APPENDIX D
STATE HISTORIC PRESERVATION OFFICER CORRESPONDENCE

CP&L
A Progress Energy Company

MAY 1 2 2003

SERIAL: BSEP 03-0083

Dr. Jeffrey Crow
Deputy Secretary of Archives and History and
State Historic Preservation Officer
North Carolina Department of Cultural Resources
4610 Mail Service Center
Raleigh NC 27699-4610

BRUNSWICK STEAM ELECTRIC PLANT, UNIT NOS. 1 AND 2
LICENSE RENEWAL - REQUEST FOR INFORMATION
HISTORIC AND ARCHAEOLOGICAL RESOURCES

Dear Dr. Crow:

Progress Energy Carolinas, Inc. (PEC) is preparing an application to the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for the Brunswick Steam Electric Plant (BSEP), which expire in 2016, for Unit 1 and 2014, for Unit 2. PEC intends to submit this application for license renewal in December 2004. As part of the license renewal process, the NRC requires license applicants to assess whether any historic or archaeological properties will be affected by the proposed project. The NRC will consult with your office, at a later date, under Section 106 of the National Historic Preservation Act of 1966, as amended (16 USC 470), and Federal Advisory Council on Historic Preservation regulations (36 CFR 800). By contacting you early in the application process, we hope to identify any issues that need to be addressed or any information your office may need to expedite the NRC consultation.

PEC has operated BSEP and associated transmission lines since 1975, when Unit 2 began commercial operation. Unit 1 began operating in 1976. BSEP is located in Brunswick County in southeastern North Carolina, near the mouth of the Cape Fear River. The plant is situated on approximately 1,200 acres of land. The facility includes the powerblock area and support facilities, the nuclear exclusion zone, a buffer zone, a three-mile long intake canal that is used to withdraw cooling water from the Cape Fear River, and a six-mile long discharge canal that conveys heated effluent to the Atlantic Ocean (i.e., see Figure 1).

PEC, previously known as Carolina Power & Light Company built eight transmission lines to connect BSEP to the regional transmission system. All eight lines share the first 1.3 miles of corridor. At that point, the Whiteville, Delco East, Delco West, and Weatherspoon lines veer to the northwest, and divide again with the Whiteville line traveling parallel to and south of the Weatherspoon and Delco lines which share a

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corridor to the Delco Substation and then the Weatherspoon lines continues to the Weatherspoon Substation. The Wallace, Jacksonville, Castle Hayne East and Wilmington Corning lines travel northeast from the split near BSEP (i.e., see Figure 2). Approximately 15 miles north of BSEP, the Castle Hayne line moves east and then north to the Castle Hayne Substation. The other lines continue north, and then split after they cross into Pender County, with one line proceeding north to the Wallace Substation and the other line moving northeast to Jacksonville.

The Final Environmental Statement (FES) for the construction and operation of BSEP Units 1 and 2, prepared by the U.S. Atomic Energy Commission (AEC) in 1974, listed seven properties on the National Historic Register within the vicinity of BSEP. After evaluating the project, the AEC concluded that the plant will not impose unacceptable impact upon National Register properties.

Using the National Register Information System (NRIS) online database, PEC compiled a list of sites on the National Register of Historic Places within a six-mile radius of the BSEP property. As of December 2002, the Register listed 12 locations in Brunswick County and 26 locations in New Hanover County, North Carolina. Of these 38 locations, 14 fall within a six-mile radius of BSEP. This information will be provided to the NRC to aid in the evaluation of the license application.

PEC does not expect BSEP operation, through the license renewal term (i.e., an additional 20 years), to adversely affect cultural or historical resources in the area because PEC has no plans to significantly alter current operations over the license renewal period. No expansion of existing facilities is planned, and no major structural modifications have been identified for the purpose of supporting license renewal. No land-disturbing activities are anticipated beyond those required for routine maintenance and repairs.

PEC would appreciate a response to this letter, by June 15, 2003, detailing any concerns regarding historic or archaeological properties in the area of BSEP or confirming PEC's conclusion that operation of BSEP, over the license renewal term, would have no effect on any historic or archaeological properties in North Carolina. This will enable PEC to meet the current application preparation schedule. PEC will include a copy of this letter and your response in the license renewal application to the NRC.

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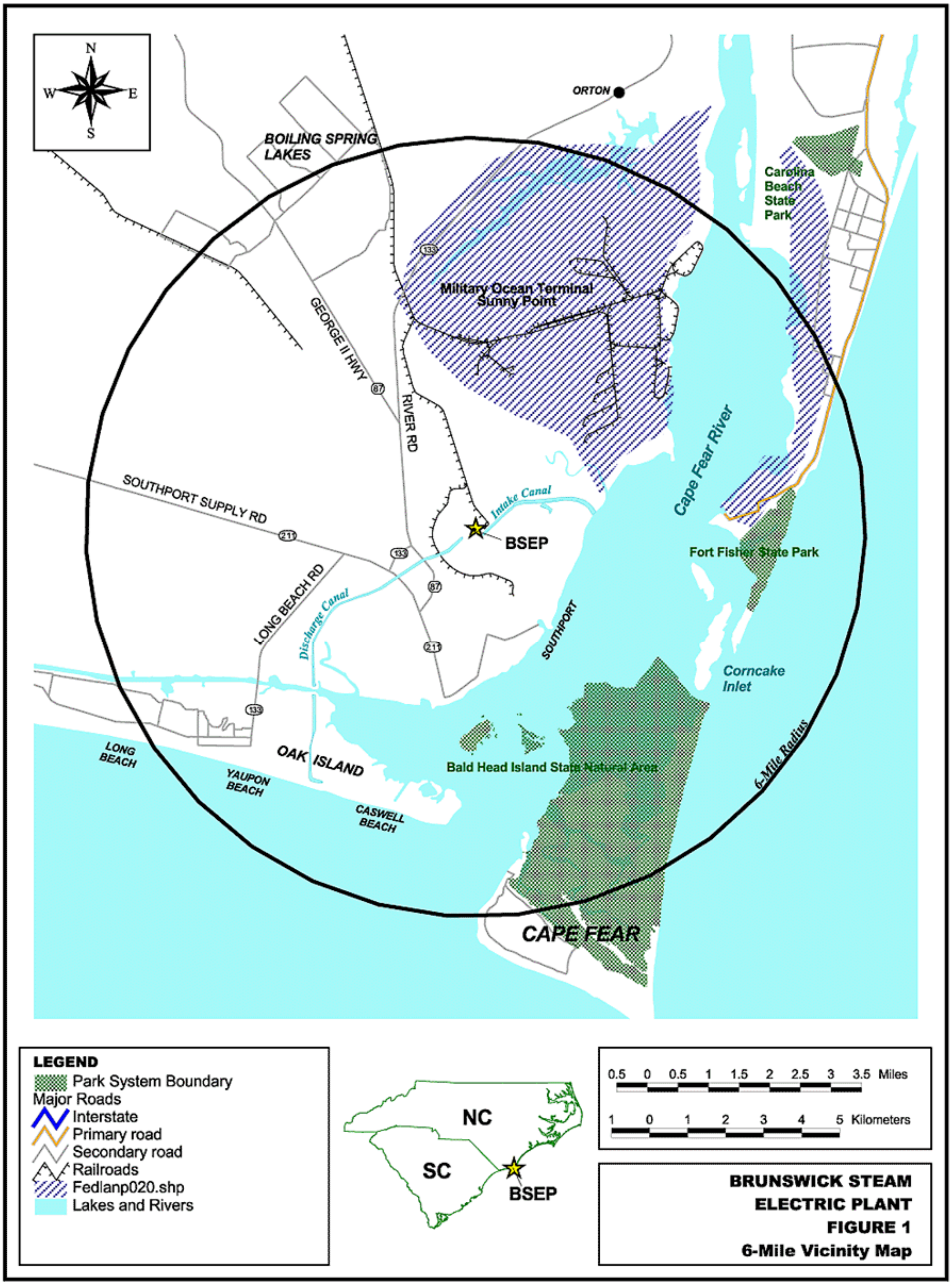
Please refer any questions regarding this submittal to Mr. Jan Kozyra, Lead Engineer - License Renewal, at (843) 857-1872.

Sincerely,

Edward T. O'Neil
Manager - Support Services
Brunswick Steam Electric Plant

MAT/mat

Enclosures:
Figure 1 - Brunswick Steam Electric Plant 6-Mile Vicinity Map
Figure 2 - Brunswick Steam Electric Plant Transmission Line Map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Carolina Beach State Park
Military Ocean Terminal Sunny Point
GEORGE II HWY
RIVER RD
SOUTHPORT SUPPLY RD
Intake Canal
BSEP
Cape Fear River
Fort Fisher State Park
LONG BEACH RD
Discharge Canal
SOUTHPORT
Corncake Inlet
LONG BEACH
OAK ISLAND
YAUPON BEACH
CASWELL BEACH
Bald Head Island State Natural Area
6-Mile Radius
CAPE FEAR
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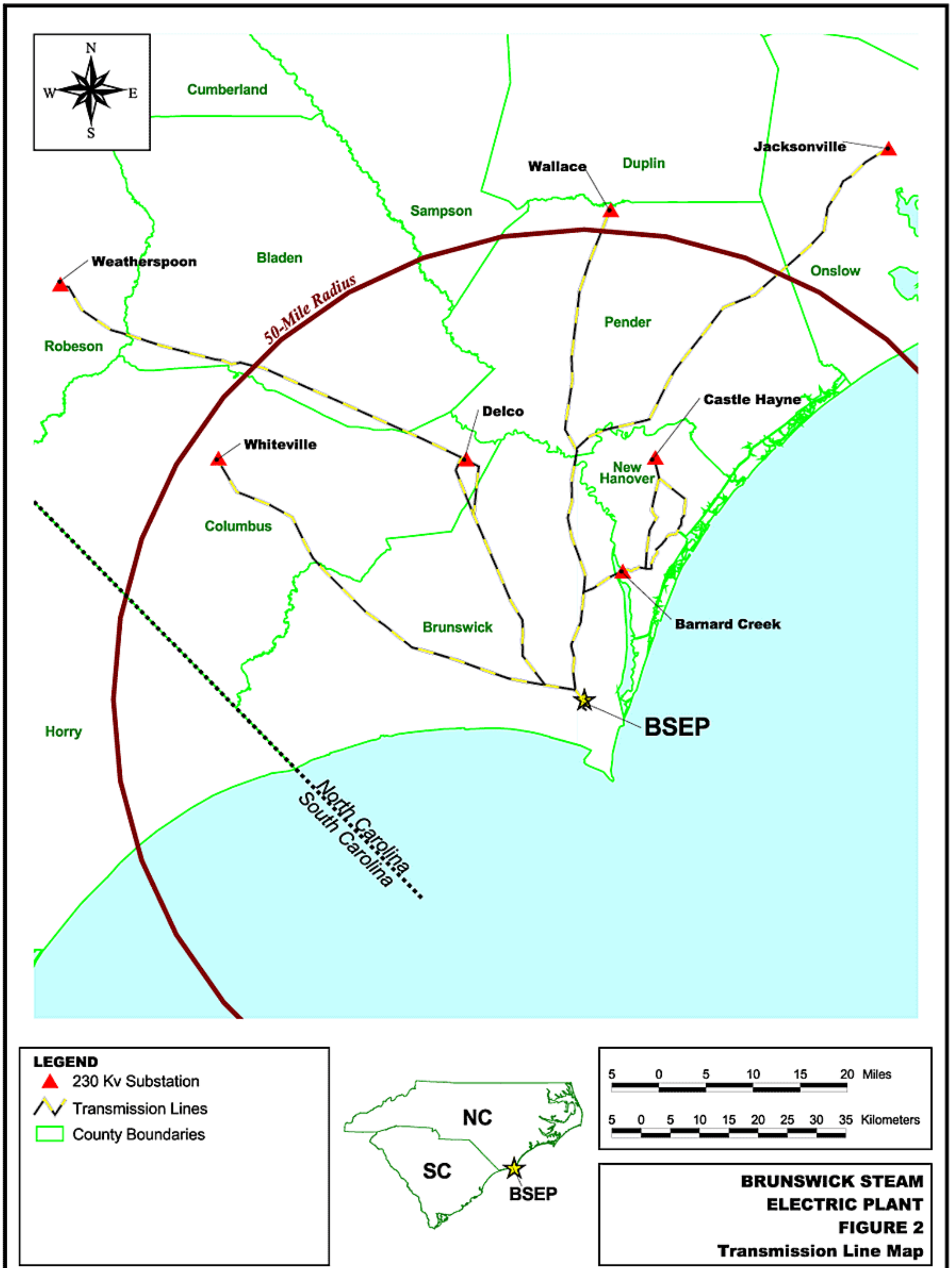
BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 1
6-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE 2
Transmission Line Map

APPENDIX E
COASTAL ZONE CONSISTENCY CERTIFICATION

FEDERAL CONSISTENCY CERTIFICATION FOR FEDERAL PERMIT AND LICENSE APPLICANTS[1]

This is the Progress Energy certification to the U. S. Nuclear Regulatory Commission (NRC) that renewal of the Brunswick Steam Electric Plant Unit 1 and Unit 2 (BSEP) operating licenses would be consistent with enforceable policies of the federally approved state coastal zone management program. The certification describes background requirements, the proposed action (i.e., license renewal), anticipated environmental impacts, North Carolina enforceable coastal resource protection policies and BSEP's compliance status, and summary findings.

CONSISTENCY CERTIFICATION

Progress Energy certifies to the NRC that renewal of the BSEP operating licenses would be consistent with the federally approved North Carolina coastal management program. Progress Energy expects BSEP operations during the license renewal term to be a continuation of current operations as described below, with no station structural or operational modifications related to license renewal that would change effects on North Carolina's coastal zone.

NECESSARY DATA AND INFORMATION

Statutory Background

The federal Coastal Zone Management Act (16 USC 1451 et seq.) imposes requirements on an applicant for a federal license to conduct an activity that could affect a state's coastal zone. The Act requires an applicant to certify to the licensing agency that the proposed action would be consistent with the state's federally approved coastal zone management program The Act also requires the applicant to provide to the state a copy of the certification statement and requires the state, at the earliest practicable time, to notify the federal agency and the applicant whether the state concurs with, or objects to, the consistency certification. See 16 USC 1456(c)(3)(A).

The National Oceanic and Atmospheric Administration (NOAA) has promulgated implementing regulations that indicate that the certification requirement is applicable to renewal of federal licenses for activities not previously reviewed by the state [15 CFR 930.51(b)(1)]. The Administration approved the North Carolina coastal management program September 1978 (Ref. 2). In North Carolina, the approved program is the Coastal Area Management Act, North Carolina General Statutes (NCGS) 113-100, with regulations at 15A North Carolina Administrative Code (NCAC) 7. NRC licensing of BSEP Unit 2, in 1974, and BSEP Unit 1 in 1976, pre-dated state program approval.

Proposed Action

NRC operating licenses for BSEP will expire in 2014 for Unit 2 and in 2016 for Unit 1. NRC regulations provide for license renewal, and Progress Energy is applying for renewal of the Unit 2 license to 2034 and the Unit 1 license to 2036.

BSEP is an electric generating plant located within the North Carolina coastal zone, in Brunswick County, near the mouth of the Cape Fear River. The plant withdraws water from the Cape Fear River via a 3-mile long intake canal for non-contact cooling, and returns the heated discharge to the Atlantic Ocean via a 6-mile long discharge canal. Approximately 60 percent of the area within a 50-mile radius of BSEP is the water of the Atlantic Ocean. Figures E-1 and E-2 are BSEP 50- and 6-mile vicinity maps, respectively.

[1] This certification is patterned after the example certification included as Appendix E of the NRC Office of Nuclear Reactor Regulation's "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues" (LIC-203, 6-21-01).

BSEP Units 1 and 2 are boiling water reactors with an expected total output of 5,846 MW thermal and an expected electric output of 1,909 MW electric after completion of an NRC-approved Extended Power Uprate in 2005 (67 FR 39445; June 7, 2002). Each unit has a separate intake structure with four circulating water pumps per intake structure. The eight pumps provide a continuous supply (maximum of 1.25 million gallons per minute [gpm]) of condenser cooling water. After moving through the condensers (and service water systems) water is discharged into a 6-mile discharge canal to Caswell Beach where the heated water enters two 13-foot diameter underwater pipes that move it 2,000 feet offshore where it is ultimately discharged at the bottom of the ocean.

The BSEP workforce consists of approximately 760 Progress Energy employees and 300 long-term contract employees. Approximately 90 percent reside in Brunswick or New Hanover counties. The BSEP reactors are on a 24-month refueling cycle. During refueling outages, site employment increases by approximately 1,000 workers for temporary (approximately 30 days) duty. Progress Energy has no plans to add additional employees due to license renewal.

NRC and Progress Energy have identified no refurbishment activities necessary to allow operation for an additional 20 years, and have identified no significant environmental impacts from programs and activities for managing the effects of aging. As such, renewal would result in a continuation of environmental impacts currently regulated by the state. Table E-1 lists state and federal licenses, permits, and other environmental authorizations for current BSEP operations and Table E-2 identifies compliance activities associated specifically with NRC license renewal.

Eight transmission lines were built to connect BSEP to the regional electric grid. These lines are co-located in common corridors to the extent practical with all eight lines in a single corridor for the first 1.3 miles. In all, approximately 220 miles of transmission corridor are associated with BSEP; and approximately 140 miles traverse the coastal counties of Brunswick, New Hanover, Pender and Onslow (Figure E-3). The proposed action, renewing the license of BSEP for an additional 20 years, would not require additional transmission lines, nor is Progress Energy anticipating that it would change any corridor maintenance practices.

Environmental Impacts

NRC has prepared a generic environmental impact statement (GEIS; Ref. 3) on impacts that nuclear power plant operations could have on the environment and has codified its findings (10 CFR 51, Subpart A, Appendix B, Table B-1). The regulation identified 92 potential environmental issues, 69 of which the NRC identified as having small impacts and termed “Category 1 issues.” NRC defines “small” as:

> Small – For the issue, environmental effects are not detectable or are so minor that they will neither destabilize nor noticeably alter any important attribute of the resource. For the purpose of assessing radiological impacts, the Commission has concluded that those impacts that do not exceed permissible levels in the Commission’s regulations are considered small as the term is used in this table (10 CFR 51, Subpart A, Appendix B, Table B-1)

The NRC regulation and the GEIS discuss the following types of Category 1 environmental issues:

- Surface water quality, hydrology, and use
- Aquatic ecology
- Groundwater use and quality
- Terrestrial resources
- Air quality

- Land use
- Human health
- Postulated accidents
- Socioeconomics
- Uranium fuel cycle and waste management
- Decommissioning

In its decision-making for plant-specific license renewal applications, absent new and significant information to the contrary, NRC relies on its codified findings, as amplified by supporting information in the GEIS, for assessment of environmental impacts from Category 1 issues [10 CFR 51.9(c)(4)]. For plants such as BSEP that are located in coastal areas, many of these issues involve impacts to the coastal zone. Progress Energy has adopted by reference the NRC findings and GEIS analyses for all 58[2] applicable Category 1 issues.

The NRC regulation identified 21 issues as "Category 2," for which license renewal applicants must submit additional site-specific information.[3] Of these, 11 apply to BSEP[4], and like the Category 1 issues, could involve impacts to the coastal zone. The applicable issues and Progress Energy's impact conclusions are listed below.

- <u>Entrainment of fish and shellfish in early life stages</u> – This issue addresses mortality of organisms small enough to pass through the plant's circulating cooling water system. Progress Energy has monitored the fishery in the Cape Fear Estuary since 1968 (since 1974 as a condition of the NPDES permit) to identify impacts of plant operations, and has implemented several design and operational changes to ensure that best available technology is in place to minimize entrainment. Operational changes involve seasonal reductions in water flow. Design changes include installing fine-mesh screens on two and a half of the four traveling screens of each unit. Progress Energy concludes that impacts of entrainment during current operations are small and it has no plans that would change this conclusion for the license renewal term.
- <u>Impingement of fish and shellfish</u> – This issue addresses mortality of organisms large enough to be caught by intake screens before passing through the plant's circulating cooling water system. The monitoring program and permit discussed above also address impingement. Since 1982, a permanent fish diversion structure has been maintained at the mouth of the intake canal and, since 1983, a fish return system has been maintained at the intake screens. These design modifications have reduced the number of large fish impinged and impingement mortality. Progress Energy concludes that impacts of impingement during current operations are small and it has no plans that would change this conclusion for the license renewal term.

[2] The remaining Category 1 issues do not apply to BSEP either because they are associated with design or operational features the BSEP does not have (e.g., cooling towers) or to an activity, refurbishment, that BSEP does not intend to undertake.
[3] 10 CFR 51, Subpart A, Appendix B, Table B-1 also identifies 2 issues as "NA" for which NRC could not come to a conclusion regarding categorization. Progress Energy believes that these issues, chronic effects of electromagnetic fields and environmental justice, do not affect the "coastal zone" as that phrase is defined by the Coastal Zone Management Act [16 USC 1453(1)].
[4] The remaining Category 2 issues do not apply to BSEP either because they are associated with design or operational features the BSEP does not have (e.g., cooling towers) or to an activity, refurbishment, that BSEP will not undertake.

- Heat shock – This issue addresses mortality of aquatic organisms by exposure to heated plant effluent. Cooling water flow rates and heat rejection rates are limited by provisions of NPDES permit number NC0007064.

- Threatened or endangered species -- This issue addresses effects that BSEP operations could have on species that are listed under federal law as threatened or endangered. In analyzing this issue, Progress Energy has also considered species that are protected under North Carolina law (Table E-3).

  Three federally-listed sea turtle species (loggerhead [*Caretta caretta*], green [*Chelonia mydas*], and Kemp's Ridley [*Lepidochelys kempi*]) could potentially be affected by BSEP operations. In 1998, in compliance with the Endangered Species Act, the U.S. Nuclear Regulatory Commission initiated a formal Section 7 consultation with the National Marine Fisheries Service regarding the effect of BSEP operations on the sea turtles. The NMFS reviewed the data on the incidental take of sea turtles at BSEP and the operation of the cooling water intake system and, in January 2000, issued a final Biological Opinion (with an incidental take statement) that concluded that "operation of the water intake system of the Brunswick Steam Electric Plant…is not likely to jeopardize the continued existence of the loggerhead, leatherback, green, hawksbill, or Kemp's ridley sea turtles. No critical habitat has been designated for these species in the action area; therefore, none will be affected. This conclusion is based on the proposed action's (operation of the cooling water intake system) anticipated effects on each of these species being limited to incidental take, through death or injury, of a small number of immature sea turtles per year over the next 20 years" (Ref. 4). No hawksbill or leatherback turtles have ever been observed in the vicinity of BSEP.

  Progress Energy has installed and maintains blocker panels in the diversion structure to curtail the entrance of sea turtles and patrols the intake canal daily to find and return to the ocean any turtles that do get past the diversion structure. Progress Energy has a permit from North Carolina Wildlife Resources Commission to capture, tag, and relocate these turtles to the open ocean.

  Four federally-listed terrestrial species could potentially be affected by BSEP operations: the red-cockaded woodpecker (*Picoides borealis*), Cooley's meadowrue (*Thalictrum cooleyi*), rough-leaved loosestrife (*Lysimachia asperulaefolia*), and golden sedge (*Carex lutea*). Red-cockaded woodpecker nesting habitat is not found on the BSEP site; however, birds may forage in the area. Cooley's meadowrue, rough-leaved loosestrife, and golden sedge populations are known on the transmission line corridors. Progress Energy has a Memorandum of Understanding with the North Carolina Department of Environment and Natural Resources to protect endangered, threatened or special concern species along the rights-of-way. The company also maintains best management practices for management of rare plants on Progress Energy rights-of-way (Ref. 5).

  Progress Energy correspondence with cognizant federal and state agencies has identified no impacts of concern. Progress Energy concludes that BSEP impacts to these protected species are small during current operations and has no plans that would change this conclusion for the license renewal term.

- Electromagnetic fields, acute effects (electric shock) – This issue addresses the potential for shock from induced currents, similar to static electricity effects, in the vicinity of transmission lines. Because this human-health issue does not directly or indirectly affect natural resources of concern within the Coastal Zone Management Act definition of "coastal zone" [16 USC 1453(1)], Progress Energy concludes that the issue is not subject to the certification requirement.

- Housing – This issue addresses impacts that additional Progress Energy employees required to support license renewal and the additional resulting indirect jobs could have on local housing availability. NRC concluded, and Progress Energy concurs, that impacts would be small for plants located in medium population areas that do not have growth control measures which limit housing development. Using the NRC definitions and categorization methodology, BSEP is located in a medium population area without restrictive growth controls. Progress Energy expects no additional employees would be required to support license renewal. Progress Energy concludes that impacts during the BSEP license renewal term would be small.

- Public services; public utilities – This issue address impacts that adding license renewal workers could have on public utilities, particularly public water supply. Progress Energy has analyzed the availability of public water supplies in the area and has found no limitations that would suggest that additional BSEP workers would cause impacts. Progress Energy expects no additional employees to support license renewal. Therefore, Progress Energy has concluded that impacts during the BSEP license renewal term would be small.
- Offsite land use – This issue addresses impacts that local government spending of plant property tax dollars can have on land use patterns. BSEP property taxes comprised 4 percent of Brunswick County's total tax revenues in 2002. Progress Energy projects that BSEP taxes will remain relatively constant during the license renewal term. At some time in the future deregulation could affect utilities' tax payments, however, changes to BSEP tax rates due to deregulation would be independent of license renewal. Progress Energy concludes that impacts during the BSEP license renewal term would be small and not warrant mitigation.
- Public services; transportation – This issue addresses impacts that adding license renewal workers could have on local traffic patterns. Progress Energy expects no additional employees would be required to support license renewal. Therefore, Progress Energy has concluded that impacts during the BSEP license renewal term would be small.
- Historic and archaeological resources – This issue address impacts that license renewal activities could have on resources of historic or archaeological significance. Although a number of archaeological or historic sites have been identified within 6 miles of BSEP, Progress Energy is not aware of any adverse or detrimental impacts to these sites from current operations and Progress Energy has no plans for license renewal activities that would disturb these historic and archaeological resources.
- Severe accidents – Preliminary results from the Progress Energy severe accident mitigation alternatives (SAMA) analysis identify cost-beneficial ways to mitigate risk to public health and the economy in the area of the plant, including the coastal zone, due to potential severe accidents at BSEP. The SAMAs, however, are unrelated to aging management issues that are the subject of the license renewal analysis and, therefore, are not related to the consistency certification for license renewal.

State Program

The North Carolina Coastal Management Program is administered by the Division of Coastal Management within the Department of Environment and Natural Resources. The Department maintains a website that describes the program in general terms (Ref. 6). The North Carolina Coastal Management Statutes (Ref. 7) contain guidelines for preservation and management of the coastal area that are set forth in policy statements, standards, and management objectives. Attachment E-1 lists these objectives and discusses for each the applicability to BSEP. Attachment E-2 lists Brunswick County Land Use policies and discusses for each the applicability of BSEP and its associated transmission corridors. Attachment E-3 lists New Hanover County Land Use policies and discusses for each the applicability of BSEP transmission corridors. Attachment E-4 lists Onslow County Land Use policies and discusses for each the applicability of BSEP transmission corridors. Attachment E-5 lists Pender County Land Use policies and discusses for each the applicability of BSEP transmission corridors.

In addition, CAMA charges the Division of Coastal Management with managing “development” in “areas of environmental concern” (definitions within the regulatory context are provided in the authorizing legislation) within the 20 coastal counties through a well-structured permitting program. BSEP plans no development during the license renewal period.

Findings:

1. NRC has determined that the impacts of certain license renewal environmental issues (i.e., Category 1 issues) are small. Progress Energy has adopted by reference NRC findings for these issues as they are applicable to BSEP.

2. For other license renewal issues (i.e., Category 2 and “NA” issues) that are applicable to BSEP, Progress Energy has determined that the environmental impacts are small.

3. To the best of Progress Energy’s knowledge, BSEP and its transmission corridors are in compliance with all North Carolina’s licensing and permitting requirements and are in compliance with its state-issued licenses and permits.

4. Progress Energy’s license renewal and continued operation of BSEP would be consistent with the enforceable policies of the North Carolina coastal zone management program.

