Appendix F

GEIS Environmental Issues Not Applicable to Brunswick Steam Electric Plant, Units 1 and 2

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Table F-1 lists those environmental issues listed in the *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (GEIS) (NRC 1996, 1999)[(a)] and Title 10 of the Code of Federal Regulations (CFR) Part 51, Subpart A, Appendix B, Table B-1, that are not applicable to Brunswick Steam Electric Plant, Units 1 and 2 (BSEP) because of plant or site characteristics.

Table F-1. GEIS Environmental Issues Not Applicable to BSEP

ISSUE—10 CFR Part 51, Subpart A, Appendix B, Table B-1	Category	GEIS Sections	Comment
SURFACE WATER QUALITY, HYDROLOGY, AND USE (FOR ALL PLANTS)			
Altered thermal stratification of lakes	1	4.2.1.2.2 4.4.2.2	BSEP does not discharge into a lake.
Eutrophication	1	4.2.1.2.3 4.4.2.2	BSEP does not discharge into a lake.
Water use conflicts (plants with cooling ponds or cooling towers using makeup water from a small river with low flow)	2	4.3.2.1 4.4.2.1	BSEP does not discharge into a small river with low flow.
AQUATIC ECOLOGY (FOR PLANTS WITH COOLING TOWER BASED HEAT DISSIPATION SYSTEMS)			
Entrainment of fish and shellfish in early life stages	1	4.3.3	BSEP does not dissipate heat using cooling towers.
Impingement of fish and shellfish	1	4.3.3	BSEP does not dissipate heat using cooling towers.
Heat shock	1	4.3.3	BSEP does not dissipate heat using cooling towers.
AQUATIC ECOLOGY (FOR ALL PLANTS)			
Premature Emergence of Aquatic Insects	1	4.2.2.7 4.4.3	Aquatic insects not present in vicinity of BSEP discharge.

(a) The GEIS was originally issued in 1996. Addendum 1 to the GEIS was issued in 1999. Hereafter, all references to the "GEIS" include the GEIS and its Addendum 1.

Table F-1. (contd)

ISSUE—10 CFR Part 51, Subpart A, Appendix B, Table B-1	Category	GEIS Sections	Comment
GROUNDWATER USE AND QUALITY			
Groundwater use conflicts (potable and service water, and dewatering; plants that use >100 gpm)	2	4.8.1.1 4.8.2.1	BSEP uses less than 100 gpm groundwater.
Groundwater use conflicts (plants using cooling towers withdrawing make-up water from a small river)	2	4.8.1.3 4.4.2.1	BSEP does not dissipate heat using cooling towers.
Groundwater use conflicts (Ranney wells)	2	4.8.1.4	BSEP does not have or use Ranney wells.
Groundwater quality degradation (Ranney wells)	1	4.8.2.2	BSEP does not have or use Ranney wells.
Groundwater quality degradation (cooling ponds in salt marshes)	1	4.8.3	BSEP does not have cooling ponds in salt marshes.
Groundwater quality degradation (cooling ponds at inland sites)	2	4.8.3	BSEP does not use cooling ponds.
TERRESTRIAL RESOURCES			
Cooling tower impacts on crops and ornamental vegetation	1	4.3.4	BSEP does not use cooling towers.
Cooling tower impacts on native plants	1	4.3.5.1	BSEP does not use cooling towers.
Bird collisions with cooling towers	1	4.3.5.2	BSEP does not use cooling towers.
Cooling pond impacts on terrestrial resources	1	4.4.4	BSEP does not use cooling ponds.
HUMAN HEALTH			
Microbiological organisms (public health) (plants using lakes or canals, or cooling towers or cooling ponds that discharge to a small river)	1	4.3.6	BSEP does not have cooling towers or cooling ponds and its cooling canal does not discharge to a small river.

F.1 References

10 CFR 51. Code of Federal Regulations, Title 10, *Energy*, Part 51, “Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions.”

U.S. Nuclear Regulatory Commission (NRC). 1996. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants*. NUREG-1437, Volumes 1 and 2, Washington, D.C.

U.S. Nuclear Regulatory Commission (NRC). 1999. *Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Main Report*, “Section 6.3 – Transportation, Table 9.1 Summary of findings on NEPA issues for license renewal of nuclear power plants, Final Report.” NUREG-1437, Volume 1, Addendum 1, Washington, D.C.

Appendix G

NRC Staff Evaluation of Severe Accident Mitigation Alternatives for Brunswick Steam Electric Plant, Units 1 and 2 in Support of the License Renewal Application Review

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G.1 Introduction

Carolina Power and Light Company (CP&L), now doing business as Progress Energy Carolinas, Inc., submitted an assessment of severe accident mitigation alternatives (SAMAs) for Brunswick Steam Electric Plant, Units 1 and 2 (BSEP) as part of its Environmental Report (ER) (CP&L 2004). This assessment was based on the most recent BSEP Probabilistic Safety Assessment (PSA) available at that time, a plant-specific offsite consequence analysis performed using the MELCOR Accident Consequence Code System 2 (MACCS2) computer program, and insights from the BSEP Individual Plant Examination (IPE) (CP&L 1992) and Individual Plant Examination of External Events (IPEEE) (CP&L 1995). In identifying and evaluating potential SAMAs, CP&L considered SAMA candidates that addressed the major contributors to core damage frequency (CDF) and population dose at BSEP, as well as SAMA candidates for other operating plants that have submitted license renewal applications. CP&L identified 43 potential SAMA candidates. This list was reduced to 36 unique SAMA candidates by eliminating SAMAs that are not applicable at BSEP because of design differences, that would require extensive changes that would involve implementation costs known to exceed any possible benefit, or that would exceed the dollar value associated with completely eliminating all internal and external event severe accident risk at both BSEP units. CP&L assessed the costs and benefits associated with each of the potential SAMAs and concluded that several of the candidate SAMAs evaluated may be cost-beneficial and warrant further review for potential implementation.

Based on a review of the SAMA assessment, the U.S. Nuclear Regulatory Commission (NRC) issued a request for additional information (RAI) to CP&L by letter dated February 24, 2005 (NRC 2005). Key questions concerned changes to the Level 2 PSA model and source terms since the IPE, the approach for calculating replacement power costs, further information on several specific candidate SAMAs and low-cost alternatives, the potential impact of uncertainties on the assessment results, and licensee plans for future consideration of potentially cost-beneficial SAMAs. CP&L submitted additional information by letters dated April 21, 2005, and June 1, 2005 (Progress Energy 2005a, b). In the responses, CP&L provided a description of the changes to the Level 2 analysis and how the source terms were derived using the Modular Accident Analysis Program (MAAP) 4.0.4 computer program, an assessment of the impact of assuming replacement power cost based on loss of a single unit versus both units, a table that mapped the candidate SAMAs to important basic events and additional information regarding several specific SAMAs, a further assessment of uncertainties in the Level 1 model, and a description of future plans for evaluating potentially cost-beneficial SAMAs. CP&L's responses addressed the staff's concerns.

An assessment of SAMAs for BSEP is presented below.

G.2 Estimate of Risk for BSEP2

CP&L's estimates of offsite risk at the BSEP are summarized in Section G.2.1. The summary is followed by the staff's review of CP&L's risk estimates in Section G.2.2.

G.2.1 CP&L's Risk Estimates

Two distinct analyses are combined to form the basis for the risk estimates used in the SAMA analysis: (1) the BSEP Level 1 and 2 PSA model, which is an updated version of the IPE (CP&L 1992), and (2) a supplemental analysis of offsite consequences and economic impacts (essentially a Level 3 PSA model) developed specifically for the SAMA analysis. The SAMA analysis is based on the most recent BSEP Level 1 and 2 PSA model available at the time of the ER, referred to as the MOR03 Unit 2 model. CP&L considers the Unit 2 model to be appropriate for both Unit 1 and 2 as it incorporates the changes from the extended power uprate (EPU), which was approved in 2002 (the Unit 1 model does not yet include all EPU-related changes). The scope of the BSEP PSA does not include external events.

The baseline CDF for the purpose of the SAMA evaluation is approximately 4.2×10^{-5} per year. The CDF is based on the risk assessment for internally initiated events. CP&L did not include the contribution from external events within the BSEP risk estimates; however, it did account for the potential risk reduction benefits associated with external events by doubling the estimated benefits for internal events. This is discussed further in Section G.6.2.

The breakdown of CDF by initiating event is provided in Table G-1. As shown in this table, events initiated by loss of offsite power (dual unit) and turbine trips are the dominant contributors to CDF. In response to an RAI, CP&L stated that station blackout (SBO) sequences contribute 1.56×10^{-5} per year (about 37 percent of the total internal events CDF), while anticipated transients without scram (ATWS) sequences contribute 3.3×10^{-6} per year (about 8 percent of the CDF). Internal floods contribute 8.8×10^{-7} per year (about 2 percent of the CDF) (Progress Energy 2005a).

