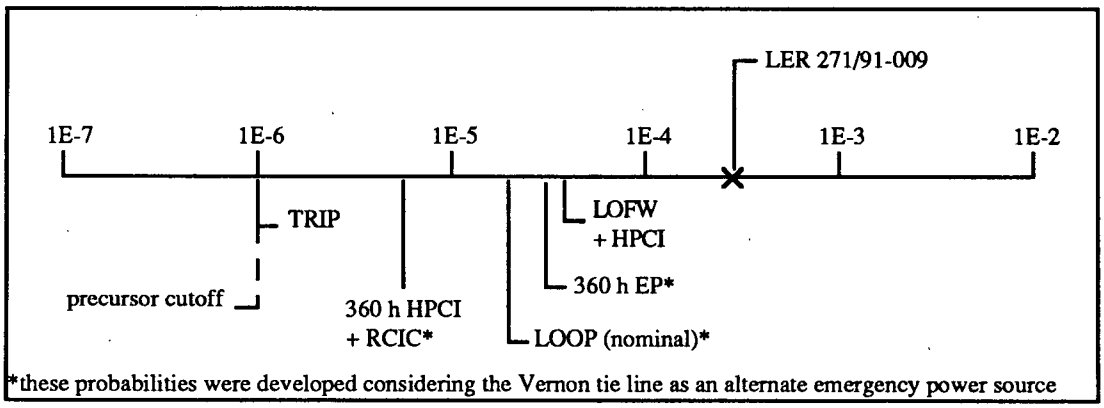
ACCIDENT SEQUENCE PRECURSOR PROGRAM EVENT ANALYSIS

LER No.: 271/91-009, 271/91-012
Event Description: Extended loss of offsite power
Date of Event: April 23, 1991
Plant: Vermont Yankee

Summary

A loss of offsite power (LOOP) occurred at Vermont Yankee during switchyard maintenance activities. Both emergency diesel generators (EDGs) started and provided power to their respective safety-related buses. Recovery of offsite power, which took ~13 h, was complicated by communications and organizational difficulties and travel time for support personnel. The conditional core damage probability estimated for this event is 2.9 x 10^{-4}. The relative significance of the event compared to other postulated events at Vermont Yankee is shown below.



Event Description

On April 23, 1991, at 1448 hours, during normal operation with the reactor at 100% power, a reactor scram occurred as a result of a generator/turbine trip on generator load reject due to the receipt of a 345-kV breaker failure interlock (BFI) signal. This resulted in a total loss of 345-kV and 115-kV offsite power. Both EDGs provided power for essential safety-related systems during the loss of power until approximately 0430 hours on April 24, 1991, at which point 345-kV offsite power was restored and backfed through the station auxiliary transformer. Restoration of 115-kV power had been accomplished at 1925 hours on April 23, 1991; however, it was decided to continue supplying power to the emergency buses via the EDGs since only one offsite breaker was closed and testing was continuing in the switchyard. A chronological list of activities during this event is provided in Table 1.

Prior to the event, the plant was in the process of completing the replacement of switchyard battery bank 4A. All work, with the exception of restoring the connection of the battery bank to the DC 4A bus, was completed without incident. While performing the final sequence of actions necessary to reconnect the battery bank to DC bus 4A, a voltage transient occurred on the bus when battery charger 4A-5A was disconnected from the DC-5A bus (this rendered the DC-4A bus susceptible to voltage spikes due to the absence of a battery bank). The voltage transient caused the failure of zener diodes in the trip logic cards for several breakers, which initiated the BFI signals.

The recovery of offsite power began with an attempt to restore 115-kV power from the switchyard via 115-kV breaker K186 and the startup transformers. This was determined to be the easiest path in obtaining an offsite power source due to the need to close only one breaker. However, the K1 breaker BFI signal remained locked in due to a failed zener diode on the associated trip card and prevented the closure of K186. At 1925 hours, the BFI signal from the K1 to the K186 breaker was blocked, allowing reclosure of K186 and subsequent restoration of power to 4-kV buses 1 and 2. The K1 BFI trip card was subsequently replaced with an identical card from a spare breaker. Closure of the K186 breaker required 4 h, in part because of the length of time required for New England Power Service Co. (NEPSCO) relay technicians to travel to Vermont Yankee from Providence, Rhode Island.

