve actuation. No further corrective action is necessary.

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NRC Form 366 (9-83)

On June 27, 1984, unit 1 was in startup at 1 percent power, unit 2 was at 49 percent power, and unit 3 in a refueling outage. Unit 1 was the only unit affected by this event.

Unit 1 was in startup and approaching 1 percent power at approximately 400 psig reactor pressure, when the pressure control valve 1-4 (RV) unseated. As reactor (RCT) pressure decreased, torus (BT) temperature was approaching its technical specification limit; therefore, a reactor manual scram was initiated at 350 psig. The valve subsequently reseated at 100 psig. No unusual events followed, and there was no safety significance to this event.

The relief valve was completely and thoroughly tested, both electrically and mechanically, by TVA, Wyle, and Target Rock personnel. The initial test actuation pressure was recorded to be 2.2 percent above acceptable criteria. This is a common problem industry wide for first time actuation of relief valves after a long period of standby readiness. Subsequent actuations were all within limits. After it was tested, the valve was disassembled and inspected. No reason could be found for premature valve actuation. The valve was recertified and placed into service on unit 3. No further corrective action is required.

Responsible Plant Section - N/A

Previous Similar Events

BFRO-50-259/7726
BFRO-50-259/7713
BFRO-50-260/7503
BFRO-50-260/7430
BFRO-50-260/7429
BFRO-50-259/7349
BFRO-50-259/7314

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)
Browns Ferry - Unit 1	0 5 0 0 0 2 5 9	1 OF 0 4

TITLE (4)
Overpressurization of Core Spray Piping

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	1 4	8 4	8 4	— 0 3 2 —	0 0	0 9	1 3	8 4		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)	X 50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
P. N. Ehersole	2 0 5 7 2 9 - 0 7 8 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

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)

With the reactor operating at 100 percent steady state power, a personnel error during the performance of surveillance test 4.2.B.39-A, "Core Spray Logic Test," allowed the inboard injection valve, FCV 75-25, to open. Previous maintenance to the solenoid which controls the air to the actuator of the inboard isolation valve (a testable check valve) caused the actuator to hold the check valve in the open position. This allowed a backflow of reactor coolant into loop I of the core spray system at the system relief valve letdown flow rate. This valve alignment also pressurized the core spray piping to near reactor pressure and heated portions of the piping to a maximum of 400°F.

Loop I was isolated which placed the unit in a 7-day limiting condition of operation. The unit was shutdown and the solenoid repaired. The system and appurtenant equipment were inspected and no damage was noted. Engineering evaluation of the affected piping and supports indicated that the transient did not affect system integrity for continued use.

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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	
Browns Ferry - Unit 1	0 5 0 0 0 2 5 9	8 4	— 0 3 2	— 0 0	0 2 OF 0 4

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

During normal operation on August 14, 1984 at 0938, unit 1 was at 100 percent power, unit 2 was at 66 percent power, and unit 3 was in a refueling outage. This event affected unit 1 only.

During conduct of a surveillance test 4.2.B.39-A, "Core Spray Logic," a licensed reactor operator error [failure to open valve breaker (BKR)] was made that allowed the inboard injection valve (INV), FCV 75-25, to open while the outboard injection valve, FCV 75-23, was in its normally open position. During normal operation, logic interlocks prevent this situation from occurring. This surveillance test, however, simulates automatic core spray (BM) actuation; therefore, administrative controls, specifically the opening of the FCV 75-25 breaker, are necessary to prevent valve movement.

In this configuration, isolation from the reactor vessel (RPV) to the core spray system is provided by the testable check valve (V), FCV 75-26. However, as post-incident investigations indicated, maintenance previously performed on the testable check valve caused it to be held open while indicating closed. This is discussed in more detail below.

In this arrangement, the core spray system was aligned to the reactor. The operator in the control room and the operator conducting the test were aware that FCV 75-25 had opened. This action was not addressed in the procedure and the operator conducting the test proceeded to review the test instruction to ascertain if this operation was erroneous. A core spray system high pressure annunciator (ANN) would have been expected to alarm if the testable check valve was not holding. Also, the control room operator did not notice a system pressure change.

At about 0945 a roving fire watch noticed smoke near loop I core spray piping and phoned in a fire alarm. The fire brigade entered the reactor building (NG) and correctly assessed that reactor water was leaking back into the core spray system. The unit 1 assistant shift engineer phoned the unit 1 operator and instructed him to close the injection valve to isolate the system. The operator responded and terminated the event. Duration of the event was approximately 13 minutes. The fire brigade had also noted a water/steam mixture being sprayed from the core spray pump "A" seal area. Several workers received clothing contamination as a result of walking in this water.

Core spray loop I was isolated and tagged, which placed the unit in a 7-day limiting condition of operation. In the meanwhile, the plant manager ordered an investigation of the event. Site engineering and maintenance staffs inspected all affected components and found no damage. The extent of the pipe heating was determined by examination of paint damage on the piping. The maximum temperature experienced was estimated to be below 400°F. Paint damage extended from the injection valves down to the system relief valve (RV). Tennessee Valley Authority's Engineering Design analyzed the system piping and supports (SPT) for the transient and found that integrity for continued use was assured. The pump "A" seal (SEAL) was removed and no damage was observed. Also, there was no evidence that hot water entered the pump area piping, which indicates the pump discharge check valve was holding. This apparent seal leakage was attributed to be backflow through the above seal leakoff from the clean radwaste (WD) drain system header. The system relief valve ties to the same local header.

The investigations and analyses suggested that the testable check valve was not holding. The affected unit was shutdown on August 21, 1984 and the drywell (BD) entered for a physical inspection of the valve. This inspection indicated that the testable check valve was being held open because of an improper insert in the testable actuator solenoid (SOL). Improper operation of the solenoid apparently caused confusion which resulted in the indicating wiring being altered to provide the apparent correct indicated position. Maintenance history was researched; however, it cannot be conclusively determined when the error was made.

Immediate corrective action was to correct the solenoid assembly and indicating circuitry. Similar installations on the other core spray loop, and the residual heat removal (BO), high pressure coolant injection (BJ), and the reactor core isolation coolant (BN) systems on units 1 and 3 were examined and found not to have a problem. History records and accessible wiring were examined on unit 2 to provide confidence to continue operation to the scheduled refueling outage in September 1984. The root cause of this event was determined to be twofold. First, an improper insert in a rebuilt solenoid valve caused the airflow internal to the solenoid to be misdirected. Secondly, an operator error, which in part may have been prevented by improved wording in the procedure regarding the valve breaker manipulations, caused the opening of FCV 75-25. To prevent recurrence, procedures have been revised to be more descriptive in valve and actuator maintenance and return to service checks. In addition operator training was conducted on this event with particular attention to valve breaker manipulation and a change is being made to this surveillance instruction which will make the wording more specific. A detailed report is being prepared at the plant which will address generic considerations. This report will be finished by the end of September.

An additional event occurred following the incident which had no bearing on the sequence described above, but which is reportable. As the licensed reactor operators began to "back out" of the surveillance test, all eight diesel generators (DG) received an automatic start signal. This occurred under similar circumstances as was reported in Licensee Event Report BFRO-50-296/84008 on unit 3. A special test was subsequently performed to determine if the test switch (HS) utilized in this surveillance was causing these spurious starts. No problem was found and the automatic starts are attributed to incomplete reset of the core spray logic prior to disconnecting the test switch. The surveillance instruction is being examined to see if resequencing particular steps can minimize recurrence possibilities. There was no safety concern as the diesel generators were available to perform their intended functions.

The purpose of this core spray check valve is to limit loss of reactor coolant outside containment in the event of a core spray line break. The design is passive to the extent that the testable actuator will not impede valve closure if any substantial flow is across the valve in the reverse direction. Thus, for this case, the check valve remained operable to fulfill its design function. The reverse flow during this event was comparatively low and would not have been sufficient to override the actuator and close the valve.

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

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

There are broader considerations regarding protection of the core spray system from pressure and temperature transients. Generic implications of the incident and additional recommendations to prevent similar recurrences will be completed by September 30, 1984.

Responsible Plant Section OP

Previous Similar Events BFRO-50-296/84008

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)
Quad-Cities Nuclear Power Station, Unit 2	0 5 0 0 0 2 6 5	1 OF 0 5

TITLE (4)

Reactor Scram Due to High Reactor Pressure While in Hot Standby

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)
									NA	0 5 0 0 0
1 0	2 5	8 4	8 4	0 1 0	0 0	1 1	1 6	8 4		0 5 0 0 0

OPERATING MODE (9)	3	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	XX 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
H. DO	3 0 9 6 5 4 - 2 2 4 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On October 25, 1984, Unit 2 was in HOT STANDBY with all outboard Main Steam Isolation Valves closed. At 6:41 a.m., Unit 2 scrammed due to an increase in Reactor pressure resulting from a procedure deficiency which lacked specific instructions dealing with controlling Reactor pressure while in HOT STANDBY. During the scram, one control rod was not inserted because its scram discharge riser valve was mispositioned. The procedure is being revised and necessary measures have been taken to guard against a recurrence of this event. Core reactivity was under control and the Reactor was shutdown throughout the event, therefore, the safety implications were minimal.

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NRC Form 366
(9-83)

Event Description

On Wednesday evening, October 24, 1984, the Unit Two nightshift Control Room operator was assigned the task of bringing the unit to the HOT STANDBY condition per procedure QGP 2-4. At 5:46 a.m., on October 25, 1984, this procedure was completed through step D.35 and all outboard Main Steam Isolation Valves (MSIV) were closed. Once the outboard MSIVs were closed, it was observed that Reactor pressure started to increase. In an attempt to control pressure, additional control rods were inserted into the core. Since the Reactor core was already subcritical, the insertion of additional rods had no effect on the increasing pressure. A second attempt was made to control pressure by starting the Reactor Core Isolation Cooling (RCIC)(BN) System. RCIC tripped on overspeed and had to be manually and locally reset at the Turbine. Concurrently, the High Pressure Coolant Injection (HPCI)(BJ) System was started by another operator; but, the Reactor scrammed from a high pressure of 1044 psig at 6:41 a.m.

When the Reactor scrammed, one rod, K-13, remained at position 48. Control Rod K-13 was successfully inserted from the individual rod scram back-panel at 7:12 a.m. At 7:13 a.m. it was confirmed that all control rods were fully inserted.

Although other personnel performance and equipment failure concerns were identified, the actual consequences of this deviation were minimal. The Reactor properly tripped by a function of the Reactor Protection System. Although one control rod was not inserted during the scram, core reactivity was under control, and the Reactor was shutdown.

This report is being submitted as required by the Code of Federal Regulations, Title 10, Part 50.73(a)(2)(iv).

Cause

The root cause of this scram was procedural inadequacies. Contributing causes were equipment failure and personnel performance.

Shutdown From Power Operation to Hot Standby procedure, QGP 2-4, failed to anticipate a possible pressure increase while in HOT STANDBY, due to decay heat from the core. This resulted in the lack of specific instructions dealing with such a condition.

Cause (continued)

An inspection of the Hydraulic Control Unit (HCU) 38-51, which drives Control Rod K-13, revealed that the scram discharge riser valve, EP 305-112, was CLOSED, preventing the drive from venting properly when the scram took place. A thorough investigation was conducted to determine the root cause of the manual valve 112 being closed by re-examining Work Requests, Out of Service requests subsequent to the refueling outage, the September 18 hot scram timing surveillance tests, accumulator alarms logged in the Unit Operator's log book subsequent to the September 18 hot scram surveillance tests, and work performed on CRD modules in the vicinity of that for the K-13 HCU (on both units). Despite all of the above measures, the reason for valve EP 305-112 being in the improper position could not be determined.

The overspeed trip of RCIC is being investigated by Station Nuclear Engineering Department as per Action Item Record 4-84-27.

Personnel performance concerns centered around operator attentiveness at Unit One during the transient on Unit Two, and Shift Supervisor responsibilities during a transient.

Corrective Action

Shutdown From Power Operation to Hot Standby procedure, QGP 2-4, will be revised to include necessary steps to control Reactor pressure while in HOT STANDBY. All Control Room personnel were instructed to make a thorough review of the computer rod position scan as soon as possible after a scram to detect any unscrammed control rods as well as rods at intermediate position.

After the discovery of the mispositioned valve 112, Operating Department personnel inspected the other 176 HCU's on Unit Two and all 177 HCU's on Unit One to verify correct position of all valves. No other valves that would affect the operability of the drives were found mispositioned. The Shift Foremen were instructed to survey the position of all manual valves on the Hydraulic Control Units once per day, in the evening, for both units. This surveillance will continue until the six valves that control the major lines from the HCU are lockwired and valves associated with the accumulator charging equipment are relabeled to eliminate possible confusion.

Corrective Action (continued)

The following additional corrective actions were taken in response to some of the Nuclear Regulatory Commission's concerns as mentioned in the Confirmatory Action Letter dated on October 26, 1984:

1. Friction, Timing, Scram and Stall Flow Tests were performed on Control Rod Drive 38-51 per procedures QTS 130-1, 3, and 4 prior to its removal. All results obtained from these tests were found acceptable.

2. The Control Rod Drive 38-51 was replaced by a new drive and operability tests were conducted on the newly installed drive per procedures QTS 130-1, 3, and 4. All results of the Friction, Timing, Scram, and Stall Flow tests were within limits specified in the appropriate procedures.

3. The internals of the removed Control Rod Drive were examined. No excessive wear or damage was found on the seals of the drive piston, on the bushing of the stop and drive pistons, on the index tubes, and on the spring washers of the stop piston. The seal on the stop piston was found to be damaged, however, this has been considered as normal wear.

4. The Control Room operators were instructed not to leave an operating unit unless Control Room evacuation is necessary. The method of relief when leaving the Control Room or going behind the control panels does not change. If one of the units requires the help of an additional operator, either the center desk operator or the operator from the stable unit may assist, but not both at the same time. There must always be a qualified operator, at the control, who is aware of his responsibility, left in charge of the stable unit. Also, all Operating personnel were instructed not to attempt a shift change when a unit is experiencing a transient. The shift change must wait until the unit is stabilized. The apparent reason for Control Rod K-13 failure to scram was discussed with all Equipment Attendants and Operators so that they can be on the alert for other incidents of a similar nature.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Quad-Cities Nuclear Power Station, Unit 2	0 5 0 0 0 2 6 5	8 4	— 0 1 0	— 0 0	0 5 OF 0 5

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

Corrective Action (continued)

5. As a result of the deviation, the Corporate Office is re-evaluating their Nuclear Stations Division Directives and will issue any necessary revisions.

Items 1, 2, and 4 were completed prior to the return of Unit Two to service.

There have been no previous occurrences of this type at Quad-Cities Station.

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)
Quad-Cities Nuclear Power Station, Unit 2	0 5 0 0 0 2 6 5	1 OF 0 3

TITLE (4)
Unit 2 HPCI Isolated Due to Temperature Switches Tripped. (5 west. area)

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	1 9	8 4	8 4	— 0 1 4	— 0 0	0 1	2 9	8 5	NA	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	4	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 9 9	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
H. Do	3 0 9 6 5 4 - 2 2 4 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	B J	J S	L 2 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 September 19, 1984, Unit Two was operating at 99 percent thermal power. At 11:20 a.m. a High Pressure Cooling Injection System (HPCI) (BJ) isolation occurred while the system was being run at low speed during Turbine warming. This was caused by a small intermittent leak from a steam seal on the HPCI Turbine. The HPCI isolation was reset at 11:45 a.m. However, when reset, valve MO 2-2301-4 failed to open from the Control Room. This rendered HPCI inoperable. Since the Low Pressure Coolant Injection mode of the Residual Heat Removal System was also inoperable for preventative maintenance, the decision was made to shutdown Unit Two. This shutdown was never initiated however, because Electrical Maintenance personnel got valve 2-2301-4 open at 12:10 p.m., only five minutes after deciding to shutdown, and prior to initiating a load drop. Because of the short time duration of the event, the safety impact of this occurrence was minimal.

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(9-83)

Event Description

On September 19, 1984, Unit Two was operating at 99 percent thermal power. At 11:10 a.m., the High Pressure Coolant Injection System (HPCI) (BJ) was being run at approximately 2500 rpm in accordance with the HPCI System Manual Startup procedure, QOP 2300-3.

At 11:20 a.m., a HPCI isolation occurred. This isolation was caused by a small intermittent steam leak from a steam seal on the Turbine. The HPCI isolation was reset at 11:45 a.m. The outboard steam isolation valve, MO 2-2301-5, was opened fully. When the Unit Operator tried to open the inboard steam isolation valve, MO 2-2301-4, from the Control Room, a dual indication was received. This indicated the valve had come off its seat but would not open completely. The HPCI System was declared inoperable. Because the Low Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal System (RHRS) was also inoperable, due to preventative maintenance, the decision was made at 12:05 p.m. to shutdown Unit Two to satisfy the requirements of Technical Specification 3.5.C.3. At 12:10 p.m., prior to any actual load drop, Electrical Maintenance personnel got the 2-2301-4 valve open and successfully cycled the valve three times. Therefore, the Reactor shutdown was terminated. HPCI monthly operability tests, QOS 2300-2 and QOS 2300-3, were successfully completed at 5:10 p.m. on September 19, 1984. The seal leak present at extended low Turbine speeds did not appear at higher speeds. Had an Auto initiation of HPCI occurred, the Turbine would have rapidly ramped up to full speed and successfully operated.

The 10 CFR 50.72 Red Phone Notification to the Nuclear Regulatory Commission was not made in this case because the problems that caused the HPCI System to be inoperable were corrected (i.e., HPCI became operable again) well within the reporting time interval required.

Because of the short time duration, approximately 25 minutes, during which valve 2-2301-4 was inoperable, the safety impact of this deviation was minimal. Initially, this occurrence had been treated as a non-reportable event. However, during the evaluation process, it was decided to upgrade this event to a reportable occurrence as required by the Code of Federal Regulations, 10 CFR 50.73(a)(2)(v).

Cause

The cause of the HPCI isolation was a small intermittent steam leak from the Turbine seal during extended low speed operation. There are temperature switches located at each end of the Turbine near the seals. Due to the design of the existing Temperature Detection System in the HPCI room, the temperature switches in the proximity of the steam leak responded to initiate an unnecessary HPCI isolation.

The setpoint of the motor operator's closed side limits has been determined to be the cause of valve 2-2301-4 failure to open. The closed side limits were set too close to the point where the valve disc just lifted off of its seat. This in turn caused the LS/C contact, which bypasses the torque switch on initial valve opening, to open prematurely. When the valve was opened, the amount of torque that was required to lift the valve disc off its seat was of sufficient magnitude to cause a spurious opening of the torque switch; thus, preventing the valve from opening any further. A borderline setting of these limits can also cause the open position indicator to energize before the disc actually lifts off its seat; thus, giving a dual indication.

The limit switch is a two-train geared limit switch, part number 310A49, manufactured by Limitorque Corporation.

Corrective Action

The closed side limits on valve 2-2301-4 were readjusted so that the LS/C contact, which bypasses the torque switch on initial valve opening, will open only after the valve disc has lifted off its seat. The valve was successfully stroke tested three times on December 29, 1984, after the readjustments were performed under Work Request Q39536.

HPCI isolations due to the activation of the HPCI high temperature switches have occurred in the past. The last occurrence of a similar nature is documented in Deviation Report 4-2-84-51. Because of past occurrences, Action Item Record 4-82-30 was initiated to find a more reliable design for the temperature detection systems in the HPCI rooms.

As for the failure of valve MO 2-2301-4 to open, there has been one previous occurrence of a similar nature. This is documented in Deviation Report 4-1-77-89, in which valve MO 1-2301-4 failed to re-open after a monthly HPCI Steam Line High Flow Functional Test.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Vermont Yankee Nuclear Power Corporation	0 5 0 0 0 2 7 1	1 OF 0 3

TITLE (4)
Diesel Generator Lockout Trip of Both Generators

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 3	8 4	8 4	— 0 2 2	— 0 0	1 1	2 0	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	1 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	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
James P. Pelletier, Plant Manager	AREA CODE 8 0 2 2 5 7 - 7 7 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	
X	E K	8 7	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 10/22/84 at 1335 EST, diesel generator 1-1-A experienced a generator lockout trip caused by a differential relay trip. At 0140 EST on 10/23/84, Control Room personnel noted a loss of diesel generator 1-1-B, also resulting from generator lockout trip caused by differential relay trip.

The differential relay trips resulted from the failure of a Zener diode in each of the differential relays. The Zener diode is in parallel with a silicon-controlled rectifier in the Westinghouse type SA-1 differential relays.

On 10/23/84 at approximately 1730 EST and on 10/24/84 at approximately 2000 EST, the relays for diesel generators 1-1-B and 1-1-A respectively were restored and the diesels were declared operable.

Corrective action will consist of installing the newer version of the Westinghouse SA-1 relay which is designated for Class 1E applications and no longer uses the Zener diode across the output SCR.

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(9-83)

With the plant at normal full power on 10/22/84 at 1335 EST, Control Room personnel received diesel generator 1-1-A lockout and differential alarms. Local investigation revealed that the lockout relay had tripped due to differential relay trip and that it would not reset. This occurrence happened 11 days after completion of monthly technical specification surveillance on the diesel generator.

At 2105 EST on 10/22/84, alternate surveillance testing on diesel generator 1-1-B was successfully completed.

At 0140 EST on 10/23/84, Control Room personnel received diesel generator 1-1-B lockout and differential alarms. Local investigation again revealed that the lockout relay had tripped due to differential relay trip and that it would not reset.

Since both diesel generators were inoperable, a reactor shutdown was initiated in accordance with Tech. Spec. Section 3.5.H.1 and an Unusual Event was declared.

On 10/23/84 at approximately 1730 EST, the relay for diesel generator 1-1-B was repaired and, after satisfactory testing, the diesel was declared operable. The reactor shutdown was terminated and ascension to full power began. On 10/24/84 at approximately 2000 EST, the relay for diesel 1-1-A was repaired and, after testing, the diesel was declared operable.

The cause of the Westinghouse SA-1 differential relay malfunction was determined to be due to failure of a Zener diode in each of the relays. The Zener diode is installed across the anode and cathode of the SCR on the output of the differential relay. The diode short-circuited, which resulted in actuation of the lockout relay.

During investigation of the cause of the differential relay trip it was noted that surge protection across the lockout relay coils of both diesel generators lockout relays were installed backwards. The surge protection consists of a 47 ohm resistor and a 180 volt Zener diode. It was determined that the surge protection circuit did provide some protection as it was installed since the diode was a Zener diode, and any time the voltage exceeded the 180 volt breakdown voltage, the Zener diode would conduct. The diode was, however, reversed so that the anode was connected to the positive side of the DC supply.

Due to the unusual circumstances of the same diode failure occurring in redundant systems, an investigation to attempt to determine the cause of the diode failures was conducted. Vermont Yankee personnel met with Westinghouse Relay-Instrument Division and it was mutually concluded that the specific cause of the Zener diode failures could not be positively determined. The Zener diode failures probably resulted from component end of life or from the cumulative damage from normally experienced switching transients within the DC system. The polarity of the suppression circuit of the lockout relay may have contributed to increased stress and shortened life.

The corrective action will consist of installing the newer version of the Westinghouse SA-1 relay which is designated for Class 1E applications. The relay no longer uses the Zener diode across the output SCR but has a resistor capacitor network across the SCR. The circuit also uses two additional capacitors for surge protection.

It was also determined during the meeting with Westinghouse that use of the repaired relays did not place the system in immediate jeopardy of another Zener failure.

In order to have the best possible system reliability, the latest Westinghouse design commercial grade relays, which have been evaluated to be a one-for-one replacement for the existing relays, are being installed on an interim basis until receipt of relays designated for Class 1E service. These relays are electrically and functionally the same as those designated for Class 1E use.

Another significant item was discovered during troubleshooting of one of the failed differential relays. It was determined that replacement of the relay trip indicating lamp with an incorrect voltage bulb can prevent the relay from tripping. When the relay simulated a trip upon Zener diode failure, illumination of the indicating lamp was expected. Since the bulb did not light as expected, it was replaced. Inadvertent replacement of the bulb with one with a lower voltage rating resulted in the relay not tripping when tested. Due to the higher amperage through the bulb, insufficient current was available for firing the output SCR. It should also be noted that the part number for the bulb is not contained in the parts list for either the relay in service at Vermont Yankee or for the present Westinghouse design relay. The correct part number of the bulb was obtained and the installed bulbs were verified correct.

No similar occurrences of this type have been reported to the Commission.

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(9-83)

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Salem Generating Station	0 5 0 0 0 2 7 2	1 OF 0 4

TITLE (4)

Foreign Material in Charging Pump Suction Lines

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 6	8 4	8 4	— 0 1 7	— 0 0	0 8	1 6	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	POWER LEVEL (10)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
6	0 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
J. L. Rupp	AREA CODE 6 0 9 — 3 3 9 - 4 3 0 9

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	C B	P	P 0 2 5	Y							

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X YES (If yes, complete EXPECTED SUBMISSION DATE)	NO		1 0	1 8	8 4

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

On July 16, 1984, No. 12 Charging Pump was disassembled for inspection and repair, due to seizure of the pump during surveillance testing on July 13, 1984. A small amount of resin particles and metal filings were discovered in the pump casing. Further inspection revealed similar material in the suction lines to all charging pumps. Because of the extremely close internal tolerances of the centrifugal charging pumps, it is felt that the metal filings probably caused the seizure of the pump. If this was actually the cause, and not an isolated case of pump failure, it is reasonable to assume that if the redundant centrifugal charging pump had been operating, it could possibly have experienced a similar failure. Since this event could be interpreted as a condition which alone could have prevented the fulfillment of the safety function of a system to mitigate the consequences of an accident, the occurrence is being conservatively reported in accordance with 10CFR 50.73(a)(2)(v)(D). It is felt that the metal filings originated from maintenance activities, and were entrained in the Spent Fuel Pit Demineralizer or the Mixed Resin Bed Demineralizer. These were then released (along with resin particles) during previous resin flushing operations. An investigation is continuing, and a supplemental report will be issued, identifying the cause and corrective actions taken.

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NRC Form 366
(9-83)

PLANT AND SYSTEM IDENTIFICATION:

Westinghouse - Pressurized Water Reactor

Energy Industry Identification System (EIIS) codes are identified in the text as [XX].

IDENTIFICATION OF OCCURRENCE:

Foreign Material in Charging Pump Suction Lines

Discovery Date: 07/16/84

Report Date: 08/16/84

This report was initiated by Incident Report No. 84-113

CONDITIONS PRIOR TO OCCURRENCE:

Mode 6 - Rx Power 000 % - Unit Load 0000 MWe

DESCRIPTION OF OCCURRENCE:

On July 13, 1984, during a refueling outage, while performing surveillance testing of No. 12 Charging Pump [CB], the pump seized after running for approximately thirty (30) seconds. No. 12 Charging Pump was declared inoperable. The redundant charging pumps remained in an operable status, and the Unit was in Mode 6; therefore, entering into an action statement was not required.

Upon disassembly of the pump, on July 16, 1984, a small amount of resin particles and metal filings were discovered in the pump casing. As a result of these findings, an investigation ensued to determine the source and extent of the problem. On July 19, 1984, similar material was found in the common suction line of all charging pumps.

APPARENT CAUSE OF OCCURRENCE:

The resin originated from either the Spent Fuel Pit Demineralizer or the Mixed Resin Bed Demineralizer during previous resin flushing operations. The metal filings, entrained in the resin and released to the system during the resin flushes, apparently entered the system from maintenance activities. Due to the close internal tolerances of the centrifugal charging pumps, and the lack of any other positive findings upon inspection of the pump, it is felt that the metal filings (although a very small amount) could possibly have contributed to the seizure of No. 12 Charging Pump. In addition, inspections of the Refueling Water Storage Tank revealed that it contained a significant amount of resin.

ANALYSIS OF OCCURRENCE:

If the failure of No. 12 Charging Pump was actually caused by the metal filings introduced into the Charging System, it is reasonable to assume that if the redundant centrifugal charging pump (No. 11) had been operating, it could possibly have experienced a similar failure. If this was actually the cause, and not an isolated case of pump failure, the event could be interpreted as a condition which alone could have prevented the fulfillment of the safety function of a system to mitigate the consequences of an accident. For this reason, the occurrence is being conservatively reported in accordance with the Code of Federal Regulations, 10CFR 50.73(a)(2)(v)(D), and an analysis of the occurrence follows.

Since the positive displacement type pump (No. 13 Charging Pump) had been operated on numerous occasions since the suspected intrusion of the resins and metal filings, it appears that the clearances in that pump were sufficient to allow the material to pass without causing damage. However, had that pump also failed, the charging pumps and boration flow paths required by Technical Specification 3.1.2.1 and 3.1.2.3 would not have been available. This is an acceptable condition during Mode 5 and 6 operation, provided there are no evolutions in progress which would result in a positive reactivity addition to the core. This is not an acceptable condition during Modes 1 through 4 operation, since the loss of the charging pumps would also result in a loss of seal injection to the Reactor Coolant Pumps and the inoperability of both Emergency Core Cooling System trains. The loss of both centrifugal charging pumps during an accident is not an analyzed condition.

As previously stated, No. 12 Charging Pump failed while the Unit was in Mode 6, and operability of the pump was not required. In addition, the problem was discovered during a routine pump surveillance. We feel confident that if the pump failure was, in fact, due to the metal filings, it would most likely have failed (and been discovered) prior to Mode 1 or 2 operation. This is due to the additional required surveillances to prove pump and system operability prior to changing operational modes.

Although the Refueling Water Storage Tank contained a significant amount of resin, a minimal amount was actually located in the charging pump suction lines. The recent undercore support plate inspection of the reactor vessel revealed no foreign material; i.e., resin, metal filings or any other contaminants. This inspection was performed with the reactor core empty, prior to the fuel reload. In addition, no resin or metal filings have ever been discovered during any maintenance activities performed on Reactor Coolant System components.

CORRECTIVE ACTION:

The rotating element in No. 12 Charging Pump is being replaced. Inspections of No. 11 Charging Pump revealed wear; therefore, as a precautionary measure, the rotating element of that pump is also being replaced. Boroscope inspections and extensive cleaning of the charging pump suction lines has been performed. The horizontal portion of the suction header was hydrolazed, and the Refueling Water Storage Tank was cleaned. Temporary strainers were installed in the suction to the charging pumps. These strainers will be utilized during the final flushes of the Charging System.

Due to this occurrence, Unit 2 Refueling Water Storage Tank was also inspected. The tank bottom was vacuumed, and a minimum amount of debris was removed, indicating that the problem was unique to Unit 1. An investigation is continuing, and a Safety Evaluation is being prepared. The Safety Evaluation will address the cause of the resin and metal filing contamination. Based on the findings, system, quality control during maintenance and/or procedural changes will be made, as necessary, to preclude recurrence. A Safety Evaluation is also being prepared.

General Manager-
Salem Operations

JLR:tns

SORC Mtg 84-103

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)
DIABLO CANYON, UNIT 1	0 5 0 0 0 2 7 5	1 OF 0 3

TITLE (4)
INOPERABLE EMERGENCY CORE COOLING SUB 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 4	0 7	8 4	8 4	— 0 1 3 —	0 0	0 5	0 7	8 4	DIABLO CANYON UNIT 2	0 5 0 0 0 3 2 3
										0 5 0 0 0

OPERATING MODE (9)	3	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	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
WILLIAM J. KELLY, REGULATORY COMPLIANCE ENGINEER	AREA CODE 8 0 5 5 9 5 - 7 3 5 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On April 7, 1984, at 0930 PST, while in Mode 3 (Hot Standby), it was discovered that both subsystems to Emergency Core Cooling System (ECCS) (BQ) had been inoperable since 1910 PST on April 6, 1984. This condition was not in compliance with Technical Specifications Sections 3.0.3 and 3.5.2. Both ECCS subsystems were restored to operable condition at 1010 PST on April 7, 1984. The causes contributing to this condition were 1) operators failed to recognize that a Limiting Condition for Operation (LCO) had been exceeded and 2) an operating procedure that did not provide adequate guidance to alert operators to a Technical Specification requirement. Corrective actions include revision of the applicable operating procedures, review of all other safety-related operating procedures to detect and correct similar situations, and initiating the development of a Plant Component/Technical Specification cross reference document for operator use.

8405100006 840507
PDR ADOCK 05000275
S PDR

NRC Form 366
(9-83)

On April 7, 1984, at 0930 PST while in Mode 3 (Hot Standby), it was discovered that both subsystems of the Emergency Core Cooling System (ECCS) (BQ) had been inoperable since April 6, 1984 at 1910 PST (14 hours, 20 minutes). This condition was not in compliance Technical Specification sections 3.0.3 and 3.5.2.

On April 6, 1984, the plant experienced an anticipated safety injection as part of steam generator safety valve (RV) startup testing. The safety injection resulted in the discharge of the contents of the Boron Injection Tank (BIT) (TK) (CB) into the Reactor Coolant System (AB). To recharge the BIT with 12 percent boric acid solution, licensed operators, using approved procedures, inhibited the automatic opening feature of the BIT inlet and outlet valves (ISV) (CB) during the recharging operation. This practice prevents problems which might occur due to an inadvertent safety injection signal (JE) while the BIT is being drained prior to recharging with boric acid. With the BIT inlet and outlet valves disabled, there is no ECCS flowpath from the charging pumps (P) (BQ) through the BIT to the Reactor Coolant System. Operations personnel were concentrating on restoring the BIT and did not consider the requirement of the ECCS Technical Specification. Additionally, the approved operating procedure did not provide any Technical Specification guidance to the operators that two sections of Technical Specifications were involved.

After completion of recharging the BIT with 12 percent boric acid solution, and upon discovery of this condition, the BIT inlet and outlet valves were made operable and the system returned to operable status by 1010 PST on April 7, 1984.

Postulating a scenario in which the plant was initially operating in modes 1 or 2, following the injection of the BIT into the core the plant would be in a condition in which additional boron injection would not be required. Additionally, in the event a valid SI signal had subsequently occurred while the high head injection flowpath was isolated, operator action would have been required to perform Emergency Operating Procedure OP-0, "Reactor Trip With Safety Injection," and to identify the absence of flow. At that time, manual action initiated by the operators would have been required to restore high pressure injection by manually shutting the circuit breakers (52) for the isolation valves.

The ECCS and the BIT are not required in Modes 4, 5, and 6.

A new operating procedure, OP B-1C:IV, "12 PERCENT BORIC ACID SYSTEM - RESTORING BORON INJECTION TANK AFTER SAFETY INJECTION" has been written to allow recharging the BIT without exceeding Technical Specifications. All safety-related operating procedures are being reviewed to identify and correct similar situations, if they exist. A method is being developed to enable the cross-reference of major plant components to Technical Specification sections. Operations personnel will be trained in its use.

POW 28-06-01

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) charging pump
INTERMEDIATE SEAL COOLERS ~~[illegible]~~ 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)
0 5	[illegible]	8 4	8 4	0 1 1	0 0	0 6	1 5	8 4		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				

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
J. L. WILSON, STATION MANAGER	AREA CODE 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)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	NO				

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

On ~~[illegible]~~ May 18, 1984 ~~with the unit at full power,~~ operations personnel performing a system walkdown following maintenance discovered the intended heat sink for the charging pump component cooling water system was isolated. ~~[illegible]~~ (Insert (pg 2.))

Due to the complexity of the maintenance involved, the existing procedures were not adequate to provide the necessary valve alignments.

Immediate corrective actions involved placing "B" intermediate seal cooler in service to provide a necessary heat sink and making "A" cooler available as a backup.

To prevent recurrence, specific maintenance operating procedures were written to ensure control of removal and return to service of the intermediate seal coolers. Operating procedures used to shift service coolers have been strengthened and proper valve alignment will be verified weekly. Finally, personnel involved have been re-instructed and a significant operating event report has been issued to all operations personnel.

8509160067 840615
PDR ADOCK 05000280
S PDR

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME	DOCKET NUMBER	LER NUMBER			PAGE
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
SURRY POWER STATION, UNIT 1	0 5 0 0 0 2 8 9	8 4	— 0 1 1	— 0 0	0 4 OF 0 3

1. Description of the Event

On May 18, 1984, with the unit at full power, operations personnel performing a system walkdown discovered charging pump component cooling water isolated to intermediate seal cooler 1-SW-E-1B and service water isolated to intermediate seal cooler 1-SW-E-1A. This alignment isolated the system's intended heat sink.

A review of plant logs and operator interviews has confirmed that both intermediate seal coolers were isolated during two separate events. The first event started May 16 at 2045 hours, when "B" cooler was improperly placed in service and "A" cooler was removed from service until 2125. The second event started 2140 hours on the same day when "A" cooler was again removed from service with "B" cooler remaining improperly valved in service. Both coolers were isolated for a total of 40 minutes during the first event and 32 hours for the second event.

2. Safety Consequences and Implications

One charging pump is sufficient to supply 100% of the charging and safety injection requirements. During this event, service water remained unisolated to the charging pump lubricating oil cooler and charging pump bearing temperatures did not increase above normal, therefore, the health and safety of the public were not affected.

During the postulated design based accident isolation of both intermediate seal coolers would place the unit in an unanalyzed condition.

3. Cause

Due to the complexity of the maintenance involved, the existing procedures were not adequate to provide the necessary valve alignments.

During the first event, while placing "B" intermediate seal cooler in service during system maintenance, and securing "A" cooler, component cooling water was inadvertently left isolated to "B" cooler.

During the second event, "A" cooler was again removed from service, with "B" cooler remaining improperly valved in service.

4. Immediate Corrective Action

"B" intermediate seal cooler was placed in service with "A" cooler in standby.

LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)	PAGE (3)
SURRY POWER STATION, UNIT 1	0 5 0 0 0 2 8 0	YEAR 8 4 — SEQUENTIAL NUMBER 0 1 1 — REVISION NUMBER 0 0	0 3 OF 0 3

5. Subsequent Corrective Action

None deemed necessary.

6. Action Taken to Prevent Recurrence

Following this event, specific maintenance operating procedures were written to ensure control of removal and return to service of the intermediate seal coolers. Previously, a generic procedure for safety related heat exchangers was used. Operating procedures used to shift service coolers have also been strengthened. Proper valve alignment will be verified weekly by inclusion on the engineered safeguards valve alignment checklist. Finally, personnel involved have been re-instructed and a significant operating event report has been issued to all operations personnel.

Corrective actions following a similar event which occurred in 1983 were not effective because a less specific approach to corrective actions was employed.

7. Generic Implications

On November 18, 1983, with the unit at full power, both intermediate seal coolers were found isolated. (LER 83-052/03L-0)

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)
Indian Point, Unit 3	0 5 0 0 0 2 8 6	1 OF 0 3

TITLE (4)

Equipment Failure During Station Loss of Normal Offsite Power

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 6	8 4	8 4	— 0 1 5	— 0 1 (Rev.)	0 6	2 6	8 5 (on file)		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	POWER LEVEL (10)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
N	0 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
John J. Anderson, Assistant Plant Engineer	AREA CODE 9 1 4 7 3 9 - 8 2 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	E A	F U	S 1 5 6	Y		X	E C	7 2	W 1 2 0	N	
X	E C	F U	B 5 6 9	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 November 16, 1984, with the reactor in the cold shutdown condition, a phase to phase fault across the Station Auxiliary Transformer (ST) buswork caused a loss of normal offsite power to the unit. Both operable emergency diesel generators started as required. During the temporary loss of normal offsite power, several breakers in the plant's electrical distribution system failed to operate. The plant operators restored station power through an alternate offsite source, and restarted all necessary equipment. The fault was found to have been caused by a piece of metal which was blown onto the A and B phase buswork of the ST by high winds.

8507180323 850626
PDR ADOCK 05000286
S PDR

NRC Form 366

On November 16, 1984, the reactor was at cold shutdown for a scheduled maintenance and inspection outage. Reactor Coolant System (RCS) temperature was approximately 115 degrees with No. 32 Residual Heat Removal (RHR) pump providing core cooling. All plant electrical loads were being supplied from offsite 138KV sources through the Station Auxiliary Transformer (ST). 6.9KV buses 5 and 6 were energized from the ST via breakers ST-5 and ST-6. All other inservice 6.9KV buses were energized via tie breakers to buses 5 and 6. No. 31 Emergency Diesel Generator (DG) was out of service for scheduled maintenance. Nos. 31 through 36 Service Water Pumps (SWP) were out of service to provide protection for divers cleaning the suction to the pumps on the intake structure. Nos 38 and 39 SWP and Nos. 31 and 32 Component Cooling Water (CCW) Pumps were operating.

At 1242 hours on November 16, breakers ST-5 and ST-6 were tripped open via fault detection circuitry. A phase to phase fault had occurred as a piece of metal was blown onto the 138KV primary side A and B phase ST buswork from an adjacent building roof. As breakers ST-5 and ST-6 opened, normal offsite power to the plant was lost. Nos. 32 DG and 33 DG started automatically due to the undervoltage condition on their respective 480V buses (6A and 5A), and achieved normal operating voltage. 33 DG successfully re-energized bus 5A, automatically starting 31 CCW pump. The output breaker, 52-EG2, for 32 DG did not close, leaving bus 6A de-energized.

The control room operators closed breakers GT-35 and GT-36 at 1256 hours to re-energize 6.9KV buses 5 and 6 from the 13.8KV offsite sources. 480V buses 2A and 3A were then manually energized via normal supply and tie breakers. 31 RHR pump was started manually to re-establish core cooling. Attempts to energize 480V bus 6A by closing the Station Service Transformer (SST) supply breaker SST-6 were unsuccessful due to an apparent loss of DC control power to the breaker. The operators then attempted to energize bus 6A from bus 3A by closing tie breaker 3AT6A. This breaker alsc failed to close. No. 38 Service Water Pump was started manually to supply essential header cooling water. Both operating diesel generators were secured since offsite power had been successfully restored. After replacing failed control fuses, breaker SST-6 was closed, re-energizing 480V bus 6A. All equipment was then returned to original status with the exception that outside power was being supplied by the 13.8KV source instead of the normal 138KV source. RCS temperature increased approximately three degrees Fahrenheit during the time RHR was interrupted.