The current Level 2 BSEP PSA model has been developed for the EPU configuration and represents a significant update to the IPE. The Level 2 PSA involved the development of

Table G-1. BSEP Core Damage Frequency for Internal Events

Initiating Event	**CDF (Per Year)**	**% Contribution to CDF**
Loss of offsite power – dual unit (LOOP)	1.47×10^{-5}	35.1
Turbine trip	1.14×10^{-5}	27.2
Main steam isolation valve closure/loss of condenser vacuum	4.78×10^{-6}	11.4
Loss of direct current (DC) panel	3.18×10^{-6}	7.6
Loss of alternating current (AC) emergency bus	2.39×10^{-6}	5.7
Loss of control rod drive (CRD)	1.72×10^{-6}	4.1
LOOP – single unit	1.01×10^{-6}	2.4
Other	1.01×10^{-6}	2.4
Internal floods	8.80×10^{-7}	2.1
Loss of reactor building closed cooling water	4.60×10^{-7}	1.1
Interfacing systems loss of coolant accident/ excessive loss of coolant accident	3.40×10^{-7}	0.8
Total CDF (internal events)	$\mathbf{4.19 \times 10^{-5}}$	**100**

containment event trees, which are stated to incorporate a number of technical advances to make them consistent with current state of knowledge on severe accident issues and useful for risk-informed applications. A separate containment event tree is used for each of the Level 1 accident classes to describe the response of the containment. The containment event tree end states are grouped into release categories by magnitude and timing of the expected releases. The result of the Level 2 PSA is a set of release categories with their respective frequency and release characteristics. The results of this analysis for BSEP are provided in Table F-5 of the ER. The frequency of each release category was obtained from the quantification of the containment event tree for each Level 1 accident sequence. The release characteristics were obtained from the results of MAAP analyses of conservatively selected, representative sequences for each release category.

The offsite consequences and economic impact analyses use the MACCS2 code to determine the offsite risk impacts on the surrounding environment and public. Inputs for these analyses include plant-specific and site-specific input values for core radionuclide inventory, source term and release characteristics, site meteorological data, projected population distribution (within a 50-mi radius) for the year 2036, emergency response evacuation modeling, and economic data. The core radionuclide inventory is based on the generic boiling water reactor (BWR) inventory provided in the MACCS2 manual, adjusted to represent the BSEP uprated power level of 2923 megawatts-thermal (MW[t]). The magnitude of the onsite impacts (in terms of cleanup and decontamination costs and occupational dose) is based on information provided in NUREG/BR-0184 (NRC 1997a).

In its ER, CP&L estimated the dose to the population within 50 mi of BSEP to be approximately 29.35 person-rem per year. The breakdown of the total population dose by containment release mode is summarized in Table G-2. Containment failures within the intermediate time frame (6 to 24 hours following event initiation) and early time frame (less than 6 hours following event initiation) dominate the population dose risk at BSEP.

Table G-2. Breakdown of Population Dose by Containment Release Mode

Containment Release Mode	Population Dose (Person-Rem Per Year)	% Contribution
Early Containment Failure	8.38	28
Intermediate Containment Failure	20.92	71
Late Containment Failure	0.05	<1
Intact Containment	Negligible	Negligible
Total Population Dose	**29.35**	**100**

G.2.2 Review of CP&L's Risk Estimates

CP&L's determination of offsite risk at BSEP is based on the following three major elements of analysis:

1. the Level 1 and 2 risk models that form the bases for the 1992 IPE submittal (CP&L 1992) and the 1995 IPEEE submittal (CP&L 1995)

2. the major modifications to the IPE model that have been incorporated in the BSEP PSA

3. the MACCS2 analyses performed to translate fission product source terms and release frequencies from the Level 2 PSA model into offsite consequence measures.

Each of these analyses was reviewed to determine the acceptability of CP&L's risk estimates for the SAMA analysis, as summarized below.

The original BSEP PSA was submitted to the NRC in May 1988 (CP&L 1988). This Level 1 PSA included internally and externally initiated events, and was reviewed by the Idaho National Engineering Laboratory (now known as Idaho National Laboratory) under contract for the NRC (NRC 1989). The overall conclusion of this review was that the PSA was a reasonable and competent investigation into the risks associated with operation of BSEP. The ER states that many of the insights provided by this review were factored into the IPE.

The BSEP IPE (CP&L 1992) was an update of the original PSA. The staff's review of the BSEP IPE is described in an NRC report dated January 21, 2000 (NRC 2000). Based on a review of the original IPE submittal, related supplements, and responses to RAIs, the staff concluded that the IPE submittal met the intent of Generic Letter 88-20; that is, the IPE was of adequate quality to be used to look for design or operational vulnerabilities.

There have been numerous revisions to the IPE model since its submittal. A comparison of internal events risk profiles between the IPE and the PSA used in the SAMA analysis indicates an increase of approximately 1.5×10^{-5} per year in the total internal events CDF (from 2.7×10^{-5} per year in the IPE to 4.19×10^{-5} per year in MOR03). The increase is mainly attributed to modeling changes that have been implemented since the IPE was submitted rather than plant hardware changes. A summary listing of those changes that resulted in the greatest impact on the internal events CDF was provided in the ER (CP&L 2004) and further discussed in response to an RAI (Progress Energy 2005a). The major changes are summarized in Table G-3.

The IPE CDF value for BSEP is close to the average of the CDF values reported in the IPEs for BWR 3/4 plants. Figure 11.2 of NUREG-1560 shows that the IPE-based total internal events CDF for BWR 3/4 plants ranges from 9×10^{-8} to 8×10^{-5} per year, with an average CDF for the group of 2×10^{-5} per year (NRC 1997b). It is recognized that other plants have updated the values for CDF subsequent to the IPE submittals to reflect modeling and hardware changes. The current internal events CDF results for BSEP are comparable to other plants of similar vintage and characteristics.

The PSA results used in the SAMA analysis were based on the Unit 2 PSA. In response to an RAI, CP&L described the differences between Unit 1 and Unit 2 that might affect the PSA results and concluded that the differences do not significantly affect the CDF (Progress Energy 2005a). The Unit 2 model incorporates the changes from the EPU; therefore, it is more up-to-date and consistent with the current plant configuration. The staff concludes use of the Unit 2 PSA results for the SAMA analysis for both units is acceptable.

Table G-3. BSEP PSA Historical Summary

PSA Version	Summary of Changes from Prior Version	CDF[(a)] (per year)
MOR92	• IPE Submittal	2.7×10^{-5}
93 IPE Update	• Increased LOOP initiating event frequency • Added credit for new SBO procedure • Improved human reliability analysis • Numerous system fault tree model changes	NA
94 IPE Update	• More detailed model of diesel generator failures and offsite power recovery options	1.1×10^{-5}
MOR96	• Consolidated selected event trees • Changed numerous system fault tree models • Updated failure data in conjunction with maintenance rule implementation	9.1×10^{-6}
MOR98	• Replaced prior Level 1 model with separate models for Units 1 and 2 • Modified Level 2 model to calculate only large early releases frequency results	2.54×10^{-5}
MOR98R1	• Revised modeling of credit for battery charger given battery failure • Modified Level 2 model to calculate releases for eight release categories	4.92×10^{-5}
MOR02	• Periodic update • Numerous miscellaneous changes and corrections, some in response to peer review	4.97×10^{-5}
MOR03	• Incorporated changes related to EPU implementation • Updated various common cause failure values • Updated LOOP frequency and recovery rules • Numerous additional changes and corrections to the Level 1 model • Modified the Level 2 model to calculate releases for 12 release categories	4.19×10^{-5}

(a) Values for MOR98 and later are based on a Unit 2-specific model.

The staff considered the peer reviews performed for the BSEP PSA and the potential impact of the review findings on the SAMA evaluation. In the ER and in response to an RAI, CP&L described the previous peer reviews, the most significant of which was the Nuclear Energy Institute/Boiling Water Reactor Owners Group (BWROG) Peer Review of the MOR98R1 PSA model conducted in 2001. In its ER, CP&L stated there were no “A” level facts and observations (i.e., facts and observations important and necessary to address before the next regular PSA update), and there were 66 “B” level facts and observations (i.e., facts and observations important and necessary to address, but disposition may be deferred until the next PSA update), six of which were resolved prior to the MOR03 model being used for the SAMA analysis. In response to an RAI, CP&L stated that resolution of the outstanding Level B peer review comments is still in progress, and described the six major issues associated with the outstanding comments (Progress Energy 2005a). These issues involve the need to address the following:

- safety relief valve re-closure in loss of decay heat removal (DHR) sequences during which the containment pressurizes

- net positive suction head issues in scenarios involving failure of suppression pool cooling and successful containment venting

- reactor building environmental conditions in scenarios in which the containment fails prior to core damage

- potential conservatisms in modeling including common cause failure modeling (double counting), heating, ventilation, and air-conditioning (HVAC) modeling for the diesel generator cells, failure of DC initiating events, modeling of CRD initiating events, and giving credit for alternate rod insertion for ATWS events

- potential non-conservatism in LOOP initiating event data

- refinement in human error probability estimates.

The impact of these issues on the results of the PSA was discussed by CP&L in general terms. CP&L concluded that only the first three issues could result in an increase in risk and potential retention of some additional SAMAs. These issues predominantly impact core damage sequences associated with loss of injection late in the event or with complete loss of DHR. CP&L identified four candidate SAMAs that would help mitigate these accident sequences. Phase II SAMA 36 (use fire-fighting water as a backup for containment spray) was already identified as potentially cost-beneficial in the baseline analysis in the ER; thus, the impact of the peer review comment resolution on this SAMA was not further evaluated. In its ER, CP&L identified three additional SAMAs that would have estimated benefits close to their implementation costs but that were not positively identified as cost-beneficial in the baseline SAMA analysis. Further evaluation of these three SAMAs considered conservative modeling assumptions that would tend to offset, to some extent, the potential impact of the resolution of the comments (Progress Energy 2005a). These three additional SAMAs are listed below, along with CP&L's assessment regarding the potential impact of peer review comment resolution.

