Licensee Event Report No. 247-99-015

Event Description: Loss of offsite power to safety-related buses following a reactor trip and an emergency diesel generator output breaker trip open

Date of Event: August 31, 1999

Plant: Indian Point No. 2

Event Summary

On August 31, 1999, the reactor inadvertently tripped while the licensee was replacing a defective bi-stable in a pressurizer low pressure instrument channel. After the reactor trip, the station blackout logic matrix generated a blackout signal as a result of a sustained under-voltage condition at the safety-related 480-V buses. The station blackout signal stripped the 480-V buses and reloaded them onto the emergency diesel generators (EDGs). The EDG output breaker to the 480-V bus 6A tripped within 14 seconds after closing due to an over-current condition on the bus.

The conditional core damage probability (CCDP) for this event is 1.1×10^{-4}. Core damage sequences where auxiliary feedwater fails and batteries deplete are the dominant contributors to the CCDP.

Event Description

On August 31, 1999, the reactor inadvertently tripped while the licensee was replacing a defective bi-stable in a pressurizer low pressure instrument channel (Refs. 1,2). Following the reactor trip, the main generator tripped and the generator output breakers opened as designed. The 6.9-kV service buses fast-transferred to the external 138-kV supply via the station auxiliary transformer (STAUX). During the fast-transfer, while power was supplied via STAUX, an under-voltage condition (voltage dropping below the degraded voltage set point of 421-V +/- 6V) was detected on all safety-related 480-V buses. (See Figure 1 for details of the electrical distribution system.)

Normally when the STAUX tap changer is in the automatic mode, the tap changer would move to restore degraded voltage conditions in the switchyard. However, due to a defective voltage control relay, the tap changer was being operated in the manual mode at the time of the event. As the result of the voltage anomaly in the switchyard caused by the main generator trip, the tap changer was not able to correct the degraded condition. Therefore, a sustained under-voltage condition on the safety-related buses exceeded the allowable setpoint value (180 sec +/- 30 seconds). Consequently, the station blackout logic matrix generated a blackout signal. The station blackout signal stripped the 480-V buses and reloaded them onto the emergency diesel generators (EDGs).

Bus 6A loaded onto its EDG (EDG 23). Eight seconds after EDG 23 started, the output breaker from the EDG to bus 6A closed. Approximately 14 seconds later, the breaker tripped to its open position due to an over-current condition. Consequently, bus 6A lost power from both the EDG and offsite power supply. The other 480-V buses were energized by their respective EDGs.

The blackout logic prohibits the transfer of safety-related 480-V buses 2A, 3A, 5A, and 6A back to their 6.9-kV buses until the blackout logic signal is reset. With bus 6A de-energized, the under-voltage interlock prevented the reset of the blackout logic. Consequently, bus 6A remained de-energized. After approximately 7.4 hours, instrument bus 24 was lost when the voltage on DC bus 24 became low (battery charger 24 is powered from bus 6A). Offsite power was restored to 480-V bus 5A approximately 12 hours following event initiation.

Additional Event-Related Information

<u>Loss of 480-V bus 6A and consequences</u>

During this event, the reactor trip was followed by a loss of offsite power to safety-related 480-V buses. Due to tripping of the output breaker of EDG 23, emergency onsite power from EDG 23 was unavailable to 480-V bus 6A. That is, both offsite and onsite power was unavailable to bus 6A. De-energization of bus 6A caused the unavailability of power to the following risk-important equipment:

- Motor-driven auxiliary feedwater pump P-23;
- High-pressure safety injection pump P-23;
- Charging pump P-23;
- Sump recirculating pump P-22;
- Residual heat removal pump P-22;
- Block valve for one of the two pressurizer power-operated relief valves; and
- Battery charger 24.

Even though power was unavailable to loads powered from bus 6A, offsite power was available to non-safety-related loads powered from the 6.9 kV buses. Further, buses 2A, and 3A were powered from EDG 22; bus 5A was powered from EDG 21.

<u>Loss of DC bus 24 and consequences</u>

DC bus 24 is fed from two power sources. One of these sources is battery charger 24, which is powered from bus 6A. When power supply to bus 6A failed, there was no power supply to battery charger 24. The second power supply for DC bus 24 is battery 24. This battery is designed to supply its shutdown loads for a period of two hours following a plant trip and loss of all AC power. However, during this event, the battery supported the DC loads for approximately 7.4 hours without any power to the battery charger. During that period of time, power was not restored to battery charger 24. As a result, battery 24 continued to drain and the DC bus 24 voltage continued to drop. Instrument bus 24 was lost when the voltage on the DC bus 24 became too low for inverter 24 to provide AC power to the instrument bus.

When instrument bus 24 lost power, the auxiliary feedwater (AFW) flow control to steam generator 24 lost power. As a result, the flow control valve assumed its fully open position. In response, the operators secured AFW pump 22 (the turbine-driven AFW pump). Water levels in the steam generators were maintained by starting and stopping the turbine-driven AFW pump three times (in lieu of running the pump continuously while taking local-manual control of the flow control valves).

Potential for steam generator tube rupture or loss of EDG-21

The event analyzed in this report occurred on August 31, 1999. On February 15, 2000, (approximately six months later) a steam generator tube leak occurred at Indian Point 2 (LER 247-00-001, Ref. 3). During that event, steam generator leakage rapidly increased from 4 gallons per day to greater than 75 gallons per minute. Primary-to-secondary leakage (0.5 gallons per day) was first detected by condenser off-gas sampling in September 1998. The leak rate slowly increased during the next 12 months and reached 2 gallons per day when the plant tripped on August 31 due to the loss of offsite power (Ref. 4). In spite of the presence of the degraded tube, that tube did not rupture as the result of the plant transient that followed the loss of offsite power event. However, if additional mitigating system failures that could introduce additional stresses on the steam generator tubes would have occurred during the loss of power event (e.g., steam generator dry out as a result of loss of auxiliary feedwater), the degraded tube may have ruptured. The analysis includes an evaluation of the significance of this condition in addition to the evaluation of the trip and loss of EDG 23.

EDG surveillance test failure

On November 29, 1998, with the unit operating at 99% power, surveillance test PT-M21 "Emergency Diesel Generators" was being performed. After 20 minutes operation under load, the fuel injection line to number eight cylinder of EDG 21 began to leak. Operators had to terminate the surveillance and repair the leak (LER 247-98-019, Ref. 5). The condition that lead to the loss of offsite power on August 31, 1999, co-exited with this condition. Therefore, a reactor trip could have lead to a loss of offsite power as well as a loss of an EDG. The analysis includes an evaluation of the significance of this condition in addition to the evaluation of the trip and loss of EDG 23.

Modeling Details and Key Assumptions

Several changes were made to the Revision 2QA SPAR model (Ref. 6) in order to estimate the increased risk significance due to loss of bus 6A. Other changes were made to incorporate reduction in the risk since offsite power was available to balance-of-plant loads on the 6.9-kV buses. Additional changes were made to incorporate sequence-specific non-recovery factors appropriate for this event. Table 1 summarizes changes made to the SPAR model. The discussion below provides the basis for significant changes:

- *Loss of offsite power* - The loss of offsite power initiator was chosen.[1]
- *Probability of failing main feedwater (MFW)* - During this event, MFW and the main condenser, which are powered from the 6.9-kV buses, remained available to remove decay heat (Ref. 2). The SPAR model was modified to credit MFW by creating an external transfer to the MFW fault tree from the AFW fault tree used for loss of offsite power analysis.

[1] Even though the loss of power to bus 6A did not fail due to extremely severe weather, in order for examine and adjust probabilities of offsite non-recovery probabilities by individual sequences, the extremely weather loss of offsite power category in the SPAR model was used in the analysis.

- *Probability of failing the turbine-driven AFW pump* - During the event, the turbine-driven AFW pump was cycled three times in order to compensate for the failed-open flow control valve. Therefore, the failure probability of the turbine-driven AFW pump was modified to include the probability of failure from three start attempts. The failure probability of the turbine-driven AFW train to start and run (basic event AFW-TDP-FC-22) was changed from 0.033 to 0.093 { = 0.003 (fail to run) + 3 x 0.03 (fail to start)}.