STATE NOTIFICATION

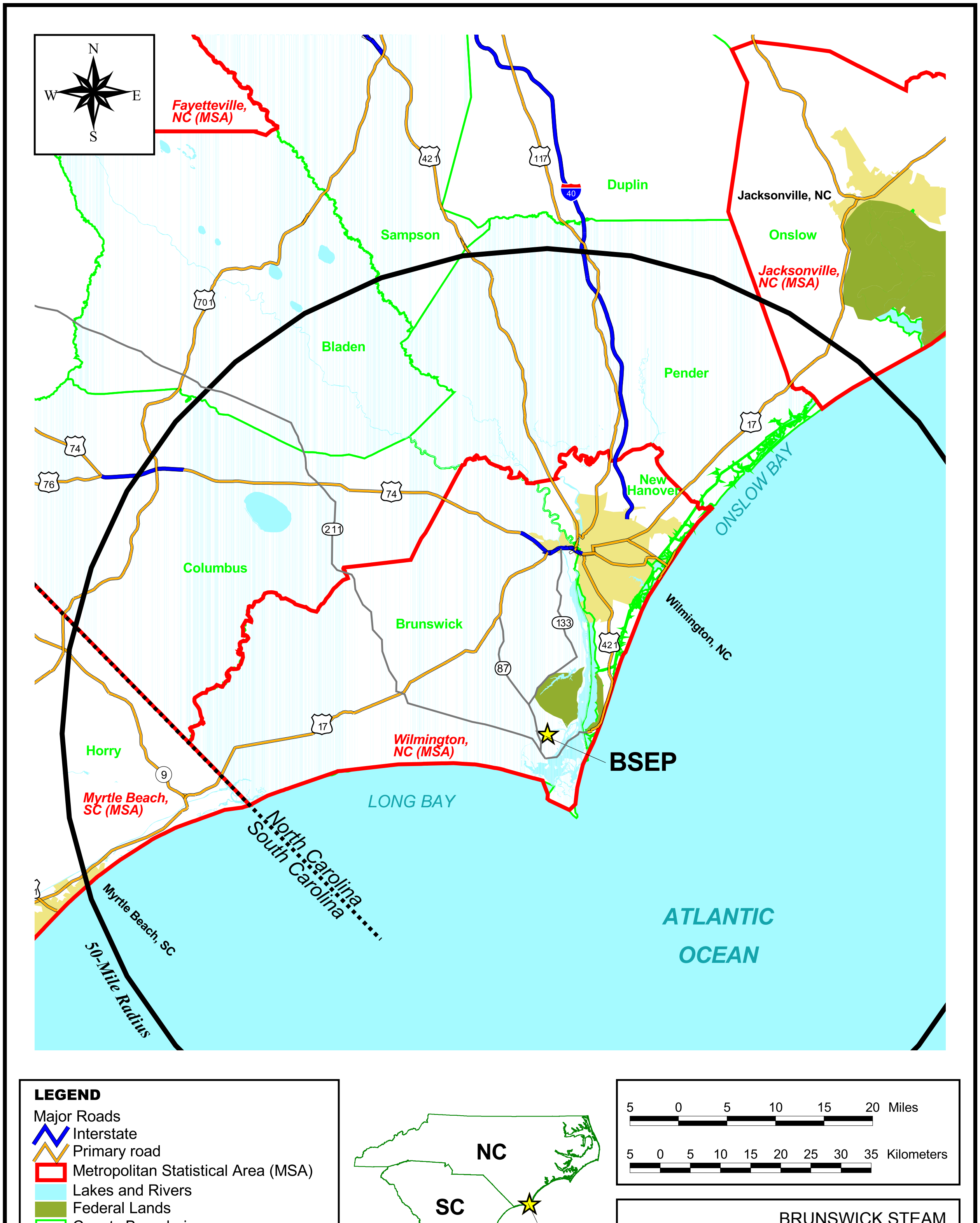
By this certification that BSEP license renewal is consistent with North Carolina’s coastal zone management program, North Carolina is notified that it has six months from receipt of this letter and accompanying information in which to concur with or object to Progress Energy’s certification. However, pursuant to 301 CMR 21.08(3)(b), if North Carolina has not issued a decision within three months following the commencement of state agency review, it shall notify the contacts listed below of the status of the matter and the basis for further delay. North Carolina’s concurrence, objection, or notification of review status shall be sent to:

Mr. Richard L. Emch
Senior Project Manager
United States Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Rockville, MD 20852-2738

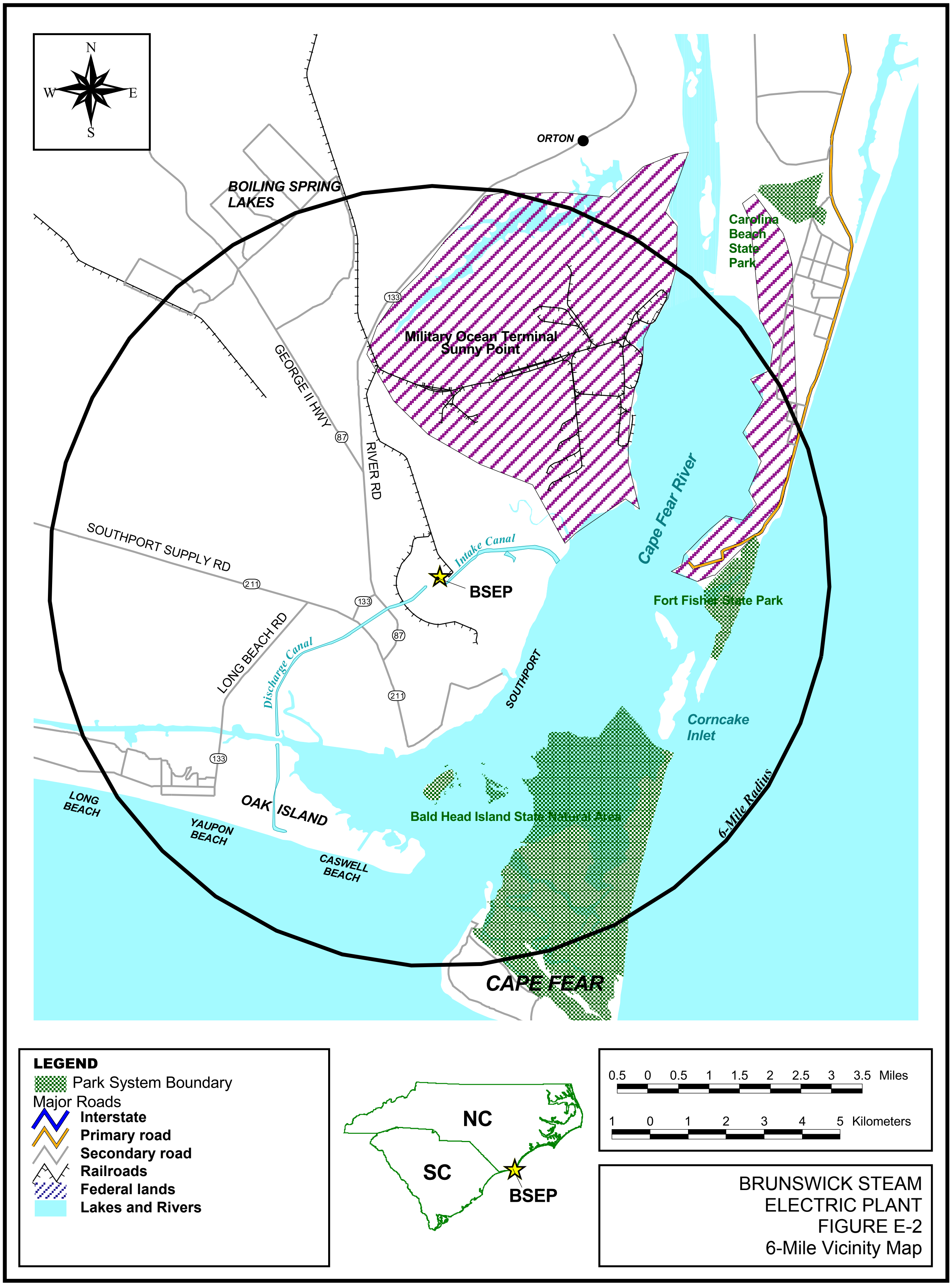
Mr. C. J. Gannon
Vice President
Brunswick Steam Electric Plant
Carolina Power & Light Company
Post Office Box 10429
Southport, North Carolina 28461

REFERENCES

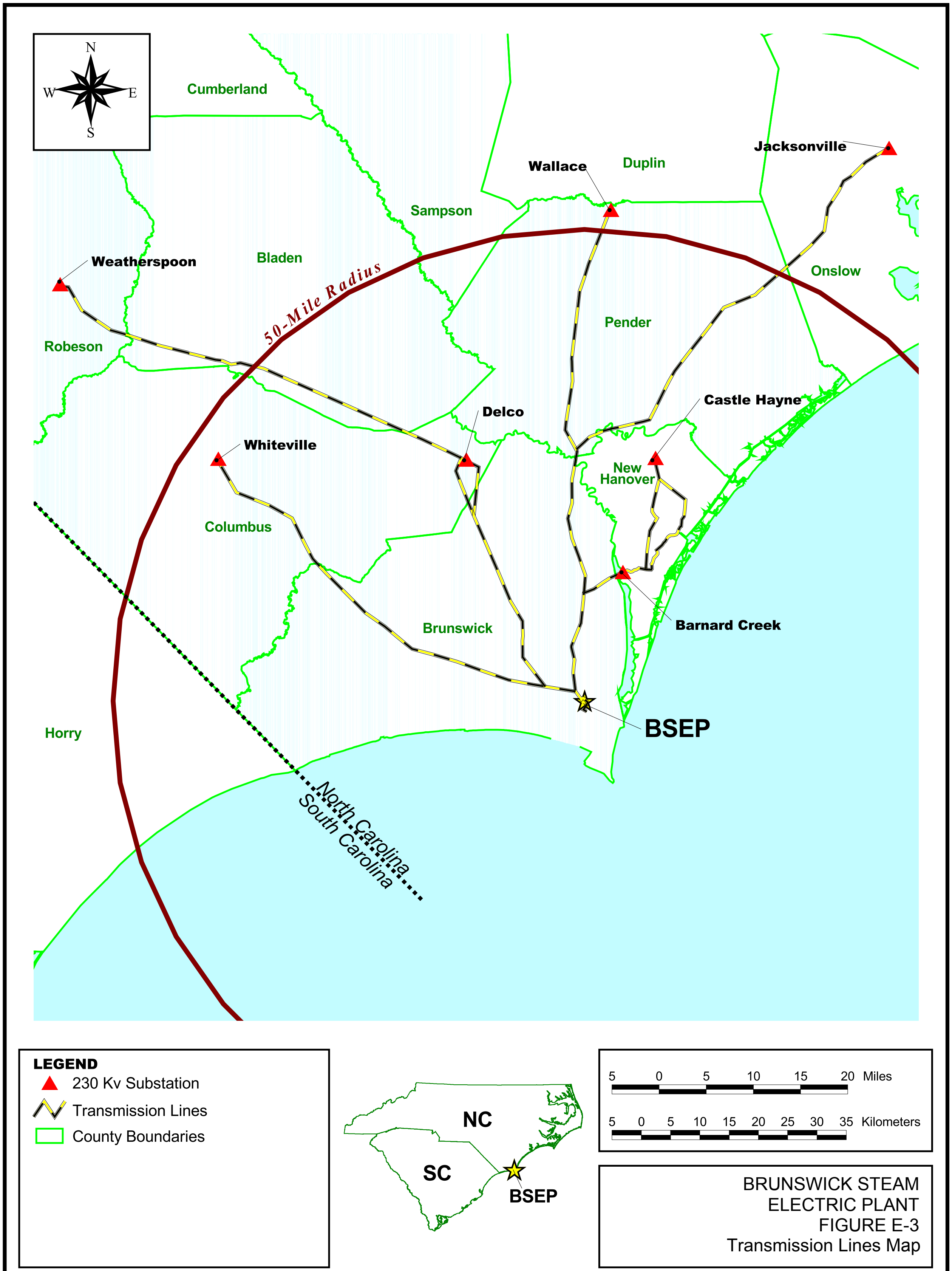
1. *NRR Office Instruction No. LIC-203, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues."* U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation. June 21, 2001.
2. *State and Territory Coastal Management Program Summaries*, National Oceanic and Atmospheric Administration. Available on line at http://www.ocrm.nos.noaa.gov/czm/czmsitelist.html (accessed April 23, 2003).
3. *Generic Environmental Impact statement for License Renewal Nuclear Plants*, U. S. Nuclear Regulatory Commission, NUREG-1437, May 1996. Available on line at http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1437. Accessed 12-23-03.
4. NMFS (National Marine Fisheries Service). 2000. Endangered Species Act – Section 7 Consultation Biological Opinion: Operation of the Cooling Water Intake System at the Brunswick Steam Electric Plant Carolina Power and Light Company. January 20.
5. BSEP (Brunswick Steam Electric Plant). 2002. Endangered and Threatened Species. EVC-SUBS-00011, Rev 0. October.
6. North Carolina Department of Environment and Natural Resources. No Date. Division of Coastal Management. Available at http://dcm2.enr.state.nc.us/index.htm. Accessed April 23, 2003.
7. North Carolina Administrative Code, Title 15A Department of Environment, Health, and Natural Resources, Chapter 7, Coastal Management.



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE E-1
50-Mile Vicinity Map



BRUNSWICK STEAM ELECTRIC PLANT
FIGURE E-2
6-Mile Vicinity Map



BRUNSWICK STEAM
ELECTRIC PLANT
FIGURE E-3
Transmission Lines Map

Table E-1
Environmental Authorizations for Current
BSEP Units 1 and 2 Operations

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
		Federal Requirements to License Renewal			
U. S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011, et seq.), 10 CFR 50.10	License to operate	Unit 1: DPR-71 Unit 2: DPR-62	Issued 11/12/1976 Expires 9/8/2016 Issued 12/27/74 Expires 12/27/2014	Operation of Units 1 and 2
U.S. Fish and Wildlife Service	16 USC 703-712	Federal Fish and Wildlife Permit, Depredation	MB789112-0	Issued 4/01/03; Expires 3/31/04	Removal and relocation of migratory bird nests
U.S. Department of Transportation	49 USC 5108	Registration	050603550001L	Issued 5/06/03; Expires 6/30/04	Hazardous materials shipments
North Carolina Department of Environment and Natural Resources, Division of Water Quality	Clean Water Act (33 USC 1251 et seq.), NC General Statute 143-215.1	National Pollutant Discharge Elimination System Permit	NC0007064	Issued 6/30/03 Expires 11/30/06	Wastewater discharges to Atlantic Ocean (Part I) and stormwater discharges to waters of the State (Part II).

Table E-1
Environmental Authorizations for Current
BSEP Units 1 and 2 Operations (continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
North Carolina Department of Environment and Natural Resources, Division of Waste Management	NC General Statutes 143-215.95 et. Seq., Part 3 of the NC Oil Pollution and Hazardous Substances Control Act	Certificate of Registration of Oil Terminal Facility	104021005	Issued 2/29/00 updated as necessary to reflect changes of facilities/operation s/organization	PE operation of an oil terminal supplying fuel to emergency diesel generator and lubrication oils
North Carolina Department of Environment and Natural Resources, Division of Air Quality	Clean Air Act Construction and Operating Permit (42 USC 7661 et seq.); NC General Statutes Article 21B of Chapter 143	Air Permit	5556R13	Issued 12/17/03; Expires 12/01/08	Air emissions for boilers and emergency generators source operation
North Carolina Department of Environment and Natural Resources, Division of Coastal Management	Federal Coastal Zone Management Act (16 USC 1451 et seq); State Dredge and Fill Permit (NC General Statutes 113-229)	Dredging Permit	293	Issued 10/20/03; Expires 12/31/06	Maintenance dredging of existing cooling water intake canal
North Carolina Wildlife Resources Commission	Endangered Species Act of 1973 (16 USC 1531-1544)	Endangered Species Permit - Sea Turtles	04ST49	Issued 1/15/04; Expires 12/31/04	Tagging, Possession and Disposition of Entrained or Stranded Sea Turtles

Table E-1
Environmental Authorizations for Current
BSEP Units 1 and 2 Operations (continued)

Agency	Authority	Requirement	Number	Issue or Expiration Date	Activity Covered
North Carolina Wildlife Resources Commission	NC Statutory Authority 113-274(c)(1)(a) NC Administrative Code Title 15A, Subchapter 10B.0106	Special Migratory Bird Permit	No Number	Issued 1/30/03; Expires 12/31/03	Removal and relocation of migratory bird nests
South Carolina Department of Health and Environmental Control, Division of Waste Management	South Carolina Radioactive Waste Transportation and Disposal Act (Act No. 429)	South Carolina Radioactive Waste Transport Permit	0041-32-04	Issued 11/20/03; Expires 12/31/04	Transportation of radioactive waste into the State of South Carolina
Utah Department of Environmental Quality, Division of Radiation Control	Utah Division of Radiation Control Rule R313-26	Utah Radiation Control Generator Site Access Permit	0109000007	Issued 9/30/01; Expires 6/30/04	Transportation of radioactive waste into the State of Utah
State of Tennessee Department of Environment and Conservation, Division of Radiological Health	Tennessee Department of Environment and Conservation Rule 1200-2-10.32	Tennessee Radioactive Waste License-for-Delivery	T-NC001-L04	Issued 1/01/04; Expires 12/31/04	Transportation of radioactive waste into the State of Tennessee

Table E-2
Environmental Authorizations for
BSEP Units 1 and 2 License Renewal[a]

Agency	Authority	Requirement	Remarks
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.)	License renewal	Environmental Report submitted in support of license renewal application
U.S. Fish and Wildlife Service	Endangered Species Act Section 7 (16 USC 1536)	Consultation	Requires federal agency issuing a license to consult with the U.S. Fish and Wildlife Service
North Carolina Department of Environment and Natural Resources	Clean Water Act Section 401 (33 USC 1341)	Certification	State issuance of NPDES permit (Section 9.1.5) constitutes 401 certification
North Carolina Division of Coastal Management	Coastal Zone Management Act (16 USC 1452 et seq.)	Certification	Requires applicant to prove certification to federal agency issuing the license that license renewal would be consistent with the federally approved State Coastal Zone Management program. Based on its review of the proposed activity, the State must concur with or object to the applicant's certification
North Carolina Department of Cultural Resources	National Historic Preservation Act Section 106 (16 USC 470f)	Certification	Requires federal agency issuing a license to consider cultural impacts and consult with State Historic Preservation Officer (SHPO). SHPO must concur that license renewal will not affect any sites listed or eligible for listing

a. No renewal-related requirements identified for local or other agencies.

Table E-3
Endangered and Threatened Species Known to Occur in Brunswick County or in Counties Crossed by BSEP-Associated Transmission Lines[a]

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Mammals			
Neotoma floridana haematoreia	Eastern woodrat – Coastal Plain population	-	T
Puma concolor couguar	Eastern cougar	E	E
Trichechus manatus	Manatee	E	E
Birds			
Charadrius melodus	Piping plover	T	T
Falco peregrinus	Peregrine falcon	-	E
Haliaeetus leucocephalus	Bald eagle	T	E
Mycteria americana	Wood stork	E	E
Picoides borealis	Red-cockaded woodpecker	E	E
Sterna nilotica	Gull-billed tern	-	T
Reptiles and Amphibians			
Alligator mississippiensis	American alligator	T(S/A)	T
Ambystoma tigrinum	Tiger salamander	-	T
Caretta caretta	Loggerhead sea turtle	T	T
Chelonia mydas	Green sea turtle	T	T
Dermochelys coriacea	Leatherback sea turtle	E	E
Eretmochelys imbricate	Hawksbill sea turtle	E	E
Lepidochelys kempii	Kemp's ridley sea turtle	E	E
Rana capito	Carolina gopher frog	-	T
Fish			
Acipenser brevirostrum	Shortnose sturgeon	E	E
Elassoma boehlkei	Carolina pygmy sunfish	-	T
Etheostoma perlongum	Waccamaw darter	-	T
Menidia extensa	Waccamaw silverside	T	T
Invertebrates			
Anodonta couperiana	Barrel floater (mussel)	-	E
Catinella vermata	Suboval ambersnail	-	T
Elliptio marsupiobesa	Cape Fear spike (mussel)	-	T
E. roanokensis	Roanoke slabshell (mussel)	-	T
E. waccamawensis	Waccamaw spike (mussel)	-	T

Table E-3
Endangered and Threatened Species Known to Occur in Brunswick County or in Counties Crossed by BSEP-Associated Transmission Lines[a] (continued)

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Fusconaia masoni	Atlantic pigtoe (mussel)	-	T
Lampsilis cariosa	Yellow lampmussel	-	T
L. fullerkati	Waccamaw fatmucket (mussel)		
Planorbella magnifica	Magnificent rams-horn (snail)	-	E
Toxolasma pullus	Savannah lilliput (mussel)	-	T
Triodopsis soelneri	Cape Fear threetooth (snail)	-	T
Plants			
Adiantum capillus-veneris	Venus hair fern	-	E
Amaranthus pumilus	Seabeach amaranth	T	T
Amorpha georgiana var *confusa*	Savanna indigo-bush	-	T
A. g. var *georgiana*	Georgia indigo-bush	-	E
Asplenium heteroresiliens	Carolina spleenwort	-	E
Astragalus michauxii	Sandhills milk-vetch	-	T
Calopogom multiflorus	Many-flowered grass-pink	-	E
Carex lutea	Golden sedge	E	E
Carya myristiciformis	Nutmeg hickory	-	T
Chrysoma pauciflosculosa	Woody goldenrod	-	E
Fimbristylis perpusilla	Harper's fimbry	-	T
Helenium brevifolium	Littleleaf sneezeweed	-	E
H. vernale	Dissected sneezeweed		E
Lindera melissifolia	Southern spicebush	E	E
L. subcoriacea	Bog spicebush	-	E
Lilaeopsis carolinensis	Carolina grasswort	-	T
Lophiola aurea	Golden crest	-	E
Lysimachia asperulaefolia	Rough-leaved loosestrife	E	E
Macbridea caroliniana	Carolina bogmint	-	T
Muhlenbergia torreyana	Pinebarren smokegrass	-	E
Myriophyllum laxum	Loose watermilfoil	-	T
Panicum hirstii	Hirsts' panic grass	C	E
Parnassia caroliniana	Carolina grass-of-parnassus	-	E
P. grandifolia	Large-leaved grass-of-parnassus	-	T
Plantago sparsiflora	Pineland plantain	-	E

Table E-3
Endangered and Threatened Species Known to Occur in Brunswick County or in Counties Crossed by BSEP-Associated Transmission Lines[a] (continued)

Scientific Name	Common Name	Federal Status[b]	State Status[b]
Plantanthera integra	Yellow fringeless orchid	-	T
P. nivea	Snowy orchid		T
Pteroglossapsis ecristata	Spiked medusa	-	E
Rhexia aristosa	Awned meadow-beauty	-	T
Rhus michauxii	Michaux's sumac	E	E
Rhynchospora thornei	Thorne's beaksedge	-	E
Schwalbea americana	American chaffseed	E	E
Solidago pulchra	Carolina goldenrod	-	E
Sporobolus teretifolius	Wireleaf dropseed	-	T
Stylisma pickeringii var *pickeringii*	Pickering's dawnflower	-	E
Thalictrum cooleyi	Cooley's meadowrue	E	E
Trillium pusillum var *pusillum*	Carolina least trillium	-	E
Utricularia olivacea	Dwarf bladderwort	-	T

Source: USFWS 2002a, CP&L 1998, NC DENR 2001, NC DENR 2002

a. Bladen, Brunswick, Columbus, New Hanover, Pender, Onslow, and Robeson counties.

b. E = Endangered; T = Threatened; T(S/A) = Threatened due to similarity of appearance; a species which is protected because it is very similar in appearance to a listed species; - = Not listed.

Attachment E-1

North Carolina Coastal Regulations Passed by the CRC

The North Carolina Coastal Area Management Act (the Act) establishes a Coastal Resources Commission (CRC) within the Department of Environment and Natural Resources[5] which is responsible for administering the Act.

The purpose of the Act is found in Section 113-102(b) of the statute:

(1) To provide a management system capable of preserving and managing the natural ecological conditions of the estuarine system, the barrier dune system, and the beaches, so as to safeguard and perpetuate their natural productivity and their biological, economic and esthetic values;

(2) To insure that the development or preservation of the land and water resources of the coastal area proceeds in a manner consistent with the capability of the land and water for development, use, or preservation based on ecological considerations;

The Act is codified in the North Carolina Administrative Code (NCAC)[6] and requires that "[S]tate guidelines for the coastal area shall consist of statements of objectives, policies and standards to be followed in public and private use of land and water areas within the coastal area."[7] The Act further states that "[S]uch guidelines shall be used … for review of and comment on proposed … federal agency activities that are subject to review for consistency with state guidelines for the coastal area."[8] Finally, the Act stipulates that each county shall prepare a land use plan that "consist[s] of objectives, policies and standards to be followed in public and private use of land within the county…."[9] Therefore entities seeking approval for coastal activities must demonstrate that the activity is consistent with all policies passed by the CRC, regulations administered under the authority of the CRC by the Division of Coastal Management, and local land-use plans certified by the CRC.

Progress Energy is seeking NRC renewal of operating licenses for Brunswick Steam Electric Plant Units 1 and 2. The following paragraphs enumerate provisions of NCAC Subchapter 7M, General Policy Guidelines for the Coastal Area, and provide the Progress Energy demonstration that BSEP license renewal would be consistent with these guidelines. Attachments E-2 through E-5 enumerate land use policies of the coastal counties in which BSEP and its associated transmission lines are located and demonstrate that BSEP license renewal would be consistent with those policies.

Because Progress Energy has no plans for further development of the BSEP during the license renewal term, those provisions of the CAMA dealing with "development" do not apply and are not addressed here.

<u>Subchapter 7M – General Policy Guidelines for the Coastal Area</u>

<u>15A NCAC 07M. 0102 Purpose</u> – The purpose of these rules is to establish generally applicable objectives and policies to be followed in the public and private use of land and water areas within the coastal area of North Carolina.

> <u>Progress Energy Response</u> - GS 113A-103(2) defines the coastal area and directs the Governor to designate the counties that constitute the "coastal area." Twenty counties comprise the North Carolina coastal area, including Brunswick County, where BSEP is located, and New Hanover, Pender and Onslow counties, which are crossed by transmission lines associated with BSEP.

[5] North Carolina General Statute 113A-104.
[6] North Carolina Administrative Code (NCAC) Title 15A, Department of Environment and Natural Resources, Chapter 7, Coastal Management
[7] NC General Statutes. Article 7, Coastal Area Management, Part 1, Organization and Goals, § 113A-107(a), State guidelines for the coastal area.
[8] GS §113A-107(a).
[9] GS §113A-110(a).

BSEP Units 1 and 2 operations, begun in 1976 and 1974, respectively, pre-dated federal approval of the North Carolina Coastal Area Management Act in 1978. Since operations began, the state has issued a number of licenses, permits, and other authorizations for construction and operations at BSEP. The state also reviews required reports on BSEP operations (e.g., NPDES discharge monitoring reports) and routinely inspects the BSEP site and facilities. Through review of permit applications and required monitoring, together with routine inspections, the state assures itself and Progress Energy that BSEP is in compliance with state environmental protection policies, including those for coastal zone management.

Section .0200 – Shoreline Erosion Policies
15A NCAC 07M .0202 Policy statements–

(a) Pursuant to Section 5, Article 14 of the North Carolina Constitution, proposals for shoreline erosion response projects shall avoid losses to North Carolina's natural heritage.

(b) Erosion response measures designed to minimize the loss of private and public resources to erosion should be economically, socially, and environmentally justified. Preferred response measures for shoreline erosion shall include but not be limited to Areas of Environmental Concern (AEC) rules, land use planning and land classification, establishment of building setback lines, building relocation, subdivision regulations and management of vegetation.

(c) The replenishment of sand on ocean beaches can provide storm protection and a viable alternative to allowing the ocean shoreline to migrate landward threatening to degrade public beaches and cause the loss of public facilities and private property.

(d) The following are required with state involvement (funding or sponsorship) in beach restoration and sand renourishment projects:

1. the entire restored portion of the beach shall be in permanent public ownership;
2. it shall be a local government responsibility to provide adequate parking, public access, and services for public recreational use of the restored beach.

(e) Temporary measures to counteract erosion, such as the use of sandbags and beach pushing, should be allowed, but only to the extent necessary to protect property for a short period of time until threatened structures may be relocated, or until effects of a short-term erosion event are reversed.

(f) Efforts to permanently stabilize the location of the ocean shoreline with seawalls, groins, shoreline hardening, sand trapping or similar protection devices should not be allowed except when the project meets one of the specific exceptions set out in 15A NCAC 7H .0308 [ocean hazard areas].

(g) The state of North Carolina will consider innovative institutional programs and scientific research that will provide for effective management of coastal shorelines.

(h) The planning, development and implementation of erosion control projects will be coordinated with appropriated planning agencies, affected governments, and interested public.

(i) The state will promote education of the public on the dynamics of nature of the coastal zone and on effective measure to cope with our ever changing shorelines.

Progress Energy Response – Brunswick County land use maps indicate the area in the immediate vicinity of BSEP is dry, sloping upland. The manmade intake and discharge canals are not considered estuarine shoreline, though both pass through floodplains and salt marshes. Transmission corridors cross streams and run through swamps, but do not occur along Atlantic beaches. Transmission corridor maintenance involves mowing, handcutting, and herbicide applications and is governed by procedures, including MNT-TRMX-00176, Transmission line right of way. Routine maintenance is consistent with, and in most cases exempt from, CAMA regulations.

The pumping station at Caswell Beach is within the ocean hazard Area of Environmental Concern. Progress Energy owns approximately 3 acres of beachfront land between the Caswell Beach pumping station and the Atlantic Ocean. In the event of serious erosion, Progress Energy would cooperate with appropriate state and federal agencies to renourish the beach. Progress Energy has no plans for license renewal that would affect the ocean shoreline or its potential to erode.

Section .0300 – Shorefront Access Policies
15A NCAC 07M .0301 Declaration of General Policy

(a) The public has traditionally and customarily had access to enjoy and freely use the ocean beaches and estuarine and public trust waters of the coastal region for recreational purposes and the state has a responsibility to provide continuous access to these resources.

(b) The state has created an access program for the purpose of acquiring, improving and maintaining waterfront recreational property at frequent intervals throughout the coastal region for pedestrian access to the important public resources.

(c) In addition, some properties, due to their location, are subject to severe erosion so that development here is not possible or feasible. In these cases, a valid public purpose may be served by the donation, acquisition and improvement of these properties for public access.

Progress Energy Response – The public has access to Caswell Beach via a parking lot on Progress Energy property and to a freshwater canal near the discharge canal via a public boat ramp on Progress Energy property. Progress Energy has no license renewal plans that would limit public use of the Caswell Beach parking lot or he adjacent beachfront.

Section .0400 – Coastal Energy Policies
15A NCAC 07M .0401 Declaration of General Policy

(a) It is hereby declared that the general welfare and public interest require that reliable sources of energy be made available to the citizens of North Carolina. It is further declared that the development of energy facilities and energy resources within the state and in offshore waters can serve important regional and national interests. However, unwise development of energy facilities or energy resources can conflict with the recognized and equally important public interest that rests in conserving and protecting the valuable land and water resources of the state and nation, particularly coastal lands and waters. Therefore, in order to balance the public benefits attached to necessary energy development against the need to protect valuable coastal resources, the planning of future land uses, the exercise of regulatory authority, and determinations of consistency with the North Carolina Coastal Management Program shall assure that the development of energy facilities and energy resources shall avoid significant adverse impact upon vital coastal resources or uses, public trust areas and public access rights.

(b) Exploration for the development of offshore and Outer Continental Shelf (OCS) energy resources has the potential to affect coastal resources. The federal Coastal Zone Management Act of 1972, as amended, requires that federal oil and gas leasing actions of the US Department of the Interior be consistent to the maximum extent practicable with the enforceable policies of the federally approved North Carolina Coastal Management Program, and that exploration, development and production activities associated with such leases comply with those enforceable policies. Enforceable policies applicable to OCS activities include all the provisions and policies of this Rule, as well as any other applicable federally approved components of the North Carolina Coastal Management Program. All permit applications, plans and assessments related to exploration or development of OCS resources and other relevant energy facilities must contain sufficient information to allow adequate analysis of the consistency of all proposed activities with these Rules and policies.