- Phase II SAMA 6. Proceduralize all potential 4-kV AC bus cross-tie actions. The benefit of this SAMA is limited because the loss of DHR sequences are long evolutions and even without these procedures the onsite staff would likely perform the 4-kV cross-ties given that the hardware is in place to support it.

- Phase II SAMA 13. Install an inter-unit CRD cross-tie. Implementation of this SAMA could help mitigate the consequences associated with the Class II sequences by delaying the onset of core damage and containment failure. However, the cross-tie introduces the potential to fail the CRD system on the opposite unit. Additionally, in quantifying the benefit of this SAMA it was conservatively assumed that the initial failure of the CRD would not prevent the cross-tie from being performed. As a result, the actual benefit of this SAMA would be less than the estimated value, and the SAMA is not considered to be a candidate for further consideration.

- Phase II SAMA 34. Provide supplemental power supplies for offsite power recovery after battery depletion during SBO. This SAMA would remove the dependence on the switchyard station battery so that a means of aligning offsite power will be available when the station batteries are depleted. Recovery of AC power in loss of DHR sequences appears to be a viable means of reducing risk and one that may be cost-beneficial upon resolution of the BWROG peer review Level B facts and observations.

As a result of the evaluation, CP&L determined that Phase II SAMAs 6 and 13 should not be retained for further evaluation because the true benefits would be less than the benefit assessed, and the impact of the resolution of the facts and observations would probably not prove them to be cost-beneficial. However, the benefits associated with Phase II SAMAs 34 and 36 may increase if relevant facts and observations are resolved. Based on the information provided, the staff agrees with CP&L's general assessment of the potential impact of comment resolution on the results of the PSA. The SAMAs potentially impacted by resolution of the peer review comments are discussed further in Section G.6.

Given that the BSEP Level 1 PSA has been peer reviewed and the potential impact of the unresolved peer review findings has been assessed, that CP&L has satisfactorily addressed staff questions regarding the PSA, and that the CDF falls within the range of contemporary CDFs for BWR 3/4 plants with Mark I containment, the staff concludes that the Level 1 PSA model is of sufficient quality to support the SAMA evaluation.

As indicated above, the current BSEP PSA does not include external events. In the absence of such an analysis, CP&L used the BSEP IPEEE in the SAMA analysis to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences, as discussed below.

The 1988 BSEP PSA, which preceded the IPEEE, included external events with a seismic contribution to CDF of 6.6 x 10^{-5} per year (CP&L 1988). However, this was an early seismic risk assessment described by the licensee as "preliminary" and with results that were described as "screening values." The Idaho National Laboratory review of the external events analysis concluded that the analysis provided a reasonable and credible estimate of the external events risk, but that "it is fully expected that with more refined ongoing and planned analysis of seismic events, the core damage results will be significantly reduced" (NRC 1989). In response to an RAI, CP&L indicated that no further seismic analysis had been performed other than that associated with the IPEEE or Unresolved Safety Issue (USI) A-46 programs (Progress Energy 2005a).

The BSEP IPEEE was submitted in 1995, in response to Supplement 4 of Generic Letter 88-20 (CP&L 1995). BSEP did not identify any fundamental weaknesses or vulnerabilities to severe accident risk in regard to the external events related to seismic, fire, or other external events. In a letter dated November 18, 1998, the staff concluded the submittal met the intent of Supplement 4 to Generic Letter 88-20, and the licensee's IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities (NRC 1998).

The IPEEE uses a focused-scope seismic margins analysis developed by the Electric Power Research Institute (EPRI). This method is qualitative and does not provide numerical estimates of the CDF contributions from seismic initiators (EPRI 1991). The seismic IPEEE identified a number of outliers of items within the scope of the USI A-46 program. Resolution of these outliers was to be accomplished in the context of USI A-46. Given the satisfactory resolution of these outliers, BSEP found that, based on the EPRI assessment methodology, none of the plant's high confidence, low probability of failure values were less than the 0.3g review level earthquake used in the IPEEE. The NRC review and closure of USI A-46 for BSEP is documented in a letter dated August 5, 1999 (NRC 1999).

Based on the licensee's IPEEE efforts to identify and address seismic outliers and the expected large costs associated with further seismic risk analysis and potential seismic-related plant modifications, the staff concludes the opportunity for seismic-related SAMAs has been adequately explored, and it is unlikely that cost-effective SAMAs that address seismic vulnerabilities will exist. This conclusion is based on the high cost of the required structural modifications compared to the benefits expected.

The BSEP fire analysis was based on EPRI's Fire-Induced Vulnerability Evaluation methodology. The methodology employs a graduated focus on the most important fire zones using qualitative and quantitative screening criteria (EPRI 1992). The fire zones or compartments were subjected to at least two screening phases. In the first phase, a compartment was screened out if it was found to not contain any equipment or cables associated with safe shutdown or an initiating event. In the second phase, CP&L used the IPE model of internal events to quantify the CDF resulting from a fire-initiating event. The conditional core damage probability associated with each fire compartment was based on the equipment and systems unaffected by the fire. The CDF for each compartment was obtained by multiplying the frequency of a fire in a given fire compartment by the conditional core damage probability associated with that fire compartment.

After the assessment was completed, six fire compartments remained that contributed more than 1×10^{-6} per year. These compartments are:

Fire Compartment	Compartment Description	CDF
CB-21, CB-23	Southwest control room area	1.93×10^{-5}
RB2-1g(NC)	20-ft level reactor building north central area	3.14×10^{-6}
RB2-1g(NW)	20-ft level reactor building north west area	1.58×10^{-6}
CB-06	Unit 2 cable spreading room	1.56×10^{-6}
DG-14	E4 switchgear room	1.10×10^{-6}
DG-9	E8 switchgear room	1.07×10^{-6}

The resulting fire CDF was estimated as 3.62×10^{-5} per year (CP&L 1996a).

The fire CDF is approximately 85 percent of the current internal events CDF. In its ER, CP&L described each of the fire compartments listed above and identified candidate SAMAs to potentially reduce the associated fire risk. As a result, CP&L identified the following potential enhancements that it further considered as SAMAs:

- improvements to the alternate shutdown panel
- improvements to the training operators receive on operating the plant from outside the control room and improvements to ex-control room communications equipment
- addition of automatic fire-suppression system to control room cabinets, in the 20-ft level of the reactor building (north-central and northwest), and in switchgear rooms (E4 and E8)
- prohibiting transient combustibles in the cable spreading room and/or requiring

fire-suppression personnel to be present during work that may cause a fire

- improvements to fire barriers between cabinets in the cable spreading room.

The IPEEE analysis of other external events is an update of that performed as part of the 1988 BSEP PSA. The total high-wind-induced CDF was determined to be 4 x 10^{-6} per year. All other external events were determined to contribute less than 1 x 10^{-6} per year to CDF. The high-wind contribution to CDF was caused by failure of the switchyard and the resulting long-term loss of offsite power. While not considered a vulnerability, CP&L reviewed the existing procedures and training and concluded that the ability to cope with a long-term SBO event was adequately addressed (CP&L 1996b). In its ER, CP&L considered enhancements to the switchyard and offsite power connections to prevent damage from high winds; however, such modifications are very expensive (> $25 million). CP&L concluded that no further modifications would be cost-effective for high-wind events.

Because of relatively low contributions from the fire CDF value and other external events, CP&L doubled the benefit derived from the internal events model to account for the contribution from external events. This doubling was not applied to those SAMAs that specifically addressed fire risk (i.e., Phase II SAMAs 30-33). Doubling the benefit for Phase II SAMAs 30-33 is not appropriate because these SAMAs are specific to fire risks and would not have a corresponding benefit on the risk from internal events. The risks discussed above that are caused by external events are the results of analyses that were performed at various times prior to the current BSEP internal events PSA. The methodologies also vary in their degree of completeness and conservatism. Consequently, the results cannot be directly compared with those from the current PSA. Regardless of the above, the staff agrees with CP&L's conclusion that the risks posed by external events is roughly equivalent to the risks from internal events. Therefore, the staff concludes that CP&L's use of a multiplier of two to account for external events is reasonable for the purposes of the SAMA evaluation.

