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Reevaluation of Station Blackout Risk at Nuclear Power Plants

Resolution of Comments

Idaho National Laboratory

U.S. Nuclear Regulatory Commission
Office of Nuclear Regulatory Research
Washington, DC 20555-0001

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ABSTRACT

This report is an update of previous reports analyzing loss of offsite power (LOOP) events and the associated station blackout (SBO) core damage risk at U.S. commercial nuclear power plants. LOOP data for 1986–2004 were collected and analyzed. Frequency and duration estimates for critical and shutdown operations were generated for four categories of LOOPs: plant centered, switchyard centered, grid related, and weather related. Overall, LOOP frequencies during critical operation have decreased significantly in recent years, while LOOP durations have increased. Various additional topics of interest are also addressed, including comparisons with results from other studies, seasonal impacts on LOOP frequencies, and consequential LOOPs. Finally, additional engineering analyses of the LOOP data were performed. To obtain SBO results, updated LOOP frequencies and offsite power nonrecovery curves were input into standardized plant analysis risk (SPAR) models covering the 103 operating commercial nuclear power plants. Core damage frequency results indicating contributions from SBO and other LOOP-initiated scenarios are presented for each of the 103 plants, along with plant class and industry averages. In addition, a comprehensive review of emergency diesel generator performance was performed to obtain current estimates for the SPAR models. Overall, SPAR results indicate that core damage frequencies for LOOP and SBO are lower than previous estimates. Improvements in emergency diesel generator performance contribute to this risk reduction.

FOREWORD

The availability of alternating current (ac) electrical power is essential for the safe operation and accident recovery of commercial nuclear power plants (NPPs). Offsite power sources normally supply this essential power from the electrical grid to which the plant is connected. If the plant loses offsite power, highly reliable emergency diesel generators provide onsite ac electrical power. A total loss of ac power at an NPP as a result of complete failure of both offsite and onsite ac power sources, which rarely occurs, is referred to as a "station blackout" (SBO).

Unavailability of power can have a significant adverse impact on a plant's ability to achieve and maintain safe-shutdown conditions. In fact, risk analyses performed for NPPs indicate that the loss of all ac power can be a significant contributor to the risk associated with plant operation, contributing more than 70 percent of the overall risk at some plants. Therefore, a loss of offsite power (LOOP) and its subsequent restoration are important inputs to plant risk models, and these inputs must reflect current industry performance in order for plant risk models to accurately estimate the risk associated with LOOP-initiated scenarios.

One extremely important subset of LOOP-initiated scenarios involves SBO situations, in which the affected plant must achieve safe shutdown by relying on components that do not require ac power, such as turbine- or diesel-driven pumps. Thus, the reliability of such components, direct current (dc) battery depletion times, and characteristics of offsite power restoration are important contributors to SBO risk.

Based on concerns about SBO risk and associated reliability of emergency diesel generators, the U.S. Nuclear Regulatory Commission (NRC) established Task Action Plan (TAP) A-44 in 1980. Then, in 1988, the NRC issued the SBO rule and the associated Regulatory Guide (RG) 1.155, entitled "Station Blackout." The SBO rule requires that NPPs must have the capability to withstand an SBO and maintain core cooling for a specified duration. As a result, NPPs were required to enhance procedures and training for restoring both offsite and onsite ac power sources. Also, in order to meet the requirements of the SBO rule, some licensees chose to make NPP modifications, such as adding additional emergency ac power sources. The NRC and its licensees also increased their emphasis on establishing and maintaining high reliability of onsite emergency power sources.

On August 14, 2003, a widespread loss of the Nation's electrical power grid (blackout) resulted in LOOPs at nine U.S. commercial NPPs. As a result, the NRC initiated a comprehensive program to review grid stability and offsite power issues as they relate to NPPs. That program included updating and reevaluating LOOP frequencies and durations, as well as the associated SBO risk, to provide risk insights to guide agency actions. This report, published in three volumes, presents the results of those evaluations.

Volume 1 constitutes an update of two reports that the NRC previously published to document analyses of LOOP events at U.S. commercial NPPs. The first report, NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," covered events that occurred in 1968–1985 and incorporated many of the actions performed as part of TAP A-44. The second, NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980–1996," covered those that occurred in 1980–1996. This update was necessary, in part, because of a change in electrical power grid regulations beginning around 1997 and the associated concern about the impact that deregulation might have on LOOP frequencies and/or durations and, therefore, on nuclear plant safety.

The analyses documented in Volume 1 provide frequency estimates for NPPs at power and shutdown operations under four categories: plant-centered, switchyard-centered, grid-related, and weather-related LOOPs. For power operation, grid-related LOOPs contribute 52 percent to the total frequency of 0.036 per reactor critical year (rcry), while switchyard-centered LOOPs contribute 29 percent, weather-related LOOPs contribute 13 percent, and plant-centered LOOPs contribute 6 percent. By contrast, for shutdown operation, switchyard-centered LOOPs contribute 51 percent to the total frequency of 0.20 per reactor shutdown year, while plant-centered LOOPs contribute 26 percent.

Overall, LOOP frequencies during power operation decreased significantly over the 37 years from 1968 through 2004. The overall trend shows a statistically significant decrease through 1996, and then stabilized from 1997 through 2002. This decrease in the frequency of LOOP events is largely attributable to a decrease in the number of plant-centered and switchyard-centered events beginning in the mid-1990s. In fact, only one plant-centered event occurred during the period from 1997 through 2004. Nonetheless, the number of LOOP events in 2003 and 2004 was much higher than in previous years. Specifically, 12 LOOP events occurred in 2003, and 5 occurred in 2004.

The analyses documented in Volume 1 also indicate that, on average, LOOP events lasted longer in 1997–2004 than in 1986–1996. However, the LOOP duration data for 1986–1996 exhibited a statistically significant increasing trend over time. By contrast, no statistically significant trend exists for 1997–2004.

Volume 2 presents the current core damage risk associated with SBO scenarios at all 103 operating U.S. commercial NPPs. The results indicate an industry average SBO core damage frequency (point estimate) of about $3x10^{-6}$ rcry, which Volume 2 compares with historical estimates that show a decreasing trend from a high of approximately $2x10^{-5}$/rcry during the period from 1980 through the present. This historical decrease in SBO core damage frequency is the result of many factors, including plant modifications in response to the SBO rule, as well as improved plant risk modeling and component performance.

Volume 2 also documents several sensitivity studies, showing that SBO core damage frequency is sensitive to emergency diesel generator performance, as expected. Degraded diesel performance and/or large increases in diesel unavailability can significantly increase SBO risk. In addition, SBO risk is significantly higher during the "summer" period (May–September), compared with the annual average result, because the LOOP frequency is significantly higher at that time, as discussed in Volume 1.

Using data from 1997 through 2004, the NRC's SBO reevaluation reveals that SBO risk was low when evaluated on an average annual basis. However, when we focus on grid-related LOOP events, the SBO risk has increased. Our current results show that the grid contributes 53 percent to the SBO core damage frequency. Severe and extreme weather events, which are generally related to grid events, contribute another 28 percent. Therefore, the increasing number of grid-related LOOP events in 2003 and 2004 is a cause for concern. Additionally, if we consider only data from the "summer" period, the SBO risk increases by approximately a factor of two.

Volume 3 lists review comments received on draft versions of Volumes 1 and 2. This final report benefited greatly from the resolution of those comments.

Overall, this study succeeded in updating the LOOP frequencies and nonrecovery probabilities, as well as evaluating the risk of SBO core damage frequency for U.S. commercial NPPs. The NRC staff has already begun to apply these results and insights, and they will continue to guide agency actions related to grid stability and offsite power issues at the Nation's NPPs.

Carl J. Paperiello

Carl J. Paperiello, Director
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission

CONTENTS

APPENDIXES

TABLES

ACKNOWLEDGMENTS

The authors acknowledge the support of Jeffrey Einerson, who prepared many of the figures for Volume 1. Corwin Atwood reviewed several drafts of Volume 1 and provided many helpful comments. For Volume 2, John Schroeder and Robert Buell updated the standardized plant analysis risk (SPAR) models used to estimate the core damage risk from loss of offsite power initiators and subsequent station blackout events. In addition, Ted Wood and Kellie Kvarfordt provided software support for the SAPHIRE code. Finally, the many comments received through the formal review process (outlined in Volume 3) led to significant improvements.

The authors express their appreciation to the following NRC staff who helped to guide this study from its start: Patrick O'Reilly, Donald Dube, Gary DeMoss, John Lane, and William Raughley (Office of Nuclear Regulatory Research) and George Morris, James Lazevnick, Gareth Parry, and Martin Stutzke (Office of Nuclear Reactor Regulation). The authors also thank Patrick Baranowsky, Nilesh Chokshi, and Michael Cheok for their support and efforts in completing this report.

Finally, the authors greatly appreciate the assistance of Myrtle Siefken, Debra Iverson, Mary Schlegel, Penny Simon, and Debbie Southwick in editing and producing this report.

ACRONYMS

ac	alternating current
ADAMS	Agencywide Documents Access and Management System
AFW	auxiliary feedwater system
AOT	allowable outage time
B&W	Babcock & Wilcox
BNL	Brookhaven National Laboratory
BWR	boiling water reactor
CDF	core damage frequency
DSARE	Division of Systems Analysis and Regulatory Effectiveness
DSSA	Division of Systems Safety and Analysis
ECAR	East Central Area Reliability Coordination Agreement
EDG	emergency diesel generator
EEE	extreme external event
EF	error factor
EPIX	Equipment Performance and Information Exchange
EPRI	Electric Power Research Institute
EPS	emergency power system
ERCOT	Electric Reliability Council of Texas
FSAR	final safety analysis report
FTLR	fail to load and run (for 1 h)
FTR	fail to run (beyond 1 h)
FTS	fail to start
GE	General Electric
GTG	gas turbine generator
HPSI	high-pressure safety injection
INL	Idaho National Laboratory
INPO	Institute for Nuclear Power Operations
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events

Acronyms

LER	licensee event report
LERF	large early release fraction
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LOOP-IE	loss of offsite power initiating event
LOOP-IE-C	loss of offsite power initiating event consequential
LOOP-IE-I	loss of offsite power initiating event initial
LOOP-IE-NC	loss of offsite power initiating event not consequential
LOOP-NT	loss of offsite power no trip
LOSP	loss of offsite power
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MOOS	Maintenance out of service
MTTR	mean time to repair
MVAR	megavolt ampere reactive
NEC	New England Coalition
NEI	Nuclear Energy Institute
NERC	North American Electric Reliability Council
NPCC	Northeastern Power Coordinating Council
NPP	commercial nuclear power plant
NPP	nuclear power plant
NRR	Office of Nuclear Reactor Regulation
OSP	offsite power
PE	Progress Energy
PORV	power-operated relief valve
PRA	probabilistic risk assessment
PW	Pilgrim Watch and Others
PWR	pressurized water reactor
RADS	Reliability and Availability Database System
RCP	reactor coolant pump
rcry	reactor critical year
rcy	reactor calendar year

RES	Office of Nuclear Regulatory Research
RG	regulatory guide
ROP	Reactor Oversight Process
rsy	reactor shutdown year
SBO	station blackout
SEE	severe external event
SERC	Southeastern Electric Reliability Council
SPAR	standardized plant analysis risk
SPP	Southwest Power Pool
SSC	system, structure, or component
SSF	safe shutdown facility
SSU	safety system unavailability
SUSQ	PPL Susquehanna
TM	test and maintenance outage
TSC	technical support center
UA	unavailability
UCS	Union of Concerned Scientists
WCAP	Westinghouse Commercial Atomic Power (report)
WE	Westinghouse
WECC	Western Electricity Coordinating Council
WOG	Westinghouse Owners Group
WSRC	Westinghouse Savannah River Company

REEVALUATION OF STATION BLACKOUT RISK AT NUCLEAR POWER PLANTS

Resolution of Comments

1. INTRODUCTION

This volume of the report *Reevaluation of Station Blackout Risk at Nuclear Power Plants* contains the comments received from stakeholders and the Nuclear Regulatory Commission (NRC) staff on draft versions of Volume 1 (loss of offsite power or LOOP event analysis) and Volume 2 (station blackout or SBO risk). The comments for each volume are listed and discussed in the order in which they were received in Appendices A and B, respectively.

The draft version of Volume 1 was issued for review as a standalone draft report. Table 1 shows the history of correspondence announcing the draft LOOP NUREG report. Table 2 shows the receipt of stakeholder comments and the comment reference.

Table 1. Draft Volume 1 (LOOP analysis) correspondence.

No.	Topic	ADAMS Ascension Number	Date
1	NRC Request for Review	ML043030477	10/28/2004
2	Two Week Advanced Notice Memo	ML043020484	01/31/2004
3	Draft LOOP Report	ML043380322	10/01/2004
4	External Review Letter	ML043380290	12/06/2004
5	Federal Register Notice Request	ML043440117	12/08/2004

Table 2. Draft Volume 1 stakeholder responses.

No.	Organization	ADAMS Ascension Number	Date
1	NRC/J. Lazevnick	Received	11/05/2004
2	Entergy Northeast	Received	01/10/2005
3	Institute for Nuclear Power Operations	ML050390213	01/21/2005
4	Nuclear Energy Institute	ML050390219	02/02/2005
5	Westinghouse Owners Group	ML050380314	02/02/2005
6	Electric Power Research Institute	Received	02/11/2005
7	NRC/NRR/DSSA	ML050690305	03/15/2005
8	NRC/RES/DSARE	ML050250124	03/17/2005

The draft SBO report was also issued for review as a standalone report. Table 3 shows the history of correspondence announcing the draft SBO report. Table 4 shows the receipt of stakeholder comments and the comment reference.

Table 3. Draft Volume 2 (SBO analysis) correspondence.

No.	Topic	ADAMS Ascension Number	Date
1	NRC Request for Review	ML050130308	01/14/2005
2	Two Week Advanced Notice Memo	ML050120308	01/21/2005
3	Draft SBO Report	ML050140399	01/31/2005
4	External Review Letter	ML050210284	12/11/2005
5	Federal Register Notice Request	ML050800469	02/16/2005

Table 4. Draft Volume 2 stakeholder responses.

No.	Organization	ADAMS Ascension Number	Date
1	Union of Concerned Scientists	ML050840201 and ML05110362	03/08/2005
2	NRC/RES/DSARE	ML050800469	03/17/2005
3	Electric Power Research Institute (EPRI)	ML051110357	04/06/2005
4	NRC/NRR/DSSA	ML050770142	04/06/2005
5	PPL Susquehanna	ML051160218	04/12/2005
6	Progress Energy	ML051120240	04/14/2005
7	Pilgrim Watch and Others	ML051120239	04/15/2005
8	New England Coalition	ML051250352	04/15/2005

Appendix A

Loss of Offsite Power Event Analysis (Volume 1) Comments and Resolution

Appendix A

Loss of Offsite Power Event Analysis (Volume 1) Comments and Resolution

Various organizations were invited to comment on Volume 1 of this report, which was issued as the draft *Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1986–2003* (S. Eide et al., October 2004). Comments were received from the following individuals and organizations:

- J. Lazevnick, U.S. Nuclear Regulatory Commission (JL)
- Entergy Northeast (ENTERGY), J. Bretti
- Institute of Nuclear Power Operations (INPO), C. Goddard
- Nuclear Energy Institute (NEI), A. Marion
- Westinghouse Owners Group (WOG), F. Schiffley
- Electrical Power Research Institute (EPRI), D. Modeen
- NRC, Office of Nuclear Regulatory Research (RES), Division of Systems Analysis and Regulatory Effectiveness (DSARE), W. Raughley
- NRC, Office of Nuclear Reactor Regulation (NRR), Division of Systems Safety and Analysis (DSSA), M. Stutzke.

Table A-1 lists the comments and their resolutions.

Table A-1. List of comments and resolutions for Volume 1.

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
JL	1	I've taken a look at the LERs on the four events between 1997 and 2003 identified in your report as LOOPs that are the result of a plant trip. These events are identified in Table A-2 of the report as LOOP Class: LOOP-IE-C. The Indian Point 2 and Oyster Creek 1 events are clearly LOOPs that were the result of the plant trip. Both events were degraded voltage LOOPs that occurred following the plant trip with voltage regulating equipment inoperable or not set properly. The TMI 1 and Salem 1 events, however, appear to be events where a common problem caused both the plant to trip and the LOOP. In the case of TMI 1 an internal generator breaker fault occurred that resulted in the loss of one of the two switchyard buses. When the other generator breaker attempted to open on the initial fault, it suffered a re-strike and also internally faulted, resulting in the loss of the remaining switchyard bus. With the switchyard now gone, a LOOP occurred, the reactor tripped, and the turbine tripped. In the case of the Salem 1 event, a fault in the control circuitry of a switchyard 500 kV circuit breaker caused loss of one of the two switchyard buses which resulted in the loss of the #2 and #14 station power transformers, a generator trip, a turbine trip, and a reactor trip. The loss of the #2 and #14 station power transformers resulted in transfer of vital and non-vital loads to the #13 station power transformer with subsequent loss of the vital loads as a result of degraded voltage protection actuation. The plant trip and LOOP in both these events were the result of a common initiator and appears they should have been classified as such (LOOP Class: LOOP-IE-I?). I'm also having trouble with the definition for LOOP Class: LOOP-IE-I in Section A.2.5. It's not clear to me whether the statement, "both the LOOP event and the reactor trip can be part of the same transient" applies to the LOOP-IE-I category or the LOOP-IE category.	The TMI 1 and Salem 1 events were reclassified as LOOP-IE-I events, as suggested. The statement "both the LOOP event and the reactor trip can be part of the same transient" applies to LOOP-IE and not LOOP-IE-I.	Appendix A tables