Progress Energy Response – Progress Energy operates BSEP, a power-generating facility, in compliance with all applicable state and federal permits and authorizations. Progress Energy has no plans to conduct refurbishment or construction activities, or to change current operations during the license renewal term. Therefore, policies relating to the development of energy facilities are not applicable to the BSEP license renewal term. Progress Energy has no plans for offshore exploration for the development of energy sources. Therefore, no specific coastal energy policies are relevant to BSEP operations during the license renewal term.

SECTION .0500 - POST-DISASTER POLICIES
15A NCAC 07M .0501 DECLARATION OF GENERAL POLICY

It is hereby declared that the general welfare and public interest require that all state agencies coordinate their activities to reduce the damage from coastal disasters. As predisaster planning can lay the groundwork for better disaster recovery, it is the policy of the state of North Carolina that adequate plans for post-disaster reconstruction should be prepared by and coordinated between all levels of government prior to the advent of a disaster.

Progress Energy Response - Progress Energy believes that this policy applies to the state and for natural disasters, and not to private entities.

SECTION .0600 - FLOATING STRUCTURE POLICIES
15A NCAC 07M .0601 DECLARATION OF GENERAL POLICY

It is hereby declared that the general welfare and public interest require that floating structures to be used for residential or commercial purposes not infringe upon the public trust rights nor discharge into the public trust waters of the coastal area of North Carolina.

Progress Energy Response **-** 15A NCAC 07M .0602 defines a floating structure as "any structure, not a boat, supported by a means of flotation, designed to be used without a permanent foundation, which is used or intended for human habitation or commerce. A structure will be considered a floating structure when it is inhabited or used for commercial purposes for more than thirty days in any one location. A boat may be deemed a floating structure when its means of propulsion has been removed or rendered inoperative and it contains at least 200 square feet of living space area."

Progress Energy has no floating structures associated with BSEP, nor any plans to construct or purchase any such floating structure during the license renewal term. Therefore, this policy is not relevant to BSEP license renewal and no specific policy statements on floating structures are included in this certification document.

SECTION .0700 - MITIGATION POLICY
15A NCAC 07M .0701 DECLARATION OF GENERAL POLICY

(a) It is the policy of the state of North Carolina to require that adverse impacts to coastal lands and waters be mitigated or minimized through proper planning, site selection, compliance with standards for development, and creation or restoration of coastal resources. Coastal ecosystems shall be protected and maintained as complete and functional systems by mitigating the adverse impacts of development as much as feasible by enhancing, creating, or restoring areas with the goal of improving or maintaining ecosystem function and areal proportion.
(b) The CRC shall apply mitigation requirements as defined in this Section consistent with the goals, policies and objectives set forth in the Coastal Area Management Act for coastal resource management and development. Mitigation shall be used to enhance coastal resources and offset any potential losses occurring from approved and unauthorized development. Proposals to mitigate losses of coastal resources shall be considered only for those projects shown to be in the public interest, as defined by the standards in 15A NCAC 7M .0703, and only after all other reasonable means of avoiding or minimizing such losses have been exhausted.

Progress Energy Response - Progress Energy believes this policy is relevant to new development in coastal counties. Progress Energy plans no refurbishment or major construction at BSEP or along associated transmission lines associated with the license renewal term. Therefore, this policy is not relevant to license renewal and no specific mitigation policy statements are included in this certification document.

SECTION .0800 - COASTAL WATER QUALITY POLICIES
15A NCAC 07M .0801 DECLARATION OF GENERAL POLICIES

(a) The waters of the coastal area are a valuable natural and economic resource of statewide significance. Traditionally these waters have been used for such activities as commercial and recreational fishing, swimming, hunting, recreational boating, and commerce. These activities depend upon the quality of the waters. Due to the importance of these activities to the quality of life and the economic well-being of the coastal area, it is important to ensure a level of water quality which will allow these activities to continue and prevent further deterioration of water quality. It is hereby declared that no land or water use shall cause the degradation of water quality so as to impair traditional uses of the coastal waters. To the extent that statutory authority permits, the Coastal Resources Commission will take a lead role in coordinating these activities.
(b) It is further recognized that the preservation and enhancement of water quality is a complex issue. The deterioration of water quality in the coastal area has many causes. The inadequate treatment of human wastes, the improper operation of boats and their sanitation devices, the creation of increased runoff by covering the land with buildings and pavement and removing natural vegetation, the use of outdated practices on fields and woodlots and many other activities impact the water quality. Activities outside the coastal area also impact water quality in the coastal area. Increases in population will continue to add to the water quality problems if care is not taken in the development of the land and use of the public trust waters.
(c) Protection of water quality and the management of development within the coastal area is the responsibility of many agencies. It is hereby declared that the general welfare and public interest require that all state, federal and local agencies coordinate their activities to ensure optimal water quality.

15A NCAC 07M .0802 POLICY STATEMENTS

(a) All of the waters of the state within the coastal area have a potential for uses which require optimal water quality. Therefore, at every possible opportunity, existing development adjacent to these waters shall be upgraded to reduce discharge of pollutants.
(b) Basin wide management to control sources of pollution both within and outside of the coastal area which will impact waters flowing into the rivers and sounds of the coastal area is necessary to preserve the quality of coastal waters.
(c) The adoption of methods to control development so as to eliminate harmful runoff which may impact the sounds and rivers of the coastal area and the adoption of best management practices to control runoff from undeveloped lands is necessary to prevent the deterioration of coastal waters.

Progress Energy Response – BSEP currently holds an NPDES permit that allows the plant to discharge storm water into Nancy's Creek and storm water, wastewater, and cooling water into the Atlantic Ocean. BSEP's NPDES permit conditions and permit limits (effluent limitations) are periodically reevaluated by NCDENR to ensure that the best available technology is in place to prevent water quality degradation. In addition, other on-going activities at BSEP, such as periodic maintenance dredging of intake and discharge canals, are conducted under and in accordance with permits issued by the Division of Coastal Management. Prior to issuance, those permits are reviewed and approved by other state and federal agencies to ensure consistency with water quality, land use, and other environmental regulatory programs. Policies (b) and (c) do not apply to BSEP.

SECTION .0900 - POLICIES ON USE OF COASTAL AIRSPACE
15A NCAC 07M .0901 DECLARATION OF GENERAL POLICY

It is hereby declared that the use of aircraft by state, federal and local government agencies for purposes of managing and protecting coastal resources, detecting violations of environmental laws and rules and performing other functions related to the public health, safety and welfare serves a vital public interest. The Commission further finds that future economic development in the coastal area and orderly management of such development requires air access to and among coastal communities.

> Progress Energy Response - Progress Energy does routinely not use aircraft at BSEP. Because BSEP is a nuclear facility, security requirements may restrict the airspace for some distance around the facility, however. Progress Energy believes that any limited restricted airspace in the vicinity of the plant would not inhibit the development of the coastal area in the vicinity of BSEP, nor would it prevent state, federal or local governments from carrying out their assigned functions.

SECTION .1000 - POLICIES ON WATER AND WETLAND BASED TARGET AREAS FOR MILITARY TRAINING ACTIVITIES
15A NCAC 07M .1001 DECLARATION OF GENERAL POLICY

The use of water and wetland-based target areas for military training purposes may result in adverse impacts on coastal resources and on the exercise of public trust rights. The public interest requires that, to the maximum extent practicable, use of such targets not infringe on public trust rights, cause damage to public trust resources, violate existing water quality standards or result in public safety hazards.

> Progress Energy Response - The U.S. Government does not use waters or wetlands at BSEP as target areas for military training.

SECTION .1100 - POLICIES ON BENEFICIAL USE AND AVAILABILITY OF MATERIALS RESULTING FROM THE EXCAVATION OR MAINTENANCE OF NAVIGATIONAL CHANNELS

15A NCAC 07M .1101 DECLARATION OF GENERAL POLICY

Certain dredged material disposal practices may result in removal of material important to the sediment budget of ocean and inlet beaches. This may, particularly over time, adversely impact important natural beach functions especially during storm events and may increase long term erosion rates. Ongoing channel maintenance requirements throughout the coastal area also lead to the need to construct new or expanded disposal sites as existing sites fill. This is a financially and environmentally costly undertaking. In addition, new sites for disposal are increasingly harder to find because of competition from development interests for suitable sites. Therefore, it is the policy of the state of North Carolina that material resulting from the excavation or maintenance of navigation channels be used in a beneficial way wherever practicable.

15A NCAC 07M .1102 POLICY STATEMENTS

(a) Clean, beach quality material dredged from navigation channels within the active nearshore, beach, or inlet shoal systems must not be removed permanently from the active nearshore, beach or inlet shoal system unless no practicable alternative exists. Preferably, this dredged material will be disposed of on the ocean beach or shallow active nearshore area where environmentally acceptable and compatible with other uses of the beach.
(b) Research on the beneficial use of dredged material, particularly poorly sorted or fine grained materials, and on innovative ways to dispose of this material so that it is more readily accessible for beneficial use is encouraged.
(c) Material in disposal sites not privately owned shall be available to anyone proposing a beneficial use not inconsistent with Paragraph (a) of this Rule.
(d) Restoration of estuarine waters and public trust areas adversely impacted by existing disposal sites or practices is in the public interest and shall be encouraged at every opportunity.

Progress Energy Response – Progress Energy periodically dredges deposited material from the intake canal and, less frequently, from the discharge canal. This material is generally not of "beach quality," nor is it suitable for structural use, and has thus been placed in on-site, permitted spoil ponds. Progress Energy would support innovative disposal and beneficial use of this material where possible.

SECTION .1200 - POLICIES ON OCEAN MINING
15A NCAC 07M .1201 DECLARATION OF GENERAL POLICY

(a) The Atlantic Ocean is designated a Public Trust Area of Environmental Concern (AEC) out to the three-mile state jurisdictional boundary; however, the ocean environment does not end at the state/federal jurisdictional boundary. Mining activities impacting the federal jurisdiction ocean and its resources can, and probably would, also impact the state jurisdictional ocean and estuarine systems and vice-versa. Therefore, it is state policy that every avenue and opportunity to protect the physical ocean environment and its resources as an integrated and interrelated system will be utilized.
(b) The usefulness, productivity, scenic, historic and cultural values of the state's ocean waters will receive the greatest practical degree of protection and restoration. No ocean mining shall be conducted unless plans for such mining include reasonable provisions for protection of the physical environment, its resources, and appropriate reclamation or mitigation of the affected area as set forth and implemented under authority of the Mining Act (G.S. 74-48) and Coastal Area Management Act (G.S. 113A-100).
(c) Mining activities in state waters, or in federal waters insofar as the activities affect any land, water use or natural or historic resource of the state waters, shall be done in a manner that provides for protection of those resources and uses. The siting and timing of such activities shall be consistent with established state standards and regulations and shall comply with applicable local land use plan policies, and AEC use standards.

Progress Energy Response - Progress Energy does not mine the ocean. This policy is not relevant to BSEP operations, therefore, no additional specific policy statements are included in this certification document.

Attachment E-2

Brunswick County Land Use Plan Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each of the 20 counties in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county[10]. The most recent Brunswick County Land Use Plan (Ref. 1) available is the 1997 plan. BSEP activities were reviewed for consistency with the policies in the 1997 plan.

BSEP is in the Cape Fear River Watershed and, in the 1997 Brunswick County Land Use Plan, has a land use classification of Industrial. Several transmission lines leave BSEP and traverse Brunswick County in four transmission corridors. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

The following discussion presents the six major land use policies of Brunswick County, and, if BSEP operations could affect the resource protected by the policy, a discussion of BSEP operations as they relate to the policy.

<u>Policy 8.1.1(a)</u>. Development is encouraged to locate in areas without soil suitability problems and where infrastructure is available. In areas where suitability problems exist, engineering solutions are supported to the extent that the natural environment is not compromised.

<u>Policy 8.1.1(b)</u>. In the absence of sewer facilities, the County shall work cooperatively with property owners to evaluate site suitability for septic tank use. When soil conditions are such that, in the opinion of County sanitarians, health or environmental standards would be compromised, full explanation of the reasons for denial shall be given, and alternatives for possible solutions provided.

<u>Policy 8.1.1(c)</u>. Brunswick County supports the administration and enforcement of applicable flood plain management regulations and the national flood insurance program.

<u>Progress Energy Response</u> – These policies are directed at overcoming the limitations on growth due to the lack of a centralized sewage treatment system and the tendency of many areas of the county to flood or be unsuitable for septic systems. Progress Energy has no plans to perform refurbishment or construction on BSEP during the license renewal term, so policies related to development are not relevant to the license renewal application. BSEP has modern sewage treatment facilities and does not plan to increase the number of employees during the license renewal term. Therefore, the current sewage treatment facilities at BSEP are adequate to support the plant through the license renewal term, including planned outages that require additional staff. According to Brunswick County land use maps, BSEP is located on dry uplands, not prone to flooding.

<u>Policy 8.1.2.0.</u> Brunswick County will support and enforce, through its local CAMA permitting capacity, the state policies and permitted uses in the Areas of Environmental Concern (AEC's). Such uses shall be in accord with the general use standards for coastal wetlands, estuarine waters, public trust areas and ocean hazard areas as stated in 15A NCAC Subchapter H.

<u>Progress Energy Response</u> – Attachment E-1 provides information on how BSEP complies with state guidelines found in 15A NCAC Subchapter M for protecting coastal areas, estuarine waters, public trust areas and ocean hazard areas. BSEP is located on dry uplands in an area zoned industrial by the county. The intake and discharge canals traverse estuarine waters, the pumping station at Caswell Beach is in an ocean hazard area, and the transmission lines cross tidal creeks throughout the county. Progress Energy complies with its own procedures and state and federal permitting requirements when performing maintenance work on the plant or associated infrastructure. Progress Energy is in compliance with this policy.

<u>Policy 8.1.2(a).</u> …Brunswick County strongly supports the efforts of the state and federal agencies to properly designate and preserve coastal wetlands…

[10] NCGS § 103A-109.

Progress Energy Response – Progress Energy does not anticipate any further development of the BSEP site. However, Progress Energy does support and comply with the state and federal regulatory programs that ensure protection and orderly development of the coastal area.

Policy 8.1.2(b). Developments and mitigation activities which support and enhance the natural function, cleanliness, salinity, and circulation of estuarine water resources shall be supported.

Progress Energy Response – The greatest potential impact of BSEP operations on the Cape Fear Estuary is on the biological community. BSEP operations have been scrutinized by state and federal resource agencies since Unit 2 came on line in 1974, focusing on potential impacts of the plant's cooling water systems on the Cape Fear Estuary. BSEP has not been found to have adverse impacts on the aquatic communities of the Cape Fear Estuary (as verified by biological monitoring programs required by the state).

Progress Energy holds an NPDES permit for BSEP cooling water withdrawals and discharges. For this reason, and because of mitigation measures in place, Progress Energy concludes that operations at BSEP are in compliance with this policy.

Policy 81.2.(c). …Efforts of state and federal agencies to limit the length of docks and piers as they project into estuarine waters are especially supported.

Progress Energy Response – BSEP has docks and piers in the intake and discharge canals. Progress Energy is not anticipating that license renewal will change any current operations; therefore, BSEP will not require larger or additional docks or piers during the license renewal term.

Policy 8.1.2(d). Brunswick County supports the protection and preservation of its estuarine shorelines, as enforced through the application of CAMA use standards.

Progress Energy Response – Progress Energy has a long history of support of the environment, through corporate contributions, direct employee involvement and other activities. For instance, the Progress Energy Foundation has established a goal of providing direct financial support to non-profit groups and projects that directly benefit buffers, riparian areas and similar areas, including estuarine shorelines.

Policy 8.1.2(e). Brunswick County supports state and federal standards for the management of development in the ocean hazard AEC's under the county planning jurisdiction: the Baptist assembly grounds and part of Bird Island.

Progress Energy Response – Progress Energy has no plans to develop the area around the Caswell Pumping Station due to license renewal. This is the only part of the plant that is near an Ocean Hazard AEC.

Policy 8.1.2(f). Brunswick County supports the designation of Public Water Supply AECs when such designation meets state prerequisites and when such action is deemed necessary to ensure the long term viability of the County's public water supplies.

Progress Energy Response – Currently there are no small surface water supply watersheds or public water supply well fields identified in Brunswick County. BSEP is not located near a Public Water Supply AEC. This policy is not relevant to BSEP or its license renewal application.

Policy 8.1.2(g). Brunswick County supports the selective designation of appropriate areas as natural and cultural resource AEC's.

Progress Energy Response – The designation of areas as AECs lies with the CRC and not with Progress Energy.

Policy 8.1.2(h). The abundance and diversity of wildlife in Brunswick County shall be preserved and enhanced through protection of the unique coastal ecosystem, including marshes, woodlands, open fields, and other areas upon which they depend.

Progress Energy Response – Undeveloped portions of the BSEP site provide habitat for a variety of amphibians, reptiles, songbirds, wading birds, waterfowl, and small mammals. Transmission corridors associated with BSEP transmission lines also provide important wildlife habitat. Progress Energy uses an integrated vegetation management approach to controlling vegetation under its transmission lines. Mowing, hand-cutting and small amounts of EPA-approved herbicides are used to maintain the rights-of-way under the lines. One benefit of this program is that the plant communities that develop under the power lines provide good habitat for species such as songbirds, deer, quail, rabbit, and turkeys. Progress Energy also supports the maintenance of food plots in some rights-of ways, further enhancing the diversity of wildlife that use the corridors as habitat. Progress Energy is in compliance with this policy. Further, Progress Energy has developed a cooperative agreement with NCDENR's Natural Heritage Program under which we identify and protect state and federally listed plant species on our rights-of-way. In many cases, these species are sun-loving, and flourish only in the ROWs, as fire suppression has reduced their normally open, prairie-like habitat.

Policy 8.1.3 There are none at this time.

Policy 8.1.4(a). Brunswick County will continue to support the efforts of the CAMA program and the U.S. Army Corps of Engineers 404 permitting program to preserve and protect sensitive freshwater swamps and marsh areas.

Progress Energy Response –Progress Energy has a corporate goal to fully comply with all applicable environmental regulatory programs.

Policy 8.1.4(b). Maritime forests in Brunswick County shall receive a high level of environmental protection when considering public and private sector use.

Progress Energy Response – Progress Energy has no plans to perform refurbishment or construction during the license renewal term. Therefore, this policy is not relevant to the license renewal application.

Policy 8.1.4(c). Brunswick County supports … efforts to restore the water quality of …estuarine waters in the county to a water quality level deserving of O[utstanding] R[esource] W[aters] designation.

Progress Energy Response – There are currently no ORW identified within Brunswick County. All of the county's estuarine waters have been classified as SA (high quality), but many are closed to shellfishing due to unacceptable fecal coliform counts. BSEP has a permitted sewage treatment facility with effluent limits that prescribe discharge limits below state and federal regulatory limits. Progress Energy is in compliance with this policy.

Policy 8.4.1(d). The County supports and encourages the activities of the state's shellfish management program. The County shall continue to promote estuarine water quality through its stormwater management planning and stormwater runoff policies.

Progress Energy Response – In addition to reducing point source contamination, the county recognizes the need to control nonpoint source runoff. BSEP has an NPDES permit for stormwater discharges that limits contaminant concentrations in the effluent such that the discharge is protective of the receiving waters. Progress Energy is in compliance with this policy.

Policy 8.1.4(e). The county's groundwater resources, including but not limited to the Castle Hayne aquifer, shall be recognized as an invaluable source of public and private potable water and shall receive the highest level of protection when considering County policies, standards and actions, including the possible creation of an overlay district.

Progress Energy Response – BSEP receives its potable water from the Brunswick County Public Utilities (which gets approximately 70 percent of its water from the Lower Cape Fear River and the rest from the Castle Hayne Aquifer). BSEP has one well in the Castle Hayne aquifer that pumps less than 30 gallons per minute. The well serves an intermittently occupied facility. Progress Energy has no plans to change its mode of operations during the license renewal term. Progress Energy is in compliance with this policy.

Policy 8.1.4(f). Brunswick County encourages efforts to protect cultural and historic resources to preserve their cultural, educational and aesthetic values.

Progress Energy Response -- No cultural or natural resources AECs are known on the BSEP site or along the transmission lines. The Natural Historic Preservation Act (NHPA) requires that any proposed activity requiring a federal permit include a consideration of cultural resource impacts prior to initiation of the activity. Progress Energy is in compliance with this Brunswick County policy.

Policy 8.1.4(g). Brunswick County will seek to minimize potential land use conflicts and hazards related to development in areas near existing potentially hazardous facilities.

Progress Energy Response -- BSEP is recognized by Brunswick County as a manmade hazard. Progress Energy's emergency preparedness group works with county emergency planners to ensure that plans are in place to protect life and property in the unlikely event of an emergency at the site. Progress Energy is in compliance with this policy.

Policy 8.1.4(h). Plans for the safe transportation of hazardous materials, for the prevention of cleanup of spills of toxic materials, and for the evacuation of area residents in response to hazardous events shall be supported.

Progress Energy Response -- Progress Energy transports hazardous materials to and from the site. All transportation of hazardous materials follows established Department of Transportation regulations for notification and transport. In addition, Progress Energy's emergency preparedness personnel are trained to clean up hazardous material spills or protect the area in the unlikely event of an accident involving radioactive materials. In conjunction with county emergency response personnel, Progress Energy maintains emergency evacuation plans as part of its license requirements. Progress Energy is in compliance with this policy.

Policy 8.1.5(a). Brunswick County supports federal, state, and local efforts to protect the quantity and quality of water in the Cape Fear River whether such protection involved controls over point sources discharges, surface runoff, interbasin water transfers, or other appropriate means, including upstream activities.

Policy 8.1.5(b). Brunswick County supports federal, state, and local efforts to protect the quantity and quality of water in the region's groundwater system whether such protection involves control over location and management of activities involving hazardous substances, restrictions on groundwater drawdowns, or any other activity which would jeopardize the short and long term viability of groundwater resources.

Progress Energy Response – As stated earlier, BSEP has state-issued NPDES permits which regulate cooling water, wastewater, and stormwater discharges into waters of the state. BSEP gets its potable water from the Brunswick County Public Utilities, and has only one small well withdrawing from the Castle Hayne aquifer. BSEP has no plans to change facility operations during the license renewal term. Progress Energy is in compliance with these policies.

Policy 8.1.5(c). Brunswick County will continue improvements to and expansion of the County's potable, piped water supply system, with emphasis on the development of a self supporting operation, where costs are assigned in relative proportion to benefits conveyed.

Policy 8.5.1 (d). So as to facilitate the orderly development of the County water system, Brunswick County shall establish and maintain utility extension and tap-on policies designed to address the timing, location, priorities and sequence, etc., for system expansion.

Progress Energy Response – These policies apply to County activities and are not relevant to BSEP or Progress Energy.

Policy 8.1.6. Brunswick County advocates the development and use of regional sewage treatment plants over smaller, privately operated package sewage treatment plants. When package treatment plants are employed, they should be designed to allow for future connections to a larger regional system.

Progress Energy Response – Progress Energy operates two package sewage treatment plants at BSEP, one inside and one outside of the protected area. Both are permitted under the NPDES permit. Although these plants could be connected to a regional sewage treatment plant or plants, Progress has no plans for doing so.

Policy 8.1.7(a). Brunswick County shall take a proactive role in the development of storm water management and design standards intended to protect the quality of the county's streams, rivers, marshes, and estuarine systems.

Policy 8.1.7(b). Brunswick County shall support a program of vegetated buffers adjacent to all streams, rivers, marshes, and estuarine waters in the county, with the intent of reducing the flow of nutrients and other contaminants into area surface waters.

Policy 8.1.7(c). Brunswick County shall advocate a policy of stormwater runoff management in which post-development runoff has a rate of flow and volume which approximates, as closely as practical, pre-development conditions.

Progress Energy Response – Progress Energy conducts all land-disturbing activities using policy EVC-SUBS-00022 Land Disturbing Activities which include procedures for minimizing stormwater discharges, maintaining sediment and erosion control measures, and protecting river buffers, wetlands and waters of the U.S. This policy includes full compliance with applicable state and federal stormwater and water quality regulatory programs.

Policy 8.1.8. This policy deals with marinas and commercial fishing operations. Because BSEP is not a marina and Progress Energy owns no marinas nor participates in any commercial fishing, this policy does not apply and is not presented here.

Policy 8.1.9. Industries shall be encouraged to locate in suitable, non-fragile areas. Environmental impacts on air, land, and water resources, as well as compatibility with surrounding land uses and the availability of required services, shall be factors employed in evaluating the merits of any particular industrial development proposal.

Progress Energy Response – BSEP became operational in the 1970s, after thorough regulatory review under the existing environmental protection programs. The site and surrounding land are zoned industrial. Progress Energy holds all appropriate permits for discharges to water and air. Progress Energy has no plans for refurbishment or major construction, or to change the plant operations during the license renewal term. Progress Energy is in compliance with this policy.

Policy 8.1.10. Development of sound and estuarine islands, while not encouraged, is permitted, providing the impacts on the natural environment are properly mitigated….

Progress Energy Response – BSEP is not on an island nor does Progress Energy own any islands in the vicinity of the site. This policy is not applicable to Progress Energy and BSEP.

Policy 8.1.11. Development within areas susceptible to sea level rise, shoreline erosion, and/or wetland loss, should take into consideration such conditions upon initial development.…The County will not permit efforts to harden the shoreline in an attempt to counteract such conditions; however, this policy shall not preclude the use of innovative shoreline preservation techniques as approved by the CRC.

Progress Energy Response – This policy deals with the possibility of sea level rise and shoreline erosion. BSEP is constructed on land not prone to flooding, according to Brunswick County land use maps. The Caswell Beach pumping station could be affected by a rise in sea level, but Progress Energy would modify the facility before rising sea levels caused erosion around the facility. All activities would be in compliance with existing regulations.

Policy 8.1.12. This policy deals with marina basins. The policy is not applicable to Progress Energy or BSEP and is not included here.

Policy 8.1.13. Brunswick County supports state and federal standards which seek to prevent or minimize marsh damage from bulkheads or riprap installation. The County recognizes, however, that some limited marsh damage may be necessary to provide for otherwise environmentally sound development.

Progress Energy Response – When BSEP was constructed, the native marsh grass (*Spartina*) was planted to control erosion of the intake and discharge canals' banks. Progress Energy supports alternative means of controlling erosion rather than riprap or other hardened structures.

Policy 8.1.14. Brunswick County shall encourage and support state and federal standards which seek to prevent or minimize adverse water quality impacts. The county shall work proactively with the state on measures to reduce stormwater runoff rates, soil erosion, and sedimentation, and point source discharges into area waters.

Progress Energy Response – Progress Energy conducts all land-disturbing activities using policy EVC-SUBS-00022 Land Disturbing Activities which include procedures for minimizing stormwater discharges, maintaining sediment and erosion control measures, and protecting river buffers, wetlands and waters of the U.S.

Policy 8.1.15. Brunswick County shall encourage and support state and federal standards which seek to prevent or minimize adverse air quality impacts. The County shall work constructively with state and federal agencies and local industries on measures to reduce or eliminate air quality problems, including odor problems that may not fall under prescribed environmental standards.

Progress Energy Response – Progress Energy operates several emergency diesel generators and boilers on an intermittent basis at BSEP. These sources are permitted under CAA Title V. There are no other sources of air pollutants at BSEP. The plant is not a source of noxious odors. Progress Energy is in compliance with this policy.

8.2. Resource Production and Management Policies

Progress Energy Response – This group of policies relates to the use and protection of natural resources, including agricultural land, mines, commercial forest lands, gamelands, and hunt clubs. Progress Energy manages pine plantations around BSEP for timber production and wildlife. All thinning, harvesting, and associated land preparation and maintenance are done under the direction of a registered forester, and follow best management practices and standard operating procedures. As previously mentioned, Progress Energy cooperates with the DENR Natural Heritage Program to identify and protect areas on transmission and distribution line rights-of-way that contain state- or federally-listed plants.

8.3. Economic and Community Development Policies

Progress Energy Response – This group of policies relates to economic and community development. BSEP is an established facility, with no plans to expand during the license renewal term, therefore, the policies are not relevant to the continued operation of BSEP and are not included here.

8.4. Public Participation Policies

Progress Energy Response – This group of policies relates to public participation in developing the land use plan, therefore, the policies are not relevant to the continued operation of BSEP and are not included here.

8.5. Storm Hazard Mitigation/Post-Disaster Recovery and Evacuation Policies and Plans

Progress Energy Response – This group of policies relate to the county's preparations for and response to a natural disaster, most likely a hurricane, therefore, the policies are not relevant to the continued operation of BSEP and are not included here. It can be noted that Progress Energy, as a provider of electricity in the region, and with a licensed nuclear facility, maintains extensive disaster and disaster recovery plans designed to ensure that the nuclear facility is maintained in a safe condition and that electricity is restored to the service area as quickly and efficiently as possible, in the event of a natural disaster. These plans are prepared in close cooperation with local governments, including Brunswick County.

Attachment E-3

Wilmington and New Hanover County Land Use Plan Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each county in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county. The most recent City of Wilmington and New Hanover County Land Use Plan (Ref. 2) available is the 1999 plan. Two transmission lines from Brunswick Steam Electric Plant run through New Hanover County. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

Natural Resource Policies

A. Resource Protection

Water Quality The City of Wilmington and New Hanover County will:

1.1. Prevent further deterioration of estuarine water quality and loss of public trust uses in the creeks and sounds and bring all coastal water quality up to its use designation….

1.2. Ensure the protection of water quality throughout the Cape Fear River Basin within New Hanover County and the management and maintenance of drainage within our coastal watersheds through participation in the development of regional water quality/stormwater management programs.

1.3. Ensure the protection, preservation and wise use of our natural resources by careful review and consideration of the anticipated impacts of development through the creation and implementation of and Environmental Review Program.

1.4. It is the intent of this plan to further provide for the protection and improvement of out water quality through our Unified Development Ordinance. ….

Progress Energy Response – Transmission corridors from BSEP cross tidal streams and wetlands in New Hanover County. Progress Energy performs all transmission corridor maintenance according to established procedures and best management practices, and in accordance with applicable state and federal regulations. These procedures and best management practices are intended to be protective of water quality in streams and wetlands crossed by Progress Energy transmission lines. The Progress Energy integrated vegetation management program specifically identifies that cut brush must be removed from water bodies so as not to impede flow, and that when cuts occur through existing canals, the canal must be restored to its original condition.