The total time that power was unavailable to the RHR system was fourteen minutes. Since the reactor had been in the cold shutdown condition for over a month and Tavg was significantly below the 200° limit for cold shutdown at the time of the event, the plant operators voluntarily chose to proceed cautiously and deliberately in restoring power. This was in light of the amount of equipment out of service at the time.

Investigation into the series of breaker failures associated with bus 6A has yielded the following results: 1) Breaker 52-EG2, the output breaker for No. 32 DG, operated in accordance with design even though it did not close. Logic circuitry for the plant's electrical distribution system prevents any 480V vital bus from being tied to two separate power supplies simultaneously. The bus 6A normal feed breaker, 52/6A, failed to open when offsite power was lost due to failed control power fuses (Fusetron Model FRN 3.2 Amp.) The logic circuitry therefore prevented breaker 52-EG2 from closing since two supply breakers to bus 6A would have been closed. 2) Breaker SST-6, the SST supply breaker for bus 6A, opened as required on the loss of offsite power. The control power fuses (Shawmut Model OT40, 40 Amp.) for this breaker are believed to have failed the previous time the breaker was closed. The operators were unable to close SST-6 until the fuses were replaced. 3) No cause for the failure of breaker 3AT6A (Westinghouse Model DS-532) was determined. The breaker worked properly the following day during testing.

On November 17, 1984 the events of the previous day were simulated to check the operation of all undervoltage associated equipment. As previously mentioned, new power supply fuses had been installed in breakers SST-6 and 52/6A. All equipment operated correctly. The roof from which the metal had fallen was inspected and all remaining loose material was removed.

This event is reportable under 10CFR 50.73(a)(2)(iv) due to the actuation of the Emergency Diesel Generator System, and under 10CFR 50.73(a)(2)(v) because No. 32 Emergency Diesel Generator did not automatically tie to the bus. It should be noted that redundant offsite power sources and the distribution of safety equipment power supplies among the remaining vital 480V buses (2A, 3A, and 5A) ensured that the required safety related equipment could be restarted with bus 6A de-energized.

No similar events have been reported to date.

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)
Browns Ferry - Unit 3	0 5 0 0 0 2 9 6	1 OF 0 2

TITLE (4) ~~Reactor Manual Scram Due~~ to Condensate Booster Pumps Failure to Start During Unit Startup

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
1 1	2 0	8 4	8 4	0 1 2	0 0	1 2	2 0	8 4		0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 5	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	X 50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	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
Jimmy B. Walker	2 0 5 7 2 9 - 2 5 3 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		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)

Unit 3 was manually scrammed by the licensed reactor operator when control room indication showed that the vessel low water level scram set point had been exceeded. Master Refueling Test Instruction requires functional testing of the main steam relief valves per approved Surveillance Instruction (SI).

During performance of the SI, the reactor water level decreased close to the Technical Specification limit and the unit was manually scrammed.

No safety limits were exceeded. Procedure inadequacy was the root cause for the event.

8501020502 841220
PDR ADOCK 05000296
S PDR

NRC Form 366
(9-83)

Unit 1 was operating at 100 percent power, unit 2 was in a refueling outage, and unit 3 was in startup mode at approximately 4.5 percent power. Unit 3 was the only unit affected by this event.

On November 20, 1984, during preparation for performance of relief valve (RV) functional surveillance testing the licensed reactor operator manually scrammed the unit. Master refueling test instruction requires performance of the functional surveillance instruction. In preparation for the test, the pressure set point controller was lowered to 270 psig thereby opening approximately 1.5 bypass valves (V). The reactor vessel water level began decreasing due to the increased steam flow through the bypass valves. Condensate booster pumps (P) 3B and 3C were attempted to be placed in service to increase feedwater flow without success. The pumps local start switches were found to be set in the SAFE/STOP position. Plant procedure did not have a checkoff verification for proper position for the start switches. The operating procedures did not allow for insertion of reactor control rods (R). The operator felt that raising the pressure set point by closing the bypass valves would cause a pressure spike and drive the reactor water level lower.

When the reactor pressure vessel level indication by the control room level instruments decreased below plus 11 inches without an automatic scram, the shift engineer directed the unit operator to manually scram the reactor.

The contol room level instruments do not input to the reactor protection system (JE). Independent scram switches are used for the reactor protection system automatic scram for reactor vessel low level. Reactor level instrumentation is calibrated for rated temperature and pressure. At less than rated conditions, indicated level and actual level may not agree exactly. Nuclear Engineering calculations show that the actual level at the time of the scram was 12 inches and not 8 inches as indicated by the control room instruments (see attached). The scram instrumentation had been calibrated the morning prior to the event and would have actuated to provide the required low water level scram. These instruments were again checked following the event and vertified to be within calibration.

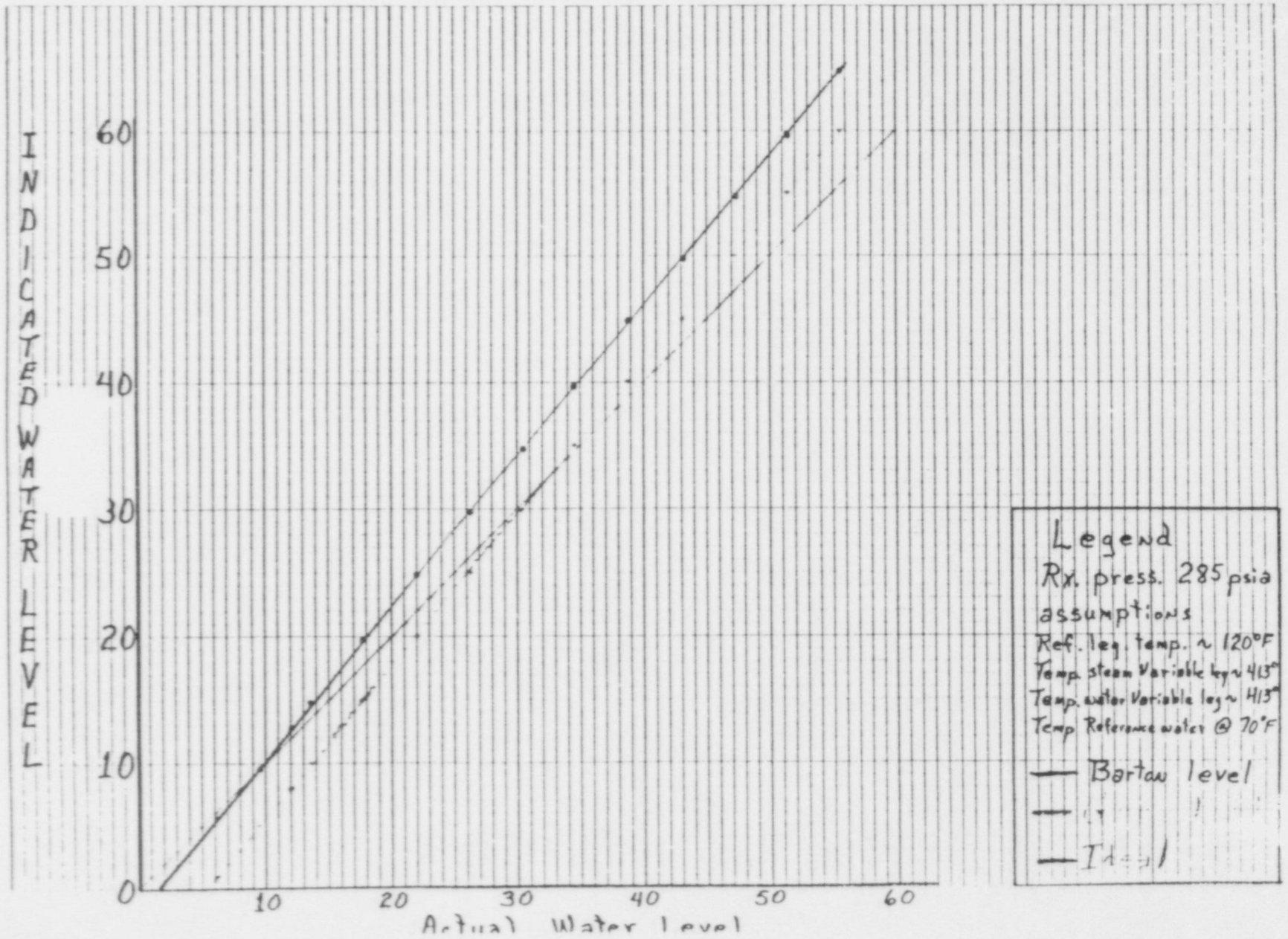
Procedural inadequacy relating to standby lineup of the condensate booster pumps were the root cause of the event. Necessary procedures for startup have been revised.

No further corrective action is planned.

Responsible Plant Section - OP

Previous Similar Events - None

ATTACHMENT 2 - LER 50-296/84012



Problem: Determine the actual level and the level sensed by the scram Barton switches based on an indicated level of +8" on the GEMACS.

Reference: Reactor Water Level Calculations (June 1979)
BFNP File Document 364 L20

BF SCI 234

Given: Indicated level on GEMACS = 8"
Reference leg temperature = 120°F (ASSUMED)
RPV pressure = 270psig (285psia)

Assumptions:

Avg. Temperature of reference leg = 120°F	D_1 = 61.71 lbm/ft³
Temperature of steam in variable leg = 413°F	D_2 = .6159 lbm/ft³
Avg. Temperature of water in variable leg = 413°F	D_3 = 53.12 lbm/ft³
Temperature of reference water = 70°F	D_4 = 62.30 lbm/ft³

Determine ma output of 6-72 A, B

$\frac{40 ma}{60"} \times \underline{8"} + 10 ma = \underline{15.33 ma}$

Determine Ma input #2 to 6-72 A, B

$\underline{270 psig} \times \frac{40 ma}{1500 psig} + 10 ma = \underline{17.2 ma}$

Output of prog. Amps 6-72A,B is given by:

$[K_1(\text{level}) + K_2(\text{Pressure}) - IB] \cdot G + OB = \text{output}$

where:

$K_1 = 0.8$ scaling factor (level)
$K_2 = 0.125$ scaling factor (pressure)
$IB = 12.75$ (Input Bias)
$OB = 10.00$ (Output Bias)
$G = 1.25$ (Gain)

$[.8\ X_L + .125(17.2) - 12.75]\ 1.25 + 10 = 15.33 \text{ ma}$
$[.8\ X_L + 2.15 - 12.75]\ 1.25 + 10 = 15.33$

$X_L = \underline{18.58 \text{ ma}}$

Determine inches H_2O input to 6-52A,B level sensors to yield output of 18.58 ma.

$\frac{60''}{40 \text{ ma}} (18.58 \text{ ma} - 10 \text{ ma}) = \boxed{12.87 \text{ inches}}$

This is level seen Bartons saw.

Determine the actual level in RPV:

convert sensed level to ΔP in inches H_2O

$\underline{12.87} \text{ inches} \times \frac{[-29.16 - (-71.59)]}{60 \text{ inches}} + (-71.59) = \underline{-62.49}\ ''H_2O\ \Delta P$

Determine actual level

$$\Delta P = (Act - 517)\frac{D_3}{D_4} + (600.5 - Act)\frac{D_2}{D_4} - (600.5 - 517)\frac{D_1}{D_4}$$

$$= (Act - 517)\frac{53.12}{62.30} + (600.5 - Act)\frac{-61.59}{62.30} - (83.5)\frac{61.21}{62.30}$$

$$= .8428\,Act - 440.82 + 5.94 - 82.71$$

$$-62.49 = .8428\,Act - 440.82 + 5.94 - 82.71$$

$$455.10 = .8428\,Act$$

$Act = 540''$ above vessel zero

Actual Water level relative to Instrument Zero is

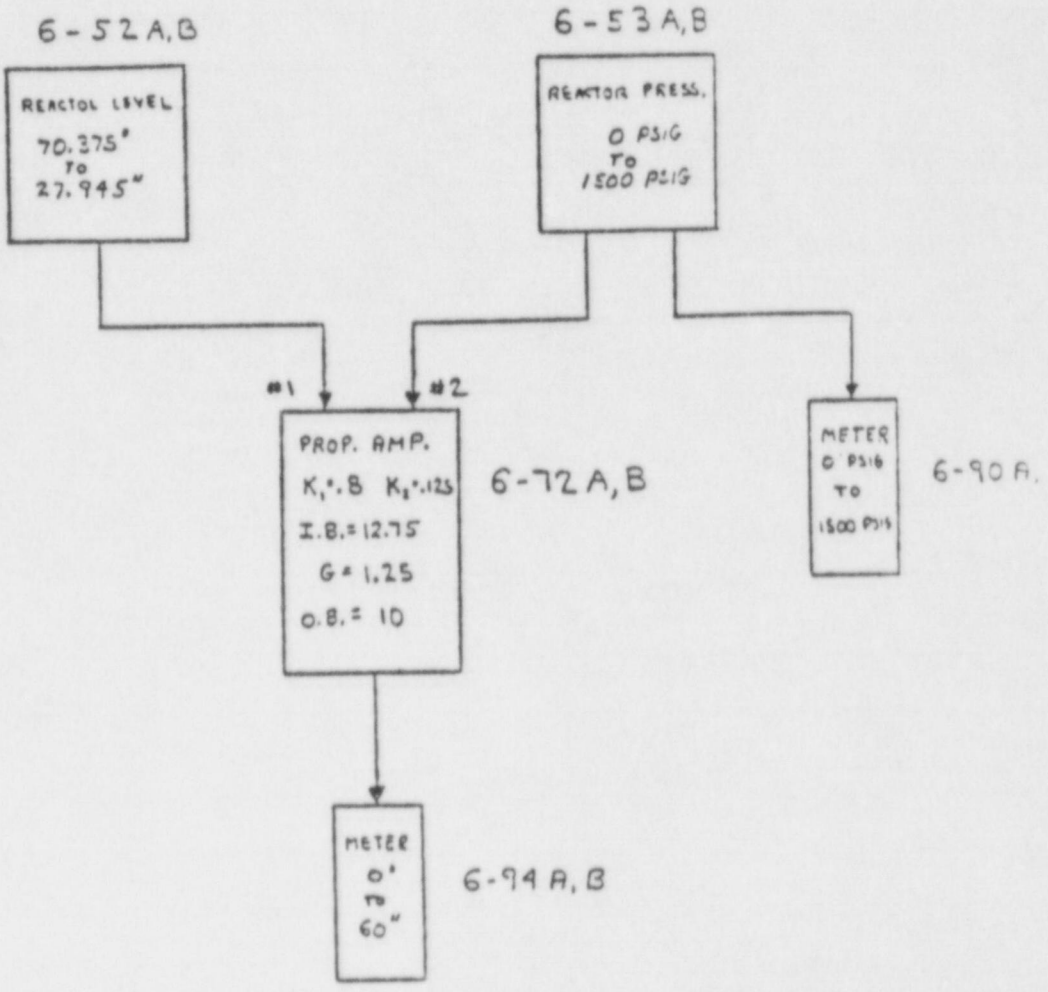
$540 - 528 =$ **12.0** inches Actual water level

Performed by: J.D. Thompson + E.D. Nave

Reviewed by: B.T. Williamson

FEEDWATER CONTROL SYSTEM LEVEL

4 of 4



6-52 A,B LEVEL XTMR.	71.59"	TO	29.16"	INPUT
	10 MA	TO	50 MA	OUTPUT
6-53 A,B PRESS. XTMR.	0 PSIG	TO	1500 PSIG	INPUT
	10 MA	TO	50 MA	OUTPUT
6-72 A,B PROP. AMP.	K_1=.8 , K_2=.125	IB=12.75	G=1.25	O.B.=10	

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)
Browns Ferry - Unit 3	0 5 0 0 0 2 9 6	1 OF 0 3

TITLE (4): Valve Limitorque Motor Pinion Gear Failures (FCV-73-3) and (FCV-74-12 & 61)

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	2 2	8 4	8 4	- 0 1 3	- Rev. 0, 1, & 2 on file	0 7	0 9	8 5		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
N		20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)	0 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)	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
Jimmy B. Walker	2 0 5 7 2 9 - 2 5 3 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

		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)

During startup after cycle 5 refueling outage, the high pressure coolant injection (HPCI) outboard steam supply isolation valve would not open. This made the HPCI system inoperable. All Technical Specification (TS) requirements for redundant systems were met. The valve would not open due to the motor pinion gear being installed backwards.

The valve motor pinion and mating worm shaft gears were replaced in the proper direction. A random sample of similar valves was inspected.

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PDR ADOCK 05000296
S PDR

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

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

Unit 1 was operating at 74 percent power, unit 2 was in a refueling outage, and unit 3 in the startup mode at 138 psig. Only unit 3 was affected by this event. But in addition, units 1 and 2 valves were randomly sampled to ensure no problems were present.

On November 22, 1984, at 2130, the High Pressure Coolant Injection (HPCI) (BJ) System was being realigned to the standby readiness condition after reaching a pressure consistent with reset of the HPCI low pressure isolation. HPCI outboard flow control valve (FCV) 73-3 could not be opened electrically, and the HPCI system was declared inoperable.

FCV 73-3 is a 10-inch gate valve which is manufactured by Crane. The limitorque valve operator was disassembled and visually inspected for damage. Inspection determined that the motor pinion gear (GR) was installed backwards during previous maintenance work. When the gear was installed backwards, full engagement of mating gears was not maintained. This caused additional loading of the outer portion of the motor pinion gear teeth which in turn caused some of the teeth to break which allowed the motor to spin without engaging the limitorque operator. The motor pinion gear and mating worm gears were replaced with new gears in the proper direction.

Also, the cable from the power supply to motor shunt field was found to be open. The open cable caused FCV-73-3 to operate in approximately 8 seconds since the motor operates as a series DC motor with the shunt field open. The cable was repaired and the valve then operated in approximately 16 seconds. The maximum stroke time for this valve is 20 seconds.

FCV 73-3 failed in the closed position. Primary containment isolation was maintained by the inboard isolation valve, but the inoperable outboard valve rendered the high pressure coolant injection system inoperable. All technical specification requirements were complied with.

A 20 percent random sample of all accessible emergency core cooling system valves have been inspected on all units. A total of 36 valves were inspected and all of the valves motor pinion gears were found to be installed in the proper arrangement.

During the inspection of the 36 valves for motor pinion gear problem, the motor pinion gear setscrew on 2FCV 73-34 was found to be loose and 3FCV 73-16 was found to have missing split ring parts as described in LER 296/84014. As a result of these findings the valves were inspected for gear condition, setscrew tightness, worm gear retainer, split ring and snap ring installation. Two valves were found to have loose setscrews, and four valves had missing setscrew wires. The manufacturer indicated that the loose setscrew or missing setscrew wires would not cause a valve failure.

The preventative and corrective maintenance instruction has been revised to inspect all CSSC SMB-1 through 4 operators for all these identified problems. All applicable maintenance personnel have been trained and made aware of these problems and the revisions made to the maintenance instruction.

The following is in addition to the information given in revision 1 as a continuing effort to identify all motor pinion gear problems.

During the performance of a surveillance instruction (motor operability valve test) on March 13, 1985, on residual heat removal (RHR) valve 3FCV-74-12 (loop I RHR), it was determined that the valve would not operate. The valve was inspected, and the motor pinion gear was found to be installed backwards. The motor pinion gear setscrew was also found to be loose which allowed sufficient clearance between motor pinion and mating worm shaft clutch gear to completely disengage with each other. A new motor pinion gear was installed in the proper orientation.

On March 18, 1985, during an inspection of limitorque operator for proper motor pinion gear orientation, valve 3FCV-74-61 (loop I RHR containment spray injection valve) was found to have damage to both the motor pinion gear and worm shaft clutch gear. Teeth were missing from both gears and the worm shaft clutch gear hub was cracked. The gears were oriented properly, and the valve had been cycled satisfactorily prior to the inspection. It appeared that one or more teeth broke off and lodged between the remaining gear teeth causing more teeth to break. The inspection caught the problem before the valve actually failed.

Based on these findings the scope of the inspection has been expanded to all emergency core cooling systems with limitorque operator sizes SMB-1 through 4. valves.

Responsible Plant Section - MM

Previous Similar Events - BFRO 50-259/79035; BFRO 50-260/80002

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Browns Ferry - Unit 3	0 5 0 0 0 2 9 6	1 OF 0 2

TITLE (4)

HPCI Turbine Steam Isolation Valve ~~Leakage~~ Leaked Past Its Seat

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	0 6	8 4	8 4	0 1 4	0 0	0 1	0 4	8 5		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 3 6	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
Pat Ebersole	2 0 5 7 2 9 - 3 7 8 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	

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)

The high pressure coolant injection (HPCI) system was removed from service to repair FCV 3-73-16 (turbine steam isolation valve) which was leaking.

The valve was disassembled and repairs were made to the valve seat and wedge in order that a better seat between the valve mating surfaces could be achieved. Following repairs to the valve an additional problem with the limitorque operator was identified and corrected. Insert

On December 11, 1984, the valve and operator maintenance was complete and surveillance instructions required to demonstrate operability were successfully performed.

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S PDR

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

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

Unit 3 was operating at 36 percent power, unit 1 was at 97 percent and unit 2 was in a refueling outage. This event affected unit 3 only.

During the startup of unit 3 following its cycle 5 refueling outage, the high pressure coolant injection system (HPCI) (BJ) was removed from service on December 6, 1984, to repair a leaking steam supply valve (FCV) to the HPCI turbine. The valve was disassembled and repairs were made to its seat and wedge to reduce steam leakage.

After reassembly of the valve and installation of the drive motor onto the limitorque operator, an attempt to operate the valve electrically with the limitorque operator failed. Disassembly of the valve operator revealed that a split ring, retaining ring and snap ring that position a gear on the limitorque worm shaft that engages with the motor pinion gear were missing. ~~An inspection of the work area did not reveal the missing parts.~~ The gear disengagement after valve disassembly was probably a result of the motor pinion gear pulling the worm shaft gear out of position when the operator motor was removed. The valve operability had been demonstrated prior to start of the maintenance activity.

An inspection of 31 limitorque operators (approximately one-third of the operators of this type on CSSC systems) revealed no other valves with this assembly error; therefore, we believe this is an isolated case. Checks have been added to the maintenance instructions for limitorque operators to verify that these components are installed.

The retaining rings for the worm shaft gear were installed and the operator and its drive motor were reassembled. The HPCI system was proven operable on December 11, 1984, after successful completion of the pump and MOV surveillance instructions.

Responsible Plant Section - MM

Previous Similar Events - None

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APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Browns Ferry - Unit 3	0 5 0 0 0 2 9 6	1 OF 0 2

TITLE (4) Failure of Condensate pump motor and its feeder breaker ~~Manual Scram of Reactor Unit 3~~

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)		
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR
1 2	0 9	8 4	8 4	0 1 5	0 0	0 1	1 8	8 5

OTHER FACILITIES INVOLVED (8)	
FACILITY NAMES	DOCKET NUMBER (S)
	0 5 0 0 0
	0 5 0 0 0

OPERATING MODE (9)		POWER LEVEL (10)	
	N		0 3 6

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)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)
	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)

	73.71(b)
	73.71(c)
	OTHER (Specify in Abstract below and in Text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
Alan W. Gordon	2 0 5 7 2 9 - 2 5 3 7

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

		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)

Failure of the feeder breaker for condensate pump motor 3A to trip resulted in the normal feeder breaker for the unit board tripping. Brief Control rod drive (CRD) pump 3A was out-of-service for maintenance and loss of control rod drive pump 3B, supplied by the same board, caused multiple CRD accumulator alarms. Also, a low water level scram was anticipated so the licensed unit operator manually scrammed the reactor. Repairs were made to the condensate pump breaker and motor.

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PDR ADOCK 05000296
S PDR

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

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

During normal operation, unit 1 was operating at 99.8 percent, unit 2 was in a refueling outage, and unit 3 was operating at 36 percent. Only unit 3 was affected by this event.

The cause of this event was failure of the feeder breaker (BKR) for condensate pump motor (MO) 3A to trip when the motor shorted to ground. A burned-up trip coil (CL) prevented the breaker from operating. The effect was that the normal feeder breaker for the unit board (BD) tripped when one of its overcurrent relays (RLY) operated. This also locked out the alternate feeder breaker and deenergized the loads connected to the unit board.

The safety loads supplied by the unit board then automatically transferred to their alternate sources as designed. Diesel generators 3A and 3B started but were not needed to tie on. The unit was manually scrammed following loss of control rod drive (CRD) pump 3B which tripped due to loss of board voltage. CRD pump 3A was out-of-service for maintenance and loss of CRD pump 3B generated multiple CRD accumulator alarms. In anticipation of a low water level scram, and to determine as quickly as possible that all rods were fully inserted, the licensed unit operator scrammed the reactor.

The condensate pump breaker and motor were repaired, and there was no other apparent damage. The safety related equipment operated as designed during this event. Therefore, no further corrective action is necessary.

Responsible Plant Section - N/A

Previous Similar Events - None

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(9-83)

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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)
Rancho Seco Unit #1	0 5 0 0 0 3 1 1 2	1 OF 0 5

TITLE (4)
Related Incidents to Hydrogen Explosion

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	1 9	8 4	8 4	— 0 1 5	—	0 4	1 9	8 4	None	0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)					
POWER LEVEL (10)	0 8 5	20.402(b)	20.405(c)	X	50.73(a)(2)(iv)	73.71(b)	
		20.405(a)(1)(i)	50.36(c)(1)	X	50.73(a)(2)(v)	73.71(c)	
		20.405(a)(1)(ii)	50.36(c)(2)		50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)	
		20.405(a)(1)(iii)	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
Ron W. Colombo	9 1 6 4 5 2 - 3 2 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	
X	T C	M O	W 1 2 0			X	A B	R V	D 2 4 3		
X	E C	B R K	I 2 0 2								

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On March 19, 1984 Rancho Seco Nuclear Generating Station No. 1 was generating at 92% power. The Westinghouse main generator Hydrogen Seal Oil System hydrogen side pump had been off for one hour due to secondary plant electrical bus problems. Operation at full load is permitted in this condition. Due to Seal Oil System problems, high defoaming tank and hydrogen side drain regulator tank levels occurred which required the operators to take manual control of drain regulator tank level. Inadequate manual level control caused Hydrogen seal oil pressure to decrease allowing hydrogen to escape from the generator, resulting in an explosion and fire. The turbine/generator was manually tripped (2151:05 hours) and the reactor tripped on anticipatory trip from the turbines. One hour later a four minute partial loss of Non-Nuclear Instrumentation (NNI) power occurred due to an overvoltage trip setpoint drift.

Three reportable events occurred: 1) Lubricating oil was discharged into the plant liquid effluent stream. A Hydrogen Seal Oil System malfunction caused oil to enter the generator. When the generator hydrogen was vented after the fire, some of the oil went out through the vent, travelled to a storm drain and to the plant effluent. 2) The fire protection CO2 tank was emptied by automatic timed discharge of the system into the fire area; minimum tank level is 60% per Technical Specifications. 3) A primary code safety valve lifted about 140 psig below the 2500 psi setpoint during the RCS pressure transient associated with the partial NNI power loss.

Corrective action to be completed includes a concerted effort by the District for implementation of various recommendations in order to prevent future similar events.

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(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Rancho Seco Unit No. 1	0 5 0 0 0 3 1 2	8 4	— 0 1 5	— 1	0 2 OF 0 5

Hydrogen Explosion Event

Rancho Seco was operating at 92% power and generating about 859 MW when MCC 2E1 bus became de-energized when its supply breaker from the 3E bus tripped. This supply breaker could not be reclosed. The loss of MCC 2E1 due to a ground fault on a Gland Steam Exhaust Motor resulted in a loss of the H_2 Side Seal Oil Pump which is powered from that MCC. The District's procedure and the Westinghouse Technical Manual allow full load operation with the Hydrogen Side pump shut down. Seal oil problems eventually resulted in the escape of H_2 from the generator and subsequent explosions.

An Operator was checking the oil level in the Turbine End Defoaming Tank and upon entering the turning gear area enclosure he noticed a strange smell. He closed the door and a small explosion blew it back open. He immediately exited the area and notified the Control Room by phone, then went to the Control Room. A reduction in power was initiated at a maximum rate of 99 MW/Min. Shortly after, a large explosion occurred. The generator remained on the line; no automatic trip signals were received since the explosion did not damage the generator or exciter. The Shift Supervisor was notified that the exciter was on fire. He immediately tripped the Turbine. The Reactor was then tripped by the Anticipatory Trip Circuit. Reactor power had been reduced from 92% to 85% prior to the trip.

The Reactor trip was normal except a Turbine Bypass Valve stuck open which was identified and closed within six minutes. The Reactor Coolant System (RCS) cooled to 505°F (40°F below the nominal post trip temperature) pressurizer level remained on scale and RCS pressure reached a minimum of 1794 psig (about 50 psig below nominal post trip minimum). Operators manually started both HPI Pumps and opened one of four High Pressure Injection (HPI) inject nozzles to help control RCS pressure and pressurizer level.

Background for Hydrogen Explosion Event

When the Hydrogen Side Seal Oil Pump is off, Hydrogen side seal oil is supplied by the air side pump. The oil that flows to the H_2 seals ends up in the drain regulator tank and is rejected to the suction of the air side pump. Prior to the loss of the H_2 side pump swing shift logs were taken and Defoaming Tank levels were normal. Shortly after the pump stopped, Equipment Attendant #1 (EA#1) was sent to assess the condition of the Seal Oil System. The Defoaming Tank levels were found high and Generator Moisture Detector level switches were dry. The Operator reported these facts to the Control Room and was instructed to manually operate the Drain Tank Level Control Valves and gas the generator to reduce Defoaming Tank level. EA #1 manually overrode the Automatic Level Control Valves on the Drain Regulator Tank, observed a slow level decrease then left the area to obtain another Operator (EA #3) to control tank level while he checked Defoaming Tank levels. Before EA #3 reached the Drain Regulator Tank (about two minutes) the Regulator Tank emptied which allowed H_2 to enter the suction of the Air Side Seal Oil Pump. This caused reduction in seal oil pressures and allowed H_2 and seal oil to blow out of the generator seals. H_2 escaped for several minutes before it exploded.

CO_2 Tank Exhausted During Subsequent Fire

Following the large explosion, the fire burned for an estimated five to eight minutes and smoldered for a few more minutes. It was reported to be out 14 minutes after the explosion. The fire was concentrated in the area of the exciter to generator housing interface on the outside of the housing. All exciter doors were blown open or off and CO_2 was observed emanating from all door openings. No fire was noted inside the exciter or on the turning gear end of the generator. The CO_2 System discharged as designed for 36 minutes. This resulted in the CO_2 tank being exhausted. Offsite fire fighting support was retained and continuous fire watches on other CO_2 protected zones were maintained.

Loss of NNI-X and Pressurizer Code Safety Valve Lifting Early

About an hour after the Reactor trip, NNIX ±24 VDC was lost for approximately four minutes. In initiating the SFAS manually by procedure for loss of NNI, full HPI flow increased RC pressure. A pressurizer code safety valve lifted 140 psi below its 2500 psi setpoint.

When NNIX DC power was lost, it was diagnosed as a total loss of NNI based on Control Room indications, Casualty Procedure C.45 "Complete Loss of NNI Power" was then followed. This procedure required, among other things, manual initiation of SFAS Channels 1A and 1B. This resulted in both the "A" and "B" High Pressure Injector Pumps starting and the HPI inject valves opening. Due to HPI injection, RCS pressure began to increase. At a pressure of approximately 2360 psig, Pressurizer Code Safety Valve PSV-21507 lifted prematurely and blew down RCS pressure 100 psig and then reseated. Pressure began to increase again and the code safety again lifted then reseated. During the second lifting of the code safety valve, the HPI inject valves were being throttled based on pressure/temperature indications on instrumentation unaffected by the loss of NNIX grouped together on a special panel. HPI was manually controlled per procedure and RCS pressure and pressurizer level restored to normal valves. A steam line Atmospheric Dump Valve opened due to loss of NNIX, was immediately recognized and closed from the Control Room.

Safety Implications

Reactor was tripped immediately after the Control Room Operators were informed about the Hydrogen fire. Thus, during the time the CO_2 Fire Prevention System was extinguishing and controlling the fire, the reactor had sufficient negative shutdown margin. Additionally, during the NNIX channel loss, although initially diagnosed as complete NNI failure, the Y channel remained in service. The failure was of such short duration that the operating personnel took the most conservative assumption at the time of the initial problem and, since it was corrected within minutes, they did not become aware that only the NNIX had failed. Since Operator actions were conservative and correct throughout this event, plant and public safety were properly protected.

Corrective Action Prior To Startup will include the following:

Hydrogen Seal Oil

Preventive maintenance will be performed on the local H_2 common alarm panel and all alarms which input to the panel will be checked. In addition, the Seal Oil System Casualty Procedures will be revised to include cautions to continuously monitor Drain Regulator Tank level when using the hand jacks and the Drain Regulator Tank level gauge face will be modified to more correctly indicate tank oil level. This modification will consist of interim markings until permanent dial face changes can be made if needed. Finally, appropriate prestartup tests, as recommended by the Manufacturer, to assure proper system operation will be performed.

NNI

All of the NNI and ICS ± 24 volt power supplies overvoltage and undervoltage trip setpoints will be calibrated and set to the Manufacturer's recommended setting. Also, the problem with the X_2 ± 24 volt supply's failure to trip on overvoltage will be resolved prior to startup.

Pressurizer Code Safety Valve

The pressurizer code safety valve PSV-21507 will be reset during initial startup.

Corrective Action Subsequent To Startup will include the following:

Hydrogen Seal Oil

A recommendation, regarding on-line testing of panel alarms, will be prepared. This will include a study as to how this testing could be conducted, if at all, and an implementation schedule. Also, a determination will be made of what preventive maintenance, if any, should be performed on the alarm panel and incorporated into the PM Program.

An investigation of the need for additional instrumentation in the Seal Oil System, to allow better monitoring of system performance, will also be performed. In addition, a review will be done on the seal oil installation for conformance to the Manufacturer's recommendations, particularly in regard to component elevations and piping configuration. These actions will be addressed by August 1, 1984.

CO_2 Tank

The instructions in Operating Procedure A.35 "CO_2 System" regarding manual termination of automatic CO_2 discharge will be verified and revised, if necessary, to ensure that it is applicable to all CO_2 zones. In addition, a determination will be made of the impact on insurance liability of turning off a long lasting CO_2 discharge during an actual fire event on the Turbine Deck. If there is an unacceptable impact, a revision will be made to the appropriate procedure to include

cautions not to terminate the discharge. These actions will be addressed by June 1, 1984.

Further investigation into changes of the NNI power supply to improve reliability will be completed as well as revisions to PM Program of NNI power supplies and outside 480 volt circuit breakers by September 30, 1984.

It is believed that these actions sufficiently address the incidents discussed in this report and will prevent similar events from occurring in the future.

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)
CALVERT CLIFFS, UNIT 2	0 5 0 0 0 3 1 8	1 OF 0 3

TITLE (4)
D/G Inoperability

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 4	2 6	8 4	8 4	— 0 0 5	— 0 0	0 5	2 4	8 4	N/A	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	6	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iii)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(iv)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(v)	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)(vii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(vii)(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
P. PIERINGER, SR. ENGINEER-OPERATIONS	3 1 0 2 1 6 0 - 4 1 7 4 1 2

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)

With the Plant in MODE 6, an electrical lineup was performed to allow preventive maintenance on 24A 480V AC Bus. This lineup powered 21 Diesel Generator (DG) auxiliaries from a bus receiving its backup power from 12 DG, thereby causing a loss of independence between 21 and 12 DGs. Although 21 DG was considered inoperable at this point, that fact was not conveyed to personnel on subsequent shifts. Since only one DG is required operable in MODE 6, no technical specification action statements were entered and hence no log entry to the effect that 21 DG was inoperable was made. The following shift, not realizing the lack of independence, removed 12 DG from service, which resulted in inoperability of both DGs. Believing 21 DG to be operable, T.S. 3.8.2.2 was violated in that containment integrity was not established within 8 hours. To prevent a recurrence of a similar event the conditions surrounding this event will be reviewed with all licensed personnel. Additionally, lists of equipment required for the operability of each DG have been compiled for use in aiding the operator in ascertaining the operability of required DGs prior to removing the redundant DG from service.

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
CALVERT CLIFFS, UNIT 2	0 5 0 0 0 3 1 8	8 4	— 0 0 5	— 0 0	0 2 OF 0 3

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

During this event Unit 2 was in MODE 6 with a refueling outage in progress. The reactor vessel head (RPV) was detensioned and reactor vessel water level ranged between 1.2 and 1.5 feet above the bottom of the hot leg. Primary temperature ranged between 106° and 112° F and the steam generator (SG) manways were removed. No core alterations had yet been performed and none were scheduled during the period of concern. No reactivity changes occurred during the period of concern.

At 2115 on April 25, 1984, 24A 480V AC Safety bus (ED-BU) was removed from service for preventive maintenance. To maximize 21 DG (EK-DG) availability, 21 DG auxiliaries (Fuel oil transfer pump DC-9, room ventilation fan VJ-Fan, air start system air compressor LC-CMP, and various other engine auxiliaries LB-EHT, P and LA-EHT, P), normally supplied from 24A 480V AC Bus via MCC 204R (ED-BU), were kept energized by powering MCC 204R from MCC 214R (ED-BU) via a tie breaker (ED-BKR). This lineup, which is shown in the drawing (see Attachment 1), allowed 12 DG (EK-DG) to power 21 DG auxiliaries but in turn removed the independence between the two DGs. 21 DG was declared out of service, but not logged as such since T.S. 3.9.1.2 requires only one diesel to be operable in MODES 5 and 6. Had the unit been in a higher mode, less severe consequences would have occurred as the log entry concerning entry into a T.S. action statement would have prevented 12 DG from being taken out of service.

At 0625 on April 26, 1984, licensed personnel on the next shift failed to recognize the dependence of 21 DG on 12 DG and placed 12 DG out of service so preventive maintenance could be performed. Although operations personnel were aware that Unit 2 480V Bus 24A was out of service, the correlation was not made between that work and its effect on 21 DG operability. Consequently, both 12 and 21 Diesels were made inoperable.

At 1615 on April 26, 1984, a Senior licensed operator noted that both 12 and 21 DGs were inoperable and containment integrity had not been established as required by T.S. 4.8.2.2. Restoration of 12 DG to operability was in progress at the time and was continued. At 2105 12 DG was declared operable terminating the event.

During this event, the 2 500KV offsite power circuits and the 69KV SMECO offsite power circuit remained operable. Had the 2 normal offsite power circuits been lost during the event, the 69KV SMECO power supply could have been aligned to Unit 2 to supply the safety loads required for shutdown operation. Had a total loss of offsite power occurred during the event, DG 11 would have automatically started and paralleled to Unit 1 Bus 11 (EK-DG). DG 21 would have automatically started and paralleled but would have eventually shutdown when the fuel oil day tank was depleted or on a fault condition caused by the high DG room temperature (because of the inoperable ventilation fan). Existing inspection procedures and Control Room alarms would have ensured the operators' awareness of these conditions prior to an actual diesel trip condition. By realigning 11 DG to Unit 2 4KV Bus 21 and 21 DG to Unit 1 4KV Bus 14, an independent DG would be available for each unit allowing, in this case, Unit 1 to be safely shutdown and Unit 2 to be maintained in a MODE 6 configuration.

Procedurally, the Unit 2 operations staff would be expected to implement the abnormal operating procedure dealing with loss of shutdown cooling should a total loss of offsite power occur. For various times after shutdown, this procedure provides time periods until core boiling and fuel uncovery. Following a complete loss of shutdown cooling, the calculations supporting this information assume the reactor coolant system (AB) is drained to the bottom of the hot leg, that initial RCS temperature is 150° and the reactor vessel head is removed. All of these conditions are conservative to those actually existing. Had an offsite power loss occurred at the time of maximum decay heat for this event (when both DGs first became inoperable) the operator would have determined he had approximately 18 minutes until primary coolant saturation temperature was reached and 68 minutes prior to the start of fuel assembly uncovery. As the required electric system lineup could be established well within the time before fuel uncovery, it is concluded that the loss of offsite power condition could not have produced consequences of a more serious nature.

To prevent a recurrence of a similar event the following corrective actions will be (or have been) taken:

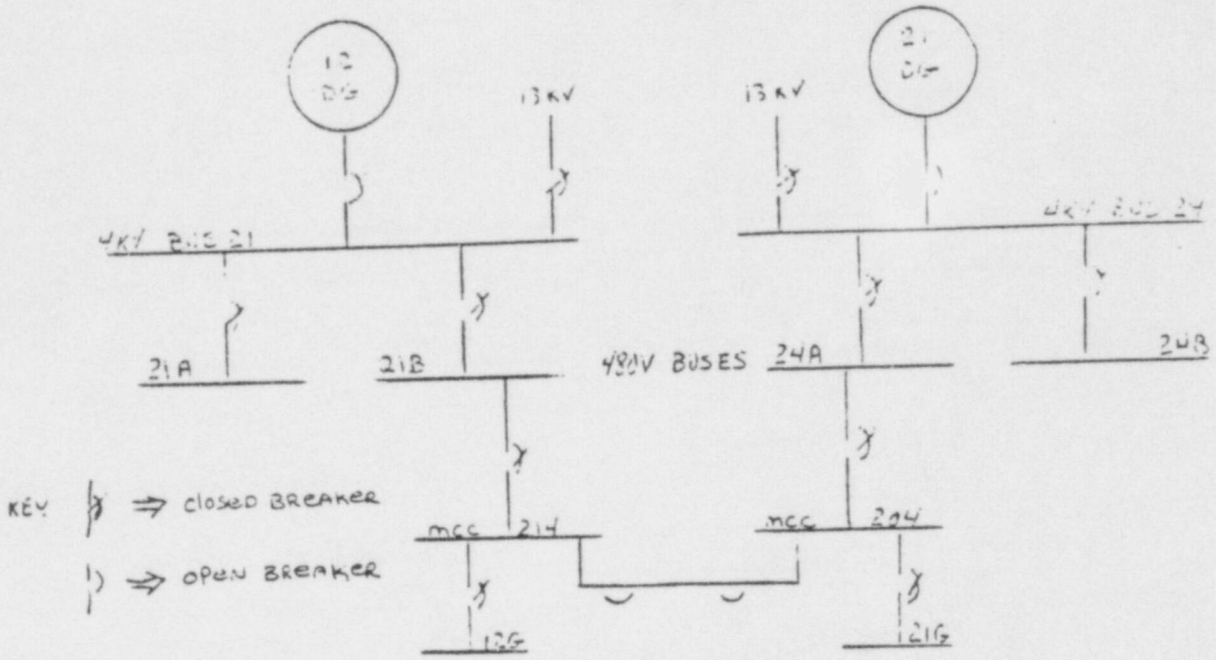
1. A list of equipment required to maintain DG operability has been prepared for each DG. When a condition arises which requires a DG to be placed out of service, these lists which will become part of the Calvert Cliffs Operating Manual, are used as an operator aid for verifying the operability of the redundant DG. These lists include both mechanical and electrical systems, which are required to maintain DG operability.

