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APPENDIX A

Grid Events

Appendix A
Grid Events

This section of the appendix provides summaries of grid events that affected NPP performance from 1994 through 2001. The events were identified and summarized from licensee event reports (LERs) in the NRC Sequence Coding and Search System. Appendix A summaries provide the plant name, the source of the information, the date the event occurred, the reactor power level, and a brief discussion of the event in relation to the grid and the NPP.

In a few cases, the summaries reference NRC inspection reports, NRC preliminary notification (PNO) reports, and NERC DAWG reports. The LER, PNO, and DAWG event dates were cross- referenced to identify the events affecting multiple NPPs in Appendix A. The DAWG reports helped identify when the event was part of a larger grid disturbance.

Grid events were defined as events initiated from the grid and causing reactor trips or various forms of LOOP, and events initiatied by a loss of electric power from any remaining power supplies as a result of, or coincident with, a reactor trip. The grid was defined to start at the NPP main and station power transformer high-voltage terminals and to include: (a) the high-voltage switchyard or substation nearest the NPP which is typically under the control of the transmission organization, (b) the transmission and generation system beyond the switchyard or substation, and (c) the protective relaying and control circuits of the switchyard and transmission system which are often located inside the NPP. The boundary between the NPP and the grid was based on typical organizational responsibility for equipment design, maintenance, and operational control. In a deregulated environment this boundary is typically the boundary between the regulated transmission system company and the deregulated nuclear generating company.

A LOOP was indicated by the start and loading of all EDGs. A partial LOOP was indicated by the start and loading of one or more, but not all the EDGs. Momentary LOOPs and partial LOOPs were indicated by the start of the EDGs; however, the voltage quickly recovered so the EDGs did not load. Partial or momentary LOOPs are generally not risk significant, however, for the purposes of this assessment they were used to identify potential NPP sensitivities to a grid-related event.

The grid events were grouped as follows:

- R events are losses of electric power from any remaining power supplies as a result of, or coincident with, a reactor trip at power. Losses of electric power include any LOOPs, partial LOOPs, momentary LOOPs, or voltage degradations below the technical specification low limit.

- S events are reactor trips where the first event in the sequence of events leading to the reactor trip was in the switchyard or substation nearest the plant.

- T events are reactor trips where the first event in the sequence of events leading to the reactor trip was in the transmission system beyond the switchyard or substation nearest the plant.

- L events are LOOPs where the first event in the sequence of events leading to the LOOP was in the grid. LOOPs at zero power are indicated by a zero suffix.

- PL events are partial LOOPS where the first event in the sequence of events leading to the partial LOOP was in the grid.

- I events are events of interest that provide insights into the plant response to a grid initiated event, but did not involve a unit trip, LOOP, or partial LOOP.

1. S Oyster Creek, LER 21994007, "Reactor Scram Due To Personnel Error While Performing Switchyard Work." On May 31, 1994, while at 100 percent power a reactor scram occurred due to human error while transmission company personnel were installing a modification in the switchyard. At the time of this event, Oyster Creek (OC) was operated by General Public Utility-Nuclear (GPUN) and the switchyard equipment was maintained by Jersey Central Power and Light (JCP&L). After notifying the OC control room, JCP&L Relay Department technicians loosened a wire that caused opening of the generator output circuit breakers while installing a digital fault recorder. After the event OC planned to establish a new agreement between GPUN and JCP&L to strengthen the control and review of switchyard activities.

2. I Oyster Creek Unit 1, LER 21994019, "SBO Power Source Unavailable Due To Inadequate Design of Modification Due To Inadequate Administrative Control." On October 19, 1994, while at 0 percent power, the SBO combustion turbine (-CT)ailed to start during functional testing. At the time of this event, Oyster Creek (OC) was operated by General Public Utility-Nuclear (GPUN) and the SBO-CT was under operational control of Jersey Central Power and Light (JCP&L). Of interest was that JCP&L modified the SBO-CT in May 1994 by installing a trip for a loss of AC power and defeated its safety function. After the event, OC planned to establish an agreement between JCP&L and GPUN that provides for review and testing of all SBO CT modifications.

3. R Oyster Creek Unit 1, LER 21997010, "Manual Reactor Scram, ESF Actuation and Design Deficiencies Noted As A Result of Generator Exciter PM." On August 1, 1997, the reactor was manually tripped from 100 percent power causing a low voltage condition that resulted in the start and loading of the EDGs. The licensee found that the start-up transformer (SAT) voltage regulators were not set to regulate consistent with the degraded voltage study assumptions. When the reactor tripped the regional grid voltage dropped 4.5 percent due to heavy demand and a 500 kV substation out-of-service. During transfer of in-house loads the voltage dropped an additional 3 to 6 percent from no-load to full load. As corrective action, the SAT voltage regulator setpoint was raised to ensure the required voltage levels are maintained.

4. S Nine Mile Point Unit 1, LER 22094002, "Reactor Scram Caused By Main Generator Trip as a Result of Failed Output Breaker Protective Relay." On April 5, 1994, while at 100 percent power, one of the two generator circuit breakers was opened to prepare for maintenance on a 345 kV transmission line disconnect switch. At this time, the other generator circuit breaker tripped unexpectedly due to mis-operation

of a degraded [transmission line] protective relay resulting in a generator trip and a reactor scram.

5. I Nine Mile Point 1, LER 22096004, “Reactor Scram Caused by Turbine Trip Due to Feedwater Oscillations.” At 1318 EDT on May 20, 1996, while at 100 percent power, a turbine trip and reactor scram occurred as a result of feedwater control valve oscillations. NERC DAWG Report No. 7, 1996 indicates that at 1319 on the same day the New York Power Pool (NYPP) initiated a 5 percent voltage reduction as a result of the loss of NMP1 and the controlled shutdown of Indian Point 3 earlier that day. Of interest was that the NYPP adjusted the grid voltages quickly, (i.e., 1 minute after NMP1 tripped).

6. S Dresden Unit 2, LER 23700004, “Reactor Scram Due To Failure To Close Current Transformer Knife Switches Following Maintenance.” On November 30, 2000, while at 100 percent power, the reactor and several 345 kV circuit breakers tripped when Bulk Power Operations closed a 345 kV circuit breaker in the switchyard. Prior to the event, substation construction personnel completed maintenance and test on the 345 kV circuit breaker that was closed without verifying proper restoration of the equipment.

7. PL Ginna, LER 24494005, “Loss of 34.5 kV Offsite Power Circuit 751, Due to Loss of Power to #2 34.5 kV Bus at Station 204, Causes Automatic Activation of RPS System (Turbine Runback).” On February 17, 1994, while at 98 percent power, Rochester Gas and Electric Energy Operations opened a degraded 34.5 kV circuit breaker at remote Substation #204. A high voltage condition followed and the Substation #204 circuit breaker that was feeding Ginna 34.5 kV offsite power Circuit 751 tripped. At this time, EDG “A” was being tested and loaded through Circuit 751. The circuit breakers to safety buses 14 and 18 tripped on undervoltage, and EDG “A” isolated and successfully powered safety buses 14 and 18. Power was restored to safety buses 14 and 18 through Circuit 751 in 23 minutes.

8. PL Ginna, LER 24494012,”Loss of 34.5 kV Offsite Power Circuit 751, Due to External Cause, Results in Automatic Start of B Emergency Diesel Generator.” On September 29, 1994, while at 98 percent power, a tree was accidently knocked into the 34.5 kV Circuit 751 by a private citizen operating heavy machinery. The event resulted in a partial LOOP to safety buses 16 and 17 and the start and loading of one EDG. Power was restored to safety buses 16 and 17 through Circuit 767 in 30 minutes. The loss of power resulted in a loss of program memory to a radiation monitor.

9. PL Ginna, LER 24497002, “Loss of 34.5 kV Offsite Power Circuit 751, Due to External Cause, Results in Automatic Start of “B” Emergency Diesel Generator.” On July 20, 1997, while at 100 percent power, 34.5 kV Circuit 751 lost power for approximately 12 hours and 15 minutes after a raccoon climbed an offsite utility pole causing a phase to phase short. “B” EDG started and loaded per design.

10. PL Ginna, LER 24498005, “Loss of 34.5 kV Offsite Power Circuit 751, Due to Faulted Cable Splice, Results in Automatic Start of “B” Emergency Diesel Generator.” On

November 20, 1998, while at 100 percent power, 34.5 kV Circuit 751 lost power after a cable splice failed. EDG "B" started and loaded to safety buses 16 and 17. Power was restored to safety buses 16 and 17 through Circuit 767 in 15 minutes.

11. PL Indian Point Unit 2, LER 24794001, "ESF and Emergency Diesel Generator Actuation." On January 26, 1994, while at 100 percent power, the in-service feeder from Buchanan 138 kV Substation to IP2 faulted resulting in (1) a 60 MW load reduction on Unit 2 due the loss of 2 circulating water pumps and (2) start and loading of two of three EDGs. Power was restored in 61 minutes.

12. S Indian Point Unit 2, LER 24795016, "Direct Generator Trip and Reactor Trip." On June 12, 1995, while at 90 percent power, a broken wire and ground in a pilot wire protective relay circuit in the Buchanan 345 kV substation resulted in generator, turbine, and reactor trips.

13. T Indian Point 2, LER 24796003, "Direct Generator Trip due to Pilot Wire Feeder Protection." On March 5, 1996, while at 100 percent power, generator, turbine, and reactors trips resulted from mis-operation of a pilot wire protective relay following a fault on a 345 kV transmission line between Buchanan and Sprain Brook Substations. The pilot wire relay that protects equipment between Indian Point 2 and Buchanan substation had not been modified as it had at other company locations.

14. I Indian Point Unit 2, LER 24796021, "Containment Isolation Valve Closure Due to Offsite Electrical Disturbance." On October 30, 1996, while at 100 percent power a significant voltage disturbance in the 345 kV transmission system tripped one of two generator output circuit breakers. The disturbance de-energized a radiation monitor and caused the closure of safety related steam generator blowdown containment isolation valves. NERC DAWG Report 26, 1996 indicates that the 345 kV disturbance was due to a faulted offsite 765 kV electrical reactor and resulted in voltage reductions of 5 to 8 percent through-out New York. Of interest was the voltage sensitivity of a few NPP components to the grid disturbance.

15. R Indian Point Unit 2, LER 24797018, "Buchanan's Substation Ringbus Breaker Trip Caused IP2 Turbine Overspeed Trip and Reactor Trip." On July 26, 1997, while at 99.4 percent power, one of two available 345 kV transmission paths for Indian Point 2 (IP2) was taken out of service for repairs. At this time a degraded protective relay circuit in the Buchanan 345 kV Substation misoperated and tripped the remaining transmission path for IP2. This resulted in a loss of load to IP2, a turbine-generator overspeed, a turbine trip, and reactor scram without an immediate generator trip. When the 345 kV transmission path was taken out of service, the Buchanan 345 kV Substation ring bus circuit breakers were placed in a configuration that disabled a generator protective trip. The main generator remained operational for approximately 7 seconds until it tripped from an overcurrent condition on the IP2 unit auxiliary transformer (UAT).

During the 7 seconds the main generator output remained connected to the UAT, the turbine overspeed increased the frequency to between 68 and 73 hertz. The bus transfer from the UAT to the station auxiliary transformer (SAT) did not take place

due to the frequency mismatch between the UAT and the SAT power supplies. In addition, the increased frequency increased rpm of all electric motors connected to the UAT, specifically 6.9 kV buses 1 to 4 and the 480 v safety buses 2A and 3A. The reactor coolant pump (RCP) speed overspeed increased the RCP flow from 96 percent to 111.8 percent for 10 seconds. Westinghouse evaluation found that "gross tilting" or rocking of the reactor internals to be limiting with respect to allowable RCP flow conditions and that a new RCP flow limit of 115.8 percent is more limiting than the previous 125 percent limit identified in its Final Safety Analysis Report.

After the UAT tripped, safety bus 3A lost power. EDG 22 started and was available to feed buses 2A and 3A. The 6.9 kV buses were manually transferred to the start-up transformers after the generator tripped, energizing safety buses 2A and 3A. Motor Driven Auxiliary Feedwater Pump 21 was then used to feed Steam Generators 21 and 22.

16. R Indian Point 2, LER 24799015, "Reactor Trip, ESF Actuation, Entry into TS 3.01, and Notification of an Unusual Event." On August 31, 1999, the turbine and reactor tripped from 99 percent power following spurious initiation of the RPS during calibration. About 30 seconds later the generator tripped as designed and the 6.9 kV station buses transferred 3300 amps of load from the Unit Auxiliary Transformer to the Station Auxiliary Transformer (SAT). A sustained low voltage condition followed and all EDGs started and loaded. Throughout the event the SAT tap changer remained in the manual mode due to a defective voltage control relay; an NRC inspection report found the tap changer had been inoperable for several months and plant procedures allowed manual operation without compensatory measures.

EDG 23 (that was feeding bus 6A) tripped on overcurrent 14 seconds after it began loading due to a low overcurrent relay setpoint. The EDG overcurrent trip was set at 3200 amps not 6000 amps as designed. The setpoint error was not discovered as there was no requirement for a test to measure the actual trip point. The trip activated from the 4400 amps surge from multiple overlapping motor starts (Motor Driven Auxiliary Feedwater (AFW) Pump 23 starts in 12 seconds and takes 5 seconds to start; the Component Cooling Water Pump 23 and Service Water Pump 23 start in 11 and 15 seconds, respectively) following bus transfer.

The risk from this event was due to the loss of the EDG, one motor driven AFW pump, one pressure operated relief (PORV) block valve, and automatic control of one AFW control valve. Battery Charger 24, which is powered from bus 6A lost power and the battery supported DC loads for 7.4 hours. Instrument Bus 24 was lost when the voltage on DC bus 24 became too low for Inverter 24 to provide power. Approximately 75 percent of the safety system annunciators were lost for more than approximately 5.5 hours. Offsite power was available the entire time but not available without resetting the generator trip and operations believed resetting the generator trip to be inadvisable. An NRC Inspection report calculated a CCDP of 2E-04 assuming no credit for feed and bleed (need both PORVs), loss of AFW pump was unrecoverable, and low probability of operator success for using the

feedwater system to provide make-up to the steam generators. The NRC ASP Program determined the conditional core damage frequency was 2.8E-06 based on new information that showed the feedwater system was available.