Open Space The City of Wilmington and New Hanover County will:

2.1 Ensure the preservation of adequate open space for its continued enjoyment and contribution to our community today and for generations to come, to protect our natural environment and wildlife habitats and to provide educational and recreational opportunities.

Progress Energy Response – Progress Energy manages the vegetation along the transmission corridors to enhance habitat for certain kinds of wildlife. Progress Energy is in compliance with this policy. As previously mentioned, Progress Energy cooperates with the DENR Natural Heritage Program to identify and protect areas on transmission and distribution line rights-of-way that contain state- or federally-listed plants.

2.2 Identify and protect wildlife corridors as a part of the greenway system and require their protection or mitigation with all new development.

2.3 Preserve Airlie Gardens…

2.4 Ensure the protection of our community's significant trees and the provision of adequate landscaping….

2.5 Provide for the protection, acquisition, and development of public shorefront and boat access areas.

Progress Energy Response – Policies 2.2 – 2.5 are not relevant to Progress Energy.

Natural Resource Constraints The City of Wilmington and New Hanover County will:

3.1 Preserve and restore shell fishing to all SA waters and bring all coastal waters designated or formerly SA up to their use designation.

3.2 Provide for the continued protection of the Cape Fear River from the cumulative impacts of development by ensuring that Industrial permitting does not exceed the River's carrying capacity and land disturbing activities are carefully reviewed and considered for their potential sedimentation/turbidity and nutrient impacts.

Progress Energy Response – Progress Energy has no plans to construct additional transmission lines during the BSEP license renewal term, so no land disturbing activities will occur. This policy is not relevant to the BSEP license renewal application.

3.3 Minimize dense development activities in ocean erodable areas, high hazard flood areas, inlet hazard areas, and coastal and federally regulated wetlands…

3.4 Ensure the protection of coastal and federally regulated wetlands that have important functional significance through early identification in the development process…

3.5 Ensure the protection of our undeveloped barrier and estuarine islands…

3.6 Carefully control development activities within the 100-year floodplain….

3.7 Require that the cumulative and secondary impacts of land use and development, and the limited carrying capacity of our coastal ecosystems be considered in all land use decisions…

3.8 Allow channel maintenance projects only where the public interest is preserved or enhanced, significant economic or recreational benefits will occur for planning area residents and no significant adverse impacts will occur on shoreline dynamics. Support state and federal channel and inlet maintenance projects, including the continued use and development of the Wilmington Harbor and the state Ports, maintenance of the Atlantic Intracoastal Waterway, and beach renourishment projects.

Progress Energy Response – Progress Energy periodically maintains the portion of the BSEP intake canal that crosses Snows Marsh. All maintenance is permitted by the Army Corps of Engineers and NCDENR and done to the requirements of the permit. Progress Energy is in compliance with this policy.

3.9 Allow estuarine shoreline erosion control only when the public trust interest is not adversely impacted and the public shoreline will be the primary beneficiary….

3.10 Carefully control development activities within the estuarine watersheds to prevent the degradation of water quality in the creeks and sounds, to protect public health, and to ensure the protection of these vital natural resources…

3.11 To preserve, protect, and where possible, restore water quality and vital estuarine resources, a naturally vegetated buffer … shall be established or maintained within established setback areas defined as Conservation Overlay Districts. The determination and management of buffers must balance the above stated goals with the property owner's right to develop and use the property….

3.12 Limit density in hydric soils and Areas of Environmental Concern (AECs) and encourage Planned Residential Development and Planned Unit Development to allow greater design flexibility to save trees and natural buffers.

3.13 Clearcutting or mowing of coastal wetland vegetation within any coastal wetland AEC shall not be allowed.

<u>Progress Energy Response</u> – Note that only two of the 13 policies under Natural Resource Constraints, policies 3.2 and 3.8, relate to the maintenance of infrastructure associated with the continued operation of BSEP and therefore are relevant to the BSEP license renewal application.

<u>Areas of Environmental Concern</u> The City of Wilmington and New Hanover County shall:

4.1 Prohibit use of estuarine waters, estuarine shorelines and public trust areas for development activity which would result in significant adverse impact to the natural function of these areas.

4.2 Carefully control development activities within AECs to prevent the degradation of water quality and to ensure the protection of these vital natural resources by reducing nutrient, pesticide, sediment, and other harmful loadings through the use of density control, setbacks, buffers, impervious surface limits, and other means….

4.3 Support the preservation, protection, and acquisition of the Masonboro Island Estuarine Research Reserve.

4.4 Discourage the development of undeveloped barrier and estuarine system islands

4.5 Continue the phased development and extension of the County sewer system …

4.6 Allow only tertiary sewage treatment plants….

4.7 Seek to provide additional boat access facilities

4.8 Allow the development of marinas…

4.9 Allow use of estuarine and public trust waters that provide benefits to the public and which satisfy riparian access needs of private property owners….

4.10 Not allow dredging activities in Primary Nursery Areas (PNA), Outstanding Resource Waters (ORW), or Shellfishing Waters (SA), except for the purpose of scientific research….

4.11 Clearcutting or mowing of coastal wetland vegetation within any coastal wetland AEC shall not be allowed.

<u>Progress Energy Response</u> – Progress Energy controls vegetation in transmission corridors according to established procedures and best management practices and in accordance with applicable state and federal regulations. Site-specific and terrain-appropriate methods to are used to control vegetation under transmission lines in wetland areas. These include mechanical (pruning, felling, and hand-clearing) and chemical control of unwanted vegetation. Heavy mowing equipment is not used in wetlands. EPA-registered herbicides approved for use in wetlands are sometimes used in small amounts when other methods of vegetation control are not feasible. Progress Energy has signed a Memorandum of Understanding with the N.C. Department of Environment and Natural Resources to cooperate in the management of rare plants, including wetland plants along power line corridors. Progress Energy is in compliance with this policy.

4.12 Prohibit floating home development….

4.13 Pursue a policy of “retreat” along our estuarine shorelines in order to accommodate future sea level rise and wetland migration.

4.14 Allow shoreline erosion control and stabilization above our marsh wetlands only where the public trust interest is not impacted and the public shoreline will be the primary beneficiary….

<u>Progress Energy Response</u> – Note that only one of the 14 policies under Areas of Environmental Concern, policy 4.11, relates to the maintenance of transmission corridors associated with continued operation of BSEP and is therefore relevant to the BSEP license renewal application.

<u>Potable Water Supply</u> – The City of Wilmington and New Hanover County shall:

5.1 Ensure that all land use and development decisions protect our groundwater aquifers

5.2 Not allow the development of mining operations…

5.3 Conserve and protect the best sources of potable surface and groundwater

5.4 Preserve the Castle Hayne and Pee Dee aquifers….

Progress Energy Response – These policies are not related to the maintenance of transmission corridors associated with the continued operation of BSEP.

Other Fragile or Hazardous Areas – The City of Wilmington and New Hanover County shall:

6.1 Continue to support plans for the safe transportation of hazardous materials, for the prevention and clean-up of spills of toxic materials, and the evacuation of area residents in response to natural or man-made hazardous events.

Progress Energy Response – Progress Energy transports hazardous materials to and from BSEP in Brunswick County. Some of these materials could pass through the Port of Wilmington or on roads through New Hanover County. All transportation of hazardous materials follows established Department of Transportation regulations for notification and transport. In addition, Progress Energy's emergency preparedness personnel are trained to clean up any hazardous material spills or protect the area in the unlikely event of an accident involving radioactive materials. In conjunction with county emergency response personnel, Progress Energy maintains emergency evacuation plans as part of its license requirements. Progress Energy is in compliance with this policy.

6.2 Carefully review the siting of all industries, including energy facilities and high voltage utilities, to ensure the protection of area residents and natural resources. Development of all offshore mineral, oil, and gas resources should be discouraged.

Progress Energy Response – Progress Energy has no plans to expand the operations at BSEP during the license renewal term. No construction activities are planned on any transmission corridor associated with BSEP, nor are new transmission corridors planned. This policy is not relevant to the BSEP license renewal application.

6.3 Ensure that industrial permitting on the Cape Fear River does not exceed the river's carrying capacity and that land disturbing activities are carefully reviewed and considered for their potential cumulative impacts.

6.4 Ensure the continued protection of the Masonboro Island Estuarine Research Preserve….

Progress Energy Response – Policies 6.3 and 6.4 are not related to the maintenance of transmission corridors associated with the continued operation of BSEP.

Air Quality -- The City of Wilmington and New Hanover County shall

7.1 Ensure the protection and enhancement of air quality in our community through continued commitment and actions to meet or exceed the Cape Fear Region's National Air Quality Standards.

Progress Energy Response – Progress Energy transmission lines cross New Hanover County. The NRC has determined that transmission lines do not contribute measurably to ambient levels of ozone and oxides of nitrogen and do not affect air quality; therefore, this policy is not relevant to BSEP license renewal.

B. Resource Production and Management

Progress Energy Response – These policies relate to the use and protection of natural resources, including agricultural land, mines, commercial forest lands, gamelands, and hunt clubs. The policies are not relevant to BSEP operations, including maintenance of transmission corridors, and are not included here.

Land Use and Urban Design Policies

Progress Energy Response – These policies relate to various types of land use designations in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Transportation

Progress Energy Response – These policies relate to traffic and transportation issues in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Community Infrastructure Policies

Progress Energy Response – These policies relate to municipal services and infrastructure in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Housing Policies

Progress Energy Response – These policies relate to providing adequate housing for county residents. The policies are not relevant to transmission lines location or maintenance and are not included here.

Economic Development Policies

Progress Energy Response – These policies relate to ensuring a diverse economy in the county. The policies are not relevant to transmission lines location or maintenance and are not included here.

Historic Preservation Policies

Progress Energy Response – These policies relate to the preservation of historic resources in the county. Progress Energy has no plans to perform construction or maintenance activities below the surface on any transmission lines as a condition of license renewal. The policies are not relevant to license renewal and are not included here.

Storm and Natural Hazards Policies

Progress Energy Response – These policies relate to the county's preparations for and response to a natural disaster, most likely a hurricane. The policies are not relevant to transmission lines location or maintenance and are not included here.

Attachment E-4

Onslow County Land Use Plan Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each county in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county. The most recent Onslow County Land Use Plan (Ref. 3) available is the 1997 plan. One transmission line from Brunswick Steam Electric Plant runs to Jacksonville in Onslow County. Progress Energy has no plans to add additional lines in the existing transmission corridor as a result of BSEP license renewal. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

Resource Protection Policy Statements

Soils

(a) Onslow County opposes the installation of package treatment plants and septic tanks or discharge of wastes in any area classified as coastal wetlands, freshwater wetlands (404) or natural heritage areas.

(b) ….The county supports the protection of splashable wetlands as defined by Section 404…

Progress Energy Response – These policies relate to development in the county. Because license renewal will not require ay operational changes at BSEP, Progress Energy has no plans to change the way it operates and maintains the existing BSEP transmission lines. Likewise, Progress Energy has no plans to construct any additional lines in support of license renewal. Consequently, these policies are not relevant to the BSEP license renewal application. To the extent CWA is applicable, maintenance of lines are performed under Corps of Engineers' Nationwide Permit 12

Flood Hazard Areas

Onslow County desires to minimize the hazards to life, health, public safety, and development within flood hazard areas.

Progress Energy Response – This policy relates to minimizing flood hazards in the county. It is not relevant to maintenance procedures for BSEP-associated transmission lines in Onslow County and therefore is not relevant to the BSEP license renewal application.

Groundwater/Protection of Potable Water Supplies

It is the policy of Onslow County to conserve its surficial groundwater resources.

Progress Energy Response – This policy relates to groundwater protection. It is not relevant to maintenance procedures for BSEP-associated transmission lines in Onslow County and therefore is not relevant to the BSEP license renewal application.

Manmade Hazards

(a) Onslow County supports plans for expansion of the Albert Ellis Airport…

(b) With the exception of bulk fuel storage tanks used for retail and wholesale sales, and individual heating fuel storage tanks, Onslow County opposes the bulk storage of man-made hazardous materials….

(c) Onslow County is opposed to the establishment of toxic waste dump sites within the county including dump sites on military reservations.

(d) Onslow County opposed the disposal of any toxic wastes….within its planning jurisdiction.

Progress Energy Response – These policies relates to waste sites and fuel storage tanks. They are not relevant to maintenance procedures for BSEP-associated transmission lines in Onslow County and therefore not relevant to the BSEP license renewal application.

Stormwater Runoff

(a) Onslow County recognizes the value of water quality maintenance to the protection of fragile areas and to the provision of clean water for recreational purposes and supports the control of stormwater runoff to aid in the preservation of water quality.

(b) It is county policy to recognize shellfishing waters as a valuable resource and provide protection to this fragile resource…..

Progress Energy Response – These policies are related to reducing stormwater runoff. Progress Energy uses an integrated vegetation management program that protects vegetation and waterways the transmission corridors traverse. Any maintenance procedures that require earth moving are done according to best management practices and established corporate procedures for sedimentation and erosion control. Progress Energy is in compliance with this policy.

Cultural/Historic Resources

It is policy to preserve and protect the county's significant architectural, archaeological, and cultural resources.

Progress Energy Response – Progress Energy has no plans to perform construction or maintenance activities below the surface on any transmission lines during the license renewal term. This policy is not relevant to the BSEP license renewal application.

Industrial Impacts on Fragile Areas

Onslow County deems industrial development within fragile areas acceptable only if the following conditions are met:

(a) CAMA minor or major permits can be obtained.

(b) Applicable zoning ordinance provisions are met in zoned areas.

(c) Within coastal wetlands, estuarine waters, and public trust waters, no industrial use will be permitted unless such use is water related.

Progress Energy Response – Progress Energy has no plans to expand the transmission corridors or transmission lines as a result of BSEP license renewal. This policy is not relevant to any potential impacts from BSEP license renewal on Onslow County.

Miscellaneous Resource Protection

These policies relate to package treatment plants, marinas, mooring fields, off-road vehicles, development of islands, bulkhead construction, sea level rise, maritime forests, estuarine systems, outstanding resource waters, and water quality management.

Progress Energy Response – These policies are not relevant to any potential impacts from BSEP license renewal on Onslow County.

Resource Production and Management Policies

Progress Energy Response – These policies relate to recreation resources, productive agricultural lands, aquaculture, productive forestlands, development, marine resource areas, and mining and are not relevant to any potential impacts from BSEP license renewal on Onslow County.

Economic and Community Development Policies

Progress Energy Response – These policies relate to water, sewer, and solid waste infrastructure; energy facility siting and development; redevelopment; urban growth patterns; estuarine access; types and locations of desired industry; commitment to state and federal programs; channel maintenance and interstate (sic) waterways; tourism; transportation; and land use trends and are not relevant to any potential impacts from BSEP license renewal on Onslow County.

Attachment E-5

Pender County Land Use Policies

The Coastal Area Management Act passed by the North Carolina General Assembly in 1974 and approved by the federal government in 1978 requires that each county in the coastal area develop a land use plan and update it every five years, or the CRC will prepare and adopt a land use plan for that county. The most recent Pender County Land Use Plan (Ref. 4) available is the 1991 plan, with amendments through 2001. Two transmission lines from Brunswick Steam Electric Plant cross Pender County. Maintenance practices in the transmission corridors were reviewed for consistency with the policies in the land use plan.

Resource Protection Policy Statements

1. Areas of Environmental Concern and Appropriate Land Use in AECs

   Pender County will permit those land uses which conform to the general use standards of the North Carolina Administrative Code for development within the estuarine system. Generally only those uses which are water-dependent will be permitted.

   Progress Energy Response -- The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

2. Constraints to Development Including Flood Prone Areas, Soil Suitability and Septic Tank Use

   County Policy will be to permit development which is proposed to be located outside hydric soil areas and meets all zoning, Health Department and flooding regulations and other State and federal regulations.

   Progress Energy Response – The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

3. Development Density in Proximity to Designated Outstanding Resource Waters

   Pender County policy shall be to protect the water quality in designated ORW waters and in waters within 1,000 feet of designated ORW waters. Development density in proximity to designated Outstanding Resource waters and within ORW buffer zones hall be only that allowed under applicable CAMA regulations or locally adopted regulations.

   Progress Energy Response – The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

4. Other Hazard or Fragile Land Areas

   (a) maritime forests – there are no known significant stands of maritime forest

   (b) freshwater swamps – Pender County policy shall be to continue to support the U.S. Army Corps of Engineers 404 program which has jurisdiction in regulating development in freshwater swamp and freshwater marsh areas and pocosins.

   (c) Other fragile areas – county policy on ORS is outlined in Section III.3 of this plan.

   Progress Energy Response – The transmission lines in Pender County will be maintained according to established practices and procedures. No development will occur. These policies are not relevant to any potential impacts from BSEP license renewal on Pender County.

5. Hurricane and Flood Evacuation Needs -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.

6. Protection of Potable Water Supply -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
7. Use of Package Treatment Plants -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
8. Stormwater Runoff – This policy refers to efforts the county is making to establish a conservation district in the zoning ordinance, and to establish better stormwater management controls in new developments. The policies are not relevant to the operation of BSEP transmission lines on Pender County.
9. Marinas and Floating Home Development and Dry Stack Facilities -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
10. Industrial Impact on Fragile Areas -- Pender County policy will be to continue to support applicable State and Federal regulations as they relate to the siting of new or expanded industry or impact of new or expanded industry on environmentally sensitive areas. This policy is not relevant to the maintenance of transmission lines in Pender County.
11. Development of Sound and Estuarine System Islands -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
12. Restriction of Development in Areas up to Five Feet Above Mean High Water -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
13. Upland Excavation for Marina Basins -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.
14. Damaging of Existing Marshes by Bulkhead Installation -- This policy is not relevant to any potential impacts from BSEP license renewal on Pender County.

Resource Production and Management Policies

Progress Energy Response – These policies relate to recreation resources, productive agricultural lands, aquaculture, productive forestlands, development, marine resource areas, and mining and are not relevant to any potential impacts from BSEP license renewal on Pender County.

Economic and Community Development Policies

Progress Energy Response – These policies relate to highway and port facility improvements; energy facility siting; redevelopment; urban growth patterns; estuarine access; types and locations of desired industry; commitment to state and federal programs; channel maintenance and dredging; tourism; recreation; transportation; and land use trends and are not relevant to any potential impacts from BSEP license renewal on Pender County.

Storm Hazard Mitigation and Post Disaster Reconstruction Policies

Progress Energy Response – These policies are related to planning before and recovery after a hurricane and are not relevant to any potential impacts from BSEP license renewal on Pender County.

References

1. Brunswick County Board of Commissioners. 1997. Brunswick County Land Use Plan. 1997 Update.
2. Wilmington City Council and New Hanover County Board of Commissioners. 1999. Wilmington – New Hanover County CAMA Land Use Plan Update and Comprehensive Plan.
3. Onslow County Board of Commissioners. 2000. Onslow County, North Carolina 1997 Land Use Plan Executive Summary.
4. Howard T. Capps and Associates. 2001. 1991 Pender County Land Use Plan Update.

APPENDIX F

SEVERE ACCIDENT MITIGATION ALTERNATIVES

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Acronyms Used in Appendix F

ADM	Archer Daniel Midland
ADS	Automatic Depressurization System
ATWS	Anticipated Transient Without Scram
BOP	Balance of Plant
BSEP	Brunswick Steam Electric Plant
BWR	Boiling Water Reactor
BWROG	Boiling Water Reactor Owners Group
CAC	Containment Atmospheric Control
CCF	Common Cause Failure
CDF	Core Damage Frequency
CET	Containment Event Tree
CRD	Control Rod Drive
CP&L	Carolina Power & Light
CST	Condensate Storage Tank
CSW	Conventional Service Water
DDDIP	Direct Drive Diesel Injection Pump
DG	Diesel Generator
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOPs	Emergency Operating Procedures
EPU	Extended Power Uprate
EPZ	Emergency Planning Zone
FIVE	Fire Induced Vulnerability Evaluation
GIS	Geographic Information System
HCTL	Heat Capacity Temperature Limit
HEP	Human Error Probability
HPCI	High Pressure Coolant Injection
HRA	Human Reliability Analysis
HVAC	Heating Ventilating Air Conditioning
IA	Instrument Air
IDCOR	Industry for Degraded Core Rulemaking
INEL	Idaho National Engineering Laboratory
INPO	Institute of Nuclear Power Operations
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination – External Events
ISLOCA	Interfacing System LOCA
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
MAAP	Modular Accident Analysis Program
MACCS2	MELCOR Accident Consequences Code System, Version 2
MCC	Motor Control Center

Acronyms Used in Appendix F

MCR	Main Control Room
MACR	Maximum Averted Cost-Risk
MMACR	Modified Maximum Averted Cost-Risk
MOV	Motor Operated Valve
MSIV	Main Steam Isolation Valve
MWe	Megawatts-electric
MWt	Megawatts-thermal
NEI	Nuclear Energy Institute
NPSH	Net Positive Suction Head
NRC	U.S. Nuclear Regulatory Commission
NSW	Nuclear Service Water
NUMARC	Nuclear Management and Resources Council
OCB	Oil Circuit Breaker
OECR	Off-site economic cost risk
PCB	Power Circuit Breaker
PCPL	Primary Containment Pressure Limit
PRA	Probabilistic Risk Analysis
PSA	Probabilistic Safety Assessment
PWR	Pressurized Water Reactor
RAI	Request for Additional Information
RAW	Risk Achievement Worth
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Core Isolation Cooling
RDR	Real Discount Rate
RHR	Residual Heat Removal
RFP	Reactor Feed Pump
RLE	Review Level Earthquake
RPV	Reactor Pressure Vessel
RRW	Risk Reduction Worth
RWCU	Reactor Water Cleanup
SAIC	Science Applications International Corporation
SAMA	Severe Accident Mitigation Alternative
SAMGs	Severe Accident Management Guidelines
SAT	Startup Auxiliary Transformer
SBO	Station Blackout
SER	Significant Event Report
SJAE	Steam Jet Air Ejector
SLC	Standby Liquid Control
SLOCA	Small Loss of Coolant Accident
SOER	Significant Operating Event Review
SP	Suppression Pool
SRV	Safety Relief Valve
SSE	Safe Shutdown Equipment
TE	Loss of Offsite Power Event Tree or Initiating Event

Acronyms Used in Appendix F

UAT	Unit Auxiliary Transformer
USI	Unresolved Safety Issue

Appendix F
Severe Accident Mitigation Alternatives

The severe accident mitigation alternatives (SAMA) analysis discussed in 4.20 is presented below.

F.1 METHODOLOGY

The methodology selected for this analysis involves identifying SAMA candidates that have the highest potential for reducing core damage frequency and person-rem and determining whether or not the implementation of those candidates is beneficial on a cost-risk reduction basis. This process consists of the following steps:

- **BSEP Probabilistic Safety Assessment (PSA) Model** – Use the BSEP Internal Events PSA model as the basis for the analysis (Section F.2). Incorporate External Events contributions as described in Section F.1.2.

- **Level 3 PSA Analysis** – Use BSEP Level 1 and 2 Internal Events PSA output and site-specific meteorology, demographic, land use, and emergency response data as input in performing a Level 3 probabilistic safety assessment (PSA) using the MELCOR Accident Consequences Code System Version 2 (MACCS2) (Section F.3). Incorporate External Events contributions as described in Section F.1.2.

- **Baseline Risk Monetization** – Use NRC regulatory analysis techniques, calculate the monetary value of the unmitigated BSEP severe accident risk. This becomes the maximum averted cost-risk that is possible (Section F.4).

- **Phase I SAMA Analysis** – Identify potential SAMA candidates based on the BSEP PRA, IPEEE, and documentation from the industry and the NRC. Screen out Phase I SAMA candidates that are not applicable to the BSEP design or are of low benefit in boiling water reactors (BWRs) such as BSEP, candidates that have already been implemented at BSEP or whose benefits have been achieved at BSEP using other means, and candidates whose estimated cost exceeds the maximum possible averted cost-risk (Section F.5).

- **Phase II SAMA Analysis** – Calculate the risk reduction attributable to each remaining SAMA candidate and compare to a more detailed cost analysis to identify any net cost benefit. Probabilistic safety assessment (PSA) insights are also used to screen SAMA candidates in this phase (Section F.6).

- **Uncertainty Analysis** – Evaluate how changes in the SAMA analysis assumptions might affect the cost/benefit evaluation (Section F.7).

- **Conclusions** – Summarize results and identify conclusions (Section F.8).

The steps outlined above are described in more detail in the subsections of this appendix and Figure F-1 provides a graphical representation of the SAMA process.

F.1.1 BSEP SPECIFIC SAMA

The initial list of SAMA candidates for BSEP was developed from a combination of resources. These include the following:

- BSEP PRA results
- Industry Phase II SAMAs [References 3, 4, 5, 6, 7, 8]
- BSEP IPE [Reference 9]
- BSEP IPEEE [Reference 10]

These resources are judged to provide a list of potential plant changes that are most likely to reduce risk in a cost-effective manner for BSEP.

In addition, a generic SAMA list has been included in Addendum (see Table A-1). This list was compiled as part of the development of several industry SAMA analyses. It has been used in the BSEP SAMA analysis as a reference source to identify the types of plant changes that could be suggested to improve selected functions of the plant. Specifically, the list was used to help correlate events in the BSEP importance listings with potential plant improvements. The details of the SAMA identification process are provided in Section F.5.1.

F.1.2 EXTERNAL EVENTS

External events have been identified by the nuclear industry as non-negligible contributors to plant risk. While the focus of nuclear PSA applications has typically been on internal events models, efforts have been made to expand the types of PSA insights used in the SAMA analysis to include external events issues.

The Brunswick External Events analysis has not been maintained as a “living” analysis. The documentation and results are limited to what was produced during the performance of the IPEEE. As a result, any qualitative insights or quantitative estimates related to external events used in the SAMA analysis must be extrapolated based on existing information. As a result, external events models are considered to be useful tools for identifying important accident sequences and mitigative equipment, but the quantitative results should not be directly combined with those from the internal events models.

F.1.2.1 USE OF EXTERNAL EVENTS IN THE BSEP SAMA ANALYSIS

The IPEEE was used in the BSEP SAMA analysis primarily to identify the highest risk accident sequences and the potential means of reducing the risk posed by those sequences. The available results allowed review of the following types of initiators not addressed by the internal events model:

- Fires
- Seismic events
- High wind events
- Transportation and nearby facility accidents

The type of information available for these initiators varied due to the manner in which they were addressed in the IPEEE. For instance, the fire analysis was performed using a combination of standard PSA modeling techniques and the EPRI FIVE methodology, which produced results similar to those yielded by the internal events analysis. However, the seismic margins analysis does not produce a core damage frequency and is predicated on the ability to evaluate the seismic durability of the equipment required to safely shut the plant down. The results of this kind of analysis do not directly lend themselves to the type of frequency-based analysis implemented in the SAMA evaluation. As a result, each of the external event contributors must be considered in a manner suiting the type of analysis performed. A summary of the review process is provided for each of the external event types listed above followed by a description of the method used to quantitatively incorporate external events contributions into the SAMA analysis.

F.1.2.1.1 Fires

<u>Overview of Fire PRA Development</u>

As discussed above, the techniques used to model external events vary according to the type of initiator being analyzed. The BSEP Fire model shares many of the same characteristics as the internal events model, but limitations on the state of technology produce results that are more conservative than the internal events model. The following summarizes the fire PRA topics where quantification of the associated figure of merit, CDF, may introduce different levels of modeling uncertainty than the internal events PRA.

The uncertainties generally reflect the following:

- lack of adequate data for initiating events
- lack of realistic fire modeling capabilities including mitigation
- lack of ability to track all cables (e.g., BOP cables)
- uncertainty in crew response, especially for control room fires, and their modeling
- limited peer reviews that examine the need for realism instead of conservatism

In many cases, analysts choose to address these uncertainties by incorporating margin into the analysis (i.e., conservative assumptions).

Elements of Fire PRA

Fire PRAs are useful tools to identify design or procedural items that could be clear areas of focus for improving the safety of the plant. Fire PRAs use a structure and quantification technique similar to that used in the internal events PRA.

Since less attention historically has been paid to fire PRAs, conservative modeling is common in a number of areas of the fire analysis to provide a “bounding” methodology for fires. This concept is contrary to the base internal events PRA which has had more analytical development and is judged to be closer to a realistic assessment (i.e., best estimate) of the plant.

There are a number of fire PRA topics involving technical inputs, data, and modeling that prevent the effective comparison of the calculated core damage frequency figure of merit between the internal events PRA and the fire PRA. These areas are identified as follows:

Initiating Events:	The frequency of fires and their severity are generally conservatively overestimated. A revised NRC fire events database indicates the trend toward lower frequency and less severe fires. This trend reflects the improved housekeeping, reduction in transient fire hazards, and other improved fire protection steps at utilities.
System Response:	Fire protection measures such as sprinklers, CO_2, and fire brigades may be given minimal (conservative) credit in their ability to limit the spread of a fire. Cable routings are typically characterized conservatively because of the lack of data regarding the routing of cables or the lack of the analytic modeling to represent the different routings. This leads to limited credit for balance of plant systems that are extremely important in CDF mitigation.
Sequences:	Sequences may subsume a number of fire scenarios to reduce the analytic burden. The subsuming of initiators and sequences is done to envelope those sequences included. This results in additional conservatism.
Fire Modeling:	Fire damage and fire spread are conservatively characterized. Fire modeling presents bounding approaches regarding the immediate effects of a fire (e.g., all cables in a tray are always failed for a cable tray fire) and fire propagation.
HRA:	There is little industry experience with crew actions under conditions of the types of fires modeled in fire PRAs. This has led to conservative characterization of crew actions in fire PRAs. Because the CDF is strongly correlated with crew actions, this conservatism has a profound effect on the calculated fire PRA

results.

Level of Detail: The fire PRAs may have reduced level of detail in the mitigation of the initiating event and consequential system damage.

Quality of Model: The peer review process for fire PRAs is less well developed than for internal events PRAs. For example, no industry standard, such as NEI 00-02, exists for the structured peer review of a fire PRA. This may lead to less assurance of the realism of the model.

Fire PRA Modeling Summary

The fire PRA may be subject to more modeling uncertainty than the internal events PRA evaluations. While the fire PRA is generally self-consistent within its calculational framework, the fire PRA does not compare well with internal events PRAs because of the number of conservative assumptions that have been included in the fire PRA process. Therefore, the use of the fire PRA figure of merit as a reflection of CDF may be inappropriate. Any use of fire PRA results and insights should consider areas where the “state of the art” in fire PRAs is less evolved than other PRA topics.