- *Probability of failing feed-and-bleed cooling* - Indian Point 2 operates with both block valves for the pressurizer power-operated relief valves (PORVs) in the closed position (basic events PPR-MOV-FC-BLK1 and PPR-MOV-FC-BLK2). Both PORVs are required for feed-and-bleed cooling. With the power supply via 480 bus 6A unavailable, one block valve cannot be opened to bleed reactor coolant. Further, one of the two isolation valves (in-series) in the reactor vessel head vent used as a alternate bleed path is also powered from bus 6A. Therefore, the feed-and-bleed cooling function was not available during this event.

- *Probability of failing to recover emergency power to bus 6A* - During this event, the power on bus 6A failed because the EDG 23 output breaker tripped on over-current. The bus and EDG were not damaged; however, the bus was tagged out of service during the event. Emergency power to bus 6A could have been recovered by clearing the tag on the bus, manually starting the EDG, and then closing the EDG output breaker. The operators did not attempt to restore EDG 23 early in the event since the other two EDGs functioned properly. If the other two EDGs had failed, the operators would have attempted to recover bus 6A.

  The fault tree for EDG 23 was modified by adding a new basic event, EPS-DGN-FC-23-OB, to model the capability to re-close the output breaker. The human error probability for recovering emergency power to bus 6A was estimated using ASP Program human reliability analysis methods. Based on these methods, the estimated failure probability of basic event EPS-DGN-FC-23-OB is 0.1. Section 1 of Attachment 1 provides additional details about the human error probability calculation.

- *Probability of failing to recover offsite power to safety-related 480-V buses from 6.9-kV buses* - During this event, AC power was available in the switchyard. The operators did not rush to restore power from the switchyard to the safety-related buses since two of the three EDGs functioned properly. Had both operating EDGs failed, operators would have attempted to recover offsite power to the 480-V buses from the 6.9-kV buses.

  Human error probabilities for restoring offsite power to the safety-related 480-V buses were estimated using ASP Program human reliability analysis methods. The recovery-related basic events used in the SPAR model for the various loss of offsite power and station blackout sequences are based on the time to core uncovery (two, four, five, and six hours) and battery depletion (seven hours). The recovery failure probability for each recovery time was modified to reflect the difficulty in restoring offsite power to the safety buses based on actual conditions.

  The probabilities for failure to recover offsite power to the 480-V safety-related buses (via the 6.9-kV buses) are 1.0 when the time available for recovery is 2 hours, 0.51 when the time available for recovery is 4 hours, and 0.06 when the time available for recovery is 5 to 7 hours.

Section 2 of Attachment 1 provides additional details about the human error probability calculations.

Changes to basic event failure probabilities (OEP-XHE-NOREC-2H, OEP-XHE-NOREC-6H, OEP-XHE-NOREC-BD, OEP-XHE-NOREC-SL, and OEP-XHE-NOREC-ST) and sequence-specific non-recovery probabilities are summarized in Tables 1 and 2, respectively.

- *Probability of failure to recover offsite power by starting and aligning gas turbines* - Throughout the event, the 6.9-kV buses were powered from the offsite power supply. The capability to supply power to the 6.9-kV buses from gas turbines (basic events OEP-XHE-XM-GTSL, OEP-XHE-XM-GTST, OEP-XHE-XM-GT2, OEP-XHE-XM-GT6, OEP-XHE-XM-GTBD) do not provide any additional benefit. Therefore, recovery actions associated with the gas turbines were not credited in the analysis.

- *Probability of failing RCP seals when seal cooling is lost* - In accordance with guidance provided in Reference 7, the Rhodes Model (Ref. 8) was used to estimate the probability of failure of the reactor coolant pump (RCP) seals. The RCPs at Indian Point 2 have "improved" Westinghouse seal assemblies. Based on the Rhodes Model, the probability of failing the RCP seals with improved Westinghouse seal assemblies (basic event RCP-MDP-LK-SEALS) is 0.22.

- *Probability of opening pressurizer safety relief valves (SRVs) during transient* - Power to balance-of-plant systems used for condenser heat removal was available throughout the event. Therefore, the probability of challenges to the pressurizer SRVs (PORVs at Indian Point are blocked during power operations) was less than that expected during a typical loss of offsite power or station blackout event where secondary systems would be lost. The probability that the pressurizer safety valves open (PPR-SRV-CO-L, PPR-SRV-CO-SBO) during the event was reduced to 0.04–the value used in the SPAR model for general transients.

- *Non-recovery probabilities for individual sequences* - Table 1 shows the sequence-specific, non-recovery probabilities of dominant sequences. Table 2 provides the basis for those probabilities.

- *Time available to recover high-pressure injection in the event of an RCP seal LOCA* - Based on Reference 8, the time available to prevent core damage by high-pressure injection if RCP seals fail is four hours. Therefore, EDGs or offsite power must be recovered within four hours to avert core damage. From the SPAR model, the probability of non-recovery of an EDG within four hours is 0.5. From the discussion above, the probability of non-recovery of offsite power within 4 hours is 0.51. These non-recovery probabilities are used to update non-recovery probabilities of RCP seal LOCA sequences in the station blackout event tree (Table 2).

- *Time available to recover high-pressure recirculation in the event of a stuck-open pressurizer SRV* - The time available prior to deletion of the refueling water storage tank during a small

LOCA is conservatively assumed to be five hours[2]. Therefore, high-pressure (sump) recirculation via the low-pressure injection (LPI) pumps must occur within this time period. For those sequences (e.g., minimum cut sets) where LPI pumps are unavailable due to loss of offsite and emergency power, an EDG or offsite power must be recovered within five hours to avert core damage. From the SPAR model (Ref. 6), the probability of non-recovery of an EDG within 5 hours is 0.42. From the discussion above, the probability of non-recovery of offsite power within 5 hours is 0.06.

These non-recovery probabilities were used to update non-recovery probabilities of stuck-open pressurizer PORV/SRV sequences in the loss of offsite power event tree (Table 2).

- *Effect of degraded steam generator tube* - The impact of the degraded steam generator tube on the conditional core damage probability (CCDP) associated with this event is negligible due to the following reasons: (a) sequences that could have resulted in causing a consequential steam generator tube rupture (e.g., steam generator dryout due to loss of AFW) are already treated as core damage sequences, and (b) the probabilities of additional failures that must occur (e.g., steam line break, stuck-open SRV) in order to cause a significant pressure differential between the primary and secondary systems are low. Details about the basis of this conclusion are provided as Section 3 to Attachment 1. The impact of the degraded tube on the conditional large early release probability is provided in Reference 10.

- *Effect of co-exiting conditions that could cause a loss of offsite power and loss of EDG 21* - This analysis estimated the CCDP associated with the loss of offsite power event, which occurred on August 31, 1999. The conditions which lead to this event (operating the tap changer in manual mode due to a defective voltage control relay, and erroneous trip set point of the output breaker of EDG 23) could have coexisted with another condition (degraded EDG 21 due to fuel oil leak).

  Based on information provided by the licensee [3] it was determined that erroneous trip point of the output breaker of EDG 23 did not coexist when the EDG 21 was in its degraded condition. Based on additional discussions with an NRC agency expert on EDGs,[4] it was determined that the fuel leak of EDG 21 could have affected its function, if and only if the leak was not detected in a timely manner. In fact, according to the NRC's diesel expert "leaks of the nature reported in the LER, can be fixed while diesel is running," if they are detected in a timely manner. The Resident Inspector of Indian Point 2 indicated[3] that at Indian Point 2, a non-licensed operator is dedicated to monitor its operation, locally, whenever an EDG is started. Therefore, any fuel leaks in the EDG 21 would have detected and repaired before adverse consequences (e.g., fires) could result.

[2] Based on the design discharge capacity of the pressurizer SRV and the Technical Specification minimum capacity of the refueling water storage tank (RWST), the calculated flow rate through a fully stuck-open SRV at rated pressure would deplete the RWST in about 11 hours. However, this additional time would not change the CCDP for this event.