The staff reviewed the general process used by CP&L to translate the results of the Level 1 PSA into containment releases, as well as the results of this Level 2 analysis. CP&L characterized the releases for the spectrum of possible radionuclide release scenarios using a set of 12 release categories, which are defined by the timing and magnitude of the release. The frequency of each release category was obtained from the quantification of a containment event tree for each Level 1 accident sequence. The release characteristics for each release category were obtained from the results of MAAP 4.0.4 analyses of conservatively determined representative sequences for each category. The process for assigning accident sequences to the various release categories and selecting a representative accident sequence for each release category is described in the ER and in response to RAIs (Progress Energy 2005a). The release categories and their frequencies are presented in Tables F-2 through F-4 of the ER (CP&L 2004). In response to an RAI, CP&L described the basis for some of the more significant results. The source terms used to characterize fission product releases for the applicable containment release category are given in Table F-5 of the ER and are stated to be best estimates for the selected sequences. All releases were modeled as occurring at ground level and with a thermal content the same as ambient. CP&L assessed the impact of alternative assumptions (e.g., releases at higher elevations and thermal contents). The results of these sensitivity studies showed that the 50-mi population dose would increase by less than 4 percent. This small increase has a negligible impact on the analysis and its results. The staff concludes that the process used for determining the release category frequencies and source terms is reasonable and appropriate for purposes of the SAMA analysis.

As mentioned previously, the reactor core radionuclide inventory used in the consequence analysis is based on the generic BWR inventory provided in the MACCS2 manual, adjusted to represent the BSEP uprated power level of 2923 MW(t)h. In response to an RAI concerning the impact of current and future fuel management practices, CP&L performed an additional BSEP-specific MACCS2 sensitivity calculation assuming a 65 percent increase in the inventories for strontium-90, cesium-134, and cesium-137. This level of increase was based on a prior calculation for the Nine Mile Point Nuclear Station in which the end-of-cycle activity levels for a bounding case of 1400 effective full-power days were compared to the reference BWR inventories. Use of this increased inventory results in about a 30-percent increase in the total costs associated with a severe accident. Using realistic mid-life or average conditions would result in a smaller increase. CP&L assessed the impact that this change might have on the SAMA screening process and determined that two SAMAs (Phase II SAMAs 13 and 34) could become marginally cost-beneficial. However, these two SAMAs were already identified as potentially cost-beneficial when using a 3-percent real discount rate, as discussed in Section G.6.2. Based on this limited impact, the staff concludes that the scaling based on the plant-specific power level yields sufficiently accurate and reasonable results for the dose assessment.

The staff reviewed the process used by CP&L to extend the containment performance (Level 2) portion of the PSA to an assessment of offsite consequences (essentially a Level 3 PSA). This included consideration of the major input assumptions used in the offsite consequence analyses. The MACCS2 code was utilized to estimate offsite consequences. Plant-specific input to the code includes the source terms for each release category and the reactor core radionuclide inventory (both discussed above), site-specific meteorological data, projected population distribution within a 50-mi radius for the year 2036, emergency evacuation modeling, and economic data. This information is provided in Appendix F of the ER (CP&L 2004).

CP&L used site-specific meteorological data processed from hourly measurements for the 2001 calendar year as input to the MACCS2 code. The hourly data were collected from the onsite meteorological tower. Data from 1997 through 2001 were also considered, but the 2001 data was found to result in the largest risk and was subsequently used in all MACCS2 risk calculations. The staff concluded that use of the 2001 meteorological data in the SAMA analysis is reasonable.

The population distribution CP&L used as input to the MACCS2 analysis was estimated for the year 2036, based on the U.S. Census population data for 2000 and the expected annual population growth rate (USCB 2000a). The 1990 and 2000 county-level census data were used to estimate the annual population growth rate (USCB 2000b). It was assumed that the growth rate would remain the same as that reported between 1990 and 2000. Using sector-specific population growth rates, projections were made by linearly extrapolating the 2000 sector population data to year 2036. The staff concluded the methods and assumptions for estimating population are reasonable and acceptable for purposes of the SAMA evaluation.

The emergency evacuation model was modeled as a single evacuation zone extending 10 mi from the plant. It was assumed that 95 percent of the population would move at an average speed of approximately 0.24 meters per second with a delayed start time of 30 minutes (CP&L 2004). This assumption is conservative relative to the NUREG-1150 study (NRC 1990), which assumed evacuation of 99.5 percent of the population within the emergency planning zone. The staff concluded that the evacuation assumptions and analysis are deemed reasonable and acceptable for the purposes of the SAMA evaluation.

Site-specific economic data requiring spatial distributions as input to MACCS2 were prepared by specifying the data for each of the eight counties within 50 mi of the plant. The values used in each of the 160 sectors surrounding the plant corresponded to the county that made up a majority of the land in that sector. For eight sectors, no county encompassed more than two-thirds of the area, conglomerate data (weighted by the fraction of each county in the sector) were defined for these sector. In addition, generic economic data that applied to the region as a whole were revised from the MACCS2 sample problem input when better information was available. These included value of farm and non-farm wealth and fraction of farm wealth from improvements (e.g., buildings, equipment). The agricultural economic data were updated using available data from the 1997 Census of Agriculture (USDA 1998). Information on the duration of growing seasons for some crops was obtained from the North Carolina Department of Agriculture, while for other crops the data were taken to be the same as used previously in Southern Nuclear Operating Company’s ER for the Edwin I. Hatch Nuclear Plant (SNC 2000).

The staff concludes that the methodology used by CP&L to estimate the offsite consequences for BSEP provides an acceptable basis from which to proceed with an assessment of risk reduction potential for candidate SAMAs. Accordingly, the staff based its assessment of offsite risk on the CDF and offsite doses reported by CP&L.

G.3 Potential Plant Improvements

The process for identifying potential plant improvements, an evaluation of that process, and the improvements evaluated in detail by CP&L are discussed in this section.

G.3.1 Process for Identifying Potential Plant Improvements

CP&L's process for identifying potential plant improvements (SAMAs) consisted of the following elements:

- review of the most significant basic events from the BSEP MOR03 Levels 1 and 2 PSA
- review of Phase II SAMAs from license renewal applications for six other U.S. nuclear sites
- review of potential plant improvements identified in the BSEP IPE and IPEEE
- review of each of the dominant fire compartments, and SAMAs that could potentially reduce the associated fire risk.

Based on this process, an initial set of 43 candidate SAMAs, referred to as Phase I SAMAs, was identified. In Phase I of the evaluation, CP&L performed a qualitative screening of the initial list of SAMAs and eliminated SAMAs from further consideration using the following criteria:

- the SAMA is not applicable at BSEP because of design differences
- the SAMA would require extensive changes that would involve implementation costs known to exceed any possible benefit
- the SAMA would cost more than $9.6 million to implement (the modified maximum averted cost-risk, which represents the dollar value associated with completely eliminating all internal and external event severe accident risk at both BSEP units).

Based on the above criteria, seven SAMAs were eliminated, leaving 36 for further evaluation. The remaining SAMAs, referred to as Phase II SAMAs, are listed in Table F-16 of the ER (CP&L 2004), and were subjected to further evaluation. During Phase II of the evaluation, CP&L screened out some of the remaining SAMA candidates based on plant-specific insights regarding the low-risk significance of systems affected by the SAMA. Seven such SAMAs were screened from further evaluation. Additionally, it was determined that one SAMA had already been implemented, and one SAMA was subsumed by another SAMA. A detailed cost-benefit analysis was performed for each of the 27 remaining SAMA candidates. To account for the potential impact of external events, the estimated benefits based on internal events were multiplied by a factor of two (except for those SAMAs specific to fire risks because those SAMAs would not have a corresponding benefit on the risk from internal events.)

Of the 27 SAMAs evaluated in the final phase, seven were identified as potentially cost-beneficial in the baseline analysis. Several additional SAMAs were determined to be potentially cost-beneficial when using a 3-percent real discount rate or when accounting for the impact of uncertainties. The remaining SAMAs were evaluated and subsequently eliminated, as described in Sections G.4 and G.6 below.

G.3.2 Review of CP&L's Process

CP&L's efforts to identify potential SAMAs focused primarily on areas associated with internal initiating events and fires. The initial list of SAMAs generally addressed the accident sequences considered to be important to CDF from functional, initiating events and risk-reduction-worth perspectives at BSEP. Selected SAMAs from other nuclear plants were included.

The preliminary review of CP&L's SAMA identification process raised some concerns regarding the completeness of the set of SAMAs identified and the inclusion of plant-specific risk contributors. The staff requested information on certain risk-important events that did not appear to be addressed by a candidate SAMA (NRC 2005). In response to the RAI, CP&L updated tables in its ER to provide a more complete accounting of the SAMAs associated with each of the important basic events (CP&L 2005a). Based on this additional information, the staff concludes that the set of SAMAs evaluated in the ER addresses the major contributors to CDF and offsite dose, and the review of the top risk contributors does not reveal any new SAMAs.

Although the IPE did not identify any vulnerabilities, several procedural improvements and hardware modifications were identified for implementation (NRC 2000). Subsequently, a decision was made by CP&L not to implement two of these improvements (a fifth diesel generator and a dedicated DC power supply for the switchyard breakers). These two improvements were included in the initial list of candidate SAMAs (CP&L 2004).

CP&L identified BSEP-specific candidate SAMAs for fire events using a combination of the BSEP PSA models and the IPEEE. The fire risk at BSEP has been shown to be dominated by control room fires, though several other major contributors were also identified. As a result, six SAMAs were identified and retained for evaluation. Potential plant enhancements for other external events (e.g., high-wind events and transportation and nearby facility accidents) were determined to be too expensive, sufficiently addressed by existing requirements, or bounded by existing scenarios. The staff concludes that CP&L's rationale for eliminating these enhancements from further consideration is reasonable.