After 115-kV power was established through the K186 line, efforts to close breaker K1 continued to establish a more reliable source of 115-kV power through the auto transformer. However, due to communication problems between Vermont Yankee and the New England Switching Authority (REMVEC) concerning priorities over breaker testing, a 3-h delay occurred before 115-kV power was made available through the auto transformer.

In a parallel effort, at 1900 hours, operation orders were given to complete backfeeding of the plant from the 345-kV switchyard through the main transformer. This effort was also hampered by communication problems with REMVEC, personnel delays (including a 45-min delay while exiting the radiologically controlled area because of noble gas activity), and equipment malfunctions. Backfeeding was completed at 0410 hours on April 24, 1991. In all, recovery of offsite power took ~13 h.

Reduced EDG and air compressor cooler service water (SW) flow was observed during the event. This was caused by the SW discharge alignment, in which SW was directed to the cooling tower basin instead of to the main discharge structure. Directing SW to the cooling tower basin had been the standard mode of operation since 1987. This "alternate" lineup resulted in higher flow resistance and significant backpressure at the discharge of both EDG heat exchangers. An analysis performed shortly after the event concluded that the EDGs would perform acceptably with the reduced SW flow immaterial

of SW temperature. However, this conclusion was later revised (LER 271/91-012 Rev. 1); it was determined that, at maximum SW temperatures, the EDGs would perform acceptably with the loads experienced during the April 23, 1991, event (approximately 33% of rated load: four SW pumps, two residual heat removal (RHR) SW pumps, two RHR pumps, plus lower power loads). The utility apparently concluded that adequate SW margin existed during the event, when SW temperature was 48°F.

During the recovery, the torus volume increased above Technical Specifications limits twice. The volume increase was caused by condensation of steam being used by the high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems. The second time that torus volume increased above limits, the volume stayed above the limit until all AC power was restored. The torus water volume increased because the radwaste system could not handle the addition of water (condensed steam) used by the HPCI and RCIC systems due to the lack of normal AC power.

Also during the recovery, RCIC tripped when an operator incorrectly matched flow during changeover from manual to automatic operation mode. RCIC was immediately reset and restored to the automatic mode of operation.

Additional Event-Related Information

A simplified diagram of the Vermont Yankee AC power system is shown in Fig. 1. Each EDG is capable of supplying 100% of the emergency loads required under postulated design-basis accident conditions. Each of the EDGs has a continuous rating of 2750 kW and a 7-d rating of 3000 kW. Each EDG is physically and electrically independent of the other and of any offsite power source.

Tables 2 and 3 indicate emergency loads connected to 4.16-kV buses 3 and 4 and the associated 480-V buses. In addition to automatically and manually started loads, the EDGs can supply other loads on buses 3 and 4 and the associated lower voltage buses, if required.

The EDGs receive cooling water via separate SW headers. Each header is supplied by two SW pumps located at the intake structure. The headers are cross-connected on the upstream and downstream side of the in-line mechanical strainers, and normally three of four pumps are operated to remove plant service heat loads. One pump provides sufficient capacity to remove head loads during accident conditions.

If a loss of AC power occurs on emergency bus 3 and diesel generator 1B (connected to bus 3) fails to start or run, then the Vernon Hydroelectric Station 4.16-kV tie line can be connected to bus 3 through a manual switching operation in the control room. If the above described situation arises on emergency bus 4, the Vernon tie line can be connected manually to bus 4.

The 4.16-kV tie from the Vernon Hydroelectric Station to Vermont Yankee is connected through a transformer to the Vernon Hydroelectric Station 2.4-kV bus system. This bus system is connected to the station's ten hydroelectric generators and also is connected through six transformers to the outside 69-kV switchyard. Four 69-kV transmission lines from this switchyard connect the Vernon Hydroelectric Station to the interconnected transmission system of New England. Thus, the Vernon Hydroelectric Station 2.4-kV bus system is normally energized and available whether the Vernon generators are operating or not.