BSEP Fire Model

While the ability to directly compare the results of the internal events and fire models is limited, information is available that may be used to identify the most important contributors for BSEP. The fire risk at Brunswick has been shown to be dominated by control room fires (CB-21, CB-23) (53.3 percent of the fire CDF). Several other major contributors have also been identified and include the following fire compartments as documented in Reference 39:

- RB2-1g(NC): 20’ level of the reactor building north central (8.7 percent)
- RB2-1g(NW): 20’ level of the reactor building north west (4.4 percent)
- CB-06: Unit 2 cable spreading room (4.3 percent)
- DG-14: E4 switchgear room (3.0 percent)
- DG-9: E8 switchgear room (3.0 percent)

Detailed information about accident sequence progression for these fire compartments is not currently available. The core damage frequencies for the fire compartments are documented, but the relative importance of specific equipment is not typically contained in the available documentation. General descriptions of the fire compartments are available, however, and these have been used to identify potential plant improvements.

Control Room Fires

A major contributor to the core damage frequency for control room fires is the failure to operate the plant from outside the control room. The total failure probability assigned to this action is 0.1 and is considered to be comprised of failures to 1) coordinate actions between operators, 2) failures of communication between local operators due to technical difficulties with communications equipment, and 3) improper operation of equipment. The ex-control room hardware failure probability is 1.5E-2, but these failures are not addressed here. Based on this information, the following SAMAs have been identified that may reduce plant risk:

- Enhance the alternate shutdown panel such that at least one complete division of controls is available to all equipment that would normally be used to place the plant in a safe, stable state. This could further be improved by adding controls for both divisions of equipment.

- Enhance the training the operators receive on operating the plant from outside the control room and improve the ex-control room communications equipment.

- Automatic CO_2 suppression could be added to the control room cabinets to ensure rapid fire mitigation and avoid control room evacuation.

These SAMAs have been incorporated into the initial BSEP list. Other SAMAs related to equipment improvements/additions are possible, but the human error of operating the plant outside the control room dominates the results. In addition, given that the dominant contributor to control room fires are those fires which do not damage vital equipment and only require evacuation of the MCR, the equipment response is considered to be similar to what is modeled in the internal events PRA model. This indicates that the fire related benefit of a given SAMA may be proportional to the internal events results.

20' Level of the Reactor Building North Central

The fire contributors for this area are comprised of cable fires originating in the cable tray located 20 feet above the floor and in the MCCs directly below the cable tray. The critical equipment damaged in these fires includes RHR train "A" and E7. RHR train "B" is assumed to be recoverable outside the control room.

No automatic fire suppression is available for this area. Addition of automatic fire suppression equipment may reduce the fire risk in this area. This change has been included in the BSEP SAMA list.

Control of E7 is failed by some fire scenarios, but it is assumed to be recoverable through local action. No additional SAMAs have been suggested to mitigate loss of E7.

While failure of the "A" RHR train is a significant impediment, no potentially cost effective SAMAs have been specifically included in the BSEP SAMA list to mitigate this damage. Independent injection pumps and alternate DHR methods may improve plant response, but these types of SAMAs have already been included based on the review of the internal events importance list.

20’ Level of the Reactor Building North West

The consequences of a fire in this compartment are nearly identical to those described for the North area with the exception that no MCCs are identified as failed items or as ignition sources. The conclusions are considered to be the same as those made for the North Central area.

Unit 2 Cable Spreading Room

The Cable Spreading Room contains cables for both division 1 and division 2 equipment. Failure of these cables will result in the loss of equipment control in the main control room and will require evacuation for shutdown with the alternate shutdown panel.

The main contributors to Cable Spreading Room Fires are transient fires that are not suppressed prior to extensive cable damage. While automatic actuation of fire suppression is available, the Cable Spreading Room is not constantly manned, which limits the credit for early identification and suppression of fires. A potential means of reducing the fire risk for this area would be to post a fire watch; however, a more cost-effective means of reducing risk would be to limit the transient combustibles allowed into the cable spreading room. The transient fire initiating event frequency for cable spreading room fires is dominated by welding work. Prohibiting welding while the plant is at-power and/or requiring a fire suppression person to be present for any welding work may have the greatest impact on reducing fire risk in this area. This potential change has been included in the BSEP SAMA list.

It has also been noted that not all electrical cabinets contain vital cables; however, a fire in one of these cabinets is assumed to spread to any attached cabinet. As a result, vital cables are assumed to be damaged even if a fire starts in a non-vital cabinet. Improved fire barriers between cabinets is another potential means of reducing fire risk in the Cable Spreading Room. This change has been included in the BSEP SAMA list.

Improvements in alternate shutdown capabilities would also reduce risk in this area. These SAMAs have been addressed as described in the Control Room fire section above.

E4 Switchgear Room

Fire in this area is important due to its impact on the E8 substation. E8 supports equipment such as MSIVs, the division “B” battery chargers, some division “B” of RHR components, and two of three containment vent paths. Recovery from a fire in this area is possible and effectively mitigated by performing a cross-tie between E7 and E8 (the fire only fails the supply to E8, not E8 itself).

The following changes have been identified as potential means of reducing the fire risk in this area:

- Provide remote cross-tie capability to improve E7-E8 cross-tie reliability (Already included in the BSEP SAMA list based on PSA results)
- Install automatic fire suppression equipment in the Switchgear Rooms (included in BSEP SAMA list).

The initiating event frequency is based on the breaker cubicles in the bus and no potentially cost effective methods have been identified to reduce the ignition frequency.

E8 Switchgear Room

The E8 switchgear is the only fire initiator and the only component of interest in this room. A fire in the switchgear is assumed to fail the entire switchgear and precludes recovery by cross-tying to the E7 substation. Otherwise, the consequences and conclusions for this fire area are the same as those for the E4 Switchgear Room.

F.1.2.1.2 Seismic

The EPRI seismic margins methodology [Reference 12] is used to identify the minimal set of equipment required to safely shut the reactor down and to determine if that equipment is capable of surviving the Review Level Earthquake (RLE). Equipment that is not capable of withstanding the RLE is identified and required to be addressed. While methods exist for using this information to develop a seismic induced core damage frequency, this was not performed as part of the Brunswick IPEEE. In addition, the pedigree of information is not equivalent to what is used in the internal events models and it is not considered appropriate to combine the internal events and seismic core damage frequencies.

The nature of the seismic model limits its use in the SAMA analysis compared with the internal events model. The results of the IPEEE seismic analysis were reviewed in order to identify either of the following:

- Unfinished plant enhancements that were determined to be required to ensure the equipment on the Safe Shutdown List would be capable of withstanding the RLE
- Additional plant enhancements that were identified as means of reducing seismic risk but were not pursued due to cost considerations

At the time the IPEEE was completed, the USI A-46 analysis was not completed and was identified as an open item. After the submittal of the BSEP IPEEE, this item was addressed to the satisfaction of the NRC and closed out as documented in Reference 13.

Based on review of the IPEEE seismic results, no plant enhancements were identified and then not pursued based on cost concerns for Brunswick.

F.1.2.1.3 High Winds

The high wind risk at BSEP was examined for tropical storms, non-tropical storms, and tornadoes. Given the equipment required for safe shut down of the plant is contained in buildings designed for 360 mph winds, the risk posed to the plant from these types of events was considered to be due to loss of additional support systems outside of the class 1 structures.

Based on the site's tornado frequency, corresponding wind speeds, and damage potential, tornado risk was judged to be bounded by hurricane winds. Further examination of hurricane winds showed that the BSEP switchyard was the most vulnerable to these types of events.

The potential damaging factors included both high wind and flooding due to storm surge. Switchyard damage due to storm surge flood was determined to be possible; however, the frequency was estimated to be a factor of 20 less than damage due to high winds. In addition, the wind conditions required to cause the postulated storm surge flood would fail the switchyard without the flood effects. More detailed flood analysis showed that the potential flood conditions at BSEP would not fail the Reactor Building, Control Building, Service Water Building, or the diesel generator/diesel generator fuel oil vaults. For these reasons, the loss of the switchyard due to high wind was determined to be the most critical component of the high wind analysis.

The conditional core damage frequency developed for the loss for the switchyard (extended LOOP) combined with the Probable Maximum Hurricane wind initiating event frequency was below the cutoff frequency for the IPEEE (1E-6/yr) and no further analysis was considered to be required.

Enhancements to the switchyard and offsite power connections to prevent damage from high winds are possible, but these kinds of improvements are highly resource intensive. For instance, the installation of underground offsite power lines would improve the reliability of offsite power at the plant given high winds, but the cost of this improvement has been estimated to exceed $25 million (Reference 3). In addition, the switchyard itself would have to be placed in a Class 1 structure (or some equivalent enhancement) in order to take advantage of the available power. This upgrade would inflate the cost of implementation beyond the original estimate. The installation of additional sources of emergency onsite power are also effective means of reducing the plant risk due to high winds. As a fifth diesel generator is already included in the BSEP SAMA list, no additional SAMA has been added. It should also be noted that because the estimated high wind core damage frequency is low, the high wind component of any SAMA's averted cost-risk would be minimal.

Given the low potential for identifying cost-beneficial SAMAs to mitigate the risk posed by high winds, no further effort was made in the SAMA analysis to develop high wind related SAMAs.

F.1.2.1.4 Transportation and Nearby Facility Accidents

Transportation and nearby facility accidents were included in the IPEEE to account for human errors outside the normal operation of BSEP. The types of hazards identified for analysis included:

- Aircraft Impact
- Industrial Accidents
- Military Accidents
- Pipeline Accidents
- Hydrogen Storage Failures
- Transportation Accidents

In general, these threats were analyzed and determined to be dominated by the fire and high wind events described above. A short summary of each of these reviews has been provided for completeness.

Aircraft Impact

At the time the IPEEE was performed, available information related to military, commercial, and general aviation traffic was used to estimate a core damage frequency caused by aircraft impact. Given the information and conditions present at the time of the analysis, the CDF was determined to be less than 1E-6/yr and further analysis was not considered warranted.

It is recognized that the types of credible threats to nuclear facilities by aircraft have changed since the time the IPEEE was published. While this is true, efforts are underway within the industry to address this issue in conjunction with other forms of sabotage. Based on the fact that this topic is currently being analyzed in another forum and due to the complexity of the issue, aircraft impact events are considered to be out of the scope of the SAMA analysis. No SAMAs were developed to mitigate aircraft impact events.

Industrial Accidents

The BSEP IPEEE reviewed the types of industry present around the site in order to determine if any of the facilities posed a hazard to the safe operation of the plant. The following facilities were identified as potential hazards:

- Archer Daniel Midland (ADM) Company
- A natural gas pipeline
- Cogentrix Southport Cogeneration Plant

It was determined that ADM only produced citric acid and had no known explosive materials on-site. Any threat posed by ADM was considered to be bounded by Military Ocean Terminal Sunny Point (included in Military Accidents).

The natural gas pipeline is included below in the Pipeline Accidents subsection.

Southport Cogeneration Plant, owned and operated by Cogentrix Energy, Inc., is a coal-fired power plant that provides steam to ADM and electric power for sale to Progress Energy. The worst postulated accident based on the operation of the Cogentrix facility was a turbine missile ejection or a high energy steam line break. These events were considered to be less severe than the same events occurring at BSEP due to scale of size considerations and the space between the sites. As these are design base accidents at BSEP, further review of Southport Cogeneration Plant initiators was not considered warranted.

The assumptions made in the IPEEE are judged to be valid and no credible risk to the safe operation of BSEP is considered to be posed from the operation of nearby facilities. No SAMAs were developed related to industrial accidents.

Military Accidents

Military Ocean Terminal Sunny Point’s cargo load was analyzed during the performance of the IPEEE. The largest concentration of explosives at the site was identified as two fully loaded barges equivalent to 19.2 million pounds of TNT. The blast pressure resulting from the detonation of this explosive source was determined to be 0.5 psi overpressure and 1 psi reflected overpressure. It was noted that this pressure load is less than the tornado loads, which the Class 1 buildings were designed to withstand. No further analysis was performed in the IPEEE and no SAMAs were determined to be required to address military accidents at Brunswick Steam Electric Plant.

Pipeline Accidents

A 12 inch natural gas pipeline runs just outside the 3000 foot Brunswick exclusion zone. The worst case failure of the pipeline, which was assumed to be a guillotine rupture, was examined to identify the impact on the BSEP site. The resulting radiant heat from the fire at the nearest safety structure would be less than a flat surface receives in the midday sun. For an un-ignited gas leak, control room habitability analysis showed that the control room ventilation system still met the requirements set forth in Regulatory Guide 1.78.

No SAMAs were developed for the BSEP list based on the presence of this pipeline.

Hydrogen Storage Failures

Detonation of the BSEP hydrogen storage tankers was investigated to determine the impact of such an explosion. Industry guidance on the minimum separation distance between plant structures and hydrogen storage units was used as the basis of the analysis (Reference 14). The results indicated that the minimum safe distance for storage of the BSEP hydrogen tankers was 200 feet from any safety structure. As this distance was less than the distance between the hydrogen tankers and the building containing safe shutdown equipment, no credible threat was determined to exist based on hydrogen detonation.

No SAMAs were developed for the BSEP list based on the hydrogen storage equipment at BSEP.

Transportation Accidents

Transportation accidents were judged to include accidents on the roadways around the plant (river traffic was addressed in “Military Accidents”). The highest concentration of explosives on Highway 87, which is one mile from the plant, was determined to be 50,000 pounds of TNT. The impact of an accident on Highway 87 with this explosive load was determined to be bounded by the worst case explosion at Military Ocean Terminal Sunny Point. All chemical and hazardous materials accidents that could occur on the highway were also considered to be bounded by the worst case explosion at Military Ocean Terminal Sunny Point.

No SAMAs were developed for the BSEP list based on the potential for transportation accidents near the site.

F.1.2.1.5 Quantitative Strategy for External Events

The quantitative methods available to evaluate external events risk at BSEP are limited, as discussed above. In order to account for the external events contributions in the SAMA analysis, a two stage process has been implemented to provide gross estimates of the averted cost-risk based on external events accidents.

The first stage is used in the Phase I analysis and is based on the assumption that the risk posed by external and internal events is approximately equivalent. Given that the risk is assumed to be equal, the maximum averted cost-risk calculated for the internal events model has been doubled to account for external events contributions. This total is referred to as the “modified maximum averted cost-risk” or MMACR. The MMACR is used in the Phase I screening process to identify and screen SAMAs that could not be cost beneficial even if all risk related to power operations was eliminated. These are the SAMAs with costs of implementation that are greater than the MMACR (refer to Section F.4 for information related to dual unit implementation).

The second stage of the strategy is used in the Phase II analysis and begins with the assumption that the external events component of the averted cost-risk for a given SAMA is equivalent to the averted cost-risk based on internal events. This would require that any averted cost-risk calculated for a SAMA be multiplied by two to account for the corresponding reduction in external events risk. Insights from the existing external events evaluations are used, where appropriate, to modify the initial factor of two multiplier for any SAMAs requiring detailed averted cost-risk calculations. Engineering judgment is used to determine how to quantitatively address the available external events insights. If no information is available to justify the modification of the base multiplier of two, then the factor of two is retained. No adjustments have been made in the BSEP analysis to further alter the multiplier of two.

F.2 BSEP PSA MODEL

The SAMA analysis is based on the most recent version of the Brunswick Steam Electric Plant (BSEP) Probabilistic Safety Assessment (PSA) model for internal events (i.e., the MOR03 model for Brunswick Unit 2), which represents the latest update to the upgraded model completed in 2000 to the original Individual Plant Examination (IPE). The upgraded models for Unit 1 and 2 have been subsequently updated in 2001, 2002, and 2003 to maintain design fidelity with the operating plant. The Unit 2 PSA model is currently the more advanced of the two units in implementation of extended power uprate (EPU) modifications for 2923 MW_t operation as begun in 2002.

The following subsections provide more detailed information related to the evolution of the BSEP internal events PSA model and the current results. These topics include:

- PSA changes since the IPE
- Level 1 model overview
- Level 2 model overview
- PSA model review summary

Section F.1.2 provides a description of the process used to integrate external events contributions into the BSEP SAMA process; therefore, no additional discussions of the external events models are included here.

F.2.1 PSA MODEL CHANGES SINCE IPE SUBMITTAL

The original Level 1 IPE model was updated in 1993 (Section F.2.1.1), 1994 (Section F.2.1.2), and 1996 (Section F.2.1.3). The IPE models for Level 1 CDF and Level 2 analyses were completely upgraded and replaced in 1998-2001 with the contractual assistance of Ricky Summitt Consulting and ERIN Engineering, respectively. The PSA and Level 2 models were made more robust than the previous IPE models but still retain the principal elements of the previous IPE system modeling. The details of the original IPE model upgrade are documented and controlled through calculations BNP-PSA-001 and BNP-PSA-050, EC 44622 (Rev. 0) and EC 45913 (Rev. 1), “PSA Model Upgrade,” and EC 47888 (Rev. 0), “Level 2/LERF PSA Model Update 1998.” The Level 1 PSA was subsequently updated in 2002 and 2003 for the primary purpose of incorporating plant modifications due to extended power uprate (EPU), to resolve peer review findings, and to incorporate user identified modeling corrections and enhancements. The details of these changes are described in EC 47885 (Rev. 0), “PSA Model Update 2002”, and EC 49660 (Rev. 0), “PSA Model Update 2003,” respectively. The Level 2/LERF model based on Unit 2 for MOR03 was updated by ERIN Engineering during the preparation of the SAMA analysis and is being documented and owner-reviewed for the BSEP license renewal project.

The historical nominal Brunswick CDF and Level2/LERF results for Unit 2 are as follows:

BSEP Model	Truncation (per yr)	CDF (per yr)	LERF (per yr)	Level 2 (per yr)
MOR92	-	2.7E-5	NA	1.9E-5
MOR96	1.0E-9	9.1E-6	NA	NA
MOR98	2.0E-9	2.54E-5	4.27E-6	NA
MOR98R1	2.0E-9	5.49E-5/4.92E-5*	4.78E-6	NA
MOR02	2.0E-9	4.97E-5	NA	NA
MOR03	5.0E-10	4.19E-5	2.13E-6	2.38E-5

* The updated CDF result was modified by calculation BNP-PSA-052 to include modeling corrections prior to the LERF analysis.

Summary descriptions of the model changes that were made as part of the 1993, 1994, and 1996 updates are provided is subsections F.2.1.1 through F.2.1.3 for reference purposes. Descriptions of the 1998-2003 changes are maintained in plant controlled documents.

F.2.1.1 1993 IPE UPDATE

The Brunswick Steam Electric Plant PRA IPE was submitted in August, 1992. Since then, a PRA model update standard has been established that requires elements of CP&L/Progress Energy PRA models to be updated after every refueling cycle. The model update described below reflects the BSEP Unit 2 plant configuration after the ninth refueling outage and includes the forced shutdown from April 1992 through May 1993.

The update effort involved the examination of various information sources. These sources included the review of plant operating logs, trouble ticket and out of service time histories for selected components, industry data, plant modifications which were implemented, model review comments and suggested changes, and industry operating experience.

As a result of this examination the following areas of the PRA model were revised for this update:

- Initiating Events
- Event Trees
- Fault Trees
- Human Reliability Analysis
- Component Performance Data

F.2.1.1.1 Initiating Events

Since the IPE submittal, the Brunswick Plant operated for approximately 4 months after the ninth refueling outage until the forced outage which occurred in April of 1992. The plant remained shut down until May of 1993. During this time, one event occurred which required an initiating event update. The accumulation of salt on transformer insulators caused by salt spray led to a loss of offsite power. The loss of offsite power initiating event frequency was updated using Bayesian techniques. The frequency increased from 0.074/reactor year to 0.10/reactor year. Additionally, the dual unit loss of offsite power probability was changed from 0.48 to 0.695. All other initiating event frequencies were unchanged from the IPE submittal.

F.2.1.1.2 Event Trees

A comprehensive review of the loss of offsite power event tree (TE) was performed for this model update. Additionally, a cursory review of the remaining event trees was performed. As part of the event tree update a top logic model conversion was performed for all event trees. This conversion resulted in many nomenclature changes to all event trees. The purpose of the conversion was to streamline the quantification process by maximizing the use of macros. The new quantification process is consistent with the one used for quantifying the Harris IPE.

The main reason for focusing on the TE tree was the results of the IPE. The IPE results indicated that station blackout contributed approximately 65 percent of the total core damage frequency. The IPE TE event tree, however, did not include the effects of guidance provided by the newly developed Station Blackout Procedure, AOP-36.2. The review of the TE event tree and the incorporation of AOP-36.2 resulted in the following significant changes:

- The timeframe for recovery of offsite power was increased due the operator's ability to manually close the 4160V breakers without DC power.

- In case of a unit blackout, the use of the LPCI pump that can be powered from the non-blacked out unit for low pressure injection on the blacked out unit was added.

- The deletion of the emergency bus crosstie event and use of firewater for low pressure injection for sequences involving the failure of high pressure injection. These events were deleted since there is inadequate time to perform these actions before core damage occurs.

F.2.1.1.3 Fault Trees

There were many changes made to the IPE fault trees. These changes were primarily the result of incorporating items from the PRA Change Log. The noteworthy changes are highlighted below:

- The automatic operation of the Automatic Depressurization System (ADS) was deleted from the ADS top logic because the automatic function may be inhibited by the operator in accordance with the Emergency Operating Procedures (EOPs).

- The Control Rod Drive (CRD) System was added as an injection source because it is a means to provide makeup for decay heat removal. CRD injection combined with RPV head seal venting make up a new process named in the model as the W6-Process.

- The success criteria for emergency bus crosstie during a loss of offsite power was changed from an "OR" gate to an "AND" gate because one emergency diesel generator is capable of supplying the needed power for both units during a station blackout event. This success criteria is consistent with AOP-36.2.

- The W5-Process, which includes containment venting and injection from Core Spray or firewater, was modified to include the hardened wetwell vent.

- The failure probability of the operator action to crosstie emergency busses was updated to reflect the addition of the crosstie logic switches.

- A new operator action was added to the model to reflect the need to depressurize the reactor within 30 minutes following a loss of high pressure injection.

F.2.1.1.4 Human Reliability Analysis (HRA)

An improved HRA methodology developed since the IPE submittal has allowed the deletion of several pre-initiator events. This updated methodology added screening criteria and allowed removal of errors associated with components which:

- are independently verified by two or more people using a written verification procedure.

- are annunciated in the main control room.

Additionally, a selected number of post-initiator errors were evaluated and updated using an EPRI methodology (failure tree method) used by the Harris and Robinson plants in their IPE submittals. The failure tree method has the advantage of pointing out areas to be considered for improving accident mitigation. This method is considered an improvement over the EPRI time-reliability methodology used for the Brunswick IPE.

F.2.1.1.5 Component Performance Data

Component performance data for major pumps in the following systems plus the emergency diesel generators was collected for a time frame beginning in March of 1987 and ending in January of 1991:

- RHR
- Core Spray
- HPCI
- RCIC
- SLC
- Condensate (Condensate pumps only)
- Service Water
- CRD

- Fire Protection (Diesel-Driven Fire pump only)

These data include the failure rates for run failures, probabilities for start failures, and test and maintenance unavailabilities.

F.2.1.1.6 Industry Operating Experience

Operating experience reports were reviewed for applicability to the PRA model. The reports included NRC Information Notices, INPO reports (SOERs, SERs, etc.), Brunswick Adverse Condition Reports, and Licensee Event Reports for the period 1991 to 1993. A preliminary screening of the report titles produced about 70 reports that could have potential applicability. Each of these reports was reviewed for applicability to the model. Consideration was given to common cause failures, operator errors, precursors to larger failures, and specific component degradation or design problems. The problems identified in these reports appeared to be within the expected realm of failures. Although the review did not identify any reasons to change the PRA model, the review itself was valuable because of the insights it provided on how failures can occur at a nuclear plant.

F.2.1.2 1994 IPE UPDATE

A partial update to the PSA model was performed in August 1994 to support regulatory related work. The work required a more detailed and up-to-date model with respect to diesel generator failures and offsite power recovery options. The result of these changes was a new estimate of CDF of 1.1E-5 per reactor-year. The PSA model was used as the basis for a study of electrical distribution system proposed enhancements, and the study was presented to the NRC as part of Progress Energy's final position.

F.2.1.3 1996 IPE UPDATE

This model update had several objectives. The primary objectives were to (1) consolidate event trees where possible to speed up model quantification, (2) review selected system level fault tree logic to gain better familiarity and correct known discrepancies, and (3) incorporate plant-specific data from the efforts of the Maintenance Rule.

The previous model contained too many event trees, which dramatically slowed quantification due to the large number of plant sequences. The event tree transfers to Anticipated Transient Without SCRAM (ATWS), stuck open Safety Relief Valve (SRV), and internal plant flooding event trees were therefore consolidated. Model quantification time for accident sequences greater than 1E-9 was reduced to less than 1 hour.

Several system fault trees were selected for intensive review. These included Service Water, RHR, CRD, ADS, Instrument Air (including nitrogen backup), and Containment Atmospheric Control (CAC)(Venting Process). Multiple Change Log items had been identified for these systems during previous model reviews. This intensive review was considered necessary to prepare the model for increased application activity.

Changes to the database were made in conjunction with the implementation of the Maintenance Rule. This effort was very beneficial because of the technology transfer of PSA to the plant engineers. Additionally, a means to collect data for future model updates was developed.

The overall model results did not change significantly. The previous CDF was 1.1E-5 and the updated CDF was 9.1E-6 per year. System and human error importances shifted slightly, but the overall risk profile of BSEP remains the same. Station blackout, transients, and loss of decay heat removal remained the dominant accident types.

F.2.2 CURRENT LEVEL 1 BSEP PSA MODEL

The SAMA analysis is based on the most recent version of the Brunswick Steam Electric Plant Probabilistic Safety Assessment (PSA) model for internal events (MOR03, Unit 2). This model is used as it incorporates the changes that were required to support the BSEP extended power uprate project and includes the latest enhancements in model. The MOR03 baseline CDF is 4.19E-5 per reactor year. The results are summarized below.

The contribution to core damage frequency is dominated by two initiators at BSEP. Loss of Offsite Power (site) is the larger of the two with 35.1 percent of the total. This is followed closely by the turbine trip initiator at 27.2 percent.

For Loss of Offsite Power events, if AC power can be restored to the emergency buses by the diesel generators, then the plant response is similar to transient events. If more than one diesel generator is unavailable, the unit is considered to be in a station blackout sequence. These sequences involve:

- successful scram following a loss of offsite power
- failure of the unit emergency diesel generators to start and run
- failure to recover offsite power to Unit 2 in conjunction with either a failure of the Unit 1 crossties to restore power to the Unit 2 emergency buses or a failure of one of the Unit 1 diesels.

To prevent battery depletion, AC Power must be recovered. Depending on the equipment that is available and the outcome of battery load shed actions, the time to battery depletion could vary from 1 to 4 hours (30 minutes if no injection source is available). However, battery load shed is always assumed to fail in the BSEP model and no credit is taken for the potential additional coping time from load shed. Consideration is given to system failure timing, which does impact the available time to recover AC power.

Note that these are one-unit PSA models. The term "station blackout" is actually a unit blackout if only one unit is affected, but for the purposes of the PSA analyses, station blackout is used to describe the above conditions. The LOOP event may impact offsite

AC availability to the unit's switchyard or to both units' switchyards, which may in turn result in a dual unit Station Blackout (SBO).

The loss of AC E-buses and DC power panels have been modeled in considerably more detail in the current PSA models. The models are thus more indicative of the significance of these contributions to CDF compared to prior IPE evaluation.

Transients with Main Steam Isolation Valve (MSIV) closure and loss of condenser vacuum are also large contributors for BSEP. These initiators contribute about 11.4 percent to the CDF due to their relatively high frequency of occurrence combined with the need for the plant to respond from an isolated condition without the benefit of BOP systems. The ability to safely shut down during this type of transient is still very likely due to the redundant mitigating systems available.

Loss of CRD, loss of Reactor Building Closed Cooling Water (RBCCW), internal flooding events, and other transients contribute a smaller amount to the CDF.

Figure F-2 provides a more complete depiction of the BSEP CDF contributions grouped by initiating event category.

In addition, Figures F-3 and F-4 provide the contribution to CDF by system and the system based Risk Achievement Worth rankings, respectively.

It has been observed in past PSAs that the calculation of radionuclide releases are strongly linked to the results of the Level 1 accident sequences. More specifically, there is a high correlation between the types of accident sequences (e.g., Level 1 end states or Plant Damage States or Accident Classes) and the determination of the radionuclide release categories. This observation can be explained because the severe accident progression is strongly influenced by the systems available and the accident sequence timing as determined in Level 1. These features are directly correlated to the Plant Damage States or Accident Classes.

Table F-1 is a summary of the Brunswick Level 1 accident classes. Table F-1 also summarizes the core damage frequency (CDF) determined from the Brunswick Level 1 PSA. These CDF calculations are one of the inputs to the Level 2 calculational process. The Level 1 results including the cutsets are derived from the Brunswick Unit 2 PSA model (January 2003).

In addition, the Level 2 CETs are quantified using the cutset inputs from Level 1 that make up the CDF for each accident class, that is, a separate CET calculation has been performed for the cutsets transferred from Level 1 for each individual CET associated with an accident class.

F.2.3 CURRENT LEVEL 2 BSEP PSA MODEL

The BSEP Level 2 PRA analysis was developed consistent with the Extended Power Uprate (EPU) configuration of the Brunswick plants to be used as a basis for the assessment of PSA Applications, such as SAMA. It involved the development of a set of containment event trees (CETs) as a framework for examining severe accident phenomena, including both active and passive mitigation functions of the Brunswick Mark I containment. This effort was based upon previous methods used in the Shoreham PSA, other BWR Level 2 PSAs, IDCOR Task 4.1, and the Vermont Yankee Containment Safety Study. In addition, this effort considered the BWROG effort on generic Mark I containment performance for NUMARC. The NRC sponsored research on simplification of the CET structure to address LERF issues only was acknowledged but not used in this full Level 2 analysis.