[3] S. Weerakkody (U.S. NRC, Office of Nuclear Regulatory Research), Private communications with D. Gaynor (Consolidated Edison Co.), February 22, 2001.

[4] S. Weerakkody (U.S. NRC, Office of Nuclear Regulatory Research), Private communications with P. Habighorst (U.S. NRC, Resident Inspector at Indian Point 2) and E. Tomlinson (U.S. NRC, Office of Nuclear Reactor Regulation), February 27, 2001.

Based on the above, it was concluded that the EDG-21 was degraded, but functional. The importance calculated using this assumption was less than the CCDP of the initiating event.

Analysis Results

The conditional core damage probability (CCDP) for this event is 1.1×10^{-4}. Tables 3 and 4 provide details of the dominant sequences. The CCDP is dominated by sequences in which auxiliary feedwater fails with feed and bleed cooling unavailable (Sequence No. 17, 47% of CCDP), and all EDGs fail and power could not be restored to the emergency buses before battery depletion (Sequence Nos. 18-02, 28% of CCDP). A third dominant sequence involved failure of all EDGs and failure to restore power to the emergency buses before RCP seal failure (Sequence No. 18-08, 14% of CCDP). The impact of the degraded steam generator tube in steam generator 24 on the CCDP is negligible. The basis for this conclusion is provided in Section 3 of Attachment 1.

Figures 2 and 3 show the event trees with dominant sequences highlighted.

References

1. LER 247/99-015, "Reactor Trip, ESF Actuation, Entry into TS 3.0.1, and Notification of Unusual Event," August 31, 1999.

2. U.S. Nuclear Regulatory Commission, "NRC Augmented Inspection Team - Reactor Trip with Complications," Report No. 50-247/99-08, October 19, 1999.

3. LER 247/00-001, "Manual Reactor Trip Following Steam Generator Tube Rupture," March 17, 2000.

4. U.S. Nuclear Regulatory Commission, "NRC Augmented Inspection Team - Steam Generator Tube Failure," Report No. 50-247/2000-002, April 28, 2000.

5. LER 247/98-019, "Emergency Diesel 21 Failure," November 24, 1998.

6. Idaho National Engineering and Environmental Laboratory, Simplified Plant Analysis Risk Model for Indian Point Unit 2, Revision 2QA, April 1998.

7. Memorandum from Ashok C. Thadani to William D. Travers, "Closeout of Generic Safety Issue 23: Reactor Coolant Pump Seal Failure," U.S. Nuclear Regulatory Commission, November 8, 1999.

8. R.G. Neve and H.W. Heiselmann, "Cost/Benefit Analysis for Generic Issue 23: Reactor Coolant Pump Seal Failure," NUREG/CR-5167, April 1991.

9. Individual Plant Examination for Indian Point Unit No. 2 Nuclear Generating Station, August 1992.

10. U.S. Nuclear Regulatory Commission, "Final Significance Determination for a Red Finding and Notice of Violation at Indian Point 2," November 20, 2000.

11. Reserved.

12. F.M. Marshall, D.M. Rasmusson, and A. Mosleh, "Common-Cause Failure Parameter Estimations," NUREG/CR-5497, October 1998.

13. G. M. Grant, et al., "Reliability Study: Emergency Diesel Generator Power System, 1987-1993," NUREG/CR-5500, Vol. 5, September 1999.

14. J. P. Poloski, et al., "Reliability Study: Auxiliary/Emergency Feedwater System, 1987-1995," NUREG/CR-5500, Vol. 1, August 1998.

15. Reserved.

16. J. P. Poloski, et al., "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995," NUREG/CR-5750, February 1999.

17. S. D. Weerakkody, et al., "Assessment of Risk Significance Associated with Issues Identified at D. C. Cook Nuclear Power Plant," NUREG-1728, October 2000.