The switching arrangement for connection of the Vernon tie line to a Vermont Yankee emergency bus is shown in Fig. 1. Three circuit breakers are used: 3V, to connect to emergency bus 3; 4V, to connect to emergency bus 4; and 3V4, which is the feeder breaker for the Vernon Hydroelectric Station tie line. The control switches for the three breakers are located on the electrical section of the main control board, and the availability of the Vernon tie line is indicated by a voltmeter and ammeter adjacent to the control switches. In addition, there is a direct telephone circuit between the main control room and the Vernon Hydroelectric Station to allow communications between the two stations.

ASP Modeling Assumptions and Approach

The event has been modeled as a nonrecoverable loss of offsite power. The Vernon tie line was considered to be an alternate power source to one emergency bus; a probability of 0.12 was assumed for failing to connect this power source given both EDGs fail and cannot be recovered in the short term (station blackout scenario). This was included in the model by revising the nonrecovery probability for emergency power from 0.8 to 1.0 [0.8 x 0.12]. Because of the nature of the switchyard failures and the difficulties encountered in recovering from them, the probability of failing to recover AC power prior to battery depletion was assumed to be 1.0, given that emergency power and the Vernon tie line were unavailable.

Because of the temperature of the SW system, adequate EDG cooling was assumed to be available during this event. However, to assess the impact of inadequate EDG cooling at higher SW temperatures, a sensitivity analysis was performed (the EDGs were apparently determined to be operable at all temperatures if loaded as they were during this event). In this analysis, it was assumed that both EDGs would fail if they were fully loaded — for example, if low-pressure coolant injection and core spray were actuated following automatic depressurization. To implement this assumption in the Accident Sequence Precursor LOOP model, the automatic depressurization system (ADS) was assumed failed in sequences associated with emergency power success.

Analysis Results

The conditional probability of subsequent core damage estimated for this event is

2.9×10^{-4}. The dominant sequence, highlighted on the following event tree, involves the loss of offsite power, failure of emergency power (including the Vernon tie line), and failure to recover AC power prior to battery depletion.

The assumption that the EDGs fail if fully loaded raises the conditional core damage probability to 3.1×10^{-4}.

Additional information concerning this event is included in Augmented Inspection Team report 50-271/91-13, dated June 5, 1991.

Table 1. Chronological listing of activities

Time	Activity
	April 23, 1991
14:48	LOOP from 100% power. Total loss of all 345-kV and 115-kV power. The Vernon Hydrostation was available to provide backup power to one emergency bus, if required.
14:48:45	Both emergency diesel generators started and reenergized safety buses.
14:50	HPCI manually employed to control reactor pressure and level.
15:33	Torus water volume exceeded Tech Spec limit of 70,000 ft^3. Volume was restored to within limit.
15:42	"A" station air compressor tripped due to inadequate service water cooling flow.
16:45	RCIC used for first time during event.
17:31	"B" station air compressor tripped due to inadequate service water cooling flow.
17:36	"B" station air compressor restarted. Instrument air header pressure dropped 15 psig during 5 min of air compressor unavailability.
17:59	Reserve diesel air compressor operable and hooked to outlet of "D" station air compressor. "C" and "D" station air compressors were unavailable due to the LOOP.
19:04	RCIC tripped on overspeed — operator error in the adjustment of RCIC flow controls during process of switching from manual to auto mode of operation.
19:12	RCIC operation resumed.
19:25	115-kV power restored to startup transformers. 4-kV breakers 13 and 23 were closed to reenergize buses 1 and 2, which power the normal station loads. Because testing was continuing in the switchyard with only 1 breaker closed, a decision was made to leave EDGs connected to buses 3 and 4.
21:12	Torus water volume again above 70,000 ft^3 and could not be readily reduced.
	April 24, 1991
04:10	Back-feeding 345-kV power through station auxiliary transformer completed.
04:30	Both emergency diesels secured.
19:25	Torus water volume reduced below 70,000 ft^3.
19:50	Unusual event terminated.