17. T Monticello, LER 26394003, "Transmission System Electrical Fault Causes Loss of Circulating Water Pumps Resulting in a Reactor Scram." On April 15, 1994, while at 100 percent power, a 345 kV fault due to a transmission line wave trap [a device used transmit/receive high frequency signals through the transmission line] failure at another generating plant switchyard caused the voltage at Monticello 345 kV substation to drop to 55 percent for 2 to 3 cycles. The momentary decrease in voltage tripped the synchronous circulating water pump motors and resulted in low condenser vacuum. The reactor was manually scrammed. The low voltage condition also tripped the Recirculation Pump Motor-Generators on a low power factor protective trip, and caused the Emergency Filtration Train system to change modes due to de-energized 120 volt relays.

18. T Quad Cities Unit 2, LER 26500008, "Reactor Trip Due to a Main Generator Differential Relay Operation." On July 18, 2000, while at 100 percent power a 345 kV transmission line faulted due to a failed insulator about 5 miles from the NPP. The Unit 2 generator protective relaying circuit mis-operated tripping the generator, turbine, and reactor. About 10 seconds later, one of the 345 kV circuit breakers that opened to isolate the fault, automatically reclosed per design causing the Unit 2 Reserve Auxiliary Transformer (RAT) that normally feeds the safety buses to trip and transfer its loads to the Unit 1 Auxiliary Transformer. Power was restored to the RAT in approximately 10 hours. The licensee found the relay mis-operated as the expected operation of protective relays under faulted conditions changed over the years after the plant added and replaced current transformers in the protective relay circuits.

19. T Oconee Unit 2, LER 27095002, "Incorrect Timer Setting Due to a Design Deficiency Results in a Reactor Trip." On April 14, 1995, while at 100 percent power, a 100 kV transmission line fault, an offsite substation breaker failure, and an incorrect timer setting on the Oconee main generator loss of excitation relay resulted in generator, turbine, and reactor trips.

20. T Oconee Unit 2, LER 27097002, "Grid Disturbance Results in Reactor Trip Due To Manufacturing Deficiency." On July 6, 1997, while at 100 percent, the main generator voltage regulator on Unit 2 did not respond to a system grid disturbance created by the loss of two hydro units 15 miles from Oconee. The Oconee voltage could not be maintained within acceptable ranges as the main generator voltage regulator had been mis-calibrated in 1994. The voltage dropped to 80 percent of nominal, tripping the reactor coolant pumps. The reactor tripped on underpower. The voltage fluctuation also resulted in the loss of several non-safety electrical loads in the turbine building and programmable controllers on a "control room vertical board."

21. S Vermont Yankee, LER 27197023, "A Component Failure in the Main Generator Protection Circuitry Results in a Reactor Scram." On November 25, 1997, while at

85 percent power, a 345 kV phase to phase fault lasting 5 cycles occurred due to errors made during 345 kV switching to support transmission system maintenance. The reactor scrammed due the failure of turbine-generator runback controls in response to the 345 kV fault. The licensee stated that the switchyard equipment was owned and controlled by the transmission entity and the NPP's received periodic updates of the status of the switchyard.

22. R Vermont Yankee, LER 27198016, "Reactor Scram on High Water Level as a Result of a Stuck Open Feedwater Level Control Valve Due To A Cap Screw Lodged Underneath the Valve Disk." On June 9, 1998, while at 65 percent power, high reactor water level resulted in turbine and reactor trips. About 50 minutes later non-safety related A and B feedwater pumps motors (5500HP) auto-started simultaneously and caused an overcurrent condition on 4 kV non-safety bus 1 that tripped the supply circuit breaker to 4 kV non-safety bus 1 and 4 kV safety bus 3. EDG B started and loaded to safety bus 3.

23. 2I Diablo Canyon Unit 1 and 2, LER 27594016, "Diesel Generators Started as Designed Upon De-Energization of Startup Bus Due to Offsite Wildfire." On August 15, 1994, with Units 1 and 2 at 100 percent power, two nearby transmission lines tripped due to a wildfire. Morro Bay Unit 3, one of four nearby generators, also tripped due to the system disturbance. At this time Diablo Canyon made plans for a two unit LOOP/reactor trip. About 13 hours after the initial fault, two more nearby 230 kV lines and Morro Bay Units 1 and 4 tripped due to the wildfire and all Diablo Canyon 1 and 2 EDGs started but did not load. Morro Bay Unit 2 was out of service for maintenance. Of interest was the dual unit aspect of the event.

The transmission and generation losses affected the distribution system voltage. It was subsequently determined that the early warning sirens were inoperable for approximately 5 hours due to the power losses**.**

24. 2T On December 14, 1994, a transmission line fault in Idaho affected 6 nuclear units in California and Arizona. A Western Systems Coordinating Council (WSCC) System Disturbance Report noted that the event resulted in the loss of 11,300 MW of generation for various reasons (underfrequency, overfrequency, low voltage), divided the grid into four islands, and 1.7 million customers lost power for times lasting a few minutes up to four hours. During the event, voltages were as low as 81 percent of rated and noted to exceed equipment maximum rated voltages of 105 percent [typically transformer maximum allowable voltages under loaded conditions limit maximum allowable system voltages]. The frequency was as low 58.5Hz in one island and as high as 61.4 Hz in another island.

The WSCC report identified 35 recommendations to address conditions that were not fully consistent with grid reliability criteria, relay misoperations, the need for additional system circuit breakers, improved methods to coordinate grid operation, and improved voice back-up communication systems.

Diablo Canyon Unit 1, LER 27594020, "Reactor Trip Due to Reactor Coolant Pump Bus Undervoltage that Resulted from an Electrical System Disturbance." On

December 14, 1994, while Units 1 and 2 were at 100 percent power, a transmission line fault in Idaho resulted in Unit 1 and 2 reactor trips due to reactor coolant pump motor bus undervoltage. Some primary 500 kV protective relaying was out of service for testing. EDGs 1-1 and 2-2 started but did not load as power was available to their buses. At the time of the trip, EDG 1-3 was paralleled to the grid for routine surveillance testing and picked up its safety bus load. EDG 1-3 tripped on overcurrent when attempting to restore offsite power approximately 45 minutes into the event. One containment fan cooler unit did not start due to a low speed timing relay failure. The instrument uninterruptible power supply (UPS) 2-2 experienced a failed ac input due to protective features that trip the UPS during voltage transients below 30 percent and above 20 percent normal. The UPS was reset by cycling the ac input circuit breaker. As part of corrective action, the RCP undervoltage and underfrequency trips were increased to the maximum allowed by the Technical Specifications.

PNO-IV-94062. The grid disturbance also affected WNP-2, Palo Verde 1 & 2, and San Onfre 2. While at 100 percent power several WNP-2 UPSs tripped off line and realigned to their alternate power source. Palo Verde Units 1 and 2 were operating at 98 percent and 100 percent, down-powered 1 percent, and received several UPS alarms on the Class IE electrical system. San Onfre Unit 2 was at 98 percent power and lost 40 MWe as a result of one of four turbine governor valves closing.

25. 4T On August 10, 1996, at 1549 a major electrical disturbance resulted from a fault on an overloaded 500 kV transmission line that sagged into a tree in Oregon. A Western Systems Coordinating Council (WSCC) System Preliminary Disturbance Report (Draft) noted that the event resulted in the loss of 25,455 MW of generation for various reasons (underfrequency, overfrequency, low voltage), 7.5 million customers lost power for periods ranging from a few minutes to six hours, and separated the grid into four islands. The industry report stated the contributing factors were high Northwest transmission loads due to hot weather throughout the WSCC region, large power transfers from Canada, and equipment out of service (three 500 kV transmission lines in the Portland area were forced out of service, a 500/230kV transformer was out for a modification, 2000 MW of generation to protect salmon migration). The report also stated the grid was operating in a condition in which a single contingency outage would overload parallel transmission lines; operating studies had not been conducted for this condition so the operators were unknowingly operating the system in a condition that violated WSCC minimum reliability criteria.

The WSCC report identified 30 recommendations to address conditions that were not fully consistent with grid reliability criteria, relay misoperations, the need for additional system monitoring, operating, and control facilities; improved operating personnel performance; improved system, operating, restoration planning; and preventive maintenance. NERC DAWG Report 18, 1996, indicates that multiple transmission line outages over a period of one hour prior to the disturbance, primarily related to hot temperatures, weakened the system and led to growing voltage oscillations. The NERC report also indicates that random outages over a

short time pushed the system into an abnormal condition in which it could not withstand the next contingency.

Diablo Canyon Units 1 & 2 are in the Northern Island where the frequency initially dipped to 58.54Hz, spiked to 60.7Hz, drooped again to 58.3Hz and returned to normal in 2.5 hours. The Northern Island lost 11,603 MW of load from manual and automatic underfrequency load shedding; and 6,246 MW of generation due to low voltage, out of step protection, and turbine-generator vibration. Diablo Canyon Unit 1, LER 27596012, "Reactor Trip on Units 1 and 2 Due to Major Western Grid Disturbance," states the electrical disturbance resulted a Unit 1 reactor trip due tripping its reactor coolant pumps (RCPs) on undervoltage and a Unit 2 reactor trip due to loss of two of four RCPs. Two Unit 2 containment fan cooler units tripped on thermal overload when they attempted to restart in high speed (improperly aligned).

Palo Verde is in the Southern Island where the frequency initially spiked to 61.3 Hz, dropped to 58.5 Hz and returned to normal in 70 minutes. The Southern Island lost 15,982 MW of load from manual and automatic underfrequency load shedding; and 13214 MW due to loss of excitation, overcurrent, underfrequency, overfrequency and line trips. Palo Verde Unit 3, LER 52896004, no title, states that Unit 1 and Unit 3 reactors tripped due to load fluctuations (a substantial 700MW decrease and significant load demand increase) that caused the steam bypass control system (SBCS) valves to open and exceed the variable over power trip (VOPT) setpoint within the core protection calculators (CPC). Unit 2 momentarily spiked to 102 percent power without reaching the (VOPT) setpoint.

Differences in the moderator temperature coefficient (MTC) levels explain why Palo Verde Units 1 and 3 tripped and Unit 2 did not trip. On Units 1 and 3, the MTC was more negative and near the end of core condition (EOC) on Units 1 and 3 (-34 and -23.5 pcm per degree Fahrenheit respectively). On Unit 2 the MTC was less negative at the beginning of core conditions (-9 pcm per degree Fahrenheit). The CPC VOPT is an expected response to the load change as is the opening of the SBCVs, excess steam demand, and resulting power increase due to decreasing temperature with a negative MTC. However, the closer the unit is to the EOC, the more rapid the power increase and the higher probability of reaching the VOPT setpoint.

PNO-IV-96042. At 1320 on August 12, 1996, Diablo Canyon reported that 100 of the 135 offsite early warning sirens had been without power. Power was subsequently restored to all sirens within 10 miles, and as of the reporting, all but 4 sirens were restored outside the 10 mile area. In addition, the grid disturbance resulted in frequency oscillations from 58.5 Hz to 61.3 Hz and slight load losses at San Onfre 1 & 2. WNP-2 also experienced frequency oscillations and remained operational.

26. 2I Diablo Canyon Units 1and 2, LER 27598013, "Actuations of Engineered Safety Features, Diesel Generators Started When Startup Power Was Lost Due to an Inappropriate Relay Setpoint (Personnel Error)." On November 20, 1998, while Units 1 an 2 were at 100 percent power, offsite power was lost while energizing

Startup Transformer (SUT) 1-1 through a new 230 kV circuit switcher 211-1. All six Unit 1 and 2 EDGs started but did not load as the emergency buses remained energized through their respective Auxiliary Transformer. The circuit switcher 211-1 tripped due to inappropriate setting of the SUT differential relays. The settings should have been re-evaluated due to changes in the inrush currents from the installation of the new circuit switcher, recent replacement of SUTs 1-1 and 2-1, and new switchyard capacitor banks. Of interest was the dual unit aspect of the event.

27. 2I Diablo Canyon Unit 1, LER 27501001, "Automatic Emergency Diesel Generator Start Upon Loss of Startup Power Due to 230 kV Line Arcing in Heavy Smoke From Escaped Fire Caused By Inadequate Administrative Controls." On April 5, 2001, while Units 1 an 2 were at 100 percent power, a scheduled and controlled brush burn generated heavy smoke that caused a phase to phase fault on 230 kV transmission lines that supply offsite power to Diablo Canyon. All Unit 1 and 2 EDGs started and did not load as the emergency buses remained energized through their respective Auxiliary Transformer. The 230 kV power was restored in 73 minutes. Of interest was the dual unit aspect of the event.

28. 2I Peach Bottom Units 2 and 3, LER 27796007, "Actuation Due to a Loss of One Off-Site Electrical Source as a Result of Off-Site Substation Activities." On June 4, 1996, while Unit 2 was at 80 percent power and Unit 3 was at 100 percent power, the 220 kV 2SU (licensee nomenclature for its transmission line) off-site power source tripped as a result of a transmission system perturbation caused by remote switching operation. All station buses transferred to an alternate power source. Of interest was the dual unit aspect of the event.

29.I Peach Bottom Unit 2, LER 27701001, "Loss of Offsite Power Source Results in Specified System Actuation and Safety System Functional Failure." On June 18, 2001, while Unit 2 and 3 were at 100 percent power, a raccoon caused a phase to phase short on offsite power supply 343SU-E (licensee nomenclature for its transmission line). The emergency 4.16 kV buses on Units 2 and 3 transferred to their respective offsite power supply. Of interest was that due to a procedure deficiency, two of four emergency buses per unit would not have automatically received power from their respective EDGs in the event of a LOOP.

30. I Fort Calhoun, LER 28595003, "Manual Reactor Trips Due to Water Leakage Into Reactor Coolant Pump Lube Oil." On May 11, 1995, and May 24, 1995, the reactor was manually tripped from 100 percent power and the EDGs started but did not load. By design reactor trip logic initiates autostart of the EDGs.