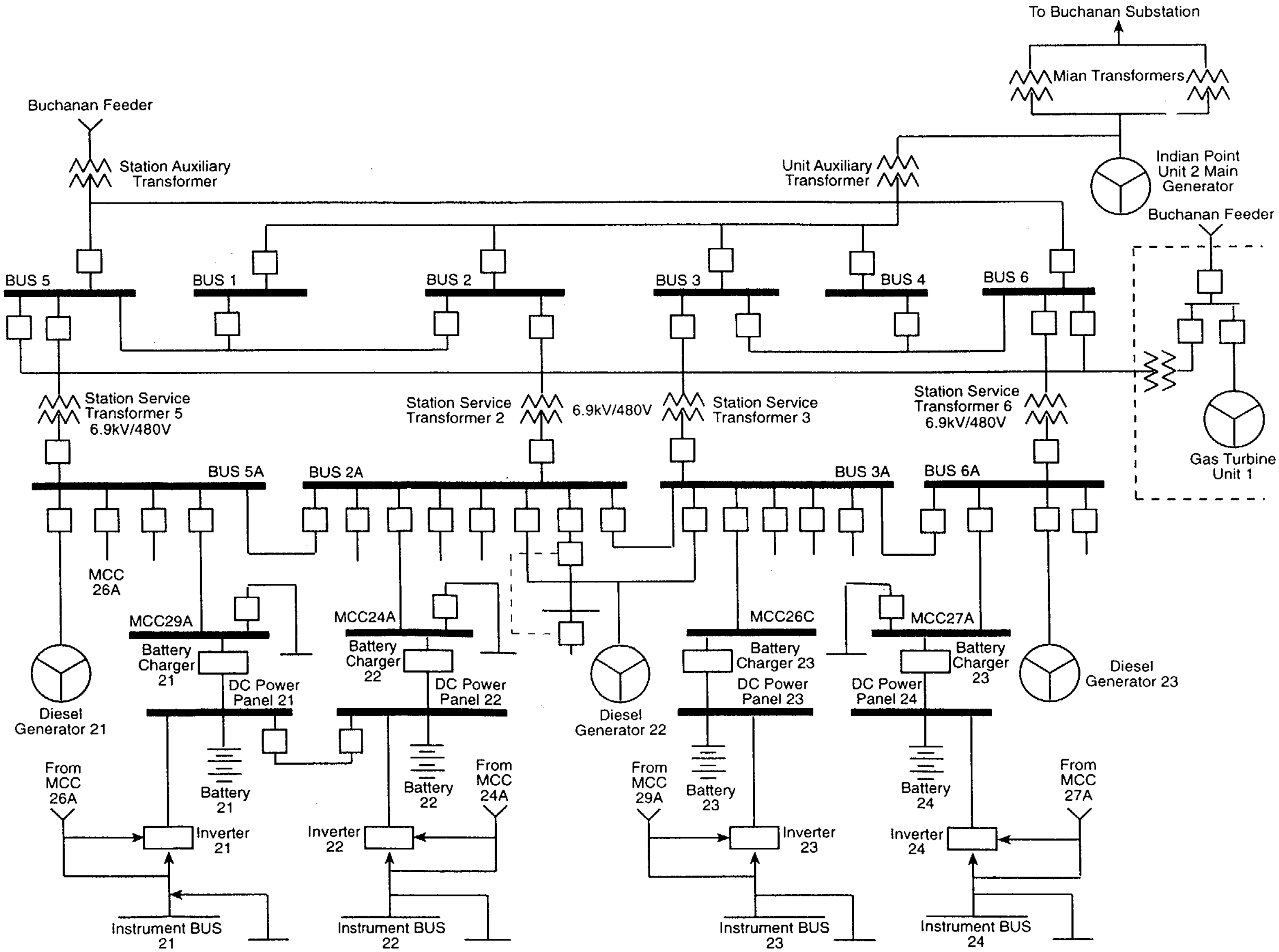

Figure 1. Electric Power System Diagram, Indian Point 2

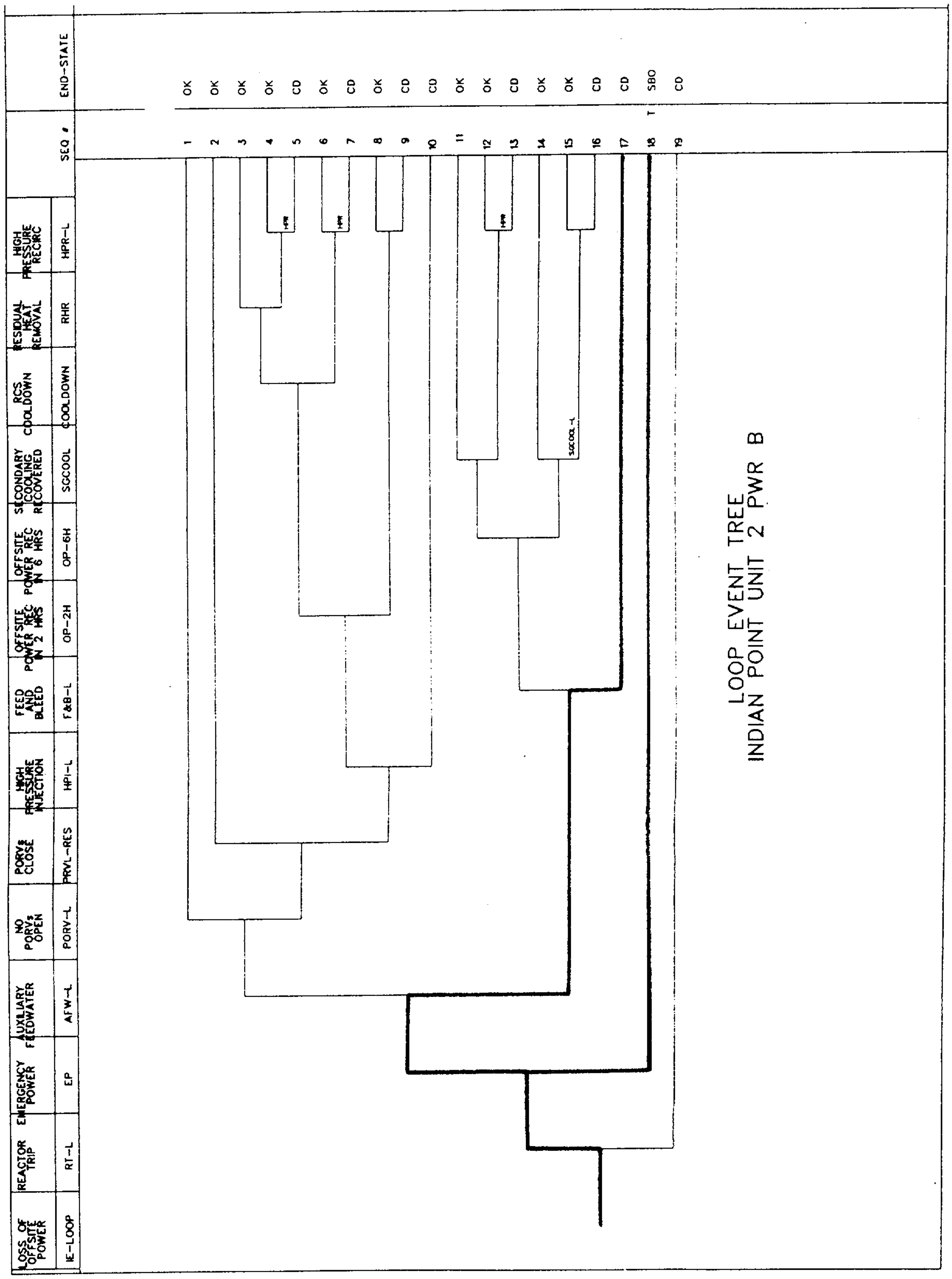

Figure 2. Loss of Offsite Power Event Tree (Sequence 18 Transfers to Station Blackout Event Tree)