By letter dated, February 24, 2005, the staff sent CP&L an RAI about several other candidate SAMAs that were identified as potentially cost-beneficial at other BWR plants but not addressed by CP&L (NRC 2005). In response to the RAI, CP&L provided an assessment of the applicability/feasibility of each of the specific enhancements identified at BSEP by the staff, and concluded that these SAMAs either would not provide a significant benefit at BSEP or are addressed by existing SAMAs for BSEP (Progress Energy 2005a).

The staff notes that the set of SAMAs submitted is not all-inclusive, because additional, possibly even less expensive, design alternatives can always be postulated. However, the staff concludes that the benefits of any additional modifications are unlikely to exceed the benefits of the modifications evaluated and that the alternative improvements would not likely cost less than the least expensive alternatives evaluated, when the subsidiary costs associated with maintenance, procedures, and training are considered.

The staff concludes that CP&L used a systematic and comprehensive process for identifying potential plant improvements for BSEP, and the set of potential plant improvements identified by CP&L is reasonably comprehensive and, therefore, acceptable. This search included reviewing insights from the plant-specific risk studies, reviewing plant improvements considered in previous SAMA analyses, and using the knowledge and experience of its PSA personnel.

G.4 Risk Reduction Potential of Plant Improvements

CP&L evaluated the risk-reduction potential of the 27 remaining SAMAs that were applicable to BSEP. The changes made to the model to quantify the impact of the SAMAs are detailed in Section F.6 of Appendix F to the ER (CP&L 2004) and in the response to an RAI (Progress Energy 2005a). Most of the SAMA evaluations were performed using realistic assumptions with some conservatism. For several of the SAMAs, the risk reduction was based on more bounding assumptions; for example, Phase II SAMA 18 (provide alternate feeds to essential loads directly from an alternate emergency bus) assumes that all loss of emergency 4-kV bus initiating events are eliminated.

CP&L used model re-quantification to determine the potential benefits. The CDF and population dose reductions were estimated using the MOR03 version of the BSEP Unit 2 PSA. Table G-4 lists the assumptions considered to estimate the risk reduction for each of the evaluated SAMAs, the estimated risk reduction in terms of percent reduction in CDF and population dose, and the estimated total benefit (present value) of the averted risk. The determination of the benefits for the various SAMAs is further discussed in Section G.6.

For those SAMAs that specifically address fire events (i.e., Phase II SAMAs 30-33), the reduction in CDF and population dose was not directly calculated. For these SAMAs, a bounding estimate of the impact of the SAMA was made based on general assumptions regarding the approximate contribution to total risk from external events (relative to that from internal events), the fraction of the external event risk attributable to fire events, and the fraction of the fire risk affected by the SAMA and associated with each fire compartment (based on information from the IPEEE). For example, it is assumed that the contribution to risk from external events is approximately equal to that from internal events, and that fires contribute 75 percent of the external-events risk. The IPEEE fire analysis was then used to identify the fraction of the fire risk that could be eliminated by potential enhancements in various fire compartments. A similar process was applied to the proposed fire enhancements for each fire compartment considered.

The staff reviewed CP&L's bases for calculating the risk reduction for the various plant improvements and concludes that the rationale and assumptions for estimating risk reduction are reasonable and somewhat conservative (i.e., the estimated risk reduction is similar to what would actually be realized). Accordingly, the staff based its estimates of averted risk for the various SAMAs on CP&L's risk-reduction estimates.

G.5 Cost Impacts of Candidate Plant Improvements

CP&L estimated the costs of implementing the 27 candidate SAMAs through the application of engineering judgement, use of estimates from other licensees' estimates for similar improvements, and development of site-specific cost estimates. To ensure conservatism, the cost estimates did not include the cost of replacement power during extended outages required to implement the modifications, nor did they include contingency costs associated with unforeseen implementation obstacles. The cost estimates provided in the ER did not generally account for inflation. When using costs estimates prior to 1995, CP&L applied a 2.75 percent per year inflation rate to arrive at year 2003 estimated costs. All cost estimates were indicated to be on a site basis.

Table G-4. SAMA Cost/Benefit Screening Analysis for BSEP

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate ($)	Total Benefit Using 3% Discount Rate ($)	Cost ($)
		CDF	Population Dose			
1 - Portable generator for DC power	**Increases time available for AC power recovery from time based on loss of turbine-driven injection at battery depletion to the time based on loss of turbine-driven injection at heat capacity temperature limit (HCTL). Credit for portable generator also taken for non-SBO with loss of normal DC supply. A lumped failure probability of 1 x10^{-2} is used to represent operator alignment errors and hardware failure of the portable generator.**	**21**	**18**	**1,613,000**	**2,048,000**	**489,300**
3 - Provide the main control room with the capability to align the required to align the unit auxiliary trans-former (UAT) to the emergency buses	Reduces the manipulation time required to align the UAT to the emergency buses following failure of the startup auxiliary transformer from 40 min to 20 min. The human error probability (HEP) for the action was reduced from 1.8 x 10^{-1} to 4.1 x10^{-2} based on reduced time and improved man-machine interface.	0.5	0.7	54,000	70,000	434,800
4 - Direct drive diesel injection pump	Supplements existing high-pressure injection sources and is capable of operating during an SBO. The injection path is defined to be through an existing feedwater injection line. Division II DC power is required for success. A lumped failure probability of 5 x 10^{-2} is used to represent operator alignment errors and hardware failures of the pump.	15	12	1,085,000	1,370,000	4,000,000
5 - Enhanced CRD flow	Results in an increase in the CRD injection flow rate such that it is capable of making up for boil-off even in the early time frame for transient sequences.	13	9	896,000	1,115,000	>1,000,000[1]

Table G-4. (contd)

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate ($)	Total Benefit Using 3% Discount Rate ($)	Cost ($)
		CDF	Population Dose			
6 - Proceduralize all potential 4-kV AC bus cross-tie actions	Abnormal operating procedures are updated such that instructions are available to provide power from any given emergency 4-kV AC bus to any other emergency 4-kV AC bus in accident conditions. The existing inter-divisional, cross-tie HEP is used to represent the failure probability of the inter-unit cross-tie actions based on the procedure improvements.	0.7	0.6	51,000	64,000	100,000
10 - Improve procedures/equipment to prevent boron dilution	Upgrades the low-pressure coolant injection controls to allow more precise control over the injection flow rate in an ATWS. The HEP for the flow control action was reduced from 4.3×10^{-2} to 3.4×10^{-2}. The corresponding dependent HEPs were also adjusted to account for the change in the base HEP.	0.5	1	64,000	84,000	434,800
11 - Enhance the main control room (MCR) to include capability to perform 480-V AC substation cross-tie	Improves the HEPs governing the 480-v AC cross-tie actions by reducing the time required to perform the action and by improving man-machine interface of the controls used in the action. The HEP for the cross-tie action was reduced from 6.9×10^{-2} to 2.1×10^{-2}. The corresponding dependent HEPs were also adjusted to account for the change in the base HEP.	1	3	185,000	245,000	434,800

Table G-4. (contd)

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate ($)	Total Benefit Using 3% Discount Rate ($)	Cost ($)
		CDF	Population Dose			
12 - Enhance the MCR to include capability to align the alternate DC power supply to specific DC panels	Reduces the HEPs governing the DC alternate power alignment actions by reducing the time required to perform the action and by improving man-machine interface of the controls used in the action. The HEP for the alternate alignment action was reduced from 1.2×10^{-1} to 8.4×10^{-2}. The corresponding dependent HEPs were also adjusted to account for the change in the base HEP.	1	2	115,000	148,000	434,800
13 - Install an inter-unit CRD cross-tie	**Credits the use of the opposite unit's CRD system as an additional means of providing high-pressure injection. While not credited for preventing a loss of CRD initiating event or for providing injection during an ATWS, the cross-tie is assumed to be capable of providing makeup for transient cases. A lumped failure probability of 5×10^{-2} is used to represent operator alignment errors and hardware failures of the cross-tie flow path.**	**6**	**9**	**727,000**	**951,000**	**836,900**
15 - Diverse emergency diesel generators (EDG) HVAC logic	**Reduces the failures of EDG HVAC initiation caused by malfunction of the logic systems through the addition of a redundant logic train. A lumped failure probability of 1×10^{-2} is used to represent hardware and support system failures for the alternate logic train.**	**3**	**2**	**226,000**	**285,000**	**200,000**

Table G-4. (contd)

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate ($)	Total Benefit Using 3% Discount Rate ($)	Cost ($)
		CDF	Population Dose			
16 - Diverse swing diesel generators air compressor	Provides a diverse, diesel-driven air compressor that can be used to start any/all of the EDGs given a common cause failure of the normal starting system. Eliminates the common cause failure to start term of EDG starting air compressors.	1	1	111,000	140,000	159,100
17 - Provide alternate feeds to panels supplied only by DC bus 2A-1	**Allows directly supplying the loads for DC Bus 2A-1 with a portable generator given failure of the bus. Only supplies the 2A-1 loads and can be used when the bus has failed. The alignment action is assigned the same 1.2×10^{-1} failure probability that is used for similar alternate power source alignments in the model.**	**19**	**13**	**1,287,000**	**1,607,000**	**489,300**
18 - Provide alternate feeds to essential loads directly from an alternate emergency bus	Loss of emergency 4-kV bus initiating events were eliminated.	3	4	315,000	409,000	434,800
19 - Provide an alternate means of supplying the instrument air header	**A portable compressor can be used to mitigate a loss of the instrument air compressors due to either compressor failure or support system failure. A lumped failure probability of 1×10^{-2} is used to represent hardware and operator failures to align the portable compressor.**	**4**	**8**	**580,000**	**772,000**	**489,300**
20 - Enhance the MCR to include capability to swap AC power supplies to the battery chargers	Allows the operator to swap AC supplies to the battery chargers from the control room. An HEP of 1×10^{-2} is assigned to the action.	1	2	141,000	183,000	434,800