Table 2. Category 1 loads (automatically starting or restarting loads)

Reactor core spray cooling system
Residual heat removal system
Standby gas treatment system
All AC motor-operated isolation valves (momentary load) (except for valves connected to UPS-powered MCC-849A and MCC-89B)
Emergency AC lighting
Instrumentation and control
Service water (1 of 2 pumps)
Diesel auxiliaries, diesel room fan, and diesel air compressor
Reactor building cooling water system
Drywell cooling
Distribution transformers
Reactor building HVAC
Battery chargers

Table 3. Category II loads (manually started shutdown loads)

Standby liquid control system
Turbine turning gear
Service water system
Control rod drive system
Station and instrument air system
Containment air system
Battery chargers
Control valves (as required by above systems but not included as battery load)
Vital AC motor generator system
Residual heat removal — station service water system
Reactor protection motor generator system
Fuel pool cooling system
Control room air conditioning
Torus cooling
Turbine building cooling water
Drywell cooling

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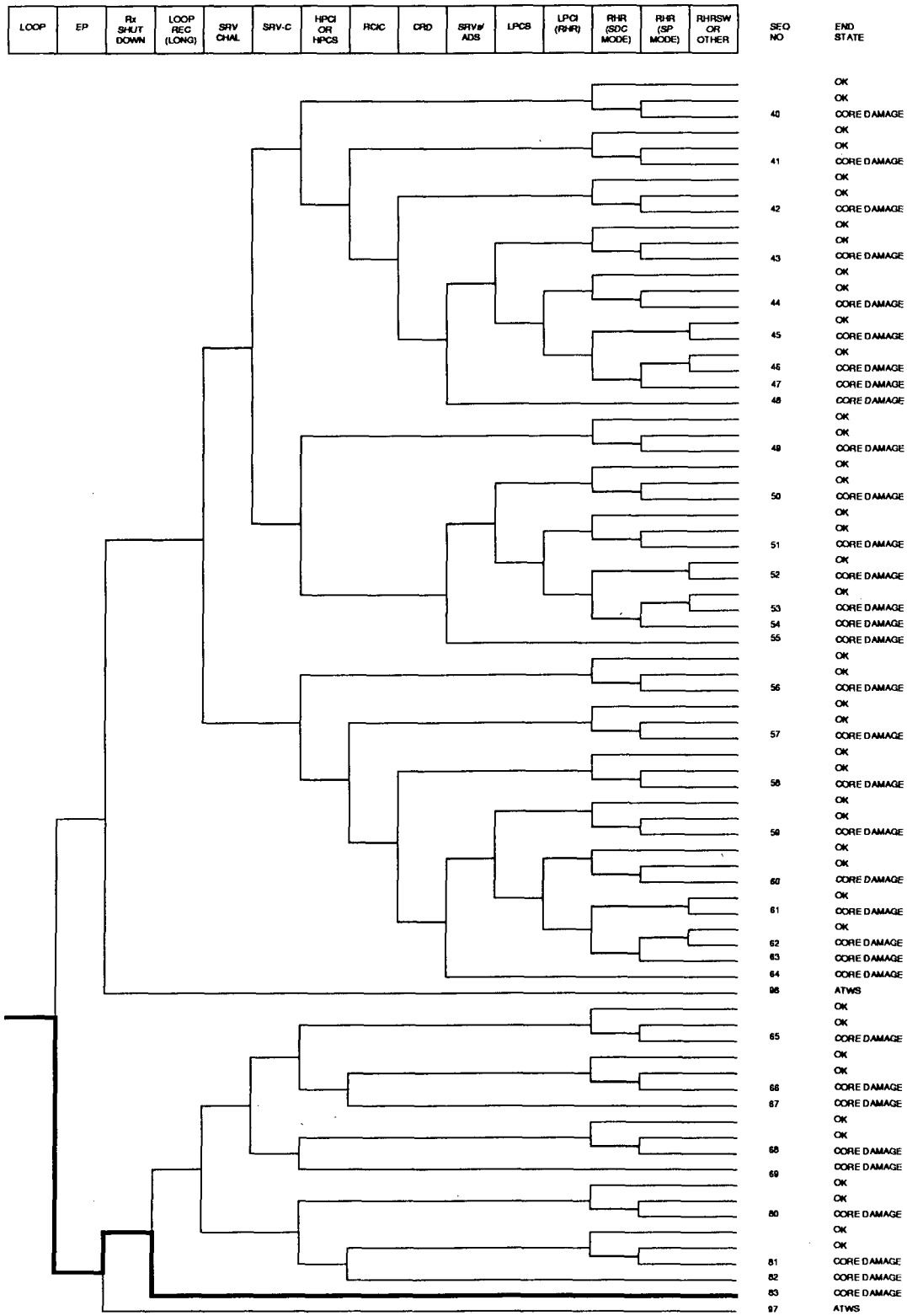
Figure 1. Vermont Yankee AC power system