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
ENTERGY	1	I thought the report was very well done and provides an excellent source for updating LOOP frequencies and durations.	No resolution is necessary.	
ENTERGY	2	In Table 4-1, the probabilities of exceedance are incorrect for 0.1 and 0.2 hours.	The hours column in that table was formatted to show only one significant figure beyond the decimal point. These two entries are actually 3 min (0.05 h, rounded to 0.1 in the table) and 10 min (0.17 h, rounded to 0.2). The table has been changed to show two significant figures beyond the decimal point, and these two entries have been deleted.	Section 4, Table 4-1
ENTERGY	3	In Table 4-1, the "Actual Data Mean" of 4.71 hours for severe weather events should be 3.30, using the information from Appendix A, Table A-6.	Severe weather and extreme weather events have been combined into a single weather-related LOOP category in the final report. A mean for the combined category was calculated and rechecked to make sure it is correct.	Section 4, Table 4-1; Appendix A, Table A-6
ENTERGY	4	There should be a footnote for Table 4-1, indicating that the 5/15/00 Diablo Canyon was not included in the estimate of LOSP durations. Likewise for other events not included.	The Diablo Canyon event is now included in the LOOP duration results because, with the addition of 2004 events and other changes in the data, the event is no longer an outlier. However, the LaCrosse and two Pilgrim events are still excluded. A footnote was added to Table 4-1.	Section 4, Table 4-1
ENTERGY	5	In Appendix A, Tables A-5 and A-6, the Indian Point 2 and 3 event should have two LERs listed, because both plants experienced the LOOP.	This change was made in the final report.	Appendix A, Tables A-5 and A-6
INPO	1	INPO has no comments to offer on this document.	No resolution is necessary.	
NEI	1	The inclusion of the August 14, 2003, blackout event that resulted in loss of offsite power at nine units distorts the conclusions as stated in the report. The inclusion of this event does not only lead to a conclusion the grid has become less reliable during the 1997-2003 time period, but it significantly dominates the seasonal risk evaluation. Of the ten grid-related LOOPs identified during the	A LOOP event is defined, in this study and previous NRC-sponsored risk studies (i.e., NUREG-1032 and NUREG/CR-5496), as "the simultaneous loss of electrical power to all unit safety buses (also referred to as emergency buses, Class 1E buses, and vital buses) requiring all emergency power generators to start and	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		1997-2003 period, eight were associated with the August 14 blackout. This suggests the overall LOOP frequency increased from 0.02 per reactor critical year to 0.033. There were multiple causes for this blackout that clearly suggest it was very unique and unusual. Additionally, other plants were affected by this event but did trip. We believe that including this event on an industry-wide basis can be misleading. Separate activities are underway by the various stakeholders, at local, regional and national levels to address the recommendations made by the U.S. Canada Power System Outage Task Force to prevent and mitigate such events in the future. Therefore, we recommend the August 14 event not be considered in this evaluation.	supply power to the safety buses" (see Glossary). This is the standard definition that has been and is currently used for risk analyses. The definition refers to individual units, not to other groupings. Note that the definition does not focus on the cause of the LOOP or other considerations, only that power was lost to the safety buses. If we want to count events that affect the grid, then the August 14, 2003, event would be considered as one event. The inclusion of these LOOP events does not necessarily lead to a conclusion that the grid has become less reliable. Over the period 1997-2004 (note that 2004 was added to the final report), there were 15 grid-related, plant-level LOOP events (13 while at power and two while plants were shutdown). The event count is one grid-related LOOP (shutdown) in 1997, no events in 1998–2002, 11 events in 2003 (10 critical and one shutdown), and three events in 2004 (all critical). There is potentially a significant trend in grid-related LOOP occurrences over this period, resulting from the high numbers of events in 2003 and 2004. However, only time will tell if these two years signal an increasing trend in the grid-related LOOP frequency or if they are just "outlier" years. The approach used in the draft and final report is what might be described as a "middle of the road" approach to quantifying the grid-related LOOP frequency. One approach might be to ignore the August 14, 2003 event. That approach leads to a grid-related LOOP frequency of (5 + 0.5)/724.3rcry = 0.0076/rcry. Another approach might be to use only 2003 and 2004 data as most indicative of current industry performance for grid-related LOOPs. That approach results in a grid-related LOOP frequency of (15 + 0.5)/187.5rcry = 0.083/rcry. The approach used in	

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
			the final report is to use all grid-related LOOP events during 1997–2004. That approach results in a grid-related LOOP frequency of (13 + 0.5)/724.3rcry = 0.0186/rcry.	
NEI	2	The rationale for development of five event categories appears to provide valuable insights. However, care must be taken to ensure such information can be used in assessing plant-specific risk assessments. Parsing plant centered and weather related events into two additional categories adds additional complexity to the overall assessment. It is unclear how this is a significant improvement beyond the current categorization of events as plant centered, grid disturbance and severe weather.	The final report uses four categories of LOOPs: plant centered, switchyard centered, grid related, and weather related. The two weather-related categories in the draft report—severe weather related and extreme weather related—were combined into a single weather-related category. In addition, combining these categories eliminated the difficulty in determining which category a weather event belonged in, severe weather or extreme weather. We retain the plant-centered and switchyard-centered categories in this report because these categories are useful for applications such as the Accident Sequence Precursor Program. The data are provided so that a person can combine them according to the need. To accommodate risk assessments that use only three categories of LOOPs—plant/switchyard centered, grid related, and weather related—results are presented in the final report for the combined plant/switchyard-centered LOOP category.	Sections 3 and 4
NEI	3	The evaluation of events over the period of 1986-2003 needs further consideration. Comparison of LOOP events that occurred since deregulation in the utility industry beginning in the mid-1990s may provide a better understanding of grid reliability. An evaluation of regulated and deregulated states and regions of the country over the past several years may be more representative of the current state of the transmission system.	The purpose of the report was to update the LOOP frequencies and the core damage frequency resulting from station blackout. It was not to address grid reliability. Some insights related to the grid can be obtained from the report, but a direct measure of grid reliability cannot. Over the period 1997-2004, four grid events resulted in 15 LOOP events at commercial nuclear power plants. That is, 15 NPPs lost power to all of their safety buses. This limited number of grid events resulting in LOOPs makes the type of evaluation suggested difficult. We did	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
			perform statistical analyses to determine if the grid-related LOOP frequency varied by state, region, NERC reliability council, etc. (Note that this frequency is not the frequency of blackout events on the grid, which requires different/additional data.) Those results indicated that there was a difference between NERC reliability councils and NERC sub-regions, as discussed in Section 3.4. However, those results are complicated by the dependencies between LOOPs (nine caused by one grid event, three caused by another grid event, two caused by a grid event, and one caused by a single grid event). Because of these dependencies between grid-related LOOPs, we do not recommend the use of the NERC reliability council grid-related LOOP frequencies presented in Section 3.4.	
NEI	4	Duration of the event needs to be carefully considered since nuclear plant operators do not in all cases immediately restore offsite power when that power is available to the plant switchyard. The report acknowledged that safety bus restoration times were estimated for 73% of the events. U.S. nuclear power plants operators have demonstrated the capability to maintain the plant in a safe shutdown condition given a loss of offsite power event.	The report identifies three different restoration times associated with each LOOP event: time to restore offsite power to the switchyard, potential time to recover offsite power to a safety bus, and actual time to restore offsite power to a safety bus. The potential bus recovery time was used to generate the offsite power nonrecovery curves, rather than the other two times, because of the very reason mentioned by the reviewer—operators often delay restoring offsite power to a safety bus after power is restored to the switchyard (as long as the emergency diesel generators are operating in a stable manner). A detailed discussion of the process used to estimate the potential bus recovery times is presented in the response to DSARE Comment 1. The capability to achieve and maintain safe shutdown is treated in the Volume 2 risk analysis.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
WOG	1	The 14 Aug 2003 event is routinely noted to have caused nine plant LOOPs and ten trips. It would be better to describe the 14 Aug 2003 event on a site level as that better characterizes the effect of the grid on the NPPs that day. One event caused five American sites to loose high-voltage power. Nine-Mile 2 kept an intermediate voltage supply available throughout the course of the day on 14 Aug 2003. One event caused 10 American plants to scram their reactors for various reasons. One can question whether the event becomes more or less significant as a result of 12 other CANDU plants also scramming on that day. If a plant were to count the number of events that caused a relevant LOOP, the 14 Aug 2003 event would count once for any given plant in the northeast. It would be absolutely incorrect to describe the LOOP frequency as 9/year at, for example, Indian Point 3 for 2003. The 14 Aug 2003 should be referred to as a single event. The frequency of this type of event has nothing to do with the number of NPPs on-line. Page xvi among others describes the 14 Aug 2003 grid-event as highly unusual in that it affected nine reactors. While this is true, there is an excessive repetition of the consequence of the grid-event—see pages xi, xvi, 1, 8, 19, 25, 47, 50 (twice), 57, and 61. There is no "cause and effect" in terms of grid reliability between the 14 Aug 2003 grid-event and the number of operating NPPs on that day. Several other events including Aug 1996 in the west and Jul 1989 in the vicinity of V.C. Summer were no less far reaching. In addition, two of the three major northeast grid events occurred well before deregulation—once in Jul 1977 and once in Nov 1965.	See response to NEI Comment 1. The August 14, 2003 event resulted in nine plant-level LOOP events (eight during critical operation and one during shutdown operation). These plant-level events were included in the frequency analysis. However, these nine events were collapsed to six site-level events for the offsite power nonrecovery curve analysis. (Nine Mile Point 1 and Fitzpatrick were considered as one site, and Nine Mile Point 2 as another site, based on locale and incoming offsite power lines. (See the response to DSARE Comment 1.) The approach taken in the report is consistent across all four categories of LOOPs, and results in LOOP category frequencies that accurately estimate the number and types of plant-level LOOPs observed over the period 1997–2004. The plant-level approach to calculating LOOP frequencies does not attempt to predict how many nuclear power plants might be affected by a grid disturbance; it merely counts the observed number of plant-level LOOPs from such events. This includes the nine LOOPs from the August 14, 2003 event; the three LOOPs from the June 14, 2004 event; the two LOOPs from the September 15, 2003 event; and the one LOOP from the June 16, 1997 event. Note that the V.C. Summer event mentioned by the reviewer is included in the LOOP database, but was not included in the calculation of grid-related LOOP frequency because it did not occur during the period 1997–2004. Grid disturbances that did not result in a plant-level LOOP are not included in the database.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
WOG	2	Defining "summer" to have five months skews the conclusion that LOOP events are predominantly in the summer. Plants from Kewanee to Pilgrim are at a latitude that would challenge the assumption that May is part of the "summer season." A more conventional view of "summer" in the various regional grids shows that some of them have more than an expected number of grid-events and LOOPs. However, it is unfair to characterize all regional grids to have the same summertime propensity to cause a LOOP. The definition of summer affects the values that appear on Table 6-1 (see page 46).	The term "summer" or "summer months" includes May through September for all U.S. commercial nuclear power plants. This was first used in NUREG-1784. (The author of NUREG-1784 saw a concentration of LOOP events during these months for 1997-2002.) It was used to denote those particular months of the year, not necessarily the season. The present report used that same definition for consistency. In the final report, the terms "summer" period and "nonsummer" period are used. Additional information is presented by month (rather than by season (summer or nonsummer) in the final report for informational purposes. NERC has also seen increases in the transmission load relief requests during this same period (May–September). We could develop a much more complicated definition of "summer," based on climate, grid load characteristics, etc. However, a quick review of the LOOP events indicates that we would show a concentration of LOOP events in the hottest time of the year. The simplified definition of "summer" is adequate. This does not prohibit users from modifying the definition of "summer" for specific plant studies.	Section 6.2
WOG	3	The custom at many NPPs is to categorize LOOPs into three groups: plant-centered, weather-related, and grid-centered. Other plants, such as Palo Verde, include the switchyard explicitly in the PRA model. Thus, some plants represent the effect of the off-site AC supply with a single LOOP frequency number. The draft NUREG does not present a compelling statistical argument for sub-dividing plant-centered and weather-related events. Having five categories adds to the already existing problem of having little empirical data for any particular category of LOOP event. The current draft of the NUREG will inappropriately force PRA staffs around the country into a recurring job to explain and defend the use of the three groups (or single LOOP frequency)	The final report uses four LOOP categories (plant centered, switchyard centered, grid related, and weather related). We grouped the severe and extreme weather events together. We present results for three categories (plant/switchyard centered, grid related, and weather related) to support risk assessments using only three categories. LOOP frequencies and offsite power nonrecovery curves are presented at both the LOOP category level and the combined or composite level in order to support a variety of risk assessment approaches. We agree that, at first glance, the final report LOOP	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		rather than the five selected by the NRC contractor. Although it may be statistically interesting, it is not particularly useful to the PRA community to sum all LOOP frequencies associated with (1) power operation and (2) LPSD (see Section 3.1 and Section 3.4 of the draft NUREG). Each initiator in a model is married to a particular event tree. It is customary in LOOP models to run post-processing recovery rules to correctly represent the probability of extended LOOP durations. The event tree needed to represent the mitigation of a LOOP transient starting from full-power conditions is wholly different from an event tree that handles the LPSD condition. Combining all LOOP frequencies is thus confusing and unnecessary. The numbers proffered in the draft NUREG should meet the purpose described in the Abstract, that is "... to accurately model current risk from LOOP and associated station blackout scenarios." As plant status is not particularly relevant to weather-events, there seems to be no reason to have an at-power weather-related LOOP separate from the LPSD weather-related LOOP. With the same reasoning, grid-events due to high-voltage equipment failures far away from the NPP again do not depend on the on/off status of any NPP station generator. Extreme weather includes a criterion for 125 mph winds that is not well defined (compare page xxii and page 3). A hurricane may have 125 mph winds at the eye-wall with a substantial drop off in velocity within a few miles. An eye-wall approach to a site inevitably leads to a plant transition to one of the LPSD modes either voluntarily or as a result of consequential grid-events. The draft NUREG does not make a strong statistical case for treating extreme-weather separately from other weather phenomenon. By design, the NPPs have the capability of running on-site AC systems for up to seven days without offsite assistance (see ANSI Standard N195-1976, Regulatory Guide 1.9 and Regulatory	frequencies that indicate a significant difference in weather-related LOOP frequency between critical operation and shutdown operation are puzzling. (From Section 3, Table 3-1, the weather-related LOOP frequency is 4.83E–3/rcry during critical operation and 3.52E–2/rsy during shutdown operation.) One might expect these two rates to be similar. However, at least three factors impact these results. The first factor is that while plants are shut down, they often have abnormal electrical configurations that make them more susceptible to LOOPs. The second factor is that plants sometimes choose to shut down their plants in anticipation of severe or extreme weather events. This is observed in the LOOP data and an extra column was added in Appendix A, Table A-1 to indicate such cases. This practice partially explains why the shutdown operation frequency is higher than the critical operation frequency. Therefore, on average, if a weather event occurs while the plant is shut down, the plant is more likely to experience a LOOP. This can be observed from the LOOP data in Appendix A, where the "Abnormal Electrical Configuration" column indicates whether such a configuration existed at the time of the LOOP. Section 6.10 also discusses this issue. The third factor is that some of the more localized weather events have been categorized as plant centered or switchyard centered. (See Appendix A, Table A-1 for LOOPs in these two categories that have a "Cause" entry of SEE or EEE.) Therefore, not all of the weather-caused LOOPs are in the weather-related LOOP category. This approach of including weather events in three different categories—plant centered, switchyard centered, and weather related—impacts the comparison of critical operation weather-related LOOP frequency with shutdown operation weather-related LOOP frequency. All three factors discussed above tend to move the	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		Guide 1.137 and FSAR commitments to implement them). Even the most spectacular NPP-weather event (hurricane Andrew, 1992) caused a LOOP of only five days. The low frequency of such extreme weather and the relatively long LOOP durations of all weather-related LOOPs make treating "extreme-weather-events" separately from any other weather-related LOOP an unproductive means of identifying NPP vulnerabilities. It would be more appropriate to handle extreme-weather events in sensitivity studies as warranted by the application. Section 2 describes the sub-division of traditional plant-centered-LOOP into plant-centered and switchyard-centered. The distinction is generally not crucial because the standard error for the LOOP duration statistic is quite large whether the events are lumped or not. As demonstrated by the NUREG, selecting a particular duration for any LOOP is a challenging exercise. Separating plant-centered and switchyard-centered events makes the subjective judgments on event duration more important than they should be. Some sites, such as Diablo Canyon, have distinct switchyards that (1) distribute power produced from (2) the switchyard that supplies house-loads. See additional discussion in Section 6.9 of the draft NUREG. It would be best to allow the PRA staff studying a particular plant to determine which events are plant-centered and leave some switchyard-events in the grid-centered category. Generalizations made in the draft NUREG of the near-plant switchyards are bound to oversimplify a complex situation. The costal versus inland distinction is an interesting observation and has potential to well characterize grid-centered and weather-related events. However, the assignment of an NPP to one of these two groups needs to be done with more than simply an "80-miles to the ocean" criterion. For example, the draft NUREG characterizes Indian Point as a costal plant. However, there exist large mountains and other geographic obstacles between Indian Point and the south shore of Long Island. The Indian Point 3 FSAR, Chapter 2 (Section 2.6.1) describes the predominant wind direction as controlled by the topography, i.e., the shape of the Hudson Valley.	shutdown and critical operation weather-related LOOP frequencies towards more similar values. However, the results as presented represent actual plant experience and practices. Statistical analyses of the grid-related LOOP data indicated that such events did not show a significant difference between critical operation and shutdown operation. For consistency with the other three LOOP categories, the grid-related LOOPs were also broken down into critical operation and shutdown operation. This has a negligible impact on the critical operation frequency. From Section 3.3, Table 3-5, if the shutdown and critical operation events were combined, the result would be (13 + 2 + 0.5)/(724.3rcry + 104.7rsy) = 0.0187/rcy. The critical operation grid-related LOOP frequency used in the report is 0.0186/rcry. The final report combined the severe weather and extreme weather events into a single weather-related LOOP category. This eliminates the difficulty in trying to distinguish severe weather events from extreme weather events. Also, with the addition of the 2004 LOOP data (with some extreme weather events with short offsite power recovery times), the combined weather-related LOOP category events present a spectrum of offsite power recovery times that could be fitted to a lognormal curve. That curve fit uses all of the weather events, even the five-day outages in 1992. The classification of coastal versus non-coastal was taken from NUREG-1032 (with some changes). Statistical analyses indicated that this breakdown of plants was significant only for shutdown operation weather-related LOOPs, as shown in Section 3.4, Table 3-6. Similar to the case for grid-related LOOPs during critical operation, if plant-specific frequencies are desired, the industry-average weather-related LOOP	