Table G-4. (contd)

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate ($)	Total Benefit Using 3% Discount Rate ($)	Cost ($)
		CDF	Population Dose			
21 - Enhance CRD logic	Reduces the probability of loss of CRD system flow by allowing the automatic bypass of the drive path and suction filters given plugging/clogging. The bypass path failure probabilities include events for logic/support system failures (i.e., 5×10^{-4}) and motor-operated valve failures (i.e., 3×10^{-3}).	3	2	202,000	254,000	500,000
22 - Install self-cooled CRD pumps	Eliminates the cooling dependency for the CRD pumps.	1	2	139,000	182,000	500,000
25 - Proceduralize battery charger high-voltage shutdown circuit inhibit	**Allows the operators to prevent the loss of the battery chargers as a DC source when the batteries have failed or are unavailable. A failure probability of 5×10^{-2} is assigned to the HEP used to represent high-voltage shutdown circuit inhibit.**	**9**	**0.5**	**334,000**	**378,000**	**50,000**
29 - Portable EDG fuel oil transfer pump	**Reduces the contribution of sequences involving failure of the existing EDG fuel oil transfer pumps. A lumped failure probability of 1×10^{-2} is used to represent hardware and operator failures for the alignment and operator of the portable fuel transfer pumps.**	**3**	**2**	**207,000**	**260,000**	**186,900**
30 - Improve alternate shutdown panel	Improves operator reliability over the use of the current panel by a factor of five for all control room fire scenarios.	not estimated	not estimated	1,047,000	1,334,000	1,531,900

Table G-4. (contd)

Appendix G

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate ($)	Total Benefit Using 3% Discount Rate ($)	Cost ($)
		CDF	Population Dose			
31 - Improved alternate shutdown training and equipment	Improves operator reliability over the use of the current panel by 10 percent for all control room fire scenarios.	not estimated	not estimated	131,000	167,000	250,000
32 - Add automatic fire suppression system	Suppression system is 95 percent effective in eliminating the risk of fires in the 20-ft elevation of the north-central and northwest areas of the reactor building.	not estimated	not estimated	379,000	483,000	750,000
33 - Improve fire barriers between cabinets in the cable spreading room	Eliminates the risk associated with all fires in non-critical cabinets. Prevents the spread of fires to cabinets containing equipment required for the safe shutdown of the plant.	not estimated	not estimated	3,700	4,700	100,000
34 - Provide supplemental power supplies for offsite power recovery after battery depletion during SBO	**Ensures that a means of operating the switchyard circuit breakers is available to recover offsite power after the station batteries have been depleted. Represented by crediting the boildown and fuel heat-up time in the offsite power recovery calculations for long-term SBO calculations (i.e., injection is lost at the time of battery depletion).**	**6**	**5**	**409,000**	**516,000**	**489,300**

Table G-4. (contd)

SAMA	Assumptions	% Risk Reduction		Total Benefit Using 7% Discount Rate ($)	Total Benefit Using 3% Discount Rate ($)	Cost ($)
		CDF	Population Dose			
35 - Use fire-fighting water as a backup for EDG cooling	Reduces the contribution of most loss of EDG cooling sequences by crediting the alignment of fire-fighting water to the EDG cooling system. A lumped failure probability of 1×10^{-2} is used to represent the operator alignment errors and hardware failures of the fire-fighting water cross-tie.	1	0.7	70,000	88,000	2,000,000
36 - Use fire-fighting water as a backup for containment spray	**Reduces the probability of sequences including containment spray failures in the Level 2 PSA model. A lumped failure probability of 5×10^{-1} is used to represent the operator alignment errors and hardware failures of the fire-fighting water cross-tie.**	**1**	**2**	**161,000**	**224,000**	**100,000**
37 - Low-pressure RCIC operation	Credits operation of reactor core isolation cooling (RCIC) after reactor coolant system depressurization at HCTL when power is available for flow control. Operators are always successful in implementing low pressure RCIC injection.	0.4	0.7	53,000	70,000	200,000

SAMAs in bold are potentially cost-beneficial when either a 7-percent or 3-percent real discount rate is used in staff's analysis.

[1] The staff judges the cost of this SAMA to be on the order of $5 million to $10 million.

The staff reviewed the bases for the CP&L's cost estimates (presented in Section F.3 of Appendix F to the ER). For certain improvements, the staff also compared the cost estimates to estimates developed elsewhere for similar improvements, including estimates developed as part of other licensees' analyses of SAMAs for operating reactors and advanced light-water reactors. The staff reviewed the costs and found them to be consistent with estimates provided in support of other plants' analyses.

The staff questioned CP&L about the cost estimate for Phase II SAMA 1, portable generator for DC power. In the ER, the implementation cost for Phase II SAMA 1 is stated to be for a single-unit site; however, the estimated benefit is based on the risk reduction achieved at both units. In response to the RAI, CP&L stated that it assumed that power cables were installed that could be used to align a portable generator to either unit; however, it was also assumed that the generator would only be used at one unit at a time. Because credit was taken for the enhancement in dual-unit SBO sequences, two generators or a single, larger-capacity generator would be required to achieve the estimated benefit in these events. Because dual-unit SBO accounts for 37 percent of the total CDF compared with only 2.3 percent from single-unit SBO, the design of the SAMA would need to account for simultaneous use at both units to derive the full benefit. CP&L concluded that the cost estimate was, therefore, conservative. The staff considers the cost estimate value in Table G-4, which reflects the cost for one generator, to represent a lower-bound cost.

The staff notes that the cost estimate for Phase I SAMA 1 was also used for several other SAMAs (i.e., Phase II SAMAs 17, 19, and 34) because the cost of those SAMAs was considered to be equivalent to the cost of using portable generators to back up the station batteries. Phase II SAMA 17 – provide alternate feeds to panels supplied only by DC bus 2A-1, and Phase II SAMA 19, provide an alternate means of supplying the instrument air header – would derive most of their benefits from single-unit events. Thus, the cost estimate, which is based on a single, portable generator (or air compressor) that could be connected to either unit, is reasonable for these SAMAs. Phase II SAMA 34 – supplemental power supplies for offsite power recovery after battery depletion during SBO – obtains much benefit from dual-unit SBO events. This SAMA involves providing portable power supplies for the switchyard. DC generators would be used to provide power to operate the power control breakers, while a 480-V AC generator would be used to supply line compressors for breaker support. While one set of power supplies may be sufficient to deal with dual-unit SBO events, both a DC and an AC power supply would be needed. The cost estimate addresses providing only a DC power supply. Consequently, the staff considers the cost estimate for Phase II SAMA 34 to also represent a lower-bound cost. The staff concludes that the cost estimates provided by CP&L are sufficient and appropriate for use in the SAMA evaluation.

G.6 Cost-Benefit Comparison

CP&L's cost-benefit analysis and the staff's review are described in the following sections.

G.6.1 CP&L's Evaluation

The methodology used by CP&L was based primarily on NRC's guidance for performing cost-benefit analysis, *Regulatory Analysis Technical Evaluation Handbook*, NUREG/BR-0184 (NRC 1997a). The guidance involves determining the net value for each SAMA according to the following formula:

Net Value = (APE + AOC + AOE + AOSC) - COE

where

APE = present value of averted public exposure ($)
AOC = present value of averted offsite property damage costs ($)
AOE = present value of averted occupational exposure costs ($)
AOSC = present value of averted onsite costs ($)
COE = cost of enhancement ($).

If the net value of a SAMA is negative, the cost of implementing the SAMA is larger than the benefit associated with the SAMA and it is not considered cost-beneficial. CP&L's derivation of each of the associated costs is summarized below.

NUREG/BR-0058 was recently revised to reflect the agency's policy on discount rates. Revision 4 states that two sets of estimates should be developed – one at 3 percent and one at 7 percent (NRC 2004). CP&L provided both sets of estimates and indicated that it would consider for further evaluation any SAMA that was cost-beneficial using a 3-percent discount rate (CP&L 2004).

<u>Averted Public Exposure (APE) Costs</u>

The APE costs were calculated using the following formula:

APE = Annual reduction in public exposure (Δ person-rem per year)
x monetary equivalent of unit dose ($2000 per person-rem)
x present value conversion factor (10.76 based on a 20-yr period with a 7-percent discount rate).

As stated in NUREG/BR-0184 (NRC 1997a), it is important to note that the monetary value of the public health risk after discounting does not represent the expected reduction in public health risk resulting from a single accident. Rather, it is the present value of a stream of potential losses extending over the remaining lifetime (in this case, the license renewal term) of the facility. Thus, it reflects the expected annual loss resulting from a single accident, the possibility that such an accident could occur at any time over the license renewal term, and the effect of discounting these potential future losses to present value. For the purposes of initial screening, CP&L calculated an APE of approximately $632,000 for the 20-yr license renewal term, which assumes elimination of all severe accidents.