The principal technical advances that have been incorporated into the Brunswick containment evaluation effort include the following:

- Use of a containment event tree that includes sufficient detail to quantify effects of plant modifications and changes in procedures.
- Establishment of added success paths for recovery of degraded core conditions within the reactor vessel (e.g., TMI-2 events). These paths involved recovery actions during in-vessel core melt progression accidents.
- Incorporation of the Brunswick EOPs and Severe Accident Management Guidelines (SAMGs). This includes the latest BWR Owners Group (BWROG) containment flooding guidance, which is a major model perturbation from previous studies.
- Interface with the BWROG/NUMARC containment safety study to incorporate the latest input on severe accident issues as they affect containment response (e.g., direct containment heating, heat management, seal performance).
- Establishment of plant specific deterministic calculations to support the improved success criteria using MAAP (Modular Accident Analysis Program) calculations as the basis.
- Development of a traceable documentation path through the containment event tree so that both qualitative and quantitative insights can be developed. This facilitates both communication with the NRC and internal use within Progress Energy.
- Consideration of NRC sponsored insights for simplifying the CET process.

The results of the BSEP Level 2 analysis are summarized in sections F.2.3.1 and F.2.3.2.

F.2.3.1 BSEP LEVEL 2 PSA RELEASE CATEGORIES

The frequency of radionuclide release is characterized by the quantification of the Level 1 and Level 2 PSA models. The Level 2 containment event tree end states are delineated by the magnitude and timing of the calculated radionuclide release. Therefore, the containment event tree end states are characterized using a two-term matrix (severity, time) as shown in Table F-2.

Given this characterization strategy, the Level 2 quantification can be summarized in two complementary tables. These tables provide quantitative information that is useful in the interpretation of the current containment capability given the spectrum of core damage sequences calculated in the Level 1 PSA.

Table F-3 includes the following information:

Input:	Individual Level 1 accident sequences with their failure cutsets and frequencies are transferred into Level 2. However, only a summary of the Level 1 PRA total accident sequence frequency is presented here. This total frequency is not used directly as input to the containment event tree evaluation. Nevertheless, it represents a convenient summary of the total frequency of the sequences that are being transferred into the CET.
Radionuclide Release End States:	The release categories used to discriminate among the CET end states are identified.
Output:	The output frequencies of the CETs as a function of the end state bins are identified.

Table F-4 summarizes the radionuclide releases by accident class that contribute to each of the radionuclide release categories established for the Brunswick Level 2 evaluation. In addition to the radionuclide release categories, Table F-4 also identifies the intact containment conditions.

The quantification provides a yardstick with which to measure the best estimate of containment performance given that severe accidents could progress to beyond core damage. The quantification may include some conservatisms to account for the inability of current models and experiments to predict certain severe accident related phenomena.

A substantial fraction (43 percent) of the accidents transferred from Level 1 PRA are effectively mitigated such that releases are essentially contained within an intact containment (i.e., OK release bin). Approximately 95 percent of the postulated accidents do not have "large" releases occurring before protective action can be taken (i.e., approximately 95 percent of the accidents do not result in LERF).

Figure F-5 summarizes in graphical form a histogram comparing the total core damage frequency (i.e., the results of the Level 1 PRA) with the end state frequencies of the Level 2 analysis, i.e., High (H), Medium or Moderate (M), Low (L) and Low-Low (LL) release magnitudes plus those severe accident sequences that result in an intact containment (OK). A substantial fraction (approximately 57 percent) of the core damage end states lead to either low release or the containment remains intact and no substantial release occurs. These release categories have a minimal impact on the SAMA analysis.

Figure F-6 provides a graphical summary of LERF contributors by accident class. As can be seen from the figure, loss of reactivity control (Class IV) and unisolated LOCA outside containment (Class V) accidents are the dominant contributors to High-Early releases. While the LERF release category is a recognized risk metric and an important contributor to risk at BSEP, it is not the largest contributor to offsite consequences. Section F.3 provides additional information on the dose-risk and offsite economic cost-risk associated with the BSEP release categories.

Figure F-7 provides a graphical comparison of the percentage of plant CDF leading to a Large Early release (5.1 percent) and the percentage of plant CDF leading to no release (43.2 percent) or releases less severe than Large Early (51.7 percent).

F.2.3.2 BSEP LEVEL 2 PSA SOURCE TERMS

The input to the Level 3 BSEP model provided by the Level 2 model is a combination of radionuclide release fractions, the timing of the radionuclide releases relative to the declaration of a general emergency, and the frequencies at which the releases occur. This combination of information is used in conjunction with other BSEP site characteristics in the Level 3 model to evaluate the consequences of a core damage event.

Source terms were developed for 9 of the 13 release categories identified in Table F-3. The “OK”, “Low-Low/Early”, “Moderate/Late”, and “High/Late” release categories were excluded as they were minimal contributors. Table F-5 provides a summary of the Level 2 results that were used as Level 3 input for the BSEP SAMA analysis. This table includes the following information:

- Frequency
- BSEP Modular Accident Analysis Program (MAAP) case identifier (for reference)
- Airborne release percent at 48 hours for each of the fission product groups provided by MAAP
- Start time of the airborne release (measured from the time of accident initiation)
- End time of the airborne release (measured from the time of accident initiation)

The consequences corresponding to each of these source terms are provided in section F.3.

F.2.4 BSEP PSA REVIEW SUMMARY

The Brunswick Steam Electric Plant (BSEP) Unit Nos. 1 and 2 Individual Plant Examination (IPE), Individual Plant Examination for External Events (IPEEE), and the associated Probabilistic Safety Assessment (PSA) models have been subjected to a number of assessments and reviews. The following comprehensive peer reviews have been performed:

1988: The original Brunswick PRA which included a Level 1 PRA and external events PRA was docketed in May 1988. The PRA was reviewed by INEL under contract to NRC and the results documented in November 1989 through NUREG/CR-5465 (Reference 15). Many of the insights provided by this review were factored into the PRA for submittal to NRC under the IPE program.

1990-1992: As indicated in Section 5 of the IPE (Reference 9), inputs to and outputs from the IPE analysis were reviewed by Progress Energy's Nuclear Fuels Section; Brunswick plant personnel from operations, training, the plant simulator, and engineering; and other external organizations. Consultants from NUS Corporation provided review of PRA tasks performed by the CP&L staff. Ed Burns, PhD, from ERIN Engineering and Alan Kolaczkowski from SAIC performed a comprehensive external review of the major elements of the PRA. Chris Amos, PhD, from SAIC performed an independent review of the Level 2 analysis. CP&L also used multi-disciplined project teams (including plant and corporate engineering staff, plant operations and training staff, and PSA personnel) to determine possible actions to address the results and insights.

1994-1995: As indicated in Section 6 of the IPEEE (Reference 10), a variety of peer reviews were provided. Vectra Technologies, Inc performed a seismic peer review. CP&L engineers performed an in-depth review of each of the separate analyses that comprised the fire analysis and the analysis of external events. A multi-disciplined independent review team composed of corporate and Brunswick plant personnel in operations, training, fire protection, licensing, and nuclear engineering considered the final results of the IPEEE analysis. The results were evaluated using NEI 91-04 closure guidelines for potential plant vulnerabilities, identification of alternative solutions, and recommendation of actions to resolve severe accident issues. The results and conclusions were subsequently reviewed and accepted by Brunswick senior plant management.

2000: An independent peer review was performed by E.T. Burns, PhD, ERIN (Reference 38).

2001: BWROG Peer Certification Review. A comprehensive review of the BSEP Level 1 and Level 2 (LERF) models was performed Ed Burns, PhD, ERIN; Vincent Andersen, ERIN; Rashid Abbas, Browns Ferry Nuclear Plant; Gerry Kindred, Perry Nuclear Power Plant; Clement Littleton, Entergy Nuclear Northeast; and Vishu Visweswaran, GE. A description of this review is provided in Section F.2.4.1.

F.2.4.1 IMPACT ON THE SAMA ANALYSIS OF UNRESOLVED PSA REVIEW COMMENTS

The BWROG peer review of the Brunswick PSA was completed in December 2001. A final report summarizing the results of the review has been received (Reference 11). The results of peer review are characterized in the following table that provides the element grades assigned to the BSEP PSA.

PRA Element	Summary Grade
Initiating Events	3
Accident Sequences Evaluation	3
Thermal Hydraulic Analysis	2
Systems Analysis	3
Data Analysis	3
Human Reliability Analysis	3
Dependency Analysis	3
Structural Response	3
Quantification and Results Interpretation	3
Containment Performance Analysis	3
Maintenance and Update Process	3

A grade of “3” is defined in the report as follows: “This review grade extends the requirements to ensure that risk significance determinations made by the PRA are adequate to support regulatory applications, when combined with deterministic insights. Therefore, a PRA with elements certified at Grade 3 can support physical plant changes when it is used in conjunction with other deterministic approaches that ensure that defense-in-depth is preserved. Grade 3 is acceptable for Grade 1 and 2 applications, and also for assessing safety significance of equipment and operator actions. This assessment can be used in licensing submittals to NRC to support positions regarding absolute levels of safety significance if supported by deterministic evaluations.”

For the Brunswick PSA, the only element that received a summary grade lower than "3" from the certification team was "Thermal Hydraulic Analysis." This was an area in which the team believed that attention was merited to reduce identified conservatism in the existing success criteria and data of the BSEP PSA models. This was also a recognized area for improvement by Progress Energy. Measures have been taken during 2002-2003 to generate more Level 1 and Level 2 supporting thermal hydraulic analyses in support of the Brunswick PSA. These results are to be linked into the risk models in subsequent model updates.

The peer review team identified no findings of significance level “A” that needed to be evaluated and potentially addressed before the next regular PRA update. The team did identify 66 findings of significance level “B”. The primary focus of these findings was aimed at improving upon the conservative logic and data elements in the model identified by the team. These “B” level findings are considered important and necessary to address, but disposition may be deferred until the next PSA update. These “B” level findings have been entered into the Progress Energy corrective action process for evaluation and disposition. Six of the findings were resolved prior to the MOR03 model being used for the SAMA analysis. The large number of remaining findings and the need for thermal hydraulic analyses to validate the resolution of some findings has required that resolution of the remaining findings be spread over subsequent model updates. There were six areas of strength identified. The team acknowledged as strengths:

- The inclusion of initiator fault trees directly into the accident sequence logic.
- The use of state of technology approach for HRA dependency analysis based on explicit review and quantification of human error probabilities within a cutset.
- The comprehensiveness of the HRA documentation.
- The completeness and plant-specific nature of the primary containment capability evaluation.
- The thoroughness of the documentation for the quantification process.
- The explicit analysis of the BSEP Emergency Action Level declaration procedure and how it relates the characterization of the Level 2 release timing.

In general, the resolution of the open comments will remove conservative modeling assumptions in the BSEP PSA. Removal of these assumptions would result in a lower Maximum Averted Cost-Risk and lower SAMA specific averted cost-risk estimates, which would reduce the likelihood that SAMAs will be identified as cost beneficial. No open issues have been identified that would result in the retention of a SAMA for implementation that would be screened based on the current PSA model results.

F.3 LEVEL 3 PSA ANALYSIS

The MACCS2 code (Reference 28) was used to perform the level 3 probabilistic risk assessment (PRA) for the BSEP. The input parameters given with the MACCS2 "Sample Problem A," which included the NUREG-1150 food model (Reference 29), formed the basis for the present analysis. These generic values were supplemented with parameters specific to BSEP and the surrounding area. Site-specific data included population distribution, economic parameters, and agricultural production. Plant-specific release data included the time-nuclide distribution of releases, release frequencies, and release locations. The behavior of the population during a release (evacuation parameters) was based on plant and site-specific set points (i.e., declaration of a General Emergency) and the emergency planning zone (EPZ) evacuation times (Reference 30). These data were used in combination with site-specific meteorology to simulate the probability distribution of impact risks (exposure and economic) to the surrounding (within 50 miles) population from the representative accident sequences at BSEP.

Population

The population surrounding the plant site was estimated for the year 2036. The distribution was given in terms of population at distances to 1, 2, 3, 4, 5, 10, 20, 30, 40 and 50 miles from the plant and in the direction of each of the 16 compass points (i.e., N, NNE, NE……NNW). The total population for the 160 sectors (10 distances × 16 directions) in the region was estimated as 847,834, the distribution of which is given in Tables F-6 and F-7.

Population projections within 50 miles of BSEP were determined using a geographic information system (GIS), U.S. Census Bureau Block Group population data for 2000, and population growth rates based on 1990 and 2000 county-level census data. Population sectors were created for 16 sectors at an interval of 1 mile from 0 to 5 miles, the interval from 5 to 10 miles and at 10-mile intervals from 10 miles to 50 miles. The counties were combined with the sectors to determine what counties fell within each sector. The area of each county within a given sector was calculated to determine the area fraction of a county or counties that comprise each sector. The decennial growth rate for each county was converted to an equivalent annual growth rate. The annual growth rate in each sector was then calculated by the sum of the products of the annual growth rate of each county within a sector and the fraction of the area in that sector occupied by that county. This weighted-average annual growth rate for each sector is given in Tables F-8 and F-9. Zero values in Tables F-8 and F-9, as well as Table F-7, indicate a sector that totally encompasses water.

The U.S. Census Bureau Block Group population data for BSEP (Reference 31), was projected to the year 2036 using the county area-weighted-average annual growth rate in each sector. The county populations in 1990 and 2000 are provided in Reference 32. It was assumed that the annual population growth rate would remain the same as that reported between 1990 and year 2000. Using the sector specific population growth rates, projections were made for the year 2036 by multiplying the 2000 sector population data by 36 times the annual growth rate (expressed as an increment).

Economy

MACCS2 requires the spatial distribution of certain economic data (fraction of land devoted to farming, annual farm sales, fraction of farm sales resulting from dairy production, and property value of farm and non-farm land) in the same manner as the population. This was done by specifying the data for each of the 8 counties surrounding the plant, to a distance of 50 miles. The values used for each of the 160 sectors was then the data corresponding to that county which made up a vast majority of the land in that sector. For 8 sectors, no county encompassed more than 2/3rd of the area, so conglomerate data (weighted by the fraction of each county in that sector) was defined.

In addition, generic economic data that is applied to the region as a whole was revised from the MACCS2 sample problem input when better information was available. These revised parameters include value of farm and non-farm wealth and fraction of farm wealth from improvements (e.g., buildings, equipment).

Agriculture

Agricultural production information was taken from the 1997 Agricultural Census (Reference 33). Production within 50 miles of the site was estimated based on those counties within this radius. Production in those counties, which lie partially outside of this area, was multiplied by the fraction of the county within the area of interest. Of the food crops, grains and legumes (approximately 38 percent of total cropland each) were harvested from the largest areas; pasture made up 15 percent of this land.

The duration of the growing seasons for grains, legumes, and stored forage were obtained from Reference 34. The duration of the growing season for the remaining crop categories (pasture, roots, green leafy vegetables, and other food crops) were taken to be the same as those used previously at a site in the neighboring state of Georgia (Reference 35).

Nuclide Release

The core inventory at the time of the accident was based on the input supplied in the MACCS Users Guide (Reference 28). The core inventory corresponds to the end-of-cycle values for a 3578-MWth BWR plant. A scaling factor of 0.817 was used to provide a representative core inventory of 2923-MWth at BSEP. Table F-10 gives the estimated BSEP core inventory. Release frequencies (ranging from 5.09E-8/yr for Sequence L/I to 1.06E-5/yr for Sequence M/I) and nuclide release fractions (of the core inventory) were analyzed to determine the sum of the exposure (50-mile dose) and economic (50-mile economic costs) risks from 9 sequences representative of the suite of potential accident releases. BSEP nuclide release categories were related to the MACCS categories as shown in Table F-11.

Each BSEP category corresponded with a single release duration (either puff or continuous).

The reactor building has a width of 140 feet and a height of 160 feet. All releases were modeled as occurring at ground level. The affect of this assumption on the exposure risk was analyzed by varying the release height of all 9 sequences from ground level to the height of the reactor building; the risk increased by less than 4 percent with increased release height. The thermal content of each of the releases was conservatively assumed as to be the same as ambient, i.e., buoyant plume rise was not modeled. The affect of this assumption on the exposure risk was analyzed by varying the heat content of all of the modeled releases from 0 megawatts to 10 megawatts; the risk decreased with increasing plume heat by 3 percent over this range.

Evacuation

Scram for each sequence was taken as time 0 relative to the core containment response times. A General Emergency is declared when plant conditions degrade to the point where it is judged that there is a credible risk to the public; for example, a General Emergency will be declared when 2 of the 3 fission product barriers have been breached and the third is in jeopardy. General Emergency declarations would range from 5 minutes for sequence H/L to 60 minutes for Sequence M/L.

The MACCS2 Users Guide input parameters of 95 percent of the population within 10 miles of the plant (Emergency Planning Zone) evacuating and 5 percent not evacuating were employed. These values have been used in similar studies (e.g., Hatch, Calvert Cliffs, References 35 and 36) and are conservative relative to the NUREG-1150 study, which assumed evacuation of 99.5 percent of the population within the emergency planning zone (Reference 29). The evacuees are assumed to begin evacuation 30 minutes (Reference 30) after a general emergency has been declared and are evacuated at a radial speed of 0.24 m/sec. This speed is taken from the minimum speed from any evacuation zone under adverse weather conditions.

Meteorology

Annual onsite meteorology data sets from 1997 through 2001 were investigated for use in MACCS2. The 2001 sequential hourly data set was found to result in the largest risk and was subsequently used in all MACCS2 risk calculations. Wind speed from the lower wind sensor (11.5-meter height) was reduced to equivalent 10-meter speed using the power law wind profile as applied in MACCS2. This wind speed and the direction from the lower sensor were combined with precipitation (hourly cumulative) and atmospheric stability (Pasquill-Gifford) class.

Atmospheric mixing heights were specified for AM and PM hours by season. These values ranged from 500 to 580 meters and from 900 to 1280 meters for AM and PM, respectively. (Reference 37)

MACCS2 Results

The resulting annual risks from the 9 BSEP release sequences are provided in Table F-12. The largest risks are from sequences M/I and H/I. The former is characterized by its high frequency (1.06×10^{-5}); the latter is also a relatively high frequency release (3.79×10^{-6}) combined with relatively large releases of Cs, I, Te and Sb. These two sequences contribute over 70 percent of the exposure risk and over 80 percent of the economic risk from BSEP.

F.4 BASELINE RISK MONETIZATION

F.4.1 OFF-SITE EXPOSURE COST

This section explains how Progress Energy calculated the monetized value of the status quo (i.e., accident consequences without SAMA implementation). Progress Energy also used this analysis to establish the maximum benefit that a SAMA could achieve if it eliminated all BSEP risk.

F.4.2 OFF-SITE EXPOSURE COST

The baseline annual off-site exposure risk was converted to dollars using the NRC's conversion factor of $2,000 per person-rem (Reference 2), and discounting to present value using NRC standard formula (Reference 2):

$$W_{pha} = C \times Z_{pha}$$

Where:

W_{pha} = monetary value of public health risk after discounting

C = $[1-\exp(-rt_f)]/r$

t_f = years remaining until end of facility life = 20 years

r = real discount rate (as fraction) = 0.07/year

Z_{pha} = monetary value of public health (accident) risk per year before discounting ($/year)

The Level 3 analysis showed an annual off-site population dose risk of 29.35 person-rem. The calculated value for C using 20 years and a 7 percent discount rate is approximately 10.76. Therefore, calculating the discounted monetary equivalent of accident risk involves multiplying the dose (person-rem per year) by $2,000 and by the C value (10.76). The calculated off-site exposure cost is $631,782.

F.4.3 OFF-SITE ECONOMIC COST RISK (OECR)

The Level 3 analysis showed an annual off-site economic risk of $48,492. Calculated values for off-site economic costs caused by severe accidents must be discounted to present value as well. This is performed in the same manner as for public health risks and uses the same C value. The resulting value is $521,915.

F.4.4 ON-SITE EXPOSURE COST RISK

Occupational health was evaluated using the NRC methodology in Reference 2, which involves separately evaluating “immediate” and long-term doses.

Immediate Dose - For the case where the plant is in operation, the equation that NRC recommends using (Reference 2) is:

Equation 1:

$$W_{IO} = R\{(FD_{IO})_S - (FD_{IO})_A\}\{[1 - \exp(-rt_f)]/r\}$$

Where:

W_{IO} = monetary value of accident risk avoided due to immediate doses, after discounting

R = monetary equivalent of unit dose ($/person-rem)

F = accident frequency (events/yr)

D_{IO} = immediate occupational dose (person-rem/event)

$_S$ = subscript denoting status quo (current conditions)

$_A$ = subscript denoting after implementation of proposed action

r = real discount rate

t_f = years remaining until end of facility life.

The values used in the BSEP analysis are:

R = \$2,000/person-rem

r = 0.07

D_{IO} = 3,300 person-rem/accident (best estimate, as documented in Reference 2)

t_f = 20 years (license extension period)

F = 4.19×10^{-5} (total core damage frequency)

For the basis discount rate, assuming F_A is zero, the best estimate of the immediate dose cost is:

$$W_{IO} = R\,(FD_{IO})_S\,\{[1 - \exp(-rt_f)]/r\}$$

$$= 2{,}000 * 4.19 \times 10^{-5} * 3{,}300 * \{[1 - \exp(-0.07 * 20)]/0.07\}$$

$$= \$2{,}976$$

Long-Term Dose - For the case where the plant is in operation, the NRC equation (Reference 2) is:

Equation 2:

$$W_{LTO} = R\{(FD_{LTO})_S - (FD_{LTO})_A\}\,\{[1 - \exp(-rt_f)]/r\}\{[1 - \exp(-rm)]/rm\}$$

Where:

W_{IO} = monetary value of accident risk avoided long-term doses, after discounting, \$

m = years over which long-term doses accrue

The values used in the BSEP analysis are:

R = \$2,000/person-rem

r = 0.07

D_{LTO} = 20,000 person-rem/accident (best estimate, as documented in Reference 2)

m = “as long as 10 years”

t_f = 20 years (license extension period)

F = 4.19×10^{-5} (total core damage frequency)

For the basis discount rate, assuming F_A is zero, the best estimate of the long-term dose is:

W_{LTO} = $R\ (FD_{LTO})_S\ \{[1 - \exp(-rt_f)]/r\}\ \{[1 - \exp(-rm)]/rm\}$

= $2{,}000*4.19\times10^{-5}*20{,}000*\{[1 - \exp(-0.07*20)]/0.07\}\ \{[1 - \exp(-0.07*10)]/0.07*10\}$

= \$12,973

Total Occupational Exposure - Combining Equations 1 and 2 above and using the above numerical values, the total accident related on-site (occupational) exposure avoided (W_O) is:

W_O = $W_{IO} + W_{LTO}$ = (\$2,976 + \$12,973) = \$15,949

F.4.5 ON-SITE CLEANUP AND DECONTAMINATION COST

The net present value that NRC provides for cleanup and decontamination for a single event is \$1.1 billion, discounted over a 10-year cleanup period (Reference 2). NRC uses the following equation to integrate the net present value over the average number of remaining service years:

U_{CD} = $[PV_{CD}/r][1-\exp(-rt_f)]$

Where:

PV_{CD} = net present value of a single event

r = real discount rate

t_f = years remaining until end of facility life.

The values used in the BSEP analysis are:

PV_{CD} = $\$1.1\times10^9$

r = 0.07

t_f = 20

The resulting net present value of cleanup integrated over the license renewal term, $\$1.18\times10^{10}$, must be multiplied by the total core damage frequency of 4.19×10^{-5} to determine the expected value of cleanup and decontamination costs. The resulting monetary equivalent is \$496,062.

F.4.6 REPLACEMENT POWER COST

Long-term replacement power costs was determined following the NRC methodology in Reference 2. The net present value of replacement power for a single event, PV_{RP}, was determined using the following equation:

$$PV_{RP} = [\$1.2\times10^8/r] * [1 - \exp(-rt_f)]^2$$

Where:

PV_{RP} = net present value of replacement power for a single event, ($)

r = 0.07

t_f = 20 years (license renewal period)

To attain a summation of the single-event costs over the entire license renewal period, the following equation is used:

$$U_{RP} = [PV_{RP} /r] * [1 - \exp(-rt_f)]^2$$

Where:

U_{RP} = net present value of replacement power over life of facility ($-year)

After applying a correction factor to account for BSEP's size relative to the "generic" reactor described in NUREG/BR-0184 (Reference 2)(i.e., 1006 MWe/910 MWe) and multiplying by 2 to account for the assumption the remaining unit has to shutdown after a core damage event, the replacement power costs are determined to be 1.74×10^{10} ($-year). Multiplying this value by the CDF (4.19×10^{-5}) results in a replacement power cost of $730,963.

F.4.7 TOTAL

The sum of the baseline costs is as follows:

Off-site exposure cost	=	$631,782
Off-site economic cost	=	$521,915
On-site exposure cost	=	$15,949
On-site cleanup cost	=	$496,062
Replacement Power cost	=	$730,963
Total cost	=	$2,396,671

This is the single unit Maximum Averted Cost-Risk (MACR) based on internal events contributions (rounded to $2,397,000). As some SAMAs may be implemented on a site basis, all cost calculations for the BSEP SAMA analysis are also presented on a site basis. This convention maintains consistency between the averted cost-risk estimates and the costs of implementation. Thus, the single unit MACR is doubled to obtain the site MACR of $4,794,000. Use of a factor of two to account for both units is based on the assumption that the two units are symmetrical.

As described in section F.1.2, the internal events MACR is doubled to account for external events contributions. The resulting modified MACR (MMACR) is $9,588,000 and was used in the Phase I screening process to eliminate SAMAs that are not economically feasible. If the estimated cost of implementing a SAMA exceeded $9,588,000, it was excluded from further analysis.

Exceeding this threshold would mean that a SAMA would not have a positive net value even if it could eliminate all severe accident costs. On the other hand, if the cost of implementation is less than this value, then a more detailed examination of the potential fractional risk benefit that can be attributed to the SAMA is performed.

F.5 PHASE I SAMA ANALYSIS

F.5.1 SAMA IDENTIFICATION

The SAMA identification process for BSEP is primarily based on the PRA importance listings, the IPE, and the IPEEE. In addition to these plant specific sources, selected industry SAMA analyses were reviewed to identify any Phase II SAMAs that were determined to be cost beneficial at other plants. These SAMAs were further analyzed and included in the BSEP SAMA list if they were considered to be potentially cost beneficial for Brunswick. The following subsections provide a more detailed description of the identification process.

F.5.1.1 LEVEL 1 BSEP IMPORTANCE LIST REVIEW

The BSEP PRA was used to generate a list of events sorted according to their Risk Reduction Worth (RRW) values. The top events in this list are those events that would most reduce the BSEP CDF if the failure probability were set to 0.0. The events were reviewed down to the 1.01 level, which approximately corresponds to a 1 percent change in the CDF given 100 percent reliability of the event. If the dose-risk and offsite economic cost-risk were also assumed to be reduced by 1 percent, the corresponding averted cost-risk would be approximately $23,000. Applying a doubling factor to estimate the potential impact of External Events (refer to Section F.1.2), the result is less than $50,000 ($100,000 per site). This is considered to be the lower end of the implementation costs for potential plant changes, especially given that this estimate is based on complete reliability of the proposed change. No further review of the importance listing was performed below the 1.01 level. Table F-13 documents the disposition of each event in the Level 1 BSEP RRW list.

F.5.1.2 LEVEL 2 BSEP IMPORTANCE LIST REVIEW

A similar review was performed on the importance listing from the Level 2 results. A composite cutset file containing the High/Early, High/Intermediate, and Medium/Intermediate cutsets was used as the basis for the importance listing. This method was used to ensure the Risk Reduction Worth rankings were based on the largest contributors to dose-risk. These three release categories represent 90 percent of the BSEP person-rem/yr contributions. Inclusion of the remaining release categories may mask important events and they have been excluded for this reason.

The Level 2 RRW values were also reviewed down to the 1.01 level. As described for the Level 1 RRW list, events below the 1.01 cutoff value are estimated to yield an averted cost-risk less than $100,000/site and are not considered to be likely candidates for identifying cost effective SAMAs. As such, the events with RRW values below 1.01 were not reviewed. Table F-14 documents the disposition of each event in the Level 2 BSEP RRW list.

F.5.1.3 INDUSTRY PHASE II SAMAS

Phase II SAMAs are those plant changes that require more detailed analysis than what is performed in the Phase I screening process for proper disposition. While many of these SAMAs are shown not to be cost-beneficial, some are close contenders and a small number have been shown to be cost-beneficial at other plants. Use of the BSEP importance ranking should identify the types of changes that would most likely be cost beneficial for Brunswick, but review of selected industry Phase II SAMAs may capture potentially important changes not identified for BSEP due to PRA modeling differences. Given this potential, it was considered prudent to include a review of selected industry Phase II SAMAs in the BSEP SAMA identification process.

The Phase II SAMAs from the following U.S. nuclear sites have been reviewed:

- Calvert Cliffs [Reference 3]
- H.B. Robinson [Reference 4]
- Edwin I. Hatch [Reference 5]
- Peach Bottom [Reference 6]
- Dresden [Reference 7]
- Quad Cities [Reference 8]

Three PWR and three BWR sites were randomly chosen from available documentation to serve as the Phase II SAMA sources. Not all of the Phase II SAMAs from these sources were included in the initial Brunswick SAMA list. Many of the industry Phase II SAMAs were already represented by other SAMAs in the Brunswick list or it was judged that they would not be close contenders for BSEP. These SAMAs were not considered further. Based on engineering judgment, the SAMAs considered to be potentially cost beneficial for BSEP were retained and included in the initial BSEP SAMA lists. These SAMAs include:

- Diverse EDG HVAC Logic
- Add Alternate/Manual Methods for Containment Venting
- Use Firewater as a Backup for EDG Cooling
- Auto Re-Fill of the CST
- Use Firewater as a Backup for Containment Spray
- Demonstrate RCIC Operation following Depressurization
- Enhance EOPs to Include Control Band for Containment Venting

F.5.1.4 BSEP IPE

Performance of the Brunswick IPE generated a list of risk-based insights and potential plant improvements. Typically, changes identified in the IPE process are implemented and closed out for each of the sites; however, there are some items that are not completed due to high projected costs or other criteria. As the criteria for implementation of a SAMA may be different than what was used in the post IPE decision-making process, these SAMAs are re-examined in this analysis and include the following changes:

- 5th Diesel Generator
- Dedicated DC Power Supply for Switchyard Breakers

F.5.1.5 BSEP IPEEE

Similar to the IPE, there may be a number of proposed plant changes that were previously rejected based on non-SAMA criteria that should be re-examined. In addition, there may be issues that are in the process of being resolved, which may be important to the disposition of some SAMAs. The IPEEE was used to identify these items.