31. L0 Indian Point 3, LER 28697008, "Automatic Actuation of Emergency Diesel Generators Following a Loss of Offsite Power Due to a Personnel Error that Inadvertently Grounded the Feed to the Station Auxiliary Transformer." On June 16, 1997, while at 0 percent power, a Consolidated Edison Company substation operator mistakenly closed the wrong ground switch to support maintenance and caused a 138 kV phase to ground fault on the Buchanan feeder that was supplying offsite power to IP3. Two out of three EDGs started and loaded. One EDG was out of service for maintenance. The LOOP lasted 43 minutes.

32. S Indian Point Unit 3, LER 28600008, “Automatic Reactor Trip As A Result of Direct Trip From the Buchanan 345 kV Substation Upon Protective Relay Conductors Low Insulation Resistance Fault.” On June 9, 2000, while at 100 percent power, faulted protective circuitry wiring between IP3, IP3 138 kV control house, and the Buchanan 345 kV Substation control house resulted in generator and reactor trips.

33. R Three Mile Island Unit 1, LER 28997007, “Generator Output Breaker Failure Resulting In A Loss Of Offsite Power and Reactor Trip.” On June 19, 1997, a switchyard relay technician reported unbalanced current readings on phase B of generator 230 kV output circuit breakers GB1-02 (current readings on each phase were 1020, 420, 1080 amps) and GB1-12 (current readings on each phase were 1182, 2100, 1140 amps) and a thermal scan was planned for June 23, 1997. [phase currents are usually balanced within a few percent of each other]

On June 21, 1997, at 0956 while at 100 percent power, A and B Main Transformer top oil high temperature alarm was received and transformer cooling spray was initiated at 1022 and terminated 1109. At 1145 the generator reactive power was raised to +220 VARS per load dispatcher request, and lowered to +200 VARS at 1200 per the shift supervisor direction due to main transformer temperature rise. At 1214 230 kV generator circuit breaker GB1-02 phase B faulted to ground and failed to open. The other generator circuit breaker GB1-12 opened as designed and resulted in generator and reactor trips. An arc re-strike on Phase B resulted in failure of GB1-12 and a fault on another 230 kV bus. The faulted 230 kV buses resulted in the opening of additional 230 kV circuit breakers and a LOOP. Both EDGS started and loaded. Offsite power was restored in 90 minutes.

The data gathered from the event indicated undervoltage occurred 2 seconds after the generator and reactor trips. The generator residual voltage continued to feed one fault for 17.7 seconds.

Two reactor coolant system, loop A and B, wide range pressure instruments indicated failed to zero signals to the plant process computer. Although the instruments were not directly affected by the loss of power, the plant process computer input from these instruments feeds through the Diverse Scram System and this system was de-energized by the LOOP.

LER 28997008, “Control Rod Trip Insertion Times Exceed TS Section 4.7.1.1 Limits,” dated June 21, 1997, reports that, as a result of the LOOP, power was lost to the control rod drive mechanisms. The licensee evaluation of the scram found that 8 of 61 control rods exhibited slower than normal scram times and (4 of 61 were not within Technical Specification limits) due to the hydraulically induced effect from reduced clearances in the thermal barriers because of deposits on the internal check valves and between the thermal barrier parts. The licensee determined that there would be no adverse affects associated with this condition.

LER 28997010, “Pilot Operated Relief Valve (PORV) Inoperability Due to Being Mis-Wired and Failure To Perform Post-Maintenance Test (PMT) Following Replacement During 11R Refueling Outage,” dated October 12, 1997, reported that the PORV installed during 11R refueling outage was not capable of being opened

during the operating cycle prior to refueling outage 12R. Consequently, the PORV was failed during the June 21, 1997, event.

The NRC ASP Program determined the conditional core damage frequency was 9.6E-06.

34. I Pilgrim, LER 29397007, “Safeguards Buses De-Energized and Losses of Offsite Power During Severe Storm While Shut Down.” On April 1, 1997, while at 0 percent power, a LOOP occurred during a severe storm. Severe undervoltage transients occurred on the 345 kV transmission system that resulted in automatic shutdown of safety related 480/120v voltage regulating transformers that were installed in 1992. Of interest was that these transformers contain programmable microprocessor control units that automatically shutdown the transformer when the voltage drops to 384v (20 percent of nominal), in this case for 6 to 8 cycles.

35. S Salem Unit 2, LER 31195004, “Engineered Safety Features Actuation (Reactor Trip) During Unit 2 Controlled Shutdown Per Technical Specification 3.0.3.” On June 7, 1995, Unit 2 began a controlled shutdown from 100 percent power due to the inoperability of both Residual Heat Removal trains. At 20 percent reactor power, the station non-safety buses were transferred from auxiliary to start-up power (the safety buses are always feed from “startup” power). At 14 percent reactor power the turbine was tripped, and both 500 kV generator output circuit breakers 1-9 and 9-10 opened. However, 500 kV circuit breaker 1-9 breaker failure relay operated unexpectedly, and opened two more 500 kV circuit breakers and five 13 kV breakers. An automatic reactor trip followed due to low flow conditions in two reactor coolant pumps from the loss of power. (Westinghouse previously notified users that its SBF-1 breaker failure relay was susceptible to premature actuation and recommended actions to prevent malfunction)

36. S Arkansas Nuclear One, LER 31395009, “Reactor Trip on High Reactor Coolant System Pressure Which Resulted From Closure Of The Main Turbine Governor And Intercept Valves Due To The Failure Of A Main Generator Output Circuit Breaker Contact.” On July 15, 1995, while at 100 percent power, a reactor trip occurred when one of the two main 500 kV generator output circuit breakers was opened for maintenance. The Electro Hydraulic Control system sensed that the both 500 kV generator output circuit breakers were open due to a failed auxiliary contact in the closed 500 kV generator output circuit breaker.

37. 2PL0 D.C. Cook Unit 1 & 2, LER 31600004,”Partial Loss of Offsite Power Results in Start of Emergency Diesel Generators.” On June 8, 2000, while Units 1 and 2 were at 0 percent power, Transmission Department personnel inadvertently opened the wrong 34.5 kV switch resulting in a partial loss of power to Unit 1 and 2 Train A buses. The EDGs on both units started and loaded as expected. It was planned that the Interface Agreement between D.C. Cook and American Electric Power (AEP) Western Transmission Region would be revised to require concurrent verification of switching operations in the switchyard.

38. R Calvert Cliffs Unit 2, LER 31896001, “Automatic Plant Trip Due To Partial Loss of Offsite Power.” On February 2, 1996, while at 100 percent power, plant personnel

and System Operation and Maintenance Department (SOMD) were troubleshooting a switchyard circuit breaker with two out of three offsite transmission lines in service. Less than adequate work control and a relay card failure in a 500 kV circuit breaker caused three 500 kV switchyard circuit breakers to trip resulting in the concurrent : (1) loss of power to the Unit 2 reactor coolant pumps (RCPs) and the automatic reactor trip of Unit 2 on low RCP flow and (2) loss power to one vital bus on Unit 1 and another on Unit 2 and the start and loading of EDGs 12 (Unit 1) and 21 (Unit 2). During troubleshooting activities a SOMD analyst recommended closing of the switchyard circuit breaker and no one recognized that this invalidated the original premise of the plant circuit breaker troubleshooting plan that no breaker would be operated.

39. I Diablo Canyon 2, LER 32397002, “Reactor Trip on Low-Low Steam Generator Water Level Following the Failure of Main Feedwater Pump 2-1 Due to Mechanical Problems.” On March 29, 1997, the reactor tripped from 50 percent power on steam generator (SG) water level low-low in SG 2-2 due to loss of one main feedwater pump. Prior to the reactor trip, operators compensated for the partial loss of feedwater by rapidly reducing the load from 100 percent to 50 percent and starting all (two motor driven and one steam driven) auxiliary feedwater pumps. EDGs 2-2 and 2-3 started due to the momentary voltage dip on their respective buses during the bus transfer to start-up power. The EDGs did not load as the voltage recovered quickly. DG 2-1 did not start due to different loading conditions on the vital bus. By design, the EDG autostarts if the voltage has not recovered in one second.

40. I Diablo Canyon 2, LER 32397003, “Manual Reactor Trip on Loss of Normal Feedwater Due to Unknown Condensate/Feedwater Transient.” On July 27, 1997, the reactor was manually tripped after the loss of both main feedwater pumps. Operators initiated a load reduction and two motor driven and on a steam driven auxiliary feedwater pumps started automatically. EDG 2-2 started due to the momentary voltage dip. The EDG did not load as the voltage recovered quickly. By design, the EDG autostarts if the voltage has not recovered in one second.

41. I Diablo Canyon Unit 2, LER 32398005, “Manual Reactor Trip Due to Heavy Debris Loading of the Circulating Water System During a Pacific Ocean Storm.” On December 1, 1998, operators initiated rapid Unit 2 generator load reduction from 100 percent to 50 percent and subsequently tripped the reactor due to heavy debris loading of the circulating water systems during a Pacific Ocean storm. EDG 2-2 started following bus H transfer to startup power, but did not load as startup power was available to the 4 kV buses. By design, the EDG autostarts if the voltage has not recovered in one second.

42. L0, PL Brunswick Unit 2, LER 32494008, “Dispatcher Switching Evolution Results in Loss of Offsite Power to Unit 2. On May 21, 1994, while Unit 2 was at zero power the dispatcher made an error while executing six actions as part of returning a 230 kV line to service. The actions were completed in 52 seconds and the time between actions did not allow for self checking or feedback from the Brunswick control room. All Unit 1 and 2 EDGs started and the Unit 2 EDGs loaded.

43.L0 Brunswick Unit 1, LER 32500001, “Loss of Offsite Power During a Refuel Outage.” On March 3, 2000 while Unit 1 was at zero power and Unit 2 was at 100 percent power, utility transmission maintenance technicians mispositioned a switch in protective relay circuitry during switchyard relay trip activities. A LOOP occurred on Unit 1. The Unit 1 and 2 EDGs started. The Unit 1 EDGs loaded; however, one EDG failed to run due to failure of is excitation system transformer.

44. S Sequoyah Unit 1, LER 32796006, “A Failed Coupling Capacitor Potential Device Caused Actuation of the Generator Backup/Transformer Feeder Relay Tripping the Turbine and the Reactor.” On June 26, 1996, while at 100 percent power, a coupling capacitor potential device in the 500 kV switchyard faulted and caught fire resulting in generator, turbine, and reactor trips.

45. S Sequoyah Unit 2, LER 32895007, “Reactor Trip With Auxiliary Feedwater Start and Feedwater Isolation as a Result of a Switchyard Power Circuit Breaker Failure.” On December 12, 1995, while at 100 percent power, a 161 kV transmission line circuit breaker opened to clear a ground fault due to a latent defect in one of its insulators. The perturbation was sensed by protective circuitry on 2 of 3 and all synchronous circulating water pump motors (CCPM) on Unit 1 and Unit 2, respectively. Unit 2 reactor was manually tripped due to loss of condenser vacuum due to the loss of the CCPMs. Security system lost power after transferring to its UPS but its battery was “faulty.”

46. T Beaver Valley, LER 33494005, “Main Transformer Bushing Failure Results in Electric Grid Disturbance and Dual Unit Reactor Trip.” On June 1,1994 while Units 1 and 2 were at 100 percent power, a bushing failure on the Unit 1 Main Transformer initiated a voltage disturbance on the grid. Generator and reactor trips followed. The transformer fault also causes a voltage perturbation on the grid that caused inadvertent actuation of protective relaying that tripped the 138 kV transmission line that was supplying Unit 2 System Station Service Transformer (SSST) 2A. The loss of SSST 2A resulted in actuation of the two reactor coolant pump underfrequency protective relays, a Unit 2 reactor trip, and the start and loading of one Unit 2 EDG.

47. I Beaver Valley Unit 1, LER 33496008, “Reactor Trip During Solid State Protection System Turbine Testing.” On May 31, 1996, the reactor tripped due to an inadvertent turbine trip signal generated during RPS Testing. All auxiliary feedwater pumps (2 motor driven and one steam) started. The B train EDG automatically started but did not load in response to a momentary undervoltage condition. The licensee stated that calculations showed the EDG may start as the EDG undervoltage diesel start trip setpoint is very close to the actual value expected during a fast bus transfer and reactor coolant pump re-starts.

48. 2T Beaver Valley Units 1 & 2, LER 33497005, “Inadvertent Operation of 345 kV Backup Timer Relay Results in Dual Unit Reactor Trips.” On March 19, 1997, while Units 1 and 2 were at 100 percent power, both units experienced simultaneous reactor trips following a grid disturbance. A fault on remote 345 kV transmission line, whose primary protective relaying was out of service, resulted in shedding various loads through opening of transmission line circuit breakers. Eight circuit breakers opened in the Beaver Valley Switchyard. Beaver Valley Units 1 and 2 reactors tripped after

Unit 1 and 2 generator 345 kV output breakers opened due to inadvertent operation of a breaker failure and its backup timer relays on the #3 345 kV bus in response to the disturbance. An events recorder indicated Unit 1 safety bus voltage dipped for 0.2 seconds and Unit 1 EDG-1 autostarted (voltage dip duration was above setpoint of 0.198 seconds) and the other safety bus voltage dipped for 0.166 seconds but EDG-2 did not autostart (voltage dip duration was below setpoint of 0.194 seconds).

49. S St. Lucie Unit 1, LER 33594007, "Automatic Reactor Trip on Loss of Electrical Load Due To Flashover On 240 kV Switchyard Potential Transformer." On October 26, 1994, while at 100 percent power, a potential transformer failed and caught fire in the 240 kV switchyard resulting in generator, turbine, and reactor trips. As a result, Utility Power Delivery replaced its potential transformer and began replacing other potential transformers in its switchyard maintenance coating program.

50. T North Anna Unit 1, LER 33896010, "Automatic Reactor Trip Due to Failure of a Generator Negative Phase Sequence Relay." On October 24, 1996, while at 100 percent power, a fault occurred on a 230 kV transmission line in North Carolina and produced a negative phase sequence current of 1 percent at North Anna. The line fault cleared; however, Unit 1 reactor tripped due to the negative phase currents from the fault and the 4.6 percent downward calibration drift of its main generator negative phase sequence relay that was set for approximately 6 percent.