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
			frequency during shutdown should be used as a prior in a Bayesian update with plant-specific data over 1997–2004.	
WOG	4	The "LOOP Frequency" Section (e.g., page 12) describes the use of gamma and 'constrained noninformative' distributions. The "LOOP Duration" Section describes log-normal distributions and Weibull distributions. Neither Section has much discussion on why this level of complexity is necessary. The technique of matching LOOP data to a particular probability distribution typically has little effect on the mean values loaded into PRA models. The curve fitting compensates for an absence of empirical data with statistical approximations. Discussion on page 26 shows that curve-fit values can result in noticeable differences from mean values. The bigger problem comes when the curves are used to represent the 5% and 95% bounds on the likelihood estimate. Because the regulations and guidance on assessing CDF and LERF changes focus on particular numerical values, using an over-estimated 95% value in an application sensitivity study can unrealistically distort the "bounding risk estimates." Given the epistemic uncertainties in LOOP modeling, there is no strong argument given for using these distributions and the associated advanced statistical techniques to describe LOOP frequency and LOOP duration. It is difficult to rigorously select relevant LOOP events for a particular plant PRA. Furthermore, once a LOOP event is selected as relevant, the determination of LOOP duration is at least as difficult as described later in the draft NUREG. More transparent and less costly approaches to establishing the LOOP frequencies such as those currently in use by the industry serve all stakeholders well. Regarding Appendix D, the primary numbers that should change from plant to plant are those for weather and grid. The second approach described in Section 3.4 (using Table 3-5) gives large	The final report presents distributions for the four LOOP category frequencies (and the combined frequency), assuming a gamma distribution. This type of distribution is typical for rate-based quantities. In most cases, the LOOP category data for 1997–2004 included too few events to perform a sophisticated uncertainty analysis (such as the empirical Bayes analysis described in Appendix B) or there were dependencies between events that rendered the empirical Bayes results questionable. In such cases, the constrained noninformative distribution was assumed. This distribution uses a value of 0.5 for the gamma shape parameter (α) and calculates the shape parameter (β) from the mean and α. This distribution has an error factor (95%/median) of approximately 8.4. This approach is not very complex and is felt to appropriately model the uncertainty in the industry-average LOOP frequencies as applied to a given plant. Note that the total LOOP frequency of 0.0359/rcry for critical operation has an error factor of 3.2, with a 5% value of 4.57E–3/rcry and a 95% value of 9.19E–2/rcry (obtained from simulation and subsequent curve fitting). This range is reasonable, given the data observed. Unlike the draft report, the final report uses lognormal curve fits to the offsite power recovery times. Any software capable of fitting data to a lognormal distribution should be able to reproduce the results presented in the report. As indicated by the reviewer, such curve fitting is helpful in terms of providing a smooth set of nonrecovery probabilities over the entire period typically needed in risk assessments—0 to 24 h. Also, the final report presents uncertainty bounds for	Sections 3 and 4

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		variations between regions, but either doesn't vary enough for weather (St. Lucie is much more likely to have a weather event than Oconee) or give adequate credit for grid reliability (but at the same time too much penalty for those affected by the 14 Aug 2003 event). The third approach (using Bayesian updates with plant-specific data using priors from Table 3-3) gives no variation in extreme weather, essentially no variation in severe weather, and very large differences in grid related categories compared to the grid related values from the applicable region of the 2nd approach. Note that adopting approach 2 versus approach 3 can result in a factor of 10 differences in the grid-centered LOOP frequency. This is particularly significant for plants in the regions with relatively high grid reliability. Thus, the use of either approach should be used with caution as neither accurately represents grid-reliability for an individual plant. One way to establish the reliability of a node in a grid system would be to exercise a model such as the ones used by grid-operators in their "contingency analyses." A more generic model could have been used. However, using a general model of a grid system would be akin to a building a generic PWR risk model and applying conclusions from it to a particular plant. In the absence of either a detailed grid model for a particular region or sub-region, the draft NUREG statistically established the regional trend of grid events. The regional frequencies are provided without the associated error factor. The error factor was provided only for the national data. When the regional grid-event frequency is used, the regional EF becomes another important input to estimate the uncertainty that supports risk-based change applications to the NRC. The EF for national grid events data was estimated to be approximately 8. Since there was a clear regional trend, the regional data EF should not exceed 4. The frequency of applicable grid events and the choice of statistical technique used (such as Bayesian Updating with an assumed distribution) should remain flexible for PRA analysts to apply their appropriate favored techniques.	these curves. (The draft report did not present any uncertainty information for its curves.) The method used to estimate these curve uncertainties is more complex than that for the LOOP frequencies and is discussed in Appendix B. Figures 4-1 through 4-4 in Section 4.1 show the lognormal curve uncertainty bounds. Those bounds qualitatively appear to be reasonable given the actual data curves. As noted in the report, the lognormal curve fits to the offsite power recovery times may not result in medians and means that closely match the data. However, what is most important is how close the fitted curve is to the actual data curve for a given LOOP duration. That information is provided qualitatively in Section 4.1, Figures 4-1 through 4-4. Also, quantitative comparisons are presented in Table 4-1 for the composite curves. We agree that there are many other types of uncertainties involved when evaluating the risk from LOOP and related station blackout events. These should be included in the risk model used to calculate that risk. As was done in the draft report, Section 3.5 in the final report presents three possible ways to estimate plant-specific LOOP frequencies for a given plant. The first is to use the industry-average LOOP frequencies for all four categories. The second is to use the region-specific average LOOP frequencies (as listed in Table 3-6). Finally, the third approach is to use the industry-average frequencies as priors in a Bayesian update with plant-specific data over 1997–2004. All three approaches have merit and each one might be the most appropriate for specific applications. The second approach with respect to the grid data is highly sensitive to whether a grid disturbance resulting in plant-level LOOPs occurred during 1997–2004. The four	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		The data in Appendix A (as well as data from EPRI and the Department of Energy) indicates that the number of grid-events leading to LOOP at an NPP is strongly dependent on the NERC region in which the NPP is located. Regions with long-distance power flows operate differently than those with shorter distances. NPCC, ECAR, and MAIN exchange power and MVARs routinely; whereas, the WECC has little to do with ERCOT. The rigor of regional operation and administration varies widely as described in the Department of Energy joint task force report on the 14 Aug 2003 event. It would be thus, incorrect to assign grid-centered-LOOP frequencies to an individual NPP based on a national average. There are many grid-events documented with the Department of Energy that had no effect on a particular NPP. It is incorrect to characterize the reliability of the grid-system unless the analysis considers a more complete list of large grid-events. Section 4.1 of the draft NUREG ignores the wide-spread grid-centered LOOPs of Aug 1996 and Jul 1989. Table 6-4 in the draft ignores EPRI Category III LOOP events at Comanche Peak (May 2003) and Limerick (Feb 1995). The listed Peach Bottom event of Sep 2003 was only a momentary LOOP according to the LER filed on that event (re ADAMS Accession number ML033230324). Appendix C of NUREG-1784 has additional errors beyond the one noted for Byron 2 in Section 6.3. See the shaded areas in the Table below. *The reviewer presents a corrected version of NUREG-1784 Table 6-12.*	NERC reliability councils with such events during this period (ECAR, MAAC, NPCC, and WECC) have grid-related LOOP frequencies for critical operation ranging from 2.07E–2/rcry to 6.42E–2/rcry. Other NERC reliability councils without such events have frequencies ranging from 2.04E–3/rcry to 8.92E–3/rcry. As an example of this sensitivity for the second approach, the draft report covering 1997–2003 in Table 3-5 lists a grid-related LOOP frequency for critical operation of 6.24E–3/rcry for WECC. (During that period, there were no grid disturbances resulting in plant-level LOOPs in that reliability council.) However, with the addition of the 2004 data (and the June 14, 2004 grid disturbance that resulted in three plant-level LOOPs), the final report lists a grid-related LOOP frequency of 4.18E–2/rcry for WECC (Table 3-6 in the final report). This represents almost a factor of seven difference from the draft report, all because of the addition of the 2004 data. In contrast, the third approach (Appendix D in both the draft and final reports) lists grid-related LOOP frequencies during critical operation for Palo Verde 1 of 1.38E–2/rcry (draft report covering 1997–2003) and 4.38E–2/rcry (final report covering 1997–2004). This third approach is much less sensitive to this single grid event than is the second approach. Hence, the authors prefer the third approach for risk analysis applications. In the future, as more is known about regional differences in grid reliability (i.e., measures are not overly sensitive to single events), we may propose using regional data. Also refer to the response to WOG Comment 2.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
			In this study we are concerned with events that meet the LOOP definition defined in the Glossary. Nuclear power plants did not lose offsite power during the wide-spread grid events of August 1996 and July 1989. Similarly, Comanche Peak (May 2003) and Limerick (February 1995) did not lose power to safety buses and are, therefore, not LOOP events per our definition. Thus, they are not listed in Table 6-4. Peach Bottom lost power momentarily to the switchyard and power to all safety buses. The restoration time to the switchyard in our report is 1 min. The actual bus restoration times are 41 min for Unit 2 and 103 min for Unit 3 Potential errors in Appendix C of NUREG-1784 were referred to the author of that document. Any changes identified did not affect the use of that document in the present report.	
EPRI	1	The main feature of the report is an analysis of LOOP experience during the 18 year period 1986 thru 2003. The majority of the discussion focuses on the full 18 year period as an entity. We believe that industry should base decisions relative to enhancing the reliability of offsite power on more recent experience. A period in the range of perhaps seven to ten years is more appropriate. Our reason for this is that the grid has continued to be strengthened during the past 18 years. There are more switchyards and more and heavier transmission lines. On the other hand, deregulation has come into play and many regions of the grid are more heavily loaded than they once were. What is important is LOOP experience during the recent period, not during the now unrepresentative past.	The final report compares LOOP frequencies obtained from two periods, 1986–1996 and 1997–2004. Based on this comparison, all of the four LOOP category frequencies during critical operation are based on data from 1997–2004. Therefore, the critical operation LOOP frequencies are based on the most recent period. However, for shutdown operation, data from both periods, 1986–2004, were used because statistical analyses indicated no significant difference.	Section 3.1 and Appendix C
EPRI	2	It is our view that loss of offsite power data and cascading grid blackout data should not be co-mingled in the manner addressed in the report. The report counts the nine LOOPs that occurred during the grid	See the responses to WOG Comment 1 and NEI 1 with respect to the overall modeling of grid-related LOOP frequency. With the addition of the 2004 LOOP data in the final	Section 3.1

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		blackout on August 14, 2003 as separate, discrete events. This is a decision of overwhelming importance and warrants careful reconsideration. These nine LOOP events (eight at operating units, one at a shutdown unit) from August 14, 2003 dominate the statistics during the seven year period 1997 thru 2003. There were ten grid related LOOPs while in critical operation if the blackout is included, but only two if the blackout is not included. The occasional loss of offsite power usually occurs because of an isolated equipment or human random failure, or because of adverse weather. In contrast, a grid blackout is not the result of random failures. It indicates an overall grid weakness. The impact can cover a broad territory and many plants. The loss of power can last from many hours to the better part of a day. If combined, blackout losses overwhelm normal loss of offsite power statistics and totally obscure their meaning. For these reasons, we view a grid blackout as something very different. Moreover, the August 14, 2003 event is the only event in the history of the industry that resulted in complete loss of offsite power to a nuclear unit. The policy implications of these conclusions can be very misguided, because of the conservative frequencies and durations that result. Therefore, it is prudent to not co-mingle the data until the basis for that combination is better understood. The attachment to this letter further elaborates on this point. The eight LOOP events at operating units from August 14, 2003 dominate the statistics during the seven year period 1997 thru 2003. There were ten grid related LOOPs while in critical operation if the blackout is included, but only two if the blackout is not included. For the full 18 year period 1986–2003 there were 11 grid-caused LOOPs if the blackout is included but only three if the blackout is not included. Loss of offsite power usually occurs because of an isolated equipment or human random failure, or because of adverse weather. Such failures can be minimized but never completely eliminated. The impact of such failures is usually limited to one plant and a loss of power for hours. In the U.S. there is typically 1,	report, the June 14, 2004 grid event contributed another three plant-level LOOPs to the database. Therefore, over 1997-2004, there were four grid events resulting in one, two, three, and nine plant-level LOOPs. With the addition of the 2004 data, the August 14, 2003 event still dominates, but not as much as in the draft report. We did not review the grid-related LOOP events to determine whether they resulted in a "complete loss of offsite power to a nuclear unit." However, all LOOPs in the study, by definition, resulted in complete loss of offsite power to the safety buses, requiring the emergency power sources to start and provide power to these buses. Also, the great majority of the LOOPs resulted in complete loss of offsite power.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		2, or 3 such losses of all offsite power per year. On the other hand, a cascading grid blackout reveals an overall grid weakness. Several approaches to this issue are under active consideration at EPRI and the industry. The August 2003 event is a single blackout from the point of view of each plant site. It is not nine events. In the past, we have conservatively counted multiple unit LOOPs as multiple events, but that is no reason to continue a conservative practice that was tolerable for two units, but distorts all things out of meaningful proportions for the August 2003 event. *The reviewer presents a table comparing early and later LOOP frequencies with and without the August 14, 2003 events.* Excluding the grid blackout, there were only a total of ten LOOP events when the plant was critical during the seven years 1997-2003. And, only two of the ten were grid related. On the other hand, when the blackout is included, there was a total of 18 LOOPs of which ten were grid related. By including the blackout LOOPs, the number of grid related LOOPs was increased by a factor of five and the total number of LOOPs was increased by a factor of 1.8. It is equally informative to examine the overall LOOP frequencies for the 1997-2003 period with the 1986-1996 period, both with and without the blackout data included. Without the blackout data included the total LOOP frequency was 0.016 in the recent period vs. 0.046 for years 1986–1996, which is a reduction of about two thirds. Note however that even if the blackout LOOPs are included, the total frequency drops from 0.046 for years 1986-1996, to 0.029 for years 1997–2003, which is a reduction of about one third. It is clear that underlying LOOP experience has greatly improved with or without considering the August 14, 2003 grid blackout. This is not to argue that the risk of grid blackout does not require dedicated attention. Rather we believe a new approach is required to develop with a method for estimating the frequency of cascading grid events that is representative of what is likely to occur.		

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
EPRI	3	A general area that merits reconsideration in the report has to do with LOOPs during plant shutdown. As the report notes, LOOP experience during critical operation has continued to improve during the years. If the August 14, 2003 cascading grid event is not included, the reduction in plant-centered loss of offsite power events has dramatically improved. Consequently, we were surprised when the report noted that LOOP experience during shutdown operation has shown no improvement. The report's statistics indicate that the frequency of shutdown LOOP events is many times the frequency of loss of offsite power during critical operation. Our analyses do not have similar results. The shutdown LOOP frequencies that we have determined have been generally similar to the critical operation LOOP frequencies. We provide further details in the attachment. The differences in the NRC contractor and EPRI results come about because of major differences in our approaches and manner of event classification, not because of numerical or statistical treatment differences. Because of this, the brief comments here will discuss the comparative overall approaches and not further consider the actual numerics. These are secondary to the methodologies. The NRC contractor report approach to classifying shutdown LOOPs appears to be straightforward. If a Unit is in shutdown and experiences a LOOP, the event is classed as a LOOP while shutdown. The report appears to accurately provide this information. However, such statistics do not shed light on whether the shutdown, or shutdown activities, played a role in initiating the LOOP. Would, for example, the LOOP have initiated even if the unit had not been shutdown? EPRI's shutdown LOOP statistics were intended to answer a somewhat different question. How frequently was a shutdown or shutdown activities responsible for initiating a LOOP? We identified at least eight events in the draft report's data where the shutdown played no role in initiating the LOOP. It would have been initiated regardless of whether the plant was at power or	The approach taken to estimate LOOP category frequencies during shutdown operation is identical to that used for critical operation. If a LOOP occurred while a plant was shut down, that LOOP was placed in the shutdown category. We agree that many LOOPs that occurred during shutdown operation could just as well have occurred during critical operation, and vice versa. We feel that a sufficient number of shutdown LOOP events exist in the database to provide credible estimates. Results in Table 3-1 indicate that plant-centered, switchyard-centered, and weather-related LOOPs occur more frequently during shutdown per unit time. Potential reasons for this are more frequent abnormal electrical configurations during shutdown, different test and maintenance activities during shutdown, anticipatory shutdowns (for inclement weather), and perhaps others not readily apparent. See the response to WOG Comment 3 for more information.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		shutdown. In this area, EPRI's classifications have tended to focus more on the cause of the LOOP rather than the fact of the LOOP. An example might help. A plant shuts down because of an approaching hurricane. Subsequently the hurricane causes a grid related LOOP. EPRI would enter this event in the general LOOP data, and not segregate it as a shutdown LOOP because neither the shutdown nor shutdown activities were responsible for initiating the LOOP. The draft report's methodology embodies one further feature that tends to magnify the apparent shutdown LOOP frequencies. The shutdown LOOP frequencies are determined using the number of LOOP events while shutdown and the hours only while shutdown. While EPRI's approach was somewhat different, the report's approach would also appear to yield understandable results. However, with this approach, when the non-shutdown initiated LOOPs are charged to shutdown hours, the results become questionable. This is because the hours while shutdown is only about one quarter of the hours at power. When, as described in the preceding paragraphs, a significant number of LOOP events that were not initiated by the shutdown, are charged against the small number of shutdown hours, greatly magnified shutdown LOOP frequency values emerge.		
EPRI	4	This section contains LOOP-related comments received with the SBO comment letter. SBO comments from that letter are covered in Appendix B of this volume. 1. We concur with INEEL that it is appropriate to base core damage frequency values on LOOP experience when the plants are critical (as contrasted to shutdown). At the same time we believe it would be appropriate to include those LOOP events, while shutdown, whose cause had absolutely nothing to do with the shutdown status of the plant. An extreme example might be a plant that is shutdown for refueling and a hurricane deenergizes the grid. This LOOP perhaps should be considered because the shutdown status of the plant in no way was a cause of the LOOP. On the other hand, if the	See the response to EPRI Comment 3 with respect to the methodology used to estimate LOOP frequencies appropriate for critical and shutdown operation. As noted previously, inclusion of the 2004 data added another grid event that resulted in three plant-level LOOPs. With this addition, the August 14, 2003 event still dominates, but not as much. All four grid events during 1997–2004 occurred during the summer period (May through September). We agree that four events (resulting in 15 grid-related LOOPs) is a relatively small number, and future performance could	