Dominant core damage sequence for LER 271/91-009

CONDITIONAL CORE DAMAGE PROBABILITY CALCULATIONS

Event Identifier: 271/91-009
Event Description: Extended loss of offsite power
Event Date: 04/23/91
Plant: Vermont Yankee

INITIATING EVENT

NON-RECOVERABLE INITIATING EVENT PROBABILITIES

LOOP	1.0E+00

SEQUENCE CONDITIONAL PROBABILITY SUMS

End State/Initiator	Probability
CD	
LOOP	2.9E-04
Total	2.9E-04
ATWS	
LOOP	3.0E-05
Total	3.0E-05

SEQUENCE CONDITIONAL PROBABILITIES (PROBABILITY ORDER)

	Sequence	End State	Prob	N Rec**
83	LOOP EMERG.POWER -rx.shutdown/ep EP.REC	CD	2.8E-04	1.0E-01
98	LOOP -EMERG.POWER rx.shutdown	ATWS	3.0E-05	1.0E+00

** non-recovery credit for edited case

SEQUENCE CONDITIONAL PROBABILITIES (SEQUENCE ORDER)

	Sequence	End State	Prob	N Rec**
98	LOOP -EMERG.POWER rx.shutdown	ATWS	3.0E-05	1.0E+00
83	LOOP EMERG.POWER -rx.shutdown/ep EP.REC	CD	2.8E-04	1.0E-01

** non-recovery credit for edited case

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

No Recovery Limit

BRANCH FREQUENCIES/PROBABILITIES

Branch	System	Non-Recov	Opr Fail
trans	2.5E-04	1.0E+00	
LOOP	1.6E-05 > 1.6E-05	3.6E-01 > 1.0E+00	
Branch Model: INITOR			

Event Identifier: 271/91-009

Initiator Freq:	1.6E-05		
loca	3.3E-06	5.0E-01	
rx.shutdown	3.0E-05	1.0E+00	
rx.shutdown/ep	3.5E-04	1.0E+00	
pcs/trans	1.7E-01	1.0E+00	
srv.chall/trans.-scram	1.0E+00	1.0E+00	
srv.chall/loop.-scram	1.0E+00	1.0E+00	
srv.close	1.0E-02	1.0E+00	
EMERG.POWER	2.9E-03 > 2.9E-03	8.0E-01 > 1.0E-01	
Branch Model: 1.OF.2			
Train 1 Cond Prob:	5.0E-02		
Train 2 Cond Prob:	5.7E-02		
EP.REC	1.6E-01 > 1.0E+00	1.0E+00	
Branch Model: 1.OF.1			
Train 1 Cond Prob:	1.6E-01 > 1.0E+00		
fw/pcs.trans	4.6E-01	3.4E-01	
fw/pcs.loca	1.0E+00	3.4E-01	
hpci	2.9E-02	7.0E-01	
rcic	6.0E-02	7.0E-01	
crd	1.0E-02	1.0E+00	1.0E-02
srv.ads	3.7E-03	7.1E-01	1.0E-02
lpcs	3.0E-03	3.4E-01	
lpci(rhr)/lpcs	1.0E-03	7.1E-01	
rhr(sdc)	2.1E-02	3.4E-01	1.0E-03
rhr(sdc)/-lpci	2.0E-02	3.4E-01	1.0E-03
rhr(sdc)/lpci	1.0E+00	1.0E+00	1.0E-03
rhr(spcool)/rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/-lpci.rhr(sdc)	2.0E-03	3.4E-01	
rhr(spcool)/lpci.rhr(sdc)	9.3E-02	1.0E+00	
rhrsw	2.0E-02	3.4E-01	2.0E-03

* branch model file
** forced

Minarick
08-06-1992
10:01:45

Event Identifier: 271/91-009