2. All licensed operators will receive training during the annual requalification cycle on the conditions surrounding this event. Particular emphasis will be given to the role electrical distribution plays in supporting DG operability.

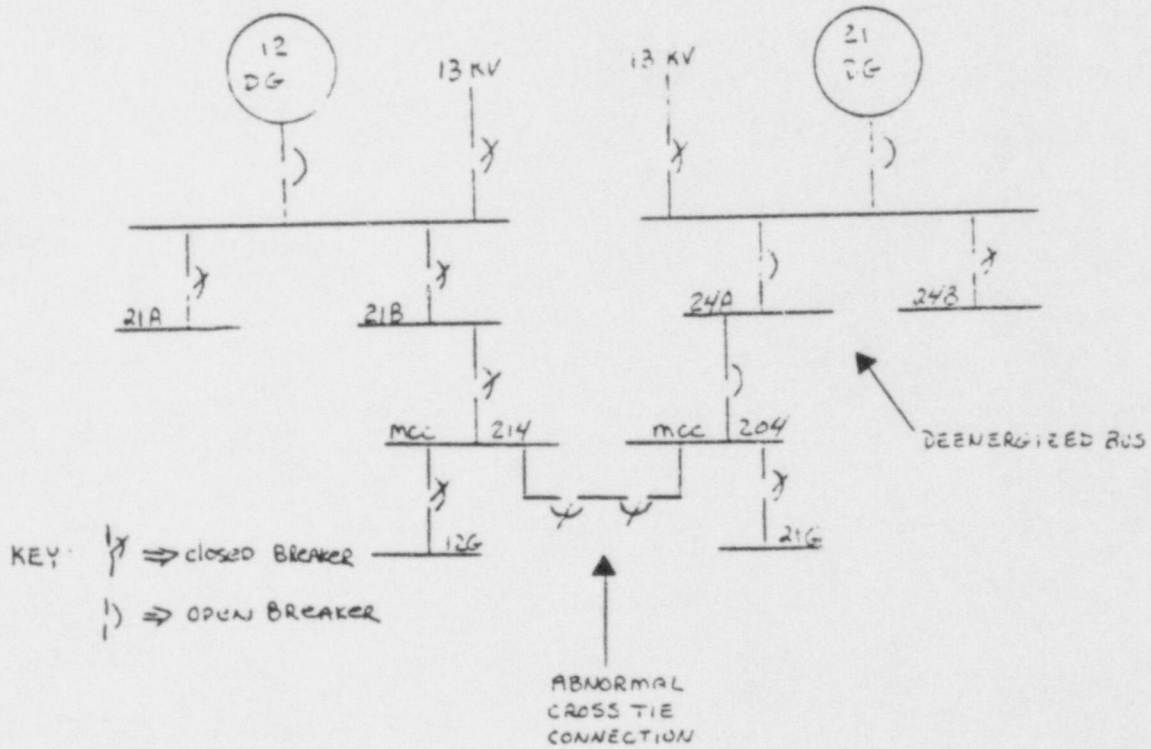
No similar events have been reported.

ATTACHMENT 1

NORMAL LINEUP

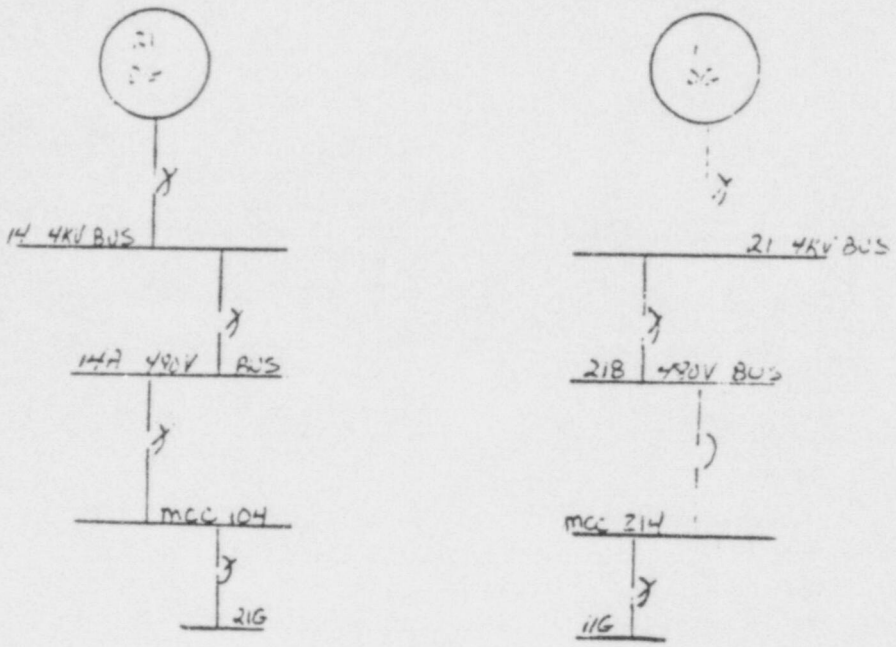


EVENT LINEUP



ATTACHMENT 2

REQUIRED ELECTRICAL LINEUP
DURING LOSS OF OFFSITE POWER



KEY: ⇒ CLOSED BREAKER

⇒ OPEN BREAKER

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APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Brunswick Steam Electric Plant Unit 2	0 5 0 0 0 3 2 4	1 OF 0 4

TITLE (4) Reactor Low Level No. 1 and Inoperability of Residual Heat Removal RHR Subsystem Loop A Due to Failure of RHR Subsystem A Loop Heat Exchanger Level Control Valve E11-LV-F053A

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
										0 5 0 0 0
1 1	2 7	8 4	8 4	— 0 1 4	— 0 0	1 2	2 7	8 4		0 5 0 0 0

OPERATING MODE (9)	3	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	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
R. M. Poulk, Jr., Regulatory Specialist	AREA CODE 9 1 9 4 5 7 - 9 5 2 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

While attempting to establish shutdown cooling on the A loop of Residual Heat Removal (RHR) System, two separate events occurred: 1) A water hammer event damaging supports on the steam condensing line, and 2) a Reactor Protection System (RPS) trip on low vessel level. At the time of these events, the reactor was shut down and at approximately 90 psi. Following both events, the plant was restored to its normal condition.

Both events occurred when the control signal to the E11-F053A valve caused the valve to travel to its "open" position instead of the desired "close" position. There is no position indication of the F053A valve on the reactor turbine gaugeboard (RTGB). An investigation determined that the output jack was in the "high" position instead of the "low" position. This mispositioning caused the F053 controller to select the higher of two signals (RHR heat exchanger pressure/level) instead of the lower. When the controller was turned on in preparation for warming up the RHR lines prior to establishing shutdown cooling, the valve immediately went to the full open position. The first time this was attempted the water hammer occurred; the second attempt resulted in a low level scram and water hammer.

Vessel level was restored to the normal operating band, the output jack was connected to its correct position, and the damaged supports were repaired. The cause for the subject output jack being in the wrong position could not be determined.

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While attempting to place the RHR System into shutdown (S/D) cooling on the A loop at approximately 2000 on November 27, 1984, it was determined that a water hammer event occurred on the steam condensing line of the A loop of RHR. This was identified approximately a day following the event.

An inspection of the affected piping determined that of the 19 supports inspected, 15 supports required repairs. These supports are identified in Table 1 and are catagorized as follows: seven snubbers, one anchor, one strut, two fixed hangers, and four spring hangers. Four of the supports were repaired by a plant modification while the remaining supports were corrected using in-house maintenance procedures. The snubbers were satisfactorily functionally tested prior to being restored to service. The portions of the RHR piping involved were visually inspected by ASME Section XI qualified, VT-3 Level II/III inspectors. In addition, 8 of 25 welds on the line received NDE testing--7 due to their proximity to pipe anchors and the associated high stress levels and 1 which was located at the location of two broken snubbers (E11-47SS227 and 228). The examinations included one or more of the following: magnetic particle, radiographic, or ultrasonic. No evidence of piping overstress or fatigue was discovered.

Approximately five hours following the water hammer event (not identified by Operations at the time of occurrence), a warm-up of the A loop of RHR was again attempted. While the warm-up was in progress, a reactor vessel low level alarm was received. Manual and automatic shutting of the E11-F008 valve (S/D cooling suction valve) terminated the decreasing water level; however, due to the stroke time of this valve, the low level trip setpoint was reached causing an RPS trip actuation. Vessel level was restored to normal.

A review of this event revealed that the level instrument, B21-LT-N017A-1, failed to actuate at the low level 1 setpoint due to the transmitter being out of calibration. This instrument causes the following Group 2, 6, or 8 valves to isolate: E11-F009, E11-F079A, G16-F003, and G16-F019. In each case, the other isolation valves on those lines isolated their respective systems as required. The transmitter was recalibrated, verified operable, and restored to service.

Following these events, an investigation was conducted to determine the cause. This investigation determined that the E11-F053A valve was traveling to the full open position when the controller was turned on, whereas the F053A valve should remain closed. The E11-SS-R605A high/low auto selector station for the F053A valve receives a signal from the E11-LIC-R604A RHR heat exchanger level controller and the E11-PIC-R609 RCIC suction pressure controller. When the E11-SS-R605 signal jack is in the "high" position, the higher of the two signals (level/pressure) is used for control of the F053 and when in "low," the lower of the two is used. Plant procedures require that the jack be left in the "low" position. During both of these events, the E11-SS-R605 jack was in the "high" position. Therefore, when the RCIC suction pressure controller was set to auto in accordance with the procedure (OP-17) with a setpoint greater than the actual (existing) RCIC suction pressure, the controller output increased, causing the E11-F053A valve to ramp open. However, the E11-F053A valve should have remained closed until the RHR heat exchanger level controller output was subsequently increased.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 2	0 5 0 0 0 3 2 4	8 4	— 0 1 4	— 0 0	0 3 OF 0 4

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

To prevent this problem in the future, the following actions have been or will be taken:

1. The signal jack was repositioned to the correct plug.

2. Plant procedures will be revised to require stroke checks or other position verification on the F053 valves prior to opening the downstream F011 valves.

3. Engineering will evaluate the need to modify the steam condensing portion of the system and complete any modifications required.

4. Water hammer damage to the supports has been repaired.

5. Real time training in this event will be provided to licensed operators.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 2	0 5 0 0 0 3 2 4	8 4	— 0 1 4	— 0 0	0 4 OF 0 4

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

TABLE 1

	SUPPORT	PROBLEM
Snubbers	2E11-47SS223	Bent paddle, bent shaft
	47SS224	Loose bolting, bent paddle
	47SS225	Broken shaft
	47SS227	Bent coupling, bent shaft
	47SS228	Broken shaft, damaged paddle
	47SS326	Bent steel, broken welds
	47SS328	Spherical bearing broken
Anchor	47A320	Bent loose anchor bolts
Fixed Hangers	47FH230	Bent hanger rod
	47FH229	Bent steel, broken welds
Struts	47PG456	Bent steel, insert sheared
Spring Hangers	47VH226	Loose bolting, spring can misaligned
	47VH457	Clamp misalignment
	47CH325	Bent hanger rod
	47CH327	Hanger misalignment

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APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Brunswick Steam Electric Plant Unit 2	0 5 0 0 0 3 2 4	1 OF 0 2

TITLE (4): ~~Automatic Reactor Scram Resulting From MSIV Turbine~~ Moisture Separator Reheater ~~High~~ Level Switch Fails

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	2 7	8 4	8 4	— 0 1 8	— 0 0	1 2	2 7	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
1	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10): 0 9 8	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
M. J. Pastva, Jr., Regulatory Technician	AREA CODE: 9 1 9 — 4 5 7 — 9 5 2 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On 11-27-84, at 1023, a Unit 2 automatic reactor scram occurred due to a main turbine trip and stop valve closure caused by a main turbine moisture separator (MSR) high level actuation trip signal. At the time Unit 2 was operating at 98% power. In addition the unit low pressure coolant injection (LPCI) subsystem loop B and Reactor Core Isolation Cooling System were inoperable. However, the redundant unit LPCI loop A, both core spray subsystems, and the High Pressure Coolant Injection System were operable.

During the scram recovery, reactor level was controlled by use of the reactor condensate system and steam-driven feed pumps. Reactor pressure was automatically controlled by the main turbine bypass system. The reactor recirculation pump B did not automatically run back to minimum speed and was manually run back.

The MSR high level trip resulted from failure of the unit east MSR high level actuation trip switch to reset within the design ten-second time delay following a spurious high level. Crud accumulation in the instrument internals of the level switch, 2-MD-LSH-MS-2, caused the instrument float to mechanically bind and prevent resetting. The instrument internals of LSH-MS-2 were cleaned, the switch was calibrated and returned to service. Reactor recirculation pump B did not run back due to a bad reset potentiometer in the pump controller, which was then replaced.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 2	0 5 0 0 0 3 2 4	8 4	— 0 1 8	— 0 0	0 2 OF 0 2

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

On November 27, 1984, at 1023, an automatic reactor scram of Unit 2 occurred due to a main turbine trip and stop valve closure caused by a main turbine moisture separator-reheater (MSR) high level trip signal. A unit scram recovery was carried out. Reactor level was controlled through use of the unit reactor condensate main steam driven feed pumps. Reactor pressure, which peaked at 1032 psi, was automatically controlled through use of the main turbine bypass control system. Reactor recirculation pump B did not automatically run back to minimum operating speed and was manually run back. At the time of this event, Unit 2 was operating at 98% power and preconditioning to 100% power was in progress. In addition, the unit low pressure coolant injection (LPCI) subsystem loop B was inoperable due to excessive seat leakage past the loop inboard Primary Containment Isolation Valve (PCIV), 2-E11-F015B. Also, the unit Reactor Core Isolation Cooling System was inoperable due to failure of the inservice test requirement for pump-developed pressure as a function of pump flow criteria. However, the redundant unit LPCI subsystem loop A, both unit reactor core spray subsystem loops, and the unit High Pressure Coolant Injection System were operable. Following the unit scram recovery, while subsequently placing the unit residual heat removal (RHR) subsystem loop A into reactor shutdown cooling, the loop steam condensing piping encountered an apparent water hammer which consequently rendered the loop inoperable. Reactor shutdown cooling was then established utilizing main condenser cooling. Refer to LER 2-84-14 for more information concerning the inoperability of RHR subsystem loop A.

The investigation of this event determined the incurred MSR high level trip resulted from failure of the unit east MSR high level actuation switch, 2-MD-LSH-MS-2, to reset within its design ten-second actuation time delay following a spurious MSR high level. An examination of the instrument internals revealed the instrument float was sticking in the actuated position, thereby preventing reset. The sticking problem with 2-MD-LSH-MS-2 is attributed to crud buildup on the switch internal mechanism. The instrument, 2-MD-LSH-MS-2, Part No. 402-XS-M-14, was cleaned and tested for proper operation. A calibration of 2-MD-LSH-MS-2 showed the instrument actuation trip setpoint was within the specified tolerance. A calibration check of the respective west MSR high level actuation switch, 2-MD-LSH-MS-1, revealed the instrument actuated within tolerance but would not reset when the instrument float chamber was empty. An inspection of 2-MD-LSH-MS-1 instrument internals revealed the instrument float plunger was loose, thereby causing the float to hang up. The float plunger was tightened and the instrument was returned to service. Troubleshooting the problem which prevented the automatic run back of reactor recirculation pump B revealed the pump controller reset potentiometer was defective. The pump controller, 2-B32-R622B, Part No. 50-543041DAAZIPBE, was replaced, functionally tested, and the pump was returned to service.

As a result of this event, applicable plant procedures regarding the periodic testing of the Units 1 and 2 east and west MSR high level switches will be revised to ensure the instruments are checked for possible mechanical binding problems within the instruments.

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APPROVED OMB NO. 3150-0104
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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	1 OF 0 3

TITLE (4)

Reactor Scram on Low Water Level

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)		
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR
0 3	3 1	8 4	8 4	— 0 0 6	— 0 0	0 4	3 0	8 4

OTHER FACILITIES INVOLVED (8)	
FACILITY NAMES	DOCKET NUMBERS
	0 5 0 0 0
	0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10): 0 9 5	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
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	20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
M. J. Pastva, Jr., Regulatory Technician	9 1 9 4 5 7 - 9 5 2 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
A											

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On March 31, 1984, at 2308, a Unit 1 reactor scram occurred due to reactor low level. At the time, the unit was operating at 95% power with a gradual increase to rated power in progress.

A scram recovery was carried out. The reactor level decreased such that reactor low level No. 2 instrumentation actuated. A Group 1 isolation along with automatic starting of the reactor High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) Systems and tripping of the reactor recirculation pumps occurred. The HPCI System isolated shortly after starting and the RCIC System was utilized to restore and maintain reactor level. Reactor pressure, which peaked at 1040 psig, was controlled by manual opening of reactor safety-relief valves 1-B21-F013A and E. The event would not have been more severe under other plant conditions specific to Unit 1.

The event resulted from an interruption of condensate flow to the reactor feed pumps, which tripped the B reactor feed pump and caused a decrease in feedwater flow to the reactor. While shifting the instrument air supply to the plant Radwaste System from Unit 1 to Unit 2, a closed Unit 2 instrument air supply valve resulted in the Unit 1 condensate filter demineralizers' outlet valves closing due to lack of actuation supply pressure. Involved personnel were counseled and appropriately disciplined concerning their actions and have received appropriate real-time training.

NRC Form 366
(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	8 4	— 0 0 6	— 0 0	0 2 OF 0 3

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

On March 31, 1984, at 2308, actions were in progress to shift the instrument air supply source to the plant Radiological Waste Control (Radwaste) Building from the Unit 1 instrument air supply header to the corresponding Unit 2 supply header. At the time, Unit 1 was at power operation of 95% and Unit 2 was in a unit refueling outage. These actions were initiated to remedy a problem of overheating of the Unit 1 D service air compressor.

On each unit at the Brunswick Steam Electric Plant, the instrument and service air headers are provided from a common air supply source fed from four air compressors which are designated as service air compressors for each unit. The instrument air supply to the plant Radwaste Building is designed to be simultaneously aligned to the Units 1 and 2 instrument air supply headers. At the time of this event, the Radwaste Building instrument air header was being supplied by the Unit 1 instrument air supply header. Personnel performing this evolution checked open the Unit 2 instrument air supply header isolation valve, IAI-V384, and then closed the corresponding Unit 1 instrument air supply header isolation valve, IAI-V383. These personnel did not verify open the Unit 2 instrument air isolation valve, IAI-V302, which is downstream of and in series with the Unit 2 IAI-V384. The involved personnel did not review applicable plant drawings of the instrument air supply to the building from each unit prior to performing the evolution. These drawings show the existence of IAI-V203 as well as both corresponding Unit 1 isolation valves IAI-V383 and IAI-V202. At the time of this evolution, IAI-V203 was closed.

When the Unit 1 supply header was isolated by the closing of IAI-V383, a loss of instrument air supply to the Radwaste Building resulted. A direct consequence of this was a loss of actuation supply pressure to the outlet flow control valves of the Unit 1 condensate filter demineralizers (CFDs). The CFD outlet flow control valves closed as a result of the actuation air supply pressure loss. A loss of condensate flow to the reactor feed pumps resulted and caused the B reactor feed pump to trip. The reactor scrammed on low level No. 1 due to the interruption of reactor feedwater flow.

A reactor scram recovery, in accordance with the scram recovery procedure of plant emergency instruction EI-31, was carried out. During the scram recovery, the reactor level decreased such that reactor low level No. 2 instrumentation actuated. A primary containment Group 1 isolation, along with automatic starting of the reactor High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) System, resulted. In addition, the reactor recirculation pumps tripped, as per design, due to the reactor low level No. 2. Shortly after starting, the HPCI System automatically isolated. The RCIC System was utilized to restore and maintain normal reactor vessel level. During the reactor scram recovery, reactor pressure, which peaked at a recorded value of 1040 psig, was controlled by manually opening reactor vessel safety-relief valves 1-B21-F013A and E. The event would not have been more severe under other plant conditions specific to Unit 1. Had Unit 2 also been operating at the time of this event, it would have experienced the same loss of reactor feedwater and reactor low level scram that Unit 1 experienced since both unit's CFDs are supplied by Radwaste Building instrument air.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	8 4	— 0 0 6	— 0 0	0 3 OF 0 3

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

As a result of the event, involved personnel were appropriately counseled and disciplined concerning their actions which led to the event. In addition, appropriate Operations personnel also received real-time training concerning this event.

Information concerning the incurred Unit 1 HPCI System failure is contained in LER 1-84-7.

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)
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	1 OF 0 3

TITLE (4)

Automatic Isolation of High Pressure Coolant Injection 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)
0 3	3 1	8 4	8 4	— 0 0 7	— 0 0	0 4	3 0	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	3	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)					
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	X	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
M. J. Pastva, Jr., Regulatory Technician	AREA CODE 9 1 9 4 5 7 - 9 5 2 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
A	B J	C B L 4	A 3 8 0	Yes							

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

On March 31, 1984, at approximately 2308, the Unit 1 High Pressure Coolant Injection (HPCI) System, automatically initiated on decreasing reactor level following a reactor scram. Shortly thereafter, the HPCI System isolated on B isolation logic concurrent with a HPCI steam line high flow annunciation. Attempts to reset the isolation signal and manually restart the HPCI System were unsuccessful.

The Reactor Core Isolation Cooling (RCIC) System was utilized to restore and maintain reactor level.

The HPCI System isolated and tripped due to a loss of turbine speed control resulting from a broken wire at the turbine speed control and indication magnetic pickup amphenol connector. The subject wire was replaced and the HPCI System was satisfactorily tested and returned to service.

Work requests were initiated to install signs on both units warning personnel not to pull or step on exposed instrumentation or electrical cables on or in the vicinity of the HPCI System turbine/pump assembly.

Safety of the unit was not impacted by the failure of the HPCI System.

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(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	8 4	— 0 0 7	— 0 0	0 2 OF 0 3

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

On March 31, 1984, at 2308, the Unit 1 reactor scrammed due to low reactor vessel level. Following the scram, reactor vessel level decreased to the low level No. 2 setpoint and the unit High Pressure Coolant Injection (HPCI) System automatically initiated. Shortly thereafter, the HPCI System isolated due to isolation channel B logic and the HPCI System turbine tripped concurrent with the receipt of the HPCI System steam line flow differential pressure alarm. The isolation cleared and the HPCI System turbine trip was reset. The HPCI turbine was manually restarted, and the HPCI System channel B logic isolation, along with a HPCI System turbine trip, occurred once again. The isolation cleared and the turbine trip was reset and the HPCI turbine was manually started; however, the turbine speed indication did not function and the HPCI System was shut down, manually isolated, and declared inoperable.

The Reactor Core Isolation Cooling (RCIC) System, which also received an automatic initiation on reactor vessel low level No. 2, was utilized to restore and maintain reactor vessel level following the incurred reactor scram and throughout the unit reactor scram recovery. It is felt the safety of the unit was not impacted by the event.

An investigation revealed the HPCI isolations resulted from a lack of HPCI System turbine speed control feedback. A broken wire at the HPCI System turbine speed magnetic pickup amphenol connector solder joint caused the turbine speed feedback to the turbine speed controller and turbine speed indication in the Control Room to fail. This caused the HPCI turbine speed control circuit to demand maximum turbine speed. Therefore the HPCI turbine throttle valve E41-V9 received a full open signal. Consequently, when V9 fully opened during starting of the HPCI turbine, an actual HPCI System turbine high steam flow differential pressure resulted which was followed by the HPCI System isolation.

The subject wire was repaired by resoldering at the magnetic pickup solder joint and the HPCI System was subsequently returned to service on April 8, 1984.

The subject wire which is run within a cable conduit is exposed approximately three feet from the conduit to the magnetic pickup amphenol, thereby making it susceptible to possible accidental damage from pulling, twisting, or being stepped upon. Although it could not be definitely determined, it is felt the incurred broken wire resulted from such accidental damage to the wire at an indeterminate time. As a result, work request authorizations applicable for each unit were initiated to provide for the placement of warning signs in the immediate vicinity of the HPCI System turbine/pump assembly on each unit. These signs will reflect that personnel are not to stand upon, or otherwise cause physical stress to exposed instrumentation and electrical cables of the HPCI System turbine/pump assembly.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	8 4	— 0 0 7	— 0 0	0 3 OF 0 3

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

Following the repair of the HPCI System speed control amphenol wire, an investigation was conducted to determine why each incurred HPCI System isolation was initiated from the B isolation logic. The HPCI System Steam Line Flow High Channel Calibration Periodic Test, PT-A1-1, was performed to verify the proper operation of the HPCI System steam line flow high isolation logic. The instrument slave trip unit of HPCI System steam line flow high channel A logic instrument, E41-PDT-N004, was found actuating out of specified tolerance by 0.05 inch of water applied in the conservative direction. The as-found trip unit actuation setpoint equivalent to 202.2 inches of water applied is well within the technical specification actuation tolerance of ≤ 230 inches of water applied. The as-found actuation trip setpoint of the instrument slave trip unit for the corresponding channel B logic HPCI System steam line flow high instrument, E41-PDT-N005, was found to be equivalent to 203.7 inches of water applied. In addition, a review of the HPCI System steam line high differential pressure response time test, PT-45.2.14, indicated the A channel response time was 3.5 seconds and the B channel response time was 3.2 seconds. Based on the results of the response time findings, it is reasonable to expect a channel B HPCI System isolation to occur before a channel A logic isolation.

Information specific to the involved reactor scram is contained in LER 1-84-6.

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(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)
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	1 OF 0 3

TITLE (4)

Reactor Scram Resulting From False Recirculation Loop Flow Signals

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 1	8 4	8 4	— 0 1 4	— 0 0	0 8	3 1	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 9 4	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
M. J. Pastva, Jr., Regulatory Technician	AREA CODE 9 1 9 4 5 7 - 9 5 2 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	B J D	P S V	A 1 4 9 7	Yes							

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On August 1, 1984, at 1417, a Unit 1 automatic reactor scram occurred due to a reactor average power range monitor upscale trip initiation of the Reactor Protection System. The upscale trip resulted from erroneous signals of decreasing flow spikes, occurring simultaneously in both reactor recirculation system loops. At the time Unit 1 was at 94.6% power with a planned increase to rated power. In addition, the unit High Pressure Coolant Injection System was out of service pending periodic testing.

During the scram recovery, reactor level, with the lowest recorded value of 142.8", was controlled by the Reactor Core Isolation Cooling System. A Group 1 isolation occurred. Reactor pressure, which peaked at 997 psig, was controlled by manual opening of reactor safety-relief valves 1-B21-F013A, E, J, and B. Following the Group 1 isolation, main steam line isolation valve 1-B21-F022A did not close automatically or manually.

The subject erroneous flow spike signals were induced into the unit recirculation loop flow instruments due to electronic keying of two-way radios in use during periodic testing in the vicinity of the loop flow instrumentation racks in the unit Reactor Building.

By September 14, 1984, various types of plant communication radios will be electronically keyed in the vicinity of Unit 2 instrument racks to determine if Control Room instrumentation is adversely affected. Unit 2 is currently shut down for a planned maintenance outage.

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(9-83)

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PDR ADOCK 05000325
S PDR

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	8 4	— 0 1 4	— 0 0	0 2 OF 0 3

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

On August 1, 1984, at 1417, a Unit 1 reactor scram was automatically initiated by the Reactor Protection System (RPS) due to an instrument upscale trip of the reactor Average Power Range Monitor (APRM) System. At the time Unit 1 was operating at 94.6% power with a planned increase to rated power in progress. In addition, the unit High Pressure Coolant Injection System was out of service pending the performance of periodic testing.

A unit scram recovery was carried out. Reactor level, with the lowest recorded value of 142.8", was controlled through use of the Reactor Core Isolation Cooling System (RCIC). A Group 1 isolation occurred, as per design, when the reactor pressure decreased to the low pressure setpoint while the unit mode switch was in Mode 1. Reactor pressure, which peaked at 997 psig, was controlled by manual opening of the unit reactor safety-relief valves 1-B21-F013A, E, J, and B. Following the Group 1 isolation, the Unit 1 Control Operator discovered that inboard main steam line isolation valve (MSIV) 1-B21-F022A did not automatically close. An attempt to manually close the valve proved unsuccessful. An assessment of the safety consequences and implications of this event determined there are no reasonable and credible alternative events which would have been more severe under these conditions.

The subject APRM System upscale trip resulted from the reactor recirculation loop flow instrumentation receiving erroneous input signals. The erroneous input signals caused the instruments to sense simultaneous decreasing flow spikes in each reactor recirculation loop (A and B). This resulted in an automatic reduction of the APRM System high reactor power scram setpoint to less than the actual reactor power, thereby causing the APRM System upscale trip. The cause of the erroneous input signals to the recirculation loop flow instrumentation was electronic keying of two-way radios in use in the immediate vicinity of the subject instrumentation in the unit Reactor Building. Plant Auxiliary Operators were using the two-way radios in the performance of an annual periodic test (PT) of the Reactor Building fire protection sprinkler systems, PT-35.12.11.1.

Following the Unit 1 scram recovery, an investigation was conducted to determine why inboard MSIV 1-B21-F022A did not close. The three-way ac/dc air operator actuation solenoid pilot valve for F022A apparently failed and was continuously sending an air signal to the four-way pilot valve. With electrical power to both of the ac and dc pilot valve solenoids, resulting from either a Group 1 isolation or a manual command to close, the three-way ac/dc solenoid pilot valve should have actuated to remove this air signal. However, the investigation revealed the subject air signal was still present. The F022A three-way ac/dc solenoid pilot valve, ASCO part number ER8320A183E, was replaced and the removed component was subsequently bench-tested.

No evident signs of failure were noted during testing of the three-way solenoid pilot valve.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Brunswick Steam Electric Plant Unit 1	0 5 0 0 0 3 2 5	8 4	— 0 1 4	— 0 0	0 3 OF 0 3

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

An inspection of the removed three-way ac/dc solenoid pilot valve revealed an outward discoloration of the pilot valve body. Nothing was found during inspection of the valve which may have prevented it from operating properly.

1-B21-F022A was satisfactorily tested and returned to service.

Subsequent testing was performed on Unit 2 which supported the determination that the failure of the Unit 1 MSIV to close was the result of a failure of the ac/dc three-way solenoid valve.

As a result of this event, various types of communication radios utilized in both units will be electronically keyed in the vicinity of the Unit 2 instrumentation racks in the Reactor Building to determine if Control Room instrumentation is adversely affected. This testing of plant communication radios will be completed by September 14, 1984. Following this testing, signs prohibiting the use of plant communication radios within specific identified plant areas will be appropriately posted in those areas. In addition, plant Engineering will be requested to evaluate the apparent failure of the MSIV F022A solenoid pilot valve to determine applicable corrective action.

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(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)
Sequoyah, Unit 1	0 5 0 0 0 3 2 7	1 OF 0 2

TITLE (4)
Reactor Trip [illegible]

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	1 1	8 4	8 4	— 0 3 3	— 0 0	0 6	0 5	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (Check one or more of the following) (11)			
POWER LEVEL (10)	0 2 1	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
Glenn B. Kirk, Compliance Section Engineer	6 1 5 8 7 0 - 6 1 4 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
X	S B	F C V -	C 6 3 5	Y					

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

During a normal startup on 05/11/84 at 1400 CST, unit 1 experienced an automatic reactor trip on low-low level in the number 2 steam generator following a turbine trip. Just prior to the event, unit 1 was in mode 1 (554 degrees F, 2235 psig) at 21% reactor power.

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S PDR

NRC Form 366
(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Sequoyah, Unit 1	0 5 0 0 0 3 2 7	8 4	0 3 3	0 0	0 2 OF 0 2

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

During a normal reactor startup following a reactor trip on 05/10/84 (see SQRO-50-327/84032), unit 1 experienced another reactor trip. Just prior to the event which occurred at 1400 CST on 05/11/84, unit 1 was in mode 1 (554 degrees F, 2235 psig) at 21% reactor power with steam generator level controls in manual.

Steam dump valve 1-FCV-1-107 spuriously opened resulting in swell of steam generator levels. This action resulted in a high-high level in the number 3 steam generator which caused a turbine trip and main feedwater isolation to all four steam generators. The transient then resulted in shrink of steam generator levels causing a reactor trip on low-low level in steam generator number 2. All equipment and personnel responded as expected and the unit stabilized at 547 degrees F.

Inspection revealed a broken repositioning linkage on steam dump valve 1-FCV-1-107 allowing the valve to cycle erratically. The repositioning linkage was replaced and the valve was returned to service.

There was no effect on public health or safety. For 1984, this was the sixth automatic reactor trip on low-low steam generator level and the second event initiated by the opening of a steam dump valve.

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(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/88

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): Duane Arnold Energy Center

DOCKET NUMBER (2): 0 5 0 0 0 3 3 1

PAGE (3): 1 OF 0 4

TITLE (4): Scram due to ~~Rx. W.~~ Feedwater reduction and SRV actuation

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	0 7	8 4	8 4	— 0 0 1	— 0 0	0 2	0 6	8 4	NONE	0 5 0 0 0
									NONE	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)	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
Michael S. Harris, Technical Support Engineer	AREA CODE 3 1 9 8 5 1 - 7 3 0 6

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	S J	T B G	X 9 9 9	N							
A	S B	R V	D 2 4 3	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)

While in run mode at approximately 100% power, the "B" Feedwater Recirculation valve failed open, thereby decreasing feedwater flow to the vessel. Due to an unrelated error in the performance of an ongoing surveillance test procedure, a main steam relief valve was inadvertently opened 43 seconds later. Vessel level decreased to the low level setpoint (170" above top of active fuel) and initiated a scram as designed. The relief valve was reseated approximately 75 seconds later. Both RFP's tripped on low suction pressure. The vessel level continued to fall until the HPCI/RCIC initiation setpoint was reached (119.5" above top of active fuel). Level was restored to 194" and HPCI/RCIC were secured within 4 minutes. Prior to startup, both feedwater recirc valves were repaired or inspected and the surveillance test procedure was revised to reduce the margin for personnel error in the future.

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PDR ADOCK 05000331
S PDR

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At 08:08:26 (T=0), while the reactor was at 99.8% power, the "B" Feedwater Recirculation Valve (SJ-FCV-1611) failed open due to a broken air supply line fitting. As a result, a portion of "B" reactor feedwater flow was returned to the condenser and the vessel level immediately began to drop. While operators were diagnosing and compensating for the decrease in vessel level, the "B" Reactor Feedwater Pump tripped on low suction pressure and 1 of 2 safety/relief valves (SB-RV-4401) utilizing lo-lo set logic cycled open at T +43 seconds. After the relief valve opened, a momentary upswing in vessel level was experienced, followed by an rapid decrease in level to the low level trip setpoint (170") and an automatic scram initiation at T +44 seconds. At T +57 seconds, the "B" feedwater pump breaker was reset. At T +66 seconds, both feedwater pumps tripped on low suction pressure (due to condensate pumps being unable to match RFP flow with the high vessel demand and return flow to the condenser). During this time, the vessel level was continuing to fall until the lo-lo level HPCI/RCIC initiation setpoint of 119.5" was reached at T +73 seconds. At this point, HPCI and RCIC initiated per design and the level began to rise. As the vessel level fell to the lo-lo level setpoint momentarily, HPCI initiated but did not inject at any time in the event. HPCI control logic requires low-low level signal to remain present for the duration of the injection valve initiating time (approximately 15 seconds) to have HPCI actually inject. At T +112 seconds, the "B" reactor feedwater pump breaker was again closed to provide additional makeup and remained closed with no further trips. The open safety/relief valve was reseated at T +118 seconds after operator action and remained closed. As RCIC was injecting and the "B" feedwater pump was functioning, the level quickly recovered to normal operating level (Maximum level reached was 204.4" at T +4 min. 30 sec.). After the level had recovered, RCIC was secured at T +3 min. 50 sec. and HPCI was secured at T +4 min. 30 sec.. At this point, the vessel level and pressure were stable at 194" and 810 psig respectively. All systems necessary for remaining in a safe shutdown condition were operable, and no further system perturbations were experienced.

In retrospect, the following causes and determinations can be made as to the exact component failures and related events leading up to, and after, the scram.

The feedwater recirculation valve (SJ-FCV-1611) is an air actuated, fail open, control valve, Control Components model no. PDA964-96BW. Investigation revealed that a flexible air supply line fitting broke due to fatigue. When the air supply was lost, the valve cycled open. Prior to startup, the broken airline on the 'B' recirc valve was repaired. As an additional precaution, the identical airline on the 'A' recirc valve (SJ-FCV-1569) was inspected and found satisfactory. As a long term corrective action, a maintenance action request has been generated to replace the fittings subject to fatigue with higher strength fittings.

Main steam safety/relief valve (SB-RV-4401) is one of two non-ADS safety relief valves that are utilized in the lo-lo set logic. Following an event that has opened one of the six (6) safety/relief valves, the lo-lo set logic establishes a lower opening pressure (lifting pressure: 1020/1025 psig, reseating pressure: 900/905 psig) respectively. Investigation revealed that the lifting of the SRV was totally unrelated to the failure of the feedwater recirc valve. Prior to the recirc valve failure, a lo-lo set instrument functional test had commenced. While

performing the routine surveillance procedure, the instrument technician erroneously placed an ohmmeter across the hi pressure switch contacts too early in the procedure. As a result, the SRV actuation solenoid relay was falsely energized with a hi pressure test signal, which, in conjunction with the procedure step to push the test button, caused the valve to cycle open (approx 40 seconds after the recirc valve failure). Approximately 75 seconds after the SRV had opened, the operators reset the lo-lo SRV logic, thereby disarming the solenoid and cycling the valve closed. It was later theorized that due to the relatively low internal impedance of the ohmmeter, the meter acted as a jumper and bypassed the contacts. It is noteworthy that prompt identification of the cause of the SRV actuation was greatly aided by the technician volunteering that he had indeed committed an error. This theory was confirmed prior to startup after running a special test procedure. This procedure recreated the applicable sequence of test steps leading up to the opening of the SRV and revealed that the connection of an ohmmeter across the contacts in question in conjunction with pressing the test button, would in fact energize the SRV solenoid.

To preclude recurrence of similar situations, all instrument technicians were assembled and shown during a step by step reconstruction, the exact cause of the event. The importance of procedural compliance without deviating from the prescribed testing sequence was impressed upon them. To reduce the margin for personnel error, the surveillance test procedure has been revised to utilize a volt meter in lieu of an ohmmeter. This revision will eliminate the possibility of the meter acting as a jumper in a circuit under test, regardless of when it is inserted. As a long term corrective action, selected surveillance test procedures are continuing to be revised to simplify and clarify the testing sequence, thereby reducing the possibility of personnel error. In addition to this, a joint management/union task force is being formed to determine and implement methods of maintaining a heightened awareness of the importance of minimizing personnel errors.

Prior to startup, all systems initiated during the scram and subsequent evolutions were reviewed to determine whether they had functioned per design and technical specifications. At 170" reactor water level, the reactor scramed, valve groups 2, 3, 4 and 5 isolated, and both trains of the standby gas treatment system initiated per design. At 119.5" reactor water level valve group 8 isolated, LPCI logic tripped both recirc pumps, loop select logic initiated and performed its' function, and HPCI/RCIC initiated per design. During and after the transient, the operators observed a normal SRV tail pipe temperature response. As an additional precaution, a walkdown was performed on the tailpipe of the opened SRV. The piping and restraints were inspected and found satisfactory.

It was also observed that only one "side" of the reactor lo-lo level switches initiated HPCI/RCIC. This was later attributed to the location of the level switches' sensing lines in relation to the opened SRV. It appears that when the SRV opened, the resultant pressure profile across the top of the vessel skewed the actual level such that the low level was only seen by the switches whose sensing lines were attached to the vessel opposite the steam line on which the relief valve lifted. It appears that vessel level just reached the 119.5" setpoint and did not decrease appreciably below that level. To ensure that the low level indicating switches were functioning properly, a surveillance test procedure was performed on both sides (4 channels) of the HPCI/RCIC initiation level switches. Prior to startup, both sides were found to be in calibration and functioning per design.

With the exception of the unrelated failure of the recirc valve and safety/relief valve, all components and systems functioned per design throughout the event. At no time was the safety of the plant or public endangered. Apart from the corrective actions outlined above, no further action is warranted or planned at this time.