An effort was also made to use the IPEEE to develop new SAMAs based on a review of the original results. However, the BSEP IPEEE was not maintained as a “living” analysis. This limits the qualitative insights and quantitative estimates that can be made with regard to external events contributors. The results of the review include the identification of the following SAMAs:

- Improve Alternate Shutdown Panel
- Improve Alternate Shutdown Training and Communications Equipment

- Add Automatic Fire Suppression System
- Prohibit Transient Combustibles in the Cable Spreading Room and/or Require Fire Suppression Personnel to be Present During Work that May Cause a Fire
- Improve Fire Barriers between Cabinets in the Cable Spreading Room
- Add Alternate/Manual Methods for Containment Venting

These SAMAs have been included in the initial BSEP SAMA list. This list contains all of the initial SAMAs identified for the Phase I analysis and are presented in Table F-15.

F.5.2 PHASE I ANALYSIS

The initial list of SAMA candidates is presented in Table F-15. This list was developed as described in Section F.5.1 and is used as the starting point for the BSEP SAMA review. The screening process used in this analysis is summarized in Figure F-1.

The purpose of the Phase I analysis is to use high level knowledge of the plant and SAMAs to preclude the need to perform detailed cost-benefit analyses on them. The following criteria are used in the Phase I analysis to eliminate SAMAs from further consideration:

- Applicability to the Plant: If a proposed SAMA does not apply to the BSEP design, it is not retained. For example, inclusion of an automatic alternate refill system for an Isolation Condenser System would not require further analysis for a plant that does not have an Isolation Condenser System.
- Excessive Implementation Cost: If a SAMA requires extensive changes that are known to exceed any possible benefit, they are screened without developing an estimated cost of implementation. For example, the cost of installing an additional, buried offsite power source over a path of fifty miles is known to exceed any potential benefit and would be immediately disqualified.
- Implementation Cost Greater than Screening Cost: If the estimated cost of implementation is greater than the Modified Maximum Averted Cost-Risk, the SAMA cannot be cost beneficial and is screened from further analysis.

The potential for screening SAMA candidates using the first of these criteria is limited as the BSEP list was developed from plant specific insights and other industry SAMAs that were judged to be potentially cost beneficial at BSEP. The second and third criteria are also limited in there use as the BSEP MMACR is relatively high at $9,588,000. However, these criteria were applied to the initial SAMA list in order to identify the list of SAMAs to be passed to the Phase II analysis.

Table F-15 provides a description of how each SAMA was dispositioned in Phase I. Those SAMAs that required a more detailed cost-benefit analysis are evaluated in Section F.6. A list of these SAMAs is provided in Table F-16.

F.6 PHASE II SAMA ANALYSIS

It was possible to screen some of the remaining SAMA candidates from further analysis based on plant specific insights regarding the risk significance of the systems that would be affected by the proposed SAMAs. The SAMAs related to non-risk significant systems were screened from a detailed cost benefit analysis as any change in the reliability of these systems is known to have a negligible impact on the PSA evaluation. In addition, those SAMAs that can be shown to have a small averted cost-risk based on relevant importance rankings are excluded from further review. No detailed analysis is performed for these SAMAs and the bases for their dispositions are considered to be contained within Table F-16.

For each of the remaining SAMA candidates that could not be eliminated based on screening cost or PSA/application insights, a more detailed conceptual design was prepared along with a more detailed estimated cost. This information was then used to evaluate the effect of the candidates' changes upon the plant safety model.

The final cost-risk based screening method used to determine the desirability of implementing the SAMA is defined by the following equation:

Net Value = (baseline cost-risk of site operation (MMACR) – cost-risk of site operation with SAMA implemented) – cost of implementation

If the net value of the SAMA is negative, the cost of implementation is larger than the benefit associated with the SAMA and the SAMA is not considered beneficial. The baseline cost-risk of plant operation was derived using the methodology presented in Section F.4. The cost-risk of plant operation with the SAMA implemented is determined in the same manner with the exception that the PSA results reflect the application of the SAMA to the plant (the baseline input is replaced by the results of a PSA sensitivity with the SAMA change in effect).

Subsections F.6.1 – F.6.27 describe the detailed cost benefit analysis that was used to determine how the remaining candidates were ultimately treated. Refer to Table F-16 for the cost of implementation bases for each SAMA candidate.

F.6.1 PHASE II SAMA NUMBER 1: PORTABLE DC GENERATOR

Description: Loss of DC power can be mitigated in some circumstances through the alignment of a portable DC generator. It is assumed that these generators can be aligned to any and all of the 125V DC switchboards (1A-1, 1A-2, 1B-1, 1B-2, 2A-1, 2A-2, 2B-1, 2B-2) and can at least provide the full DC load (no load shed required). This enhancement is not assumed to provide benefit when the DC bus/switchboard has failed or during accidents where the batteries are disconnected from the DC system.

The portable DC generator will provide benefit in several types of scenarios including the following:

- Loss of the AC power supply to the battery charger with on-site AC power available (and failure to align the alternate source for the "B" chargers)

- Failure of the DC charger(s)
- SBO conditions

The benefit of the portable charger is limited in SBO sequences due to the need to depressurize when HCTL is challenged. Given that a steam driven injection system is providing makeup to the RPV for these cases, injection is lost on vessel depressurization. Even if suction is maintained on the CST until high suppression pool level occurs, BSEP MAAP runs indicate HCTL is reached in about 4.5 hours given the unavailability of cooling coincident with accident initiation. Therefore, for SBO sequences, the primary benefit of the portable DC generator is realized in the increased time available for restoration of AC power. Non-LOOP, AC power failure sequences without containment heat removal face similar limitations depending on the availability of low pressure injection.

Sequences with loss of the DC chargers or the AC power supply to the chargers include a variety of circumstances in which the availability of alternate DC power may reduce plant risk. Providing motor/valve control power or instrumentation support to allow ECCS systems to operate are good examples of the types of potential benefits that could be gleaned from the portable DC generators.

The portable DC generators are assumed to require 1 hour to align and energize. No credit is taken for supporting components requiring alternate DC power prior to one hour after loss of the DC chargers.

The benefit of this SAMA is estimated through manipulation of the BSEP recovery files. This is a two step process involving the following: 1) Modification of the original recovery file to reflect the increase in available AC power recovery time due to prolonged RCIC/HPCI availability, and 2) Creation of a new recovery file to account for the availability of the portable DC generator. PORTGENREC is assigned a failure probability of $1x10^{-2}$ based on an industry example of an action to align an alternate 480V AC charger to the battery chargers. The changes that were made to the recovery file(s) to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 1 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
X-AC-18RNLS: RCIC depletes with no load shed - 3 run failures	Modified original recovery file to account for 4.5 hours of high pressure injection after loss of on-site AC and 0.5 hours of boildown time. New probability = $8.75x10^{-3}$.
X-AC-12RNLS: RCIC depletes with no load shed - 1 run failure	Modified original recovery file to account for 4.5 hours of high pressure injection after loss of on-site AC and 0.5 hours of boildown time. New probability = $2.08x10^{-2}$.
X-AC-18HPG: New recovery based on X-AC-18H, but only accounts for battery depletion cases.	New AC recovery failure based on 16 hours of EDG run time, 4.5 hours of RCIC/HPCI operation, and 0.5 hours of boildown for a total of 21 hours. New probability = $1.45x10^{-2}$.

Phase II SAMA Number 1 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
X-AC-2HPG: New recovery based on X-AC-2H, but only accounts for battery depletion cases.	New AC recovery failure based on 0 hours of EDG run time, 4.5 hours of RCIC/HPCI operation, and 0.5 hours of boildown for a total of 5 hours. New probability = 9.88×10^{-2}.
PORTGENREC: Portable generator credit adjustment	New recovery file to add on recovery for use of the portable generator. Any cutsets with the following event combinations are appended with an additional 1×10^{-2} recovery term (PORTGENREC): DCP1BAT-XXDEP1A DCP1BAT-XXDEP1B DCP2BAT-XXDEP2A DCP2BAT-XXDEP2B DCP1BAT-XXDEP1A DCP1BAT-XXDEP1B DCP2BAT-XXDEP2A DCP2BAT-XXDEP2B

F.6.1.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 1

The results from this case indicate a 20.5 percent reduction in CDF ($CDF_{new}=3.33\times10^{-05}$ per year), a 17.9 percent reduction in dose-risk (Dose-Risk_{new}=24.1 per year), and a 21.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $38,251 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 1 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.09E-06	2.77E-06	1.62E-06	8.30E-06	2.95E-06	1.49E-08	1.21E-06	4.96E-08	1.45E-07	**1.92E-05**
SAMA Dose-Risk	5.39	6.69	1.83	9.21	0.94	0.00	0.01	0.01	0.03	**24.11**
SAMA OECR	$4,557	$16,896	$1,896	$13,862	$1,028	$1	$1	$3	$9	**$38,251**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 1 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$7,675,443	$1,912,557	$489,277	**$1,423,280**

Given the relatively low cost of implementation for this SAMA, the net value is positive and is cost beneficial based on the SAMA methodology.

F.6.2 PHASE II SAMA NUMBER 3: PROVIDE THE MAIN CONTROL ROOM WITH THE CAPABILITY TO ALIGN THE UAT TO THE "E" BUSES

Description: Given a Loss of Off-site Power (LOOP) event with failure of the Startup Auxiliary Transformer (SAT), power can be aligned to the "E" buses by backfeeding through the Unit Auxiliary Transformer (UAT). This action would be desirable given the unavailability of the bus's EDG and failure of a cross-tie to an alternate 4kV bus. Providing controls within the main control room to perform this action reduces the time required to perform the manipulation and simplifies the human action required for successful execution of the alignment.

The human reliability analysis for this action was reviewed and modified based on the assumption that this main control room enhancement would reduce the manipulation time from 40 minutes to 20 minutes. The execution error contributors were also reviewed to determine if credit could be taken for improved operator interface; however, based on the available information, no further credit could be justified. In addition, the primary execution failure contributors are related to step omission. The probability of control manipulation failure is only 4.2×10^{-4} compared with the total execution failure probability of 1.8×10^{-1} and changes to those contributors would have a small impact on the results. Based on the assumed information related to the enhanced controls, the HEP for this action was recalculated to be 4.1×10^{-2}.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 3 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-GENDISC: Operators fail to backfeed through unit auxiliary transformer after failure of startup transformer	Failure probability changed from 1.8×10^{-1} to 4.1×10^{-2}.

F.6.2.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 3

The results from this case indicate a 0.5 percent reduction in CDF ($CDF_{new}=4.17\times10^{-05}$ per year), a 0.7 percent reduction in dose-risk ($\text{Dose-Risk}_{new}=29.1$ per year), and a 0.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$48,134 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 3 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.77E-06	1.62E-06	1.04E-05	3.30E-06	5.09E-08	2.00E-06	7.16E-08	2.30E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.59	1.05	0.01	0.01	0.01	0.04	**29.14**
SAMA OECR	$4,641	$22,987	$1,896	$17,441	$1,147	$3	$1	$4	$14	**$48,134**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 3 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,528,756	$59,244	$434,775	**-$375,531**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.3 PHASE II SAMA NUMBER 4: DIRECT DRIVE DIESEL INJECTION PUMP

Description: Given a failure of the existing BSEP high pressure injection systems, a direct drive diesel injection pump (DDDIP) could provide an alternate means of supplying make-up without depressurizing the RPV.

The DDDIP is assumed to be located outside of the reactor building for engine exhaust purposes, which requires the addition of a building to house the engine/pump. To reduce costs, the DDDIP is assumed to use the Feedwater injection lines rather than a new, independent high pressure line. The suction sources are assumed to be the CST or Service Water. This combination would provide the DDDIP with potential suction sources for both SBO sequences and those that require high flow makeup, such as LOCA and ATWS scenarios. Division “II” DC power is assumed to be required for valve control and operation.

It is also assumed that the DDDIP is available for injection after containment failure as the pump is located outside of containment. The lumped event representing the DDDIP hardware and operator failures was assigned a failure probability of 5×10^{-2} to approximate the potential reduction in risk (based on engineering judgement).

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 4 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
DD-DG-INJ: DIRECT DRIVE DIESEL INJECTION	New “OR” gate with the following inputs: • New basic event DG-INJ • Gate FWS2G-INJECT-A • Gate RC1-G250-XDB • New “AND” gate G002
DG-INJ: LUMPED EVENT FOR HARDWARE AND OPERATOR FAILURE TO START, ALIGN, AND INJECT	New basic event: $5x10^{-2}$
G002: WATER SUPPLY: CST OR SERVICE WATER	New “AND” gate with the following inputs: • HPC2G-CST-NOSPC • New “OR” gate G006
G006: SW SUPPLY FAILURE	New “OR” gate with the following inputs: • SWS-G2680 • SWS-G2901 • SWS-G2NSW-RHCOM
• #U • #U-ATWS • #V2	Added DD-DG-INJ
#XIU: FAILURE TO CONTROL LOWERED RCS WATER LEVEL	Added new “OR” gate #XIUDGINJ
#XIUDGINJ: FAILURE TO CONTROL LOWERED WATER LEVEL WITH DG INJECTION PUMP (COMPLETELY DEPENDENT ON HPCI)	New “OR” gate with the following inputs: • OPER-LLEVEL1 • DD-DG-INJ

F.6.3.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 4

The results from this case indicate a 14.6 percent reduction in CDF (CDF_{new}=3.58X10^{-5} per year), a 12.2 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=25.8 per year), and a 12.9 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $42,256 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 4 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.04E-06	3.33E-06	1.56E-06	8.76E-06	3.00E-06	4.14E-08	1.31E-06	7.13E-08	1.54E-07	**2.03E-05**
SAMA Dose-Risk	5.25	8.03	1.76	9.73	0.96	0.01	0.01	0.01	0.03	**25.78**
SAMA OECR	$4,436	$20,300	$1,821	$14,637	$1,045	$2	$1	$4	$9	**$42,256**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 4 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,288,310	$1,299,690	$4,000,000	**-$2,700,310**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.4 PHASE II SAMA NUMBER 5: ENHANCED CRD FLOW

<u>Description</u>: The current CRD system was examined to determine if maximizing system flow would provide a viable, single source injection system for transient cases. The results indicated that the CRD in maximized flow configuration would not provide sufficient make-up in the early time frames. This SAMA examines the possibility of further increasing CRD injection to the RPV by installing larger pumps. It is assumed that larger pumps alone would enable CRD to function with the current piping to provide makeup for transient cases from accident initiation forward such that Feedwater is not initially required.

Enhancements to allow make-up flow for the high end of the SLOCA spectrum (up to a 4” diameter steam line or 1” diameter liquid line break) are judged to require installation of an alternate injection line and are not considered here.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 5 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
FWS2G-INJ: FEEDWATER FAILS TO CONTINUE FOLLOWING TRIP	Deleted from #U2.

F.6.4.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 5

The results from this case indicate a 13.1 percent reduction in CDF (CDF_{new}=3.62x10^{-5} per year), a 9.0 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=26.7 per year), and a 9.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $44,081 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 5 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.10E-06	3.57E-06	1.62E-06	8.86E-06	3.02E-06	5.09E-08	1.26E-06	7.16E-08	1.53E-07	**2.07E-05**
SAMA Dose-Risk	5.42	8.61	1.83	9.83	0.96	0.01	0.01	0.01	0.03	**26.71**
SAMA OECR	$4,581	$21,746	$1,896	$14,791	$1,051	$3	$1	$4	$9	**$44,081**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 5 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,518,151	$1,069,849	>> $1,000,000	**Large Negative**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.5 PHASE II SAMA NUMBER 6: PROCEDURALIZE ALL POTENTIAL 4KV AC BUS CROSS-TIE ACTIONS

Description: Currently, the Abnormal Operating Procedures (AOPs) exist to direct the following 4kV cross-tie actions:

- E1 to E3
- E2 to E4

In addition, Alternate Safe Shutdown (ASSD) procedures exist that direct these additional cross-ties:

- E4 to E1 to E2
- E3 to E1 to E2

The cross-tie between Bus E1 and E2 appears to be addressed by the ASSD procedures; however, the E3 to E4 cross-tie is not.

This SAMA assumes that the AOPs include provisions to explicitly address all of these cross-ties instead of only E1 to E3 and E2 to E4. Inclusion of these cross-tie actions in the plant Abnormal Operating Procedures increases the power alignment options available to the operators. This would reduce the risk in scenarios where two diesels in the same division have failed while the diesels from the opposite division are available.

The operator action for this cross-tie is assumed to be completely dependent on the divisional cross-tie (same action used in the model). The BSEP HRA documentation includes an assessment of the inter-divisional cross-tie action; however, it is not used for this sensitivity as it is not considered to reflect the plant conditions after SAMA implementation. Given implementation of the SAMA, conditions for performing the divisional or inter-divisional cross-tie are assumed to be equivalent. Implementation of this SAMA would require appropriate controls to preclude loss of the diesel generator due to overload which would tend to increase the cost estimate.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 6 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
FL-ASSD (FLAG)	Set to FALSE
• ACP-G326: LOSS OF POWER FROM ALTERNATIVE SUPPLY E3 • ACP-G226: LOSS OF POWER FROM ALTERNATIVE SUPPLY E4	• Deleted basic event OPER-ALTBUSXC2 • Added basic event OPER-ALTUNITXC
• ACP-G026: LOSS OF POWER FROM ALTERNATIVE SUPPLY E2 • ACP-G126: LOSS OF POWER FROM ALTERNATIVE SUPPLY E1	• Deleted basic event OPER-ALTBUSXC1 • Added basic event OPER-ALTUNITXC

F.6.5.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 6

The results from this case indicate a 0.7 percent reduction in CDF (CDF_{new}=4.16x10^{-5} per year), a 0.6 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.2 per year), and a 0.6 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,193 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 6 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.05E-05	3.31E-06	5.09E-08	2.01E-06	7.06E-08	2.33E-07	**2.37E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.62	1.05	0.01	0.01	0.01	0.04	**29.17**
SAMA OECR	$4,642	$23,005	$1,896	$17,476	$1,151	$3	$1	$4	$14	**$48,193**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 6 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,524,031	$63,969	$100,000	**-$36,031**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.6 PHASE II SAMA NUMBER 10: IMPROVED PROCEDURES/EQUIPMENT TO PREVENT BORON DILUTION

Description: An important action in the BSEP accident response for ATWS sequences is the control of low pressure injection systems to prevent boron dilution after depressurization. Potential means of improving the reliability of the action include enhancing procedures to clarify instructions and/or improving the injection system controls.

The procedures governing the prevention of boron dilution were reviewed and determined to be clear. No changes to these procedures were identified that would justify a measurable change in the HEP for the action.

LPCI controls could be upgraded to include the dial-in flow rate controls similar to what is used for Feedwater systems. Flow control valves would also be required in place of the existing injection valves in order to allow variable flow. This would improve the man-machine interface and would allow the operators to more accurately control the injection flow rate. The HEP was adjusted by lowering the error rates for controlling the flow rate and for reading the flow rate. Based on these assumptions, the independent HEP was reduced from 4.3×10^{-2} to 3.4×10^{-2}. The dependent failure rates were adjusted to account for the change in the action's independent failure probability.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 10 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-DILUTE	Recovery file change: 4.3×10^{-2} to 3.4×10^{-2}
XOP-COM2-13	Recovery file change: NONE
XOP-COM2-15	Recovery file change: 1.0×10^{-2} to 9.8×10^{-3}
XOP-COM2-14	Recovery file change: NONE
XOP-COM2-12	Recovery file change: 9.1×10^{-3} to 8.5×10^{-3}

F.6.6.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 10

The results from this case indicate a 0.5 percent reduction in CDF (CDF_{new}=4.17x10^{-5} per year), a 1.4 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.0 per year), and a 0.8 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,105 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 10 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.03E-06	3.79E-06	1.53E-06	1.05E-05	3.31E-06	5.09E-08	2.01E-06	7.16E-08	2.34E-07	**2.36E-05**
SAMA Dose-Risk	5.25	9.14	1.73	11.71	1.06	0.01	0.01	0.01	0.04	**28.95**
SAMA OECR	$4,436	$23,092	$1,787	$17,617	$1,151	$3	$1	$4	$14	**$48,105**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 10 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,513,166	$74,834	$434,775	**-$359,941**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.7 PHASE II SAMA NUMBER 11: ENHANCE THE MAIN CONTROL ROOM (MRC) TO INCLUDE CAPABILITY TO PERFORM 480V AC SUBSTATION CROSS-TIE

Description: Providing the MCR with the capability to perform the 480V AC substation cross-tie can potentially improve operator reliability. Modifications which would allow the action to be performed entirely within the MCR would reduce the time required to perform the action and simplify the manipulations required for the action.

It was assumed that the manipulation time for this action would be reduced from 30 minutes to 15 minutes based on the simplification of controls, the relocation of the controls onto a single, functionally grouped panel, and on the elimination of ex-control room travel requirements.

It was also assumed that the breakers that were previously required to be "racked in" are maintained in a ready state. No local action is assumed to be required to prepare the breakers for operation.

In addition, the man machine interface is assumed to be improved through placement of the controls on a functionally grouped, well lit, and labeled control panel. Based on these assumptions, the independent HEP was reduced from 6.9×10^{-2} to 2.1×10^{-2}. The dependent failure rates were adjusted to account for the change in the action's independent failure probability.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 11 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
XOP-480X1(2)	Recovery file change: 6.9×10^{-2} to 2.1×10^{-2}
XOP-COM3-03	Recovery file change: 9.9×10^{-5} to 6.0×10^{-5}
XOP-COM2-21	Recovery file change: 7.0×10^{-4} to 4.2×10^{-4}
XOP-COM2-19	Recovery file change: 6.6×10^{-3} to 2.0×10^{-3}
XOP-COM2-17	Recovery file change: 1.4×10^{-2} to 8.2×10^{-3}

F.6.7.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 11

The results from this case indicate a 1.4 percent reduction in CDF ($CDF_{new}=4.13 \times 10^{-5}$ per year), a 2.5 percent reduction in dose-risk (Dose-Risk_{new}=28.6 per year), and a 3.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$46,855 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 11 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.56E-06	1.62E-06	1.04E-05	3.31E-06	4.12E-08	2.01E-06	7.06E-08	2.33E-07	**2.34E-05**
SAMA Dose-Risk	5.49	8.59	1.83	11.59	1.05	0.01	0.01	0.01	0.04	**28.63**
SAMA OECR	$4,642	$21,703	$1,896	$17,442	$1,151	$2	$1	$4	$14	**$46,855**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 11 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
\$9,588,000	\$9,384,334	\$203,666	\$434,775	**-\$231,109**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.8 PHASE II SAMA NUMBER 12: ENHANCE THE MAIN CONTROL ROOM (MCR) TO INCLUDE CAPABILITY TO ALIGN THE ALTERNATE DC POWER SUPPLY TO SPECIFIC DC PANELS

Description: BSEP includes alternate DC power connections to several DC panels. Currently, aligning the alternate supply to the panel requires local operator action. If the MCR was modified such that the action could be performed without any local action, the time required to perform the action and the types of manipulations associated with the action would be simplified. This could potentially improve the reliability of the action.

It was assumed that the manipulation time for this action would be reduced from 5 minutes to 2 minutes based on the simplification of controls, the relocation of the controls onto a single, functionally grouped panel, and on the elimination of ex-control room travel requirements.

It was also assumed that the breaker controls are functionally grouped, labeled in an easy to read manner, and placed in a well lit area.

The error contributors for step omission were considered to remain the same and no modifications were made to those components of the HEP.

Based on these assumptions, the independent HEP was reduced from $1.2\text{x}10^{-1}$ to $8.4\text{x}10^{-2}$. The dependent failure rates were adjusted to account for the change in the action's independent failure probability.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 12 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
XOP-DCPALTDC1(2)	Recovery file change: $1.2\text{x}10^{-1}$ to $8.4\text{x}10^{-2}$
XOP-COM2-16	Recovery file change: $7.9\text{x}10^{-3}$ to $5.6\text{x}10^{-3}$
XOP-COM2-17	Recovery file change: $1.4\text{x}10^{-2}$ to $9.7\text{x}10^{-3}$

F.6.8.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 12

The results from this case indicate a 1.2 percent reduction in CDF (CDF_{new}=$4.14\text{x}10^{-5}$ per year), a 1.6 percent reduction in dose-risk (Dose-Risk_{new}=28.9 per year), and a 1.6

percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,700 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 12 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.75E-06	1.62E-06	1.03E-05	3.28E-06	5.09E-08	1.99E-06	7.16E-08	2.25E-07	**2.34E-05**
SAMA Dose-Risk	5.49	9.03	1.83	11.42	1.05	0.01	0.01	0.01	0.04	**28.89**
SAMA OECR	$4,636	$22,822	$1,896	$17,182	$1,142	$3	$1	$4	$14	**$47,700**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 12 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,454,965	$133,035	$434,775	**-$301,740**

Given the relatively high cost of implementation for this SAMA, the net value is negative and is not cost beneficial based on the SAMA methodology.

F.6.9 PHASE II SAMA NUMBER 13: INTER-UNIT CRD CROSS-TIE

Description: Installation of a CRD cross-tie is a potential method of reducing the core damage contribution attributed to CRD mitigation. Given that a single unit requires one pump for successful injection or charging the drive headers, loss of the running pump followed by failure of the standby pump could be mitigated by using the opposite unit's standby pump to provide flow. However, performing a cross-tie to the opposite unit's CRD system may also fail the opposite unit's system. No credit is allowed for mitigating the loss of CRD initiating event due to the time required to determine that the cross-tie would not introduce a common failure to the opposite unit. The same is considered to be true for ATWS events.

Some potential exists for correctly identifying the cause for the loss of CRD in time to allow successful RPV make-up. A lumped event with an estimated failure probability of $5x10^{-2}$ was used to represent the hardware failures and operator errors for this SAMA modification.

The power dependency was addressed using the E1 and E2 emergency buses. Loss of either is assumed to imply loss of a CRD pump on the opposite unit, which would preclude CRD X-tie.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 13 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CRDXTIE	New lumped event for CRD cross-tie (hardware and operator error) with a failure probability of $5x10^{-2}$.
CRD2INJECT: CRD SYSTEM FAILS TO PROVIDE HIGH PRESSURE MAKEUP TO THE RPV	• Changed CRD2INJECT to and "AND" gate • Added new "OR" gate G002 • Added new "OR" gate G003
G002: UNIT CRD	New "OR" gate with the following inputs: • CRD2G-CH-PRESS • RHR2GFLOODA • CRD2G-FLOW • %2TCRD
G003: CRD-XTIE	New "OR" gate with the following inputs: • New basic event CRDXTIE • New "OR" gate G008
G008: CRD X-TIE POWER	New "OR" gate with the following inputs: • ACP-G4160E2 • ACP-G4160E1
• #U2-ATWS: FAILURE OF FWS AND CRD TO MAINTAIN LEVEL • #X1U4: FAILURE TO CONTROL LOWERED WATER LEVEL WITH RCIC	Deleted CRD2INJECT
• #U2-ATWS: FAILURE OF FWS AND CRD TO MAINTAIN LEVEL • #X1U4: FAILURE TO CONTROL LOWERED WATER LEVEL WITH RCIC	Added new "OR" gate CRD2INJATWS
CRD2INJATWS: CRD SYSTEM FAILS TO PROVIDE HIGH-PRESSURE MAKEUP TO REACTOR VESSEL (ATWS)	New "OR" gate with the following inputs: • CRD2G-CH-PRESS • RHR2GFLOODA • CRD2G-FLOW • %2TCRD

F.6.9.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 13

The results from this case indicate an 6.4 percent reduction in CDF ($CDF_{new}=3.92x10^{-5}$ per year), a 9.3 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=26.6 per year), and a 12.6 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $42,358 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 13 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	2.94E-06	1.62E-06	1.00E-05	3.21E-06	3.93E-09	1.78E-06	7.16E-08	2.09E-07	**2.20E-05**
SAMA Dose-Risk	5.47	7.10	1.83	11.15	1.03	0.00	0.01	0.01	0.04	**26.63**
SAMA OECR	$4,622	$17,930	$1,895	$16,775	$1,118	$0	$1	$4	$13	**$42,358**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 13 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,769,336	$818,664	$836,870	**-$18,206**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.10 PHASE II SAMA NUMBER 15: DIVERSE EDG HVAC LOGIC

Description: Failure of the HVAC logic to start the EDG room fans or to open exhaust dampers on high temperature could be mitigated through the installation of a diverse set of fan actuation logic. The backup logic would reduce the reliance on operators to perform a fan start on loss of the current automatic actuation logic.

It was assumed that the alternate logic could be represented with a lumped event with a $1X10^{-2}$ failure probability. This is assumed to account for hardware failures of the new logic and support system dependencies.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 15 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
ALT-LOGIC: ALTERNATE DIVISION FAILS TO PROVIDE SIGNAL	New lumped event for failure of the alternate HVAC logic hardware and support dependencies (1E-2 failure probability)

Phase II SAMA Number 15 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
• DGH-G1FNSIG1-AC: NO START SIGNAL TO EXHAUST FAN E • DGH-G1FNSIG1X-AC: NO START SIGNAL TO EXHAUST FAN E • DGH-G1FNSIG2-AC: NO START SIGNAL TO EXHAUST FAN F • DGH-G1FNSIG2X-AC: NO START SIGNAL TO EXHAUST FAN F • DGH-G2AOD1-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 1 • DGH-G2AOD2-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 2 • DGH-G2AOD3-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 3 • DGH-G2AOD4-1AC: FAILURE OF SIGNAL TO OPEN DAMPER FOR CELL 4 • DGH-G2FNSIG3-AC: NO START SIGNAL TO EXHAUST FAN G • DGH-G2FNSIG3X-AC: NO START SIGNAL TO EXHAUST FAN G • DGH-G2FNSIG4-AC: NO START SIGNAL TO EXHAUST FAN H • DGH-G2FNSIG4X-AC: NO START SIGNAL TO EXHAUST FAN H	Added ALT-LOGIC event

F.6.10.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 15

The results from this case indicate a 3.1 percent reduction in CDF (CDF_{new}=4.06x10^{-5} per year), an 2.4 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.6 per year), and a 2.5 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,272 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 15 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.73E-06	1.62E-06	1.01E-05	3.30E-06	5.09E-08	2.00E-06	6.40E-08	2.32E-07	**2.32E-05**
SAMA Dose-Risk	5.48	8.98	1.83	11.22	1.05	0.01	0.01	0.01	0.04	**28.64**
SAMA OECR	$4,633	$22,701	$1,895	$16,873	$1,149	$3	$1	$4	$14	**$47,272**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 15 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,320,084	$267,916	$200,000	**$67,916**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.11 PHASE II SAMA NUMBER 16: DIVERSE SWING DG AIR COMPRESSOR

Description: A shared, diverse, diesel driven air compressor would reduce the impact of CCF of the diesel generator starting air compressors at BSEP. One compressor could be shared by the two units to reduce costs. Alternatively, 1) a portable compressor could be procured that could be aligned to either unit at a potentially lower cost, or 2) nitrogen bottles could be aligned to provide the pressurized gas supply. Given that the cost of a portable compressor is likely to be less than installing a permanent, swing compressor and that the risk reduction for the two systems is considered to be approximately equivalent, the portable compressor is the most likely candidate to be cost beneficial and is pursued here. The portable nitrogen bottles have a finite supply relative to the mission time and are considered to be a less desirable alternative than the portable compressor.