51. S North Anna Unit 1, LER 33800004, "Automatic Reactor Trip Due to Malfunction of Generator Circuit Breaker." On May 7, 2000, while 100 percent, a suspected ground in one of two 500 kV generator circuit breakers resulted in generator, turbine, and reactor trips.

52. S Fermi 2, LER 34198001, "Automatic Reactor Scram Due to Main Turbine Trip." On February 1, 1998, while at 96 percent power, a Nuclear Power Plant Operator actuated a test switch in the 345 kV relay house for a 345 kV transmission line that tripped the transmission line circuit breaker, both 345 kV generator output circuit breakers, and the reactor. The test exposed degraded conditions that existed on two 345 kV transmission line relays that activated the circuit breaker trips. Maintenance of protective relaying equipment in the 345 kV switchyards is performed by corporate Equipment Performance and Predictive Maintenance personnel under a Fermi work request.

53. 2T Limerick Units 1& 2, LER 35295002, "Dual Unit SCRAM Due to an Offsite Electrical Transmission Disturbance." On February 21, 1995, while Units 1 & 2 were at 100 percent power, 220 kV transmission line 220-61 to Limerick tripped following a fault. A circuit breaker at an offsite substation failed, causing a voltage spike that faulted and failed a lightning arrester. Several other transmission lines tripped as a result of the fault. Transmission line 220-61 automatically isolated in 2 seconds and returned to service in 4 seconds but not before Unit 1 and 2 main transformer relays initiated Unit 1 and 2 generator and reactor trips. The primary and secondary ground fault detection relays failed to properly trip at the offsite substation before the Limerick units tripped. About 0.5 seconds after 220-61 was restored, 220 kV transmission line 220-60 tripped due to ground fault current at another offsite

substation. The safety bus voltage dropped from 4320v to 4020 v which was not enough to start the EDGs. One Unit 2 non-safety 13 kV bus failed to transfer due circuit breaker failure.

54. T Limerick Unit 2, LER 35396004, "Reactor SCRAM Resulting From a Main Generator Lockout Due to the Actuation of a Volts/Hertz Relay Caused by an Inadequate Design Change Package." At 1033 on May 5, 1996, while at 100 percent power, inappropriate actuation of a volts/hertz relay due to a low setpoint (made in 1988) resulted in generator, turbine, and reactor trips. NERC DAWG Report 6, 1996, indicates that at 1009, the Pennsylvania, New Jersey, and Maryland (PJM) grid started experiencing grid instabilities due a fault in Delaware that tripped several transmission lines and transformers. The industry report indicates the incident occurred during modification work at a substation in Delaware and tripped 15 high voltage circuit breakers and 290,000 customers lost electric service. Just after 1009 and again at 1030 the load dispatcher requested Limerick Unit 2 to pick up additional reactive load [and raise the generator voltage, and the volts/Hertz] to help stabilize the grid.

55. S Limerick Unit 2, LER 35399006-01, "Generator Lockout and Scram Due To Failure of B Phase Main Transformer Surge Arrestor." On December 31, 1999, while at 100 percent power load dispatchers were removing a 500 kV capacitor bank from service when a 500 KV generator output circuit breaker phase B grading capacitor failed. The capacitor failure resulted in a voltage transient that caused a failure of the B-phase main transformer 500 kV lightning arrester which was sensed by ground fault protective relaying that resulted in a generator and reactor trip. The undervoltage from the ground fault caused the Drywell Chiller, Reactor Building Enclosure HVAC system, and Turbine Building Enclosure HVAC system to trip.

56. I LaSalle Unit 1, LER 37394011, "Unit 1 Scram Due to a Feedwater Signal Spike." On July 8, 1994, while at 58 percent power the reactor tripped due to a feedwater transient. Of interest was the that EDG "B," which was running to the grid for a scheduled surveillance test, assumed an abnormal amount of current as a result of the grid disturbance caused by the loss of the Unit 1 generator. The licensee estimated that the EDG current exceeded 600 amps for 5 minutes and did not reach its overcurrent trip; no damage was found during inspection and tests. [The EDG is rated for approximately 450 amps so this was a 133 percent overload.]

57. S LaSalle Unit 1, LER 37301001, "Reactor Scram Due To Electrical Fault on Transformer Yard 345 kV Line C Phase." On January 31, 2001, while at 100 percent power, a dirty support insulator between the Unit 1 main power transformer and the 345 kV switchyard flashed over causing generator and reactor trips. The electrical perturbation caused the loss of the Unit 2 2A heater drain pump and a unit load reduction.

58. T Waterford Unit 3, LER 38295002, "Reactor Trip and Non-Safety Related Switchgear Fire." On June 10, 1995, while at 100 percent power a failed 230 kV lightning arrester at the Waterford Substation, [Waterford Unit #2 transformer] caused the Waterford Unit 3 Main Transformer protective relays to operate and trip the

generator and reactor. A circuit breaker failure resulted in a non-safety related 6.9 kV switchgear fire that lasted approximately one hour. EDG "A" started and loaded as a result of the loss of power to one safety bus. The NRC ASP Program determined the conditional core damage frequency was 9.1E-05.

59. S Susquehanna Unit 2, LER 38895005, "Reactor Scram Following Turbine Trip on Load Reject." On April 15, 1995, while at 100 percent power, one 500 kV motor operated disconnect switch was opened to support switchyard bus maintenance. An incorrectly configured cam switch in the 500 kV motor operated disconnect switch activated a protective relay causing a generator and reactor trip. The voltage transient from the restart of the B Reactor Recirculation Pump resulted in several unexpected containment isolation valve isolations and de-energized two instrument ac power panels.

60. R Harris Unit 1, LER 40096008, "Reactor Trip Due to the Failure of a Switchyard Breaker Disconnect Switch." On April 25, 1996, while at 100 percent power and one of two generator output circuit breakers in service, a manual 230 kV disconnect switch for the in-service generator output circuit breaker failed resulting in the opening of the other generator circuit breaker. Generator and reactor trips followed. Undervoltage relay contact bounced closed momentarily following the shock from opening and closing bus circuit breakers during bus transfer. The false undervoltage signal resulted in the loss of several non-safety motors and the B train safety bus. The B EDG started and loaded.

61. PL Nine Mile Point Unit 2, LER 41098006, "Engineered Safety Features Actuations Due to Partial Loss of Offsite Power." On March 28, 1998, while at 92 percent power, a partial LOOP lasting approximately 195 minutes occurred following the failure of a Scriba 345 kV Switchyard circuit breaker that de-energized the 345/115 kV transformer that supplies one of two 115kv sources of offsite power to Unit 2. Division I and III EDGs started and loaded. The transmission entity had responded to a "345 kV Breaker Trouble" alarm received by the grid control operator and classified the alarm as not requiring notifications to NMP2.

62. R Nine Mile 2, LER 41099010, "Unit 2 Reactor Trip due to a Feedwater Master Controller Failure." On June 24, 1999, while at 100 percent power the reactor tripped due to the failure of the feedwater master controller. The 13.8 kV buses fast transferred to offsite power and a 115kV line circuit breaker tripped unexpectedly. Division I and III load electrical power and their EDGs started and loaded. The 115 kV line tripped because a primary protective relay for one of the 345 kV main generator output circuit breakers failed, initiating a backup protective scheme that tripped the 345/115 kV feeder that was supplying offsite power to Unit 2.

63. S Grand Gulf, LER 41695010, "Reactor Scram Due To Turbine/Generator Trip." On July 30, 1995, while at 100 percent power, a current transformer in one of the 500 kV generator output circuit breakers failed causing generator, turbine, and reactor trips.

64. R Grand Gulf, LER 41600005, "Automatic Scram Due to Offsite 500 kV Circuit Breaker Failure." On September 15, 2000, while at 100 percent power, a ground fault and

500 kV circuit breaker failure at an offsite switchyard that directly feeds the Grand Gulf 500 kV Switchyard resulted in generator load fluctuations, fast closure of the turbine control valves (TCV), and a reactor trip. One EDG started and loaded due to low grid voltage. The end of cycle reactor recirculating pump (EOC-RPT) trip did not operate. LER 41600006, "Unanalyzed Condition-Turbine Control Valves May Move in Excess of Design Assumptions," found that a main generator partial load rejection can actuate circuitry that causes TCV motion in excess of design assumptions and may not always actuate a reactor scram/EOC-RPT downshift. (EOC-RPT logic was not satisfied.)

65. T Grand Gulf, LER 41601003, "Automatic Scram Due to Offsite 500 kV Switchyard Problem and EOC-RPT Pump Failure." On August 7, 2001, while at 100 percent power, a 500 kV disconnect switch failure at a remote switchyard that feeds the Grand Gulf switchyard resulted in generator load transient, turbine trip, and scram. The EOC-RPT did not occur.

66. S Vogtle Unit 2, LER 42594001, "Automatic Reactor Trip Due to Turbine Trip Resulting From Trip Of Switchyard Breakers." On January 7, 1994, while at 100 percent power, a loose wire connection in a 500 kV switchyard protective circuit for a 500 kV electrical reactor tripped one of two 500 kV generator output circuit breakers. Two additional 500 kV circuit breakers tripped, including the remaining Unit 2 500 kV generator output circuit breaker, due to low air pressure indications that activated breaker failure protective relaying. Generator, turbine, and reactor trips followed.

67. S Seabrook Unit 1, LER 44398014, "Reactor Trip Due To Pole Disagreement on 345 kV Breaker." On December 22, 1998, while at 100 percent power, a pole disagreement switch [a switch that monitors whether all three poles of a circuit breaker operate together] in one of two 345 kV generator output circuit breakers malfunctioned when it was opened to support transmission line maintenance. The switch malfunction activated backup protective relays that opened three more 345 kV circuit breakers, including the remaining generator output circuit breaker. Generator, turbine, and reactor trips followed. All but one bus, non-safety 4 kV bus, transferred to offsite power. One Startup Feedwater Pump failed to start due to the loss of power, and the electric and steam driven Emergency Auxiliary Feedwater Pumps automatically started. During the event the voltage transient caused some safety loads (Control Room Makeup Fan, Spent Fuel Pool Cooling Pump, Train-A Switchgear Area Supply and Return Fans, and three Containment particulate Radiation Monitor isolation valves) and non-safety loads (Loose Parts Monitoring) to trip and not restart when power was restored. The license reported that this was the second event where this switch malfunctioned however, the first event was not required to be reported as it did not cause a reactor trip.

68. S Comanche Peak Unit 1, LER 44597009, "Slow Opening of the Unit 1 East Bus Supply Resulted in Turbine Trip and Subsequent Reactor Trip." On October 27, 1997, while at 100 percent power one of the two 345 kV generator outputs circuit breakers was slow to open during test, activating backup protective relaying that resulted in generator, turbine, and reactor trips. The licensee also noted that the work instructions were insufficient in that the backup protective relaying should have been defeated for test.

69. L Bryon Unit 1, LER 45498017, “Line 0621 Trip and Subsequently, Loss of Unit 1 SATs Causing Loss of Offsite Power. On August 4, 1998, while at 100 percent power, a 345 kV transmission line faulted and tripped two 345 kV circuit breakers at Bryon and two at the remote end of the transmission line. Lightning was believed to be the most likely cause of the fault and it had no effect on the NPP. Of interest was that during power restoration, a LOOP occurred while at 100% power when a 345 kV circuit breaker supplying offsite power to the NPP opened upon reclosure of one of the two Bryon 345 kV circuit breakers due to failure a 345 kV transmission line relay failure to reset, a NPP 345 kV switchyard alarm response procedure inadequacy, and improper 345 kV circuit breaker synchronization timing. Both EDGs started and loaded. Power was restored in approximately 8 hours.

70. S Bryon Unit 2, LER 45500001, “Automatic Reactor Trip System Actuation Due to Off-site Power Line Fault and Failed Air Circuit Breaker Load Rejection Contact.” On January 13, 2000, while at 100 percent power, a fault resulted after a static line on an offsite transmission tower associated with Unit 1 fell on one phase of a transmission line associated with Unit 2. Protective relays isolated the fault opening two Bryon 345 kV switchyard circuit breakers including one of the Bryon 2 345 kV generator output circuit breakers. A failed control contact in the other Bryon 345 kV generator output circuit breaker resulted in generator, turbine, and reactor trips.

71. S River Bend Station, LER 45899014, “Automatic Reactor Scram Due to Inappropriate Work Activities in the Plant Substation.” On October 29, 1999, while at 100 percent power, a utility technician who was authorized to install a communications microwave panel in the 230 kV Fancy Pont Substation, mistakenly tested and activated protective relay circuits for the main generator 230 kV output circuit breakers resulting in generator, turbine, and reactor trips.

72. S Clinton, LER 46196004, “Inadequate Job Preparation for a Preventative Maintenance Task on a Switchyard Breaker Causes Main Steam Isolation Valve Closure and Reactor Scram.” On April 9, 1996 while at 100 percent power, protective relaying activated while utility personnel were maintaining one of the 345 kV circuit breakers that supplies offsite power through the reserve auxiliary transformer (RAT) to the safety and non-safety related buses when the unit is on line. The safety buses transferred to an alternate supply in 2.5 seconds. The non-safety buses lost power causing the turbine building main steam line high temperature instruments to lose power, initiate nuclear steam protection system logic that closed the main steam isolation values, and scram the reactor. The severe transients on the normal power supply caused the circuit breaker for the rod control and information system core map display to trip on an overcurrent condition caused by the voltage decay. The reactor operator observed that some of the rods did not indicate full insertion, initiated a manual scram, and Alternate Rod Insertion after some rods still indicated they had not inserted. It was determined that all rods did scram and that the rod insert indications were anomalous due to an unknown cause.

73. L0 Clinton Power Station, LER 46199002, “Offsite Fault on In-service Offsite Electrical Supply Line Causes Loss of Offsite Power to Safety Related-Electrical Buses.” On January 6, 1999, while at zero power and one of two transformers that provide

offsite power was out-of-service for scheduled maintenance, the 138kV offsite power feed to the in-service transformer faulted. A guy wire for an offsite power pole pulled out of the ground, causing the pole to lean and fault. All three EDGs started and loaded. The EDGs ran for approximately 10 hours until the safety buses were transferred to alternate offsite power.