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		special shutdown configuration of the plant, or the switchyard, or the adjacent grid is such that the LOOP would not have occurred if the plant had been operating, the LOOP should not be included in the core damage frequency statistics. 2. One additional comment relative to LOOP experience concerns seasonal effects. In Section 6.2 on page 49, Table 6.2 indicates that during the period 1997-2003, while in critical operation, there were 10 grid related events in the summer and none during the non-summer months. For the longer period 1986-2003 there were 16 during the summer months and 12 during non-summer months. It is important to note that 8 of the summer LOOPs for each period came from the 08/14/03 grid blackout. Without the grid blackout, during the period 1997-2003, while in critical operation, there were 2 grid related events in the summer and none during the non-summer months. For the longer period 1986-2003 there were 8 during the summer months and 12 during non-summer months. Excluding the grid blackout these LOOP values and variation appear typical of what one might expect when dealing with small numbers of random events. *We also note that grid instability is not limited to summer months—the prolonged period during 2001 in California occurred in the winter/spring and the Northeast blackout of 1966 occurred in the fall.* 3. EPRI conducted an analysis of LOOP events that occurred in the period 1994 thru 2003. We noted that there were more LOOPs during the summer months. We, like NRC and INEEL, wondered whether LOOP events were more likely to occur in summer months when temperatures are elevated and grid loads are heavier. The results that follow are for LOOPs that occurred while the plant was at power or while the plant was shutdown but the LOOP would have occurred even if the plant was critical. Ten LOOPs during the 10 year period fell in the above two classifications. Eight of the 10 above described LOOPs occurred during the summer months. Four occurred in June, one in July and three in August. We sought to determine why they occurred. Was it because of some inherent property of summer? Four of the 8 LOOPs that occurred in summer	indicate that the grid-related LOOP frequency during critical operation during the summer months (4.32E-2/rcry, Table 3-4) could be an overestimate. We did not investigate in detail why the LOOP frequencies in the report are so much higher during shutdown operation compared with critical operation. The two frequencies are 0.0359/rcry and 0.196/rsy. See the response to EPRI Comment 3 for potential reasons for this large difference. This study is limited to looking at loss of offsite power events at nuclear power plants during which power is lost to all the safety buses. No nuclear power plant lost power to its safety buses during the Northeast blackout of 1966 nor during the grid instability of 2001 in California.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		were initiated by equipment failures. A review of the failures indicates they did not occur because it was summer or because the grid loads were heavy. As might be expected, the equipment failures that caused the four LOOPs were season-independent: • The main step-up transformer failed • Both of a set of dual generator output breakers failed • An electrical fault occurred in a breaker failure relay circuitry. • A main generator exciter commutator brush shattered. Three of the eight LOOPs came about because severe storms with high winds deenergized the transmission lines into the plant. Perhaps such storms are a summer phenomenon and thus these LOOPs can be classified as summer related; however severe weather patterns (and time of year) vary significantly from region to region. It should be mentioned that the previously indicated main step-up transformer equipment failure was initiated by a close-in lightning strike where the after-strike fault currents caused the failure. The transformer probably should not have failed so we have listed it under equipment failure. However, if one considers the lightning strike as the initiator, and further judges lightning to be a summer phenomenon, then this event also might be considered to be summer related. Finally, one of the eight LOOPs was initiated by a human error during maintenance and testing activities (a spurious unit trip). This was not summer related. The final tally on weather is that 4 of the 10 LOOPs can be associated with weather. Hence to the extent that weather is related to summer, 4 of the 10 are related to summer. None of the 8 LOOPs during the summer months appeared to be directly related to heavy power transfer on the grid or high environmental temperatures.		
DSARE	1	The "potential" safety bus restoration times, i.e. estimates of the time to restore power under SBO conditions (which are less than the actual times it took to restore power to a safety bus during a	The draft Volume 1 used the guideline of adding 1 min to the switchyard restoration time (assuming no unusual situations such as equipment damage or unstable grid) to	Sections 4, 6.7, and 7; Appendix A

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		LOOP) need to consider the operational and technical challenges faced by the operator for an SBO. The report provides a sensitivity analyses using the actual safety bus restoration times which are longer. Experience shows that in at least 50 percent of the LOOPs involving a reactor trip, the choice of the potential safety bus restoration time may not always be the best estimate. We suggest revising the report to show the actual time is just as conceivable based on: (1) the reactor operation and priorities during an SBO; (2) that although faults may isolated quickly, the collateral damage may prevent use of the equipment; (3) operator actions may be quick and involve routine verification and switching, however, operations need much more time to make unit cross-ties available, implement temporary modifications, or wait for the arrival of support staff to diagnose problems during off hours, and (4) although some experience shows it could take as little as one minute under ideal conditions to back power from the switchyard to the safety bus, other experience shows it takes more than one-minute (and up to 861 minutes). We suggest the report be revised to conclude that there is truly a range of possible restoration times bounded by the potential safety bus restoration time and the actual safety bus restoration time. The supporting experience follows and in some cases we provided additional suggestions. (a) It is conceivable that given the pressure of an SBO, a potential safety bus restoration time may in some cases be justified. However, it is also conceivable that during an SBO, that the actual safety bus restoration time is just as valid as the NPP operator may not have control over recovery due to weather or grid conditions (about one-third of the LOOPs involving a reactor trip). In addition, recovery during an SBO may take longer than a LOOP as there are more operating tasks to delegate to the available staff. Typical tasks during an SBO include diagnosis of EDG failure and its recovery, battery load shedding; making alternate electric feeds from the switchyard or unit cross-ties available, and starting alternate ac power supplies; and communicating with the plant Technical	approximate the potential bus recovery time (for cases where this time is listed as estimated, indicating the LER did not provide sufficient information to determine this time with certainty). This guideline was used based on previous work done for NUREG/CR-5496 (which used a similar guideline), additional discussions with personnel who previously were reactor operators, and actual data that indicated in eight of the LOOPs the operators recovered offsite power to a safety bus within 1 min after switchyard power was restored. However, since there have been no SBOs during critical operation, assignment of potential bus recovery times when the LERs have insufficient information is an uncertain process. Based on this comprehensive comment and others, the 1-min guideline was revisited. A less optimistic guideline was developed (see Section 6.7 in Volume 1) that uses an additional 15, 10, or 5 min past the switchyard restoration time for cases where the potential bus recovery is estimated. This sliding scale of times was developed to allow for operators to adjust to the SBO conditions before having to recover power to a safety bus when the switchyard regained offsite power. If the switchyard restoration time was less than or equal to 15 min (allowing less time for the operators to adjust to the SBO), then 15 additional min were allotted for them to reconnect a safety bus to the switchyard offsite power. If the switchyard restoration time was greater than 15 min but less than or equal to 30 min (allowing more time for operators to adjust to the SBO), then an additional 10 min were allotted for operators to reconnect a safety bus to the switchyard offsite power. Finally, if the switchyard restoration time was greater than 30 min, then an additional 5 min were allotted. As a check for these guidelines, LOOPs with certain	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		Support Center (TSC), Operational Support Center (OSC), and NRC Operations Center. Although there has never been an SBO in the U.S., the operating experience indicates that as SBO conditions were approached, the LOOP lasted longer more than 50 percent of the time, i.e. we looked back to 1996 and found that for the subset of LOOPs involving a reactor trip and the loss of one EDG, three of the five LOOPs lasted longer more than the four hour SBO coping capability of most NPPs. (b) The shorter estimates of potential safety bus restoration time do not provide a general window of time for reactor operation. Following a reactor trip with an SBO the operators must first stabilize the reactor (e.g. in a pressurized water reactor, isolate the reactor coolant system and verify turbine driven auxiliary feedwater has been established), enter emergency procedures for the event, and reach the point in the procedure where attempts to restore power are first initiated (estimate 15 minutes). In addition, the operators must among other things, address reactor problems and get ready to close circuit breakers (estimate at least another 15 minutes). We suggest accounting for reactor operation time by providing a 30 minute window of time for reactor operation in the current estimates of the safety bus restoration times under SBO conditions. (c) Licensee Event Report (LERs) and other event information provide some of the practicalities of NPP operation that need to be considered in the development of realistic power restoration times as indicated below. These selected instances add to the view that the actual times are equally as valid as the potential times. A detailed review of other study events would likely yield additional, similar insights. In LER 414199600, a transformer fault occurred on Unit 2 resulting in a LOOP. At the time of the LOOP, EDG B was unavailable as a result of maintenance. A detailed sequence of events in an NRC inspection report (IR 50-413/96-03) shows the operators entered procedures for a Reactor Trip or Safety Injection (SI) immediately, a Reactor Trip Response within a 2 minutes of	switchyard restoration and potential bus recovery times were reviewed. For those LOOPs with switchyard restoration times less than or equal to 15 min, the mean additional time required to recover power to a safety bus was 19.3 min and the median was 11 min, which compare favorably with the guideline of 15 min. In addition, for switchyard restoration times greater than 30 min, the mean additional time required to recover power to a safety bus was 8.0 min and the median was 0.5 min (for those cases without extenuating circumstances such as bad weather and/or equipment damage). These compare favorably with the guideline of 5 min. Note that this guideline was not followed if the LER indicated unusual conditions (equipment damage, grid instability, etc.) that might extend the time required to recover offsite power to a safety bus. In such situations, longer times were estimated or the actual bus restoration times were used. A summary of the 121 site LOOP events (Table A-7 in Appendix A of Volume 1) reveals the following breakdown: 121 site LOOP events 35 have certain times for potential bus recovery 86 have estimated times for potential bus recovery 75 used the 15,10,5 guidelines 11 did not use the 15,10,5 guidelines 6 were limited by the actual bus time 5 were assigned longer times because of extenuating circumstances (weather, damage) There is no question that the method(s) used to estimate	

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		the LOOP, and re-entered the Reactor Trip or SI emergency procedures about 8 minutes into the LOOP, and entered procedures for the Loss of Reactor or Secondary Coolant 26 minutes into the event. In the next 30 minutes, SI was terminated, letdown re-established, and the OSC and TSC were made operational. In parallel with the stabilizing the reactor, other teams were working to restore EDG B to service, diagnose the LOOP, and restore offsite power. About 60 minutes into the event, operations decided restoring offsite power through Unit 2 equipment was not an option and decided to use the Unit 1 cross tie. Power was available from the switchyard through Unit 1 just by closing two circuit breakers; however load shedding was required before using the cross-tie and about 180 minutes into the event all but one circuit breaker was closed. The LER and the inspection report indicate that a procedure deficiency slowed the operators down and offsite power was first restored about 330 minutes into the event. The draft report assumes switchyard power was available in 120 minutes and potential safety bus restoration time one minute later. In contrast, the experience shows power was always available in the switchyard but reactor operation, problem diagnosis, returning the EDG to service, switching and load shedding, and recognition of a procedural error resulted in 330 minutes passing before power was actually restored to a safety bus; we suggest using 330 minutes in the analyses. In LER 3241989009 power was available in the switchyard. However, the bus duct on the secondary side of the Unit 2 station auxiliary transformer was faulted and did not allow the use of the Unit 1 cross tie. The fault was cleared as assumed in the study; however the fault damage left the equipment needed unusable. Plant personnel decided to bypass the problem by backfeeding offsite power from the switchyard, through the main and auxiliary transformers by manually isolating the main generator. It took approximately 6.5 hours to removal the links and this appears to be a very ambitious effort given these links are typically in the isolated phase bus several feet above the ground floor, accessible after bolted covers are removed, and held in place with several dozen bolts in each of the three phases. The draft report assumes a	potential bus recovery times can impact the nonrestoration curve results. The revised approach described above is reasonable and believed to be a best estimate, and is supported by the statistics of the LOOP events with potential bus recovery times listed as certain. All events listed by reviewers as containing potentially incorrect restoration or recovery times were reviewed again in detail to ensure that all information available had been factored into the decisions. In some cases, this review led to changes in the times (in addition to changing to the 15,10,5 guideline rather than the 1-min guideline). To determine the sensitivity of the station blackout (SBO) core damage frequency (CDF) results to assumptions used to estimate potential bus recovery times, three cases were evaluated in Volume 2: doubling the times in the 15,10,5 guideline to 30,20,10; using actual bus restoration times; and using only LOOP events occurring during critical operation. Doubling the guideline times to 30, 20, and 10 resulted in a 7% increase in the SBO CDF. Using the actual bus restoration times resulted in a 133% increase in CDF. Finally, using only the critical operation LOOP events resulted in a 10% decrease in SBO CDF. We do not believe that the actual bus restoration time results should necessarily be interpreted as a realistic upper bound for SBO CDF because of the common practice observed in the Licensee Event Reports (LERs) of letting the emergency diesel generators run longer than needed before actually restoring offsite power to a safety bus. As recommended by the reviewer, the Nine Mile Point 1 and Fitzpatrick plants were defined as a single site (based on locale and common offsite power lines) and Nine Mile Point 2 was considered as another site.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		potential safety bus restoration time of 90 minutes. Had there been an SBO, this area of the plant would have been in the dark and link removal performed with flashlights. We suggest using 6.5 hours rather than 90 minutes while recognizing that 6.5 hours maybe non-conservative. LER 2701992004 involved two LOOPs; the draft report only considers one. After initially recovering offsite power in 57 minutes, recovery actions 35 minutes later resulted in a second LOOP. It then took another 115 minutes to diagnose the problem and recover. The LOOPs occurred between 21:00 and 22:00 hours when most of the support staff is home. The plant procedures did not address this event, the electrical system at this plant is complicated, and recovery of power was largely dependent the arrival of a key engineer from home. In the past, this was counted as one LOOP lasting 207 minutes since the NRC SBO analyses does not consider the effects of a double LOOP scenario on the hardware (RCP seals, etc). We suggest using 207 minutes in the analyses. Some LERS not used in this study have identified problems with SBO procedures or NPP SBO related design weaknesses that have existed for several years; had there been an SBO recovery would not have been as expected and most likely required more time. For example, in LER 3351998007 the licensee discovered during an SBO recovery exercise that one of the methods to restore electrical power could not be performed as the procedure was written. The draft shows the analysts were certain that it one minute time to back power from the switchyard to the safety bus based in part on eight events. However, the report also shows an equal number of events where the analysts were certain it took more than one minute to back power from the switchyard to the safety bus (64, 24, 4, 60, 40, 861, 30, 60 minutes). (d) The draft report assumes that power is always of sufficient quality. This is an unverifiable assumption, particularly for events involving the grid and weather. The offsite power must be of sufficient quality for the equipment to work. If the voltage and	Finally, the 1902-min event (a plant-centered LOOP) deleted from the analysis in the draft Volume 1 was included in the final analysis presented in this report.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		frequency are not within plant or grid protective relay setpoints, restoration will not work. The actual restoration times should be used for weather and grid events unless the quality the offsite power supply (magnitude of the voltage and frequency) can be confirmed. The draft report analyses of the switchyard and potential bus restoration times from the August 14, 2003, blackout consider that the grid voltage and frequency were stable and of sufficient quality to work based on inputs that judged the grid to be stable sooner than times stated in the LERs and logs where the NPP operators thought grid was stable. The grid and NPP operators judgments during an event are likely to be the same had there been an SBO and should be used for the analyses. Our staffs have been meeting to develop a sequence of events of the power restoration for the August 14, 2003 blackout from based on times we obtained from the New York Independent System Operator (NYISO) detailed account of the recovery several months after the event, the NRC LERs, a Region I log of information reported during the event, and times your staff obtained from information Region I gathered after the event. We suggest that post event judgments about when the grid was stable enough to connect to the safety buses, after several hours of investigation and in the absence of voltage and frequency data, should not be given preference over load dispatchers or nuclear plant operator decisions based on their training, experience, and evaluation of the voltage and frequency at the time of the event. (e) As a detailed comment, the draft report averaged the recovery times at NMP 1 & 2 and Fitzpatrick for the August 14, 2003 event based on all three sites having a common 115 kV offsite power supply. Electrical diagrams in the Final Safety Analyses Reports show that the NMP2 offsite power is supplied by two 115 kV lines from two 115/345 kV transformers in the nearby 345 kV Scriba switchyard) i.e. not the same 115 kV system that supplies NMP1 and Fitzpatrick. In addition, the draft report deleted a 1902 minutes LOOP data point from the analyses as an outlier when it should		

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		have received special attention (see Comment 3). We suggest the exceedance curves and other analyses be revised to include this event.		
DSARE	2	Although the shutdown and critical LOOP data is statistically the same, a LOOP while at power is very different from a LOOP while shutdown in terms of electrical hardware alignment of electrical loads and the dynamic response. The data sets are not homogeneous from an engineering and operational perspective and should not be combined for statistical uses. Inclusion of the shutdown data minimizes the probability of exceedance of the LOOPs while critical and is a key factor in analyzing SBO risk. Based on statistical analyses, the draft report separates the LOOP frequency data for shutdown and critical operations, and combines the LOOP durations and probability of exceedance data for shutdown and critical operations. 10 CFR 50 describes a SBO as a turbine trip (power operation) and progressing to a safe condition when shutdown. Specifically, 10 CFR 50.2 "Definitions" state that "Station blackout means the complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e. loss of offsite electric power system concurrent with turbine trip and unavailability of the onsite emergency ac power system)." In addition, 10 CFR 50.2 states that "safe shutdown for station blackout means bringing the plant to those shutdown conditions specified in plant technical specifications as Hot Standby or Hot Shutdown, as appropriate." We suggest that the exceedance curves be revised to reflect only the LOOP data during critical operations. Also, a LOOP at power reduces the generation available to the grid up to approximately 1300 megawatts (mW) per unit lost, depending on the size of the plant, whereas a LOOP during shutdown increases the power available to the grid by 30-50 mW, the shutdown load.	As was done in the draft Volume 1, the final report uses both critical and shutdown LOOP restoration times to generate offsite power nonrecovery probabilities. Statistical analyses of these data indicated that both types of data could be combined. In order to determine the sensitivity of the SBO CDF results to combining the data, offsite power nonrecovery curves were also derived from only the critical LOOP data. This sensitivity case was added in the final report because of this review comment. SPAR results using these nonrecovery curves indicated a decrease in SBO CDF of 10%. The at-power restoration times do not result in higher offsite power nonrecovery curves.	

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume I Revision
DSARE	3	The raw data that shows in 11 of the 59 LOOPs with a reactor trip (19 percent), the potential safety bus restoration time was in excess of four hours, i.e. 278, 297, 297, 380, 385, 388, 454, 1428, 1902, 7921, 7921 minutes. Had there been an SBO, it follows that offsite power was not and could not have been recovered within the SBO coping capability of most plants in these events and recovery of power solely dependent the recovery of an EDGs. If the actual bus restoration time is considered, 23 of 59 LOOPs (38 percent) were not restored in 4 hours. In comparison there were 5 of 60 LOOPs (8 percent) longer than 4 hours in NUREG-1032 (the SBO rule technical bases which evaluates data from 1969-1985). We suggest the report conclusions discuss the significance of entire distribution of LOOPs with the reactor critical and evaluate the potential impact of long LOOPs in sensitivity studies in the analyses of SBO risk.	The final data set lists eight plant-level LOOPs occurring during critical operation that have potential bus recovery times greater than 4 h. These events have times of 282, 297, 297, 384, 388, 459, 1428, and 1906 min. These eight events are out of a total of 62 plant-level LOOPs occurring during critical operation (not counting the 10 "No Trip" events). These data indicate that there is a probability of 8/62 = 0.13 of a LOOP during critical operation lasting longer than 4 h. The composite nonrecovery curve in the final report (Section 4, Table 4-1) indicates a nonrecovery probability at 4 h of 0.157. So the nonrecovery curve is slightly conservative (predicts higher nonrecovery probabilities compared with the actual data) at 4 h. The significance of all types of LOOPs events (including those lasting longer than 4 h) is evaluated in an integrated manner by using the LOOP frequencies and offsite power nonrecovery curves in the plant-specific Standardized Plant Analysis Risk (SPAR) models to evaluate SBO CDF. The SPAR models include plant-specific LOOP and SBO mitigation features, such as emergency power system configuration, battery lifetime, coolant injection features that do not rely on ac power, etc. SBO results obtained from these models automatically address the significance of the entire distribution of LOOPs with the reactor critical. Therefore, it is not clear what a sensitivity study would add.	
DSSA	1	In accordance with your request dated October 29, 2004, the Division of Systems Safety and Analysis (DSSA), Probabilistic Safety Assessment Branch (SPSB) has reviewed the subject report. Since the DSSA staff actively participated in the report's development through numerous discussions with your staff and by	No response is necessary, except for the concern that Figures 3-7 through 3-10 in the draft report were illegible in the reviewer's copy of the report. These figures were enhanced in the final report.	