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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)	DOCKET NUMBER (2)	PAGE (3)
Duane Arnold Energy Center	0 5 0 0 0 3 3 1	1 OF 0 6

TITLE (4): update on Degraded Offsite Voltage

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 4	8 4	8 4	– 0 2 8	– Rev. 0 1	1 1	1 6	8 4	None	0 5 0 0 0
									None	0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (Check one or more of the following) (11)			
POWER LEVEL (10)	0 0 0	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
James R. Probst, Technical Support Engineer	AREA CODE 3 1 9 8 5 1 – 7 3 0 7

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
C	F K			No							
B	J E	T S	P 0 5 5	Yes							

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

On 7/14/84 at 1524, with the reactor subcritical in the startup mode, ~~at 0% thermal power~~, a degraded voltage condition on the offsite power grid resulted in the automatic switching of the essential buses from offsite to onsite power. As per design, the RPS logic de-energized, initiating a scram. All required systems operated as designed, including the two Diesel Generators assuming the essential loads. However, the HPCI Inboard Steam Supply Valve also closed. The reason for this response is unknown and under investigation. After consultation with the load dispatcher confirming a return to grid normality, the diesels were secured. A post-event review confirmed operability of all systems, which were then returned to service. Reactor startup commenced three and one half hours following the scram.

On 10/15/84, a special test procedure demonstrated that the cause of the HPCI Inboard Steam Supply Containment Isolation Valve closure was a spurious isolation signal upon re-energizing from either or both of two temperature switches in the HPCI Steam Leak Detection System. A minor design change within the PCI Steam Leak Detection System has resolved this problem. ~~See the attached LER Update text for details.~~

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Duane Arnold Energy Center	0 5 0 0 0 3 3 1	8 4	— 0 2 8	— 0 1	0 2 OF 0 6

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

On 7/14/84 at 1524, with the reactor at 0% thermal power, subcritical in the startup mode with rod groups one and two withdrawn and pressure at 176 psig, the essential buses were automatically transferred from offsite to onsite power due to degraded offsite grid voltage. As per design, the Reactor Protection System (JC) was de-energized during the transfer, resulting in a scram. The two essential and two non-essential 4160 kV buses (EA) were receiving offsite power via the Startup Transformer (EA) when the essential bus' undervoltage protection instrumentation sensed grid voltage less than 92.3% of nominal for 8+ seconds. Consequently the essential bus breakers tripped, as per design. The non-essential buses remained energized and no load shedding occurred as grid voltage did not drop below 65% of nominal. Both Diesel Generators (EK) auto-started upon loss of offsite power to the essential buses, and within ten seconds had assumed the essential bus' loads. The degraded voltage was caused by the accidental motoring of a 650 MWe generator for over twenty seconds at the Louisa Generating Station (fossil fuel) of Iowa Illinois Gas and Electric in Muscatine, Iowa.

Upon switching of the essential buses from offsite to onsite power, the RPS motor-generator set (JC) was de-energized, resulting in the Electrical Protection Assembly breakers (EC) tripping. This, in turn, de-energized the RPS logic, causing the scram. As per design, Group 1, 2, 3, 4, and 5 isolations and Reactor Building isolation occurred. The Recirculation Pumps (AD) tripped, the Circulation Water pumps (KE) tripped, the Control Rod Drive pump (AA) in use, pump B, tripped, the Recirculation pump trip breakers (EA) tripped, the Uninterruptable AC Motor-Generator set (EE) was transferred to DC, the Control Building habitability systems (VI) isolated, and several other systems powered off the essential buses also responded, all per plant design. The Process Computer (IQ) failed at the time of the scram due to a momentary electrical disturbance as its power source, the Uninterruptable AC Motor-Generator set, was transferred to DC. In addition, its "B" Drum Cabinet (for memory storage) and the Virtual Address Extension disk drives and CPU were without power during the switchover from offsite to onsite power, as they are powered off an essential bus.

The HPCI Inboard Steam Supply Valve (BJ-ISV-2238) closed following the scram. Although this was not per design, if necessary the valve could have been opened within a short time by manual operation after resetting the HPCI logic, which was later done at 1810 after Operations personnel had returned other systems to normal. The isolation signal was received from the Steam Leak Detection System (JM). Extensive review indicates the signal origin may have been either or both of two temperature differential switches within the Steam Leak Detection System logic. These switches contain elements powered off essential buses, and therefore would have lost and regained power during the switchover to onsite power, possibly resulting in a spurious signal(s). Investigation is continuing.

The reactor scram was reset at 1556, following the restarting of the RPS m-g sets. All required systems were returned to normal by 1600. At 1620, after the Iowa Electric system control center had advised the plant that recurrence of the grid voltage excursion was unlikely the essential buses were transferred back to the start-up transformer, and both diesels were unloaded. The diesels were secured at 1642. After a post-event review had determined the operability of all safety-related systems and that there had been no effect upon safe plant operation, startup of the reactor was commenced at 1901.

The following is being added to LER 84-028 as Revision One, and deals with the HPCI Inboard Steam Supply Valve Isolation.

On 10/15/84, a special test procedure was run on the "A" logic of the HPCI Steam Leak Detection System (HPCI SLDS). The reactor was in the shutdown mode for a planned maintenance outage, with reactor vessel pressure below that at which HPCI is required to be operable by Technical Specifications. A review of the isolation logic for the HPCI Inboard Steam Supply Valve indicated that the spurious isolation of this valve following the loss of offsite power on 7/14/84 most likely originated in the HPCI SLDS isolation logic. Within the HPCI SLDS logic (see Figures 1 and 2), the "A" logic controls the AC Inboard Steam Supply Containment Isolation Valve (BJ-ISV-2238) and the "B" logic controls the DC Outboard Steam Supply Containment Isolation Valve (BJ-ISV-2239). Power for each HPCI SLDS train is provided by a separate AC essential bus.

By design, each logic train for the HPCI SLDS consists of two temperature switches and two differential temperature switches, each a permissive for energizing a downstream relay (JM-94-K4A or B). This relay closes contacts in the HPCI isolation logic, which energize another relay that in turn results in the isolation signal for the associated HPCI Steam Supply Containment Isolation Valve being sealed in (see Figure 1). Half of each logic side consists of a HPCI Equipment Room High Differential Temperature Switch (JM-TDS-2260A or B) in parallel with a HPCI Equipment Room High Temperature Switch (JM-TS-2261A or B). The momentary closure of either switch in a logic train energizes relay K4 (A or B), resulting in isolation of the associated HPCI Steam Supply Containment Isolation Valve. The other half of each logic side consists of a Suppression Pool Area High Temperature Switch (JM-TS-2526C and D) in parallel with a Suppression Pool Area Differential Temperature Switch (JM-TDS-2521C or D). As there is a 15 minute timer immediately downstream of these switches, either switch must remain closed for a minimum of fifteen minutes to energize relay K4. Due to this significant time delay, these instruments were eliminated as the cause of the spurious HPCI isolation on 7/14/84. The test procedure run on 10/15/84 de-energized the instruments in the "A" SLDS logic, which controls the inboard HPCI steamline isolation valve that isolated, and restored power approximately ten seconds later, simulating the conditions of 7/14/84.

Three trials of the test procedure were performed. On the first and third trials the suspected switches (TS-2261A and TDS-2260A) closed and quickly reopened upon restoration of power. The result was an isolation signal of short duration which was sealed into the HPCI isolation logic. The second test produced no isolation signal. The test results proved a random signal could be expected from the two suspect instruments in the HPCI "A" SLDS logic upon re-energizing after loss of offsite power. The instruments are both Riley Pan Alarm Model 86, and appear in the identical configuration in the HPCI "B" SLDS logic, which signals for closure of the outboard HPCI steamline isolation valve. It is believed these "B" instruments did not trip during the 7/14/84 event due to the random nature of the spurious signal, as demonstrated by the test. Discussions with the manufacturer have also indicated that a short isolation signal upon re-energizing is not unexpected for these instruments due to their internal design.

After review, a minor design change was instituted to eliminate the random HPCI AC power dependency that results from powering up the HPCI SLDS logic. The design change implemented in both the "A" and "B" logic trains was to introduce a short time delay of approximately one second on restoration of AC power. (See Figures 1 and 2.) Prior to the design change, a power monitor relay (JM-30-K2A or B) for each side, connected in parallel to the HPCI SLDS instruments, activated a Control Room annunciator on loss of logic power. The design change involved replacing this relay with an Agastat (Control Products Division - Amerace Corporation) relay with time pickup controls (JM-2-K2), retaining the annunciation contacts and adding an additional set of closed when energized contacts in series with the two instruments in question. This design results in the following; a) with no loss of offsite power there is no time delay introduced for HPCI isolation from the SLDS; b) with a loss of offsite power the logic and instruments themselves are de-energized. On restoration of power the spurious isolation signals are prevented from energizing the downstream relay (K4) by the open contact controlled by the power monitor relay (K2). When this contact closes approximately one second later, the temperature switches have stabilized internally and the isolation signal is no longer present unless it is a genuine signal.

Surveillance tests on the HPCI Steam Supply Containment Isolation Valves over the past year have timed all valve closures at under 11 seconds for the Inboard Valve and under 8 seconds for the Outboard Valve compared to the Tech Spec value of 13 seconds. Channel response time for the Primary Containment Isolation System is not specified in Technical Specifications. The addition of a one second time delay in logic response time on loss and regain of essential AC bus power is judged not to be a reduction of the margin of safety. The increase in HPCI reliability, however, results in an increase in the overall margin of safety at DAEC.

General Electric has stated that it is performing a 10 CFR Part 21 evaluation on a similar problem for a requisition plant, and that this modification at DAEC is similar to that implemented at other GE plants with a similar configuration.

On 10/21/84, a revised version of the special test procedure run on 10/15/84 was performed to determine the effectiveness of the design change to the "A" and "B" HPCI SLDS logic. The reactor remained in a shutdown mode for the planned maintenance outage, with reactor vessel pressure below that at which HPCI operability is required. The HPCI SLDS logic and instrumentation power supplies (see Figure 2) were removed and restored approximately ten seconds later for each logic train. In twenty-four trials for each side, Control Room annunciation indicated spurious isolation signals from either or both of the suspected temperature switches. However, none of the spurious signals sealed in or would have caused an isolation due to the design modification. This indicated the additional power monitor relay contact is successfully preventing unnecessary HPCI isolation due to the re-energizing of the instruments in the HPCI Steam Leak Detection System. Further, post-installation/maintenance testing and routine operability testing during subsequent startup successfully demonstrated HPCI operability.

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		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Duane Arnold Energy Center	0 5 0 0 0 3 3 1	8 4	— 0 2 8	— 0 1	0 5 OF 0 6

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

ADDITIONAL INFORMATION

The Reactor Core Isolation Cooling Steam Leak Detection System (JM) has logic similar to the HPCI SLDS. In the RCIC SLDS logic, however, the two logic trains are powered off electrically separate 125 DC batteries through an inverter. The instruments (TS and TDS) are the same model and manufacturer (Riley Pan Alarm Model 86). De-energizing and restoring the power to the RCIC SLDS inverters could therefore result in a spurious isolation signal from the RCIC SLDS. As RCIC isolation will not occur as a direct result of loss and restoration of AC power, immediate incorporation of a similar design change in RCIC was judged unnecessary. However, it is our current intent to incorporate the time delay in these circuits in the near future. Consideration is also being given to a design change to power the HPCI as well as the RCIC Outboard Steam Supply Isolation Valve (DC) Steam Leak Detection logic from inverted DC (which has proven highly reliable). In this manner, the AC dependency of the HPCI SLDS logic for the Outboard (DC) Isolation Valve will be eliminated.

Our discussions with GE indicate that the tendency for these devices to generate spurious isolation signals during a power-up situation will be the subject of GE notifications to BWR operators. In parallel, Iowa Electric is notifying other utilities of our experience via the INPO "Network" system.

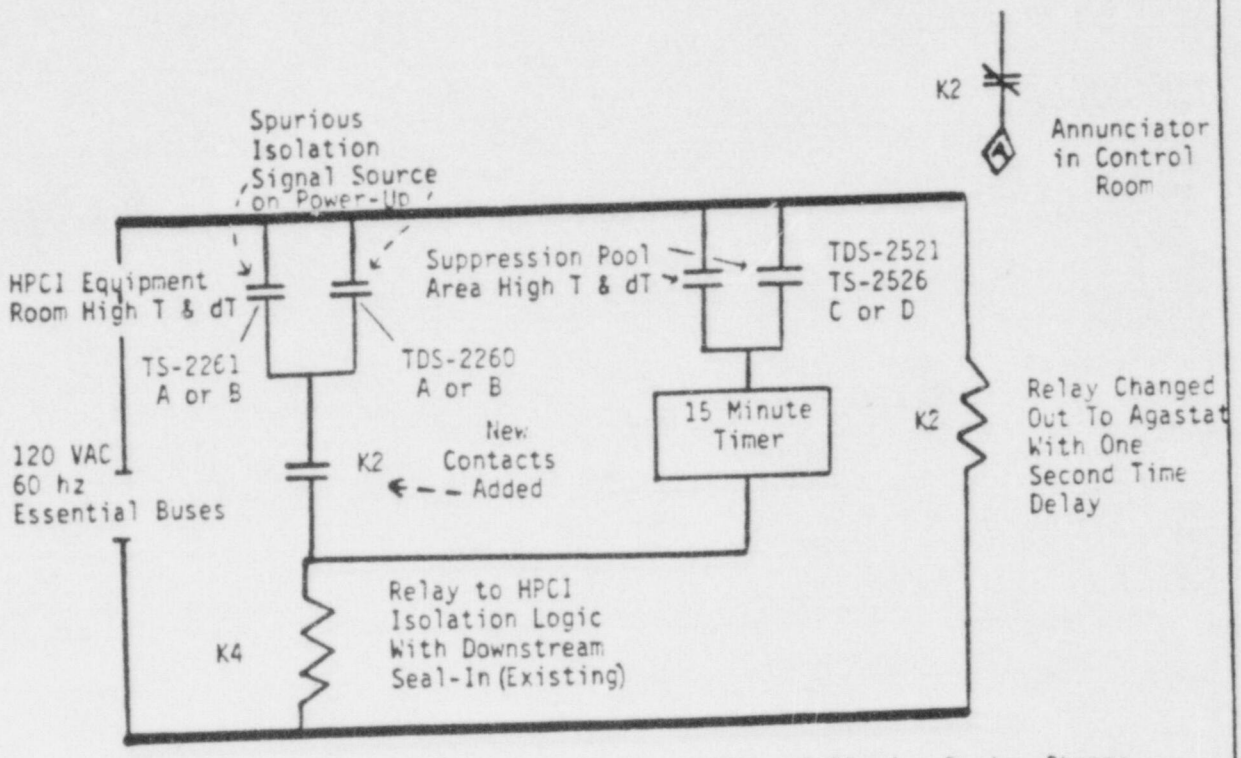

FIGURE 1: HPCI STEAM LEAK DETECTION SYSTEM - Following Design Change (A and B Sides are Identical)

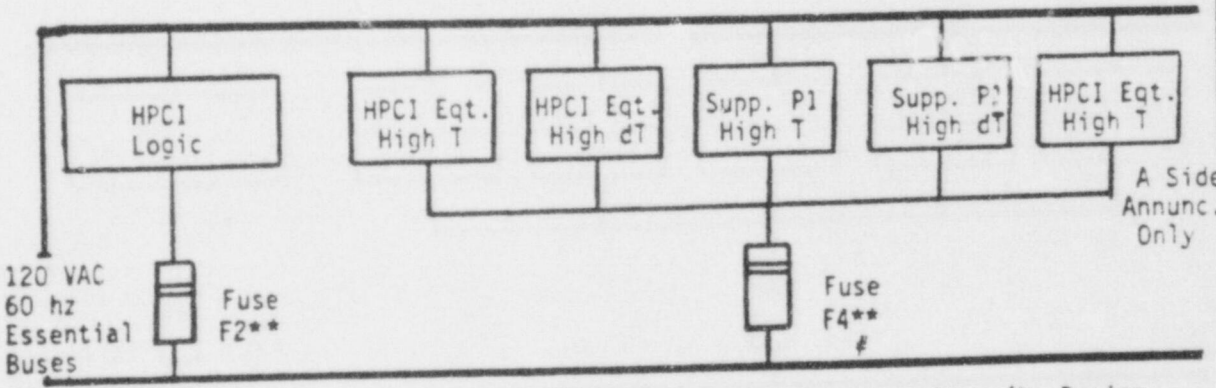

FIGURE 2: HPCI STEAM LEAK DETECTION SYSTEM - Power Supplies (No Design Change) A or B Sides.

#Pulled During First Test - 10/15/84
**Pulled During Second Test - 10/21/84

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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)	DOCKET NUMBER (2)	PAGE (3)
JAMES A. FITZPATRICK NUCLEAR POWER PLANT	0 5 0 0 0 3 3 3	1 OF 0 3

TITLE (4) ~~CONTAINMENT COOLING INOPERATIVE~~ RHR service water pump fails to start three times.

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	3 0	8 4	8 4	— 0 0 2 —	0 0	0 2	2 3	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): N

POWER LEVEL (10): 1 0 0

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

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	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)
ROBERT T. LISENO, MAINTENANCE SUPERINTENDENT	3 1 5 3 4 2 - 3 8 4 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 I	P	A 1 8 0	Y					
X	E C	5 2	G 0 8 0	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 January 30, 1984 at 1051 hrs., while performing surveillance testing for an inoperative RHR service water pump, the B Emergency Service Water pump breaker tripped as it was starting. This placed the plant in a LCO requiring that the reactor be in cold shutdown within 24 hours. After investigation and adjustment of the overcurrent trip devices for the B ESW pump breaker, it was restored to service at 1855 hrs. On February 3, 1984 it was determined that the pump breaker's settings were not correctly set due to test equipment being out of calibration. The pump was taken out of service for 35 minutes while the breaker was replaced with one correctly set. On February 8, 1984 at 0420 hrs., while performing routine surveillance testing on the Emergency Diesel Generators, the B ESW pump breaker again tripped as it was starting. This placed the plant in a LCO requiring that the reactor be in cold shutdown within 24 hours. After adjustment of the pump and breaker trip devices, the pump was restored to service at 1745.

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NRC Form 366 (9-83)

On January 30, 1984 at 1051 hrs. while performing the required surveillance testing for an inoperative "C" RHR Service Water pump (refer to LER 84-001) the "B" ESW pump breaker tripped as it was starting. The loss of "B" Emergency Service Water pump combined with the inoperative "C" RHR Service Water pump placed the plant on a 24 hour reactor cold shutdown limiting condition for operation (Technical Specification Section 3.11 and 3.5.B).

The "C" RHR Service Water pump provides 50% of the cooling flow to "A" RHR heat exchanger for the containment cooling and shutdown cooling modes. The "B" ESW pump provides cooling to the "B" Emergency Diesel Generators which could be required on loss of off-site power to provide power to "B" side containment and shutdown cooling pumps and valves. Neither containment cooling nor shutdown cooling capabilities were completely lost however.

Investigation and troubleshooting commenced immediately. The "B" ESW pump motor was checked for grounds and shorted windings. None were found. The breaker overcurrent trip devices were checked for operation and setpoint using a breaker test set manufactured by E.I.L. Instruments, Inc. During the course of testing it was found that the overcurrent trip device setpoints were out of tolerance.

The breaker overcurrent trip devices were adjusted to the required settings, and "B" ESW was retested with satisfactory results. The pump was restored to service at 1855 hrs. on January 30, 1984.

On January 31, 1984 another breaker was being adjusted using the breaker test set. In this case, none of the overcurrent trip devices could be adjusted within tolerance. Although not an unusual occurrence to have difficulty adjusting overcurrent trip devices, this event prompted further investigation. Clamp-on ammeter checks over the lower range of the breaker test set suggested the possibility of a calibration error. The breaker test set had recently been repaired and calibrated by the manufacturer, so they were contacted to perform an evaluation on the equipment immediately. Due to other commitments the vendor was unable to perform the evaluation on January 31. On February 2, 1984, the vendor representative was present at the plant for the evaluation. It was found that the breaker test set was not calibrated correctly, indicating about 50% of applied amperage in the lower ranges. The test set was re-calibrated and a review of past calibration uses, showed the "B" ESW pump breaker trip devices had been adjusted upward by approximately 50% on January 30, 1984. Immediately a spare breaker was setup to replace the "B" ESW pump breaker. To accomplish the breaker replacement, the "B" ESW pump was removed from service for about 35 minutes on February 3, 1984. Due to "C" RHR Service Water pump still in the inoperative condition, the plant entered a 24 hour LCO. After breaker replacement the "B" ESW pump was tested several times satisfactorily and restored to service.

During the period between January 30 and February 3, since the trip devices were set high, the "B" ESW pump would have performed its required function, if called upon.

On February 7, 1984 at 0537 hrs. the HPCI turbine was removed from service to perform scheduled preventative and minor corrective maintenance and a modification to the overspeed trip mechanism. This placed the plant in a 7 day LCO per Section 3.5.C of Technical Specifications. The planned outage duration was 2-3 days. On February 8, 1984 at 0420 hrs. during a routine surveillance test of Emergency Diesel Generators (EDG), the "B" ESW pump failed to start. This placed the plant in a LCO requiring the reactor to be in cold shutdown within 24 hours (Technical Specification 3.5.C.1). Re-investigation of the occurrence started immediately. Due to the two (2) previous occurrences, the breaker was tested for proper overcurrent trip device settings. The as-found values were 1950 amperes vs. the required 2150 (2000-2300) amperes. Also performed was an inspection of wiring connections, a check of pump clearances and ease of rotation. These checks revealed the pump clearances were 10 mils under those required to prevent rubbing between impeller and wear ring. The trip devices and the pump clearances were then adjusted to within tolerance. Furthermore, measurements of starting current were performed with the electrical distribution system lineup the same as it was at the time of the failure to start. This showed a starting current comparable to that specified by the manufacturer when corrected for variations in system voltage (vendor: 1510 amps at 575 volts, actual: 1633 amps at 613 volts). The narrow pump clearances and slightly reduced margin between the starting current and the instantaneous overcurrent trip device settings are probable causes for the breaker trip. However, no definite cause could be determined from these results. The "B" ESW pump was tested satisfactorily for operability and restored to service at 1745 hrs. on February 8, 1984. This returned the plant to a 7 day LCO.

Because the cause is undetermined, the following monitoring program has been initiated. Daily, for one week, the pump will be checked for operability. At the end of the week, the breaker will be checked for any drift of overcurrent trip device setpoint. If satisfactory, then every other day, for a week, the pump will be checked for operability. Again at the end of the week, the breaker will be checked for overcurrent trip device setpoint drift. If satisfactory, the operability will be checked weekly for two weeks, then bi-weekly for a month. If satisfactory, the surveillance interval for pump operability will return to the normal monthly schedule. Through this testing it is believed that a better understanding of the cause will result if this intermittent problem continues to exist.

The actual effect of having HPCI and "B" ESW pump inoperative simultaneously is minimal. Injection systems exist to backup the HPCI system and redundant containment cooling and shutdown cooling equipment exists to cover equipment inoperative as the result of a "B" ESW pump trip.

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(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)
James A. FitzPatrick Nuclear Power Plant	0 5 0 0 0 3 3 8	1 OF 0 4

TITLE (4): ~~Inoperative RCIC System Due TO Personnel Error~~ RCIC inoperable while HPCI 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)
0 2	0 7	8 4	8 4	— 0 0 3	— 0 0	0 3	0 5	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	N	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	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)	
		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
Hartford N. Keith	AREA CODE 3 1 5 3 4 2 - 3 8 4 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	
A	B N	T R B	T 1 4 7	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)

During normal full power operation the High Pressure Coolant Injection (HPCI) system was intentionally removed from service to permit maintenance and modification. Prior to removing HPCI from service completion of surveillance required by Technicial Specifications had demonstrated the Automatic Depressurization System (ADS), Reactor Core Isolation (RCIC), Low Pressure Collant Injection (LPCI) and both core spray systems operable. While the HPCI system was out of service, the Reactor Core Isolation Cooling (RCIC) system was made inoperable due to a personnel error.

This action resulted in the plant being placed in a 24 hour Limiting Condition for Operation (LCO) in accordance with Technical Specification 3.5.C.1.b. The RCIC system was demonstrated operable and placed in the standby mode approximately 10 hours later. The HPCI system maintenance and modification was completed in approximately 4 days and was demonstrated operable and placed in standby.

Corrective action to reduce the probability of recurrence includes disciplinary action for the individuals involved, implementation of a program to verify that individuals are knowledgeable of the equipment they work on, continuation of plant specific BWR Technology/Training and labeling of certain plant equipment.

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PDR ADOCK 05000333
S PDR

NRC Form 366
(9-83)

During normal full power operation the High Pressure Coolant Injection (HPCI) system was intentionally removed from service to permit maintenance and modification. While the HPCI system was out of service the Reactor Core Isolation Cooling (RCIC) system was made inoperable due to a personnel error. This resulted in the plant being placed in a 24 hour Limiting Condition for Operation (LCO) in accordance with Technical Specification 3.5.C.1.b. The RCIC system was demonstrated operable and placed in the standby mode approximately 10 hours later. The HPCI system maintenance and modification was completed in approximately 4 days and was demonstrated operable and placed in standby.

A detailed sequence of events and immediate corrective action is shown below:

2/7/84 (0535) Surveillance required by Technical Specification 3.5.C.1.a and 4.5.C.1.a was completed in preparation to make HPCI inoperable to permit general maintenance and modification of the overspeed trip.

2/7/84 (0537) The HPCI system was declared inoperable and was tagged out of service.

2/7/84 (0730) Two (2) Instrument and Control (I&C) Technicians were assigned to perform an Instrument Maintenance Procedure (IMP) for calibration of the HPCI system turbine speed indication.

Performance of the IMP requires disconnecting the turbine tachometer (speed) feedback circuit in order to insert a simulated speed signal as part of the calibration process. Disconnect of the feedback circuit makes the HPCI (or RCIC) system inoperable regardless of any other activities.

2/7/84 (1030) The I&C Technicians assigned the task of calibration of HPCI speed indication reported to the I&C Supervisor that the task was complete and noted that the speed indication circuit had to be found out of procedural tolerance by approximately forty (40) percent.

The magnitude of the "As Found" out of tolerance speed indication lead the supervisor to initiate an investigation into the cause.

2/7/84 (approx. 1445) The investigation revealed that the I&C Technicians had calibrated the RCIC turbine speed indication using the procedure for HPCI speed indication.

The RCIC system was declared inoperable and the plant was placed in a LCO requiring that the Reactor be placed in the cold condition and that reactor pressure be less than 150 psig within 24 hours in accordance with Technical Specification 3.5.C.1.b.

Calibration of the RCIC turbine speed indication utilizing the proper procedure was initiated immediately under the direct supervision of an I&C supervisor.

2/7/84 (approx 1700) Calibration of the RCIC turbine speed indication completed and the RCIC system was demonstrated operable in accordance with Technical Specification 4.5.E.1.b. The HPCI system remained inoperable as maintenance and modification continued. This action terminated the 24 hour LCO of Technical Specification 3.5.C.1.b.

2/8/84 A critique of the event was held and the following significant facts were noted.

1) The lead technician had performed a similar procedure on the RCIC Turbine prior to being assigned to the HPCI task.

2) Instrument and Control Supervisor had discussed the activity with the technician prior to the performance.

3) The technicians were aware that the HPCI system (and not the RCIC system) was out of service.

4) The Lead Technician (and probably the other technician) was familiar with the physical location of both the HPCI and RCIC units prior to the event but neither recognized that the wrong unit was being worked on until after or during the investigation that was initiated by the I&C supervisor.

5) The turbine control enclosure of both units are identical in appearance making it possible for individuals with limited experience to confuse the HPCI and RCIC units.

6) The root cause of the event was personnel error due to the technicians not paying attention to details of the task assigrment.

2/8/84 A disciplinary action hearing was held for the two (2) I&C technicians involved. Disciplinary action included placing letter in the personnel file (Lead Technician), verbal reprimand (other technician) and disqualification for performing Safety Related work (both technicians) for at least 2 weeks and until evaluation for re-qualification is completed.

2/10/84 (2300) HPCI system declared operable as a result of post maintenance testing in accordance with Technical Specification 4.5.C.1.

Long term corrective action to reduce the probability recurrence or similar errors with other systems/components is a follows:

1) Label the HPCI and RCIC turbine control enclosures for positive identification by June 30, 1984.

2) Develop and implement a program for verifying the awareness of I&C technicians with respect to the physical locations of safety related equipment by May 30, 1984.

3) Continue a program in which I&C Technicians complete a plant specific BWR Technology course. This is an on-going program currently in place and no specific completion date for all I&C Technicians can be provided, however as more personnel complete the program there is a general improvement in level of knowledge and awareness of specific and integrated purpose/effect of plant systems.

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(9-83)

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
James A. FitzPatrick Nuclear Power Plant	0 5 0 0 0 3 3 3	1 OF 0 1

TITLE (4)

~~Inoperable~~ Reactor Core Isolation Cooling ~~" declared inoperable~~

EVENT DATE (5)			LER NUMBER (6)				REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR		SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
											0 5 0 0 0
0 2	1 0	8 4	8 4	-	0 0 4	- 0 0	0 2	2 9	8 4		0 5 0 0 0

OPERATING MODE (9)		THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
N		20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10)		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
1 0 0		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
Douglas J. Lindsey	3 1 5 3 4 2 - 3 8 4 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	
D	B N	I R B	T 1 4 7	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-spaced typewritten lines) (16)

During power operation with the High Pressure Coolant Injection system out of service for scheduled maintenance, a D.C. Ground occurred on "A" Station Battery. During the performance of the ground isolation procedure the D.C. control power to the RCIC inverter was momentarily interrupted. The momentary loss of D.C. power to the RCIC inverter requires a manual reset to re-power up the inverter. The ground isolation procedure did not inform the operator that a manual reset was required. The loss of both HPCI and RCIC placed the plant on a 24 hour Limiting Condition for Operation. The operator, after determining that the inverter would not reset automatically, performed a manual reset. Surveillance testing for RCIC operability was immediately conducted and RCIC was declared operable. The consequences of this occurrence were minimized due to the short outage of the RCIC system (approximately 30 minutes) and because the ADS and low pressure injection systems were operable.

A change to the ground isolation procedure was incorporated to instruct the operator to manually reset the RCIC inverter.

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PDR ADOCK 05000333
S PDR

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LICENSEE EVENT REPORT (LER)

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

TITLE (4) Update on Leak in Feedwater Heater, ~~Manual Reactor Trip~~

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
1 1	~~1 2~~ 28	~~8 4~~ 85	8 4	0 1 2	~~0 1~~ Rev. 0	1 0	0 7	8 5	Nila	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10) 0 6 2	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
Steve Brinkman	AREA CODE 2 0 3 — 4 4 7 - 1 7 9 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 J D	H T X I	Y 1 0 3 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)

The Unit was operating in Mode 1 at 62% reactor power and was proceeding with an orderly shutdown necessitated by a leak in the #5A Feedwater Heater. Due to a steady rise in the level in the #5A Feedwater Heater, the Reactor was tripped in order to protect the turbine from water intrusion.

Reactor Trip and Post Trip actions were carried out in accordance with plant procedures. All systems functioned normally with the exception of the main feedwater check valve to the #2 Steam Generator (2-FW-5B), which failed to seat. Due to the malfunction of 2-FW-5B, initiation of Auxiliary Feedwater flow was required to maintain level in the #2 Steam Generator.

Reactor Trip recovery procedures were followed with personnel responding as expected.

Prior to returning the Unit to full power operation, all Feedwater Heater tube leaks were plugged and check valve 2-FW-5B was inspected and tested and was deemed operable. Both check valves, 2-FW-5A and 2-FW-5B, were inspected and reworked during the 1985 refueling outage.

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PDR ADOCK 05000336
S PDR

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

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

The Unit had been operating at 100% reactor power when a tube leak was detected in the #5A Feedwater Heater. An orderly shutdown of the Unit had been underway for some time when a steady rise in the level in the #5A Feedwater Heater was noted. As a result, in order to protect the turbine from water intrusion, the reactor was tripped. At the time of the trip, the Unit was operating in Mode 1 at 62% reactor power.

Following the trip, standard post trip actions were carried out in accordance with Operations Procedure 2525. In addition, reactor trip recovery procedure 2526 was also followed. All personnel and systems responded as expected with one notable exception. When the B-Steam Generator Feed Pump (SGFP) was taken to minimum speed, the level in both Steam Generators (SG) started decreasing. The B-SGFP was secured due to low discharge pressure and Auxiliary Feedwater (AFW) flow was initiated. The level in the #1 SG increased while the level in the #2 SG continued to decrease. AFW flow to the #2 SG was increased with no effect on the level decrease in the #2 SG. Operations personnel noted steam escaping from the B-SGFP. It was theorized that the main feedwater check valve to the #2 SG (2-FW-5B) failed to seat, thus resulting in a back-flow of AFW to the B-SGFW. At this time, the Feed Regulating valves, the Feed Regulating Block valves, and the SGFP discharge valves were shut. Level in the #2 SG was brought on scale and returned to normal.

The Unit was placed in hot standby (Mode 3). The tubes in the # 5A Feedwater Heater were inspected and plugged as required. The malfunctioning check valve, 2-FW-5B, was inspected. It was determined that the valve stem had bound up slightly not allowing the valve to seat. Adjustments were made to the valve and its operability was evaluated via inservice test, T84-36. The valve was deemed operable prior to returning the Unit to 100% power operation.

Corrective Action:

Check Valves 2-FW-5A & 2-FW-5B were inspected and reworked during the 1985 refueling outage. The rework consisted of machining a spacer ring internal to the valves to eliminate binding. The valve vendor concurred with this modification.

Previous Occurrence:

None.

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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
North Anna Power Station Unit 1	0 5 0 0 0 3 3 8	1 OF 0 2

TITLE (4) Update On
Reactor Trip Due to Loss of Vital Bus 1-III

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 4	8 4	8 4	- 0 1 9	- Rev. 0 on file	0 1	2 4	8 5		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
1	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10) 1 0 0	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
E. Wayne Harrell	AREA CODE 7 0 3 8 9 4 - 5 1 5 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	
X	E F	I N V T	S 2 5 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-spaced typewritten lines) (16)

ABSTRACT

On November 14, 1984, at 0640 Unit 1 STE Tripped due to a vital bus inverter failure. The inverter was supplying power to the 125V AC vital bus 1-III. The inverter failure caused this bus and its associated equipment to become deenergized. Loss of power to the relay which senses "C" Reactor Coolant Pump (RCP) breaker position caused the reactor trip on loss of reactor coolant system flow coincident with reactor power greater than 30%. The "C" RCP never stopped running during this event. Insert see next page

Most parameters and equipment responded as expected for a post trip condition. The Unit was placed in Mode 2 on 11-17-84 and returned to 100% power on 11-19-84.

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PDR ADOCK 05000338
S PDR

NRC Form 366
9-83

On November 14, 1984, at 0640 Unit 1 tripped from 100% power due to a vital bus inverter (EIIS component identifier INVT) failure. The inverter was supplying power to the 125V AC vital bus 1-III. The inverter failure caused this bus and its associated equipment to become deenergized. Loss of power to the relay which senses "C" Reactor Coolant Pump (RCP) breaker position caused the reactor trip on loss of reactor coolant system flow coincident with reactor power greater than 30%. The "C" RCP never stopped running during this event.

Vital bus 1-III was deenergized for less than two minutes. The inverter had damaged SCRs and a blown fuse which prevented it from being reenergized. The bus was subsequently powered from its SOLA transformer. All equipment power from vital bus 1-III responded as expected during loss and restoration of the bus. The most significant equipment response involved B steam generator. "B" Main Feed Valve (FCV-1488) and "B" Feed Bypass Valve (FCV-1489) both failed closed. "B" Wide Range Steam Generator Level indication (LI-1487) failed low. The Auxiliary Feedwater pump(1-FW-P-3B) which supplies "B" Steam Generator failed to auto start and was manually started by the Control Room Operator. These actions caused "B" Steam Generator level to drop below the narrow range indication while no wide range level indication was available. Level was restored to "B" Steam Generator within a few minutes.

Loss of vital bus 1-III also deenergized all four water boxes' vacuum breakers which caused all Circulating Water Pumps to trip. This vital bus also supplies power to many containment isolation trip valves including Component Cooling to the reactor coolant pumps. Other significant equipment that was powered from the 1-III Vital bus was one power range detector (N43), twenty-six incore thermocouples, SSPS channel III inputs, SSPS train "B" output relays, RVLIS train B, radiation monitor cabinet 1-2 and other equipment.

At 0654 the "B" Reactor Coolant Pump (RCP) was secured due to the number one seal leakoff flow indicating zero gpm and high stand pipe alarm. Shutting down the RCP was precautionary action and was not a required action to mitigate the effects of the reactor trip. Upon securing "B" RCP the number one seal leak off returned to normal and in a short period of time the stand pipe high level alarm cleared.

One of the blowdown containment isolation trip valves (TV-BD-100F) did not close automatically and would not close manually during this event. A SOV for this trip valve would not change position. Maintenance personnel agitated the SOV and the valve was subsequently cycled satisfactorily. Blowdown containment isolation trip valves are cycled every three months during a valve stroke time verification Periodic Test (1-PT-130). TV-BD-100F was last tested on 9-16-84 and stroked successfully during that test.

The source range excore detectors had to be manually reinstated due to one intermediate range detector (N35) being under compensated. This detector had its compensation voltage adjusted before the reactor was taken critical.

All parameters and equipment except those noted above responded as expected for a post trip condition. The Unit was placed in Mode 2 on 11-17-84 and returned to 100% power on 11-19-84.

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(9-83)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
North Anna Power Station Unit 2	0 5 0 0 0 3 3 9	1 OF 0 2

TITLE (4) Forced Shutdown ~~Required By Technical Specifications~~ Due To Two Inoperable Emergency Diesel Generators

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	0 9	8 4	8 4	— 0 1 3	— 0 0	0 1	0 3	8 5		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
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)	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
E. Wayne Harrell	AREA CODE 7 0 3 — 8 9 4 — 5 1 5 1

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

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	X NO				

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

ABSTRACT

At 0719 hrs on December 7, 1984, with Unit 2 at 100% power, the "2H' Emergency Diesel Generator (EDG) was removed from service to perform preventive maintenance. At 1321 hrs on December 7, 1984 the "2J" EDG tripped during the performance of an operability test and was declared inoperable. The "2H" EDG was returned to service and determined to be operable. The "2H" EDG was tested every 8 hours for operability in accordance with T.S. 3.8.1.1 while the "2J" EDG was inoperable. At 0652 hrs on December 9, 1984 the "2H" EDG tripped during surveillance testing and was declared inoperable. As a result of having two inoperable Emergency Diesel Generators, a plant shutdown was initiated at 0830 hrs on December 9, 1984 as required by Tech. Spec. 3.8.1.1. When the plant reached Mode 3, a Notification of Unusual Event was declared in accordance with the station Emergency Plan. This event is reportable pursuant to 10CFR50.73(a)(2)(i)(A).

The plant was placed in cold shutdown at 1920 hrs on December 10, 1984. Maintenance was performed on both Emergency Diesel Generators and they were subsequently restored to an operable status. Unit 2 was place back on line at 2355 hrs on December 16, 1984.

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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	
North Anna Power Station Unit 2	0 5 0 0 0 3 3 9	8 4	— 0 1 3	— 0 0	0 2 OF 0 2

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

On December 3, 1984, with Unit 2 at 100% power the "2H" Emergency Diesel Generator (EDG) was started for normal surveillance testing. Temporary instrumentation had been installed on the EDG to record crankcase pressure, jacket coolant temperature, and other vital parameters to further investigate prior spurious trips reported in Unit 2 LER 84-11. During the surveillance testing a longer than normal start time and a slightly positive crankcase pressure were observed. The diesel was re-started and subsequently met the required starting time and all Tech. Spec. operability requirements. For further information on this surveillance test see Unit 2 LER 84-11, revision 1, dated December 28, 1984. At 0719 hrs on December 7, 1984, the "2H" EDG was removed from service to perform preventive maintenance to correct the problems identified during the December 3, 1984 surveillance test.

At 1215 hrs on December 7, 1984, the "2J" EDG was started to determine operability while the "2H" EDG was tagged out for maintenance as required by T.S 3.8.1.1. At 1321 the "2J" EDG tripped on high crankcase pressure and was declared inoperable. Preventive maintenance was immediately stopped on the "2H" EDG. The "2H" EDG was started, loaded and determined operable at 1605 pursuant to T.S. 3.8.1.1 testing requirements. The "2H" EDG was placed on an 8 hours surveillance testing schedule as required by T.S. 3.8.1.1. At 0637 on December 9, 1984, the "2H" EDG was started for surveillance testing. At 0652 hrs the "2H" EDG tripped on high crankcase pressure and was declared inoperable.

As a result of having two inoperable Emergency Diesel Generators, a plant shutdown was initiated at 0830 hrs on December 9, 1984 as required by T.S. 3.8.1.1. At 1343 hrs on December 9, 1984, the plant was placed in hot standby. When the plant reached Mode 3, a Notification of Unusual Event was declared in accordance with the station Emergency Plan. At 1920 hrs on December 10, 1984, the plant was placed in cold shutdown. This event, completion of a plant shutdown required by the Technical Specifications, is reportable pursuant to 10CFR50.73(a)(2)(i)(A).

Throughout this event two independent offsite power supply circuits were operable and supplying power to safety related equipment.

Maintenance personnel and technical representatives from the EDG manufacturer investigated the causes of the EDG trips and performed corrective maintenance. For specific details describing this investigation and maintenance performed see Unit 2 LER 84-11, revision 1, dated December 28, 1984. The "2H" EDG met its Tech. Spec. operability requirements and was declared operable at 1159 hrs on December 11, 1984. The "2J" EDG met its Tech. Spec. operability requirements and was declared operable at 1710 hrs on December 11, 1984. The unit was taken critical at 0301 hrs on December 14, 9184, and placed on line at 2355 hrs on December 16, 1984. All equipment functioned as expected during the rampdown, cooldown, and subsequent re-start.