74. R Callaway, LER 48399003, “Manual Reactor Trip Due To Heater Drain System Pipe Rupture Caused by Flow Accelerated Corrosion,” and LER 48399005, “Operating Conditions Exceeding Previously Analyzed Values Results in Inoperability of Both Offsite Power Sources.” On August 11, 1999, at 0907 the reactor was manually tripped from 100.78 percent power due to a feedwater drain line pipe rupture (LER 48399003). On August 12, 1999, while at zero power, the switchyard voltage supplied from the grid decreased below the minimum operability level established in station procedures for 12 hours. The voltage drop resulted from near peak levels of electric system loading and the transport of large amounts of power on the grid near Callaway. The grid conditions were due to high temperatures. Licensing correspondence (ML010990214) notes that the licensee stated that the deregulated wholesale power market contributes to conditions where higher grid power flows are likely to occur as in this case.

The licensing correspondence also indicated that the plant was subsequently modified to replace the existing transformers that normally supply power to the safety buses from the 345 kV transmission network with new transformers that include automatic tap changers. Due to changes in the nature of the transmission system in the vicinity of Callaway, a wider range of grid voltages were expected in the future. The new transformers combined with the previously installed 6 MVAR capacitor banks will assure acceptable voltages are provided to the safety buses. In addition, the licensee advised that the transmission system operator, AmerenUE Energy Supply Operations (ESO) monitors and models the grid voltage, including the Callaway switchyard voltage. In addition to seasonal grid load flow analysis, ESO performs real time analysis under conditions being experienced and postulated credible contingencies such as the loss of Callaway.

75. T Callaway Unit 1, LER 48300002, “Automatic Reactor Trip Initiated By Reactor Coolant Pump Trip Caused By Motor Current Imbalance Due To External Transmission System Disturbance.” On February 13, 2000, while at 100 percent power, a fault occurred in a neighboring electric cooperative’s transmission line. The fault did not clear due to neighboring utility protective relay weaknesses, and for the next eight minutes, multiple subsequent faults were introduced onto the system. Approximately one minute into the event the B reactor coolant pump (RCP) tripped on current imbalance causing a low flow condition that tripped the reactor. Subsequent to the reactor trip all RCPs and main condenser circulating water pump motors tripped on motor current imbalance. NRC Inspection Report 50-483/00-01 notes that breaker protection for a 161 kV transmission line in southeast Missouri did not operate causing significant voltage fluctuations on the Callaway switchyard buses.

76. T South Texas Unit 1, LER 49895013, “Turbine Trip and Reactor Trip Due to Main Transformer Lockout.” On December 18, 1995, while Unit 1 was at 100 percent

power, a transmission line fault with a grounded plant current transformer protective circuit wiring caused backup protective relaying to incorrectly trip the main transformers. Generator, turbine and reactor trips followed. The train A EDG automatically started and loaded. A pinched wire caused the grounded condition.

77. PL South Texas Unit 2, LER 49999003, "Engineered Safety Feature Actuation and Entry Into Technical Specification 3.0.3 Following a Partial Loss of Offsite Power, and Failure to Verify ESF Power Availability per Technical Specification Requirements." On March 12, 1999, while at 100 percent power, a partial LOOP occurred after a 345 kV circuit breaker faulted. EDGs "B" and "C" started. EDG "C" loaded and EDG "B" did not load as its output circuit breaker did not close due to a failed to cell switch.

78. S South Texas Unit 2, LER 49901002, "Manual Reactor Trip as a Result of Switchyard Breaker Failure." On March 1, 2001, while at 95 percent power, the plant was realigning the 345 kV switchyard circuit breakers to support maintenance. Unknown to the switchyard and operating crews, one pole of a 345 kV circuit breaker stuck open after it was closed creating a phase imbalance that tripped Circulating Water Pump 21 on phase balance overcurrent. The imbalance also caused a main generator negative phase sequence alarm, high voltage alarms on Standby Bus 2F and Auxiliary Bus 2H, and the trip of Circulating Water Pumps 22 and 24. A manual reactor trip was initiated.

79. I Palo Verde Unit 1, LER 52895001, "Entry Into Technical Specification 3.0.3 Due To Transient Grid Voltage." On February 15, 1995, while at 100 percent power Control Room personnel were notified by the Energy Control Center (ECC) that the Palo Verde switchyard voltage had dropped below the administratively imposed limit of 525 kV for 2.5 minutes. The voltage was restored to normal level of 528 kV by a 100 MVAR increase on Unit 1. Of interest was that (1) ECC personnel had not anticipated the severity of Palo Verde switchyard voltage drop to 518 kV during performance of switching activities: lowering VARS and removing a transmission line from service, and the (2) the influence of the Palo 1 on the switchyard voltage.

80. I Palo Verde Unit 1, LER 52895003, "Entry Into Technical Specification 3.0.3 Due To Transient Grid Voltage," and NERC disturbance report. On July 29, 1995, while at 100 percent power Control Room personnel were notified by the Energy Control Center (ECC) that the Palo Verde switchyard voltage had dropped below the administratively imposed limit of 524 kV for 10 seconds. NERC DAWG Report No. 13, 1995, indicated that the low voltage condition was due to a fault that resulted in the loss of 206 MVAR of capacitor banks and several generating units that were providing voltage support. The voltage at Palo Verde decreased from 529 kV to 523.6 kV, increased to 537.7 kV, and then stabilized at 532.8 kV after ECC requested the MVARs be adjusted to assist in returning the voltage to normal. Of interest was the influence of the Palo Verde 1 on the switchyard voltage.

The internal review of this report resulted in the additional events of interest that for the purposes of better emphasizing some of the points in this report.

81. I DC Cook Units 1 and 2, LER 31599022-01, “Electrical Bus Degraded Voltage Could Be Too Low For Safety Related Loads,” June 23, 1999. Licensee electrical analyses found the degraded voltage setpoints may be too low; the licensee set the relays so as to prevent spurious ESF actuation due to short voltage dips. The licensee committed to make several modifications to reduce transformer loading including the addition of a switchyard circuit breaker, one voltage regulating transformer per train, and the replace of a few motor cables. The licensee also planned to establish a working agreement between the American Electric Power System Operations and the NPP so as to improve the minimum voltage during sustained degraded voltage conditions.

82. I DC Cook Units 1, LER 31599028, “ESF Actuation and Start of Emergency Diesel Generator 1CD During Transformer Maintenance,” December 16, 1999. With the reactor a 0 power, inadvertent actuation of a protective relays started and loaded one EDG. Of interest was that the licensee stated the cause of this event was inadequate ownership interface between the NPP Maintenance Department and American Electric Power (AEP) Division (transmission and distribution) personnel. The LER also stated that there was an opportunity to resolve the lack of interface in that the corrective actions were similar to this event but insufficient to prevent recurrence.

83. Diablo Canyon 1 & 2, LER 27595007, “230 kV System May Not Be Able To Meet Its Design Requirements For All Conditions Due To Personnel Error,” August 8, 1995. The 230 kV system may not be able to meet its design requirements for all system loading conditions. Studies indicated that during peak loading, all transmission lines and Morro Bay Power Plants 3 & 4 need to be in service to meet Diablo Canyon plants’ voltage requirements. The LER states that “An assessment of past 230kV operability found that, 47 times in the last five years, the 230 KV system should have been declared inoperable due to degraded voltages.” A subsequent Diablo Canyon 1 & 2 LER 27596005, “Potential For Flashing in Containment Fan Cooler Units,” July 31, 1996 states that a review of past configuration of the offsite power supplies found that it was degraded for approximately 130 hours per year since 1990.

Table A1 – Types and Number of Grid Events 1994-2001

(The numbers in the table correspond to the event numbers in Appendix A)

Type of event			Number of reactor events								
			94	**95**	**96**	**97**	**98**	**99**	**00**	**01**	**T**
S			1 4 49 66	12 35 36 45 59 63	44 72	21 68	52 67	55 71	6 32 51 70	57 78	24
T			17 24 24 46	19 53 53 76 58	13 25 25 25 25 50 54	20 48 48			18 75	65	22
R					38 60	3 15 33	22	16 62 74	64		10
LOOP	full	at power					69				1
		0 power	42			31		73	43		4
Partial LOOP			7 8 11			9	10 61	77	37 37		9 10
Total			12	11	11	10	8	7	10	3	70

Events are listed more than once indicating that the event affected more than one NPP

Appendix A, Table A–2
Event Summary

Table A-2 was prepared from the Appendix A, Grid Events. An explanation of the column headings are as follows:

Column 1 – "No.," is the Table event number.

Column 2 – "LER No.," is the Licensee Event Report (LER) number.

Column 3 – "Event Group," lists the event grouping codes as explained in Appendix A. In case of loss of offsite power (LOOP) or partial LOOP, the recovery time was also noted.

Column 4 – "EDG Status," provides the response of the emergency diesel generator (EDG) to include the number of EDGs that started, loaded, reloaded (if it was running to the grid at the time of the event), or failed to run (FTR).

Column 5 – "Degraded Grid," provides information about degradation of the grid that contributed to the event as follows:

- "Fault." An "X" in this column indicates if equipment under control of the transmission entity faulted.

- "Elect" (Electrical). An "X" in this column indicates a weakness in the electrical capability of the grid (or grid and NPP combined) to support the NPP offsite voltage.

- "HE" (Human Error). An "X" in this column indicates human error by personnel that work for the transmission entity.

- "ADM" (Administrative Control). An "X" in this column indicates a lack of control of administrative of the transmission entity's activities

- "EQP" (Equipment). This column lists equipment under control of the transmission entity that failed or mis-operated (mis-op).

- "EOOS" (Equipment Out Of Service). An "X" in this column indicates that equipment or facilities under control of the transmission entity were out of service at the time of the event.

Column 6 – "Degraded Plant" indicates degraded nuclear plant equipment that contributed to the event.

Column 7 – "Observations" provides general observations and notes.

The following abbreviations were used in addition to those in the main text:

CB	circuit breaker
CT	current transformer
CC	coupling capacitor
CCW	circulating water
HP	horsepower
RRP	reactor recirculation pump
SAT	start-up transformer
TR	transformer
T-line	transmission line

Table A-2 Event Summary

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
1	21994007	S				X	X				– New agreement between NPP and transmission entity to strengthen control and review of switchyard activities.
2	21994019	I									– Transmission entity modification defeated safety function of SBO power supply; inoperable 4 to 5 months. – Agreement between NPP and transmission company to strengthen review of activities affected SBO power supply. – Event demonstrates when SBO power supply controlled by transmission entity important to have agreement to provide for review of important SBO power supply activities including post modification and periodic tests to ensure operability of SBO power supply.
3	21997010	R	All EDGs loaded		X				X	SAT voltage regulator not set consistent with design analysis	– Licensee found that when the plant tripped the regional grid voltage dropped 4.5% from heavy demand, EOOS, and loss of station output. Additional 3–6% voltage drop from load transfer. – EOOS includes a 500 kV substation.
4	22094002	S						Relay	X		– EOOS includes one of two generator CB.
5	22096004	I									– Grid operator initiated 5% voltage reduction quickly; one minute after from loss of NMP1. – EOOS includes IP3.
6	23700004	S				X	X				– Need to ensure proper verification practices when returning equipment to service.
7	24494005	PL 23 min	EDG reloaded	X				34.5 kV CB			– Testing the EDG to the grid at time of disturbance; reload successfully.
8	24494012	PL 30 min	EDG loaded	X		X		34.5 kV T-line			– Radiation monitor program memory lost upon loss of voltage.

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
9	24497002	PL 12 hr	EDG loaded	X				34.5 kV T-line			– Raccoon climbed a utility pole and shorted two T-line phases.
10	24498005	PL 15 min	one EDG loaded	X				34.5 kV cable splice			
11	24794001	PL 61 min	2/3 EDGs loaded	X				138 kV feed			
12	24795016	S		X				relay circuit			
13	24796003	T		X				relay mis-op			– Pilot wire relay had not been modified at this location.
14	24796021	I		X				765 kV electric reactor			– Remote 765 kV fault de-energized radiation monitor.
15	24797018	R	one EDG started		X		X	relay mis-op	X	EOOS disabled generator protective trip	– Overfrequency increased RCP speed. – Westinghouse found “gross tilting” of reactor internals to be limiting with respect to allowable RCP flow and new RCP flow is more limiting than 125% FSAR limitspeed approached gross tilting. – EOOS from T-line and substation outages reduced left one of two available power generation paths unavailable. – Overfrequency effects on running safety motors.

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
16	24799015	R	EDGS loaded; one EDG FTR		X					Degraded protective relay and TR tap changer	-Analysis assumed automatic tap changer was operable -ASP 2.8E-06(licensee found 2E-04)
17	26394003	T		X				345 kV wave trap			– Synchronous motor/motor generator sensitivity to momentary low voltage (55% for 2–3 cycles fault). – Emergency filtration 120v relays de-energized.
18	26500008	T		X				345 kV T-line		Changeout of CTs over years changed operation of relays in response to a grid fault	– After fault initially isolated and reactor tripped, 345 kV circuit breaker automatic reclosed into fault resulting in momentary LOOP and load transfer to Unit 1.
19	27095002	T		X				100 kV T-line and CB		Generator protective relay setpoint in error	
20	27097002	T			X					Main generator voltage regulator did not respond to loss of two hydro units	– Operability of main generator voltage regulator important to NPP voltage support and to prevent cascading (NPP tripped following loss of two hydro units). – Loss of programmable controllers.
21	27197023	S		X		X	X			Turbine runback controls did not work correctly	

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
22	27198016	R	one EDG loaded		X						– Electric system could not support simultaneous start two 5500 HP feedwater pumps motors which tripped on bus overcurrent minutes after unit trip.
23	27594016	2I	all EDGs start	X			X		X		– Plant assessed unfavorable grid conditions and prepared for a dual unit trip and LOOP. – EOOS includes loss of several nearby transmission lines and generators several hours before the event. – Many offsite sirens lost for 4 hours.
24	27594020	2T	EDG reloaded	X				T-line in Idaho			– 2 NPPs tripped, 4 others NPPs affected. – EDG 1–3 running to grid for test at time of disturbance, successfully picked-up safety load but tripped 45 minutes into event. – UPS sensitivity :Diablo Canyon and WNP2 UPS trips; Palo Verde UPS alarms. – Effects of high(118%) voltage on safety equipment. – RCP undervoltage and underfrequency trips increased to maximum allowed by Technical Specification.
25	27596012 52896004	4T		X	X				X		– Soaring temperatures wilted transmission lines. – EOOS includes 3 500 kV T-lines in Oregon, a 500/230 kV transformer, and 2000 mW of generation that weakened the grid. – Grid operated in a unanalyzed condition that violated grid reliability criteria would overload parallel transmission lnes. – MTC level influences the NPP response to grid disturbance.
26	27598013	2I	all EDGs started				X			plant relay misoperated	– Relay setpoint changes due to increased inrush current from new 230 kV circuit switcher, SAT replacement, and new switchyard capacitor banks.