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		attending various briefings and coordination meetings, we were well aware of its contents (specifically including the origin of the statistical data used, the assumptions made, and the statistical methods employed) before we received your request for a formal review. The report provides updated loss-of-offsite-power (LOOP) initiating event frequencies and models for estimating the probability that offsite power is not recovered by a specified time following a LOOP event (commonly termed "offsite power recovery curves"), based on an analysis of LOOP events at nuclear power plants for the period 1986 through 2003. We note that this period includes the August 14, 2003, Northeast Blackout. LOOP events were identified by reviewing a variety of information sources such as NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996," Accident Sequence Precursor (ASP) Program results, licensee event reports (LERs), and information collected by resident inspectors as part of Temporary Instruction 2515/156, "Offsite Power System Operational Readiness." We did not review the list of LOOP events contained in the report against the original information sources; rather, we focused on ensuring that the process used to collect the events was technically adequate. We understand that the compilation of LOOP events required substantial effort, and feel that the final list of LOOP events input to the statistical analyses is reasonable. The report defines five types of LOOP events: plant centered, switchyard centered, grid related, severe weather related, and extreme weather related. An excellent glossary of terms pertaining to LOOP events is provided, which should prove useful in establishing a common understanding and terminology. The addition of switchyard centered LOOP category is noteworthy since some previous staff analyses (e.g., NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plants," and NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996") included these		

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		types of LOOPs into the plant centered category while other staff analyses (e.g., NUREG-1784, "Operating Experience Assessment—Effects of Grid Events on Nuclear Power Plant Performance") included them in the grid related category. Separating out the switchyard related LOOPs is useful for two reasons. First, it helps to avoid making "apples-to-oranges" comparisons when considering previous LOOP frequency and recovery curve estimates. Second, it helps the staff to understand some of the impacts of electrical grid deregulation (which commenced in 1997) since some utilities that operate nuclear power plants are no longer responsible for operating or maintaining the switchyards that connect their plants to the grid. This increased understanding of the risk impacts of deregulation will be helpful during execution of the staff's Action Plan for Resolving Electrical Grid Concerns (G20030756) and consideration of license amendment requests (e.g., diesel generator completion time extensions, etc.). The report provides estimates of LOOP frequencies that are intended for use in the probabilistic risk assessments (PRAs) of individual nuclear power plants. In order to achieve this purpose, the list of LOOP events compiled in the report contains separate entries for each plant affected by a single phenomenon (e.g., a large scale grid disturbance, a hurricane). For example, the August 14, 2003, Northeast Blackout (a single phenomenon) resulted in LOOP events at nine plants, and there are nine corresponding entries in the list of LOOP events. This approach is consistent with both the approach used to develop previous staff-developed LOOP frequency estimates (e.g., NUREG-1032 and NUREG/CR-5496) and risk-informed regulatory practices, which are based on consideration of individual plant risks as opposed to the combined risks posed by the nuclear industry. In addition to providing LOOP frequencies and recovery curves for the five LOOP categories discussed above, the report also provides LOOP frequencies for various subgroups, such as individual states, collections of states, coastal versus non-coastal, and grid-related		

Table A–1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		geographical breakdowns. The analysis of these subgroups is important since it provides additional insights into the locations and potential causes of LOOP events. A strength of the analysis is the performance of tests to identify statistically significant differences among the results. We observe that Figures 3-7 through 3-10 were illegible in our copy of the report, and suggest that they be redrawn to improve their clarity. The report contains extensive analysis and discussion concerning LOOP durations, as reflected by LOOP recovery curves. A notable improvement in understanding about LOOP events was achieved by identifying three durations: the switchyard restoration time (duration from the start of a LOOP event to when offsite power was restored to the switchyard), the actual bus restoration time (duration from the start of a LOOP event to when offsite power was actually restored to a safety bus), and the potential bus restoration time (duration from the start of a LOOP event to when offsite power could have been restored to a safety bus). This latter duration, which is of paramount importance to risk analysis, was defined in recognition of the observation that some delay is involved in restoring offsite power to safety buses once the switchyard has been restored. Some delay is always present since it takes for the plant operators to realign a plant's electrical systems. In additional, plant operators may deliberately delay the restoration of the safety buses due to competing operational priorities or staffing limitations. We feel that the report makes an important contribution to the state-of-the-art in risk analysis methods by calling attention to the definition of LOOP recovery. Many statistical methods were used to estimate LOOP frequencies and recovery curve parameters. In general, these methods are consistent with NUREG/CR-6823, "Handbook of Parameter Estimation for Probabilistic Risk Assessment" and commonly accepted statistical practices. In addition, various statistical hypothesis tests (e.g., the chi-squared goodness-of-fit test) and sensitivity analyses were conducted to help ensure that the analysis assumptions were satisfied and that the results were statistically		

Table A-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 1 Revision
		robust. We did not review the actual calculations; however, since the report is based upon commercially available software, we have few concerns about potential calculational errors. In conclusion, we recommend that the report be issued at your earliest convenience as it will provide a valuable reference during execution of the staff's Action Plan for Resolving Electrical Grid Concerns (G20030756).		

Appendix B

Station Blackout Analysis (Volume 2) Comments and Resolution

Appendix B

Station Blackout Analysis (Volume 2) Comments and Resolution

Various organizations were invited to comment on Volume 2 of this report, which was issued as the draft *Station Blackout Risk Evaluation for Nuclear Power Plants* (S. Eide et al., January 2005). Comments were received from the following individuals and organizations:

- Union of Concerned Scientists (UCS), D. Lochbaum
- NRC, Office of Nuclear Regulatory Research (RES), Division of Systems Analysis and Regulatory Effectiveness (DSARE), W. Raughley
- Electrical Power Research Institute (EPRI), D. Modeen
- NRC, Office of Nuclear Reactor Regulation (NRR), Division of Systems Safety and Analysis (DSSA), M. Stutzke
- PPL Susquehanna (SUSQ), B. McKinney
- Progress Energy (PE), T. Groblewski
- Pilgrim Watch and Others (PW), M. Lampert et al.
- New England Coalition (NEC), R. Shadis.

Table B-1 lists the comments and their resolutions.

Table B-1. List of comments and resolutions for Volume 2.

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
UCS	1	Abstract, page i: The Abstract states that the results in this report for core damage frequencies from station blackout are lower than previous estimates and singles out improved emergency diesel generator performance as an explanation for that reduction. However, the information contained in the report does not support that notion. Figure ES-I (page x) shows the historical trend for loss of offsite power (LOOP) initiating' event frequency from 1975 to now. Over that period, the trend resulted in a reduction from about 1.1E-01 to 3.3E-02, or a factor of about nearly 30. [This factor is actually three, rather than 30. An e-mail from D. Rasmuson to the reviewer pointed out this arithmetic error.] The first paragraph on page x states: *"SBO risk in terms of core damage can be thought of as the product of the LOOP frequency, the failure probability of the onsite emergency power system (EPS), and the composite failure probability of SBO coping features at a given plant."* All things being equal, a 30-fold reduction in the LOOP frequency (i.e., Figure ES-1) should produce about a 30-fold reduction in the SBO risk. But... Figure ES-5 (page xiii) plots the historical trend for SBO risk from 1975 to now. Over that period, the trend resulted in a reduction from about 2.6E-05 to 2.9E-6, or a factor of about 10. The Abstract's exclusive credit to improved emergency diesel generator performance as the reason for the SBO risk reduction appears unsupported by the evidence.	The reviewer is mistaken in thinking that a reduction in initiating event frequency from 0.11 to 0.033 per year is a factor of nearly 30 reduction. The factor is nearly three. In the final report, the historical trend in LOOP frequency indicates a decrease from approximately 0.12/year to 0.0359/rcry, or a factor of 3.3 reduction. However, LOOP event durations have increased. The combined impact of LOOP frequency and LOOP duration is examined d in Section 5 of Volume 1. Results show that the decrease in LOOP frequency is countered by the increase in LOOP durations. In addition, sensitivity studies discussed in Section 7 (the NUREG-1032 cases) indicate that the decrease in emergency diesel generator (EDG) unreliability is the main reason for the decrease in station blackout (SBO) core damage frequency (CDF). The reviewer is correct in that other changes made since the early 1980s have also probably contributed to the decrease in SBO CDF, but the EDG performance (increase in reliability) is the major cause.	
UCS	2	Executive Summary, page ix: The fifth paragraph states *"Risk [from station blackout] was evaluated for* internal *events during critical operation; risk from shutdown operation and* external *events was not addressed."* This limited scope is non-conservative and contradicts the very reason this draft report was generated and actual industry experience. The fourth paragraph on page ix discusses the August 14, 2003,	The draft report was not clear in its use of "internal event" and "external event." The standardized plant analysis risk (SPAR) models used to analyze SBO risk at present cover only what are termed internal events occurring during critical operation. These are mainly events occurring within the plant that require the plant to safely shut down. However, included in these models are LOOP initiating events, and these	Foreword, Executive Summary, Sections 1 and 8

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		grid-related LOOP that affected nine U.S. nuclear power plants and states: *"As a result* of *that event, the NRC initiated a comprehensive program that included* updating *and re-evaluating LOOP frequencies and durations and SBO risk. This report is part of that overall program and focuses on SBO risk."* In other words, the August 14, 2003, blackout — an external event-prompted this re-assessment of station blackout risk that ignores the risk from external events. That makes no sense. One of the U.S. nuclear power plants affected by the August 14, 2003, grid-related event was Davis-Besse. Davis-Besse was shut down at the time. It experienced more complications from the event (e.g., water hammer that damaged and disabled safety-related cooling equipment) than most of the reactors that were operating at the time of the blackout. The worst station blackout event in U.S. nuclear plant history occurred on March 21, 1990, at the Vogtle nuclear plant when the reactor was shut down. To summarily ignore the station blackout risk at reactors that are shut down seems ill-justified and unwarranted. In addition, the evaluation totally ignores the risk from damage to irradiated fuel in the spent fuel pool resulting from a station blackout event. The coping durations for station blackout were calculated assuming offsite power and onsite emergency power availability as defined by the full-power (Mode 1) technical specifications. During refueling, there is often a minimum complement of offsite and onsite power sources below the level defined by the Mode 1 technical specifications. Consequently, the restoration times that factor into the coping durations are invalid and the station blackout periods may be longer than the coping durations. Long station blackout periods challenge times-to-boil of the spent fuel pool during refueling outages. NRC surveys of industry refueling practices in the wake of the Millstone Unit 1 problems in 1996 revealed times-to-boil of less than 24 hours during the early stages of refueling. To summarily ignore the station blackout risk to spent fuel during refueling seems ill-justified and unwarranted.	can be the result of events external to the plant, such as severe or extreme weather impacting the electrical grid, or other types of grid disturbances. All historical causes of LOOPs are included in the modeling of internal events during critical operation. The purpose of this study was to update the CDF estimates for SBO risk using the most recent operating experience. The risk analysis supporting the SBO Rule considered only power operations. It did not consider risk during shutdown, from external events (e.g., seismic events, fire, flood), or large early release frequency (LERF). SBO risk has been addressed for these situations in other regulatory programs such as the Individual Plant Examination of External Events (IPEEE). NRC is currently developing risk models for shutdown, LERF, and external events. The current LOOP study contains estimates of LOOP frequencies and nonrecovery probabilities for shutdown events. These results can be used in shutdown risk studies. The final report was revised to more clearly indicate what the scope of the study included (and why) and what is meant by "external events."	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
UCS	3	Glossary, page xxi: The Executive Summary (page ix, 5th paragraph) states that *"Risk [from* station *blackout] was evaluated for internal events during critical* operation; *risk from shutdown operation and external events was not* addressed." The Glossary contains definitions for *"Extreme-weather-related loss of offsite power event," "Grid-related loss of offsite power event,"* and *"Severe-weather-related loss of offsite power event"* - all sounding very much like external events that are supposedly not addressed. It is not clear what is meant by "external events was not addressed" in assessing station blackout risk. LOOP frequency is a factor addressed in the SBO risk calculation. LOOP frequencies account for events caused by weather and other external causes. A definition of those external events not being addressed should be added to the Glossary.	See the response to UCS Comment 2. The Glossary was not changed, but the scope of the study was more clearly explained.	
UCS	4	Section 2.1, page 3: A number of "enhancements" to the NRC's SPAR models are discussed in this section. The line item upgrades deal with modeling reactor coolant pump (RCP) seal leakage. It appears from the write-up in this section that SPAR models for Westinghouse reactors were affected more than Combustion Engineering reactors and that SPAR models for Babcock & Wilcox reactors and General Electric reactors were essentially unchanged. To attempt to quantify the effect of the various SPAR model "enhancements," UCS compared the risk numbers from NUREG-1776[1] to the risk numbers from this draft report. Our findings: <u>Plant Core Damage Frequency (CDF)</u>: The average plant-specific CDF in this draft report is 45 percent of the average plant-specific CDF in NUREG-1776. As expected from the "enhancements" to the SPAR models for Westinghouse and Combustion Engineering reactors, most of the plant CDF values for Westinghouse reactors in this report are about 10 percent of the plant CDF values in	NUREG-1776 used plant risk numbers obtained from the original Individual Plant Examination (IPE) submittals to NRC, as contained in an IPE database compiled by NRC. (At the time NUREG-1776 was prepared, that database was the only one available that comprehensively covered plant risk for the entire industry.) Those IPEs characterized plant risk based on design information and plant-specific performance relevant to the late 1980s. Since then, plant modifications have been made, and plant performance has generally improved. The enhanced SPAR models used for the present study incorporate those design changes and plant performance improvements. From the IPE database, the average total CDF is approximately 6.4E-5/year. The present report result is 1.71E-5/rcry. This represents a reduction of	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		NUREG-1776. Most of the plant CDF values for Combustion Engineering reactors are about 30 percent of the plant CDF values in NUREG-1776. The plant CDF values for B&W and GE plants are essentially the same as reported in NUREG-1776. <u>SBO Core Damage Frequency (CDF):</u> There are large, unexplained differences between the SBO CDF values in this report and those in NUREG-1776. (Refer to the chart on page 5 comparing the station blackout core damage frequency -SBO CDF -from this draft report to that same parameter reported in NUREG-1776). For example, the SBO CDF for Vermont Yankee in NUREG-1776 is 9.17E-07. But in this draft report, the SBO CDF is merely 8.44E-10. There's no evident, physical explanation for this three order of magnitude reduction. At the other extreme of the anomalies, the SBO CDF for Susquehanna Units 1&2 was 4.2E-1 I in NUREG-1776. In this draft report, the SBO CDF mysteriously becomes 2.52E-07. There's no explanation given for this more than three order of magnitude increase. Overall, 84 of the 103 reactors have a lower SBO CDF in this draft report than in NUREG-1776 while 18 reactors have a higher SBO CDF per this draft report. One reactor (Fort Calhoun) had no SBO CDF specified in NUREG-1776. <u>LOOP Initiating Event Frequency</u>: The average plant-specific LOOP frequency in this draft report is roughly 4 times greater than the average plant-specific LOOP frequency in NUREG-1776. Ironically, the highest increase occurs at the Vogtle Unit 1& 2 reactors — the site of the worst SBO event to date. NUREG-1776 listed the LOOP frequency for Vogtle as 6.6E-04 while this report increased it to 3.3 1E-02, a whopping 5,000 percent increase! This draft report makes no mention of NUREG-1776 and contains no discussion on the reason for the humongous differences between the results from that report and this one. NUREG-1776 was issued by the NRC less than two years ago. It was issued in August 2003— the very same time period as the grid event that prompted this report. Was NUREG-1776 obsolete was it rolled off the presses? Will another report 18 months from now also report plant CDF and SBO CDF values orders of magnitude higher or lower than those	almost a factor of four. We have not compared the results for classes of plants. With respect to SBO CDF, the IPE database has an average of 1.1E-5/year. The present report result is 3.0E-6/rcry, which again represents a reduction of approximately a factor of four. The final report presents the IPE database results by plant class (and overall result) in Section 6, Figure 6-4 (under the "IPE Submittals" heading). The modeling of the Vermont Yankee emergency power system was modified for the final report, based on more up-to-date information concerning the human actions required to connect the hydroelectric backup to the plant. The final report lists a revised SBO CDF of 4.81E-7/rcry for Vermont Yankee, compared with the draft report value of 8.44E-10/rcry. See the response to NEC Comment 3 for more details. The updated IPE information discussed above indicates an SBO CDF for the Susquehanna units of approximately 2.5E-7/year, compared with the original IPE submittal value of 4.2E-11/year. Therefore, the plant has significantly modified its IPE model since the original submittal. In comparison, the present report value from SPAR is 1.73E-7/rcry. With respect to LOOP frequency, the IPE database indicates an average of approximately 0.075/yr, while the present report value is 0.0359/rcry. Therefore, the present value is approximately half of the value in the IPE database. Note that NUREG-1776 has a misprint for the Vogtle LOOP frequency. The correct value from the IPE database is 0.051/yr, rather than 0.00064/yr. In Appendix E of the present report, the Vogtle LOOP frequency is	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		reported in this draft report? Will this report supersede or replace NUREG-1776 or will people be able to cherry-pick the low or high risk values from both reports as needed to support whatever risk conclusion they've previously reached? The NRC should not issue a final report unless it reconciles the mind- numbing differences in risk numbers reported herein and therein NUREG-1776. The two reports allegedly evaluate the same subject, but yield disparate and unexplained results.	listed as 0.0294/rcry. This is approximately a factor of two reduction from the original IPE submittal value. The SPAR models for Westinghouse and CE plants were also updated with the latest reactor coolant pump seal LOCA models, which have been revised and found acceptable by the NRC. Results presented in this report indicate a significant decrease in total CDF and SBO CDF from previous estimates such as from NUREG-1032 and the original IPE submittals (used in NUREG-1776). These updated results are more representative of current plant configuration and performance and agree reasonably well with more current risk models. Therefore, these new results should be used instead of the older IPE submittal results.	
UCS	5	Section 2.1, page 3: The paragraph at the bottom of page 3 states that the NRC's SPAR models were updated using information from INPO's Equipment Performance and Information Exchange (EPIX) database. The NRC should not rely on unverified, uncontrolled, secret information for its regulatory analyses. INPO is not an NRC licensee. Therefore, INPO is not obligated to abide by the accuracy and completeness requirements in 10 CFR 50.9. NRC inspectors periodically audit component performance data collected by its licensees and not infrequently identifies errors in that data. But NRC inspectors do not audit INPO or INPO's collection of component performance data and maintenance of said data in EPIX. EPIX is neither publicly available nor periodically verified by the NRC to be an accurate, complete source of data. The information in EPIX is hardly more reliable than the output from an Ouija board absent means to ensure its validity.	The EPIX database was chosen for component unreliability information because it has up-to-date component performance information and is continually being updated (so periodic comparisons can be made). In order to verify that the EPIX data were reasonable, comparisons were made with unplanned demand data obtained from the LERs, as identified in the ongoing NRC effort to continually update its system studies (the NUREG/CR-5500 series). These unplanned demand data are publicly available. Comparisons between these two sources of data generally indicated agreement. A separate report is being prepared by the NRC to document the updated SPAR input parameters, and that report will present more details and results from the data comparison.	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
UCS	6	Section 4.2, page 17: The final paragraph on page 17 states that information from INPO's EPIX database was used to update the NRC's SPAR models for emergency power system performance. As detailed above in the comment on Section 2.1, page 3, the NRC should not rely on unverified, uncontrolled, secret information for its regulatory analyses.	See the response to UCS Comment 5. Also, Section 4.2 discusses the results of the comparison between EPIX and unplanned demand data for EDGs.	
DSARE	1	The report summarizes the history of EDG reliability trends from 1970 to the present based on NRC reports. The current report should also use the results of the EDG reliability studies performed by the Idaho National Laboratory (INL, previously INEL and INEEL) dated 1996 and 1999. INEL-95/0035 Emergency Diesel Generator Power System Reliability 1987-1993, dated February 1996 presents an evaluation of EDG train performance at nuclear power plants. INEEL/Ext-99-01312, Reliability Study Update: Emergency Diesel Generator Power System Reliability 1987-1998, December 1999 updated INEL-95/0035 to include five more years of experience that has not been issued by the NRC. These reports are based on data from tests and unplanned demands that simulate and are as stressful as real demands under low voltage conditions. INL found that the monthly surveillance tests did not simulate EDG safety system performance and excluded them from the calculation of EDG reliability. In addition, the failure criteria in the current study differs from the past INL EDG reliability calculations that included manual failures to start under actual LOOP conditions with the reactor at power. These reports show EDG unreliabilities range from 0.044 to 0.031 (0.956 and 0.969 reliability, respectively) for an 8-hour mission time for the selected data groupings and this is significantly more than the current study. Specific comments are: Table 4-2 of the report, "Data 1998–2002" shows EDG failures and demands (or hours) from the EPIX database for different EDG	We agree with the reviewer that "monthly" tests (these range from bi-weekly to monthly, depending upon the plant) of EDGs are potentially not as realistic as unplanned demands in measuring EDG performance. The unplanned demand data set does not appear to support the reviewer's hypothesis that EDG unplanned demand performance will be worse for critical operation (or critical operation LOOPs) than for shutdown operation (or shutdown operation LOOPs). The opposite is observed from the unplanned demand data set, as discussed below. However, because that data set is so limited, performance for both situations may be similar. The final report compares the SPAR EDG failure mode probabilities and rates with data from only unplanned demands. SPAR EDG estimates for failure to start (FTS), failure to load and run (FTLR), failure to run (FTR), and unavailability (UA) (sometimes called maintenance out of service [MOOS] unavailability) were obtained from the Equipment Performance and Information Exchange (EPIX) database for the period 1998–2002. (The UA data were obtained from the Reactor Oversight Process Safety System Unavailability data over the	Section 4.2 and Section 7