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)
TROJAN NUCLEAR PLANT	0 5 0 0 0 3 4 4	1 OF 0 4

TITLE (4)

DELAYED RESEATING OF MAIN STEAM SAFETY VALVE AND REACTOR TRIP

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
09	26	84	84	017	00	10	24	84		0 5 0 0 0
8 4 0 9 2 6										0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 5 0	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
		20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
		20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Gary G. Bair, Reactor Engineer, (LSP)	AREA CODE 5 0 3 5 5 6 - 3 7 1 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	
X	S B	R Y	C 7 1 0	Y							
X	J B	P T	F 1 2 0	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 26, 1984 at 10:15 PM the plant was operating at 50% rated power with the rod control system in manual for physics testing. Upon receipt of an alarm for low suction pressure on the operating main feedwater pump, main turbine loading was manually reduced by 250 MWe in an effort to avoid auto trip of the pump. Since the control rods were in manual, the reactor power did not automatically reduce in conjunction with turbine load. The resulting mismatch between turbine demand and reactor power caused an increase in the average temperature (Tave) of the reactor coolant system from 571°F to 585°F. This in turn caused an increase in steam generator steam pressure which resulted in the lifting of the first (1170 psig set point) safety valve on each of the four main steam lines. Upon discovery of this mismatch, reactor power was reduced by manually inserting control rods. The 'D' steam safety valve failed to reseat when steam pressure was reduced. An Unusual Event was declared at 11:00 PM in accordance with the Radiological Emergency Response Plan. The turbine generator was taken off line and a manual reactor shutdown initiated by inserting control rods. An automatic reactor trip occurred wi reactor power at 1.2% due to the narrow-range water level in the 'D' steam generator reaching the low-low level trip set point (20%). A plant cool-down was initiated in order to reseat the 'D' steam line safety valve. The valve reseated at 11:35 PM when steam generator pressure reached approximately 890 psig. At this time the Unusual Event was terminated.

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DESCRIPTION OF EVENT

The event began on September 26, 1984 just after a power distribution flux map had been taken at power (about 500 MWe). The control rods were in manual mode to facilitate rod repositioning to compensate for boron dilution and to achieve varying axial flux differences for the Cycle 7 physics testing program.

At 10:08 PM a plant computer alarm indicated low suction pressure on the only operating main feedwater pump. At this time the assistant shift supervisor and turbine building operator went out to investigate the problem locally. Since the feedwater pump has a low suction pressure trip at 195 psig, control room personnel started reducing turbine load to decrease the required feedwater flow and increase suction pressure. The normal feedwater pump suction pressure indicator in the control room had failed earlier in the day (a maintenance tag was hung on the control room indicator). Control room personnel decreased turbine load slowly to avoid arming the steam dumps on a load rejection signal. Turbine load was decreased by about 250 MWe by 10:15 PM.

Normally control rod motion is automatically initiated by the rod control system. Turbine impulse pressure is used to generate a reference temperature (T_{ref}) which is proportional to turbine power (and hence reactor power in steady-state conditions). As Tref changes a reactor coolant system Tave-Tref deviation occurs which initiates control rod motion to correct the deviation, assuming the control rods are in automatic. When the control room personnel first started reducing turbine load by manually closing the control valves they noticed the mismatch between Tave and Tref. They attributed the mismatch to the load run-back. The control room personnel failed to realize that reactor coolant system Tave was not decreasing since the control rods were in manual. Because of the reduced heat transfer rate out of the primary system, T_{ave} increased from 571°F to 585°F. In addition, steam generator pressure increased from approximately 970 psig to the set point of the first set of safety valves (1170 psig) on all four steam generators.

At about 10:25 PM, an auxiliary operator noticed the 20°F mismatch between Tavg and Tref. At this time control room personnel started to manually insert the control rods to reduce Tave. At about 10:30 PM, the oncoming crew informed the control room personnel that the safety valves were open. It was also noticed that the 'A' steam line power-operated relief valve was open 30% and the steam pressure was about 1130 psig in the steam generators. The 'A' steam line power-operated relief valve was closed from the control room. The turbine load and reactor power were both reduced in concert to further reduce T_{ave} and reseat the safety valves. Steam pressure was reduced to less than 1100 psig, and all safety valves reseated except for the safety valve on the 'D' steam line. The failure of this safety valve to reseat resulted in the plant's entry into the action statement for Technical Specification 3.7.1.1, "Turbine Cycle Safety Valves", and in the declaration of an Unusual Event at 11:00 PM in accordance with Table 1-3 of EP-1, "Emergency Classification", of the plant's emergency procedures. The action statement for Technical Specification 3.2.5, "DNB Parameter", for reactor coolant system Tavg was never entered since T_{ave} remained less than 589°F during the event.

At about 11:10 PM, the shift maintenance mechanics tried unsuccessfully to force the 'D' safety valve closed. Reduction in reactor and turbine power was continued with the turbine generator being taken off line at 11:26 PM. Level control problems in the 'D' steam generator resulted in a reactor trip at 11:29 PM due to low-low level. Reactor power was approximately 1.2% at the time of the trip. At 11:35 PM, the 'D' steam line safety valve reseated when the steam generator pressure reached about 890 psig. The indicated reactor coolant system temperature was about 542°F when the valve reseated. At this time the Unusual Event was terminated. A control board walk-down after the event indicated that the steam line power-operated relief valves were set to open at about 1260 psig instead of their normal set point of 1125 psig.

CAUSE OF OCCURRENCE

The indication of low suction pressure was caused by a cracked bourdon tube in the suction pressure transmitter for the main feedwater pump. The turbine building operator who had been checking the local suction pressure indicator on the pump did not communicate back to the control room personnel what the actual suction pressure was. The control room presonnel relied too heavily on one indicator to make decisions rather than checking other indications.

The instrument failure was followed by operator error in not realizing that rod control was in manual during the initial turbine load reduction and that reactor coolant system T_{ave} was increasing. It was also not immediately realized that the temperature mismatch and subsequent high steam pressure caused the safety valves to open. A contributing factor to not recognizing that the safety valves were open is that there is no indication or alarm in the control room of steam line safety valve position.

The transient continued with the failure of the 'D' steam line safety valve to reseat. An inspection of this safety valve indicates that the failure was most likely due to dirt or debris between the valve disk and disk guide area.

The main steam power-operated relief valves were not set to relieve at the normal set point of 1125 psig. It could not be determined how the controllers had been moved above their normal set points. There was no administrative requirement for formal set point control or periodic reviews of these types of controllers.

CORRECTIVE ACTION

The immediate corrective action was to reduce steam pressure to reseat the stuck open steam line safety valve. The plant was shut down while a thorough investigation was conducted regarding this and other problems experienced during the startup. An extensive list of corrective actions was developed including near-term items, which were completed prior to plant startup, and long-term items. These corrective actions are discussed in detail in separate correspondence between PGE and the Regional Administrator, Nuclear Regulatory Commission, Region V. (Letter from Bart D. Withers to Mr. John E. Martin dated October 3, 1984.)

SIGNIFICANCE OF OCCURRENCE

This event had no effect on the health and safety of the public. A more severe case, the complete loss of electrical load (from 100% power), has been analyzed and is described in FSAR Section 15.2.2. No credit was taken in the safety analysis for operation of the steam dumps or the steam generator power-operated relief valves, and one case was analyzed with the rods in manual control. The analysis concluded that plant design is such that a total loss of electrical load presents no hazard to the integrity of the reactor coolant system or main steam supply system, and that no core safety limits would be violated. A stuck open safety valve has also been analyzed with acceptable results and is presented in FSAR Section 15.1.4.

The operating crew contributed to but finally overcame the combination of difficulties and the plant was safely shut down. However, the event was considered to be significant enough to maintain the plant in a shutdown condition until the investigation referred to above was completed and corrective action taken to prevent recurrence.

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APPROVED OMB NO. 3150-0104
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LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Davis-Besse Unit 1	0 5 0 0 0 3 4 6	1 OF 0 4

TITLE (4) Modified
Reactor Trip Due to Closure of Main Steam Isolation Valve

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	0 2	8 4	8 4	— 0 0 3	— Rev. 0 1	0 7	2 5	8 4	on file	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
1	20.402(b)	20.405(c)	XX 50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10) 0 1 9	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
	20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
	20.405(a)(1)(iii)	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
Frank Swanger (Isolator)	AREA CODE 4 1 9 — 2 5 9 — 5 0 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	
B	S B	R V	D 2 4 3	Y		X	B A	I S V	L 2 0 0		
X	J E	O B	C 5 6 0								

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES (If yes, complete EXPECTED SUBMISSION DATE)	XX NO				

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

On March 2, 1984, Davis-Besse Nuclear Power Station was operating at 99% of rated power. At 1221 hours, the #2 Main Steam Isolation Valve went closed, isolating the steam side of Steam Generator #2. This was caused by an undetected failed relay in one safety instrumentation channel plus routine plant testing involving a second safety instrumentation channel. The closure of Main Steam Isolation Valve #2 caused feedwater and Reactor Coolant System temperature transients that led to a reactor trip on high flux. After the trip, one of the Main Steam Safety Valves did not fully close. This caused an excessive Reactor Coolant System cooldown rate and by procedure Steam Generator #2 was allowed to boil dry. After the failed Main Steam Safety Valve had been replaced, while attempting to restore level in Steam Generator #2, the auxiliary feedwater valve to Steam Generator #2 failed to open. It was opened manually to restore level in Steam Generator #2. It was discovered later that a Main Steam Safety Valve on Steam Generator #2 had failed to lift. The failed relay circuit was repaired, the safety valve that failed to close properly was replaced. The safety valve that failed to lift has been gagged and will be repaired in the future. The auxiliary feedwater valve that failed to open had its torque switch settings changed. Analyses have shown that no design parameters were exceeded on the Reactor Coolant System or the steam generator.

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

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

Description of Occurrence: On March 2, 1984 at 1220 hours, 103 Effective Full Power Days, EFPD, into Cycle 4, Davis-Besse 1 was operating at approximately 99% of full power. The plant was in full automatic control. During periodic Steam and Feedwater Rupture Control System, SFRCS, (JE), surveillance testing, a previously undetected SFRCS channel failure resulted in closure of the Loop 2 Main Steam Isolation Valve, MSIV, (ISV). This caused an increase in feedwater to the other steam generator (SG) which overcooled that side of the reactor. Flux increased because of the negative moderator coefficient. The reactor tripped on high flux approximately 13 seconds after MSIV #2 closed.

Following the reactor trip, steam pressure on SG #2 did not stabilize as would normally be expected. It was determined through local observation that Main Steam Safety Valve, MSSV, (RV), SP17A4, with a set pressure of 1070 psig, had not fully closed on the #2 steam line. Manual actuation of SFRCS isolated SG #2. After auxiliary feedwater, AFW, (BA), isolation, SG #2 boiled dry and depressurized to atmospheric pressure in approximately five minutes. This depressurization caused the Reactor Coolant System (RCS) to exceed the normal cooldown limits for a short time. Plant cooldown was conducted with SG #1. At approximately 340°F RCS temperature, the failed MSSV was replaced. When operators attempted to restore level in SG #2, the AFW valve (AF599) failed to open. It was opened manually, and SG #2 level was restored to operable status. The plant was then cooled down to cold shutdown.

It was determined later that an additional MSSV (SP17A1) on the #2 steam line had failed to open when it should have.

This event is being reported under 10CFR50.73(a)(2)(iv).

Designation of Apparent Cause of Occurrence: The cause of the MSIV closure was a failed optical isolator in a relay driver card for a relay in SFRCS Channel 4. This failure, undetected and in conjunction with normal testing on another channel, resulted in a close signal to MSIV #2. During troubleshooting, a wiring anomaly was found in the circuitry for MSIV #2. This anomaly was the reason the failed relay driver card had not been detected. There was both an equipment failure and an installation/construction error associated with the MSIV closure.

The cause of the excessive cooldown rate of the RCS was equipment failure. The failed MSSV released steam from SG #2 at a rate causing excessive cooldown. Therefore, equipment failure of the MSSV was also the cause for SG #2 boiling dry.

The two MSSVs, SP17A1 and SP17A4, were both equipment failures. MSSV SP17A4 failed due to the failure of a cotter pin that secures the release nut in place at the top of the stem. The failure of the cotter pin allowed the release nut to spin down the stem while the valve was open. This nut contacted the manual lifting device and prevented the valve from closing. The cause for the failure of MSSV SP17A1 is unknown at this time. When tested subsequent to its failure to open, it lifted early and inconsistently. It has been gagged and will be repaired or replaced during the next refueling outage.

The reason for the failure of the AFW valve, AF599, was attributed to the torque to the torque switch setting. After it had been opened manually, troubleshooting found no mechanical problems and the valve operated properly.

Analysis of Occurrence: There were two automatic actuations of safety systems. The Reactor Protection System (RPS) actuated to trip the reactor on high flux. The SFRCS actuated on low steam pressure in SG #2 and isolated the steam and feedwater systems to SG #2. The SFRCS was originally initiated manually on low SG level to isolate normal feedwater and align AFW to both SGs.

The availability of SG #1 was adequate for cooling down the RCS even with SG #2 dry. One SG is capable of removing the decay heat following a reactor trip.

The number of MSSVs on each steam line is more than adequate to control steam pressure following a trip. The failure of MSSV SP17A1 to lift did not pose a significant hazard.

If MSSV SP17A4 had been further open when it stuck, it would have produced an even higher cooldown rate.

There was no danger to the health or safety of the general public or station personnel as a result of any part of this event.

Corrective Action: Under Maintenance Work Order, MWO, 84-0816, MSSV SP17A4 was replaced. The cotter pins in all other MSSVs were replaced with stainless steel pins, and maintenance procedures were modified to ensure new pins are used after any maintenance or testing in the future.

MSSV SP17A1 has been declared inoperable and gagged. It will be repaired or replaced during the next refueling outage. The cause of its failure to lift is still unknown at this time. The RPS high flux trips must be set less than 99.69% of rated thermal power with this safety inoperable.

The cooldown rate exceeded Babcock & Wilcox guidelines, but was within Technical Specification limits. An evaluation of the transient has concluded that all primary pressure boundary components still meet all requirements of the ASME Boiler and Pressure Vessel Code, Section III. Plant Procedures PP 1102.10, Plant Shutdown and Cooldown, and EP 1202.24, Steam Supply System Ruptures, have been modified to incorporate lessons learned from this event to give better control of this type of cooldown.

The effects of the SG #2 boiling dry were analyzed and it was concluded that the transient was within SG design limits. The effects of high main steam flow from SG #1 when No. 2 MSIV closed was analyzed. It was concluded that some tubes (approximately 100) may have become unstable for a period of seconds. As corrective action, the suspect tubes will be eddy current tested during the next refueling outage.

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

The AFW valve AF599 problem was investigated under MWO 84-0819. Under this work order, and Facility Change Request 84-039, the motor operator torque switch settings were changed from 1.5 open and close to 1.0 close and 1.5 open. This is to prevent the valve disc from being jammed into its seat. This change was also made to AF608, the AFW valve for SG #1.

The faulty relay driver board in SFRCS Channel 4 was replaced under MWO 84-0820. The wiring anomaly was corrected and verified not to exist in the circuitry for MSIV #1. This work was done under MWO 84-0827.

Failure Data: No other reactor trips and MSSV failures due to this type of event have occurred at Davis-Besse.

Report No: NP-33-84-03

DVR No(s): 84-027 thru 84-032

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(9-83)

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

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Davis-Besse Unit 1	0 5 0 0 0 3 4 6	1 OF 0 3

TITLE (4) Update BY Moisture Separator/Reheater Level Switch
~~Inadvertent Turbine Trip From 70 Percent Full Power~~

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)		
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR
0 9	1 1	8 4	8 4	— 0 1 3	— Rev. 0 1	0 7	2 5	8 5

OTHER FACILITIES INVOLVED (8)	
FACILITY NAMES	DOCKET NUMBER(S)
N/A	0 5 0 0 0
	0 5 0 0 0

OPERATING MODE (9)	1
POWER LEVEL (10)	0 7 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)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)
	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)

	73.71(b)
	73.71(c)
	OTHER (Specify in Abstract below and in Text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
Jan Stotz	4 1 9 2 4 9 - 5 0 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	
A	J I	L S	M 0 4 0	N							
X	S B	P S V	C 6 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)

~~Davis-Besse was operating at approximately 70 percent of full power~~ During the power coastdown of cycle 4, The refueling outage was scheduled to begin on September 14, ~~1984, and~~ Maintenance personnel were positioning the rotor lifting beam onto the turbine deck in preparation for the outage. A 12-inch by 12-inch timber being used as dunnage was inadvertently slid into the piping supporting the moisture separator reheater high water level switch. The switch activated, tripping the turbine at 1235:17 hours. The Anticipatory Reactor Trip System tripped the reactor in response to the turbine trip. Following the trip, the #1 Atmos Vent (ARTS) valve failed to reseat. This was due to failed air control solenoid valves.
The post trip plant response was as expected. Since the unit was in the outage burnup window, it was decided to begin the refueling outage. A plant cooldown was initiated. During cooldown, the operators had difficulty balancing pressure in the ~~SG~~ Steam Generators. The station received a Steam and Feedwater Rupture Control System trip from low pressure in SG #1. This initiated another ARTS trip of the reactor.

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(9-83)

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

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

Description of Occurrence: On September 11, 1984 at 1235 hours, Davis-Besse experienced a turbine trip from 70 per cent full power. The turbine trip initiated an Anticipatory Reactor Trip System, ARTS, (JD) trip of the reactor. The post trip response was normal for a trip from 70 per cent full power. Pressurizer (PZR) level remained on scale, and minimum Reactor Coolant System, RCS, (AB) pressure was about 1880 psig. The Power Operated Relief Valve, PORV, (PSV) was not operated. Adequate subcooling margin existed at all times. The #1 Atmospheric Vent Valve, AVV (PSV) did not fully reseat on its own and operators had to lower steam header pressure to get it to reseat.

Since the unit was in the outage burnup window it was decided to begin the refueling outage. A Plant cooldown was initiated.

Later in the cooldown, in Mode 3, with one Reactor Coolant Pump, RCP (P) shutdown, operators had difficulty balancing pressure in the two Once Through Steam Generators, OTSG. At 0109 hours on September 12, 1984, the station received a Steam and Feedwater Rupture Control System SFRCS, (JB) trip from low pressure in OTSG #1. This initiated another ARTS trip of the reactor.

Designation of Apparent Cause of Occurrence: The cause of the trip was an error by personnel positioning a rotor lifting beam on the turbine deck in preparation for the refueling outage turbine work. A 12 x 12 inch timber being used as dunnage was inadvertently slid into the piping which supports the Moisture Separator Reheater, MSR, (SB) High Water Level Switch (LS). The bump caused the switch to actuate. The switch is intended to cause the turbine to be isolated when the water level gets too high in the MSR. This is to protect the turbine from damage that would occur if water hit the blades. The switch caused the turbine to trip which initiated an ARTS trip of the Reactor.

The cause of the #1 AVV not fully reseating was determined to be in the valve control circuit specifically the air control solenoids which are in need of replacement or refurbishment.

The cause of the SFRCS trip on September 12, 1984 was that the Plant Shutdown and Cooldown Procedure PP 1102.10 did not adequately cover an RCS cooldown using the Main Feed Pump Turbine, MFPT (SJ). This change in method of shutting down is due to not being able to use the Startup Feedpump due to pipe break criteria, (See LER 84-009.)

Analysis of Occurrence: The reactor was tripped by ARTS before any Reactor Protection System, RPS (JD) trip setpoint was reached. The PORV was not challenged. Adequate subcooling margin existed at all times. OTSG water levels were properly controlled. The AVV failure to fully reseat did not have a significant safety consideration since the valve was only slightly open. The leakage was not sufficient to affect steam pressure.

Corrective Action: The maintenance workers who actuated the switch were counseled on being more careful around operating equipment.

Facility Change Request, FCR, 84-0207 will install permanent guard rails around the MSR high level switches. FCR 85-0083 has been written to provide a two out of three trip scheme for the MSR high level trip by adding two additional level switches to the existing sensing leg. It also provides guard rails around these additional level switches.

The AVV air control solenoid valves were replaced during the 1984 Refueling Outage under FCR 82-125.

The Plant Shutdown and Cooldown Procedure, PP 1102.10, was modified on September 28, 1984, to provide guidance for an RCS cooldown using the Main Feed Pump Turbine due to not being able to use the Startup Feed Pump. On January 15, 1985, the Station received License Condition 2.c(3)(t) which allows operation of the Startup Feed Pump. PP 1102.10 was modified and now reflects the conditions that must be met.

Failure Data: The previous occurrence of this level switch being bumped causing a turbine trip was not reportable per the guidelines in effect prior to 1984.

Report No: NP-33-84-13 DVR No(s): 84-142, 84-143

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) update on inoperability Fall
HIGH PRESSURE SAFETY INJECTION PUMPS ~~INOPERABILITY~~

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 8	2 1	8 4	8 4	— 0 3 5	— Rev. 0 on file	1 1	1 9	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	1 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	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
J. G. HAYNES, STATION MANAGER	AREA CODE 7 1 4 4 9 2 - 7 7 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	

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 8/21/84 at 1815, ~~with Unit 3 in Mode 1 at 100 percent power,~~ a review of operator logs by the Control Room Supervisor identified that Train A HPSI subgroup relay testing had been conducted concurrent with the draining of the saltwater side of the Train B Component Cooling Water (CCW) Heat Exchanger.

Investigation determined that at 0416 on 8/21/84, the saltwater side of Train B CCW Heat Exchanger was removed from service for cleaning. Train B components cooled by CCW, including the Train B HPSI pump, were therefore inoperable. At 0518 on 8/21/84, the Train A HPSI bypass valves MU184 and MU186 were opened in accordance with the approved surveillance procedure for conduct of subgroup relay testing. Opening the Train A bypass valves rendered the Train A HPSI pumps inoperable. The bypass valves were shut at 0536 on 8/21/84 restoring the Train A HPSI pumps to an operable status.

The cause of this event was failure of the Control Operator (CO) and Control Room Supervisor (CRS) to follow procedure precautions in the subgroup relay testing procedure. The CO and CRS received disciplinary action and counseling on the importance of attention to detail and strict compliance with procedural requirements.

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NRC Form 366
(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQ NUMBER	REV NUMBER	
SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3	0 5 0 0 0 3 6 2	8 4	- 0 3 5	- 0 1	0 2 OF 0 3

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

On August 21, 1984, at 1815, with Unit 3 in Mode 1 at 100 percent power, a review of operator logs by the Control Room Supervisor identified that Train A High Pressure Safety Injection System (HPSI) (EIIS System Identifier BQ) subgroup relay testing had been conducted while the saltwater side of the Component Cooling Water (CCW) Heat Exchanger (EIIS Component Identifier HX) was drained for cleaning.

Investigation determined that at 0416 on August 21, 1984, the Train B CCW Heat Exchanger was removed from service for cleaning. Train B Engineered Safety Features components cooled by CCW (EIIS System Identifier CC), including the Train B HPSI pump, were therefore inoperable. At 0518 on August 21, 1984, the Train A HPSI bypass valves were opened in accordance with the approved surveillance procedure for conducting Train A subgroup relay testing. Opening the Train A HPSI bypass valves rendered Train A HPSI inoperable. The loss of both trains of HPSI while operating at 100 percent power constitutes operation outside Limiting Condition for Operation (LCO) 3.5.2 and its associated Action Statements. However, the miniflow bypass valves were shut within 18 minutes at 0536 on August 21, 1984, restoring the Train A HPSI pumps to an operable status, and placing the unit in compliance with Action Statement (a) of LCO 3.5.2.

It was initially reported to the resident NRC inspector that both trains of HPSI were inoperable for 15 minutes, but further investigation established that both trains of HPSI may have been inoperable for up to 18 minutes.

Further investigation into the reasons for this event revealed that established administrative controls intended to make all control room operators aware of inoperable safety systems were not followed by control operators. Initiation of ESF subgroup relay testing on Train A should have resulted in the manual entry of Train A HPSI pump inoperability on the Bypassed and Inoperable Status Monitor (BISM). Had this action been properly taken by the previous shift when ESF subgroup relay testing was commenced, control operators would have been made aware of Train A status and removal of the Train B CCW Heat Exchanger from service would have been delayed until completion of Train A testing and restoration to operable status.

In addition to disciplinary action taken against operators involved, corrective action has included an in-depth review of this event by station management. In conjunction with an overall review of action being taken to implement guidance provided in I&E Information Notice 84-51 and Item I.C.6 of NUREG-0737, operator training is being enhanced to emphasize the importance of the SRO function of authorizing removal of equipment from service, the importance of the manipulation of locked valves and the importance of re-reviewing procedure precautions and prerequisites prior to recommencing activity begun on a previous shift. Action has also been initiated to evaluate what improvements could be made to the Bypassed and Inoperable Status Monitor such that automatic control room indication of system inoperability would be provided as a result of any safety system valve being mispositioned.

It was also determined the HPSI ESF subgroup relay testing could be completed without opening the miniflow bypass valves. The HPSI flow through the miniflow valves alone is sufficient to prevent pump damage for the duration of the test. The surveillance procedure will be revised to remove the requirement to open the HPSI miniflow bypass valves and the need for rendering the HPSI system inoperable.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
SAN ONOFRE NUCLEAR GENERATING STATION, UNIT 3	0 5 0 0 0 3 6 2	8 4	- 0 3 5	- 0 1	0 3 OF 0 3

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

Since both trains of HPSI were inoperable for only 18 minutes and the operators who opened the Train A HPSI bypass valves remained in the valve room with communications capability and could have closed the valves restoring Train A HPSI operability in the event of ESFAS actuation, this event did not represent a significant degradation in safety margin.

Since Unit 3 was at 100 percent power throughout this event, there are no reasonable alternative conditions under which this event would have been more severe.

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(9-83)

U.S. NUCLEAR REGULATORY COMMISSION
APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1): MCGUIRE NUCLEAR STATION UNIT 1

DOCKET NUMBER (2): 0 5 0 0 0 3 6 9

PAGE (3): 1 OF 0 6

TITLE (4): LOSS OF ALL NORMAL OFF-SITE POWER

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 1	8 4	8 4	— 0 2 4	— 0 0	1 1	0 5	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 1 0 0

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

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	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: SCOTT GEWEHR - LICENSING

TELEPHONE NUMBER: AREA CODE 7 0 4 3 7 3 - 7 5 8 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 approximately 2400 on August 20, 1984, the McGuire switchyard computer was reported inoperable. On August 21, 1984, computer and inverter maintenance personnel performed corrective maintenance on the switchyard computer and static inverter. At 2114, the switchyard computer was re-started, checked for operability, and returned to service. At 2148, when the switchyard operator re-enabled the computer control outputs, thirty (30) power circuit breakers (PCBs) and associated disconnects opened, resulting in McGuire Unit 1 reactor trip and turbine trip, loss of Unit 1 offsite AC power, and startup of Unit 1 diesel generators A and B.

Unit 1 was in mode 1 at 100% power at the time.

This incident is classified as a Component Malfunction/Failure because the control circuits were changed to an undesirable state without a command from the computer, apparently during computer and inverter maintenance. Design Deficiency also contributed because the computer program did not include a function to reset the computer output control circuits to a predetermined state when the computer is restarted.

The behavior and control of the transient which resulted from the reactor and turbine trip were as could be expected, ~~and the health and safety of the public were unaffected by this incident~~.

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Corrective actions included, or will include, a modification to the computer control of switchyard PCBs, increase settings on the two transmission lines which tripped on overcurrent to allow them to carry unit 1's full output, improvement of relay house lighting, review of operating and maintenance procedures to determine potential effects on off-site power, and scheduled replacement of existing equipment (e.g., the switchyard computer).

INTRODUCTION: On August 21, 1984, a reactor trip occurred at 2148:46, initiated by a Nuclear Instrumentation (N/I) Power Range Hi Flux Rate signal. The trip signal was caused by an electrical disturbance induced into the station when two transmission line power circuit breakers (PCBs) tripped on overcurrent. All of the Unit 1 generator output had been concentrated on the two lines seventeen (17) seconds earlier (2148:29) when all but eight 230KV and 525KV switchyard PCB's and associated disconnects simultaneously opened. The opening of thirty (30) switchyard PCB's occurred when the switchyard operator re-enabled computer control outputs by pressing the ENABLE pushbutton on the switchyard control board. The switchyard computer was being returned to service, following satisfactory operability checks which were performed at the completion of computer maintenance.

The incident is classified as a Component Malfunction/Failure because the control circuits were changed to an undesirable state without a command from the computer, apparently during computer and inverter maintenance. A Design Deficiency also contributed because the computer program did not include a function to reset the computer output control circuits to a predetermined state when the computer is restarted.

COMPUTER MAINTENANCE DESCRIPTION: The McGuire switchyard computer is a GE 4010 process control digital computer. Installed in 1971, it communicates with the Charlotte Area Operating Center (C-AOC) computer over a computer to computer data link. The data link is a dedicated point to point communications path which enables the C-AOC to remotely monitor and control the McGuire switchyard. The McGuire switchyard computer also has a data link to the McGuire Nuclear Station Unit 1 Operator Aid computer (OAC) which enables the McGuire Nuclear Station to remotely monitor the switchyard.

The switchyard computer has no "bulk storage" capability for saving a copy of the software programs that run in its "core" memory. A copy of the McGuire switchyard computer software is maintained at the C-AOC. Core memory is designed to retain its contents even upon loss of power. Occasionally the memory contents are destroyed due to overwriting by maintenance diagnostic programs or other events. If the core contents have to be restored, it can be achieved by transferring a copy of the McGuire software over the data link from the C-AOC.

Switchyard monitoring capability is in service whenever the computer is put in service; however, the control circuits, which may be disabled through various disabled interlocks, can only be enabled through a manual ENABLE pushbutton on the relay house switchboard. The McGuire switchyard computer can control a "Control Test Point" relay to verify its control capability and its status monitoring

performance. The supply voltage to the test relay is not tied to the supply for the other computer control circuits so that the computer performance can be verified without having to enable control outputs to the switchyard.

The C-AOC dispatcher has full monitoring and control capability of the McGuire switchyard; however, C-AOC control of the eight (8) PCBs (8, 9, 11, 12, 58, 59, 61, and 62) that connect the unit bus lines to the switchyard is normally disabled.

On August 20, 1984 the McGuire switchyard computer was reported inoperable. On August 21 maintenance personnel performed corrective maintenance on the switchyard computer and the status inverter.

McGuire Switchyard Computer and Inverter Problems

Following the corrective maintenance on the computer, system operational checks were made which showed the computer system operating properly. The switchyard computer is used to perform control functions i.e., opening and closing PCB's as well as providing information about the status of switchyard equipment to the Charlotte dispatcher computer and the McGuire operator aid computer. The control output relays used are "Latching" type in both the open and closed positions. Power is required to change them from one state to the other. Since the state of the computer control output relay contacts is not readily observable or detectable by hardware or software, neither computer maintenance personnel nor the dispatcher were aware that the relay contacts were closed. At least some of the relays were in the wrong state at this time. There are no alarms or status lights to indicate the position of the output relay contacts. The closed relay contacts caused the subject PCB's to open when control voltage was reapplied to interposing relays via the ENABLE pushbutton.

Operation of Power Circuit Breakers in the McGuire Switchyard

When the "ENABLE" pushbutton was pressed by the switchyard operator, all of the PCBs opened except those associated with the Unit 1A and 1B bus line (PCBs 8, 9, 11, and 12) and Unit 2A and 2B bus line (PCBs 58, 59, 61, and 62). Switchyard computer control of these eight PCBs is normally disabled by selector switches in the McGuire Control Room. (This was the case during the event.) All of the Unit 1 generator output was then concentrated on the Craighead White Line and the Mecklenburg Black Line. The Craighead White Line overcurrent relay 51Z tripped PCB-8 and the Mecklenburg Black Line tripped at the Harrisburg Tie on overcurrent relay 51Y leaving McGuire Unit 1 generator feeding only its plant auxiliary equipment. The sudden loss of load caused a turbine overspeed condition, which caused the turbine overspeed protection to actuate. At this point the turbine sequential tripped scheme would normally detect a reverse power condition and trip the generator. But since Unit 1 was already separated from the transmission system, this (reverse power) could not occur. The 6.9 KV busses (1TA, 1Tb, 1TC, and 1TD) spiked to ~7.4 KV and corresponding 450 ampere neutral current spikes were recorded from the 24 KV step-up transformers 1A and 1B. This produced a power supply spike on the nuclear instrumentation which resulted in an N/I Power Range High Flux Rate Trip signal, tripping the reactor. This electrical system disturbance is being evaluated to

determine the cause and possible ways to minimize the effects should a similar incident occur.

As all offsite loads were disconnected from the generator, the turbine speed increased to 1957 RPMs, increasing generator frequency to 65.0 Hz. (Reactor and turbine had tripped by this time and main steam was isolated from the turbine.) The turbine speed and generator frequency then started decreasing until the generator volts/hertz relay tripped the generator circuit breakers. This caused an undervoltage on the 4160 V bus which initiated the blackout logic and started diesel generators (D/Gs) 1A and 1B. (Generator output voltage and 6.9 KV bus voltage remained relatively constant between the time the turbine tripped and the volts/hertz relay operated, even though frequency dropped to 51 Hz. This is attributed to compensation by the automatic voltage regulator.) When the blackout logic was initiated, both D/Gs were up to speed within 10 seconds and all 10 load groups were sequenced on within 15 seconds (both times are within the design requirements and Technical Specifications).

Unit 1 Reactor Trip Caused By N/I Power Range High Flux Rate Trip

The reactor tripped at 2148:46.230 from 100% power on Nuclear Instrumentation (N/I) Power Range High Flux Rate Trip. The setpoint for this type of trip is an excore power increase of greater than or equal to 5% in two seconds on two out of four excore channels. A review of plant parameters by the McGuire Reactor group indicated that no justification could be made to support an actual reactivity increase which could have resulted in a N/I Power Range High Flux Rate Trip. A review of the excore chart recorders indicated power range spikes on all four power range channels with channel N-42 and N-43 reaching the 5% trip setpoint. When the last transmission line was isolated, voltage immediately increased 8% on the 6.9 KV bus. If this action is assigned time zero, then the 24 KV main step-up transformer 1A and 1B neutral current spike ended in approximately 6 milliseconds. The voltage spike ended 1.23 seconds after time zero. The N/I Power Range High Flux Rate Trip was received at 1.25 seconds after time zero and reactor trip breaker "B" tripped at 1.31 seconds after time zero.

Transient Analysis

Reactivity was properly controlled by the reactor trip. Pressurizer pressure dropped immediately after the trip to ~2030 psig, then recovered to 2235 psig as pressurizer level increased because of high charging flow, with letdown isolated.

Pressurizer level dropped immediately following the trip to ~38%. Letdown was isolated about 50 seconds after the trip on a 0% level indication on channel 2 as a result of a voltage spike. Pressurizer level increased as the full charging flow of both centrifugal charging pumps was injected once they were loaded on the D/G, and as hot leg temperature increased. Level reached a post-trip maximum of ~46%, at which time the charging flow was decreased. Level then decreased toward its no-load target (25%). Level increased again to ~32% thirty minutes after the trip as charging flow was increased slightly and primary temperature began to recover. Level as indicated on channel 1 remained within acceptable limits at all times.

The pressurizer pressure master was taken to manual, and charging flow was reduced ~7 minutes after the trip. Letdown was reestablished at that time. Pressurizer pressure then began to decrease to its post-trip minimum of ~1954 psig. Pressurizer Water Temperature was almost constant during this period as the heaters had deenerigized on load shed. When the backup pressurizer heaters were sequenced on to the diesel, the operators experienced difficulty in closing the breakers, because the low pressurizer level alarm had not yet been reset. (The pressurizer heaters are deenergized on low pressurizer level to prevent them from operating in a steam environment.) Once the alarm was reset, the operators were able to energize the heaters ~25 minutes after the trip. Pressure then began to recover toward its reference value. Pressure remained well below the uncompensated PORV setpoint (2335 psig) and above the Safety Injection setpoint (1845 psig) at all times.

Reactor Coolant System Hot Leg Temperature dropped immediately after the reactor trip as heat production decreased, and steam was relieved through the steam dump valves. Hot leg temperature began to rise again as the NC pumps coasted down and natural circulation flow developed. Core ΔT stabilized between 35 an 40°F, as expected for natural circulation. Both hot and cold leg temperatures then decreased as the steam pressure decreased. Temperature stabilized and began to recover once the steam pressure decrease ended. Minimum average coolant temperature was ~530°F.

Reactor coolant flow increased prior to the trip as frequency on the busses increased, and dropped as frequency dropped. The flow coasted down as expected once the Reactor Coolant Pump breakers tripped on underfrequency.

Steam pressure peaked at ~1150 psig after the trip. This is below the setpoint the first bank of Main Steam Safety Valves (1170 psig). The steam pressure was initially controlled by the steam dump to condenser valves, which opened following the trip. These valves all closed by 50 seconds after the reactor trip. The condenser was available for steam relief until the 6900 V busses deenergized 43 seconds after the reactor trip.

Steam pressure continued to decrease after the steam dump valves closed because of the high steam demand and high auxiliary feedwater flows needed to recover level. Unit 1 was carrying the auxiliary steam load for both units at the time of the trip. (Unit 2 was preparing to start up at the time of the trip, and was drawing steam for its main feedwater pumps and other needs.) Steam pressure reached a minimum of 735 psig at 22:10:34 when the operators manually isolated main steam. Pressure had recovered to ~790 psig thirty minutes after the trip.

Steam generator level had dropped to ~55% at the time of the trip when the steam pressure rose as the turbine governor valves closed. All four low-low steam generator level reactor trip signals came in within 0.155 seconds of the Power Range High Flux Rate Reactor Trip, and all 3 auxiliary feedwater pumps initiated on low-low steam generator level. Steam generator level fell following the trip to ~34% narrow range. Main feedwater was isolated on reactor trip with coincident low Tave at 2149:12. The motor driven pumps were load shed on blackout and re-started

~10 seconds later. Flow came on full when the pumps were restarted as the valves were already open. The operators secured the Turbine Driven Auxiliary Feedwater pump at 12:57:39 as levels were above their no-load target of 38%. The operators then adjusted auxiliary feedwater flow to maintain steam generator level with the higher than normal steam demand. The levels smoothed out once main steam was isolated. At 30 minutes after the trip all 4 steam generators were within 4% of the no-load target level.

At 2149:48 the 2 out of 3 undervoltage logic for ETA and ETB was satisfied. The blackout logic initiated properly for both trains, and both diesel generators started. Once the 8 second time delay and voltage test were completed, the two sequencers load shed and loaded the blackout load groups on the diesels. All loads were on the diesel within 15 seconds of the blackout logic actuation, as expected by the accelerated sequence. Containment ventilation was isolated at 21:49:34 when the circuit breaker for EMF's 38, 39, 40 opened.

No Safety Injection actuation occurred. The pressurizer PORV's and code safety valves were not challenged. Indicated pressurizer and steam generator levels remained on-scale. The primary temperature decrease was within the 100°F/hour Technical Specification limit. There was no abnormal release of radioactivity during this event, and no abnormal coolant leakage.

CORRECTIVE ACTION: Corrective actions have been initiated to prevent recurrence of this event. These actions include addition of a control output relay test circuit to provide computer maintenance and operating personnel with confirmation that all contr l output relays are open prior to re-enabling control outputs. Also, the computer's initialization software has been modified to reset all control output relays to the "open" position on re-initialization (manual and auto-restart).

Relay settings on the Craighead White and Mecklenburg Black lines, which tripped on overcurrent during the event, have been increased to allow these two lines to carry full Unit 1 output.

Other related corrective actions include:

1) Relay house emergency lighting will be improved. Low-level emergency lighting in the switchyard relay house hampered restoration of power to the switchyard.

2) Operating and maintenance activities will be revieved for potential impact on off-site power.

3) Consideration is being given to the replacement of existing "latching" type control outputs with "momentary" type outputs.

4) Independent of this incident, plans had been made to replace the existing switchyard computer by December 1986. This schedule has been accelerated

These corrective actions will be completed by 12/85.

NRC Form 366
(9-83)

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
LaSalle County Station Unit 1	0 5 0 0 0 3 7 3	1 OF 0 3

TITLE (4): Failure of ~~RCIC Inoperable and Steam Line Isolation~~ RCIC Turbine ~~Governor~~ Governor

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 1	8 4	8 4	— 0 5 4	— Rev. 0 1	on file	1 0	0 1	8 5	None	0 5 0 0 0
											0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR § (Check one or more of the following) (11)			
POWER LEVEL (10)	0 2 4			X 50.73(a)(2)(iv)	73.71(b)
				X 50.73(a)(2)(v)	73.71(c)
				50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
David Lyon, extension 317	AREA CODE 8 1 5 — 3 5 7 — 6 7 6 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	B N	S C V	T 1 4 7	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 9/21/84 at 1130 hours, during LOS-RI-Q3, the RCIC turbine tripped on mechanical overspeed condition.

Also, on 9/21/84 at 2005 hours, during IM troubleshooting, a RCIC Channel "A" steam line high flow isolation was received.

It was determined that the erratic governor movement and overspeed condition was caused by dirty and/or contaminated lubrication oil.

At the time of the event, LaSalle Unit 1 was in Operational Condition 1, Run Mode, at 25% power. Consequences were minimal due to adherence to Technical Specification 3.7.3 which requires HPCS to be operable and take corrective actions to restore RCIC within 14 days. Also, LPCS, RHR and ADS systems were operable.

Work Request L41160 was generated to initiate repairs. The RCIC oil system was drained, flushed and new duplex oil filters were installed and refilled with Mobil Vaportex light. A sample was taken and sent to System Materials Analysis Dept. (SMAD) for analysis. Surveillance LOS-RI-Q3 was resumed and completed satisfactorily.

The analysis by SMAD indicated that the problem was caused by sediment from precipitation of rust inhibitors. As a result, Work Requests L44599 for Unit 1 and L46377 for Unit 2 were generated to replace the Mobile Vaportex Light Oil with Gulf Crest 32 oil for the RCIC turbine oil systems.