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
27	27501001	2I	all EDGs started	X				230 kV T-line			– Wildfire affecting grid and NPP a repetitive event. – Transmission restored in 73 min.
28	27796007	2I		X		X					– Momentary LOOP due to remote switching. – Safety buses transferred from degraded offsite power supply to an alternate power supply.
29	27701001	I	power transfer to other source	X				T-line			– Raccoon climbed utility pole and shorted two phases. – Safety buses transferred from degraded offsite power supply to an alternate power supply. – Procedure deficiency left 2/4 EDGs per unit inoperable for a LOOP for 3 hours.
30	28595003	I	EDGs started		X						– Reactor trip logic autostarts EDGs .
31	28697008	L0 43 min	1 EDG loaded, 1 EDG started but FTR, 1 EDG in MOOS	X		X		138 kV feed			
32	28600008	S		X				control cable			– Faulted control cabling between IP3, and 138 kV and 345 kV control houses.
33	28997007	R	all EDGs loaded	X	X		X	230 kV CB			– Slow to take corrective action; planned to operated 4 days with 60–80% current unbalance. – Effect of unbalanced current on safety related motors.
34	29397007	I									Voltage regulating transformer microprocessors sensitive to grid voltage transients.

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
35	31195004	S				X	X	relay	X		– Manufacturers bulletin specified corrective action, if implemented, would have prevented protective relay mis-operation.
36	31395009	S						-500 kV CB control	X		– EOOS includes 1 of 2 generator CBs in the switchyard.
37	31600004	2PL0	Unit 1& 2 Train A EDGs loaded			X					– Transmission company switching error. – Cook/AEP Interface agreement planned.
38	31896001	R	one EDG loaded on each unit		X	X	X				– Voltage drops on loss of unit with EOOS. – EOOS includes 1 of 3 offsite T–lines.
39	32397002	I	2/3 EDGs start		X						– Momentary voltage drop due to bus transfer from auxiliary to startup power. – EDG autostarts if voltage recovery more than 1 second.
40	32397003	I	2/3 EDGs started		X						– Momentary voltage drop due to bus transfer from auxiliary to startup power. – EDG autostarts if voltage recovery more than 1 second.
41	32398005	I	1/3 EDGs started		X						– Momentary voltage drop due to bus transfer from auxiliary to startup power. – EDG autostarts if voltage recovery more than 1 second.

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
42	32494008	L0	Unit 2 EDGs loaded. Unit 1 EDGs started			X					– Load dispatcher switching error. – Momentary LOOP.
43	32500001	L0	Unit 1 EDGs loaded, one EDG FTR, Unit 2 EDG started			X	X			EDG excitation system inoperable for unknown duration	– EDG common mode failure. – Momentary LOOP.
44	32796006	S		X				500 kV CC			– Switchyard fire.
45	32895007	S		X				161 kV CB			– Synchronous motor sensitivity on both units. – Security system LOOP.
46	33494005	T	one EDG loaded					relay mis-op		Unit 1Main TR high voltage bushing failed	– Transmission line protective relay misoperation during voltage perturbation following Unit 1 trip, tripped Unit 2 on RCP underfrequency and caused a PLOOP.
47	33496008	I	one EDG started		X						– Momentary voltage dip on bus transfer and RCP restarts,

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
48	33497005	2T	one EDG started					345 kV T–line; relay mis-op	X		– Short safety bus undervoltage trip time of approximately 0.194 seconds explains trip. – EOOS includes remote T–line relaying.
49	33594007	S		X				240 kV PT			– Switchyard fire.
50	33896010	T		X				230 kV T-line		Generator relay mis–operation	
51	33800004	S		X				500 kV CB			
52	34198001	S						2 relays			– Degraded transmission line protective relays exposed during a test.
53	35295002	2T		X				220 kV T–line			
54	35396004	T		X		X	X			V/Hz relay mis–op	– Modification work at remote facility trips several transmission lines and transformer resulting in grid instability.
55	35399006 –01	S		X				500 kV CB			– 500 kV circuit breaker grading capacitor failure caused a voltage spike that failed transformer lightning arrester.
56	37394011	I						.			– Unit tripped while EDG being tested. EDG tried to pickup grid and assumed abnormal current level.
57	37301001	S		X	X			345 kV line			– Electrical perturbation from Unit 1 trip, tripped Unit 2 heater drain and caused a Unit 2 load reduction.

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
58	38295002	T	one EDG loaded					TR		circuit breaker FTO on load transfer	– ASP = 9.1E-05 – Waterford 2 23.0kV fault sensed at Waterford 3. – One hour plant fire.
59	38895005	S			X			cam SW in 500 kV CB			– Restart of reactor recirculation pump motor caused an unexpected voltage transient that tripped some plant equipment.
60	40096008	R	one EDG started	X				230 kV SW	X	relay contact bounce on load transfer	– EOOS includes one of two generator CBs.
61	41098006	PL 195 min	2/3 EDGs loaded	X				345 kV CB			
62	41099010	R	2/3 EDGs loaded					relay			– Protective relay failure.
63	41695010	S		X				500 kV CB CT			
64	41600005 41600006	R	one EDG loaded	X	X			500 kV CB			– Partial load rejection did not actuate reactor scram or end of cycle reactor recirculation pump trip as expected.
65	41601003	T		X				500 kV SW			– Partial load rejection did not actuate EOC/RPT.
66	42594001	S						500 kV CB	X		

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
67	44398014	S			X			345 kV CB			– Voltage drop from bus transfer and start of 2 auxiliary feedwater pump motors. – Voltage transient caused 7 safety and some non-safety motors tripped and did not restart.
68	44597009	S					X	500 kV CB			
69	45498017	L 8hours	EDGs loaded					relay			– Circuit breaker reclosed during power restoration. – Reactor stayed at power
70	45500001	S		X				345 kV CB			– Static line fell on live line.
71	45899014	S				X	X				
72	46196004	S				X	X				– Voltage transient caused overcurrent condition that tripped rod control and information system map display.
73	46199002	L0 10 hours	EDGs loaded					138 kV T–line	X		– Offsite power supply pole guy wire pulled out, leaned and faulted.
74	48399003 48399005	R			X						– Related to deregulation–large amounts of power being transported across the country. – Peak transmission loading. – Grid operation changed such that wider range of grid voltage expected at NPP.

Table A-2 Event Summary (Continued)

No.	LER No.	Event Group	EDG Status	Degraded Grid						Degraded Plant	Observations
				Fault	Elect	HE	ADM	EQP	EOOS		
75	48300002	T		X				161 kV T–line			– Transmission line fault persisted for 8 minutes due to neighboring utility protective relay weakness. – RCP and CW pump motors tripped on negative phase sequence currents in contrast to safety motors do not trip on these currents.
76	49895013	T	one EDG loaded			X		relay		Grounded protective relay wiring	
77	49999003	PL	EDG C loaded, EDG B FTR	X				345 kV CB			
78	49901002	S		X				345 kV CB			– CW tripped on current imbalance. – high voltage alarm on safety bus.
79	52895001	I									– Grid operating entity had not anticipated severity of NPP voltage drop from switching activities
80	52895003	I									– Influence of NPP on offsite voltage.
TOTALS				39	19	15	14	50	11	15	

Table A-3 Event Causal Factors

(The numbers in the table correspond to the event numbers in Appendix A)

Event Group		Degraded Grid						Degraded Plant
		Fault	Elect	HFE	ADM	EQP	EOOS	
R		33, 60, 64	3, 15, 16, 22, 38, 64, 74	38	15, 33, 38	15, 33, 60, 62, 64	3, 15, 60	3, 15, 16, 60
S		12, 21, 32, 44, 45, 49, 51, 55, 57, 63, 70, 78	57, 59, 66, 67	1, 6, 21, 35, 71, 72	1, 6, 21, 35, 68, 71, 72	4, 12, 32, 35, 36, 44, 45, 49, 51, 52, 55, 57, 59, 63, 66, 67, 68, 69, 70, 78	4, 35, 36, 66	21
T		3, 17, 18, 19, 24, 25, 50, 53, 54, 65, 75	20, 25,	54, 76	54	13, 17, 18, 19, 24, 46, 48, 50, 53, 53, 58, 65, 75, 76	25, 48, 65, 75	18, 19, 20, 21, 46, 50, 54, 58, 76
L	L					69		
	L0	31, 73		31, 42, 43,	43	31, 73	73	43
PL		7, 8, 9, 10, 11, 61, 77		8, 37		7, 8, 9, 10, 11, 61, 77		

Table A-4 Summary of Event Group Causal Factors

Event Group		Degraded Grid						Degraded Plant
		Fault	Electrical	Human Error	Administrative Control	Equipment Failure	Equipment Out of Service	
R		3	7	1	3	5	3	4
S		12	4	6	7	20	4	1
T		11	2	2	1	14	4	9
L	L	1	0	0	0	1	0	0
	L0	2	0	3	1	2	1	1
PL		7	0	2	0	7	0	0
TOTALS		36	13	14	12	49	12	15
		137						16

APPENDIX B
Risk Analysis

RISK ANALYSIS

This Appendix contains the background, methods, and results of risk analyses that were used for assessing average industry core damage frequency (CDF) from a station blackout (SBO) before (1985–1996) and after (1997-2001) deregulation using simplified event trees. Several after deregulation cases were investigated. The analyses required consideration of all losses of offsite power (LOOPs) which were collected along with other operating data in Appendix C, "LOOP and Scram Data 1985-2001."

Section B.1 provides a summary of the dominant characteristics of an SBO accident sequence, Section B.2 develops simplified event trees, Section B.3 summarizes the method used to calculate the CDF, and Section B.4 summarizes results.

B.1 Summary of the Dominant Characteristic of an SBO Accident Sequence

The NPP offsite power system is the "preferred source" of ac electric power, often referred to as the grid. The safety function of the offsite power system is to provide power to ac safety loads required to shut down the nuclear power plant (NPP). Onsite ac emergency power supplies, usually emergency diesel generators (EDGs), automatically provide power to the safety buses following a LOOP. These systems provide power for various safety functions, including reactor core decay heat removal and other support systems required to preserve the integrity of the reactor core and containment following a reactor trip.

A station blackout (SBO) is defined in Section 50.2 as the "complete loss of electric power to the essential and nonessential electric switchgear buses in an NPP (i.e., a LOOP concurrent with a turbine trip and unavailability of the emergency ac power system)." The loss of all ac power to reactor core decay heat removal and other support systems can result in core damage within a few hours as follows: (1) Core cooling failures, or loss of reactor core cooling integrity (RCP seal failure) in 1 to 2 hours or (2) Support system failures (e.g. batteries, compressed air, HVAC) or design limitations (e.g. high suppression pool temperatures), typically for SBO durations lasting more than four hours.

The principle parts of SBO accident sequence are: (1) the initiating LOOP-the frequency of a LOOP (2) the loss of onsite power-the unreliability of the onsite ac emergency power supplies including common cause failures, (3) recovery-the likelihood that ac power will not be restored before the core is damaged, and (4) core damage probability - the event sequences that result in core damage from the failure to recover ac power and consequently, the failure of decay heat removal or support systems necessary to safely shutdown the reactor. Core cooling failures, or loss of reactor core cooling integrity can occur in 1 to 2 hours.

B.3 Explanation of SBO Event Trees and Data

The contributors to the CDF from an SBO are: (1) reactor trip induced LOOPs (LOOPs as a consequence of a reactor trip, i.e some of the R events in Appendix A) and (2) grid (including S and T LOOPs in Appendix A), weather, or plant related LOOP induced reactor trip. The risk contribution from that do not result in a reactor trip (non-initiating) was consideredneglig ible.

Simplified event trees were developed to represent the two principal contributor to the CDF from an SBO. Figures B-1, "Reactor Trip-Consequential LOOP Event Tree," and B-2, "LOOP Event Tree," show the event trees of interest. Figure B-1 represents a reactor trip induced LOOP and Figure B-2

represents a LOOP induced reactor trip. The event trees end with an outcome in terms of “OK meaning recovery without core damage and “CD” meaning some core damage can be expected.

The data used in event trees is shown in Table B-1 and Appendix C. All of the data in Table B-1 and Appendix C were from actual operating experience with the exception that the critical reactor years for the summer months that were estimated as indicated in Table B-1. Plant specific data could provide different results.

The following is a discussed of each element of the event tree.

(1) The initiators.

In Figure B-1, the event is a LOOP as a consequence of a reactor trip which was modeled in two steps. Figure B-1 shows this event is initiated the number of reactor trips per critical reactor year,(“Rx-Trip/(RY)” and followed by “Consequential LOOP,” the probability of a LOOP given a reactor trip or P(LOOP/RT). Table B-1 shows the “reactor trips/critical reactor year” and P(LOOP/RT) data.

In Figure B-2, the event is a LOOP that subsequently progress to a reactor trip. In Figure B-2 the event is initiated by the total number of grid (S and T events), weather, and plant LOOPs per critical reactor year, “LOOP/RY.“ Table B-1 shows the “LOOPs/RY” data.

(2) EDG unreliablity

Figures B-1 and B-2 show the events progress from a LOOP to “EDG” to reflect whether the onsite emergency power supplies (EDGs), started and loaded, or failed to start and load. The system failure rate for “EDG” was based on a two train EDG system and calculated from the square of the individual EDG rates (P) plus the product of the common mode (α) and EDG train failure rates (P squared +αP). A two train system is typical of the NPP onsite power system; of 103 operating reactors, approximately 75 percent have 2 or less EDGs per reactor unit. The same EDG data was used in the before and after analyses and based on actual demand performance data published by the NRC. Table B-1 shows the “EDG failure rate for a two train system‘‘ data.