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		failure modes. The demands (or hours) range from 23983 to 61070 for the different EDG failure modes. Section 4.2 of the report discusses the EDG performance and indicates that the EPIX data includes monthly and cyclic (refueling outage) tests. The EPIX demand data should be adjusted to exclude the monthly tests for the reasons explained in INEL-95/0035. In addition, Table 4-2 under "Unplanned Demand Data" shows shutdown experience that should be excluded since it does not simulate the loading for a LOOP when the reactor is at power. When the reactor is shutdown, and a LOOP is experienced, some of the largest pump motors that stress the EDG do not start and run. In addition, some of the motors are lightly loaded when shutdown such that the EDG running load is typically less than 50 percent of the design loading. In addition, the EDG performance is monitored by the licensees to ensure that the EDG train reliability is maintained above 0.95. We suggest a sensitivity analysis to show an impact of allowing 0.95 EDG train reliability. Also there is experience with the gas turbine generators (GTGs) following LOOPs with a reactor trip that could be entered under "Unplanned Demand Data" in Table 4-2 and analyzed. The LERs with LOOPs and a reactor trip indicate there have been seven starts with one failure due to a power dependency, and six load runs with two failures. One load run failure occurred when the GTG was stopped to remove ice from its air intake (and then it was successfully restarted), and the other was a conditional failure due to a power dependency after 8 hours (had there been an SBO with a mission time of 24 hours as postulated in the analyses it would have failed to run). Other EPIX failure data used in the analyses should be verified to be representative of the equipment and system performance for a safety mission.	same period.) These data include both test demands and unplanned demands, but the test demands are approximately 250 times more frequent than the unplanned demands. Unplanned demand data over 1997–2003 were obtained from Licensee Event Reports (LERs). These unplanned demands were limited to bus undervoltage conditions requiring the EDGs to automatically start, load onto the bus, and run for a period of time. The average run time for these demands was 8.8 h.) Both data sets were evaluated using consistent definitions for failure modes, EDG system boundaries, allowable recoveries, etc. The final comparison is discussed in Section 4.2 and summarized in Table 4-2. The unplanned demand data result in a total unreliability (UR) for an eight-hour mission time (FTS + FTLR + FTR*7h + UA) of 0.035. This compares with a mean value of 0.022 obtained from the SPAR EDG inputs. The unplanned demand result of 0.035 lies at the 86th percentile of the SPAR EDG total UR distribution. (Note that the SPAR mean of 0.022 lies at approximately the 62nd percentile of its own distribution.) Because the unplanned demand, total UR lies within the 5% and 95% bounds of the SPAR EDG total UR distribution, this is an indication that the unplanned demand data may not be significantly different from the SPAR EDG data. Also, various subsets of this unplanned demand data set (critical demands, LOOP demands, and critical LOOP demands) all result in lower total UR estimates, ranging from 0.026 (73rd percentile) for LOOP demands to 0.032 (82nd percentile) for critical LOOP demands. The unplanned demand data set is very limited compared with the EPIX data set. In terms of demands, the unplanned data set has a total of 162,	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
			while the EPIX data set has approximately 24,000. Only approximately 50% of the plants experienced an EDG unplanned demand during 1997–2003. Also, the most unplanned demands for any EDG were eight, but most had one or two. In terms of failures (with recovery considered), the unplanned demand data set has six, while the EPIX data set has approximately 200. The various subsets of unplanned demands discussed above are even more limited. Because the unplanned demand data set is so limited and its results lie within the SPAR distribution obtained from EPIX data, the baseline SPAR EDG inputs are based on the EPIX data. Most other SPAR component unreliability estimates are also based on the EPIX data. Background work supporting the SBO analysis included a review of past reports containing EDG unplanned demand data. These reports included NUREG/CR-4347, NSAC/108, and NUREG/CR-5500 Volume 5 (and its unpublished update). However, because current plant performance was desired, the LER review for 1997–2003 was performed and summarized in the report. The total UR from unplanned demands over this period, 0.035, is similar to the results quoted by the reviewer for NUREG/CR-5500 Volume 5 (0.031 to 0.044). Sensitivity analyses included in the final report related to EDG performance include one in which the EDG total unreliability is doubled (from 0.022 to 0.044) and one with the EDG total unreliability halved (to 0.011), among others. This sensitivity case is close to the 95% reliability case suggested by	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
			the reviewer. Results indicate that the SBO CDF is sensitive to EDG total unreliability. If the EDG total unreliability is doubled, the SBO CDF increases by approximately a factor of three. However, if the EDG total unreliability is halved, the SBO CDF decreases by approximately a factor of two. Therefore, SBO CDF results are sensitive to EDG performance. We did not systematically study the gas turbine generator (GTG) performance during LOOPs for 1997–2003. Since the data are believed to be very sparse, and licensees are not required to provide as detailed analyses of failures and successes as for EDGs, we chose not to study the events in detail. Finally, unplanned demand data from the ongoing project to continually update the NRC "system studies" (documented in the NUREG/CR-5500 series) have been compared with EPIX results for a variety of components. In general, those comparisons indicated that the EPIX data were representative of unplanned demand performance.	
DSARE	2	The report provides a historical summary of the SBO CDF based on an annual average. Historically the LOOPs with the reactor at power occurred more or less randomly throughout the year and the SBO CDF is best represented by the annual average. However, most LOOPs since occurred in the summer period May–September and SBO CDF is best represented by the results of sensitivity studies provided in the report for the May–September and the other months. These sensitivity studies should be shown as the basis of comparison to the historical SBO CDFs.	The final report presents SBO CDF results based on an annual average basis in Section 6. However, sensitivity cases in Section 7 identify the corresponding SBO CDFs associated with critical operation during the summer period and the nonsummer period. The SBO CDF is approximately 2.1 times higher than the annual average during the summer period and approximately 3.1 times lower during the nonsummer period. In addition, Table 6-2 in Volume 1 compares summer vs. nonsummer LOOP frequencies for the periods 1986–1996 and 1997–2004. As indicated by the reviewer, the results for the earlier period indicate similar LOOP	Sections 6 and 7. Also, Table 6-2 in Volume 1.

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
			frequencies for summer and nonsummer, while the latter period indicates a significant difference. The Foreword emphasizes the summer period as an important period.	
DSARE	3	DSARE provided other comments to the draft report, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants 1986–2003" (ML050250124). The collective effect of these comments, and those in this memorandum, may impact data, analyses, results, and conclusions in the subject report.	The DSARE comments referenced here are presented in Appendix A of this volume, along with the responses.	
DSARE	4	The executive summary and conclusions should be revised to highlight the central assumptions and the resulting equipment and operator performance that the current baseline SBO CDF relies upon in the areas of EDG reliability (e.g. the 98.8 percent EDG reliability, and 99.9 and 99.8 percent EPS reliability for a 8 hour and 24 hour mission times, respectively); LOOP frequency and duration; and SBO coping capabilities.	The current baseline SBO CDF results presented in the final report are based on an EDG reliability of 97.8% (total unreliability of 0.022), total LOOP frequency of 0.036 per reactor critical year, and SBO coping capabilities as discussed in the report. The executive summary was revised to highlight these current estimates based on industry-wide performance.	Executive Summary
EPRI	1	The nuclear licensee's Maintenance Rule (10 CFR 50.65) program controls the plant risk configuration during all modes of operation and defines unavailability and reliability performance criteria for risk significant SSCs including the EDG. Hence, even if the plant has an approved 14 days EDG AOT extension, the Maintenance Rule and the configuration-specific risk will control the actual EDG outage time. The EDG unavailability performance criteria monitor the unavailability hours on a 24 month rolling average. All plants are required to set maximum Maintenance Rule targets for EDG unavailability in the 0.025–0.03 range (which corresponds to 220 to 260 hours per EDG per year). The draft INEEL report needs to document how the plant-specific SPAR model represents the nuclear plant as built and as operated. That is to say, does the SPAR model credit the role of 10 CFR 50.65 in controlling the plant's on-line configuration risk?	The report results indicate that the summer LOOP frequency may be significantly higher than the annual average, so this may need to be included in the risk evaluations performed to control plant risk resulting from component outages. The SPAR model results presented in the report represent annual average results with representative average unavailabilities (from test and maintenance) for components and/or trains that can be out of service while the plant is in critical operation. These representative average unavailabilities were obtained from the Reactor Oversight Process Safety System Unavailability data. The average EDG unavailability from test and maintenance estimated for the SPAR models is 9E-3, which is lower than the Maintenance Rule maximum target range.	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
EPRI	2	A plant license amendment that modifies the Tech. Spec. for EDG allowed outage time (AOT) from 72 hours to 14 days typically contains additional regulatory commitments and compensatory measures in order to benefit from the 14 days EDG outage time. For example, these regulatory commitments and compensatory measures may require monitoring the weather conditions prior to removing the EDG from service, restricting work in the main switchyard while the EDG is inoperable for maintenance, and ensuring that availability of redundant on-site AC power sources. The above discussion makes the conclusions in the draft INEEL report about the EDG outage during summer months versus nonsummer months to be invalid, since the plant-specific configuration risk management and compensatory measures would not allow removing the EDG from service for maintenance unless the weather conditions are favorable. For example, page xiii of this draft report states, "If such outages were to occur only during the summer months, the increase in SBO core damage frequency could be significant. However, if such outages were limited to the nonsummer months, then the increase in SBO core damage frequency is negligible." The draft INEEL report needs to describe how the plant-specific SPAR model credits these types of regulatory commitments and compensatory measures. These are important aspects that are credited in the plant-specific PRA model in order to represent the plant as built and as operated.	See the response to EPRI Comment 1. The point made in this analysis is that external grid LOOPs are more likely to occur during the "summer" period. Compensatory measures and other regulatory commitments will reduce the SBO risk.	
EPRI	3	The draft INEEL report needs to document the range of battery depletion times used in the SPAR modeling of the SBO sequences.	Table 4-1 in Section 4 presents battery depletion times for all of the plants. This table in the draft report did not include these times.	Section 4, Table 4-1
EPRI	4	PRAs assume that the SBO sequences could lead to consequential RCP seal LOCA. The draft INEEL report needs to document the range of RCP seal LOCA (in terms of gpm) assumed in the SPAR models.	The Westinghouse plant RCP seal LOCA model has been updated based on recent WOG submittals and NRC reviews. The Combustion Engineering plant model is also based on recent Combustion Engineering submittals. BW plant SPAR models have not been updated. Finally, the SPAR BWR plants do not model significant RCP seal LOCAs, except for those with isolation condensers. This is documented in Section 2.	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
EPRI	5	In NUREG/CR-5944, a survey of EDG unavailability indicated that the mean unavailability values for the EDG during "at-power" due to preventive and corrective maintenance are 1.18E-2 and 8.2E-3, respectively. Correspondingly, the unreliability of the EDGs has decreased on an industry average from 2.0E-2 in the early 1980s to 1.4 E-2 in the early 1990s. The study suggested that the increase in EDG reliability is correlated with EDG unavailability. The draft INEEL report would be improved if it compared the EDG unavailability and unreliability with the important work done by BNL in NUREG/CR-5944 Source: NUREG/CR-5944, "Emergency Diesel Generator: Maintenance and Failure Unavailability and Their Risk Impacts," P. Samanta, et al., BNL, November 1994.	The draft report included results from NUREG/CR-5994 (we assume the reviewer meant 5994, rather than 5944), as indicated on p. 23 and in Figure 4-1 in that draft. We agree that the work in NUREG/CR-5994 is an important analysis of EDG data over the period 1988–1991 (for UR) and 1990–mid 1992 (for UA). The report lists UA (from testing and maintenance) as 0.022 in its Executive Summary. Concerning UR, NUREG/CR-5994 lists several different estimates. From test data (estimated to average approximately 1.6 hours per demand), that report lists a FTS probability of 0.005 and FTLR of 0.0093 (Table 3.1 in that report). The sum of these two failure modes is 0.014, which is the value quoted by the reviewer. However, the comparison presented in the present report includes a mission time of 8 h. One way to estimate the UR over an 8-h mission time using the NUREG/CR-5994 results is to use its FTLR rate of 0.0058/h (Section 3.3.9 in that report) for the remaining 7 h of the mission. This approach was used in the draft report, resulting in a total UR of approximately 0.073, which was plotted in Figure 4-1 of the draft report. However, a possibly more appropriate method of using the NUREG/CR-5994 data is explained in Appendix D of the present report (the sensitivity case for NUREG/CR-5496). That approach results in a total UR of 0.041. That is the value used in the final report as representative of the data presented in NUREG/CR-5994.	Section 4.2 and Appendix D

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
EPRI	6	Comments on page 11, Table 3-2 entitled "LOOP frequency distribution": a. The use of five categories of LOOP initiating events (namely, plant centered, switchyard-centered, grid-centered, severe weather-related, and extreme weather related) is inconsistent with current industry PRA practices where only three LOOP initiating event categories are used, namely, plant-centered, grid-centered, and weather-related. Plant-specific PRA models do not differentiate between severe weather and extreme weather–these initiators are lumped into weather-related. All the owner groups use these three categories for the LOOP initiating events. For example see CE NPSD-1120, "Guidelines for Modeling Station Blackout, CEOG Task 1028, October 1998." This reports discussed only three categories of LOOP, namely, plant-centered, grid related, and weather-induced. [A table is presented that indicates the combined plant/switchyard-centered LOOP frequency range is 1.63E-2 to 2.25E-2/y, the grid-related range is 2.4E-3 to 3.1E-3/y, and the weather-related range is 3.8E-3 to 5.2E-3/y.] The following table provides another example of LOOP initiating event frequencies used by the US nuclear industry PRA practitioners:	To support industry risk models that use only three categories of LOOPs, results (frequency and offsite power nonrecovery) are presented in the final report for the combined plant/switchyard-centered category. Note that the final report already combines the two weather-related categories from the draft report into a single weather-related category. Our new LOOP category frequencies take into account the August 14, 2003 and the June 14, 2004 grid events. These events resulted in 11 plant trips. Therefore, any "bias" is the result of actual operating experience data. Table 3-2 in the draft report presents the gamma distribution parameters for the individual LOOP category frequencies and the combined ("all") LOOP frequency. These are not Weibull distributions. The "All" distribution was obtained by simulating the sum of the four individual LOOP category frequencies and fitting the resulting data samples to a gamma distribution. The gamma shape factor for the sum of the four individual LOOP category frequencies can be quite different from the shape factors for the individual categories.	Sections 3 and 4

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		LOOP Initiator Description / **Mean (yr-1)** / **5% CL (yr-1)** / **95% CL (yr-1)** / **Error Factor** Loss of off-site power (Plant-Centered) / 4.44E-02 / 3.68E-02 / 5.28E-02 / 1.20E+00 Loss of off-site power (Grid-Related) / 4.18E-03 / 2.10E-03 / 7.23E-03 / 1.86E+00 Loss of off-site power (Weather-Induced) / 5.04E-03 / 2.76E-03 / 8.24E-03 / 1.73E+00 The industry data shown the above table does not take into consideration the blackout events that occurred in 2003 and hence are less biased with respect to the grid-related LOOP initiating event frequency compared to the draft INEEL report where the grid-related LOOP frequency appears to be the dominant initiator for LOOP. And to the contrary to the draft INEEL report, all industry data shows that the plant-centered LOOP initiators dominate the LOOP frequency. b. The Shape factors (α) of the Weibull distributions shown in Table 3-2 are less than 1.0 (namely, 0.5). However, under the "all" line, the shape factor (α) is greater than 1.0 (namely, 1.737). The draft INEEL report needs to explain the rationale and statistical significance of the shift in the shape factors of the Weibull distributions from < 1.0 to > 1.0.		