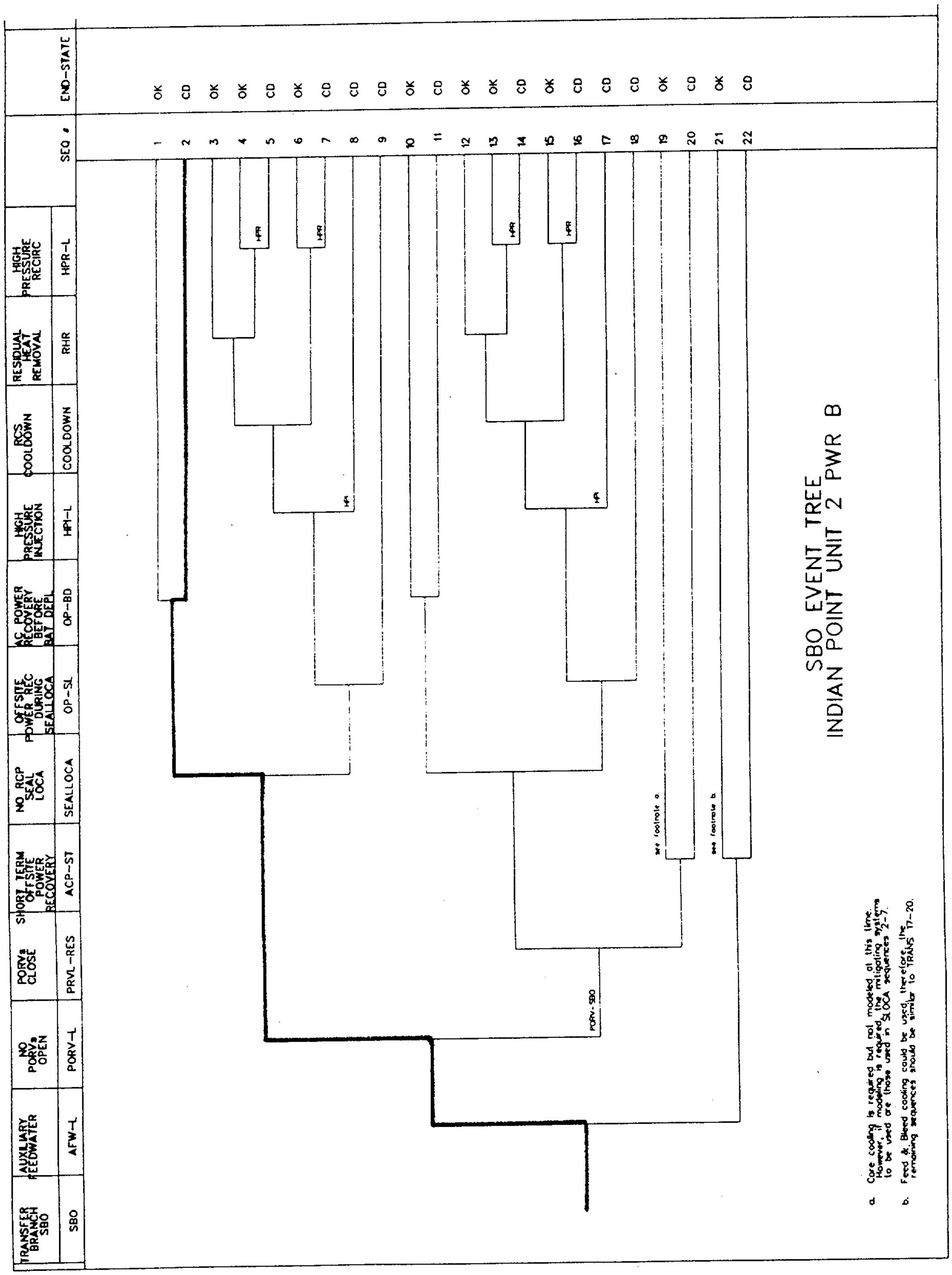

Figure 3. Station Blackout Event Tree

Table 1: Definitions and Probabilities for Selected Basic Events

Event name	Description	Base probability	Current probability	Type	Modified for this event
IE-LOOP	Initiating Event–LOOP	3.1 E-005	1.0		Yes(1)
IE-SGTR	Initiating Event–Steam Generator Tube Rupture	1.6 E-006	0.0 E+000		Yes(2)
IE-SLOCA	Initiating Event–Small Loss-of-Coolant Accident (SLOCA)	2.3 E-006	0.0 E+000		Yes(2)
IE-TRANS	Initiating Event-Transients	2.7 E-004	0.0 E+000		Yes(2)
AFW-TDP-FC-22	AFW turbine-driven pump 22 fails	3.3E-002	9.3E-002		Yes(3)
EPS-DGN-CF-ALL	Common-cause failure of diesels	8.5E-004	1.0E-003		Yes(4)
EPS-DGN-FC-21	Diesel generator 21 fails	3.3E-002	8.2E-002		Yes(5)
EPS-DGN-DC-22	Diesel generator 22 fails	3.3E-002	8.2E-002		Yes(5)
EPS-DGN-FC-23	Diesel generator 23 fails	3.3E-002	8.2E-002		Yes(5)
EPS-DGN-FC-23-OB	Operator fail to close output breaker of EDG 23		0.1	New(3)	
LOOP-05-NREC	LOOP Sequence 5 non-recovery	1.0	2.5E-002		Yes(6)
LOOP-07-NREC	LOOP Sequence 7 non-recovery	1.0	2.5E-002		Yes(6)
LOOP-09-NREC	LOOP Sequence 9 non-recovery	1.0	2.5E-002		Yes(6)
LOOP-17-NREC	LOOP Sequence 17 non-recovery	0.22	0.41		Yes(6)
LOOP-18-02-NREC	LOOP Sequence 18-02 non-recovery	0.8	0.3		Yes(6)
LOOP-18-05-NREC	LOOP Sequence 18-05 non-recovery	0.8	3.0E-002		Yes(6)
LOOP-18-07-NREC	LOOP Sequence 18-07 non-recovery	0.8	3.0E-002		Yes(6)
LOOP-18-08-NREC	LOOP Sequence 18-08 non-recovery	0.67	3.0E-002		Yes(6)
LOOP-18-11-NREC	LOOP Sequence 18-11 non-recovery	0.8	0.3		Yes(6)
LOOP-18-14-NREC	LOOP Sequence 18-14 non-recovery	0.8	3.0E-002		Yes(6)
LOOP-18-16-NREC	LOOP Sequence 18-16 non-recovery	0.8	3.0E-002		Yes(6)

Table 1 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
LOOP-18-17-NREC	LOOP Sequence 18-17 non-recovery	0.67	3.0E-002		Yes(6)
LOOP-18-20-NREC	LOOP Sequence 18-20 non-recovery	0.8	0.7		Yes(6)
LOOP-18-22-NREC	LOOP Sequence 18-22 non-recovery	0.27	0.41		Yes(6)
MFW-SYS-TRIP	Main feedwater system unavailable given a reactor trip	0.8	0.8		No
MFW-SYS-UNAVAIL	Main feedwater system fails after the reactor trip	0.2	0.2		No
MFW-XHE-ERROR	Operator fails to recover MFW-SYS-TRIP	5.0E-002	5.0E-002		No
MFW-XHE-NOREC	Operator fails to recover MFW-SYS-UNAVAIL	0.2	0.2		No
OEP-XHE-NOREC-2H	Operator fails to recover offsite power within 2 hours	3.2E-002	1.0		Yes(3)
OEP-XHE-NOREC-6H	Operator fails to recover offsite power within 6 hours	1.4E-002	6.0E-002		Yes(3)
OEP-XHE-NOREC-BD	Operator fails to recover offsite power before battery depletion (within 7 hours)	8.6E-004	6.0E-002		Yes(3)
OEP-XHE-NOREC-SL	Operator fails to recover offsite power (seal LOCA) (within 4 hrs)	0.66	0	False	Yes(7)
OEP-XHE-NOREC-ST	Operator fails to recover offsite power in short-term (within 2 hrs)	0.17	1.0		Yes(3)
OEP-XHE-XM-GTSL	Operator fails to start and align gas turbines during seal LOCA	0.34	0	False	Yes(7)
OEP-XHE-XM-GT2	Operator fails to start and align gas turbines in 2 hours	0.34	Ignore		Yes(3)
OEP-XHE-XM-GT6	Operator fails to start and align gas turbines in 2 hours	0.34	Ignore		Yes(3)
OEP-XHE-XM-GTBD	Operator fails to start and align gas turbines before battery depletion	0.34	Ignore		Yes(3)
OEP-XHE-XM-GTST	Operator fails to start and align gas turbines in short-term	0.34	Ignore		Yes(3)

Table 1 (Continued)

Event name	Description	Base probability	Current probability	Type	Modified for this event
PPR-MOV-FC-BLK1	PORV block valve is in open position			True	No
PPR-MOV-FC-BLK2	PORV block valve is in open position			True	No
PPR-SRV-CO-L	PORVs/SRVs open during LOOP	0.16	4.0E-002		Yes(3)
PPR-SRV-CO-SBO	PORVs/SRVs open during station blackout	0.37	4.0E-002		Yes(3)
RCP-MDP-LK-SEALS	RCP seals fail w/o seal cooling	3.4E-002	0.22		Yes(8)

Notes:

1. Even though this event was not caused by severe weather, to be able to examine and adjust probabilities of failure to recover offsite power on a sequence specific basis, the "Extreme Weather" category of loss of offsite power was chosen for the analysis.
2. Initiating event frequencies were set to 0.0 to reflect the event analyzed.
3. See text (Section entitled "Modeling Details and Key Assumptions,") for basis.
4. Model update using data from NUREG-5497, Tables 5-2 and 5-5 (Ref. 12), and NUREG/CR-5500, Vol. 5 (Ref. 13).
5. Model update using data from NUREG/CR-5500, Vol. 5, Tables 3, C-4, and C-7 (Ref. 13). EDG non-recovery probabilities were excluded here and included under the sequence-specific non-recovery probabilities (Table 2).
6. Model update. Refer to Table 2 for basis.
7. Model update based on Rhodes Model (Ref. 7). See Note 2 to Table 5 for details.
8. Model update based on Rhodes Model (Ref. 7).

Table 2: Basis for the probabilities of sequence-specific recovery actions

Seq. No. and basic event	Failed systems [1] and recovery time [2]	Probability of failing to recover	Combined failure probability	Modification Comment (also see footnote)
5 LOOP-05-NREC	EDGs (5 hours) Offsite power (5 hours)	0.42 0.06	0.025	Revised RWST depletion time
7 LOOP-07-NREC	EDGs (5 hours) Offsite power (5 hours)	0.42 0.06	0.025	Revised RWST depletion time
9 LOOP-09-NREC	EDGs (5 hours) Offsite power (5 hours)	0.42 0.06/1.0 [5]	0.025	Revised RWST depletion time
17 LOOP-17-NREC	EDG (2 hours) AFW Offsite power (2 hours)	0.7 0.58 [3] 1.0	0.41	Revised AFW non-recovery probability
18-02 LOOP-18-02-NREC	EDG (7 hours)	0.3	0.3	Revised battery depletion time
18-05 LOOP-18-05-NREC	EDGs (4 hours) Offsite power (4 hours)	0.5 0.06 [4]	0.03	Include Rhodes RCP seal LOCA model
18-07 LOOP-18-07-NREC	EDGs (4 hours) Offsite power (4 hours)	0.5 0.06 [4]	0.03	Include Rhodes RCP seal LOCA model
18-08 LOOP-18-08-NREC	EDGs (4 hours) Offsite power (4 hours)	0.5 0.06 [4]	0.03	Include Rhodes RCP seal LOCA model
18-11 LOOP-18-11-NREC	EDG (7 hours)	0.3	0.3	Revised battery depletion time
18-14 LOOP-18-14-NREC	EDG (4 hours) Offsite power (4 hours)	0.5 0.06 [4]	0.03	Include Rhodes RCP seal LOCA model
18-16 LOOP-18-16-NREC	EDG (4 hours) Offsite power (4 hours)	0.5 0.06 [4]	0.03	Include Rhodes RCP seal LOCA model
18-17 LOOP-18-17-NREC	EDG (4 hours) Offsite power (4 hours)	0.5 0.06 [4]	0.03	Include Rhodes RCP seal LOCA model
18-20 LOOP-18-20-NREC	EDG (2 hours) Offsite power (2 hours)	0.7 1.0	0.7	
18-22 LOOP-18-22-NREC	EDG (2 hours) Turbine-driven AFW Offsite power (2 hours)	0.7 0.58 [3] 1.0	0.41	Revised AFW non-recovery probability