Averted Offsite Property Damage Costs (AOC)

The AOCs were calculated using the following formula:

APE = Annual CDF reduction
x offsite economic costs associated with a severe accident (on a per-event basis)
x present value conversion factor.

For the purposes of initial screening, which assumes all severe accidents are eliminated, CP&L calculated an annual offsite economic risk of about $49,000 based on the Level 3 risk analysis. This results in a discounted value of approximately $522,000 for the 20-year license renewal term.

Averted Occupational Exposure (AOE) Costs

The AOE costs were calculated using the following formula:

AOE = Annual CDF reduction
x occupational exposure per core damage event
x monetary equivalent of unit dose
x present value conversion factor.

CP&L derived the values for averted occupational exposure from information provided in Section 5.7.3 of NUREG/BR-0184, the regulatory analysis handbook (NRC 1997a). Best estimate values provided for immediate occupational dose (3300 person-rem) and long-term occupational dose (20,000 person-rem over a 10-yr cleanup period) were used. The present value of these doses was calculated using the equations provided in the handbook in conjunction with a monetary equivalent of unit dose of $2000 per person-rem, a real discount rate of 7-percent, and a time period of 20 yr to represent the license renewal term. For the purposes of initial screening, which assumes all severe accidents are eliminated, CP&L calculated an AOE of approximately $16,000 for the 20-yr license renewal term.

Averted Onsite Costs (AOSC)

Averted onsite costs (AOSC) include averted cleanup and decontamination costs and averted power replacement costs. Repair and refurbishment costs are considered for recoverable accidents only and not for severe accidents. CP&L derived the values for AOSC based on information provided in Section 5.7.6 of NUREG/BR-0184 (NRC 1997a).

CP&L divided this cost element into two parts: (1) the onsite cleanup and decontamination cost, commonly referred to as averted cleanup and decontamination costs (ACC), and (2) the replacement power cost.

ACC were calculated using the following formula:

ACC = Annual CDF reduction
x present value of cleanup costs per core damage event
x present value conversion factor.

The total cost of cleanup and decontamination subsequent to a severe accident is estimated in NUREG/BR-0184 to be $\$1.1 \times 10^9$ (discounted over a 10-yr cleanup period). This value was integrated over the term of the proposed license extension. For the purposes of the initial screening, which assumes all severe accidents are eliminated, CP&L calculated an ACC of approximately $496,000 for the 20-yr license renewal term.

Long-term replacement power costs (RPC) were calculated using the following formula:

RPC = Annual CDF reduction
x present value of replacement power for a single event
x factor to account for remaining service years for which replacement power is required
x reactor power scaling factor.

CP&L based its calculations on the value of 1006 megawatts-electric [MW(e)], which conservatively bounds the maximum dependable capacity of 938 MW(e) for Unit 1 and 900 MW(e) for Unit 2. CP&L applied a power scaling factor of 1006 MW(e)/910 MW(e) to determine the RPC. Additionally, CP&L multiplied the RPC by a factor of two based on a conservative assumption that a severe core damage event in one unit would result in shutting down the second unit. This was done to maximize the RPC and provide a slightly conservative assessment of the maximum averted cost risk (MACR). For the purposes of initial screening, which assumes all severe accidents are eliminated, CP&L calculated the RPC to be approximately $731,000 for the 20-yr license renewal term.

Using the above equations, CP&L estimated the total present dollar value equivalent associated with completely eliminating severe accidents at BSEP to be about $2,397,000 for a single unit. Because all SAMA costs and benefits were provided on a site basis, CP&L doubled this value to obtain the two-unit site value of $4,794,000. To account for additional risk reduction in external events, CP&L doubled this value again (to $9,588,000), to provide the modified maximum averted cost risk (MMACR), which represents the dollar value associated with completely eliminating all internal and external event severe accident risk at both BSEP units.

<u>CP&L's Results</u>

If the implementation costs for a candidate SAMA were greater than the MMACR of $9,588,000, then the SAMA was screened from further consideration. A more refined look at the costs and benefits was performed for the remaining SAMAs. If the expected cost for those SAMAs exceeded the calculated benefit, the SAMA was considered not to be cost-beneficial. In the baseline analysis contained in the ER (using a 7-percent discount rate), CP&L identified seven potentially cost-beneficial SAMAs. These SAMAs are:

- SAMA 1 – Portable generator for DC power: This SAMA involves the use of a portable generator to supply DC power during an SBO.

- SAMA 15 – Diverse EDG HVAC logic: This SAMA involves the installation of a diverse set of fan actuation logic, which would reduce the reliance of operators to perform a fan start on loss of the automatic actuation logic.

- SAMA 17 – Provide alternative feeds to panels supplied only by DC bus 2A-1: This SAMA involves the installation of alternate DC feeds, which may reduce plant risk through diversification of the power supplies.

- SAMA 19 – Provide an alternate means of supplying the instrument air header: This SAMA involves procurement of an additional portable compressor to be aligned to the supply header to reduce the risk associated with loss of instrument air.

- SAMA 25 – Proceduralize battery charger high-voltage shutdown circuit inhibit: This SAMA involves disabling the charger high-voltage trip circuit when the batteries are disconnected from the DC circuit, thereby preventing the trip and allowing the chargers to remain online.

- SAMA 29 – Portable EDG fuel oil transfer pump: This SAMA provides additional means of supplying the EDG day tank in the event a common cause failure prevents operation of the existing pumps.

- SAMA 36 – Use fire-fighting water as a backup for containment spray: This SAMA would provide redundant containment spray function without the cost of installing a new system.

CP&L performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment (CP&L 2004). Based on an analysis using a 3-percent real discount rate, as recommended in NUREG/BR-0058 (NRC 2004), several additional SAMA candidates were determined to be potentially cost-beneficial. If the benefits are increased by approximately a factor of two to account for uncertainties, six additional SAMA candidates (beyond those identified in the 3-percent discount rate case) were determined to be potentially cost-beneficial. The potentially cost-beneficial SAMAs, and CP&L's plans for further evaluation of these SAMAs are discussed in more detail in Section G.6.2.

G.6.2 Review of CP&L's Cost-Benefit Evaluation

The cost-benefit analysis performed by CP&L was based primarily on NUREG/BR-0184 (NRC 1997b) and was executed consistent with this guidance.

To account for external events, CP&L multiplied the internal-event benefits by a factor of two for each SAMA, except those SAMAs that specifically address fire risk (Phase II SAMAs 30-33). Doubling the benefit for SAMAs 30-33 is not appropriate because these SAMAs are specific to fire risks and would not have a corresponding benefit on the risk from internal events. Given that the CDF from fires and other external events as reported by CP&L is approximately the same as the CDF for internal events, the staff agrees that the factor of two multiplier for external events is reasonable.

As discussed in Section G.6.1, CP&L applied a multiplier of two to the replacement power cost based on a conservative assumption that a core damage accident in one unit would result in permanent shutdown of the remaining unit. The staff questioned CP&L about the rationale for doubling this cost. In response, CP&L stated this was done to maximize the replacement power costs and provide a slightly conservative assessment of the MACR. CP&L indicated the benefit would be reduced by about 15 percent if loss of power generation from only one unit was assumed in its calculation (Progress Energy 2005a). The staff considers the assumption regarding loss of the second unit to be conservative, because in the majority of events (e.g., those involving an intact containment) the unaffected unit can eventually return to service. For purposes of its evaluation, the staff reassessed the benefits for each SAMA assuming replacement power costs for only a single unit. Table G-4 reflects these adjusted values.
The effect of considering replacement power for only one unit does not change the cost-effectiveness of any SAMAs in the baseline analysis; that is, the same seven SAMAs identified as potentially cost-beneficial in Section G.6.1 remain potentially cost-beneficial.

When benefits were evaluated using a 3-percent discount rate, two additional SAMAs were determined to be potentially cost-beneficial in the staff's assessment (i.e., Phase II SAMAs 13 and 34):

- SAMA 13 – Install an inter-unit CRD cross-tie as a potential means of recovering from a loss of CRD at a given unit.

- SAMA 34 – Use DC generators to provide power to operate the power control breakers while a 480-V AC generator could supply the air compressors for breaker support.

In the 3-percent discount rate case presented in its ER, which assumed replacement power costs for both units, CP&L identified these SAMAs as well as SAMAs 16 and 18 as potentially cost-beneficial. Although the latter two SAMAs are not cost-beneficial when replacement power costs are based on loss of a single unit, they become potentially cost-beneficial when the impact of uncertainties is considered, as discussed below.