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
EPRI	7	In Table 3-3 on Page 13, please explain the rationale for using Weibull distribution with a shape factor ($\alpha = 1.4$) that is greater than 1.0 for the extreme weather-related LOOP while the shape factors are less than 1.0 for plant-centered, switchyard centered, grid-related, and severe weather related probability of exceedance.	In the final report, the probability of exceedance curves are from lognormal fits to the data. This is in contrast to the draft report, where Weibull fits were used. With the addition of the 2004 LOOP data and changes made to estimating the potential bus recovery times, the lognormal distributions fit the offsite power recovery times better than did the Weibull distributions. When the recovery times are fit to lognormal or Weibull distributions, the software automatically optimizes both parameters of the distributions. The weather data are significantly different from the other LOOP categories, so it is not surprising that the shape factor is different.	
EPRI	8	Similarly for Figure 3-2 on page 14, it would be useful to provide some justification of the inconsistent trend of the extreme-weather-related curve that correlates probability of exceedance versus duration time compared to the consistent trends of the curves describing plant-centered, switchyard-centered, grid-centered, and severe weather- related.	In the final report, the severe weather and extreme weather LOOPs were combined into a single weather-related LOOP category. With the addition of the 2004 LOOP data (with some extreme weather events with short offsite power recovery times), it was possible to combine the two sets of data and get a reasonable lognormal fit to the potential bus recovery times. However, the weather-related probability of exceedance curve still lies significantly above the other three LOOP category curves, as indicated in Figure 3-4.	
EPRI	9	Comment on page 19: Table 4-1 entitled "EPS configurations at U.S. commercial nuclear power plants" contains incorrect information on key plant-specific features that reduces the level of confidence in the results presented in the draft INEEL report: For example, Table 4-1 shows that Millstone Unit 2 and Millstone Unit 3 have no electrical cross-tie capability. To the contrary, there is an electrical cross-tie between Millstone Unit 2 and Millstone Unit 3 which are credited in the PRA models and in the approved EDG AOT extensions of both units. This incorrect information, and	Millstone Units 2 and 3 have unique cross tie features. Unit 3 can supply Unit 2 via a cross tie, but Unit 2 cannot supply Unit 3. The station blackout (SBO) EDG is assigned to Unit 3 and is included in the SPAR model. Either safety bus at Unit 2 can be supplied via the cross tie from the Unit 3 SBO EDG, the Unit 3 normal station services transformer, or the Unit 3 reserve transformer. However, procedures prevent the Unit 3 (non-SBO) EDGs from supplying	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		there could be potentially other cases, is indicative of the fact that the SPAR models for Millstone Unit 2 and Millstone Unit 3 do not represent the plants as built and as operated.	power to Unit 2. Therefore, the Unit 2 SPAR model includes credit for the Unit 3 SBO EDG supplying power. The information in Table 4-1 summarizes these SPAR models, indicating that each plant has two EDGs and the SBO EDG available, with a success criterion of one of three.	
EPRI	10	Comment on page 29, Table 5-1 entitled "Probability of exceedance for EDG repair times." The draft INEEL report needs to document which probability distribution has been used to generate this table (e.g., lognormal, etc). Also, other statistical information needs to be documented such as the mode of this distribution. Finally, what is confidence level of the data presented in Table 5-1?	The EDG repair curve in the final report is different from the one presented in the draft report. The draft report curve is an exponential distribution with a median of 4 h. (The median was obtained from NUREG-1032, based on two EDGs failing and being able to choose to repair the EDG requiring the least time to repair.) A new EDG repair curve (Table 5-1) was generated for the final report. Reactor Oversight Process (ROP) Safety System Unavailability (SSU) unplanned outage data for EDGs from 1998–2002 were used. These data (repair times) were fit to a Weibull distribution, with a mean repair time of 18.7 h. This curve is applicable to a single EDG. Simulation was then used to model two EDGs failing and being able to choose to repair the EDG requiring the least time to repair. The resulting samples were then fit to another Weibull curve, which is the one presented in Table 5-1. The mean of this second curve is 7.4 h and the median is 3.8 h. The uncertainty in this curve is approximated by assuming an error factor of three. It is recognized that the use of ROP SSU data may have some limitations. These data are in the form of total unplanned outage hours for each quarter of a year. These entries could possibly include more than one repair. This would tend to result in overestimates of EDG repair times. (However,	Section 5

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
			analysis of the data indicates that at least 80% of the quarterly data have zero unplanned hours, so most quarterly data will include only one event.) Also, a single EDG repair could extend from one quarter to the next, so the total repair time would show up as two shorter times, one in each of the two adjacent quarters. In spite of these potential shortcomings, the ROP SSU unplanned outage data are a reasonable source for repair times. The average repair time for a single EDG of 18.7 h compares well with an average from previous estimates from sources such as WASH-1400, NUREG/CR-2982, NUREG/CR-4347, and the Swedish T-Book.	
EPRI	11	The SPAR model uses an EDG mean time to repair (MTTR) of 4 hours (see page 29). This MTTR is an unrealistically optimistic value. Additionally, in order to be statistically meaningful, the MTTR value should be augmented by a standard deviation that accounts for uncertainties associated with this random variable.	See the response to EPRI Comment 10. The final report uses a repair curve for a single EDG that has a mean repair time of 18.7 h, which agrees well with other sources. When this single EDG repair curve is used in a simulation to model repair of one of two EDGs (the event modeled in SPAR), the mean is 7.4 h. The final report also includes uncertainty bounds on this simulated repair curve, as required by the SPAR models in order to perform uncertainty analyses. The draft report was not very clear in indicating that the repair curve presented was for the special case of two EDGs failing and being able to choose to repair the one that takes the least time to repair.	
EPRI	12	Does the EDG MTTR of 4 hours include the diagnostic time, trouble-shooting time, and administrative time (e.g., tagging and un-tagging equipment, ordering spare parts, completing work orders, etc)? Typically, the range of EDG repair time is between 4 hours (lower bound value) and up to 70 hours (upper bound value). Industry survey data (see the study done by BNL in	See the response to EPRI Comment 10. The ROP SSU data indicate an average repair time of 18.7 h (1998–2002) for a single EDG, which is not much different from the older result of 23.3 hours from NUREG/CR-5994 (covering data from 1990 to mid 1992). However, when the simulation is performed	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		NUREG/CR-5944) suggests that corrective maintenance is performed on an EDG at a mean of 23.3 hours and a standard deviation of 46.7 hours. The use of 4 hrs MTTR of the EDG results in underestimating the EDG unavailability and, hence, this incorrect assumption impacts all the LOOP (including SBO) cut sets that contain EDG out-of-service basic events.	for the case of two EDGs failing and being able to choose to repair the one with the shortest repair time, the mean for this simulated situation decreases to 7.4 hours.	
EPRI	13	As a recommendation, the draft INEEL report needs to add a cross-comparison table of the top 10 LOOP (including SBO) cut sets as quantified by each plant-specific SPAR model versus the actual plant PRA model in order to show: a. How closely the SPAR models represent the plants as built and as operated. b. How closely all appropriate basic events and operator failures are contained in the SPAR cut sets.	The type of comparison suggested is being performed as part of the continuing program to maintain and enhance the SPAR models and to support the Mitigating Systems Performance Index implementation. SPAR model cut sets are being compared with plant PRA cut sets to identify areas of divergence and the reasons for this divergence. That effort is ongoing. Comparisons have been made with updated IPE results, both total CDF and LOOP/SBO CDF, and in general the comparisons are good, especially at the industry level.	
EPRI	14	One major limitation of this draft INEEL report is that is does not document the most dominant LOOP (including SBO) cut sets generated by the SPAR models of the 103 nuclear plants. In order to demonstrate an appropriate confidence level in the results reported in this draft document, it is imperative to show at least the top 25 LOOP (including SBO) cut sets as generated by the plant-specific SPAR models.	The plant-specific SPAR models are available through the NRC to each licensee. Listing of such cut sets in the present report is not believed to be necessary for the purposes of the report, which are to present plant class and industry average results.	
EPRI	15	The draft INEEL report needs to document how the grid-related LOOP cut sets rank relative to the weather-related and plant-centered LOOP cut sets. Furthermore, it would be useful to group those cut sets by plant geographical location to uncover trends related to the geographic locations. For example, in St. Lucie 1 and 2 (CE plants), the top 25 loss of offsite power cut sets are grid-related. For Indian Point Unit 3 (Westinghouse plant), the most dominant SBO sequence is initiated by LOOP and subsequent loss of onsite AC power. The PORVs reclose, if opened. Depressurization of the steam generators reduces the RCS pressure	The purpose of the current study was to look at industry SBO risk and grid performance. Licensees can consider plant-specific sequences in their day-to-day plant operations (i.e., Maintenance Rule analyses)	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		and temperature. RCP seal failures occur and the core is uncovered and results in core damage. This sequence contributes 16.7% of the total internal events CDF.		
EPRI	16	Accidents initiated by LOOP are typically important risk contributors both in terms of core damage frequency and off-site consequence. As a subset of LOOP, SBO sequences are major contributors to the internal events' large early release frequency (LERF). Additionally, SBO sequences dominate late radionuclide releases during the accident progression. Based on the above discussion, failure to discuss the LERF results is a major weakness in the INEEL analysis.	See response to USC Comment 2. As indicated in the report, LERF is not addressed in the report. The insights and results from this report (e.g., the trends in LOOP frequencies and durations, the contribution of EDGs and other systems to SBO risk) remain the same whether or not LERF is considered.	
EPRI	17	There are a number of methods available to model the recovery of offsite power. The three most common methods are: • The application of a single, conservatively high value for the offsite power (OSP) non-recovery probability to all accident cut sets involving the LOOP initiator, • The use of time-sequenced event trees, and • The convolution of time-dependent failure probability distributions. Which method is used in the SPAR method to model recovery of offsite power?	The SPAR models generally have several different event tree top events dealing with the timing of recovery of offsite power (as indicated in Section 2.2). All cut sets for a specific sequence (tied to recovery of offsite power by a specific time) use the same nonrecovery probability. However, different sequences may use different nonrecovery probabilities. In addition, the repair of EDGs is typically modeled as an event tree top event, again with a specific time period. This approach is characterized by the second method listed by the reviewer.	
EPRI	18	Offsite power recovery time is defined as the time from event initiation until the first offsite electrical power is available to restore power to a safety bus. The draft INEEL report needs to document how the SPAR model defines offsite power recovery time, and to answer the question, "does this time exclude/include power from the emergency diesel generators?"	The offsite power recovery time is defined as the duration from the initiation of the LOOP until offsite power is potentially recovered to a safety bus. The definition excludes diesels so that they can be treated separately in the SPAR model. The Glossary presents definitions of the various recovery times used in the study.	
EPRI	19	The draft INEEL report needs to provide more detailed discussion of the RCP seal failure probability calculations. Here is an example to illustrate the expected level of details: The conditional seal failure probability for one of four RCP's was calculated by multiplying the	See the response to EPRI Comment 4.	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		conditional seal failure probability (per pump) by the number of RCP'S at PSL. The conditional seal failure probability for 4 of 4 RCP'S was calculated by multiplying the conditional seal failure probability (one of four RCPs) by the time-dependent common cause factors. *The reviewer presents a table to show conditional failure probabilities for 1 of 4 and 4 of 4 RCPs experiencing a seal LOCA for various time periods, assuming no power.*		
EPRI	20	Comment on page 31, containing the following statement: "SBO CDF risk can be viewed as the product of the LOOP frequency, the EPS failure probability, and SBO coping failure probability." This statement, as well as the SBO event tree on page 7, gives the impression that the SBO cut sets in the draft INEEL report are just the products of hardware failures. To the contrary, the SBO cut sets are products of hardware failures and operator failure to recover. This raises the following question: how is the operator's failure to depressurize the RCS by via feed and bleed cooling credited in the SPAR models?	The top events in the SBO event trees incorporate operator errors where appropriate. The documentation associated with each individual SPAR model should be consulted to identify what plant-specific mitigating features are available given an SBO condition, and what operator actions are included.	
EPRI	21	Comment on page 35: Quotes from this page: "Grid-related LOOPs contribute 50% to the overall SBO CDF." "and only a 1% contribution from plant-centered LOOPs." These are erroneous conclusions and reflect that the SPAR models of the 103 plants do not represent those plants as built and as operated. The underlying reasons for this mismatch between the industry plant-specific PRA models and the SPAR model are as follows: • The SPAR models do not capture all the key plant-specific features of each plant. As stated above, the SPAR models of Millstone Units 2 and 3, respectively, assume that there is no electrical cross-tie capability between these two units, which is incorrect. • The SPAR models use biased LOOP initiating event frequencies that are skewed by crediting the blackout events in August 2003. To resolve this major concern, we recommend that the final report provide the top 25 LOOP (including SBO) cut sets generated by the	The SPAR models have been benchmarked against the plant-specific PRAs, and they reasonably reflect the 103 plants as they exist today. In addition, ongoing comparisons of the SPAR models with current industry models, in terms of cutsets, indicate general agreement between the two. See the response to EPRI Comment 9 concerning the Millstone 2 and 3 models. We do not feel that the LOOP initiating event frequencies presented in this report are "biased." The August 2003 event resulted in nine plant trips (eight of which resulted in LOOPs), and this is what was modeled. Finally, our summary of industry average SBO results is believed to present the most up-to-date	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		SPAR models for at least a representative sample from the 103 plants population. The report should compare these cut sets with the actual LOOP cut sets generated the plant-specific PRA models which represent the plants as built and as operated.	picture of SBO at the industry level. We do not believe that the results represent "erroneous conclusions."	
EPRI	22	Comment on page 40, Table 7-1 entitled "Sensitivity analysis results summary": The calculations based on assuming EDG 14-day outage during the summer months and the nonsummer months are incorrect, as previously discussed. To reiterate, all use plants with approved EDG AOT extensions apply additional regulatory commitments and compensatory measures that require monitoring the weather before removing the EDG from service for maintenance. Specifically, the EDG will not be removed from service for maintenance unless the weather conditions are favorable regardless of being in the summer or nonsummer months. Furthermore, all nuclear licensees use the Maintenance Rule unavailability criteria (which limit the number of hours that the EDG can be removed from service) and the integrated configuration risk management that monitor the simultaneous unavailability of risk-significant SSCs.	See the responses to EPRI Comments 1 and 2.	
EPRI	23	We conducted spot checks to compare the SPAR models total LOOP CDF that are presented in Table C-2 entitled "plant-specific LOOP, SBO, and total CDF results" versus actual plant-specific PRA models. Our comparison revealed discrepancies as shown in the following table: *The reviewer presents a table showing LOOP CDF results for seven plants (obtained using only the top 25 cut sets from plant PRAs) and the draft report results (using all SPAR cut sets).*	The type of comparison mentioned by the reviewer is the type being performed for all of the SPAR models. That effort is ongoing and covers not just LOOP but all of the important initiating events. See the response to EPRI Comment 13.	
EPRI	24	Table C-2 shows that St. Lucie 2 has LOOP CDF that is one order of magnitude less than the LOOP CDF of St. Lucie 1, that is, 4.00E-7 versus 4.43E-8. This does not make any sense because the two plants are identical. This discrepancy should be corrected in the final report.	The final report indicates that the St. Lucie 1 and 2 results are now similar, although not exactly the same. The two plants are not identical. There are differences between units with respect to valve arrangements within the AFW and HPSI systems and Unit 2 credits an additional air compressor in the instrument air system.	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
EPRI	25	Comments on the reference section on pages 47 and 48: Out of a total of 24 references cited in the draft INEEL report, only one document is an industry document (namely, WCAP). Unfortunately, there are critical data published by the owner groups and EPRI that are relevant the study performed in this daft INEEL but are not captured in this report. For example, one of the EPRI reports that contains data relevant to the draft INEEL report is the following: EPRI Report 1009889, "Losses of Off-Site Power at U.S. Nuclear Power Plants–Through 2003", April 2004. This report should be reviewed and incorporated in the final INEEL report.	The report mentioned was used extensively in the draft LOOP report. Therefore, it is an important reference in Volume 1 of the final report. (Volume 1 covers the LOOP event analysis.)	
DSSA	1	In accordance with your request dated January 14, 2005, the Division of Systems Safety and Analysis (DSSA), Probabilistic Safety Assessment Branch (SPSB) has reviewed the subject report. Since the DSSA staff actively participated in the report's development through numerous discussions with your staff and by attending various briefings and coordination meetings, we were well aware of its contents (specifically including the assumptions made and the risk assessment methods employed) before we received your request for a formal review. The report provides estimates of core-damage frequency (CDF) arising from loss of offsite power (LOOP) and station blackout (SBO) events. These estimates were generated from the Level 1, Revision 3 Standardized Plant Analysis Risk (SPAR) models which were revised to support the analysis. The specific revisions made included: 1. New models of reactor coolant pump (RCP) seal loss-of-coolant accidents (LOCAs) for Westinghouse and Combustion Engineering plants; 2. Updated LOOP frequencies and recovery curves (developed in a companion report); 3. Updated component failure rates obtained from the Equipment	The summary was revised in the final report to alert the readers to the limitations in scope of the project.	Section 8