Table 1 (Continued)

Notes:

1. Based on SPAR model (Ref. 6), non-recovery probability for an EDG is $exp(-0.173t)$, where t is recovery time in hours. When multiple EDGs are failed, only one EDG is considered for recovery, since operators would attempt to recover only one EDG. Refer to Attachment 1, Section 2 for the basis of the non-recovery probability for offsite power.
2. Recovery times used in the SPAR model are as follows:
   - 2 hours--core uncovery due to loss of heat removal (from the SPAR model, Ref. 6);
   - 4 hours--core uncovery due to RCP seal LOCA (update based on Rhodes Model, Ref. 7);
   - 5 hours--core uncovery due to refueling water storage tank depletion and failure to establish high-pressure (sump) recirculation (update assumption); and
   - 7 hours--battery depletion (update based on actual event condition).
3. Based on recovery probabilities provided in Table 4 of NUREG/CR-5500, Vol. 1 (Ref. 14).
4. Non-recovery probability for offsite power was added to this sequence non-recovery probability to account for top event OP-SL in the station blackout event tree being set to "False" to account for the Rhodes Model. See note to Table 5 for details. Refer to Attachment 1, Section 2 for the basis of the non-recovery probability for offsite power.
5. Accounts for top event OP-2H in the loss of offsite power event tree (i.e., non-recovery of offsite power within 2 hours). Combined non-recovery probability = (non-recovery probability of offsite power within five hours)/(non-recovery probability of offsite power within two hours) = 0.06/1.0.

Table 3. Sequence Conditional Probabilities

Event tree name	Sequence number	Conditional core damage probability (CCDP)	Percent contribution
LOOP	17	5.2E-005	47.3
LOOP	18-02	3.1E-005	28.2
LOOP	18-08	1.5E-005	13.6
Total (all sequences) (1)		**1.1E-004**	**100**

1. Total CCDP includes all sequences (including those not shown in this table).

Table 4. Sequence Logic for Dominant Sequences

Event tree name	Sequence number	Logic
LOOP	17	/RT-L, /EP, AFW-L, F&B-L
LOOP	18-02	/RT-L, EP, /AFW-L, /PORV-SBO, /SEALLOCA, OP-BD
LOOP	18-08	/RT-L, EP, /AFW-L, /PORV-SBO, SEALLOCA, HPI

Table 5. System Names from Table 4.

System name	Logic
AFW-L [(1)]	No or Insufficient EFW Flow During a LOOP
EP	Emergency Power Fails
F&B-L	Failure to Provide Feed And Bleed Cooling during a LOOP
HPI-L [(2)]	No or Insufficient Flow from HPI System During a LOOP
HPR-L [(2)]	No or Insufficient Flow from HPR System During a LOOP
OP-BD	Operator Fails to Recover Offsite Power Before Battery Depletion
OP-SL [(2)]	Operator Fails to Offsite Power Before a Seal LOCA Occurs
PORV-SBO	Pressurizer PORVs/SRVs Open During Station Blackout
RT-L	Reactor Fails to Trip During a LOOP
SEALLOCA	Reactor Coolant Pump Seals Fail During a LOOP

Notes:

1. See text (Section entitled "Modeling Details and Key Assumptions,") for basis.
2. SPAR model was modified to replace the existing RCP seal LOCA model with the Rhodes Model (Ref. 7). In order to replace the RCP seal LOCA model without modifying the station blackout event tree, top event OP-SL was set to "False" (basic events OEP-XHE-NOREC-SL, OEP-XHE-XM-GTSL). To account for offsite power recovery, the non-recovery probabilities for offsite power and emergency diesel generators (EDGs) were added to the sequence-specific non-recovery probabilities for the RCP seal LOCA sequences in the station blackout event tree (see Table 2). Based on the Rhodes Model, the time available to prevent core damage by high-pressure injection if RCP seals fail is 4 hours. Therefore, the non-recovery probabilities for EDGs and offsite power were modified to reflect the 4-hour recovery time to avert core damage (see Table 2). Finally, Event Tree Linking Rule Nos. 4 and 5 (Ref. 6, Table 2-1), which are triggered by the success of top event OP-SL, were negated by substituting fault tree HPI for HPI-L in LOOP Sequences 18-08 and 18-17 and HPR for HPR-L in LOOP Sequences 18-05, 18-07, 18-14, and 18-16.

Table 6. Conditional Cut Sets for Higher Probability Sequences

Cut Set number	Percent Contribution	CCDP	Cut Sets
LOOP Sequence 17		**5.2E-005**	
1	26.7	1.4E-005	AFW-TDP-FC-22, EPS-DGN-FC-22, MFW-SYS-UNAVAIL, MFW-XHE-NOREC, EPS-DGN-FC-23-OB, LOOP-17-NREC
2	26.7	1.4E-005	AFW-TDP-FC-22, EPS-DGN-FC-22 , MFW-XHE-ERROR, MFW-SYS-TRIP, EPS-DGN-FC-23-OB, LOOP-17-NREC
3	19.9	1.0E-005	AFW-TDP-FC-22, EPS-DGN-FC-22, EPS-DGN-FC-23, MFW-XHE-ERROR, MFW-SYS-TRIP, LOOP-17-NREC
4	19.9	1.0E-005	AFW-TDP-FC-22, EPS-DGN-FC-22, EPS-DGN-FC-23, MFW-SYS-UNAVAIL, MFW-XHE-NOREC, LOOP-17-NREC
LOOP Sequence 18-02		**3.1E-005**	
1	43.6	1.4E-005	EPS-DGN-CF-ALL, OEP-XHE-NOREC-BD, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, LOOP-18-02-NREC
2	32.2	1.0E-005	EPS-DGN-FC-21, EPS-DGN-FC-22, OEP-XHE-NOREC-BD, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, EPS-DGN-FC-23-OB, LOOP-18-02-NREC
3	24.0	7.4E-006	EPS-DGN-FC-21, EPS-DGN-FC-22, EPS-DGN-FC-23, OEP-XHE-NOREC-BD, /PPR-SRV-CO-SBO, /RCS-MDP-LK-SEALS, LOOP-18-02-NREC
LOOP Sequence 18-08		**1.5E-005**	
1	43.6	6.3E-006	EPS-DGN-CF-ALL, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, LOOP-18-08-NREC
2	32.2	4.7E-006	EPS-DGN-FC-21, EPS-DGN-FC-22, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, EPS-DGN-FC-23-OB, LOOP-18-08-NREC
3	24.0	3.5E-006	EPS-DGN-FC-21, EPS-DGN-FC-22, EPS-DGN-FC-23, /PPR-SRV-CO-SBO, RCS-MDP-LK-SEALS, LOOP-18-08-NREC

Attachment 1

Section 1: Additional details about the probability of failing to recover emergency power to bus 6A (EPS-DGN-FC-23-OB)

Recovery of emergency power to bus 6A entails the following diagnosis and physical action tasks:

- Recognize the need to recover emergency power to bus 6A during a postulated station blackout (diagnosis); and

- Clear the maintenance tag on bus 6A, restart EDG 23, and close the output breaker (action).

The ASP Program methods for human reliability analysis were used to estimate EDG non-recovery probabilities based on actual event conditions. The human reliability analysis involves estimating failure probabilities for diagnosis and action portions of the recovery task as discussed below.

- Recognize the need to re-close output breaker (diagnosis)

  From the SPAR model, the time available to recover emergency power during a station blackout before core uncovery is about two hours. Very little time is required to determine the availability of the EDG and output breaker, and the need to recover the 480-V bus. Therefore, the performance shaping factor (PSF) multiplier associated with the "time available" PSF is 0.1 (extra time >60 minutes). Given that all safety-related 480-V buses have lost power, the PSF level for "stress" is "extreme" (PSF multiplier is 5).

  The nominal failure probability for a cognitive error used in the SPAR model is 0.01. Therefore, the probability of cognitive error for this diagnosis activity is 0.005 (= 0.01 x 0.1 x 5).