CP&L considered the impact that possible increases in benefits from analysis uncertainties would have on the results of the SAMA assessment. Information regarding the uncertainty distribution of the internal events CDF is summarized in Section F.7.2 of the ER (CP&L 2004). In the uncertainty assessment described therein, the 95th percent confidence level for the internal events CDF is approximately 2.35 times the point estimate CDF, while the mean CDF is approximately 2.1 times the point estimate. CP&L re-examined the initial set of SAMAs to determine if any additional Phase I SAMAs would be retained for further analysis if the benefits (and MMACR) were increased by a factor of 2.35. One such SAMA was identified (i.e., Phase I SAMA 25 – additional diesel generator), but based on further consideration of its costs and its limited effectiveness due to common cause failure, CP&L concluded that this SAMA could not be cost-beneficial even if the system was 100 percent reliable. CP&L also considered the impact on the Phase II screening if the estimated benefits were increased by a factor of 2.35 in addition to the factor of two multiplier already included in the baseline benefit estimates to account for external events. Six additional SAMAs became potentially cost-beneficial in CP&L's analysis.

The staff noted that the mean CDF value (8.85×10^{-5} per year) and the 95th percentile CDF value (9.83×10^{-5} per year) reported in the ER are much closer than typical. Furthermore, the staff noticed that a potentially large number of events were assigned an error factor of 10 in CP&L's uncertainty calculation. Depending on the event, this may be conservative and can skew the results (including the mean and 95th percentile) towards higher values. Therefore, the staff requested an assessment of the impact if the mean rather than the point estimate CDF value were used in the cost-benefit analysis, and if an error factor of 3 instead of 10 were used for these events.

In response to the RAI, CP&L stated that the use of point estimate values is standard practice for the BSEP PSA, and that the 95th percentile value was computed by inputting an error factor of 10 for basic events where a common cause failure, initiator, operator action, or maintenance unavailability event did not have a pre-determined error factor (Progress Energy 2005a). CP&L performed an additional uncertainty analysis in which those error factors initially set at 10 were reset to 3. It stated the purpose of this calculation was to provide a firmer basis for the uncertainty multiplier that is applied to the baseline benefits in the SAMA analysis and the calculation does not necessarily provide a true statistical assessment of data uncertainties in the PSA model. The reduction in the assumed default error factor from 10 to 3 resulted in a 95th percentile value-to-point estimate CDF ratio of 1.89 instead of the factor of 2.35 identified previously, and a reduction in the ratio of the mean-to-point estimate from 2.1 to 1.2. In the staff's view, these results are more typical of the uncertainty distribution from other PSAs; therefore, the staff suggests the use of a multiplier of about two to account for uncertainties is reasonable. Accordingly, the staff assessed the potential impact of uncertainties by applying a multiplier of 2.0 to the estimated benefits in the baseline analysis (based on a 7-percent discount rate). If benefits were doubled to account for uncertainties, six additional SAMAs (beyond the nine SAMAs identified above as potentially cost-beneficial in the baseline and 3-percent discount rate cases) could be cost-beneficial. These additional SAMAs are Phase II SAMAs 6, 16, 18, 30, 31, and 32.

In its ER, CP&L stated that several SAMAs are potentially cost-beneficial and warrant further review for potential implementation; however, it did not specifically identify which SAMAs would be pursued (CP&L 2004). In response to an RAI on this subject, CP&L stated that the SAMAs identified as cost-beneficial in the baseline analysis (i.e., Phase II SAMAs 1, 15, 17, 19, 25, 29, and 36) had been reviewed by the BSEP Plant Review Group (PRG) prior to the submittal of the license renewal application (Progress Energy 2005a). The PRG recognized the high positive impact of implementing SAMA 1, which could affect the cost-effectiveness of the remaining cost-beneficial SAMAs. As a result, CP&L performed a probabilistic evaluation to investigate the impact on the remaining cost-beneficial SAMAs if SAMA 1 were to be implemented. Based on the information provided by CP&L in the RAI response, implementation of SAMA 1 would alter the cost-effectiveness of the remaining SAMAs such that:

- SAMA 17 would no longer be cost-beneficial when a 7-percent discount rate was used; however, it could become cost-beneficial when uncertainties were considered.

- SAMAs 19 and 36 would no longer be cost-beneficial when a 7-percent discount rate was used, nor would they become cost-beneficial when uncertainties were considered.

Also, SAMA 13, which was originally identified as potentially cost-beneficial when a 3-percent discount rate was used, would no longer be cost-beneficial if SAMA 1 is implemented, nor would it become cost-beneficial when uncertainties are considered.

The balance of the SAMAs that were cost-beneficial in the baseline analysis (i.e., Phase II SAMAs 15, 25, and 29) would remain potentially cost-beneficial after implementation of SAMA 1. Although implementation of SAMA 1 may also impact the net value of some of the SAMAs that became cost-beneficial at 3 percent (i.e., Phase II SAMA 34) or when uncertainties were considered (i.e., Phase II SAMAs 6, 16, 18, 30, 31, and 32), CP&L has not completed its assessment of this impact. Thus, these SAMAs may also remain potentially cost-beneficial.

CP&L indicated that a further evaluation of the potentially cost-beneficial SAMA will be performed (Progress Energy 2005b). This assessment will focus on SAMA 1, and those baseline case SAMAs that would remain cost-beneficial if SAMA 1 were implemented (i.e., Phase II SAMAs 15, 25, and 29). In response to the staff's notation that SAMAs other than those in the baseline case may become cost-beneficial when a 3-percent discount rate is used, or when uncertainties are considered, CP&L stated that it will include these SAMAs (i.e., Phase II SAMAs 6, 16, 18, 30, 31, 32, and 34) in the assessment that will make recommendations for the further evaluations of SAMAs (Progress Energy 2005b). Completion of the evaluations is being tracked in the BSEP action tracking system.

The staff notes that all of the potentially cost-beneficial SAMAs identified in either the baseline case or the 3-percent discount rate case (see bolded entries in Table G-4) are included within the set of SAMAs that CP&L plans to further evaluate, with the exception of Phase II SAMAs 13, 19, and 36. As discussed in Section G.2.2, SAMAs 13 and 36 could be impacted by resolution of PSA peer review comments (Phase II SAMAs 6 and 34 would also be impacted but are already among the set of SAMAs to be further evaluated by CP&L). Also, as discussed in Section G.5, the cost estimate for SAMA 19 was based on that for SAMA 1. SAMA 19 involves the addition of an engine-driven air compressor capable of supplying the full instrument air system load. Because the extent of the modifications to accommodate an additional compressor were not detailed in the ER, actual costs may be higher or lower. (Phase II SAMAs 17 and 34 are similarly affected, but are already among the set of SAMAs to be further evaluated by CP&L). Finally, if SAMA 1 is not implemented, these three SAMAs would remain cost-beneficial. Accordingly, the staff recommends these three SAMAs (i.e., Phase II SAMAs 13, 19, and 36) also be further assessed by CP&L as part of its evaluation.

The staff concludes that, with the exception of the potentially cost-beneficial SAMAs discussed above, the costs of the SAMAs evaluated would be higher than the associated benefits.

G.7 Conclusions

CP&L compiled a list of 43 SAMAs based on a review of the most significant basic events from the plant-specific PSA, Phase II SAMAs from license renewal activities for other plants, and insights from the plant-specific IPE and IPEEE. A qualitative screening removed SAMA candidates that (1) were not applicable at BSEP because of design differences, (2) would require extensive changes that involve implementation costs known to exceed any possible benefit, or (3) would cost more than $9.6 million to implement (the MMACR). Seven SAMAs were eliminated, leaving 36 for evaluation. Further screenings resulting in removal of nine additional SAMAs, leaving 27 SAMAs for further evaluation.

For each of the remaining 27 SAMA candidates, a more detailed design and cost estimate was developed as shown in Table G-4. The cost-benefit analyses showed that seven of the SAMA candidates were potentially cost-beneficial in the baseline analysis (SAMAs 1, 15, 17, 19, 25, 29, and 36). CP&L performed additional analyses to evaluate the impact of parameter choices and uncertainties on the results of the SAMA assessment. As a result, eight additional SAMAs were identified as potentially cost-beneficial (SAMAs 6, 13, 16, 18, 30, 31, 32, and 34). CP&L has committed to further evaluate SAMA 1 and SAMAs that may remain potentially cost-beneficial if SAMA 1 is implemented (SAMAs 6, 15, 16, 17, 18, 25, 29, 30, 31, 32, and 34). The staff concluded all of these SAMAs are potentially cost-beneficial. In addition, the staff concluded that SAMAs 13, 19, and 36 are potentially cost-beneficial and may remain so even if SAMA 1 is implemented.

The staff reviewed the CP&L analysis and concluded that the methods used and the implementation of those methods were sound. The treatment of SAMA benefits and costs support the general conclusion that the SAMA evaluations performed by CP&L are reasonable and sufficient for the license renewal submittal. Although the treatment of SAMAs for external events was somewhat limited by the unavailability of an external event PSA, the likelihood of there being cost-beneficial enhancements in this area was minimized by inclusion of several candidate SAMAs related to dominant fire events, improvements that have been realized as a result of the IPEEE process, and inclusion of a multiplier to account for external events.

The staff concurs with CP&L's identification of areas in which risk can be further reduced in a cost-beneficial manner through the implementation of all or a subset of the identified, potentially cost-beneficial SAMAs. Given the potential for cost-beneficial risk reduction, the staff agrees that further evaluation of these SAMAs by CP&L is warranted. However, none of the potentially cost-beneficial SAMAs relate to adequately managing the effects of aging during the period of extended operation. Therefore, they need not be implemented as part of license renewal pursuant to 10 CFR Part 54.

G.8 References

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