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		Performance and Information Exchange (EPIX) database maintained by the Institute of Nuclear Power Operations (INPO), as accessed using the NRC-developed Reliability and Availability Database System (RADS); 4. Updated test and maintenance outage probabilities obtained from the Reactor Oversight Process (ROP) Safety System Unavailability (SSU) database; 5. Updated initiating event frequencies obtained from databases maintained by the NRC; and 6. Updated common-cause failure parameters (alpha factors) obtained from databases maintained by the NRC. We separately reviewed the updated LOOP frequencies and recovery curves (Item 2 above), as indicated in our memorandum dated March 4, 2005. We did not review the remaining SPAR model revisions because of staff resource limitations. In addition, we do not believe that you intended us to conduct a detailed review of the revised SPAR models in conjunction with our review of the subject report. Our understanding of the processes and methods used to update the SPAR models gives some assurance that the report's risk insights have an adequate technical basis to support the staff's Action Plan for Resolving Electrical Grid Concerns (G20030756). We believe that you should conduct a review of the updated SPAR models if they will be used for other regulatory purposes. We note that the SPAR models do not provide estimates of the large early release frequency (LERF), do not consider accidents arising from external events such as fires and earthquakes, and are limited to at-power plant configurations and operations. In contrast, risk-informed regulatory decisions (e.g., changes to a plant's licensing basis per RG 1.174) generally consider the impacts on both CDF and LERF from all initiating events and plant operating modes. We acknowledge that your staff is working to expand the SPAR models to address LERF, external events, and shutdown risks. We do not believe that these limitations of the SPAR models are significant		

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		with respect to supporting the staff's Action Plan for Resolving Electrical Grid Concerns (G20030756). However, we suggest that discussion be added to Chapter 8, "Summary and Conclusions," to alert users of the report about limitations in the analytical approach used.		
DSSA	2	The report provides CDF point estimates and parametric uncertainty distributions for each individual plant and composite CDF point estimates (which includes plant-to-plant variability) for eight plant classes and the industry as a whole. The results are notably lower than previous studies of LOOP and SBO risks such as NUREG-1032, "Evaluation of Station Blackout Accidents at Nuclear Power Plant," which was used to support development of the SBO rule (10 CFR 50.65). The means of all uncertainty distributions are in good agreement with their corresponding point estimates. However, the magnitudes of the uncertainty on the individual plant CDF estimates seem unusually large, based on our experience. For example, Table E-4 states that the mean SBO CDF for ANO-1 is 5.25x10-7/rcy, with a fifth percentile of 8.07x10-9/rcy and a ninety-fifth percentile of 2.02x10-6/rcy. That is, the uncertainty in this CDF estimate spans over two orders of magnitude. We suggest that you recheck the uncertainty calculations and include a section in the report that discusses the reasons why such uncertainties exist.	The uncertainty models for basic events in the SPAR models were reviewed and changed for the final report. In the draft report, for basic events with insufficient information to accurately characterize uncertainty distributions, a maximum error factor (95%/median) of 50 was assumed. In the final report, that maximum was reduced to approximately 20. This change, along with others, results in narrower uncertainty bounds on the total CDF and SBO CDF results presented in Section 6 and Appendices C and E. The final choice of approximately 20 as the maximum error factor was based on a review of the maximum error factors obtained from empirical Bayes analyses of component failure modes with sufficient data to perform such analyses.	Section 6; Appendices B, C, and E
DSSA	3	The CDF estimates span over four orders of magnitude, as evidenced by Figure 6-1. Since these results were generated using common industry data set, this variability reflects differences in plant design and configurations. However, we suggest that discussion be added to Chapter 8, "Summary and Conclusions," to alert users of the report about the variability and uncertainty in the results.	Section 8 was revised to alert the readers to the variability in plant-specific results.	Section 8
DSSA	4	The report provides the results of sensitivity analyses that were performed in four areas: emergency diesel generator (EDG) modeling and performance, offsite power recovery times, seasonal variations, and historical input data (quantifying the revised SPAR	Section 7 includes a discussion of results for each of the groups of sensitivity cases. Because each group of sensitivity studies is different, an overall summary is not presented, although all of the results	

Table B-1. (continued).

Reviewer	Comment Number	Comment	Comment Resolution	Volume 2 Revision
		models with LOOP frequencies, offsite power recovery curves, and EDG performance obtained from previous studies). We suggest that discussion be added to Chapter 7, "Sensitivity Analysis Results," to briefly summarize the major conclusions of the sensitivity analyses. In conclusion, we recommend that the report be issued at your earliest convenience as it will provide a valuable reference during execution of the staff's Action Plan for Resolving Electrical Grid Concerns (G20030756). In order to generate the report's conclusions, the revised SPAR models for each of the 103 licensed nuclear power plants were extensively exercised. This approach would not have been practical several years ago due to limitations in software and computer hardware capabilities. We commend your staff's hard work in achieving the current level of SPAR model capability, and support your efforts to further develop and expand the SPAR models.	are listed in Table 7-1.	
SUSQ	1	In Table 4-1 in the column titled, "EPS Success Criteria" on Page 21, this column indicates that only one diesel generator is required for "success." The single diesel generator success criterion is true at Susquehanna SES for only diesel generators A and B but not for diesel generators C and D.	Table 4-1 was revised based on this comment. The draft report indicated an effective success criterion for the emergency power system of one of five EDGs. However, because two of the EDGs cannot support all of the loads, this effective success criterion was changed to one of two.	Section 4, Table 4-1
PE	1	One of the conclusions of the report is that severe weather is a significant contributor to station blackout core damage frequency (SBO CDF). It may be more appropriate to treat the severe weather case separately based upon actual plant practices with incoming or predicted severe weather. Examples of plant practices and procedure requirements include plant shutdowns, restoration of risk significant equipment, and start testing and restoration to standby of the emergency diesel generators. In many cases other emergency power supplies that are not safety related systems are brought up to a heightened state of readiness. This further reduces the SBO CDF from severe weather.	In the final report, severe and extreme weather events have been combined into a single weather-related LOOP category. The focus of the report is on plant class and industry average results and trends, so the level of plant-specific detail indicated in the reviewer comment is not required for this project. However, individual plant-specific analyses might include factors mentioned by the reviewer. The industry LOOP data include cases where plants shut down in anticipation of severe or extreme	

Table B-1. (continued).

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			weather. Such events were placed in the shutdown operation category rather than the critical operation category and did not contribute to critical operation LOOP frequencies.	
PE	2	It is not clear from the report if the frequency increase for a summer loss of off-site power (LOOP) is region dependent or not.	The summer versus nonsummer analysis did not look at regional differences. In general, the data are too sparse to divide into summer and nonsummer and to further subdivide into regions.	
PE 3		It appears that the impact of Maintenance Rule (10 CFR 50.65) implementation resulting in Emergency Diesel Generator (EDG) performance improvements has not been considered. It should be recognized that implementation of the Maintenance Rule resulted in more stringent EDG performance targets than the SBO Rule. In addition, implementation of Maintenance Rule Risk Assessments (10 CFR 50.65(a)(4)) for work week scheduling has contributed to scheduling of EDG maintenance tasks outside of time periods where risks to offsite power availability are known to be present. It may be more constructive to focus on Maintenance Rule Risk Assessment adjustments regarding EDG maintenance task scheduling than to block out periods of time based on the season of the year. This will ensure proper consideration of increased risks to offsite power availability throughout the year without unnecessary restrictions during mild summers.	See the response to EPRI Comments 1 and 2.	
PW	1	Overview-why a final evaluation is important *Station Black-out* Nuclear Reactors need electricity to operate-without a supply their safety systems would be disabled. They do not generate their own electricity. Like all of us, they depend on the grid-offsite power. If offsite power fails, they depend on back up generators (EDGs). If the EDGs fail, the chance of an accident approaches certainty.	See the response to UCS Comment 2. All types of events that have resulted in LOOPs at U.S. nuclear power plants have been included in the analysis. External events resulting in LOOPs are included. The draft report was not very clear in this respect. With respect to the comment that the SPAR models use industry average data , the reviewer is correct. However, programs such as the Maintenance Rule, the Reactor Oversight Process, and upcoming	

Table B-1. (continued).

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		Consequence Depending on circumstances, the station blackout reactor accident can be particularly dangerous to public health and safety-with a core melt and/or spent fuel pool fire large amounts of radioactivity will be dispersed far and wide within a few hours. Executive Summary, page 9, states that, "Risk (from station blackout) was evaluated for internal events during critical operation; risk from shutdown operation and external events was not discussed." A. Omission: External Events neither studied, nor defined: On August 14, 2003 there was a serious transmission grid blackout that affected 9 U.S. nuclear reactors and states. As a result of that blackout (external event), NRC initiated a program to examine loss-of-offsite-power events and station blackout. This study, we are told in the Executive Summary, page 9, is part of that initiative. However, external events such as deregulation of the electric market and its effects on grid reliability, terrorism, global warming, and consequent increased frequency and severity of storms are not discussed or studied. External events are half the equation and exceedingly important. B. Omission: Internal Events Studied Only During Critical Operation: Problems can occur, and be more severe, when the reactor is shut down. Therefore this should have been analyzed. Examples: Davis-Besse NPS was shut down during the August 14, 2003 black-out. It experienced more complications than most reactors operating at the time-see analysis by the Union of Concerned Scientists comments. The worst black-out event in the United States occurred at Vogtle NPS when the reactor was shut down.	Mitigating Systems Performance Index, and others, have resulted in and will continue to result in plant-specific component performance trending more towards industry average performance. Adverse component performance will be highlighted and corrected by these programs. Plant-specific data are not needed for this study, in which the main focus is on plant class and industry average results. This study was performed to determine the effect on risk from LOOP/SBO events using more up-to-date operating experience data such as LOOP frequencies, durations, and equipment reliability. It was not the intent of the study to quantify a total risk from LOOP/SBO risk. Spent fuel pool risks include risks from LOOP/SBO have been evaluated as part of other Agency programs. These risks have been shown to be low.	

Table B-1. (continued).

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		C. <u>Omission: Spent Fuel Pools not studied:</u> It is a serious omission not to analyze station blackout risk to spent fuel during refueling. Station black out can contribute to the loss-of-pool coolant event and/or prevent proper mitigation of the event. During refueling, there are fewer barriers and backup systems than when the reactor is operating. Thus, both the chances of a station blackout and the consequences from a station blackout are increased. The National Academy of Science, Safety and Security of Commercial Spent Fuel Storage Public Report (April 2005; p.57) stated that the offloading of the reactor core into the spent fuel pool during reactor outages substantially raises the decay-heat load of the pool and increases the risk of a zirconium cladding fire in a loss-of-pool coolant event. Analyzing risk to spent fuel storage pools is especially important now because pools are densely packed; accident or sabotage can cause loss-of coolant; followed by a zirconium fire and radioactive release capable of contaminating hundreds of miles downwind. <u>Omission: Internal Events Studied Generically</u> Spar models do not use site specific values; spar models simply used industry average values for component unreliability. This does not account for the fact that reactors are not stamped out by "cookie cutters." Plant data may well be outside norm and such deviation must be accounted for. This is especially important now because, for example: The decrease in NRC oversight; industry use of substandard and counterfeit parts; current and varied age of reactors, and components in those reactors, and their expected degradation along what is referred to as the "bathtub curve." At the end of the life-cycle of mechanical components, they will start to wear out and mechanical and safety problems dramatically increase---whether they are in a toaster or in a nuclear reactor. This is not accounted for or analyzed-to properly do so would require site-specific analysis.		

Table B-1. (continued).

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PW	2	Problem: Core Damage Frequency report figures differ considerably from figures in NUREG-1776, issued August 2003. There is no explanation for the wide disparity in the numbers---numbers in the Draft are far lower.	See the response to UCS Comment 4.	
PW	3	Problem: INPO used as Source Data for SPAR models. NRC's SPAR models were updated using data from INPO's Equipment Performance and Information Exchange database, Section 2.1, page 3. INPO is not a NRC licensee. Therefore they are not under NRC requirements for accuracy and are not audited by NRC. Therefore NRC is improperly relying on unverified, secret data to base regulatory analysis.	See the response to UCS Comments 5 and 6.	
NEC	1	New England Coalition has read, endorses, and herein wishes to incorporate, by reference, the comments of the Union of Concerned Scientists, submitted March 8, 2005. Our comments are at this time brief and limited to a few points: Emergency Diesel Generators (EDGs)-EDGs may start and run, but can they provide adequate power to systems that have been modified and to which additional loads have been added over time? For example, at Maine Yankee in 1996, EDGs under accident operating conditions were found to be loaded to within 3/10 % of their plate rating. A variety of common discrete conditions and circumstances could make that margin disappear, for example: variations in fuel, service water loss or restriction, or extreme temperature conditions. In 1994, Maine Yankee accepted a load of diesel fuel; then, for a time, ignored a failed viscosity test on that fuel. It was found that the fuel was what, in northern states, is termed, "winter mix;" having been cut 30 to 40 % with number one oil or, "kerosene." Although diesels run fine on this fuel, they do so at greatly reduced power. Thus, in this example, it is unlikely that the EDGs could have carried the load assigned for accident conditions.	Design deficiencies, such as those mentioned in your comments, are addressed by NRC inspection programs and are corrected as they are found. If such events result in unavailabilities for the EDGs, then those unavailability contributions are included in the ROP SSU. The EDG performance modeled in the SPAR models includes an outage due to testing or maintenance, and that event was derived from ROP SSU data. Therefore, to the extent such events result in EDG unavailability, the present study includes such events.	

Table B-1. (continued).

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		In 2004, at Oyster Creek, buried safety-related EDG power feed cables were found to have deteriorated insulation and as a consequence were shorting to ground under very light load. It was found that for the past several years the licensee had experienced several similar cable shorts. However, due to reliance on a poorly derived wiring chart rather than the appropriate design documents, the licensee did not notice that the failed cables were all from the same manufacturer and lot. Therefore, the license could not predict and interdict the next failure. Had any of the cables been fully loaded during a SBO or Loss-of-Offsite Power (LOOP) incident, it is likely as not that they would have simply burned out or caused the EDG to burn out. The SBO risk study does not appear to reflect any lessons learned from these real world operating experiences.		
NEC	2	Internal Events Studied Only During Critical Operation -We are concerned with what we see as inconsistencies in NRC's approach to assessing risk and, in particular, as it applies to the pointed exclusion from the SBO risk study of plants in shutdown mode. NRC justifies the practice of on-line maintenance with risk numbers based on the availability of more safety systems while a plant is powered-up. So, to our thinking, it follows that conversely at least certain kinds of risk are higher when a plant is in shutdown mode. We know, for example, that the risk of fire, a high-risk, relatively high frequency, initiating event is much greater in plants that are shutdown, refueling, or decommissioning. The purposeful exclusion of such considerations can only serve to skew the SBO risk study results. At this point, it may serve to mention parenthetically that NRC is pushing the limits of statistical probability in that, with few exceptions, risk studies over the last ten years have uniformly found less risk than previously identified; it is as if the FDA, under the tutelage of the American Tobacco Company had suddenly begun to find the risk in chain-smoking to be much over-blown. Statistically variable findings become suspect when they begin to approach 100% consistency; and in fact, they then become suspect of being	This study was performed to determine the effect on risk from LOOP/SBO events using more up-to-date operating experience data such as LOOP frequencies, durations, and equipment reliability. It was not the intent of the study to quantify a total risk from LOOP/SBO risk. The present study found that SBO CDF at the plant class and industry level has decreased compared with historical estimates. This decrease is due in large part to the improved performance of EDGs and other plant components, and plant modifications made as a result of NRC and Industry initiatives, such as the SBO Rule. The scope of the present study does not include risk from low-power and shutdown operations.	

Table B-1. (continued).

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		driven by predetermined conclusions. In this case, it appears that the SBO study is but one of a series that set out to find less risk.		
NEC	3	Vermont Yankee-Poster Child for Optimistic Risk Analysis in the SBO Risk Study We find that the SBO Core Damage Frequency (CDF) for Entergy Nuclear's Vermont Yankee in NUREG-1776 is 9.17E-07. But in the draft SBO Risk Study, the SBO CDF is merely 8.44E-10. Without a rational, physical explanation for this rather large difference (three orders of magnitude), the entire formulation for conclusions about risk in the study is suspect. This is especially true with the example of Entergy Nuclear's Vermont Yankee. In the spring of 2004, Vermont Yankee had a short circuit in a main generator bus leading to a transformer fire, hydrogen fire in the turbine hall, and a reactor recirculation pump motor trip. The plant was down nineteen days. NRC has yet to provide analysis of this event or of the licensee root cause report. There is no evidence that any of this was considered in the SBO risk study. In August of 2004, NRC completed a Team Engineering Inspection (TEI) at Vermont Yankee. The inspection was a pilot intended to see if the Reactor Oversight Process was adequately identifying design-basis and engineering issues. The TEI found a significant SBO issue at Vermont Yankee that had to do with the inordinate amount of time it would take to tie Vermont Yankee into alternate offsite AC power from the nearby Vernon Dam following LOOP or SBO. That issue has yet to be resolved. The licensee has promised to submit analysis in the near term. It appears to us that none of this is reflected in the new optimistic CDF assigned to Vermont Yankee.	Based on an overall review of outlier results and this comment, the SPAR model of the Vermont Yankee emergency power system was reviewed. The SPAR model used for the draft report modeled the operator action needed to connect power from the Vernon Dam hydroelectric plant to Vermont Yankee as a relatively simple action. The SPAR model has been changed based on the findings from the Team Engineering Inspection mentioned by the reviewer. The updated SBO CDF from the revised SPAR model is 4.81E-7/rcry. The 2004 Vermont Yankee event mentioned did not result in a LOOP event as defined in this study.	

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10. SUPPLEMENTARY NOTES

Anne-Marie Grady, NRC Project Manager

11. ABSTRACT (200 words or less)

This report is an update of previous reports analyzing loss of offsite power (LOOP) events and the associated station blackout (SBO) core damage risk at U.S. commercial nuclear power plants. LOOP data over the period 1986–2004 were collected and analyzed. Frequency and duration estimates for critical and shutdown operations were generated for four categories of LOOPs: plant centered, switchyard centered, grid related, and weather related. Overall, LOOP frequencies during critical operation have decreased significantly in recent years, while LOOP durations have increased. To obtain SBO results, updated LOOP frequencies and offsite power nonrecovery curves were input into standardized plant analysis risk (SPAR) models covering the 103 operating commercial nuclear power plants. Core damage frequency results indicating contributions from SBO and other LOOP-initiated scenarios are presented for each of the 103 plants, along with plant class and industry averages. In addition, a comprehensive review of emergency diesel generator performance was performed to obtain current estimates for the SPAR models. Overall SPAR results indicate that core damage frequencies for LOOP and SBO are lower than previous estimates. Improvements in emergency diesel generator performance contribute to this risk reduction.

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