- Clear the tag on bus 6A, restart EDG 23, and close the output breaker (action)

  Following the trip of EDG 23, bus 6A was tagged out for inspection. Subsequently, if the operators decided to recover bus 6A, they would have to clear the tag in order to ensure safety of the personnel working on the bus and proper configuration of the bus itself. Therefore, this activity requires about two hours.[1] From the SPAR model, the time available to recover emergency power during a station blackout before core uncovery is about two hours. Therefore, the PSF multiplier associated with the "time available" PSF is 10 (time available is approximately equal to the time required). Given that all safety-related 480-V buses have lost power, the PSF level for "stress" is "extreme" (PSF multiplier is 5). In consideration of ambiguities to clear the tag and restore the bus from the post trip inspection activities, the PSF level for "complexity" is "moderately complex" (PSF multiplier is 2).

  The nominal failure probability used in the SPAR model of an error to complete a physical action is 0.001. Therefore, the failure probability to implement the task is 0.1 (= 0.001 x 10 x 5 x 2).

[1] S. Weerakkody (U.S. NRC, Office of Nuclear Regulatory Research), Private communiations with J. Trapp (U.S. NRC, Region I), and T. Reese and P. Griffith (Consolidated Edison Co.), November 20, 2000.

- Output breaker does not trip open again due to over-current

  During the event that occurred on August 31, 1999, due to an anomaly associated with the automatic sequencer, three large loads—an auxiliary feedwater (AFW) pump, a service water (SW) pump, and a component cooling water (CCW) pump—loaded onto bus 6A within 4 seconds (Ref. 2, Page 8). During manual loading, this anomaly would not occur. The 3000-AMP range (over-current setpoint in the "as-found" condition) is sufficient to power an AFW pump, a CCW pump, and an SW pump and their auxiliaries. Even though the breaker tripped due to over-current when loads were sequenced automatically, if bus 6A were recovered and essential loads (e.g., AFW pumps) were loaded on the bus manually, the output breaker would not trip open.

- Non-recovery of emergency power to bus 6A

  The total probability of failure to recover emergency power to bus 6A is 0.1 (=0.005 + 0.1).

Section 2: Additional details on the probability of failing to recover offsite power to 480-V buses (from 6.9-kV buses)

If EDGs 21 and 22 failed, and the restart of EDG 23 was not successful, the operators would attempt to recover buses by closing the breakers between the 6.9-kV buses and safety-related 480-V buses 2A, 3A, 4A, and 5A. Recovery of offsite power to the 480-V buses entails the following diagnosis and physical action tasks:

- Recognize the need to bypass the under-voltage interlock that prevents closing breakers between 6.9-kV and 480-V buses (diagnosis),

- Develop a method and procedure to bypass the interlock (action),

- Bypass the interlock using the procedure (action), and

- Close breakers (action).

The ASP Program methods for human reliability analysis were used to estimate offsite power non-recovery probabilities based on actual event conditions. The human reliability analysis involves estimating failure probabilities for the diagnosis and action portions of the recovery task, as discussed below.

- Recognize the need to bypass the under-voltage interlock (diagnosis)

  After a station blackout signal is generated, the undervoltage interlock must be reset before the 6.9-kV buses can be reconnected to the safety-related 480-V buses. Based on communications with the licensee,[2] the operators are trained to recognize this condition. From the SPAR model, the time available to recover offsite power to the safety-related buses before core uncovery is from two to

[2] S. Weerakkody (U.S. NRC, Office of Nuclear Regulatory Research), Private communiations with J. Trapp (U.S. NRC, Region I), and T. Reese and P. Griffith (Consolidated Edison Co.), November 20, 2000.

seven hours for various core damage sequences. Based on the common knowledge of the operators to recognize the need to bypass the undervoltage interlock following the generation of a station blackout signal, very little time is needed to diagnose the condition. Therefore, the performance shaping factor (PSF) multiplier associated with the "time available" PSF is 0.1 (extra time >60 minutes). Given that all safety-related 480-V buses have lost power, the PSF level for "stress" is "extreme" (PSF multiplier is 5).

The nominal failure probability of a cognitive error used in the SPAR model is 0.01. Therefore, the probability of cognitive error for this diagnosis activity is 0.005 (= 0.01 x 0.1 x 5).

- Develop a method and procedure to bypass the interlock, implement procedure, bypass interlock, and close breakers (action)

  During the actual event, engineering staff found a temporary facility change (TFC) instruction that was previously used in 1990 to bypass the under-voltage interlock. Using this TFC, a new TFC was generated and approved for use in about eight hours following the event initiation (Ref. 2). However, there was no urgency on the part of the operators to bypass the interlock, since power was available from the other two EDGs.

  Based on discussions with operations and PRA personnel at Indian Point-2,[3] it is reasonable to assume that the operators would attempt to locate and retrieve the previously issued TFC. All TFCs are located in a computer database and accessible to the shift technical advisor on duty. Power to this computer is independent of the availability of the safety-related 480-V buses. Based on these discussions, the old TFC could be retrieved and a new TFC could be prepared in less than three hours.

  The recovery-related basic events used in the SPAR model for the various loss of offsite power and station blackout sequences are a function of time to core uncovery (two, four, five, and six hours) or battery depletion (seven hours). Using four hours as the minimum recovery time based on three hours to develop a TFC, and one hour to implement the interlock bypass and establish offsite power and core cooling, the PSF multiplier associated with the "time available" PSF is 10 (time available is the time required) for recovery time of 4 hours and a PSF multiplier of 1 (nominal time) for recovery times of 5 to 7 hours. For a recovery time of two hours, it was conservatively assumed that offsite power can not be recovered.[4]

  Given a postulated station blackout, the PSF level for "stress" is "extreme" (PSF multiplier is 5). Since the TFC would have to be reviewed and prepared during the event, the PSF level for "procedures" is "procedure available but poor" (PSF multiplier is 5). In consideration of ambiguities to bypass the interlock and close breakers to buses, the PSF level for "complexity" is "moderately complex" (PSF multiplier is 2).

[3] S. Weerakkody (U.S. NRC, Office of Nuclear Regulatory Research), Private communications with J. Trapp (U.S. NRC, Region I), and T. Reese and P. Griffith (Consolidated Edison Co.), November 20, 2000.

[4] The basic event associated with the 2-hour recovery time does not dominate the overall risk result. Therefore, a failure probability of 1.0 was chosen for basic events OEP-XHE-NOREC-2H and -ST.

The nominal failure probability used in the SPAR model for a failure to complete a physical action is 0.001. Therefore, the probability of failure to implement the task is 0.05 (=0.001 x 1 x 5 x 5 x 2) for recovery times of five to seven hours, and 0.5 (=0.001 x 10 x 5 x 5 x 2) for a recovery time of four hours. As stated above, it was assumed that offsite power was recoverable within two hours.

- Non-recovery of offsite power to the 480-V buses

  The total human error probabilities (diagnosis and actions) are 0.06 (=0.005 + 0.05) for recovery times of six and seven hours and 0.5 (=.005 + 0.5) for a recovery time of four hours. For basic events requiring a 2-hour recovery time, the failure probability was set to 1.0.

Section 3: Potential for steam generator tube rupture

A consequential steam generator tube rupture could have increased the risk associated with this event. As demonstrated below, the impact of the degraded steam generator tube on the CCDP associated with this event is negligible.

In order contribute to CCDP, the probability of one of the following sequences must be significant compared to the CCDP associated with the loss of offsite power event itself.

Sequence 1: Failure to control reactivity introduces additional stresses on the degraded steam generator tube

This sequence consists of the following events:
- Reactor trip function fails;
- Degraded steam generator tube fails as a result of additional stresses of ATWS;
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 2: Failure to introduce AFW causes dry out of steam generator and introduces additional stresses on the degraded steam generator tube

This sequence consists of the following events:
- AFW fails;
- Feed and bleed cooling fails;
- Degraded steam generator tube fails due to steam generator dry out; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 3: Secondary side pressure reduces rapidly due to main steam line break while the primary pressure stays high

This sequence consists of the following events:
- Main steam line break;
- Rapid secondary side depressurization leads to a steam generator tube rupture; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 4: <u>Secondary side pressure reduces rapidly due to stuck-open steam generator relief valve while the primary pressure stays high</u>

This sequence consists of the following events:

- Primary side heat removal degrades and consequently RCS pressure stays high;
- Secondary side pressure increases and challenges a steam generator relief valve;
- Secondary side relief valve sticks open and depressurizes secondary side;
- Degraded steam generator tube fails; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Sequence 5: <u>Primary pressure increases as a result of the failure of all AC power and relief valves fail to lift</u>

This sequence consists of the following events:

- All AC power is lost;
- RCS pressure increases;
- Pressurizer relief valves fail to lift;
- Degraded steam generator tube fails; and
- Core damage results from failure to mitigate the subsequent steam generator tube rupture.