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PDR ADOCK 05000373
S PDR

I. EVENT DESCRIPTION

On September 21, 1984, at 1130 hours, during the performance of Operating Surveillance LOS-RI-Q3, Reactor Core Isolation Cooling (RCIC, BN) Pump Operability and Valve Inservice Inspection, the RCIC turbine tripped on a mechanical overspeed condition.

Also, on September 21, 1984, at 2005 hours, during another start of the RCIC pump while the Instrument Maintenance Department was attempting to observe the RCIC turbine governor operation by a manual movement of the Servo valve, a RCIC Channel "A" steam line high flow isolation was received. When holding the Servo valve closed, the RCIC turbine ran correctly and did not go to an overspeed condition. But as soon as the Servo valve was released, the governor failed open, causing the high steam flow isolation. Operations reset the RCIC isolation and work was continued.

II. CAUSE

It was determined by the Instrument Maintenance Department that the RCIC turbine overspeed condition and erratic governor movement was caused by dirty and/or contaminated lubrication oil.

Analysis of the Unit 1 RCIC turbine oil by System Materials Analysis Department (SMAD) revealed that the sample taken on September 23, 1984, contained an oxidized form of hindered phenol. The Mobile Corporation confirmed that a hindered phenol is used as a rust inhibitor in Mobile Vaportex Light Oil. The presence of water in the RCIC Turbine Oil System caused the precipitation of the hindered phenol debris due to a decrease in solubility.

The analysis by SMAD also indicated that an amine vapor phase inhibitor in Mobile Vaportex Light Oil was causing corrosion of the copper cooling coils in the RCIC turbines.

III. PROBABLE CONSEQUENCES OF THE OCCURRENCE

At the time of the event, LaSalle Unit 1 was in Operational Condition 1, Run Mode, generating at 24% power. Consequences of this event were minimized by adherence to Technical Specification 3.7.3, which requires the High Pressure Core Spray System (BG, HPCS) to be operable and to initiate corrective actions to restore RCIC within 14 days. Also, during this event, LPCS (BM), RHR (BO) and ADS (SB) systems were operable. Safe operation of the Plant was maintained at all times.

IV. CORRECTIVE ACTIONS

When the RCIC turbine tripped on an overspeed condition, operations generated Work Request L41160 which was assigned to the Instrument Maintenance Department. They conducted their investigation by examining the RCIC turbine governor. During this troubleshooting they discovered that the prefilter which supplies oil to the governor actuator was "clogged" with a foreign particulate. The Mechanical Maintenance Department was requested to flush the RCIC oil system, install two new Duplex oil filters and refill the oil system with Mobile Vaportex Light (i.e., original oil specified). A sample of oil was taken from the replaced Duplex filters and sent to System Materials Analysis Department (SMAD) for analysis. RCIC was declared OPERABLE on September 23, 1984, at 1445 hours. Operating Surveillance, LOS-RI-Q3, was resumed and completed satisfactorily.

Work Requests L44599 for Unit 1 and L46377 for Unit 2 were generated to replace the Mobile Vaportex Light Oil with Gulf Crest 32 for the RCIC Turbine Oil Systems. A non-amine vapor space inhibitor was added to the Gulf Crest 32 oil. The Unit 1 and Unit 2 Work Requests were completed on May 1, 1985, and July 20, 1985, respectively.

Surveillance LOS-ZZ-M2 (Monthly Oil Samples) is being revised to add Unit 1 and Unit 2 RCIC turbine oil to the required monthly oil samples (AIR 01-84-67153). The RCIC turbine oil samples will be analyzed monthly by SMAD. The oil analysis will include tests for percent sediments, percent water, viscosity, rust inhibitor deterioration and precipitation, and copper concentration.

Recommendations will be made as to the frequency of the RCIC turbine oil changes based upon results from the monthly SMAD analyses.

V. PREVIOUS OCCURRENCES

None have been reported to date.

VI. NAME AND TELEPHONE NUMBER OF PREPARER

David Lyon, 815/357-6761, extension 319.

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): LaSalle County Station Unit 1

DOCKET NUMBER (2): 0 5 0 0 0 3 7 3

PAGE (3): 1 OF 1 2

TITLE (4): Reactor Scram on Group I Isolation

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 1	8 4	8 4	— 0 5 5	— 0 0	1 0	1 1	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 0 2 3

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)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)
	20.405(a)(1)(ii)		50.36(c)(2)		50.73(a)(2)(vii)
	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)

	73.71(b)
	73.71(c)
	OTHER (Specify in Abstract below and in Text, NRC Form 366A)

LICENSEE CONTACT FOR THIS LER (12)

NAME: Kenneth J. Kalmon, extension 325

TELEPHONE NUMBER — AREA CODE: 8 1 5 | 3 5 7 - 6 7 6 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	JM	PIS	B 0 1 7 0	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-spaced typewritten lines) (16)

On September 21, 1984, a Primary Containment Isolation System (PCIS) Group I isolation resulting in a reactor scram occurred during the performance of LIS-MS-01, Main Steam Line Low Pressure MSIV Isolation Calibration and Functional Test.

An Instrument Mechanic had just actuated pressure switch 1B21-N015C when he slightly bumped pressure switch 1B21-N015D. This bump was enough to actuate 1B21-N015D. Actuating both 1B21-N015C and 1B21-N015D caused the Group I isolation and the isolation caused a reactor scram. PCIS and Reactor Protection Systems operated as expected.

A sign warning personnel of the consequences of bumping the 1B21-N015 switches was hung near the switches of both units.

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PDR ADOCK 05000373
S PDR

NRC Form 366
(9-83)

I. EVENT DESCRIPTION

On September 21, 1984, with LaSalle Unit 1 operating at 23% power, a Primary Containment Isolation System (JM, PCIS) Group I isolation occurred, closing the Main Steam Isolation Valves (SB, MSIV), resulting in a reactor scram (JC) since the unit was in the Run Mode. The isolation and scram occurred during the performance of LIS-MS-01, Main Steam Line Low Pressure MSIV Isolation Calibration and Functional Test.

II. CAUSE

In accordance with LIS-MS-01, an Instrument Mechanic had just generated a Main Steam Line Isolation Valve (MSIV) half isolation signal by venting Main Steam Line Low Pressure Switch, 1B21-N015C. He radioed the Control Room to confirm the proper alarm was received, then set his radio down on the instrument rack for the 1B21-N015D switch. Both 1B21-N015C and the low pressure switch for Main Steam Line "D", 1B21-N015D, are mounted on individual instrument stands but are immediately adjacent (less than 1 foot apart). The bump caused by setting the radio down was enough to actuate 1B21-N015D. Simultaneous actuation of 1B21-N015C and 1B21-N015D caused a MSIV isolation. The MSIV closure caused a reactor scram.

These pressure switches are manufactured by Barksdale, Model #BIT-M12SS.

III. PROBABLE CONSEQUENCES OF THE OCCURRENCE

PCIS logic acted as expected as if a low pressure condition actually existed on Main Steam Lines "C" and "D". Reactor Protection System (RPS) logic acted as expected when the MSIV's closed and the reactor scrammed. The plant responded as expected for an event of this type. An MSIV isolation at full power occurred as part of the Startup Testing Program.

IV. CORRECTIVE ACTION

A sign warning personnel of the consequences of bumping 1B21-N015C/D was hung at the instrument rack. A table was set up at the location of the instrument rack to give Instrument Mechanics a place to set down their equipment while testing the switches.

V. PREVIOUS OCCURRENCES

None of this type.

VI. NAME AND PHONE NUMBER OF PREPARER

Kenneth J. Kalmon, 815/357-6761, extension 325.

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)
LaSalle County Station	0 5 0 0 0 3 7 3	1 OF 0 1 3

TITLE (4)
RCIC Steam Line Differential Pressure Hi Spurious Isolation

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 9	8 4	8 4	— 0 6 6	— 0 0	1 0	2 4	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	2	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	0 1 1	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
D. Winterhoff, extension 575	AREA CODE 8 1 5 3 7 1 — 6 7 7 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	
X	J M	2 2 2 2	Z 2 E 2	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 9/29/84 at 1000 hours following LIS-RI-101, a Division I High Steam Flow Isolation was received when an attempt to reopen the 1E51-F008, RCIC Outboard Isolation was made.

It is believed that a differential pressure was created by cooling differences upstream and downstream of the 1E51-F008. When the 1F51-F008 valve was opened per LOP-RI-04, the isolation occurred.

At the time of the event, Unit 1 was in Mode 2 going to Cold Shutdown. Consequences of this event were minimal since HPCS, ADS, LPCS and RHR Shutdown Cooling were operable. Also, this event was spurious and isolated. The plant was in a safe condition at all times. The system was returned to normal and no leakage was verified. No further isolations occurred.

8411070214 841024
PDR ADOCK 05000373
S PDR

NRC Form 366
(9-83)

I. EVENT DESCRIPTION

On September 29, 1984, at 1000 hours following the completion of Instrument Surveillance LIS-RI-101, Reactor Core Isolation Cooling (RCIC, BN) High Steam Flow Isolation Functional, a Division I High Steam Flow Isolation (JM) was received when an attempt to re-open the 1E51-F008, RCIC Outboard Isolation, was made.

II. CAUSE

It is believed that following the Instrument Maintenance Department surveillance isolation a slight cooling of the RCIC piping downstream of the 1E51-F008 occurred creating a pressure differential across valve 1E51-F008.

When the unit Operator opened the 1E51-F008 to realign the system per LOP-RI-04, Turbine Trip Recovery and Reset for RCIC, steam trapped upstream (between the 1E51-F063 valve and 1E51-F008 valve) expanded suddenly and a RCIC Outboard Isolation (Division I) was received. Following the isolation, the SCRE observed that the RCIC pressure indicator was reading approximately 300 psig.

Differential pressure switches 1E31-N013A (Division I, Outboard) and 1E31-N013B (Division II, Inboard) sense RCIC High Steam Flow isolations. Both switches were last calibrated on July 28, 1984. During calibration both switches were "found" within LCO limits in the conservative direction. These switches are located on RCIC pipe 1RI01C-4" at elbow connections approximately 8 feet apart. Differential pressure switch 1E31-N013A (Division I, Outboard Isolation) is situated in the first elbow downstream of valve 1E51-F008. It can be speculated that the sudden inflow of steam was "damped" by the first elbow and sufficient flow or pressure was not present to energize switch 1E51-N013B.

III. PROBABLE CONSEQUENCES OF THE OCCURRENCE

At the time of the occurrence LaSalle Unit 1 was in Operational Condition 2, Start-Up Mode, in the process of a unit shutdown at 1% power.

Consequences of this event were minimal since HPCS, ADS, LPCS and RHR shutdown cooling were operable. Also, this was a spurious and isolated event.

The plant was maintained in a safe condition at all times.

IV. CORRECTIVE ACTION

Following this event Operations reset the Outboard Isolation and returned the system to normal. The RCIC piping was traced to verify no leakage. No further isolations occurred.

V. PREVIOUS OCCURRENCES

None have occurred to date.

VI. NAME AND TELEPHONE NUMBER OF PREPARER

Dale Winterhoff, 815/357-6761, extension 575.

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)
LaSalle County Station Unit 1	0 5 0 0 0 3 7 3	1 OF 0 5

TITLE (4)
Loss of Shutdown Cooling Due to ~~1E21-F009~~ Valve 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 9	3 0	8 4	8 4	— 0 6 2	— 0 0	1 0	3 0	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
3	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10) 0 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)	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
M. Peters, extension 245	AREA CODE 8 1 5 3 5 7 - 6 7 6 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	B 0	V	A 3 9 2	Y							
X	B 0	2 0	L 2 0 0	Y							

SUPPLEMENTAL REPORT EXPECTED (14)

		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
X	YES (If yes, complete EXPECTED SUBMISSION DATE)		0 1	0 1	8 5
	NO				

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

Shutdown cooling suction inboard isolation valve, 1E21-F009, failed to open by the motor operator or manually. The unit was in the process of going to Cold Shutdown for a planned maintenance/surveillance outage. The unit was not required to go to Cold Shutdown. The cause of the 20-inch flex wedge gate valve not opening electrically cannot be determined at this time. The manual operation was made unuseable by a broken declutch lever. Two methods of alternate decay heat removal were available. The valve was subsequently opened and shutdown cooling initiated. An investigation of the cause of failure and corrective action is proceeding.

8411130135 841030
PDR ADOCK 05000373
S PDR

NRC Form 366
(9-83)

I. EVENT DESCRIPTION

On 9/30/84 at 0130 with the unit in Mode 3, Hot Shutdown, the Residual Heat Removal (BO, RHR) Shutdown Cooling Suction Inboard Isolation Valve, 1E12-F009, failed to open by the motor operator or manually. The unit was not required to be in Cold Shutdown during this event. A GSEP was declared at 0730 and classified as an Alert (EAL #13).

II. CAUSE

The 1E12-F009 valve is a 20 inch flexible wedge gate valve manufactured by Anchor Darling Company. The motor operator is a Model SBC manufactured by Limitorque Corporation. When the valve could not be opened by the motor operator or manually by Operating personnel, Mechanical Maintenance personnel were sent to troubleshoot the valve. The motor operator declutch mechanism was found inoperative. After mechanically declutching the motor operator, the handwheel required 15 to 20 hard hammerblows to remove the valve disc from the body seats. (A hammerblow is accomplished by rotating the handwheel in the close direction and then in the open direction until the drive lugs engage.) Once the disc was off the seats, the valve could be normally operated with the handwheel. The cause of the declutch mechanism failure is unknown but could have resulted from excess force being previously applied. The inoperability of the declutch mechanism would not affect the electrical operability of the motor operator. The motor operator was subsequently tested by Electrical Maintenance as being satisfactory (Work Request L42049). In addition, a consultant, Movats, Inc., was contracted to diagnose the operation of the valve and motor operator with the unit in Cold Shutdown. Their findings indicated that no valve/operator limitations were being exceeded.

III. PROBABLE CONSEQUENCES OF THE OCCURRENCE

During this event, the reactor recirculation pumps (AD) remained on to assure adequate core circulation. Reactor coolant temperature and pressure were monitored once per hour. Removal of decay heat was continued during the event by depressurizing the RPV to the main condenser (SG) and making up water to the RPV via the CD/CB/FW (SD, SJ) systems in accordance with LGA-02, Cooldown. Additional alternate methods of decay heat removal included the use of the SRV's (SB) and RHR systems as delineated in UFSAR Chapter 15 and LGA-02. 1E12-F009 was opened at 1020 and RHR Shutdown Cooling started. The unit was in Mode 4, Cold Shutdown, by 1629.

Since two alternate methods of decay heat removal were available, the Reactor Recirculation System was in operation, and reactor coolant parameters monitored, the Action Statements of Technical Specification 3.4.9.1 were satisfied. The probable consequences of the event would not result in any temperature or pressure transient in excess of the criteria for which the fuel, pressure vessel, or containment were designed.

IV. CORRECTIVE ACTION

Station personnel, Station Nuclear Engineering Department, and Sargent & Lundy are investigating potential causes for the valve inoperability. A supplemental LER will be issued when the cause is determined. (AIR 1-84-67165)

AIR 1-84-67166 has been issued to train all Operating personnel on the correct procedure for declutching motor operators.

V. PREVIOUS OCCURRENCES

LER 373/83-142

VI. NAME AND TELEPHONE NUMBER OF PREPARER

M. A. Peters 815/357-6761, extension 245.

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)
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	1 OF 9

TITLE (4)
Reactor Scramson Loss of Feedwater

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)
									NA	0 5 0 0 0
0 5	0 3	8 4	8 4	— 0 1 7	— 0 0	0 5	2 3	8 4	NA	0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)					
POWER LEVEL (10)	0 1 0	20.402(b)	20.405(c)	X	50.73(a)(2)(iv)		73.71(b)
		20.405(a)(1)(i)	50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
		20.405(a)(1)(ii)	50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)
		20.405(a)(1)(iii)	50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
		20.405(a)(1)(iv)	50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
		20.405(a)(1)(v)	50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
	AREA CODE
D. M. Pristave, x209	8 1 5 3 5 7 - 6 7 6 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
A	S J	Z 9 9 9	Z 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)

The Unit 2 reactor was manually scrammed on 5/3/84 at 2340 when it became apparent that the reactor vessel level could not be maintained due to the loss of the motor driven feedwater pump (MDRFP). The turbine driven feedwater pumps were valved out due to the shutdown in progress. The loss of the MDRFP was due to a non-licensed operator valving error. Valve 2CB037 was closed instead of valve 2FW037. These valves are only about five (5) feet apart. Error was due to not completely reading the valve number. A sign has been placed on the 2CB037 valve which was improperly closed. Procedures which deal with these valves will be reviewed to ensure they are proper and revised as necessary. The MDRFP has been repaired.

8406050260 840523
PDR ADOCK 05000374
S PDR

NRC Form 366 (9-83)

I. EVENT DESCRIPTION

The Unit 2 Reactor was scrammed manually on 5-3-84 at 2340 when it became apparent that the Motor Driven Reactor Feed Pump (SJ) could not be re-started and reactor vessel level could not be maintained above 12.5 inches. At the time of the event, the unit was proceeding with a normal shutdown to obtain data for the Start-Up Test Program.

The NSO (Licensed Operator) on the unit decided that at that point in the shutdown, it was convenient to close all the Reactor Feed Pump Warming Line Valves. These valves provide a flow path to the Reactor Vessel even though the discharge valve on the Reactor Feed Pump is closed. With any Warming Line Valve open on any of the Reactor Feed Pumps, it provides enough make-up to the vessel that make-up would exceed blowdown during low power operation and vessel level would rise at a rapid rate, which is not desireable. Therefore, the NSO on the unit instructed an Equipment Attendant (EA) (Non-Licensed Operator) to close the warming line valves on all three feedwater pumps. The warming line valves on the 2A and 2B TDRFP were correctly valved out. Immediately after, the Equipment Attendant valved out the Balancing Line Valve 2CB037 on the Motor Driven Reactor Feed Pump instead of the Warming Line Valve 2FW037. The Motor Driven Reactor Feed Pump tripped and could not be restarted. Both valves, the Balancing Line Valve 2CB037 and the Warming Line Valve 2FW037, are in the same room and about five (5) feet apart.

II. CAUSE

The Motor Driven Reactor Feed Pump had tripped on low lube oil pressure. The low lube oil pressure occurred due to clogging of the lube oil strainer. The clogging of the lube oil strainer occurred due to damage to the Thrust Bearing on the Motor Driven Reactor Feed Pump which released babbit into the Lube Oil System. Damage to the Thrust Bearing occurred because of a valving error which mistakenly closed the Drum Balancing Line Valve 2CB037 instead of the Warming Line Valve 2FW037. The Drum Balancing Line Valve 2CB037 must be kept open at all times except when the Motor Driven Reactor Feed Pump is to be taken out of service to ensure that no problems will occur on the Motor Driven Reactor Feed Pump.

The Equipment Attendant who closed the Balancing Line Valve 2CB037 instead of the Warming Line Valve 2FW037 indicated that he thought he was on the correct valve because the number "37" caught his eye on the valve Equipment Part Number. He did not read the entire noun name of the valve that was indicated on the associated valve tag. The Equipment Attendant also thought he was on the correct valve when he read the number "37" on the valve tag because he had just closed the Warming Line Valves on the A and B Turbine Driven Reactor Feed Pumps and there was similarity associated with the piping and valves between the Turbine Driven Reactor Feed Pumps and the Motor Driven Reactor Feed Pump. The Equipment Attendant was not given any indication that a Balancing Line Valve 2CB037 existed or the consequences if it were closed.

III. PROBABLE CONSEQUENCES OF THE OCCURRENCE

The ability to maintain Reactor Vessel Level was immediately lost. The RCIC (BN) System was started to aid in the Level Control, and the Reactor was manually scrammed while level was above 12.5 inches, which is the low level scram setpoint. Reactor Vessel Level dropped to -12 inches before level control was achieved primarily by using the RCIC System. Level was then returned to a normal range and a normal plant shutdown was commenced which followed the scram. All systems functioned per design. Since this evolution would only occur during a plant shutdown, this event is not expected to have been worse under different plant conditions.

IV. CORRECTIVE ACTIONS

1. A Caution Card was placed immediately on the Balancing Line Valve 2CB037 with instructions indicating that it should not be closed unless the Motor Driven Reactor Feed Pump is to be taken out of service (for both Units 1 and 2).

2. Work Request L36421 was initiated so that repairs could be made to the Motor Driven Reactor Feed Pump. (Repairs have been completed and the Motor Driven Reactor Feed Pump is back in operation.)

3. Signs were placed on both Unit 1 and 2 Balancing Line Valves 1CB037 and 2CB037 indicating that the valves should not be closed unless the pump is out of service. This replaced the Caution Cards.

4. AIR 01-84-67076 was submitted to ensure personnel (Equipment Attendants and License Personnel and all new Equipment Attendants) were trained on the purpose of the Motor Driven Reactor Feed Pump Balancing Line.

5. The following procedures were reviewed to ensure that the Reactor Feed Pump Warming Lines were in the proper position for the plant condition:

   a. LOP-FW-01M U-1 FW Mechanical Checklist

   b. LOP-FW-02M U-2 FW Mechanical Checklist

   c. LOP-FW-01 Feedwater System Filling and Venting

   d. LOP-FW-02 Feedwater System Draining

   e. LOP-FW-03 Start-Up of Motor Driven Reactor Feed Pump -Change submitted

   f. LOP-FW-06 Shutdown of Motor Driven Reactor Feedpump to Hot Standby - Change submitted

IV. CORRECTIVE ACTIONS (continued)

g.	LOP-FW-04	Start-Up of a Unit 1 TDRFP - Change submitted
h.	LOP-FW-05	Shutdown of a TDRFP - Change submitted
i.	LOP-FW-07	Preparation For TDRFP S/U with Main Steam System Pressurized
j.	LOP-FW-08	Condensate Recirc to Condenser via Heater Drain System
k.	LOP-FW-09	TDRFP Exhaust Duct Isolation During Unit Operation
l.	LOP-FW-11	Start-Up of Unit TDRFP - Change submitted
m.	LGP-1-1	Normal Unit Start-Up - Change submitted
n.	LGP-1-2	Unit Start-Up to Hot Standby - Change submitted
o.	LGP-1-3	Unit Start-Up From Hot Standby to Power Operation - Change submitted
p.	LGP-2-1	Normal Unit Shutdown - Change submitted
q.	LGP-2-2	Shutdown to Hot Standby - Change Submitted
r.	LGP-3-2	Reactor Scram - Change submitted

The above procedure changes will be tracked by AIR 01-84-67077. In addition, the procedures were reviewed to ensure correct reference and use of the Balancing Line Valves.

V. PREVIOUS OCCURRENCES

None.

VI. NAME AND TELEPHONE NUMBER OF PREPARER

Dennis M. Pristave, (815)357-6761, extension 209

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)
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	1 OF 0 3

TITLE (4) update on
~~02~~ HPCS Pump Breaker Malfunction

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	1 7	8 4	8 4	— 0 1 8 —	0 1	0 8	2 3	8 4		0 5 0 0 0
										0 5 0 0 0

No Rev. 0 on file

OPERATING MODE (9): 1

POWER LEVEL (10): 0 3 0

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

20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
20.405(a)(1)(i)	50.36(c)(1)	X 50.73(a)(2)(v)	73.71(c)
20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	OTHER (Specify in Abstract below and in Text, NRC Form 366A)
20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
20.405(a)(1)(iv)	50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER (AREA CODE)
R. D. Koenig, extension 499	8 1 5 3 5 7 - 6 7 6 1

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS
B	B G	3 3	G 0 8 0	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 May 17, 1984, at 0220 hours, during High Pressure Core Spray System Inservice Test LOS-HP-Q1, the HPCS Unit 2 pump breaker failed to close. NRC red phone notification was made.

The cause was traced back to a switchgear position switch (52LS). When the breaker was racked up, this switch sometimes failed to make contact. This prevented the breaker from closing. If an event occurred requiring HPCS, RCIC would have provided its function.

The position switch was replaced and readjusted. All Division III (Unit 1 and 2) 4160V switchgear position switches will be inspected. The bad position switch will be analyzed. This event is also reportable under 10CFR 50.72 (b)(2)(iii).

Similar event: 374/84-005.

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S PDR

NRC Form 366
(9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
LaSalle County Station Unit 2	0 5 0 0 0 3 7 4	8 4	— 0 1 8	— 0 1	0 2 OF 0 3

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

1. EVENT DESCRIPTION

On May 17, 1984, at 0220 hours, during the performance of LOS-HP-Q1 (HPCS System Inservice Test), the HPCS (BG) pump breaker failed to close and start the HPCS pump. The breaker was racked down then racked up again, and the breaker proceeded to function as required. During this time, the Unit 2 reactor was in Operational Condition One, 30% power.

NRC red phone notification was made at 0725, greater than 4 hours after the event.

II. CAUSE

The cause of this occurrence was attributed to a breaker position switch, 52LS, associated with the switchgear. Upon investigation by the station Technical Staff and Electrical Maintenance Department, it was noted that the 52LS position switch was not operating as designed. When the breaker was racked up into its operating position, position switch 52LS was in the state of just making its contacts. As the breaker was cycled, it was noticed that the breaker moved down slightly; this, along with the condition of 52LS, breaks the contacts on position switch 52LS. With these contacts simulating a racked down switchgear, the breaker would not close and the pump would not start.

Further investigation of the breaker limit switch (52LS) showed that the position switch contacts were not all making at the same time. The alarm contacts to the ESF (Engineered Safety Feature) status display panel were among the contacts making first. The contacts to the closing coil were among the contacts making last. → [It was also noted that the front spacer, stops, and bearing were lying loose in the front support assembly of the switch, apparently never installed on the switch shaft.]

The 10CFR50.72 notification (4 hour) was not identified immediately causing the late notification. This was due to the unique situation with the "single train" systems at BWRS which requires reporting of HPCS failures under 50.72(b)(2)(iii).

III. PROBABLE CONSEQUENCES OF OCCURRENCE

If an initiation signal (low vessel 3) had been present, RCIC (BN) would have initiated. LPCS (BM) and LPCI (BO) could also have initiated to maintain vessel level after vessel depressurization via ADS if the reactor had remained pressurized to greater than 500 psig, if required.

IV. CORRECTIVE ACTION

Position switch 52LS (8 contact, General Electric type SBM) was replaced with a new SBM switch and readjusted to close slightly sooner than before. Discrepancy Report 01-84-223 was written to investigate the loose parts found in position switch 52LS. Action Item Record 1-84-67079 was written to track and verify the completion of a visual inspection of all Division III 4160V switchgear position switches in both units. All of the Unit 2 Division III switchgear (4160V) was cleaned before being returned to service. Discussion with the vendor (General Electric) obtained information that this is an isolated incident pertaining to this switchgear. The periodic testing of this breaker will be accelerated until LaSalle County Station is satisfied with the breaker performance. Training on 10CFR50.72 notifications will be conducted for shift personnel required to make these notifications (AIR 1-84-67080).

V. PREVIOUS OCCURRENCES

Several occurrences of this type were experienced during the performance of Unit 2 HPCS (BG) preoperational testing, and during the previous performance of LOP-HP-01, Unit 2. (Refer to LER #50-374/84-005-00.)

VI. NAME AND PHONE NUMBER OF PREPARER

R. D. Koenig, 815/357-6761, extension 490.

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)
Susquehanna Steam Electric Station - Unit 1

DOCKET NUMBER (2) 0 5 0 0 0 3 8 7 — PAGE (3) 1 OF 0 2

TITLE (4)
RPS Manual Scram during Testing of ADS SRV's.

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 2	2 5	8 4	8 4	— 0 1 0	— 0 0	0 3	2 6	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 1

POWER LEVEL (10): 5 4

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

20.402(b)	20.405(c)	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: D.C. Wood

TELEPHONE NUMBER — AREA CODE: 7 1 7 5 4 2 - 3 2 4 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
B	8 3	S O L C	T 1 7	YES					

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

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

Unit 1 reactor was manually scrammed from 54% power when during functional testing of the automatic depressurization system Safety Relief Valves (SRV), one of the six valves stuck open and could not be closed within two minutes. It was determined that one of the three independent instrument air control valve solenoids had stuck open supplying air to the pneumatic piston which opens the SRV. The solenoid was replaced and there is no history of this type of event. The reactor scram systems operated properly and safety systems were available to mitigate any possible accident conditions.

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S PDR

NRC Form 366
(9-83)

On 2/25/84, at 1848, the Unit 1 reactor, in mode 1 at 54% power, was manually scrammed during preplanned testing of the Automatic Depressurization System (ADS) valves. The SSES Safety Relief Valve (SRV) System consists of sixteen (16) valves which function as safety-relief valves; six (6) of these valves also function as Automatic Depressurization System (ADS) valves. A preplanned test requirement was in progress to verify operability of the ADS valves wherein each ADS valve was to be manually, and sequentially, cycled. During the test sequence, the "M" SRV failed to close, and in accordance with the test procedure, a manual scram was initiated when attempts to close the SRV were unsuccessful.

Each of the ADS SRV's has three independent solenoid operated control valves. During testing of the "B" solenoid on the "M" SRV, the solenoid valve stuck open and the instrument gas pressure kept the SRV open. After two minutes of attempting to close the SRV by a procedure especially written for this activity, the reactor was manually scrammed. At one minute and twenty seconds after scram, the inboard MSIV's were closed to reduce vessel depressurization. Vessel pressure dropped from 946 PSIG to 682 PSIG during the transient. Several minutes later, the "M" SRV closed due to internal spring energy when the instrument gas header which was isolated for the test, dropped to approximately 60 PSIG. The "B" solenoid and air valve on the "M" SRV were replaced and the new solenoid was tested successfully. Investigation has found this to be a non-recurring event. The vendor will inspect the valves to determine the cause of the failure. This report may be updated pending the results of this investigation. The test was continued and the other SRV's and solenoid valves operated properly.

The ADS system is an Engineered Safety Features System serving as a backup to the HPCI system. During this event, the HPCI system was operable, as was the ADS feature of the SRV's to relieve primary system pressure. Hence, there was no increase in risk to public health and safety. Were the event to occur at full power, the procedures utilized would provide for a safe shutdown.

NRC Form 366 (9-83)

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APPROVED OMB NO. 3150-0104
EXPIRES 8/31/85

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
Susquehanna Steam Electric Station - Unit 1	0 5 0 0 0 3 8 7	1 OF 0 4

TITLE (4): Diesel Generator Failures.

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 9	1 0	8 4	8 4	— 0 4 0	— 0 0	1 0	1 2	8 4	SSES - Unit 2	0 5 0 0 0 3 8 8
										0 5 0 0 0

OPERATING MODE (9)	1	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10)	1 0 0	20.402(b)	20.405(c)	50.73(a)(2)(iv)	X 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
R.W. Stanley - Compliance Engineer	AREA CODE 7 1 7 — 5 4 2 - 3 9 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
X	E I K	*	C 6 3 4	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)

During the performance of SO-024-001 "Monthly Diesel Generator Operability Test", the "D" Diesel Generator tripped on high turbo charger vibration. The radial turbo charger bearing was found to be failed. A replacement turbo charger was installed, the diesel was tested and returned to service.

During the repair work on the "D" Diesel, the RHR suppression pool cooling full flow test valve 1F024A failed to stroke and was declared inoperable. This placed the plant into action statement 3.8.1.1c which requires with 1 diesel inoperable verify within 2 hours all systems that depend on the remaining diesels are operable or be in Hot Shutdown within the next 12 hours. The valve was placed into operation after 6 hours and 15 minutes. This was prior to the Hot Shutdown requirement.

While the "D" Diesel Generator was out for repairs, and after the 1F024A was repaired and declared operable, the "B" Diesel Generator developed a starting problem. With 2 diesels out of service, Technical Specification 3.8.1.1 requires restoration to 3 operable diesels or be in Hot Shutdown within the next 12 hours. At 2045 on September 12, 1984, the "D" Diesel was returned to service, and the "B" Diesel was returned to service at 0730 on September 13, 1984.

Over the next several days other failures of the "B" Diesel occured during investigation of the slow start problems. Corrective actions included maintenance of the starting air system, reworked fuel oil system, and cleaning of the air operated control valves.

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*Turbo Charger Radial Bearings.

NRC Form 366 (9-83)

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Susquehanna Steam Electric Station Unit 1	0 5 0 0 0 3 8 7	8 4	— 0 4 0	— 0 0	0 2 OF 0 4

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

From September 10, 1984 through September 25, 1984, the Station experienced several related and unrelated problems with the Emergency Diesel Generators. 1 diesel experienced a turbo charger failure and subsequent surveillance testing, per Technical Specification requirements, revealed an intermittent starting problem on another diesel generator. Turbo charger repairs were made expeditiously. Due to the intermittent nature of the slow starts on another diesel, several attempts were necessary to repair the problem. An organized systematic approach was taken which included instrumenting the diesel (visocorder for relay operation, pressure guages for starting air, etc.) to observe several parameters during diesel testing. As corrective actions were identified and implemented the diesel was successfully tested and returned to service. Subsequent slow starts led to increased troubleshooting which resulted in correction of the problem such that testing to date has been successful.

The events of the period are detailed below:

During the performance of SO-024-001 "Monthly Diesel Generator Operability Test", at 1455 on September 10, 1984, the "D" Diesel Generator tripped on high turbo charger vibration. The radial bearing was found failed; a replacement trubo charger was installed.

Technical Specification 3.8.1.1 requires the remaining diesels to be started within 4 hours and at least once per 8 hours thereafter. During this increased testing time interval, the "B" Diesel Generator did not start at 0215 on September 11, 1984. The diesel was successfully started 23 minutes later.

At 0750 on September 11, 1984, the RHR suppression pool cooling full flow test valve 1F024A was declared inoperable when its circuit breaker tripped. The valve was inspected by the Maintenance Department under WA S44663 and found to be inoperable because the key which holds the motor pinion to the motor shaft fell out. The missing key was located in the actuator grease box and reinstalled. To prevent a recurrence of the key from sliding out the end of the motor shaft, the motor shaft was peened over. The key is normally retained by friction imposed on the motor pinion gear/shaft interface by a set-screw which is located in the motor pinion gear, at 90° relative to the key. Because this has not been a recurring problem, this condition is considered to be an isolated occurrance. The proper orientation of the key and set-screw is addressed in Limitorque type SMB000-4 operator maintenance procedure MT-GM-021, thus there is adequate assurance that PP&L actuator maintenance will be proper, and no further action is required.

Action Statement 3.8.1.1c requires, with on diesel generator inoperable, the verification within 2 hours that all systems and components that depend on the remaining diesel generators as a source of emergency power are operable; otherwise be in Hot Shutdown within the next 12 hours. Since the "D" Diesel was inoperable due to turbo charger problems and the RHR suppression pool cooling full flow test valve 1F024A was declared inoperable for repairs, the above Action Statement applied. Power for the RHR full flow test valve 1F024A is powered from the "C" Diesel Generator. The RHR suppression pool full flow test valve 1F024A was out of service for only 6 hours and 15 minutes. Therefore, a Hot Shutdown was not required.

At 1721 on September 11, 1984, the "B" Diesel Generator failed to start. Another start attempt 34 minutes later resulted in a slow start of 11.2 seconds versus a start time of less than 10 seconds as required by Technical Specification 4.8.1.1.2. This attempt was declared a failure, which was the third failure of the last 100 starts which increased the testing frequency to 1 start every 7 days. At 1812 on September 11, 1984, a successful start was achieved; the diesel was declared operable.

At 0054 on September 12, 1984, the "B" Diesel required 12.5 seconds to start, and the diesel was declared inoperable. Regulatory Guide 1.108 defines this as a valid failure which was the fourth failure of the last 100 starts which increased the testing frequency to 1 start every 3 days. 17 minutes later another start attempt resulted in a successful start and the diesel was declared operable.

At 0850 on September 12, 1984, the "B" Diesel was declared inoperable for troubleshooting. At 0905 on the same day, a start attempt was made on the diesel which failed to start in the required 10 seconds. This was documented as a 'non-valid' test. 20 minutes later another start attempt resulted in a successful start. At 0930 on September 12, 1984, the diesel was declared operable.

At 1040 on September 12, 1984, the "B" Diesel was removed from service for further testing and investigation of intermittent starting problems. 2 diesels were declared inoperable which placed the plant into Technical Specification 3.8.1.1 action statement which requires at least 3 diesels operable within 2 hours or be in a Hot Shutdown condition within the next 12 hours. At 2045 on September 12, 1984, the "D" Diesel was declared operable after completion of testing, following turbo charger replacement. This restored the plant to 3 operable diesel generators.

At 1620 on September 12, 1984, the "B" Diesel Generator was started for troubleshooting. The start time was in excess of the required 10 seconds. This start was documented as a 'not valid' test. At 0427 on September 13, 1984, Maintenance completed its investigation of the starting problem on the "B" Diesel Generator, which consisted of cleaning the starting air distributer and its lines, changing the fuel oil strainers and filters, and air start pilot valves were cleaned and inspected per WA-S44669. At 0427 on September 13, 1984, the "B" Diesel was started acceptably for a post maintenance run. This run is documented as a 'valid' start. The "B" Diesel was declared operable 0730 on September 13, 1984.

The "B" Diesel was started at 2148 on September 13, 1984. The diesel required 11.9 seconds to attain rated speed. This start is documented as a failure, increasing the number of failures to 5 in the last 100 valid tests, which requires a testing frequency of one start every 3 days. The problem of the slow start time was investigated by WA S44703 which replaced the fuel oil booster pump and check valves in the system. Also, the investigation found suction flanges from the day tank to the booster pump loose. These loose suction flanges allowed air to enter the fuel oil system upon the initial start, causing a slow starting time. Seven troubleshooting runs were performed between 2205 on September 13, 1984, and 0422 on September 16, 1984. An operability run was made at 1736 on September 16, 1984. There has been no history of this type of failure before. A slow start time caused by loose suction line fittings is an isolated case, and the subsequent proper tightening has cured the problem. 3 WA's were written to check the tightness of the fittings on the fuel oil suction lines for the "A","C", and "D" Diesels.

At 0620 on September 24, 1984, while the "D" Diesel was out of service to correct the deficiencies which were noted on the "B" Diesel, the "B" Diesel was declared out of service due to a trip during a starting attempt. With 2 diesels out of service, Technical Specification 3.8.1.1 Action Statement requires at least 3 diesels to be operable within 2 hours or be in a Hot Shutdown condition within the next 12 hours. The "D" Diesel was placed into service at 1545 on September 24, 1984, therefore, no Hot Shutdown was required.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Susquehanna Steam Electric Station Unit 1	0 5 0 0 0 3 8 7	8 4	— 0 4 0	— 0 0	0 4 OF 0 4

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

A troubleshooting start on the "B" Diesel was attempted at 1945 on September 24, 1984, and the diesel tripped after 12.5 seconds. The fuel oil system pressure response time was 1.5 to 2.5 seconds, which indicated this was not a recurrence of the previous problem. The fuel racks on the "B" Diesel did not open for 6 to 7 seconds. This is in excess of a normal diesel start in which the fuel racks open to admit fuel to the cylinder within 2 seconds. This 4 to 5 second lag in the response of the fuel racks resulted in a 4 to 5 second delay in starting time. The problem was determined as the Safety Trip Fuel Oil Control Cylinder (USC-7) not venting. This cylinder is expanded when the diesel is shutdown, resulting in closed fuel racks. The venting problem was traced back to the sluggish response of the Safety Trip Control Valve (USCV-9). This control valve is an air operated valve and will vent the Safety Trip Control Cylinder (USC-7) immediately upon a start signal. Upon disassembly of USCV-9 light metal shaving and some corrosion was noted. The valve was cleaned and reassembled, and the pneumatic circuit was tested with satisfactory results. The diesel was declared operable on September 25, 1984. This is a 'non valid' failure since the Duel Oil Control Cylinder (USC-7) is vented in the emergency mode by 2 electrically operated solenoid valves, therefore, the Safety Trip Control Valve (USV-9) is bypassed in the emergency mode.

The correction of the fuel oil pressure response problem and the fuel rack response time problem has restored the reliability of the "B" Diesel. Diesel testing has been satisfactory since these repairs have been made. The degradation of the USCV-9 Control Valve was most likely caused by poor control air quality supplied from the starting air compressors. Air dryers are to be installed under PMR 82-761 during the first refueling outage to reduce the moisture problem.

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)
Susquehanna Steam Electric Station-Unit 2	0 5 0 0 0 3 8 8	1 OF 0 5

TITLE (4)
Reactor Shutdown due to inoperability of the 'B' Loop of Low Pressure Core Injection.

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 4	8 4	— 0 0 6	— 0 0	0 6	2 7	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
2	20.402(b)	20.405(c)	50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10) 0 1 0 2	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) w/i cns	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
B.L. Wilks	AREA CODE 7 1 7 — 5 4 2 - 3 2 3 9

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
X	B J0	I S V	A 3 9 1	N							

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

At 0530 hours on 5/28/84, shutdown of the Unit 2 reactor commenced from low power testing at a power level of 2% in accordance with Action Statement (b)(3) of Technical Specification (T.S.) 3.5.1.b.2 due to the inoperability of the 'B' Loop of the Low Pressure Coolant Injection (LPCI) System (Also refer to LER 84-008-00).

The LCO was incurred at 0615 hours on 5/21/84 when the LPCI Injection Valve HV-2F015B was closed and de-energized in compliance with T.S. 3.6.3 following the occurrance of dual indication on the Testable Check Valve HV-2F050B and its Bypass Valve HV-2F122B (Also refer to Time Line and Figure 1 attached to this report). Later that day, the RHR Throttle Valve HV-2F017B was closed and HV-2F015B was cycled in an attempt to seat HV-2F050B; when HV-2F017B was reopened the 'B' RHR primary side heat exchanger pressure was observed increasing. Valve HV-2F017B was closed.