In some cases the EDG is unavailable for testing times up to 24 hours or out-of-service(OOS) for allowed outage times (AOTs) up to 14 days. During the AOTs the EDG being serviced is often in some state of disassembly and unavailable so the two train system is dependent on a sinlge EDG to start and run for the full duration of the event.

Figure B-1
Reactor Trip- Consequential LOOP Event Tree

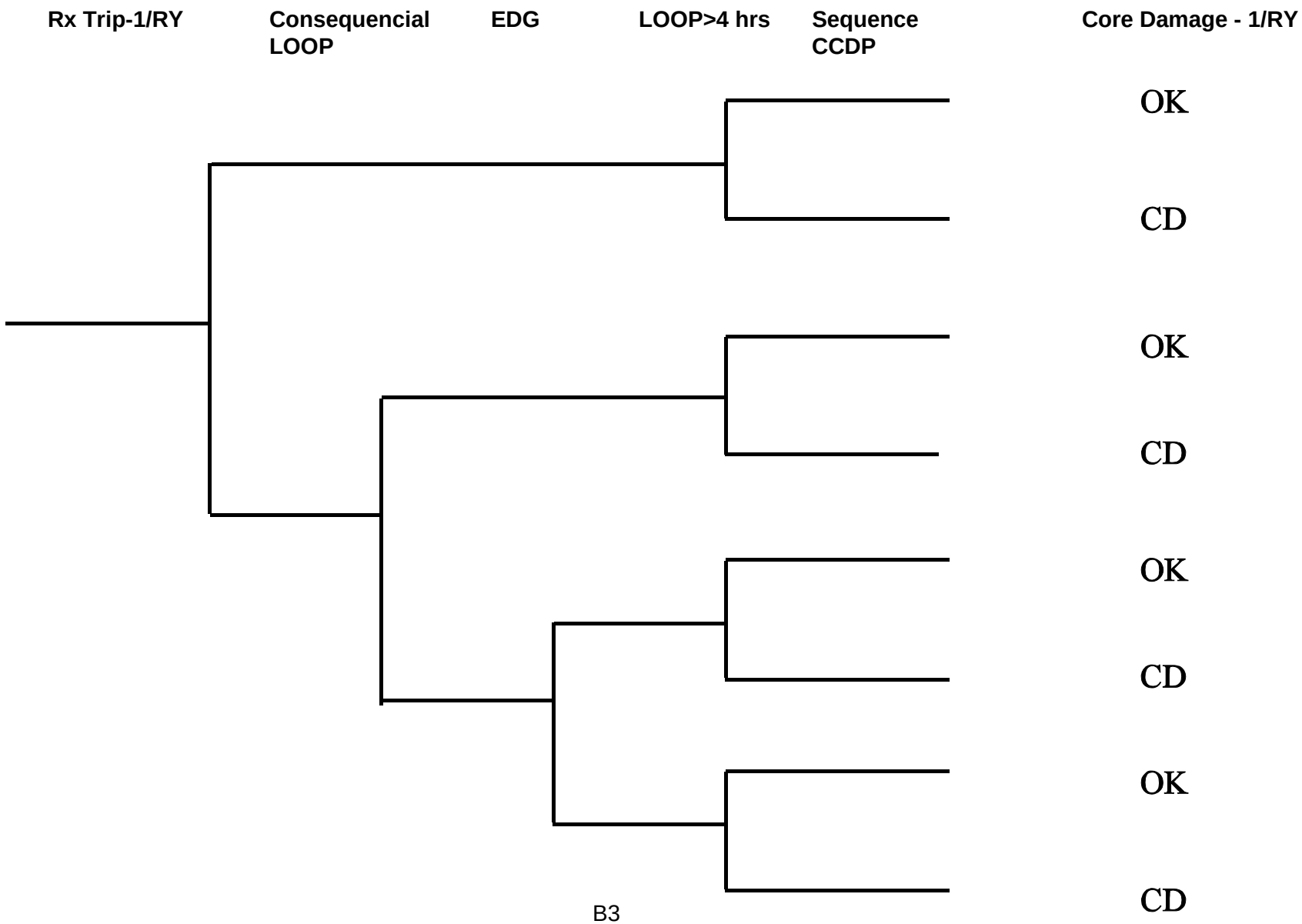

Figure B-2

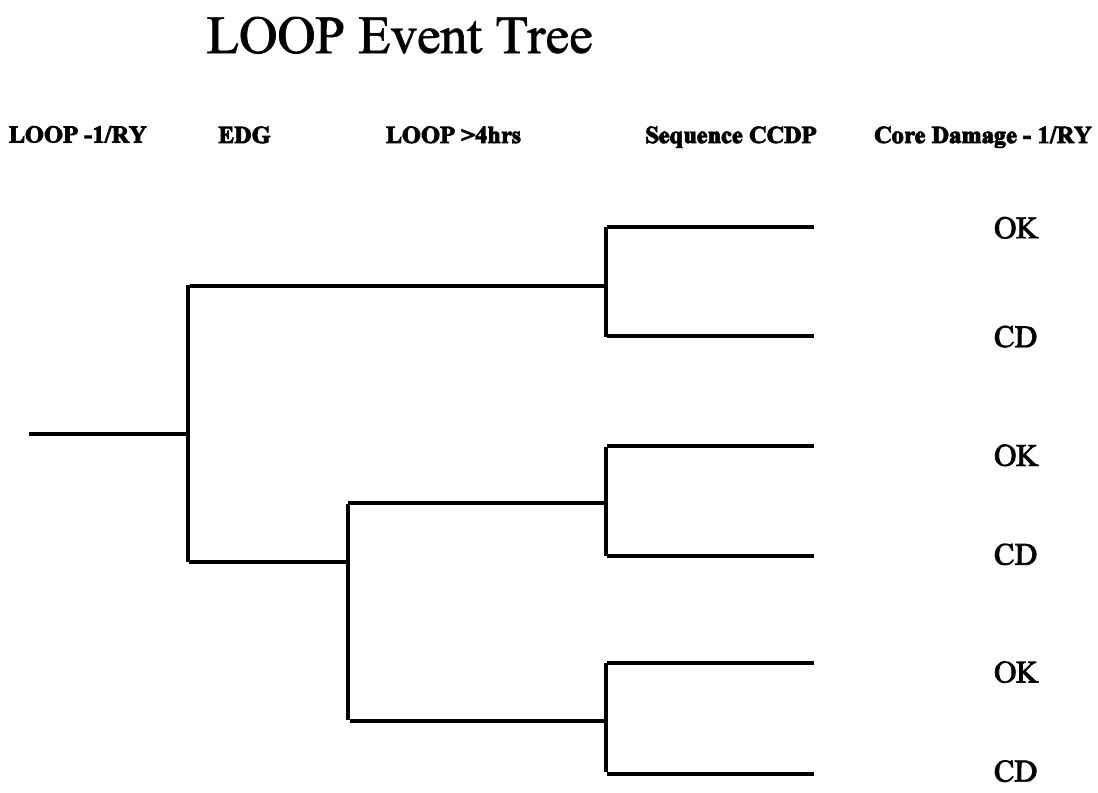
LOOP Event Tree
LOOP -1/RY
EDG
LOOP >4hrs
Sequence CCDP
Core Damage - 1/RY
OK
CD
OK
CD
OK
CD

Table B-1
Operating Data From LOOPS At Power Before and After Deregulation

Risk factor	Measurement (Reference)	All Year		Summer Months Only May 1-Sept 30	
		Before 1985-1996	After 1997-2001	Before	After
Reactor trip frequency	Reactor trips (Appendix C, Table C-6)	3161	441	1350	201
	Critical reactor years (RY) (Appendix C, Table C-6)	940	442	392	184
	Reactor trips/critical reactor years (RY)	3161/940 =3.4	441/442 =1.0	1350/392 =3.4	201/184 =1.1
LOOP Initiating frequency	LOOPs -Consequential (Appendix C, Tables C-1 and C-2) -LOOP (grid, plant, weather) (Appendix C, Tables C-1, C-3, C-4, C-5) -Non-initiating (Appendix C, Tables C-1 and C-6)	 7 47 7	 2 4 2	 2 24 3	 2 4 1
	P(LOOP/RT)	7/3161 =0.002	2/441 =0.0045	2/1350 =0.0015	2/201 =0.01
	LOOPs/RY	47/940 =0.05	5/442 =0.009	24/392 =0.061	5/184 =0.021
EDG reliability & redundancy	EDG failure rate for a two train system (Reference B.1 and B.2)	P=Failure rate for one EDG=0.044 CMF=Common mode failure= 0.031 System failure rate= P*P+ CMF*P=0.0033			
Recovery time	LOOP events exceeding 4 hours recovery time -Consequential LOOP -LOOP (Table C-1 through C-5)	 0 8	 1 4	 0 7	 1 4
	Percent LOOPs > 4hours	8/54	4/6	7/26	4/6
Plant capability	Average CCDP (Reference B.3)	LOOP at power 1.8E-04			

Note 1: May to September critical RY assumed to be 5/12 of total critical hours

References

B.1 INEL-95/0035, “Emergency Diesel Generator Power System Reliability 1987–1993,” February 1996

B.2 NUREG/CR-5497, “” Common-Cause Failure Parameter Estimations,”1997

B.3 Nuclear Regulatory Commission, Accident Sequence Precursor (ASP) Database

(3) Recovery

Figures B-1 and B-2 show the events progress from “EDG” to “LOOP>4hrs” to reflect the percentage of LOOP events where it took more than four hours to recover. This activity represents NPP and grid operators ability to restore ac power before exceeding the SBO coping time.

(4) Sequence conditional core damage probability (CCDP)

“Sequence CCDP” represents the likelihood of recovering or not recovering, ac power for decay heat removal and other support systems necessary to safely shutdown reactor. The CCDPs were obtained from the NRC ASP database by averaging the CCDPs from 1980 to the present for all LOOPs at power (1.8E-04). In some case the CCDP for some LOOP was less than E-06 and not in the ASP database; in these cases a CCDP of zero was assigned for LOOP in determining the average. The CCDP reflects actual demand performance and reflects the performance of the EDGs, availability and reliability of alternate ac power supplies and cross-ties, use of compensatory measures, operator performance, and fully credits overall NPP safety and non-safety system redundancy and performance. However, the CCDPs typically credit shorter recovery times than experienced so as to recognize that the NPP may have restored power sooner under SBO conditions.

The CCDPs for sequences involving the failure of both EDGs was assumed to be an approximately an order of magnitude higher (2.0E-03) and failure to recovery in four hours was assumed to be approximately another order of magnitude higher (2.0E-02) than the CCDP for the LOOP with recovery (1.8E-04). Peer review judged that these assumptions were optimistically low.

B.4 Method

A baseline average industry CDF from an SBO before deregulation was calculated as the sum of the CDFs leading to core damage in Figure B-1 and Figure B-2. The average industry CDF from an SBO for the after deregulation cases were calculated using the sum of the CDFs leading to core damage from Figure B-1 and Figure B-2 event trees. The data showed a need to analyze the risks in the summers (May to September); all of the LOOPs since 1997 occurred in the summer (May to September) in contrast to 23 of 54 LOOPs in the summers of 1985-1996.

The after deregulation cases were: (1) all LOOP data 1997-2001, (2) the summer months (May–September), and three summer sensitivities cases based on actual experience (3) the EDG out of service (OOS) for 14 days with a higher likelihood that grid will degrade, (4) increasing in the amount of time that the grid is degraded, and (5) the EDG OOS for 14 days while the grid is degraded. In each of the five cases, the risks after deregulation were subtracted from the risks before deregulation to obtain a “delta CDF” and the results displayed in Table B-2 and Figure B-3.

B.4 Results

The results are also summarized in Table 2, “Changes In Risk After Deregulation,” in terms of a “delta CDF” and “observations” that help explain the delta CDF in term of key data changes.

Table B-2
Changes In Risk After Deregulation

Observation		Baseline Change - Delta CDF/RY
BEFORE deregulation 1985–1996	Average industry CDF from an SBO is 1.3E-05/RY considering consequential and plant/grid/weather LOOPs . -Risk reduction from SBO rule 3.2E-05/RY; expectation 2.6E-05/RY -Reactor trips/RY=3.4 -LOOPs/RY=0.05 -Probability(LOOP/reactor trip) =0.002 -Percent LOOPs >4hours=17%	0
AFTER deregulation 1997–2001	Risk reduction from SBO rule implementation maintained. CDF decreased below baseline due to offsetting changes: -Reactor trips/RY =1.0 -LOOPs/RY=0.009 -Probability(LOOP/reactor trip)=0.0045 -Percent of LOOPs > 4 hours=67%	-0.9E-05
SUMMER After deregulation 1997-2001	Risk reduction from SBO rule implementation maintained. CDF decreased below baseline due to offsetting changes: -Reactor trips/RY=1.1 -LOOPs/RY =0.021 -P(LOOP/reactor trip)= 0.01 -Percent LOOPs > 4 hours =67%	-.5E-05
SUMMER SENSITIVITY 1997-2001	Risk reduction from SBO rule implementation offset -EDG out-of-service for 14 days with a chance of a degraded grid -Increase time grid degraded to 30 days based on experience -EDG out-of-service for 14 days with the grid degraded	1.1E-05 1.4E-05 7.8E-04

The “delta CDF” was obtained by subtracting the risk “BEFORE” deregulation from the risks after deregulation. A negative delta CDF indicates the risks have decreased since deregulation. A positive delta CDFs may offset the risk reduction obtained from SBO rule implementation. Specifically a delta CDF of more than 0.6E-05/RY (the difference between the risk reduction outcome and expectation from SBO rule implementation) and a delta CDF of more than 3.2E-05/RY (the outcome from SBO rule implementation) the partially and completely offsets the risk reduction from SBO rule implementation, respectively.