Of the five sequences stated above, Sequence 1 is negligible due to the low likelihood of an ATWS at a Westinghouse plant—7×10^{-7} per year (Ref. 16).

Since the feed and bleed function was unavailable during the event, Sequence 2 has already been included as a core damage sequence (except, consequential steam generator tube rupture may increase the conditional large early release probability via this sequence).

Sequence 3 is negligible because of the low likelihood of a main steam line break during the 24 hour mission time of an accident. Based on Reference 17, the frequency of a main steam line break outside containment is 3×10^{-4} per critical year. Therefore, the probability of this event over a 24 hour period on the affected steam generator is approximately 8×10^{-7}.

Sequence 4 has a negligible contribution to the total CCDP due to the following. On August 31, 1999, when power was lost to the emergency buses, the power remained available to the balance-of-plant systems used for condenser heat removal. Therefore, the likelihood of steam generator pressure increase and a challenge of steam generator SRV requires the loss of condenser heat sink following the reactor trip. From data from Reference 14, the total probability of loss of condenser vacuum, turbine bypass capability, or isolation of all main steam isolation valves is 5×10^{-2}. Assuming that one SRV opens on the faulted steam generator, although the atmospheric dump valve is sized for decay heat removal, from the IPE, the probability of the valve failing to close is 9×10^{-2} (Ref. 9). Conservatively assuming that the faulted tube will rupture due to the depressurization of the steam generator, the CCDP for a steam generator tube rupture during the loss of offsite power event is 2×10^{-6} [$=(5 \times 10^{-2}) \times (9 \times 10^{-2}) \times (4 \times 10^{-4})$; where 4×10^{-4} is the CCDP for a classical steam generator tube rupture from the SPAR model for Indian Point 2). This contributes to about 2 percent of the CCDP.

Sequence 5 is negligible, since the product of the probability of the relief valves failing to lift and the probability of failing all AC power is low.

GUIDANCE FOR LICENSEE REVIEW OF PRELIMINARY ASP ANALYSIS

Background

The preliminary precursor analysis of an event or condition that occurred at your plant has been provided for your review. This analysis was performed as a part of the NRC's Accident Sequence Precursor (ASP) Program. The ASP Program uses probabilistic risk assessment techniques to provide estimates of operating event significance in terms of the potential for core damage. The types of events evaluated include actual initiating events, such as a loss of off-site power (LOSP) or loss-of-coolant accident (LOCA), degradation of plant conditions, and safety equipment failures or unavailabilities that could increase the probability of core damage from postulated accident sequences. This preliminary analysis was conducted using the information contained in the plant-specific final safety analysis report (FSAR), individual plant examination (IPE), and other pertinent reports, such as the licensee event report (LER) and/or NRC inspection reports.

Modeling Techniques

The models used for the analysis of events were developed by the Idaho National Engineering and Environmental Laboratory (INEEL). The models were developed using the Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) software. The developed models are called Standardized Plant Analysis Risk (SPAR) models. The SPAR models are based on linked fault trees. Fault trees were developed for each top event on the event trees to a super component level of detail.

SPAR Version 2 models have four types of initiating events: (1) transients, (2) small loss-of-coolant accidents (LOCAs), (3) steam generator tube rupture (PWR only), and (4) loss of offsite power (LOSP). The only support system modeled in Version 2 is the electric power system. The SPAR models have transfer events trees for station blackout and anticipated transient without scram.

The models may be modified to include additional detail for the systems/components of interest for a particular event. This may include additional equipment or mitigation strategies as outlined in the FSAR or IPE. Probabilities are modified to reflect the particular circumstances of the event being analyzed.

Guidance for Peer Review

Comments regarding the analysis should address:

- Does the "Event Description" section:
  - accurately describe the event as it occurred; and
  - provide accurate additional information concerning the configuration of the plant and the operation of and procedures associated with relevant systems?

- Does the "Modeling Assumptions" section:
  - accurately describe the modeling done for the event;
  - accurately describe the modeling of the event appropriate for the events that occurred or that had the potential to occur under the event conditions; and
  - includes assumptions regarding the likelihood of equipment recovery?

Appendix G of Reference 1 provides examples of comments and responses for previous ASP analyses.

Criteria for Evaluating Comments

Modifications to the event analysis may be made based on the comments that you provide. Specific documentation will be required to consider modifications to the event analysis. References should be made to portions of the LER or other event documentation concerning the sequence of events. System and component capabilities should be supported by references to the FSAR, IPE, plant procedures, or analyses. Comments related to operator response times and capabilities should reference plant procedures, the FSAR, the IPE, or applicable operator response models. Assumptions used in determining failure probabilities should be clearly stated.

Criteria for Evaluating Additional Recovery Measures

Additional systems, equipment, or specific recovery actions may be considered for incorporation into the analysis. However, to assess the viability and effectiveness of the equipment and methods, the appropriate documentation must be included in your response. This includes:

- normal or emergency operating procedures,
- piping and instrumentation diagrams (P&IDs),
- electrical one-line diagrams,
- results of thermal-hydraulic analyses, and
- operator training (both procedures and simulation).

This documentation must be the revision or cover the practices at the time of the event occurrence. Systems, equipment, or specific recovery actions that were not in place at the time of the event will not be considered. Also, the documentation should address the impact (both positive and negative) of the use of the specific recovery measure on:

- the sequence of events,
- the timing of events,
- the probability of operator error in using the system or equipment, and
- other systems/processes already modeled in the analysis (including operator actions).

An Example of a Recovery Measure Evaluation

A pressurized-water reactor plant experiences a reactor trip. During the subsequent recovery, it is discovered that one train of the auxiliary feedwater (AFW) system is unavailable. Absent any further information regrading this event, the ASP Program would analyze it as a reactor trip with one train of AFW unavailable. The AFW modeling would be patterned after information gathered either from the plant FSAR or the IPE. However, if information is received about the use of an additional system (such as a standby steam generator feedwater system) in recovering from this event, the transient would be modeled as a reactor trip with one train of AFW unavailable, but this unavailability would be mitigated by the use of the standby feedwater system.

The mitigation effect for the standby feedwater system would be credited in the analysis provided that the following material was available:

- standby feedwater system characteristics are documented in the FSAR or accounted for in the IPE,

- procedures for using the system during recovery existed at the time of the event,

- the plant operators had been trained in the use of the system prior to the event,

- a clear diagram of the system is available (either in the FSAR, IPE, or supplied by the licensee),

- previous analyses have indicated that there would be sufficient time available to implement the procedure successfully under the circumstances of the event under analysis, and

- the effects of using the standby feedwater system on the operation and recovery of systems or procedures that are already included in the event modeling. In this case, use of the standby feedwater system may reduce the likelihood of recovering failed AFW equipment or initiating feed-and-bleed due to time and personnel constraints.

Materials Provided for Review

The following materials have been provided in the package to facilitate your review of the preliminary analysis of the event or condition:

- Preliminary ASP analysis.

- Specific LER, NRC inspection report, or other pertinent reports for each preliminary ASP analysis.

Schedule

Please refer to the transmittal letter for schedules and procedures for submitting your comments.

Reference

1. R. J. Belles et al., "Precursors to Potential Severe Core Damage Accidents: 1997, A Status Report," USNRC Report NUREG/CR-4674 (ORNL/NOAC-232) Volume 26, Lockheed Martin Energy Research Corp., Oak Ridge National Laboratory, and Science Applications International Corp., Oak Ridge, Tennessee, November 1998.

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