On 5/24/84 a Local Leak Rate Test (LLRT) showed leakage was occuring thru HV-2F015B and this leakage was the source of pressurization of the heat exchanger; LCO 3.4.3.2 was incurred at this time and Valve HV-2F017B was de-energized to ensure separation between the high and low pressure portions of the 'B' RHR. Loop B LPCI remained inoperable and the reactor was shutdown in seven days in compliance with T.S. 3.5.1.b.2. LPCI Injection Valve HV-2F015B was disassembled, repaired and returned to service. A loose plate connector on Valve HV-2F122B was found to be the cause for dual indication; the plate connector's set screws were tightened and the valve returned to service on 5/30/84.

On 6/10/84, LCO's for T.S.'s 3.6.3, 3.5.1.b.2 and 3.4.3.2 were cleared; 'B' Loop LPCI was returned to service and the Unit 2 reactor was allowed to start up for further testing.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Susquehanna Steam Electric Station Unit 2	0 5 0 0 0 3 8 8	8 4	— 0 0 6	— 0 0	0 2 OF 0 5

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

At 0530 hours on 5/28/84, shutdown of the Unit 2 reactor commenced from low power testing at a power level of 2% in accordance with Action Statement (b)(3) of T.S. 3.5.1.b.2 due to the inoperability of the 'B' Loop of LPCI (Also refer to LER 84-008-00). The LCO was incurred at 0615 hours on 5/21/84 when the LPCI Injection Valve HV-2F015B was closed and de-energized in compliance with T.S. 3.6.3 following the occurrance of dual indication on Testable Check Valve HV-2F050 and its Bypass Valve HV-2F122B. Later that day, the RHR Throttle Valve HV-2F017B was closed and HV-2F015B was cycled in an attempt to seat HV-2F050B; when HV-2F017B was reopened, the 'B' RHR primary side heat exchanger pressure was observed increasing (Also refer to Time Line and Figure 1 attached to this report). Valve HV-2F017B was closed.

On 5/24/84 an LLRT showed leakage was occurring thru HV-2F015B and this leakage was the source of pressurization in the heat exchanger; LCO 3.4.3.2 was incurred at this time and Valve HV-2F017B was de-energized to ensure separation between the high and low pressure portions of the 'B' RHR. Loop B LPCI remain inoperable and in compliance with T.S. 3.5.1.b.2; the reactor was shutdown on 5/28/84.

The HV-2F015B is a horizontally mounted gate valve. Upon disassembly and inspection of LPCI Injection Valve HV-2F015B it was found that the valve's disc would not center on its seat due to the dimensions of the disc guide bearing surface and this resulted in the valve's disc sitting "low" in the valve's body. Due to machining tolerances during manufacturing, the disc would not seat in the same location each time it was stroked. To stop leakage thru the valve, its seat was lapped and upon the vendor's recommendation, its lower disc guide bearing surface was built up one-quarter (¼) inch. The valve was reassembled and an LLRT and a hydro were satisfactorly completed on 6/7/84 and 6/8/84, respectively.

The reason for dual indication on Testable Check Valve's Bypass, HV-2F122B was attributed to a loose diaphram plate connector that resulted in improper contact with the limit switches on the bypass valve. The plate connector and its set screws were tightened, and its operator reconnected. Proper stroking and indication was observed during the performance of a subsequent LLRT.

On 6/10/84, LCO's for T.S.'s 3.6.3, 3.5.1.b.2 and 3.4.3.2 were closed; 'B' Loop of LPCI was returned to service and the Unit 2 reactor was allowed to start up for further testing. During this event, Loop A RHR remained operable, as were both systems of core spray; no release of radioactive material occurred. The health and safety of the public was not affected.

Time Line

5/21/84

0455 hours — Dual indication received on Testable Check Valve HV-2F050B and its associated Bypass Valve HV-2F122B. LCO entered in accordance with T.S. 3.6.3 allowing either four (4) hours to repair the valve or isolate the penetration.

0615 hours — LPCI Injection Valve HV-2F015B on Loop B LPCI de-energized to comply with LCO per T.S. 3.6.3 action statement (a)(2). An LCO was entered in accordance with T.S. 3.5.1.b.2 since valve HV-2F015B was shut and de-energized inopting 'B' LPCI. Action statement (b)(3) requires LPCI to be operable in seven (7) days or the reactor is to be in hot shutdown (HSD) in twelve (12) hours and cold shutdown in twenty-four (24) hours.

Between 0615 and 1730 hours — LPCI Throttle Valve HV-2F017B was closed and valve HV-2F015B was cycled in attempts to close HV-2F050B. Pressure observed increasing in the primary side of 'B' RHR Heat Exchanger when valve HV-2F017B was opened with HV-2F015B closed. Valve HV-2F017B was again placed in a closed position.

5/24/84

0430 hours — LLRT performed indicated leakage from the RCS boundary in excess of 1 gpm. An LCO was entered at this time in accordance with T.S. 3.4.3.2.d. LPCI Throttle Valve HV-2B017B de-energized to insure separation between high and low pressure 'B' Loop of LPCI.

5/28/84

prior to 0530 hours — LLRT Retest showed no leakage thru HV-2F050B and a 3.0 gpm leak rate thru HV-2F015B.

0530 hours — Commenced Unit 2 Reactor shutdown in accordance with seven (7) day limit specified by T.S. 3.5.1.b.2, action (b)(3).

1345 hours — Unit 2 reactor shut down by placing Reactor Mode Switch in shutdown.

Time Line

5/30/84 — Dual indication on Testable Check Valve HV-2F050B and Bypass Valve HV-2F122B attributed to a loose diaphram plate connector that resulted in improper contact with the bypass valve's indication limit switches. Valve's plate connector re-connected, set screws tightened. Valve returned to service on subsequent LLRT.

Between 5/28/84 and 6/7/84 — Valve 2F015B disassembled and inspected; valve's disc would not center on its seat due to improper dimensions of the disc guide bearing surface; the valve's seat was lapped and the lower disc guide bearing surface was built up ± inch with the valve vendors recommendation; the valve was then reassembled.

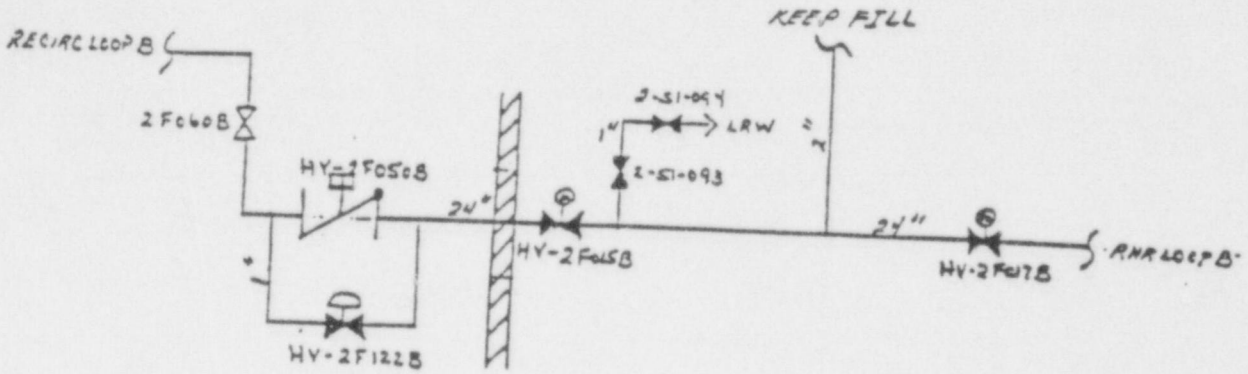
6/7/84 — LLRT (SE-259-032) completed satisfactory.

6/8/84 — Hydro per SE-259-112 completed satisfactory.

6/10/84

0045 - 0140 hours — LCO's per T.S. 3.6.3, 3.5.1.b.2 and 3.4.3.2 cleared.

Figure 1



LOOP B RHR

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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): Susquehanna Steam Electric Station-Unit 2

DOCKET NUMBER (2): 0 5 0 0 0 3 8 8

PAGE (3): 1 OF 0 2

TITLE (4): RPS Manual Scram Due To Stuck Open Turbine Bypass Valve During 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 5	2 7	8 4	8 4	— 0 0 8	— 0 0	0 6	2 7	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9): 2

POWER LEVEL (10): 0 1 0 2

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: Benjamin L. Wilks

TELEPHONE NUMBER: AREA CODE 7 1 7 — 5 4 2 - 3 2 3 9

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
B	J 1 1	P I C V	G 0 8 4	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-spaced typewritten lines) (16)

At 0530 hours on 5/28/84 shutdown of the Unit 2 reactor commenced from low power testing in compliance with Action Statement (b)(3) of Technical Specification 3.5.1.b(2) incurred at 1730 hours seven days earlier on 5/21/84 due to the inoperability of the 'B' Loop of the Low Pressure Core Injection (LPCI) System (refer to LER 84-006-00). The shutdown was being accomplished by inserting control rods individually into the reactor core utilizing the rod pull sheet. Shutdown preceeded normally until at 0605 hours when it was observed that the #1 Turbine Bypass Valve would not close below the 18% open position.

Shutdown of the Unit 2 reactor was halted and control rods in group 5 were pulled to maintain reactor pressure with the #1 Turbine Bypass Valve Controling at a position slightly greater than 18%.

Further investigation determined that the #1 Bypass Valve could not be closed below the 18%. At this time, it was determined the best means available for shutting down the reactor would be thru an RPS Manual Scram and at 1346 hours, the Unit 2 reactor was manually scrammed. The plant control operator tripped the 'B' reactor feed pump and closed all inboard main steam isolation valves at approximately 700 psig.

Subsequent investigations of the EHC pressure control and bypass valve control logic indicated that all control functions were operating normally. Investigation of the #1 Bypass Valve revealed that a chipping hammer wedged between the bypass valve seat and the valve disc preventing the #1 Bypass Valve from fully closing (ref. Memo PLA-2229). Disassembly of the #1 Bypass Valve showed small dents on the disc and the seat of the valve. The valve's seat was machined to remove the dents and the disc was replaced due to the difficulties in removing the old disc, and the valve was returned to service.

Based on a review of work documents and that system flushes were performed during preoperational testing, it is concluded that the occurrance of this loose tool in the units piping is an isolated event.

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FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Susquehanna Steam Electric Station Unit 2	0 5 0 0 0 3 8 8	8 4	— 0 0 8	— 0 0	0 2 OF 0 2

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

At 0530 hours on 5/28/84 shutdown of the Unit 2 reactor commenced from low portion testing in compliance with Action Statement (b)(3) of Technical Specification 3.5.1.b(2) incurred at 1730 hours seven days earlier on 5/21/84 due to the inoperability of the 'B' Loop of the Low Pressure Core Injection (LPCI) System (refer to LER 84-006-00). The shutdown was being accomplished by inserting control rods individually into the reactor's core utilizing the rod pull sheet until all of the control rods were at the full in position. Shutdown proceeded normally until at 0605 hours it was observed that the #1 Turbine Bypass Valve would not close below the 18% open position (ref. Memo PLA-2229, "Susquehanna Steam Electric Station Turbine Bypass Transient", B.D. Kenyon to Dr. Thomas E. Murley, dated 6/8/84). Shutdown of the Unit 2 reactor was halted and control rods in group 5 were pulled sequentially to maintain reactor pressure with the #1 Turbine Bypass Valve Controling at a position slightly greater than 18%.

Instrumentation and Control, and Mechanical Maintenance personnel were sent to investigate the valve's failure to close. These investigations determined that the #1 Bypass Valve could not be closed below 18%. It was then determined that the best means available for shutting down the reactor would be thru an RPS Manual Scram. At 1346 hours, the Unit 2 reactor was manually scrammed, and at reactor vessel pressure of 700 psig all inboard main steam isolation valves were closed.

Subsequent investigations of the EHC pressure control and bypass valve control logic indicated that all control functions were operating normally. Investigation of the #1 Bypass Valve revealed that a chipping hammer was wedged between the Bypass Valve seat and the valve disc preventing the #1 Bypass Valve from fully closing (ref. Memo PLA-2229).

Although a sizable portion of the handle and the head of the hammer itself remained intact, it is believed that a spring portion, small in comparison to the overall dimensions of the hammer, was severed from the handle. This severed portion would most likely be deposited in the bypass's sparger into the Main Condenser, posing no threat to components in other parts of the system.

Disassembly of the #1 Bypass Valve showed small dents on the disc and the seat of the valve. The valve's seat was machined to remove the dents, the disc was replaced due to the difficulties in removing the old disc and the valve was returned to service.

A review of unit work documents indicates the bypass system was one of the last systems worked on prior to startup for preoperational testing. Based on this review and the fact that system flushes are performed as part of the Preoperational Test Program, it is concluded that the occurrance of this loose tool in the Unit's piping is an isolated event.

During this occurrance, primary system integrity was maintained and no release of radiation occurred; the health and safety of the public was not affected.

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)
Susquehanna Steam Electric Station	0 5 0 0 0 3 8 8	1 OF 0 4

TITLE (4): Loss of Offsite Power [redacted] and Diesel Generators fail to Start

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
0 7	2 6	8 4	8 4	— 0 1 3	— 0 0	0 8	2 4	8 4		0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
POWER LEVEL (10): 0 3 0	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
	20.405(a)(1)(i)	50.36(c)(1)	50.73(a)(2)(v)	73.71(c)
	20.405(a)(1)(ii)	50.36(c)(2)	50.73(a)(2)(vii)	X OTHER (Specify in Abstract below and in Text, NRC Form 366A) 692
	20.405(a)(1)(iii)	50.73(a)(2)(i)	50.73(a)(2)(viii)(A)	
	20.405(a)(1)(iv)	X 50.73(a)(2)(ii)	50.73(a)(2)(viii)(B)	
	20.405(a)(1)(v)	50.73(a)(2)(iii)	50.73(a)(2)(x)	

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
R.W. Stanley, Compliance Engineer	AREA CODE 7 1 7 5 4 2 1 - 1 3 9 1 3 10

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

CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFACTURER	REPORTABLE TO NPRDS	
A	E B	J C	W 1 2 0	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 July 26, 1984, at 0137, with Unit 2 operating at 30% power, a Loss of Turbine Generator and Off-Site Power, Startup Test ST31.1 was initiated from the Control Room by opening the Unit 2 Main Generator Output Breakers and the Startup Transformer Breaker. This resulted in a scram due to Turbine Control Valve Fast Closure also, De-energization of the 13.8KV, 4.16KV. The above events were expected plant response per ST31.1.

The four emergency diesel generators which provide power to the 4.16KV Bus did not automatically start. This was due to a misalignment during the breaker line up required for ST31.1. The DC Knife Switches which were opened were for the Bus Logic Circuits, which included the Diesel Generator Start Relays. This knife switch was opened instead of the knife switch for the control and trip DC power for the 4.16KV Feeder Breakers.

A relief valve opened to limit the Reactor Vessel pressure. The Loss of Reactor Vessel Water Inventory from the relief valve opening caused a decrease in water level. Reactor Core Injection Cooling (RCIC) was manually initiated to maintain vessel level.

Power was restored on the first of four 4.16KV Buses eleven (11) minutes into the transient and the final 4.16KV Bus was re-energized seventeen (17) minutes into the transient.

The plant experienced a safe shutdown with the health and safety of the public not jeopardized. This is re-enforced by the fact that the operator has at least eight (8) hours in which to restore AC power before any safety system degradation would be expected. (Reference PLA-1136 to NRC, June 15, 1982.)

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On July 26, 1984 Operations personnel were performing plant alignment in accordance with ST 31.1, Loss of Turbine-Generator and Off-Site Power Startup Test. Included in the line up was racking out the four (4) feeder breakers which supply power to the Unit 2 4.16KV Buses from the Unit 1 T10 ESS Transformer.

The normal operating practice for racking out a 4KV breaker is to ensure the breaker is open, open the DC knife switch to the DC control power for the breaker and then to rack out the breaker. The T10 ESS Transformer feeder breakers 2A20101, 2A20201, 2A20301, and 2A20401 are all in the 01 cubicles of the 4KV ESS buses. The 01 cubicle, has two DC knife switches, whereas all other breakers in the switchgear bus have only one DC knife switch which provides DC control power to the breaker. The additional DC knife switch in the 01 cubicle provides DC power to the logic circuitry for the bus. Prior to physically racking out the breaker, the operator opened the DC knife switch to the bus logic rather than the DC knife switch to the 01 breaker control circuit. The two DC knife switches in the Unit 2 4KV ESS Bus 01 cubicle were labeled as follows:

BREAKER AND CONTROL SWITCH AND TRIP CIRCUIT FUSES	D.C. CONTROL

The DC knife switch on the left supplies DC power to the 01 breaker. The DC knife switch on the right (the one operator opened) supplies DC Control Power to the bus logic. When the operator opened the first 01 cubicle door, he called the Control Room, informed them he was at the breaker, and requested confirmation that the breaker be racked out and the DC opened. The Control Room operator, after conferring with Supervision, directed that the breaker be racked out and the DC opened. The operator subsequently opened the 'DC Control' knife switch and racked out the breaker. This action was repeated at each 4KV '01' breaker.

At 0137 on July 26, 1984, with the Unit 2 Reactor operating at 30% power, a Loss of Turbine Generator and Off-Site Power Startup Test was initiated from the Control Room by opening the Unit 2 Main Generator 500KV Output Breakers 2T and 4T and the Startup Transformer T20 to Bus 20 Breaker 0A10401. This resulted in a reactor scram due to Turbine Control Valve Fast Closure, the de-energization of the ±3.8KV Buses 20, 12A and 12B, and the de-energization of 4.16KV Buses 2A, 2B, 2C, and 2D. These were expected actions and were indicated in ST 31.1. The Turbine Bypass Valves opened to limit the initial pressure transient and the loss of power to the RPS M/G Sets initiated a Primary Containment Isolation (MSIV Closure) and Secondary Containment Isolation. Immediately after the scram the Plant Control Operator at Reactor Control Panel 2C651 noted that he did not have indication that the Control Rods were fully inserted into the core due to the power loss which de-energized the Full Core Display. A PCO verified the reactor pressure was 1040 to 1050 psig and slowly rising per HPCI and RCIC pressure indicator located on 2C601. The Neutron Monitor indicated the count rate was down and a negitive period was noted. This indicated to the PCO that Control Rods had inserted and it was normal decay heat. The PCO observed the J-Steam Releif Valve lifted and re-set several times and limited reactor vessel pressure increase caused by the core decay heat.

The reactor level was being monitored by the B and C narrow range instruments on the Standby Information Panel (SIP). When the level went offscale, below Instrument 0" (Instrument 0" is located approximately 160"above top of active fuel), the Control Room personnel contacted Instrument and Control (I&C) personnel. Level instruments, which are located at the Local Panel 2C004, were not effected by the power outage. The I&C personnel kept the Control Room informed of the reactor level.

Subsequently, the water level decrease was terminated at -28" indicated water level 38 minutes into the transient when the reactor operator manually initiated RCIC. At 20" indicated water level, the operator reduced RCIC flow to the vessel and at 45" indicated water level, tripped the RCIC turbine.

Following the initiation of the test, the PCO located at the Electrical Panel OC653 noted that the four (4) Emergency Diesel Generators did not start. When the 4.16KV Buses were de-energized, he noted that the feeder breakers from the Bus 20 ESS Transformers 201 and 211 to the 4.16KV Ess Buses were closed. Since the 4.16KV Bus was de-energized, these four (4) feeder breakers should have opened. The PCO knew that the feeder breakers had to be open for the diesel generators to automatically start. He manually opened the feeder breakers and the diesel generators still did not start. He then manually started the four (4) diesel generators (D/G). The D D/G tripped on overvoltage, the B D/G tripped on overvoltage and underfrequency. The A and C D/G's idled but did not close into their associated 4.16KV Bus. The A D/G exhibited frequency oscillations and was manually tripped by the operator. The operator then tried to manually close the C D/G onto the 4.16KV Bus but the breaker would not close. The operator then re-energized Bus 20 by closing 0A10401 and re-energized ESS Transformers 201 and 211 by closing 0A10406 and 0A10412. He then attempted to close the feeder breakers from the ESS Transformer to the 4.16KV Buses. The feeder breakers would not close. The 4.16KV Buses were still de-energized. The Unit Supervisor then instructed the Reactor Building Plant Operator to rack in the feeder breakers and close the DC Knife Switch. As the feeder breakers from the T10 ESS Transformer were racked in the DC Knife Switches closed, the preferred feeder breaker to the ESS Bus closed, Re-energizing the bus.

As its associated bus was restored, the tripped diesel-generators (A,B and D) automatically started. Power was restored to the first bus eleven minutes into the transient and to the last bus seventeen minutes into the transient. When power was restored to all four ESS busses, the operator noted that A,B, and D D/G's had Hi Priority alarms so he manually shut them down. The operator in the diesel generator building reset the Hi Priority alarm on the A D/G but could not reset the Hi Priority alarm on the B and D D/G.

When the diesel generators failed to start and initial attempts at re-energizing the 4KV ESS Busses did not succeed, the shift supervisor entered the Emergency Plan, declared an Unusual Event at 0150 and activated the TSC. Once power was fully restored, the Unusual Event was terminated at 0230.

Following the diesel generator shutdowns and failure to clear the Hi Priority alarms on the B & D D/G, Unit 1 entered an LCO on two diesel generators inoperable. The Hi Priority alarms were subsequently cleared, the diesel generator surveillance tests were successfully performed and the LCO was cleared.

Diesel Generator Response

Regulatory Guide 1.108 requires all diesel generator failures, valid or invalid, to be reported.

When the manual start of the diesel generators was initiated, the D Diesel Generator tripped on over voltage and the B D/G tripped on overvoltage and underfrequency. These trips are bypassed in the emergency start mode so the D/G's would have been able to perform their required functions under LOCA or LOOP conditions. Therefore, these are qualified as non valid failures.

The 'A' Diesel Generator exhibited frequency oscillations after it was manually started and the operator shut it down. Since the diesel would have performed its intended

emergency function the 'A' Diesel run was qualified as a non valid test.

At the time of the testing, there was one (1) valid test failure in the last 100 valid tests.

To prevent a recurrence of the overvoltage trip the generator voltage which was set at 4250 volts has been changed to 4160 volts. This should eliminate the overvoltage trips.

The 'A' Diesel Generator was tested for frequency oscillations by performing seven manual starts. In addition, the governor control settings were varied to demonstrate that the governor control circuit was operating in a region of stability. The frequency oscillations could not be reproduced. Additionally, the fuel racks on the diesel generator were upset and the oscillations immediately stabilized.

The three diesels were tested and declared operable within the hour Technical Specification limit.

The current surveillance test interval is every 31 days since there is only one vaild failure in the last 100 starts.

Attached is a detailed summary for the Unit 2 Loss of AC Power incident. Included is a list of corrective actions. The Plant Operations Review Committee (PORC) reviewed the status of corrective actions, items considered necessary for Unit restart were determined by the PORC to be satisfactorily completed. The status of the remaining actions and corrections or changes will be submitted to Region 1 under separate correspondencs.

SUMMARY STATUS REPORT
FOR THE SUSQUEHANNA STEAM ELECTRIC STATION
UNIT NO. 2 LOSS OF AC POWER INCIDENT OF JULY 26, 1984

Date of Scram: 07-26-84

Time of Scram: 0137

Cause of Scram: Main Turbine Control Valve Fast Closure; initiated by ST31.1 Loss of Turbine - Generator and Off-Site Power.

INTRODUCTION

This report is a summary of the status of our investigation of the subject incident as reviewed with NRC representatives on July 30, 1984. Those Corrective Actions required for a Unit restart have been completed. The status of short and long term Corrective Actions not completed will be described in a future report.

EVENT

With the Unit 2 reactor operating at 90% power, the ST31.1 Loss of Turbine - Generator and Off-Site Power Startup Test transient was initiated by opening the Unit 2 Main Generator 500kV Output Breakers 2T and 4T and the Startup Transformer T20 to Bus 20 Breaker 0A10401. This resulted in a reactor scram due to turbine control valve fast closure, de-energization of the 13.8 kV Busses 20, 1EA and 1EB and de-energization of 4.16 kV ESS Busses 2A, 2B, 2C and 2D which had their respective T10 feeder breakers racked out. The turbine bypass valves opened to limit the initial pressure transient and the loss of power to the RPS M/G sets initiated a primary containment isolation (MSIV closure) and secondary containment isolation. Immediately after the scram the Plant Control Operator (PCO) at the reactor control panel 2C651 noted that he did not have indication that the control rods were fully inserted into the core. The PCO at electrical distribution panel 0C653 noted that the four emergency diesel generators did not start when the 4kV ESS busses were de-energized and that the feeder breakers from the Bus 20 ESS transformers 201 and 211 to the 4kV ESS busses were closed. He opened the feeder breakers and when the diesel generator still did not start, he manually started all four diesel generators. The D D/G tripped on overvoltage and the B D/G tripped on overvoltage and underfrequency. The A and C D/G's idled but did not close in on their associated 4kV bus. The A D/G was exhibiting large frequency oscillations and was manually tripped by the operator.

The operator then tried to manually close the C D/G breaker onto the 2C Bus but the breaker would not close. The operator then re-energized Bus 20 by closing OA10401 and re-energized ESS transformers 201 and 211 by closing OA10406 and OA10412. He then attempted to close the feeder breakers from the ESS transformers to the 4kV ESS busses, but the feeder breakers would not close. The unit supervisor then instructed the reactor building plant operator to rack in the feeder breakers from the T10 ESS transformers 101 and 111 to the ESS busses. As the feeder breakers from the T10 ESS transformers were racked in and their D.C. knife switches closed, the preferred feeder breaker to the ESS bus closed, re-energizing the bus. As its associated bus was restored, the tripped diesel-generators (A,B and D) automatically started. Power was restored to the first bus eleven minutes into the transient and to the last bus seventeen minutes into the transient. When power was restored to all four ESS busses, the operator noted that A,B and D D/G's had Hi Priority alarms so he manually shut them down. The operator in the diesel generator building reset the Hi Priority alarm on the A D/G but could not reset the Hi Priority alarm on the B and D D/G.

When the diesel generators failed to start and initial attempts at re-energizing the 4kV ESS Busses did not succeed, the shift supervisor entered the Emergency Plan, declared an Unusual Event and activated the TSC. Once power was fully restored, the Unusual Event was terminated.

Following the diesel generator shutdowns and failure to clear the Hi Priority alarms on the B & D D/G, Unit 1 entered an LCO on two diesel generators inoperable. The Hi Priority alarms were subsequently cleared, the diesel generator surveillance tests were successfully performed and the LCO was cleared.

The reactor response was as expected except that the "J" relief valve opened at 1050 psig to limit the pressure transient after the MSIV's closed. The "J" S/RV is a group 4 relief valve, nominally set to actuate at 1106 psig. The "J" relief valve opened seven times at approximately 5 minute intervals to limit the reactor vessel pressure increase caused by the core decay heat. The loss of reactor vessel water inventory from the relief valve opening caused reactor water level to gradually decrease. The water level decrease was terminated at -28" indicated water level 38 minutes into the transient when the reactor operator manually initiated RCIC. At 20" indicated water level, the operator reduced RCIC flow to the vessel and at 45" indicated water level, tripped the RCIC turbine.

CAUSE

The cause of the failure of the diesel generators to start and subsequent difficulties encountered in re-energizing the ESS busses, has been identified as a problem in the ST31.1 pretest initial lineup of the 4kV ESS bus feeder breakers from the T10 ESS transformers. The ST31.1 breaker lineup checkoff list specified that the T10 ESS transformer 201 and 211 feeder breakers to the 4kV ESS busses be "Racked Out". The normal operating practice for racking out a 4kV breaker is to ensure the breaker is open, open the D.C. knife switch to the D.C. control power for the breaker and then to rack out the breaker. The T10 ESS transformer feeder breakers 2A20101, 2A20201, 2A20301 and 2A20401 are all in the 01 cubicle of the 4kV ESS bus. The 01 cubicle, has two D.C. knife switches, whereas all other breakers in the switchgear bus have only one D.C. knife switch which provides D.C. control power to the breaker. The additional D.C. knife switch in the 01 cubicle provides D.C. power to the logic circuitry for the bus. Prior to physically racking out the breaker, the operator opened the D.C. knife switch to the bus logic rather than the D.C. knife switch to the 01 breaker control circuit. The two D.C. knife switches in the Unit 2 4kV ESS Bus 01 cubicle were labeled as follows:

BREAKER AND CONTROL SWITCH AND TRIP CIRCUIT FUSES

D.C. CONTROL

The D.C. knife switch on the left supplies D.C. power to the 01 breaker. The D.C. knife switch on the right (the one the operator opened) supplies D.C. control power to the Bus Logic. When the operator opened the first 01 cubicle door, he called the control room, informed them he was at the breaker, and requested confirmation that the breaker be racked out and the D.C. opened. The control room operator, after conferring with Supervision, directed that the breaker be racked out and the D.C. opened. The operator subsequently opened the 'D.C. Control' knife switch and racked out the breaker. This action was repeated at each 4kV '01' breaker.

NUCLEAR DEPARTMENT EVALUATION

1. Plant Staff performed a detailed investigation and identified immediate, short term, and long term action items. These items are fully displayed in the remaining body of this report.

2. Nuclear Plant Engineering has conducted an independent design review of this incident and will prepare an independent report for management review.

3. The Nuclear Safety Assessment Group had conducted an independent investigation of this incident and will prepare an independent report for management review.

4. The Nuclear Quality Assurance Group will conduct an audit of the numerous action items identified and dispositioned by Plant Staff. This audit will ensure conclusions reached are properly substantiated.

PLANT STAFF INVESTIGATION AND CORRECTIVE ACTION

A detailed investigation of the incident has been performed by the Plant Staff. All available data from GETARS, the NSSS process computer, the BOP computer, the HRPD history tapes, SPDS and control room recorders has been gathered and analyzed. In addition, interviews with personnel directly involved in the incident have been conducted and documented.

The results of this substantial effort are:

- o An integrated time line that compiles information from monitoring equipment and pertinent facts from the interviews of personnel involved. This time line is displayed as Attachment 'A'.

- o A comprehensive list of action items that specify problems or areas of concern. Each action item identifies its description, specific action to accomplish resolution, the group responsible, and the priority. All of these action items are displayed as Attachment 'B'.

- o A list of specific NRC action items which were required for restart. This list is provided as Attachment 'C'.

The priority system used in Attachment 'B' is as follows:

- Priority 1: Required prior to start up of Unit 2.
- Priority 2: Short term.
- Priority 3: Long term with action plan to be completed in the short term.
- Priority 4: Required prior to performing a specific activity.

SUMMARY OF FINDINGS

As a result of the detailed investigation performed on this incident, an evaluation of several major areas of concern was made and is presented below. The section on Plant Response includes all major plant response items with the exception of 4kV ESS Bus Response, Diesel Generator Response, Instrumentation Response and Procedures and Training which are addressed as separate items.

I. Plant Response

The overall Unit 2 and Unit 1 plant response to the incident was per the plant design except for the following items:

A. The 'J' safety/relief valve lifted earlier than expected. The 'J' SRV is a group 4 SRV with a nominal setting of 1106 psig to open. Nominally, the 'B' and 'E' SRV's with setpoints of 1076 psig should open prior to 'J' on increasing pressure. The calibration of 'J' SRV relief pressure setpoint was checked and found to be 1050 psig. This valve was out of tolerance and the instrument was recalibrated. All other SRV relief setpoints were checked. Three additional setpoints were found out of tolerance and recalibrated.

B. Following the incident, when the scram was reset, the Scram Discharge Volume drain valve had dual indication. Investigation showed that the valve operator stem had pulled free from the valve disk stem. The cause of this failure was the bolt which holds the two halves of the threaded coupling together was torqued in such a fashion as to allow the upper portion of the threaded coupling halves to pull apart, allowing the actuator stem to come free from the coupling. This allowed the valve to fail close as per design. The valve coupling was repaired by fabricating a new coupling and tested. All similar valves on Units 1 and 2 (15) were identified and the Unit 2 valves (7) were inspected and found to be satisfactory. The Unit 1 valves will be inspected at a future time when they are more easily accessible.

C. The Standby Gas Treatment System started on the LOOP and then tripped. The SGTS is designed to control each affected zone (Zones II and III in this case) at a negative 0.25" w.c. Both fans started since both control switches are kept in the Auto Lead position. The power loss to the 4kV ESS busses prevented the air dampers from opening and thus the SGTS fans tripped on low delta pressure. NPE is performing a long term evaluation of this event.

D. The CREDASS was initiated during this event as per design but was reported to have tripped. Plant Staff engineers monitored the CREDASS control panel during the event and reported that CREDASS did not trip.

E. The Emergency Switchgear Room Cooling Compressors did not start. The auto start of these compressors comes from the diesel generator breaker 2AC0104 which must close. Since this breaker did not close, the compressor did not start.

The event that occurred at SSES-2 on 07/26/84, (loss of all AC power for twelve to eighteen minutes) was analyzed in a letter PLA - 1136 submitted to the NRC on June 15, 1982. This analysis showed that the drywell air temperature stayed below 250°F for a period of up to three hours and the suppression pool temperature remained below 150°F for greater than one hour. The available data indicates that these parameters in the event were well below the predictions based on conservative assumptions. Therefore, it can be concluded that the event that occurred is within the bounds of the analysis in PLA - 1136. The analysis given in the letter shows that the operator had at least three hours before damage to drywell equipment might occur and approximately eight hours before any safety systems might be degraded. This analysis assumes that no operator action would be required other than maintaining level. The available data indicated that the plant response was slower than predicted in PLA - 1136. Therefore, the operator would have had much more than the three hours indicated in the letter before any equipment degradation might be expected. Therefore, it can be concluded that the operator had at least eight hours in which to restore AC power before any safety system degradation would be expected.

II. 4KV ESS Bus Response

The 4kV ESS Bus response was not as expected, however, since the investigation showed that the D.C. knife switch to the bus D.C. logic power was opened instead of the D.C. knife switch to the breaker control circuit, each observed anomaly is explained.

A. The labeling of the D.C. knife switches on the Unit 1 and 2 4kV ESS busses was found to be misleading. The labels were changed to be more clearly descriptive. The label on the D.C. control power for the 2A20101 breaker now reads in black letters on a white background.

BKR 2A20101
CONTROL AND TRIP
D.C. POWER

The label for the D.C. control power to the bus logic circuits reads in white letters on a red background.

BUS/DIESEL GEN A
AUX RELAY, CONTROL
D.C. POWER

In addition the handle for the D.C. knife switch for the bus logic circuits has been painted red and a caution label has been added which reads in white letters on a red background.

CAUTION
OPENING THIS SWITCH
DISABLES D/G AND BUS
TRANSFER

All Unit 1 and Unit 2 4kV ESS Bus 01 cubicle Breakers have been similarly labeled. The labeling on 4.16 kV and 13.8 kV switchgear and 480V Load Centers is being evaluated.

B. The failure of the diesel generators to start initially was due to the T20 ESS transformer feeder breakers being closed in on the dead ESS bus. The diesel generator start circuit requires the preferred, the alternate, and the diesel generator breakers to be open as a permissive to start. The T20 ESS transformer feeder breakers did not open because the open D.C. knife switch to the bus control logic prevented the bus undervoltage relay from energizing and giving a trip signal to the feeder breakers. When the operator manually opened the T20 ESS transformer feeder breakers, the diesel generators did not start because the open D.C. knife switch removed power to the bus 62A timers which must energize for the diesels to start.

C. During the investigation, the correct fuse sizes and types in the 4kV ESS busses were examined. Inspection of the Unit 1 and Unit 2 4kV ESS Busses revealed that the D.C. Logic Control fuses for Busses 1A20201 and 2A20201 were 15 amps but were required to be 30 amps. The 15 amp fuses were verified to be intact and were then replaced with 30 amp fuses. All other fuses were found to be satisfactory. NPE verified that all fuse types were acceptable. Fuse sizes for 13.8KV Switchgear in Unit 1 and 2 will be investigated.

D. With the "C" Diesel Generator running and the 2C Bus de-energized, the "C" D/G breaker did not close in on the dead bus nor could the operator manually close the breaker from the control room panel. That the breaker did not automatically close is explained by the open DC knife switch which removed power to the bus undervoltage relay which must energize for the D/G breaker to auto close. For the operator to manually close the breaker, he must turn the keylocked sync switch to the "ON" position and place the D/G breaker control switch to the close position. Additional permissives in the closing circuit are auxiliary relay V1 which de-energizes on loss of bus power (and should have been de-energized) and auxiliary relay V2 which energizes when diesel generator voltage is present (and should have been energized). A retest has been performed to demonstrate that the D/G breaker can be manually closed on to a dead bus from the control room.

III. Diesel Generator Response

A. When the manual start of the diesel generators was initiated, the B&D diesel generators tripped on over voltage and the B D/G tripped on underfrequency. These trips are bypassed in the emergency start mode so the D/G's would have been able to perform their required functions under LOCA or LOOP conditions. An emergency start can be initiated from the control room by manually initiating the Core Spray and LPCI systems. Over voltage trips have been experienced in the past on manual starts and is thought to be due to the operating procedure which requires that the generator voltage be set to 4250 volts prior to shutdown. This value has been changed to 4160 volts which, based on preoperational test data should eliminate the over voltage trips. The monitoring program on D/G trips during manual starts will be continued.

B. The plant operator in the diesel generator building had difficulty in resetting the over voltage and underfrequency trips. The alarm response procedures which cover the resetting of these trips was found to be lacking in appropriate detail. Detailed steps for resetting diesel generator trips have been given to Operations and will be incorporated into an Off-Normal procedure.

C. The 'A' diesel generator exhibited frequency oscillations after it was manually started and the operator shut it down. The 'A' diesel generator was tested for frequency oscillations by performing seven manual starts. In addition, the governor control settings were varied to demonstrate that the governor control circuit was operating in a region of stability. The frequency oscillations could not be reproduced.

IV. INSTRUMENTATION RESPONSE

A. Immediately following the scram, the operator had an indication on the Reactor Full Core Display that not all control rods were fully inserted. Although the Full Core Display, the Four Rod Display, RDCS and RPIS were powered from uninterruptable power supplies, the rod position and HCU status information to the Full Core Display is fed through RSCS which is powered by Instrument A.C. (2Y218). When Instrument A.C. is lost, the information to the Full Core Display is unreliable. When Instrument A.C. is restored, the RSCS must be reset. A detailed explanation of the status of the Full Core Display has been given to Operations and will be incorporated into the appropriate Emergency Procedures for Loss of Power.

B. During the transient and subsequent investigation, there was some confusion as to what was the actual reactor vessel water level. During the transient, the operator monitored water level on the B and C Narrow Range water level indicators on the Standby Information Panel. When water level decreased below zero, water level information was phoned to the control room from I&C technicians monitoring water level on local instrumentation in the reactor building. When power was restored, the operator monitored water level using the Wide Range indicator LI-2R604 on the Standby Information Panel. This indication was verified to be reading conservatively low by the I&C technicians at the local instrument rack. RCIC was manually initiated when LI-2R604 indicated -34". The actual water level as determined by the majority of the level instrumentation operating at the time was -28". This discrepancy is within the design tolerance of LI-2R604. The -28" level indication was verified by SPDS. The advisability of making a plant modification to label or mark those level instruments which will indicate during a loss of power is being evaluated.

V. Procedural and Training Response

A. During the activation of the Emergency Plan, it was discovered that the declaration of an Unusual Event required the notification of four specific emergency response agencies, whereas the clearing of the Unusual Event required the notification of the original four agencies plus two additional agencies who would not have procedurally been notified. This discrepancy has been corrected by revision to the Emergency Plan Implementing Procedures.

B. Operator training on procedure changes made as a result of this investigation and operator retraining on the proper method of D.C. knife switch operation when racking out 13.8KV Switchgear and 480V Load Centers will be conducted as applicable prior to any of the operators to whom the training is applicable assuming shift responsibility following plant startup.

C. During the investigation following the incident, it was discovered that some of the plant operators had not received some required non-routine training.

A long term evaluation of the plant program to ensure that operators are trained on non-routine training items will be conducted.

D. Specific changes to the operator procedure program have been identified and are noted in the detailed action items-Attachment B.

RETEST

The retests to be performed are:

1) Test the 'C' D/G to verify:

   a) It will energize its associated bus in an emergency situation with normal D.C. lineup.

   b) It will energize its associated bus with the bus de-energized and fuses removed to simulate that D.C. power to the bus control logic is open.

2) ST31.1 - Loss of Turbine-Generator and Off-Site Power.