The BEFORE observations benchmark the risks, the risk reduction obtained from SBO rule implementation which are used to evaluate the significance of changes in risk after deregulation, and key data that are used to explain the delta CDF. The key data include the number of reactor trips per RY; the number of LOOPs/RY; the probability of a LOOP as a consequence of a reactor trip or and the percent LOOPs more than 4 hours. As a point of reference P(LOOP/RT) is 0.002 and corresponds to the grid being in this condition approximately 18 hours per year (8760 hours per year times 0.002). The results are compared graphically at the end of the discussion in Figure 1, “Risk Profile” in terms of the CDF/RY. Figure 1 and Table 2 indicate the following:

- The risks "AFTER" deregulation (1997-2001) have decreased just below the risk BEFORE deregulation. This indicates that deregulation has not eroded the risk reduction from SBO rule implementation. Comparison of the key factors in Table 2 before and after deregulation help to explain the decrease in the risk; i.e., the decreases in the risk from the decreases in the number reactor trips/RY and number of LOOPs/RY have offset the increases in the risk from the increases in percentage of LOOPs more than 4 hours and probability of a LOOP given a reactor trip. As a point of reference P(LOOP/RT) is 0.0045 (as compared to 0.002) and corresponds to the grid being in this condition approximately 40 hours per year.

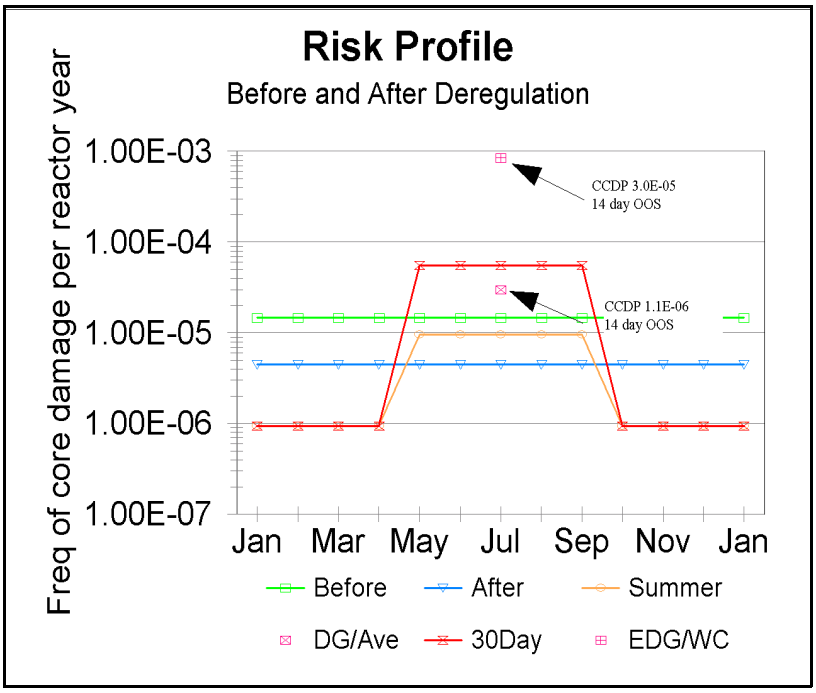

Figure B-3 -Risk Profile

- The risks after deregulation in the "SUMMER" - May to September, 1997–2001- have decreased slightly below that BEFORE deregulation; again deregulation has offset the risk reduction from SBO rule implementation. Comparison of the key factors in Table 2 before and after deregulation help to explain the decrease in the risk; i.e. the decreases in the risk from the decreases in the number reactor trips/RY and number of LOOPs/RY have offset the increases in the risk from the increases in the percentage of LOOPs more than 4 hours and the probability of a LOOP given a reactor trip. As a point of reference P(LOOP/RT) is 0.01 and corresponds to the grid being in this condition approximately 88 hours per year, all during the summer months.

- SUMMER SENSITIVITY studies were completed to evaluate the potential risk increases from (1) the EDG out of service (OOS) for 14 days with higher likelihood that the grid will be in a degraded condition, (2) increasing in the amount of time that the grid is degraded, and (3) the EDG OOS for 14 days while the grid is degraded. Actual approved EDG OOS typically range from 3 to 14 days; plant specific analyses may provide different results.

  Table 2 delta CDFs indicates that in each of these three case, the risk increase offsets the risk reduction from SBO rule implementation. In each of these cases, this risk increase may not be detected unless the risk assessment considers the increased CDF from an SBO (a) as a result of a consequential LOOP and other LOOPs separately (b) summer time operation (c) actual demand performance under LOOP conditions (d) the results of electrical analyses to determine whether a reactor trip will cause a LOOP (discussed in Section 3.3). The discussion follows:

  (1) The first sensitivity study estimated a delta CDF as a result of having one of two EDGS OOS with a 0.01 chance that a LOOP will result from a reactor trip. Table 2 and Figure 1 shows this as a spike in the risk as "EDG/Avg" that is just above the risk before deregulation.

(2) The second sensitivity study evaluated the risk increase from an increase in the amount of time the grid was degraded (the time that the probability of a LOOP given a reactor trip was 1) to approximately 800 hours or approximately 30 days . When this time is increased to 800 hours, the risk and delta CDF increase above the BEFORE values as shown in Figure 1, “30Day” and Table 2. ” At a recent meeting, EPRI shared data that showed that one region of the country experienced a “Stage 3" alert approximately 795.8 hours over a few months in one year as a result of market gaming. Stage 3 is when the system reserves have been depleted to approximately 1.5% of the load and the final stage of the grid operators three-step emergency program that is accompanied by load curtailment (rolling blackouts) to keep from further erosion of the reserves needed for system stability should there be a disturbance such as a large unit trip or transmission system fault.

(3) As shown in Figure 1 and Table 2, the worse case increase in the risk above the before deregulation values is when the one EDGs is unavailable for 14 days with the reactor at power and the grid is in a condition such that a LOOP could result from a reactor trip. Figure 1 shows this as a spike, “EDG/WC.” As previously discussed, TS typically allow one EDG to be unavailable for allowed outage times (AOTs) of up to 72 hours, and in some cases with compensatory measures, up to 14 days. As previously discussed the CCDPs used in the risk analysis reflect the use of compensatory measures.

As previously discussed the maintenance rule requires that before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventative maintenance), the licensee shall assess and manage the increase in the risk that may result from the proposed maintenance activities; consistent with the current regulations, licensees should understand the condition of the grid before scheduling EDG tests to the grid, MOOS, or AOTs. In addition, the NRC Standard TS surveillance requirements NRC Standard TS note that the 24 EDG hour test to the grid is not performed with the reactor at power but may be performed to reestablish operability provided an assessment determines the safety of the plant is maintained or enhanced. The TS bases state the assessment shall consider potential outcomes and transients associated with a perturbation of the offsite or onsite system when tied together and measure these risks against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the surveillance is performed in at power; again consistent with the current regulations, licensees should understand the condition of the grid before scheduling EDG tests to the grid, MOOS, or AOTs.

APPENDIX C

LOOP and Scram Data from 1985-2001

APPENDIX C

The data in the tables below was obtained as follows:

The 1985-1996 LOOP data were obtained from NUREG/CR-5496, “Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980–1996,” June 1998) and summarized in Table C-2 through C-4.

The CCDP data was obtained from the NRC ASP database and summarized in Table C-1 through C-5.

The scram data in Table C-6 to include the number of reactor trips and number of critical hours for 1985-1986 were obtained from NUREG-1272, “Report to the U.S. Nuclear Regulatory Commission on Analysis and Evaluation of Operational Data–1986,” 1987. The same scram data for 1987-2001and summer were obtained from the NRC performance indicator data maintained by INEL and SCSS .

Table C-1
LOOPs While At Power 1997-2001

LOOP Category		**LER**	**Plant**	**Event date**	Recovery Time (Minutes)	CCDP
Consequential LOOP		21997010	Oyster Creek 1	8/01/97	90 E	<E-06
		24799015	Indian Point 2	8/31/99	612	2.8E-06*
LOOPs	plant	27500004	Diablo Canyon 1	5/15/00	1980	<E-06
	weather	34698006	Davis Besse	6/24/98	1560	5.4E-04
		45698003	Braidwood 1	9/6/98	688	<E-06
	grid related or initiated	28997007	Three Mile Island	6/19/97	90	9.6E-06
Non-initiating		26698002	Point Beach 1	1/8/98	600	<E-06
		45498017	Bryon 1	8/4/98	501	<E-06

Table C-1 developed from the review of LERs as found in SCSS.
*Licensee estimate on the order of 2E-04.

Table C-2
Consequential LOOPS 1985-1996

LER No.	Plant	Event Date	Recovery Time (Minutes)	CCDP
23790002	Dresden 2	1/16/90	45E	3.4E-06
24785016	Indian Point 2	12/12/85	20	5.8E-05
26186005	Robinson	1/28/86	100	3.0E-04
30189002	Point Beach 2	3/29/89	90	2.5E-04
31186007	Salem 2	8/26/86	1 E	<E-06
39589012	Summer	7/11/89	130	1.5E-04
45587019	Bryon 2	1/16/90	1E	1.5E-04

Table C-3
Grid-Related or Initiated LOOPs While At Power 1985-1996

LER No.	Plant	Event Date	Description	Recovery Time (Minutes)	CCDP
219/92-005	Oyster Creek	5/18/89	Transmission line fault due to offsite fire	6	7.1E-05
249/89-001	Dresden	03/25/89	Switchyard circuit breaker fault	45E	1.3E-05
251/85-011	Turkey Point 4	05/17/85	Multiple intense brush fires shorted out three transmission lines almost simultaneously	125	3.8E-05
271/91-009	Vermont Yankee	04/23/91	Switchyard human error during battery restoration and communication delays between plant and transmission entity	277	2.9E-04
317/87-012	Calvert Cliffs 1&2	07/23/87	Faults on a transmission line from tree contact	118 118	4.8E-04 4.8E-04
327/92-027	Sequoyah 1 Sequoyah 2	12/31/92	Grid configuration heavily contributed to dual unit trip	95 95	1.8E-04 1.8E-04
334/93-013	Beaver Valley 1 Beaver Valley 2	10/12/93	Switchyard human error (HE) caused dual unit trip	15 15	5.5E-05 5.5E-05
369/91-001	McGuire	02/11/91	Switchyard human error while testing circuit breaker	40	2.6E-04
395/89-012	Summer	01/11/89	Grid instability	130	1.5E-04
456/88-022	Braidwood	10/16/88	Transmission line potential transformer failed at a remote location	95	1.8E-04

Table C-4
Plant Related LOOPs While At Power 1985-1996

LER Number	Plant	Event Date	Recovery Time in Minutes	CCDP
0299100	Yankee-Rowe	06/15/91	24	6.1E-04
20685017	San Onofre 1	11/21/85	4	9.4E-04
21989015	Oyster Creek	05/18/89	1	<E-06
23785034	Dresen 2	08/16/85	5	4.0E-05
25587024	Palisades	07/14/87	388	4.3E-04
26192017	Robinson 2	08/24/92	454	2.1E-04
27092004	Oconee 2	10/19/92	57	2.1E-04
29393022	Pilgrim	9/10/93	10	<E-06
30189002	Point Beach 2	03/29/89	90E	2.5E-04
30292001	Crystal River 3	03/27/92	20E	1.7E-05
30491002	Zion 2	03/21/91	60	2.1E-04
30988006	Maine Yankee	08/13/88	14	1.2E-04
31591004	Cook 1	05/12/91	1E	<E-06
32388008	Diablo Canyon 2	07/17/88	38	4.1E-05
32489009	Brunswick 2	06/17/89	90E	3.6E-05
32586024	Brunswick 1	09/13/86	1E	<E-06
33688011	Millstone 2	10/25/88	19	<E-06
37093008 2	McGuire	12/27/93	96	9.3E-05
37393015	LaSalle 1	09/14/93	15E	1.3E-04
40985019	La Crosse	10/22/85	60	2.05E-05
41287036	Beaver Valley 2	11/17/87	4	1.7E-05
41496001	Catawva 2	02/06/96	330	2.1E-03
44391008	Seabrook	06/27/91	20	4.4E-05
45886002	River Bend	01/01/86	46	7E-05
52885058	Palo Verde 1	10/03/85	25	3.4E-05
52885076	Palo Verde 2	10/07/85	13	3.4E-05

Table C-5
Weather Related LOOPS While At Power 1985-1996

LER Number	Plant(s)	Event Date	Recovery Time (Minutes)	CCDP
24585018	Millstone 1 Millstone 2	09/27/85 09/27/85	211E 330E	3.5E-05 3.5E-05
25092000	Turkey Point 3 Turkey Point 4	08/24/92 08/24/92	7950 7908	1.6E-04 1.6E-04
28296012	Prairie Island 1 Prairie Island 2	6/29/86 6/29/86	296 296	5.3E-05 5.3E-05
29391024	Pilgrim	10/30/91	120	1.2E-04
29393004	Pilgrim	03/13/93	1E	4.6E-06

Table C-6
Non-Initiating LOOPs While At Power 1985-1996

LER Number	Plant	Event Date	Recovery Time in Minutes	CCDP
22090023	Nine Mile Point 1	11/12/90	335	<E-06
22093007	Nine Mile Point 1	08/31/93	1E	<E-06
24488006	Ginna	07/16/88	65	<E-06
26685004	Point Beach 1	07/25/85	45E	<E-06
31194007	Salem 2	04/11/94	385	<E-06
45796001	Braidwood 2	01/18/96	113	<E-06
52989001	Palo Verde 2	01/03/89	1138	4.9E-05

Table C-7
Annual Scrams and Critical Reactor Years 1985-2001

Year	Scrams	Critical Reactor Years	Scrams: May 1 to September 30
1985	552	59.44	210
1986	469	65.29	218
1987	404	70.24	177
1988	274	75.76	121
1989	244	76.04	96
1990	232	80.66	105
1991	196	83.94	87
1992	195	83.61	84
1993	162	82.90	59
1994	142	85.80	60
1995	154	88.84	75
1996	137	87.09	58
1997	84	79.93	32
1998	80	84.39	36
1999	95	90.73	54
2000	92	92.92	41
2001	90	93.96	38
Totals: 1985-1996 1997-2001	 3161 441	 792 280	 1350 201