Prepared by — Date

Approved by — Date

UNIT 2 SCRAM NO. 2-84-04
SEQUENCE OF EVENTS

TIME		EVENT DESCRIPTION
2230	(7/25/84)	Reactor Lineup complete except for Bus 10 2A-2D AND U1 & U2 Tie Bkr.
2230		RX. Press 920 PSIG.
2230		Level 39"
0105	(7/25/84)	4KV Bus 10 Bkrs. to Busses 2A-2D and U1 & U2 Tie Bkr complete
0105		Rx Pressure 910 PSIG, Rx Level 37"
0137		U2 Loop and U2 Load Reject
0137		Opened 500KV Bkrs. 2T and 4T and T20 to Bus 20 Bkr.
0137		Scram 1:37:33:834
0137		Unit Primary LOR 1:37:33:648
0137		Rx Level Trip "A"
0137		MSIV Isolation 1:37:43
0138		D/G's did not start
0138		OPS Noted: 1) Feed Bkrs from ESS Xfrms 201 & 211 to 4KV Busses (no power) 2A, 2B, 2C & 2D closed.
0138		OPS manually opened those feed bkrs from CR
0138		D/G's still did not start
0139		Start A,B,C, & D D/G's manually.
0139		B D/G trip on overvoltage and under frequency
0139		D D/G Trip on Overvoltage
0139		A & C D/G idled but did not close in on bus

TIME	EVENT DESCRIPTION
0139	OPS manually tripped "A" due to frequency oscillations observed in Control Room
0142	Reenergized 1) Bus 2D (Closed OA10401) 2) ESS Xfmrs 201 and 211 (energized)
0142	4KV Bkrs from ESS Xfmrs 201 and 211 to ESS Busses would not close.
0142	J SRV activated
0146	J SRV Activated
0148	Racked in Bkr 20201 (T-10 Source) from U1 ESS Xfmrs to 4KV ESS Bus 2B
0148	When D/G Knife Switch closed, Bkr 20209 closed, energizing Bus 2B from Unit 2 T-2D feed (preferred)
0148	D/G B Auto Start
0148	Rx Narrow Range Pressure: NFPD1 - 917 PSIG NFPD2 - 925 PSIG
0148	Reactor Level A - 35" (HRPD) Reactor Level B - 35" (HRPD) Reactor Level C - 8" (HRPD) Reactor Upset Level - 37" (HRPD)
0150	Racked in Bkr 20401 T-10 feed to Bus 2D
0150	J SRV activated
0150	When D.C. Knife Switch closed, Bkr. 20408 closed, energizing Bus 2D from T-2D Feed (preferred)
0150	D/G D Auto Start
0150	Declared Unusual Event - TSC activated
0153	Racked in Bkr 20301 to feed to Bus 2C

TIME	EVENT DESCRIPTION
0153	When DC Knife Switch closed, Bkr 20301 closed, energizing Bus 2C from T-10 Unit 1 Feed preferred
0154	Racked in Bkr 20101 T-10 to Bus 2A.
0154	J SRV actuated
0154	When DC Knife Switch closed, Bkr 20109 closed, energizing Bus 2A preferred source from T-10
0154	D/C A Auto Start
0155	Busses 2A & 2C were transferred to be fed from ESS Xfmrs 201 and 211 CR operator
0155	D/G's A, B, & D - Hi Priority Alarm
0155	D/G's A, B, & D shut down
0155	A Hi-Priority Alarm Reset, B & D would not
0158	J SRV actuated
0203	J SRV actuated
0209	J SRV actuated
0217	J SRV actuated
0218	RCIC manually initiated
0218	Rx level - 27" (SPDS)
0220	LCO Entry on B & D D/G's
0229	Rx Level -14" (SPDS)
0229	Rx Level 29" (SETARS)
0230	End Unusual Event
0230	B & D trips cleared, clearing Hi-Priority Alarms
0240	Reactor Level at 52" (SETARS)
0240	Operator manually tripped RCIC

TIME	EVENT DESCRIPTION
0445	LCO Cleared
0445	SO completed
0720	Swapped A & C to normal supply ESS 101 and 111 from alternate supply (from PCO Log)

UNIT 2 SCRAM NO. 2-84-04
ACTION ITEM INDEX

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-01 (SR-1)	Why did the D/G's fail to start? Provide a time line, actions to prevent recurrence and an HFE review of event.
2-84-04-02 (SR-2)	Why did the "J" SRV lift first?
2-84-04-03 (SR-3 & SR-13)	At what level was RCIC manually started? What level instruments were used to determine this level.
2-84-04-04 (SR-4)	Condensate Demineralizer bypass valve requires repair.
2-84-04-05 (SR-5 & SR-22 & NRC-2)	Verify the fuse size and types in the D.C. Control Power circuits for the 13.8 KV and 4KV switchgear in Units 1 and 2.
2-84-04-06 (SR-6)	Should the 4KV Breakers from the D/G's to the ESS busses have been able to be closed remotely?
2-84-04-07 (SR-7)	Repair SCRAM discharge volume drain valve (2F011) operator.
2-84-04-08 (SR-8)	Why did the RFPT 9 and 10 valves fail to close after reenergization of Auxiliary Busses?
2-84-04-09 (SR-9)	Are D/G overvoltage trip procedural controls adequate?

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-10 (SR-10)	Specify the indications available to detect a loss of Control and Trip D.C. Power to 13.8KV, 4KV Switchgear and 480V Load Center Breakers and a Loss of Auxiliary Relay and Control D.C. Power to the 13.8KV, 4KV Switchgear and 480V Load Centers.
2-84-04-11 (SR-11 & NRC-10)	Evaluation and recommendation of testing on 4KV loss of power. D/G auto start to be performed prior to U-2 startup.
2-84-04-12 (SR-12)	Explanation of partial full core display indications immediately after transient.
2-84-04-13 (SR-14 & SR-24)	Evaluation of operation of SGTS during transient.
2-84-04-14 (SR-15)	Evaluation of operation of CREDASS during transient.
2-84-04-15 (SR-16)	Evaluation of operation of Emergency Switchgear Room Cooling during transient.
2-84-04-16 (SR-17)	EP-IP-002 and EP-IP-008 need to be reviewed for coordination. NRC hotline found to be in need of repair.
2-84-04-17 (SR-18)	Conduct operator training as a result of this event.
2-84-04-18 (SR-19)	Conduct Startup PORC.

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-19 (SR-20)	Review 13.8 KV and 4 KV Bkr tagging requests to determine how often we apply tagging to those breakers.
2-84-04-20 (SR-21)	How can an operator get a remote emergency start of the D/G's from the control or relay rooms?
2-84-04-21 (SR-23)	D/G "A" was manually tripped immediately after its manual start due to large frequency oscillation.
2-84-04-22 (NRC-1)	Training Concerns.
2-84-04-23 (NRC-3)	RCIC Flow indication of GETARS
2-84-04-24 (NRC-4)	Use of Wide Range Level During Event
2-84-04-25 (NRC-5)	D/G Reset
2-84-04-26 (NRC-6)	Reg. Guide 1.47
2-84-04-27 (NRC-7)	Suppression Pool Temperature Loss
2-84-04-28 (NRC-8)	08 and 09 Breakers
2-84-04-29 (NRC-9)	Power Transfer Switches

ACTION ITEM NUMBER	DESCRIPTION
2-84-04-30 (NRC-I1)	Loss of AC Instrument Indications
2-84-04-31 (NRC-12)	Independent Verification
2-84-04-32 (P-1)	Review of standard electrical operating practices
2-84-04-33 (P-2)	Review of Labeling Blackout Instrumentation
2-84-04-34 (P-3)	Staffing Considerations
2-84-04-35 (P-4)	Procedure Review: 480V, 4KV, & 13.8KV Bkrs.
2-84-04-36 (P-5)	Review of RHR and CS circuit breaker response to various combinations of Motive and Control Power availability.
2-84-04-37 (P-6)	Recorder Pen Colors Discrepancy between Unit 1 and 2 HFE Post Accident Inst. Levels Pressure
2-84-04-38 (P-7)	Communications considerations
2-84-04-39 (P-8)	Pre-test Walk-through

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-01

DESCRIPTION:

Why did the D/G's fail to start?
Provide a time line, actions to prevent recurrence and an HFE review of event.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Revise Knife Switch labeling in the 4 kV "01" SWGR CUBICLES listed below: 1A201, 202, 203, & 204 and 2A201, 202, 203, & 204.	Maint	1	C
3. Paint the handle of the knife switch for the "Bus/DG Aux Relay, Control D.C. Power" RED.	Maint	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-02

DESCRIPTION:

Why did the "J" SRV lift first?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Check all SRV Setpoints.	I&C	1	C
3. Recalibrate as required.	I&C	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-03

DESCRIPTION:

At what level was RCIC manually started?
What level instruments were used to determine this level?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. What level instrument used/when?	Comp	1	C
3. Explain observed level differences.	I&C	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-04

DESCRIPTION:

Condensate Demineralizer bypass valve requires repair.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Repair Condensate Demin Bypass Valve	Maint	1	C
3. Report on "as found condition" and repairs performed.	Maint	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-05

DESCRIPTION:

Verify the fuse size and tynes in the D.C. Control Power circuits for the 13.8KV and 4KV Switchgear, 480V Load Centers, 250VDC and 125VDC Load Centers and D/G Cabinets in Units 1 and 2.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Complete the As-Built verification of fuse size, fuse type and labeling in all 4KV, 13.8KV, 480V LC's, and 250VDC and 125VDC Load Centers, and D/G Cabinets. Also, verify knife switch labeling.	Tech	3	C
3. Replace fuses/change labels (for knife switches and fuses) as required.	Maint	3	
4. Establish Fuse Control Policy	Ops	3	
5. Determine proper Control Fuse size/type for: -13.8 breakers - 4.16 breakers -480V Load Centers (not MCC's)	NPE	3	C
6. Statement that type of fuse is not critical.	NPE	1	C
7. Determine fuse size and types in the 15A and 30A D.C. Control Power circuits for the 13.8KV and 4KV switchgear in Units 1 and 2.	Tech	1	C
8. Replace fuses and relabel Control Fuse nameplates as required (for item No. 7).	Maint	1	C
9. Revise appropriate procedures including CCL's (refer to item #2).	Ops	3	
10. Verify that there are no 480V Load Center alarms indicating open D.C. Knife Switches.	Ops	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-06

DESCRIPTION:

Should the 4KV Breakers from the D/G's to the ESS busses have been able to be closed remotely?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Provide copy of results of scheme checks performed by ET.	Maint	1	C
3. Test the "C" D/G's ability to close in on a dead bus with the U/V relay disabled.	S&T	1	C

Note: NRC requested notification regarding test schedule. Intend to witness tests. PP&L will provide notification.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-07

DESCRIPTION:

Repair SCRAM discharge volume drain vlave (2F011) operator.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. What should the valve position be (before the SCRAM)? What position was it in?	Tech	1	C
2. What was the Failure Mechanism?	Tech	1	C
3. Did the valve fail to its proper position? What was the "As-Found" condition?	Maint	1	C
4. What was failure method?	Maint	1	C
5. How did we find SCRAM Discharge Volume Drain Valve failure?	Ops	1	C
6. Inspect similar valves on Unit 2.	Maint	1	C
7. Revise PM's for similar valves.	Maint	3	
8. Inspect similar valves for Unit 1.	Maint	3 (cold shutdown)	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-08

DESCRIPTION:

Why did the RFPT 9 & 10 valves fail to close after reenergization of Auxiliary Busses?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Write up.	Tech	1	C
2. Write up design of 9 & 10 valve operation on LOP.	NPE	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-09

DESCRIPTION:

Are D/G overvoltage trip procedural controls adequate?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provice discussion.	Tech	1	C
2. Why left @ 4250 Volts.	Tech	1	C
3. How co you position D/G voltage required to insure successful starts?	Tech	1	C
4. Determine max T/D on Timing relay.	Maint	3	
5. Recal overvoltage relay (ratio of pickup to dropout - should be as low as possible).	Maint	3	
6. Implement recommendations from Tech/MT on Diesel Generator Voltage Regulator operation (SO's, OP's).	Ops	1	C
7. Adequacy of procedures relating to D/G remote emergency start.	NPE	2	
8. Provice RSCN for relay settings as required.	NPE	3	
9. Optimize D.V. protective scheme - (long term fix).	NPE	3	
10. Provice procedures for remote manual start of the D/G's from the control room to support emergency operations.	Ops	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-10

DESCRIPTION:

Specify the indications available to detect a loss of Control and Trip D.C. Power to 13.8KV, 4KV Switchgear and 480V Load Center Breakers and a Loss of Auxiliary Relay and Control D.C. Power to the 13.8KV, 4KV Switchgear and 480V Load Centers.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Expand definition to include lights on 13.8KV, 4KV, 480LC.	Tech	1	C
3. Indications available and what it means.	Trng	1	C
4. As result of re-label; incorporate proper terminology into training procedures, etc.	Trng	3	
5. Evaluate changes to procedure as result of re-labeling (procedures, instructions, guidelines).	Ops	3	
6. Revise surveillances and/or rounds to include Supv/Brk Control lights to the 4KV Switchgear.	Ops	1	C
7. Revise guidelines in AD (Permit and Tag).	Ops	1	C
8. Write CI for proper rack out of various breaker types (to include observation/ indication during sequence).	Ops	1	
9. Indications available and what it means.	NPE	1	1
10. Rectify labeling to prints.	NPE	1	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-11

DESCRIPTION:

Evaluation and recommendation of testing on 4KV loss of power. D/G auto start to be performed prior to U-2 startup.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Evaluate/Recommend testing. (Identify testing, conditions, and basis for performing the test(s).- discuss safety implications).	S&T	1	C
2. Perform ST31.1 (prior to leaving test plateau No. 2).	S&T	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-12

DESCRIPTION:

Explanation of partial full core display indications immediately after transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Tech	1	C
2. Provide discussion of full core display indications following loss of power. Actual indications observed. Provide information to OPS on how to restore.	I&C	1	C
3. Train the operator regarding: Full core display response to loss of power and, how to power-up.	Trng	1	C
4. Revise EO on Station Blackout procedure to address reset of Full Core Display.	Ops	1	C
5. Evaluate and revise as required the ATWS procedure.	Ops	3	
6. Review the differences between Units 1 and 2 relative to the full core display during blackout conditions and make recommendations.	NPE	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-13

DESCRIPTION:

Evaluation of operation of SGTS during transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide write up.	Tech	1	C
2. (a) Evaluate performance on restart following trip and subsequent LOCA init.	NPE	1	C
(b) Evaluate desirability of modifications for the SGTS based upon review of the trip experienced.	NPE	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-14

DESCRIPTION:

Evaluation of operation of CREDASS during transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide write up.	Tech	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-15

DESCRIPTION:

Evaluation of operation of Emergency Switchgear Room Cooling during transient.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide write up.	Tech	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-16

DESCRIPTION:

EP-IP-002 and EP-IP-008 need to be reviewed for coordination. NRC hotline found to be in need of repair.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Repair hotline to NRC.	Maint	1	C
2. Revise EP-IP for consistant notification.	Trng	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-17

DESCRIPTION:

Conduct operator training as a result of this event.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Provide discussion.	Trng	1	C
2. Define who (by position) get training (scope).	Ops	4	
3. Review all action items and determine/ conduct training required prior to startup for Ops.	Trng	1	C
4. Determine and provide additional training required for each group.	Trng	4	
5. Conduct training and incorporate lessons learned into training programs.	Trng	3	

Note: Preparations are being made to commence training activities. The NRC noted that they would like to attend a session.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-18

DESCRIPTION:

Conduct Startup PORC.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Conduct PORC when ready.	Tech	1	C

Note: PP&L will inform the NRC as to when the PORC will take place.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-19

DESCRIPTION:

Review 13.8KV and 4KV Bkr tagging requests to determine how often we apply tagging to those breakers.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Survey Permit and Tag permits over past 6 months.	Ops	2	C
2. What were the actual instructions on the permit?	Ops	2	C
3. Evaluate acequacy of written tag out direction (results may be changed to AD).	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-20

DESCRIPTION:

How can an operator get a remote emergency start of the D/G's from the control or relay room?

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Define how to get an emergency start of the Diesel Generators.	Tech	2	C
2. Evaluate manual emergency start of the Diesel Generators.	NPE	2	C
3. Evaluate the necessity of D/G emergency start capability from the Control Room other than by the methods currently available.	NPE	3	

Note: Action item 2-84-04-09 includes related items.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-21

DESCRIPTION:

D/G "A" was manually tripped immediately after its manual start due to large frequency oscillation.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Support MT/IC on evaluation of Diesel Generator "A" Frequency Oscillations.	Tech	1	C
2. From operator interview, how large were frequency oscillations?	Comp	1	C
3. Review records regarding performance of "A" D.G. (i.e., oscillations).	Maint	2	
4. Evaluate testing for "A" D/G.	S&T	1	C
5. Review/evaluate Diesel Generator test program for adequacy with respect to determining Diesel Generator performance.	NPE	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-22

DESCRIPTION:

Training Concerns.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Describe administrative program to assure required operator training is performed.	Ops	1	C
2. (a) Evaluate present program.	Ops	1	C
(b) Revise program as required.	Ops	2	
3. Review Station Program for methods of assuring Non-Routing Training is performed.	Comp	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-23

DESCRIPTION:

RCIC flow indication on GETARS.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Operator RCIC action.	Comp	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-24

DESCRIPTION:

Use of Wide Range Level During Event.

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. What Level Control Instruments were used during event?	Comp	1	C
2. Which level Instrument indicated on GETARS? (Is label correct?)	I&C	1	C
3. Determine which level instruments remain powered. - Notify Ops to correct ED.	Tech	1	C
4. Correct ED as required to 'identify level instruments'.	Ops	1	C
5. Review and revise as required procedure, including ON-117-001 and 002, and ON-217-001 and 002.	Ops	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-25

DESCRIPTION:

D/G Reset

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Write a procedure for reset of D/G on OV trip.	Ops	1	C*
2. Perform training.	Trng	1	C
3. How to reset the trips for various D/G trips AR-0DA-521, 0DB, 0DC, 0DD.	Tech	1	C

* Note: Item 1 closed pending NRC review.

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-26

DESCRIPTION:

Reg Guide 1.47

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Does our present design meet the intent of Reg. Guide 1.47 with respect to control power disconnect supervision, specifically the 30A fuse circuit.	NPE	2	
2. Review adequacy of our present design with respect to Reg. Guide 1.47 as associated with Control Power disconnects, specifically the Bus/DG Auxiliary relay, Control D.C. Power Knife Switch.	NPE	2	
3. Review and revise as appropriate monthly Surveillance Maintenance (SM) procedures to incorporate provisions for continuity checks on non-supervised circuits so as to assure full closure.	Maint	4	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-27

DESCRIPTION:

Suppression Pool Temperature Loss

ACTION	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Was SPOTMOS lost during the event?	Tech	2	C
2. Provide a description of how to reset.	Tech	3	
3. Revise ON-117 & 217.	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-28

DESCRIPTION:

08 & 09 Breakers

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. If the 13.8 Bkrs were open, the 08 & 09 Bkrs could be tripped; but could they be closed again due to the 27 relay (Knife Switch).	Tech	1	C

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-29

DESCRIPTION:

Power Transfer Switches

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Listing of all Power Transfer Switches. (Manual and Auto)	NPE	3	
2. Determine present lineup of all Power Transfer Switches and how these are checked and controlled.	Ops	3	
3. What is the desired lineup for maximum reliability?	NPE	3	
4. Review labels versus OP's/Col's and revise accordingly.	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-30

DESCRIPTION:

Loss of AC Instrument Indication

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Does the present design provide adequate instrumentation during a loss of AC power. Is the present instrumentation of sufficient range and is it in accordance with the General Design Criterion?	NPE	3	
2. Perform an HFE Review of Instrumentation Locations for instruments used during a loss of AC power.	NPE	3	
3. Are there sufficient instruments available for the operating staff to properly perform their activities during loss of AC power? a. Are ranges proper? b. Are locations proper? c. Are there a sufficient number of instruments?	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-31

DESCRIPTION:

Independent Verification

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Review the Station Program for Independent Verification and provide recommendations (Common Mode Failure Considerations)	Comp	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-32

DESCRIPTION:

Review of standard electrical operating practices.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Review of standard electrical practices.	Ops	3	
2. Poll the operators for review of standard electrical operating practices.	Comp	3	

PP&L Pennsylvania Power & Light Company
Two North Ninth Street • Allentown, PA 18101 • 215/770-5151

August 24, 1984

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

SUSQUEHANNA STEAM ELECTRIC STATION
LICENSEE EVENT REPORT 84-013-00
ER 100450 FILE 841-23
PLA-2290

Docket No. 50-388
License No. NPF-22

Attached is Licensee Event Report 84-013-00. This event was determined reportable per 10CFR50.73(a)(2)(v), in that during performance of a Loss of Offsite Power Test the diesel generators failed to start.

H.W. Kaiser
Superintendent of Plant-Susquehanna

KWS/pjg

cc: Dr. Thomas E. Murley
Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
631 Park Avenue
King of Prussia, PA 19406

Mr. R.H. Jacobs
Senior Resident Inspector
U.S. Nuclear Regulatory Commission
P.O. Box 52
Shickshinny, PA 18655

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-33

DESCRIPTION:

Review of Labeling Blackout Instrumentation.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Evaluate advisibility of Labeling Blackout Instrumentation	Tech	2	

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UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-34

DESCRIPTION:

Staffing

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Given the type of event, was our Operating Staffing adequate? (2 Units worst case)	Ops	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-35

DESCRIPTION:

Procedure Review: 480V, 4KV & 13.8KV, 250VDC, 125VDC, and Diesel Generator cubicles.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Review for adequacy SM's, PM's, OP's, and SO's that enter 480V, 4KV, 13.8KV L.C., 250VDC, 125VDC, and Diesel Generator cubicles.	Ops	3	
2. Review for adequate control, PM's that enter 480V, 4KV, 13.8KV L.C., 250VDC, 125VDC, and Diesel Generator cubicles.	Maint	3	
3. Review for adequate control, ST's that enter 480V, 4KV, 13.8KV L.C., 250VDC, 125VDC, and Diesel Generator cubicles.	S&T	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-36

DESCRIPTION:

Review of RHR and CS circuit breaker response for various combinations of Motive and Control Power availibility.
Examples: a) Closure of circuit breaker on a "dead bus".
b) Closure of circuit breaker on a "dead bus" with no control power to under voltage relays.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Conduct review	NPE	2	
2. Conduct training	Trng	2	

UNIT 2 SCRAM NO. 02-84-
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-37

DESCRIPTION:

Recorder Pen Colors Discrepancy between Unit 1 and 2 HFE Post Accident Inst. Levels, Pressure.

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Resolve recorder pen color differences in Control Room Recorders identified during event.	Tech	3	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-38

DESCRIPTION:

Communications

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Write radio communications procedure. Include unit separation requirements.	Ops	2	

UNIT 2 SCRAM NO. 02-84-04
ACTION ITEMS OF 07/30/84

ACTION ITEM NO.
2-84-04-39

DESCRIPTION:

Pre-Test Walk-Through

ACTION:	RESPONSIBLE GROUP	PRIORITY	STATUS
1. Test Director to walk through with Operations and involved primary groups which have an active role prior to major tests.	S&T	4	

UNIT 2 SCRAM NO. 02-84-04
PRIORITY 1 ACTION ITEMS REQUIRED FOR STARTUP

OPERATIONS AND TRAINING

ITEM NO.	ACTION ITEM NO. 2-84-04-	
1.	05-10	Verify that there are no 480V Load Center alarms indicating open D.C. Knife Switches.
2.	09-6	Provide procedure changes to NRC for their review.
3.	10-3	Conduct training on indications available to detect loss of Control Power to 13.8KV, 4KV, and 480V LC.
4.	10-6	Revise SO or Round's Sheets to include Supv/Bkr. Control Lights to 4KV SWGR. Training to be provided prior to procedure use.
5.	12-3	Conduct Operator Training regarding Full Core Display Response to LOOP.
6.	17-1,3	Conduct Operator Training required for Startup.
7.	25-2	Perform training on Diesel Generator Trip Resets.

STARTUP AND TEST

ITEM NO.	ACTION ITEM NO. 2-84-04-	
1.	06-3	Test the 'C' Diesel Generator ability to close in on a dead bus with under-voltage relay disabled. Have NRC review test procedure and witness test.

TECHNICAL

ITEM NO.	ACTION ITEM NO. 2-84-04-	
1.	18-1	Conduct PORC prior to Startup (Notify NRC prior to meeting).

PP&L Pennsylvania Power & Light Company
Two North Ninth Street • Allentown, PA 18101 • 215/770-5151

September 13, 1984

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

SUSQUEHANNA STEAM ELECTRIC STATION
LICENSEE EVENT REPORT 84-013-00
ER 100450 FILE 841-23
PLA-2311

Docket No. 50-388
License No. NPF-22

Attached is an addition to Licensee Event Report 84-013-00. These attachments were included with Licensee Event Report 84-013-00, but failed to get transmitted.

H.W. Keiser
Superintendent of Plant-Susquehanna

RWS/pjg

Attachment

cc: Dr. Thomas E. Murley
Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
631 Park Avenue
King of Prussia, PA 19406

Mr. R.H. Jacobs
Senior Resident Inspector
U.S. Nuclear Regulatory Commission
P.O. Box 52
Shickshinny, PA 18655

LICENSEE EVENT REPORT (LER)

APPROVED OMB NO. 3150-0104
EXPIRES: 8/31/85

FACILITY NAME (1): St Lucie Unit 2

DOCKET NUMBER (2): 0 5 0 0 0 3 8 9

PAGE (3): 1 OF 1

TITLE (4): Reactor Trip Due to Low Steam Generator Level

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBERS
0 2	0 9	8 4	8 4	- 0 0 4	- 0 0	0 3	0 9	8 4	NA	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): 1			X		
POWER LEVEL (10): 1 0 0					

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER: AREA CODE
Bruce Parks, Senior Plant Engineer	3 0 5 4 6 5 - 3 5 5 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
B	S J	P	I 0 7 5	Y		B	S B	R V	C 7 1 0	Y
X	S D	P	A 1 8 0	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)

While at 100% power the main feedwater pump tripped due to low suction pressure. The reactor subsequently tripped on Low SG Level. Following the trip the 2C auxiliary feedwater pump started then tripped on overspeed. A single steam safety on the "A" steam generator also stuck partially open following the trip. Approximately 40 minutes was required to reseat the safety. Cooldown from the open safety was successfully controlled.

The cause of the low suction pressure to the feedwater pumps was not positively determined. Condensate pump vent line design probably contributed. The design is being changed to allow proper venting during strainer cleaning.

The 2C auxiliary feedwater pump tripped due to transients on a power supply during auxiliary feedwater actuation. The cause was not immediately known. However, repeated testing, over a period of 6 days, revealed the problem. A modification has been completed to eliminate this problem.

The safety stuck open because a cotter pin was missing from a spindle nut. When the safety opened (as expected) the nut vibrated down and held the valve partially open. The nut pin was replaced and all safeties were checked.

This is the first LER of a reactor trip caused by a trip of a feedwater pump.

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PDR ADOCK 05000389
S PDR

NRC Form 366

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)
ST. LUCIE UNIT 2	0 5 0 0 0 3 8 9	1 OF 0 1

TITLE (4): ~~REACTOR TRIP DUE TO LOSS OF TURBINE LOAD - PMG FAILURE~~ generator exciter field

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	2 1	8 4	8 4	0 1 1	0 0	1 2	2 6	8 4	N/A	0 5 0 0 0
										0 5 0 0 0

OPERATING MODE (9)	POWER LEVEL (10)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
1	0 6 8	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
Susan D. Ferrel Shift Technical Advisor	AREA CODE: 3 0 5 4 6 5 - 3 5 5 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 L	P M G	W 1 2 0	N							

SUPPLEMENTAL REPORT EXPECTED (14)

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

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

At 9:27 a.m. 11-21-84 the reactor was automatically tripped from 68% power due to loss of load. The loss of load was due to a generator exciter field failure. All automatic functions performed as designed with the exception of the C Auxiliary Feed Pump, which received its start signal, attempted to start, and tripped on overspeed. The "B" Auxiliary Feed Pump functioned properly and provided the needed feed flow to the Steam Generators. The cause of the overspeed trip was the pump spinning due to steam leakage. The leakage has been corrected and the pump spinning stopped.

The cause of the loss of field excitation was determined to be due to failure of the exiter bearing which allowed the rotor to drop slightly and rub the Permanent Magnet Generator (PMG). The bearing and the PMG have been replaced and alignment and other checks performed. No cause for the failure of the bearing was able to be determined.

The Unit was returned to power operation. No adverse consequences to the health or safety of the public resulted from this event.

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S PDR

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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)
La Crosse Boiling Water Reactor	0 5 0 0 0 4 0 9	1 OF 0 4

TITLE (4)
Loss of Offsite Power

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 6	8 4	8 4	—	0 1 1	— 0 0	0 8	0 8	8 4		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)							
3	20.402(b)	20.405(c)	X	50.73(a)(2)(iv)		73.71(b)	
POWER LEVEL (10)	20.405(a)(1)(i)	50.36(c)(1)		50.73(a)(2)(v)		73.71(c)	
0 0 0	20.405(a)(1)(ii)	50.36(c)(2)		50.73(a)(2)(vii)		OTHER (Specify in Abstract below and in Text, NRC Form 366A)	
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	20.405(a)(1)(iv)	50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)			
	20.405(a)(1)(v)	X 50.73(a)(2)(iii)		50.73(a)(2)(x)			

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER
Lynne S. Goodman, LACBWR Operations Engineer	AREA CODE 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	
C	F K	X P T	W 1 2 0	N							
X	E D	B K R	A 1 8 0	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)

During a storm, the potential transformer in the LACBWR switchyard shorted out due to the accumulation of wet, dead mayflies on it. A loss of offsite power resulted. The reactor was in the hot shutdown condition at the time, with primary coolant at 395° F. Both emergency diesel generators (EDG) started, but the 1B EDG's output breaker did not close. Offsite power was regained in 20 minutes. The Technical Specification testing required when an EDG is inoperable were performed approximately 6.5 hours after the loss of offsite power, rather than 4 hours. The 1A EDG and its breaker lineup had demonstrated their operability during the event. Priority was placed on achieving a stable, knowledgable plant condition rather than performing the official surveillance tests.

Extensive troubleshooting was performed on the 1B EDG output breaker and its closing circuit. After the breaker toggle rollnut was lubricated, the breaker tested satisfactorily. The potential transformer was replaced.

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(9-83)

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PDR ADOCK 05000409
S PDR

At 1750, the potential transformer (XPT) in the LACBWR switchyard shorted out, causing protective devices (87) to operate, opening breakers (BKR) resulting in a loss of offsite power. The reactor (AC)(RCT) was in the hot shutdown condition at the time, with primary temperature at 395° F, during a plant cooldown. Both emergency diesel generators (EDG)(DG) started, but the 1B EDG output breaker, 452 EGB, did not close, leaving the 1B Essential Bus (EB)(BU) without power. The breaker could not be closed using the control switch (HC) in the control room. Equipment which tripped due to the loss of offsite power included both Forced Circulation Pumps (FCP)(AD) (P), 1B Seal Inject (SI) Pump, 1A Condensate Pump (SD), both Low Pressure Service Water Pumps (KG), 1A Circulating Water Pump (KE), 1A Shield Cooling Pump, 1A Component Cooling Water Pump (CC), 1A Fuel Element Storage Well Pump (DA), and the PASS vacuum pump (IL), which maintains isokinetic flow through the stack monitors (MON).

At 1810, offsite power was regained, but the 1B Essential Bus could not be energized. Some equipment was restarted. A successful attempt was made to close the 1B EDG output breaker locally, which energized the 1B Essential Bus. The normal alignment was then tried, with 452-52B, the normal feed breaker closed, and 452 EGB open. This also worked. The 1B EDG was then returned to "auto". Breaker 452-52B tripped open, leaving the bus de-energized. Breaker 452 EGB did not close. Only by placing the 1B EDG control switch to "OFF", was Breaker 452-52B able to be closed, re-energizing the bus. This action was completed at about 1915.

At 1920, the operating crew attempted to start 1B SI Pump, but could not. It was postulated that "load shedding" features prevented the 1B SI Pump from starting. The 1A SI Pump, which was tagged out, was checked to see if maintenance was in progress. Since the pump appeared intact, the tags were cleared at 2000 and the 1A SI pump started. The FCP's were then started. The PASS vacuum pump would not restart after restoration of power. The standby pump was placed in service.

At approximately 1815, the Shift Supervisor and STA determined that an unusual event had existed. Notifications were hampered by the PABX telephone (TEL) system (FI) being out of service. Notifications were made using NAWAS, the red phone, the separate microwave tie trunks, and sheriff's radio.

Troubleshooting was conducted on the 1B EDG output breaker. A blown fuse (FU) was found in the control power circuit for 452 EGB. The breaker's spring release coil (CL), which allows the breaker to close, was found burnt out, which could have caused the fuse to blow. The coil and fuse were replaced. The rework was tested at 0045 with unsatisfactory results. Further troubleshooting led to the discovery that 2 of 4 primary fuses for the undervoltage potential transformer on 1B Essential Bus were blown. The trip circuit for 452-52B comes through relays which are in the circuit when the diesel is in "Auto".

At approximately 0350, Alarm (ANN) F1-5, "Static Inverter Trouble" annunciated due to decreased input voltage. It was determined that the input breaker to the Diesel Building Battery Charger (BYC) was open and probably had been since the power transient. An overvoltage trip was probably actuated during the electrial transient before the protective devices operated. The breaker was closed. Alarm F1-6, "Diesel Building Battery Charger" had been in an alarm status.

Further troubleshooting and testing was conducted on the 1B Essential Bus feed breakers and circuitry. The 1B EDG output breaker was one of four 480V breakers which had not yet experienced preventive maintenance (PM) since the PM program on 480V breakers had been instituted in 1982-3. Priority had been placed on the older breakers. The 1B EDG output breaker was an Allis-Chalmers LA 1600A breaker manufactured in August, 1975. The breaker was operating sluggishly on the bench and some hardened grease was apparent. Following the PM on the breaker, the post-maintenance test was again unsuccessful. The toggle rollnut, which knocks the latch off center during the closing cycle, was lubricated.

At 1801 on July 17, a successful test of the breaker was performed, which checked the diesel starting and assuming the 1B Essential Bus load on an undervoltage condition on the bus. Additional successful tests of the system were conducted on July 18, It was determined that during the loss of power, the 1B EDG output breaker received a closing signal, but did not close. The spring release coil burnt out due to the sustained closure signal, which in turn caused the control power circuit fuse to blow. The two undervoltage fuses on the 1B Essential Bus blew during the electrical transient. These fuses did not affect the closing ability of the 1B EDG output breaker, but did simulate the existence of an undervoltage condition on the bus.

It was determined that a bus undervoltage auxiliary relay (27) prevents 1B SI Pump from starting if an undervoltage condition exists or existed on the 1B essential bus until after the 1B EDG output breaker closes, which clears the signal locked in by the auxiliary relay. The blown undervoltage fuses continued to simulate an undervoltage condition on the bus, after power was restored. Therefore, the 1B SI Pump breaker could not be closed until after the fuses were replaced and the 1B EDG output breaker was successfully closed.

The PASS vacuum pump was restarted about 1000 on July 17. The overload trip had to be reset before the pump would start. The overload condition is believed to have occurred during the electrical power transient. The standby pump was returned to standby after the main pump was started.

On July 18, offsite power was disconnected during a planned, proceduralized evolution in order to replace the potential transformer in the LACBWR switchyard. The other LACBWR switchyard transformers were also cleared of mayflies while de-energized.

A similar incident had occurred July 5, 1975. The potential transformer was a Westinghouse Line-to-Line 69 kV Potential Transformer, Type APT-350. The mayflies had accumulated mainly from a hatch the previous night. The storm wet the mayflies, which then shorted out the transformer. Mayflies are attracted to the LACBWR site by the bright security lighting.

A Generator Plant 125V DC (EI) ground alarm had annunciated among others, during the loss of offsite power. It had not cleared when power was restored. The ground was traced to the closing circuit of Breaker 452 M1B, the 1B 480V Bus (EC) Main Feed Breaker. While offsite power was disconnected on July 18, this breaker and its circuitry were examined, with no problems identified. The ground did not return when the circuit was re-energized.

The remaining 480V breakers which had not yet been examined during the 480V breaker preventive maintenance program were maintained. The breakers were tested after return to service.

The 1A EDG monthly surveillance test and the breaker alignment check were performed at approximately 0025 (diesel start) and 0015, respectively on July 17. This was somewhat beyond the 4 hours required by T.S. 4.2.3.1.1.a. The technical specification requires in part, that when an EDG is inoperable during Operating Conditions 1,2 or 3, that a timed start be performed on the other diesel and an electrical alignment check be performed within 4 hours and every 12 hours thereafter. The automatic start and load supplying that the 1A EDG performed upon the loss of offsite power did demonstrate that it could perform its function and that the electrical lineup was appropriate. Afterwards, priority was placed on achieving a stable, knowledgable plant condition. The surveillance test results were acceptable.

Whether the 1B EDG output breaker not closing should be considered a failure of the 1B EDG was evaluated per Technical Specification Table 5.2.10.1.2-1. During the monthly surveillance test, the diesel generator is started and connected to a test load. The EDG output breaker is not tested and cannot be. The 1B EDG output breaker can only be closed if the 1B Essential Bus Main Feed Breaker, 452-52B, is open. Opening Breaker 452-52B during plant operation would momentarily disrupt power to the 1B Essential Bus and cause a reator scram. Therefore, the 1B EDG is connected to a test load, not the essential bus during the monthly surveillance test, which differs from most other nuclear plants. Due to these unique circumstances, the 1B EDG output breaker is not part of the diesel generator unit. The breaker's failure is not a failure of the diesel generator. If this breaker failure had been considered an EDG failure and the test frequency increased (1B EDG did not start and load within the required time during 1 of the last 100 valid tests), the test performed at the increased frequency would not be checking the operation of the output breaker. This circumstance supports the position that at LACBWR, a failure of a diesel output breaker is not a failure of the diesel generator unit.

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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)	DOCKET NUMBER (2)	PAGE (3)
Grand Gulf Nuclear Station - Unit 1	0 5 0 0 0 4 1 6	1 OF 0 2

TITLE (4)

Reactor Scram On Low Water Level

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									NA	0 5 0 0 0
0 5	2 5	8 4	8 4	— 0 3 0	— 0 0	0 6	1 4	8 4		0 5 0 0 0

OPERATING MODE (9)	THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: (Check one or more of the following) (11)			
2	20.402(b)	20.405(c)	X 50.73(a)(2)(iv)	73.71(b)
POWER LEVEL (10) 0 1 0 4	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
Ronald W. Byrd/Licensing Engineer	6 0 1 4 3 7 - 2 1 4 9

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

CAUSE	SYSTEM	COMPONENT	MANU-FAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANU-FAC-TURER	REPORTABLE TO NPRDS	
X	S D	F C V	C 6 0								
B	B N	X C V	W 2 9 0								

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)

The reactor scrammed on a low water level 3 signal following condensate booster pump and reactor feed pump trips. Operators were unable to manually start RCIC to restore the level prior to the scram.

A broken position arm linkage on the condensate minimum flow control valve allowed the valve to open creating a flow path to the condenser, bypassing the condensate booster pumps. The condensate pump, booster pump, and feed pump immediately tripped on low suction. The RCIC turbine tripped on overspeed when operators attempted to manually start the system to restore the water level. Following the scram RCIC was started and operated properly. A modification was made to the RCIC turbine governor valve to restrict it from full opening and producing the turbine overspeed trip.

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S PDR

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NRC Form 366A (9-83)

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)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
Grand Gulf Nuclear Station - Unit 1	0 5 0 0 0 4 1 6	8 4	— 0 3 0	— 0 0	0 2 OF 0 2

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

On May 25, 1984, at approximately 0915 hours, a reactor scram occurred at low water level number 3, 11 inches above instrument zero. The low level was due to a trip of the condensate pump, condensate booster pump, and feedwater pump and the inability to manually start RCIC to restore level.

On the morning of May 25, 1984, maintenance personnel began to investigate the cause of a dual indication on valve N19F504, the condensate minimum flow control valve. The cause was determined to be a high voltage output on the controller which was then adjusted. As the technician touched the positioner arm linkage to check for tightness, a noise was heard inside the positioner and the valve moved to full open. A later investigation revealed a broken linkage and a bent valve stem positioner bracket which occurred at an unknown time.

With the valve full open, a path was created to the condenser bypassing the booster pumps. The running condensate and condensate booster pump and feedwater pump tripped immediately on low suction at 0910 hours. The reactor was operating at approximately 4 percent thermal power, 540°F, and 920 psig. Operators attempted to restart the condensate system but the condensate pumps again tripped. The reactor water level began to decrease from 38 inches above instrument zero. Operators tried twice to manually start RCIC but both times the RCIC turbine tripped. When RCIC was initially started, it operated properly and momentarily stabilized water level at approximately 27 inches before tripping on overspeed. It was reset and again tripped on overspeed. The turbine evidently oversped on initial startup, but the trip valve did not close instantaneously, allowing RCIC to operate for a short time. A reactor scram occurred on a low level 3 signal at 0915 hours. By 0927 hours all main steam inboard isolation valves were manually closed by handswitch. RCIC was restarted and began feeding the vessel at 0928 hours with the vessel level at 10 inches below instrument zero. The normal RCIC automatic initiation is at 41.6 inches below instrument zero at which time HPCS, which was available, would also start. By 0934 hours the condensate system was made available by isolating the recirculation flow path. RCIC was then secured with the water level at approximately 37 inches above instrument zero.

The N19F504 valve positioner arm was replaced and the valve was restored to service by 1640 hours the same day. A modification was made to the RCIC turbine governor valve to restrict it from full opening and causing a turbine overspeed trip. The turbine trip valve was lubricated and retested satisfactorily. Startup recommenced at 0420 hours on May 26, 1984.

NRC FORM 366A (9-83)

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1 REPORT NUMBER (Assigned by TIDC add Vol. No., if any)

NUREG/CR-4674
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Vol. 4

2 TITLE AND SUBTITLE

Precursors to Potential Severe Core Damage Accidents: 1984, A Status Report (Appendices C, D and E)

3 LEAVE BLANK

4 DATE REPORT COMPLETED

MONTH: April YEAR: 1987

5 AUTHOR(S)

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

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11a TYPE OF REPORT

Technical

b PERIOD COVERED (Inclusive dates)

1984

12 SUPPLEMENTARY NOTES

13 ABSTRACT (200 words or less)

Forty-eight operational events, reported in Licensee Event Reports (LERs) and occurring at commercial light-water reactors during 1984, 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 the work presented in earlier volumes in this series, which evaluated the 1969-1981 and 1985 events. The report sequentially discusses (1) the general rationale for this study, (2) the program methods for review and documentation of operational events as precursors, (3) the use of the conditional probability of subsequent severe core damage estimates to rank precursor events, and (4) initial conclusions from the assessment of 1984 events.

14 DOCUMENT ANALYSIS - a KEYWORDS/DESCRIPTORS

Nuclear Power Plant
Accident Sequence Precursors
Risk Analysis
Event Trees
Core Damage Probability
Accident Sequences
Licensee Event Reports
Operational Events

b IDENTIFIERS/OPEN-ENDED TERMS

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