It was assumed that the portable compressor could be connected to the output of the current air compressors and provide the required capacity for the system. It is also assumed that a single compressor can be moved between divisions to maintain control air demand, as required.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below. It was assumed that the common cause failure event used to identify this SAMA dominates the risk associated with starting air compressor failure. Elimination of the CCF event was used to estimate the risk reduction associated with implementing the portable air compressor.

Phase II SAMA Number 16 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
EDG2MDC-44SU2AC: COMMON CAUSE FAILURE OF UNIT 2 DG AIR COMPRESSORS TO START	Set to 0.0.

F.6.11.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 16

The results from this case indicate a 1.4 percent reduction in CDF (CDF_{new}=4.13x10^{-5} per year), a 1.4 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.0 per year), and a 1.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,791 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 16 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.75E-06	1.62E-06	1.03E-05	3.31E-06	5.09E-08	2.01E-06	7.00E-08	2.33E-07	**2.35E-05**
SAMA Dose-Risk	5.49	9.04	1.83	11.47	1.05	0.01	0.01	0.01	0.04	**28.95**
SAMA OECR	$4,639	$22,834	$1,895	$17,251	$1,150	$3	$1	$4	$14	**$47,791**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 16 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,452,183	$135,817	$159,078	**-$23,261**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.12 PHASE II SAMA NUMBER 17: PROVIDE ALTERNATE FEEDS TO PANELS SUPPLIED ONLY BY DC BUS 2A-1

Description: Installing alternate DC feeds to the loads that are currently only supported by DC bus 2A-1 may reduce plant risk through diversification of the power supplies. The failure of this bus precludes supplying the supported loads through the bus using a portable generator. These loads must be isolated from the 2A-1 bus and powered by an alternate connection. A potential solution would be to provide alternate connections to the supported panels from the opposite division. This connection already exists for panel DP-6A (to bus 2B-2).

Operator action evaluations for aligning the alternate DC supply already exist for BSEP. This action was assumed to apply to the alignment of the 2B-1 DC supply to the loads normally supplied by 2A-1. It was also initially assumed that the equipment used to supply the alternate feed would be similar to the alternate line feed lines that exist for the other 2A-1 panels.

However, temporary connections from portable generators are viewed as a more cost effective change. Procurement of a portable generator for MCC 2XDA, DP-12A, and DP-4A along with the required connection upgrades, procedure changes, and training is judged to be less resource intensive than providing permanent connections to the 2B-1 DC bus.

In addition, the portable generators are not limited by the battery life for SBO conditions nor are they susceptible to common cause failures of the DC system. It was assumed the operator action to align the alternate power supply was applicable to the portable generator alignment, which assumes complete dependence between the actions. As this action is assigned a relatively high failure rate (1.2E-1), it is assumed to dominate the hardware failures related to the operation of the generator. No additional hardware failures have been modeled for the generator.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 17 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
DCP-G1050: LOSS OF POWER TO EITHER 125V DC SUPPLY TO MOTOR CONTROL CENTER	• Added “AND” gate G001 • Moved DCP2G2A125VP from DCP-G1050 to G001 • Added Op action OPER-DCPALTDC2 under G001
• DCP-GDP12A: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A • DCP-GDP4A: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A • DCP-GDP12A-D: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A - DEMAND ONLY • DCP-GDP4A-D: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A - DEMAND ONLY • DCP-GDP12AX-AC: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A • DCP-GDP12A-XD: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 12A -DEMAND ONLY • DCP-GDP4A-XD: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A - DEMAND ONLY • DCP-GDP4A-CH: LOSS OF POWER ON 125V DC DISTRIBUTION PANEL 4A (LONG-TERM CHARGER ONLY)	Similar changes were made to these gates.

F.6.12.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 17

The results from this case indicate a 19.1 percent reduction in CDF (CDF_{new}=3.39x10^{-5} per year), a 13.1 percent reduction in dose-risk (Dose-$Risk_{new}$=25.5 per year), and a 13.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $41,854 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 17 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.09E-06	3.38E-06	1.62E-06	8.25E-06	2.88E-06	5.09E-08	9.95E-07	7.16E-08	1.25E-07	**1.95E-05**
SAMA Dose-Risk	5.39	8.16	1.83	9.16	0.92	0.01	0.01	0.01	0.02	**25.50**
SAMA OECR	$4,553	$20,614	$1,895	$13,775	$1,002	$3	$0	$4	$7	**$41,854**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 17 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,021,438	$1,566,562	$489,277	**$1,077,285**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.13 PHASE II SAMA NUMBER 18: PROVIDE ALTERNATE FEEDS TO ESSENTIAL LOADS DIRECTLY FROM AN ALTERNATE "E" BUS

Description: Failure of a 4kV bus results in loss of power to essential loads and precludes emergency cross-tie actions due to the bus fault. A potential means of mitigating the bus failure would be to provide alternate power feeds from the remaining 4kV power supplies. This would require the addition of the means to connect temporary cables to specific loads from other emergency buses or through the addition of permanent alternate bus connections similar to those that exist for some DC panels.

In order to simplify the modeling for this SAMA, alternate power to the emergency buses was assumed to be available despite bus failure rather that inserting alternate power connections to each 4kV load. This was modeled by setting the failure probabilities for the loss of 4kV bus initiators to 0.0. This method implicitly assumes 100 percent reliability of the alignment action and power availability.

Some of the 4kV bus failure initiators in the BSEP model are related to instrumentation and the availability of system start signals, etc. No credit was taken for mitigating these events as they may be required early and the power re-alignment would not be available at that time.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 18 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
%1TE_E1: LOSS OF 4160V AC BUS E1 %1TE_E2: LOSS OF 4160V AC BUS E2 %2TE_E3: LOSS OF 4160V AC BUS E3 %2TE_E4: LOSS OF 4160V AC BUS E4	Set to 0.0

F.6.13.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 18

The results from this case indicate a 3.1 percent reduction in CDF (CDF_{new}=4.06x10^{-5} per year), a 3.9 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.2 per year), and a 5.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $46,009 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 18 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	3.47E-06	1.62E-06	1.03E-05	3.26E-06	3.79E-08	1.90E-06	7.16E-08	2.21E-07	**2.30E-05**
SAMA Dose-Risk	5.48	8.37	1.83	11.41	1.04	0.01	0.01	0.01	0.04	**28.21**
SAMA OECR	$4,632	$21,155	$1,895	$17,173	$1,134	$2	$1	$4	$13	**$46,009**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 18 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,228,686	$359,314	$434,775	**-$75,461**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.14 PHASE II SAMA NUMBER 19: PROVIDE AN ALTERNATE MEANS OF SUPPLYING THE INSTRUMENT AIR HEADER

Description: Given the loss of the "D" air compressor in conjunction with the failure of at least two of three reciprocating compressors or their flow paths results in loss of IA. Procurement of an additional compressor that could be aligned to the supply header would reduce the risk of loss of instrument air provided that it could be aligned in time to prevent the development of the initiating event. It is assumed that the alternate compressor has the capacity to supply the full Instrument Air system load and that the compressor is engine driven such that there are no power dependencies.

It is also assumed that the alternate compressor can be started and aligned to mitigate loss of a compressor during other accident scenarios that were not initiated by loss of instrument air events.

The alternate compressor is assumed to share the “D” compressor’s flow path from the “D” receiver forward. This shared flowpath was used with a lumped event (ALTIAN) to represent the failure probability of the alternate compressor alignment (hardware and operator error). Based on engineering judgement, $1x10^{-2}$ was used for this failure probability as it is consistent with start and run failures for the BSEP compressors. Operator error could account for a greater failure contribution; however, no timeline of the accident is available to allow for a detailed HRA. In addition, the results are not highly sensitive to the value of ALTIAN. The CDF only increases to $4.035x10^{-5}$ from $4.029x10^{-5}$ when $1x10^{-1}$ is used in place of $1x10^{-2}$ for ALTIAN. Until a detailed HRA is available for ALTIAN, $1x10^{-2}$ will be used to show increased benefit.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 19 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
G001: ALTERNATE IAN COMPRESSOR “E”	New “OR” gate • Add basic event ALTIAN with failure probability $1x10^{-2}$ • Add gate IAN2G1103 (flow path)
G002: ALTERNATE IAN COMPRESSOR “E” FOR IE CASES	New “OR” gate • Add basic event ALTIAN with failure probability of $1x10^{-2}$ • Add new “OR” gate IAN2 G1103_IE
IAN2 G1103_IE: LINE FAILURES (IE)	New “OR” gate including • IAN2TNK-RP_D • IAN2XVN-OC_V783
IAN2GIANIE: LOSS OF INSTRUMENT AIR	Add gate G002
IAN2G1090: NO AIR FROM AIR COMPRESSOR HEADER	Add gate G001

F.6.14.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 19

The results from this case indicate a 3.8 percent reduction in CDF (CDF_{new}=$4.03x10^{-5}$ per year), an 8.1 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=27.0 per year), and an 11.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$42,829 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 19 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	2.93E-06	1.61E-06	1.04E-05	3.28E-06	1.26E-08	1.97E-06	7.04E-08	2.30E-07	**2.26E-05**
SAMA Dose-Risk	5.47	7.06	1.82	11.51	1.05	0.00	0.01	0.01	0.04	**26.98**
SAMA OECR	$4,625	$17,837	$1,889	$17,316	$1,141	$1	$1	$4	$14	**$42,829**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 19 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$8,950,277	$637,723	$489,277	**$148,446**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

It should be noted that a modification is currently being developed for the Instrument Air System that will significantly alter the system configuration and reliability. The three reciprocating air compressors will be replaced with a single, more reliable compressor. A cross-tie will be installed, operable from the control room, vs the current manual cross-tie. The modified system is planned to be operated with the cross-tie valve open. The system will be able to provide instrument air to both BSEP units assuming the loss of one of the D compressors and one of the new replacement compressors. Without a fully developed model to evaluate the reliability of the revised system, the impact of this SAMA on plant risk after the modifications are made is difficult to determine. However, as the potential for common cause failure of the compressors in the revised system is considered to be a possible contributor to system failure, it may be appropriate to analyze the benefit of a portable compressor once the revised system is incorporated into the PSA model. This modification is planned for implementation in 2007.

F.6.15 PHASE II SAMA NUMBER 20: ENHANCE THE MAIN CONTROL ROOM (MCR) TO INCLUDE CAPABILITY TO SWAP AC POWER SUPPLIES TO THE BATTERY CHARGERS

Description: The action to perform the alignment of the alternate AC supply to the battery chargers is currently included in the Alternate Safe Shutdown Procedures. As the EOPs do not include the guidance required to perform these steps, the internal events model does not credit the action. This SAMA assumes that the battery charger breaker controls are enhanced such that they are available within the MCR and that the EOPs are updated to include the required guidance for the alignment action.

As the BSEP model already includes this action in the structure with a value of 1.0, the recovery file was updated with an estimated failure probability of $1x10^{-2}$ for the action. This HEP is based on a similar type of action (OPER-DCPALTDC1(2); $1.2x10^{-1}$), but the failure probability has been reduced based on: 1) improved man-machine interface, 2) reduced travel time, and 3) the improved performance shaping factors and support that would be present in the MCR compared with local conditions. The reduction is not based on a requantification of the action; rather, it is based on engineering judgement considering these factors.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 20 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-DC1(2)BALT: OPERATOR FAILS TO SWITCH CHARGER TO ALTERNATE AC POWER SUPPLY-UNIT 2	Basic event data change: 1.0 to $1x10^{-2}$

F.6.15.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 20

The results from this case indicate a 1.4 percent reduction in CDF (CDF_{new}=$4.13x10^{-5}$ per year), a 2.0 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.8 per year), and a 2.1 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,486 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 20 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	3.74E-06	1.62E-06	1.02E-05	3.27E-06	5.09E-08	1.97E-06	7.16E-08	2.22E-07	**2.33E-05**
SAMA Dose-Risk	5.48	9.00	1.83	11.33	1.04	0.01	0.01	0.01	0.04	**28.76**
SAMA OECR	$4,632	$22,748	$1,895	$17,053	$1,138	$3	$1	$4	$13	**$47,486**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 20 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,422,693	$165,307	$434,775	**-$269,468**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.16 PHASE II SAMA NUMBER 21: ENHANCE CRD LOGIC

Description: Inclusion of logic and support components within the CRD system to automate flow path protection would improve CRD availability. Currently, a clogged filter requires local, manual action to restore the flow path after the operator diagnoses the problem. If sensors were included which automatically opened the alternate flowpath around the filters on high differential pressure across the running filter, the loss of CRD initiating event probability could be reduced.

The CRD suction filters (S001A and S001B) and the drive path filters (D003A and D003B) have been identified as important contributors to CRD failure. An automated bypass line around these filters requires differential pressure sensor integration with actuation logic for each of the four filters. For each pair of filters, a single, shared bypass line is assumed to be required. The suction path filters already have a bypass line, which includes manual valve V306. This valve is assumed to be replaced with an MOV that is connected to the actuation logic. The drive path filters do not currently have a bypass line; thus, new piping is required to provide an automated bypass flow path in addition to the MOV.

To simplify the modeling process, no linked dependencies or actuation logic dependencies were included in the model changes. A lumped event representing auto bypass logic and power supply failures was included with an assumed failure probability of $5x10^{-4}$. The bypass MOVs were included with a $3x10^{-3}$ failure probability, which is typical of other plant MOVs.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 21 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CRD2GCRDIE-30C: NO FLOW FROM SOURCE TO CRD - TRAIN A FILTER	• Added “AND” gate G001under CRD2GCRDIE-30C • Deleted basic events CDS2XVN-OC_V305, CDS2XVN-OC_V308, and CRD2FLT-PG_S001A
G001: PLUGGING NOT ABATED	• Added “OR” gate G003 • Added “OR” gate G009
G003: BYPASS LINE FAILS TO OPEN	• Added basic event “AUTOBYPASS” at $5x10^{-4}$ • Added basic event CRDBYPMOV1 at $3x10^{-3}$
G009: NO FLOW FROM SOURCE TO CRD - TRAIN A FILTER	Added basic events CDS2XVN-OC_V305, CDS2XVN-OC_V308, and CRD2FLT-PG_S001A
• CRD2GCRDIE-30D: NO FLOW FROM SOURCE TO CRD - TRAIN B FILTER • CRD2GCRDIE-30A: NO FLOW FROM PUMPS TO CRD - TRAIN A DRIVE WATER FILTER • CRD2GCRDIE-30B: NO FLOW FROM PUMPS TO CRD - TRAIN B DRIVE WATER FILTER	Similar changes made to these gates.

F.6.16.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 21

The results from this case indicate a 2.9 percent reduction in CDF (CDF_{new}=$4.07x10^{-5}$ per year), a 2.3 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.7 per year), and a 2.2 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,429 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 21 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.08E-06	3.72E-06	1.57E-06	1.03E-05	3.25E-06	5.09E-08	1.88E-06	7.16E-08	2.21E-07	**2.32E-05**
SAMA Dose-Risk	5.36	8.98	1.78	11.45	1.04	0.01	0.01	0.01	0.04	**28.67**
SAMA OECR	$4,528	$22,685	$1,841	$17,223	$1,131	$3	$1	$4	$13	**$47,429**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 21 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,341,293	$246,707	$500,000	**-$253,293**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.17 PHASE II SAMA NUMBER 22: INSTALL SELF COOLED CRD PUMPS

Description: RBCCW currently provides cooling to the CRD pumps. If the CRD pumps were changed such that they used the process fluid as a cooling medium, the dependence on RBCCW would be removed. The Loss of RBCCW initiating event, however, is retained. This is because failure of RBCCW would require a plant shutdown due to the cooling dependence of several other non-modeled systems.

This SAMA is considered to require the purchase of new, self cooled pumps and removing/capping old RBCCW cooling lines to the CRD system. To simplify the modeling process for this SAMA, implementation is assumed to be represented through the removal of the CRD cooling dependence.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 22 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CRD2G-PMP-AO: INSUFFICIENT FLOW - CRD PUMP A OPERATING	Deleted gate RCC2G-CRDA for RBCCW cooling dependency
CRD2G-PMP-BO: INSUFFICIENT FLOW - CRD PUMP B OPERATING	Deleted gate RCC2G-CRDB for RBCCW cooling dependency

F.6.17.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 22

The results from this case indicate a 1.2 percent reduction in CDF (CDF_{new}=4.14x10^{-5} per year), a 1.8 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.8 per year), and a 2.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,347 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 22 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.64E-06	1.62E-06	1.05E-05	3.29E-06	4.25E-08	1.97E-06	7.16E-08	2.29E-07	**2.35E-05**
SAMA Dose-Risk	5.49	8.77	1.83	11.62	1.05	0.01	0.01	0.01	0.04	**28.83**
SAMA OECR	$4,638	$22,172	$1,895	$17,475	$1,145	$2	$1	$4	$14	**$47,347**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 22 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,434,602	$153,398	$500,000	**-$346,602**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.18 PHASE II SAMA NUMBER 29: PORTABLE EDG FUEL OIL TRANSFER PUMP

Description: A diverse, engine driven, portable diesel fuel oil transfer pump would provide additional means of supplying the EDG day tank in the event that common cause pump failure prevents operation of the existing pumps.

It is assumed that a single pump can be procured that would serve to supply all four of the BSEP emergency diesel generators. A $1x10^{-2}$ failure probability has been assumed for the portable transfer pump hardware failures and operator error. This is based on an industry example for an alignment of a portable 480V AC generator, which is considered to be similar in complexity and timing ($1.5x10^{-2}$). The results are not sensitive to this value (CDF=$4.068x10^{-5}$ @ $1x10^{-3}$ and CDF=$4.074x10^{-5}$ @ $1x10^{-1}$).

The pump is assumed to be engine driven and no power dependencies are assumed to be applicable.

The Progress Energy staff has estimated the cost of implementation for a SAMA with a similar impact on the diesel fuel oil system. A pump bypass line could be installed that would allow a gravity feed from the 4 day diesel fuel oil tank to the diesel day tank (EDG saddle tank). This line would include a manual isolation valve and a throttle valve to control flow to the saddle tank and maintain the required fuel supply for the operating diesel generator. The failure rate assumed for the alignment and operation of the portable fuel oil transfer pump as applied in the SAMA quantification is $1x10^{-2}$. It is judged that the operation of the bypass line would be approximately the same. Given that a plant specific cost estimate for the bypass line is available ($186,861), this estimate is used as a surrogate for this SAMA.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 29 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
EDG-G1080: FAILURE OF DIESEL GENERATOR 1 FUEL OIL SYSTEM	• Added “AND” gate G001 • Deleted “OR” gate EDG-G1082
G001: FAILURE OF FUEL OIL TO EDG 1 MAIN TANK SUPPLY FROM NORMAL AND PORTABLE PUMPS	• Added “OR” gate EDG-G1082 • Added basic event DGFOXFER
DGFOXFER: PORTABLE DG FO TRANSFER PUMP FAILURE	New basic event for transfer pump failure. Failure probability is $1x10^{-2}$
• EDG-G1080-AC • EDG-G2080 • EDG-2080-AC • EDG-G3080 • EDG-G3080-AC • EDG-G4080 • EDG-G4080-AC	Changes similar to those above made to these gates.

F.6.18.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 29

The results from this case indicate a 2.9 percent reduction in CDF (CDF_{new}=$4.07x10^{-5}$ per year), a 2.3 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.7 per year), and a 2.4 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $47,326 per year). A further breakdown of this information is provided below according to release category.

Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 29 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.73E-06	1.62E-06	1.01E-05	3.30E-06	5.09E-08	2.00E-06	6.60E-08	2.32E-07	**2.33E-05**
SAMA Dose-Risk	5.48	8.98	1.83	11.26	1.05	0.01	0.01	0.01	0.04	**28.68**
SAMA OECR	$4,634	$22,692	$1,895	$16,934	$1,149	$3	$1	$4	$14	**$47,326**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 29 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,337,719	$250,281	$186,861	**$63,420**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.19 PHASE II SAMA NUMBER 30: IMPROVE ALTERNATE SHUTDOWN PANEL

Description: The results of the BSEP fire model indicate that 53.3 percent of the fire risk is related to control room fires. A dominant factor in control room evacuation scenarios is the ability of the operators to control the plant from the alternate shutdown panel and locally, at specific system panels. This SAMA assumes that the human action component of this failure probability could be reduced by a factor of 5 if the alternate shutdown panel were enhanced to include at least one complete division of safe shutdown equipment controls.

The existing fire model assumes that the failure probability for safe shut down from outside the control room is $1.15 x 10^{-1}$. This includes a 0.1 operator failure probability and a 0.015 hardware failure probability. Reducing the human error component by a factor of 5 results in a revised failure probability for ex-control room safe shutdown of $3.5 x 10^{-2}$.

The impact of this change is estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the BSEP CDF and release consequences related to control room evacuation can be identified that an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events
- Determine the percentage of the external events MMACR contribution attributable to fire events
- Determine the percentage of the fire component of the MMACR attributable to control room fires
- Determine the percentage of the control room fire component of the MMACR attributable to scenarios that require control room evacuation
- Calculate the reduction in the control room evacuation component of the MMACR that would occur if the enhanced alternate shutdown panel was installed

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,500.

Based on the Brunswick IPEEE RAI response, control room fires comprise 53.3 percent of the fire risk, which yields a cost-risk of $1,916,402. The IPEEE indicates that 92.7 percent of the control room fire CDF is comprised of scenarios requiring evacuation of the control room. This corresponds to an evacuation based cost-risk of $1,776,504.

The ratio of the revised ex-control room shut down failure probability to the original value is 0.035/0.115 = 0.304. If this is multiplied by the evacuation based cost-risk of $1,776,504, the product is the revised cost-risk for evacuation based shut down ($540,675). The averted cost-risk is the difference between the original evacuation based cost-risk and the revised value ($1,235,829).

The cost of implementation for this SAMA is based on a proposed upgrade of a control room from a standard layout to one that incorporates enhanced computer displays for plant parameters and procedure information. The cost of this estimate was $600,000 per unit in 1994 dollars (Reference 1) and applies to a change made during the design phase of the plant. Assuming a 2.75 percent annual inflation rate, the current cost of this modification would be about $765,928 per unit and $1,531,855 for the site. Because the cost estimate was performed for a changed during the design phase and because the proposed changes are judged to be more limited in scope than the upgrade of the alternate shutdown panel, this is considered to be a lower bound estimate for this SAMA's cost of implementation.

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 30 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
\$9,588,000	\$8,352,171	\$1,235,829	\$1,531,855	**-\$296,026**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.20 PHASE II SAMA NUMBER 31: IMPROVED ALTERNATE SHUTDOWN TRAINING AND EQUIPMENT

Description: The results of the BSEP fire model indicate that 53.3 percent of the fire risk is related to control room fires. A dominant factor in control room evacuation scenarios is the ability of the operators to control the plant from the alternate shutdown panel and locally, at specific system panels. Improved training on operating the plant from outside the control room may reduce the human error probability for required actions. Improved communication equipment and plans for coordination among local operators may also reduce the error rate. Together, these enhancements are assumed to reduce the ex-control room shut down failure probability by 10 percent.

The existing fire model assumes that the failure probability for safe shut down from outside the control room is 1.15×10^{-1}. This includes a 0.1 operator failure probability and a 0.015 hardware failure probability. Reducing the human error component by 10 percent results in a failure probability for ex-control room safe shutdown of 1.05×10^{-1}.

The impact of this change is estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the BSEP CDF and release consequences related to control room evacuation can be identified that an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events.
- Determine the percentage of the external events MMACR contribution attributable to fire events.
- Determine the percentage of the fire component of the MMACR attributable to control room fires.

- Determine the percentage of the control room fire component of the MMACR attributable to scenarios that require control room evacuation.
- Calculate the reduction in the control room evacuation component of the MMACR that would occur if the training program was enhanced and the communications equipment was improved.

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,000.

Based on the Brunswick IPEEE RAI response, control room fires comprise 53.3 percent of the fire risk, which yields a cost-risk of $1,916,402. The IPEEE indicates that 92.7 percent of the control room fire CDF is comprised of scenarios requiring evacuation of the control room. This corresponds to an evacuation based cost-risk of $1,776,504.

The ratio of the revised ex-control room shut down failure probability to the original value is 0.105/0.115 = 0.913. If this is multiplied by the evacuation based cost-risk of $1,776,504, the product is the revised cost-risk for evacuation based shut down ($1,622,026). The averted cost-risk is the difference between the original evacuation based cost-risk and the revised value ($154,479).

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 31 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,433,521	$154,479	$250,000	**-$95,521**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.21 PHASE II SAMA NUMBER 32: ADD AUTOMATIC FIRE SUPPRESSION SYSTEM

Description: The results of the BSEP fire model indicate that 13.1 percent of the fire risk is related to fires in the 20’ level of the Reactor building North Central and North West, 53.3 percent from the main control room, and 3.0 percent from the switchgear rooms.

These rooms do not have automatic suppression systems and installation of these types of systems has been suggested as a potential means of reducing plant risk.

For the main control room, an automatic suppression system would not provide a significant safety benefit. The sensing devices used for fires include both fuse elements that melt given high temperature and smoke detectors. These types of actuation devices would only actuate after the fire has progressed to a point that would cause evacuation of the control room. Even if the auto suppression system actuated prior to evacuation, the consequences of actuation would require evacuation. Halon or CO2 systems would asphyxiate any personnel remaining in the MCR and water would damage the control equipment. Given that the MCR fire risk is dominated by failure to shut down the reactor from outside the control room, extremely limited benefit is judged to exist for auto suppression systems in the MCR.

For the switchgear room, high voltage source fires are major contributors to the room's fire risk. High voltage fires have been recognized as being non-responsive to gas suppression systems. As the gas concentration goes down with time, the fire will re-ignite. In addition, the actuation of the automatic systems requires high heat or smoke concentration. Again, these are indicators of a fire that has matured and would likely have already damaged the equipment in the room. Automatic suppression systems are more effective at preventing the spread of fires than at preventing damage to equipment in a given area. Limited benefit is considered to exist related to installation of an auto fire suppression system in the E4 switchgear room.

The impact of automatic suppression systems for the 20' level of the reactor building North Central and North West is also considered to be small. Given the nature of the detection system, as mentioned above, the means for saving the equipment within the areas is limited. The installation cost for these systems can be extremely large due to the need to make the fire areas "gas tight" as self sealing. In addition, due to the personnel risk related to asphyxiation in the self sealing areas where gas suppression systems are used, these types of systems are being removed from some plants.

Automatic suppression systems are not considered to address the risk issues for either the main control room or the switchgear room and are not pursued further.

Installation of these types of systems may be possible for the 20' level of the reactor building, but the cost would be prohibitive. The cost benefit estimates are shown below:

The potential impact of installing an automatic gas suppression system in the 20' reactor building North Central and North West areas is estimated using available information from the fire model and engineering judgment. No model quantification was performed for this evaluation.

It is assumed that if the portion of the BSEP CDF and release consequences related to fires in the 20' North Central and North West areas can be identified, then an averted cost-risk can be calculated for this SAMA. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events.
- Determine the percentage of the external events MMACR contribution attributable to fire events.
- Determine the percentage of the fire component of the MMACR attributable to the 20' reactor building North Central and North West areas.
- Calculate the reduction in the 20' reactor building North Central and North West area component of the MMACR that would occur if a Halon system were implemented.

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,000.

Based on the Brunswick IPEEE RAI response, fires in the 20' Reactor building North Central and North West areas comprise 13.1 percent of the fire risk, which yields a cost-risk of $471,011.

The IPEEE cites a Halon system hardware failure probability of 0.05 and this can be used to estimate the risk reduction if the system were installed in this area. Given that the Halon system operated, it is assumed to be successful in terminating the fire event and preventing equipment damage. Thus, the averted cost-risk for this case is $471,011* 0.95 = $447,460 for the site.

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 32 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,140,540	$447,460	$750,000	**-$302,540**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology. Furthermore, the estimated cost of implementation is judged to be conservative (low), and would likely increase with a detailed engineering study.

F.6.22 PHASE II SAMA NUMBER 33: IMPROVE FIRE BARRIERS BETWEEN CABINETS IN THE CABLE SPREADING ROOM

Description: The results of the BSEP fire model indicate that 4.3 percent of the fire risk is related to sequences with fires starting in the Unit 2 cable spreading room. It was noted in the Brunswick IPEEE that both cabinets containing critical equipment and non-critical equipment are contributors to risk. The non-critical cabinet fires are contributors due to the potential of the fires to spread to the cabinets containing critical equipment. Improving fire barriers within the non-critical cabinets has been identified as a potential means of reducing risk by preventing the spread of these fires and precluding damage to critical equipment.

Review of the IPEEE indicates that fires in non-critical cabinets contribute 2.8 percent of cable spreading room CDF. This is based on fires in the cabinets without safe shutdown equipment (SSE) (non-critical) spreading to cabinets with SSE (critical) as identified in IPEEE Tables 4.5-4B and 4.5-7. The non-critical cabinet fire CDF contribution is the sum of the CDF contributions from the critical cabinets impacted by non-critical cabinet fires. This conservatively includes the fires started in the critical cabinets. The following table provides a summary:

Equipment (from IPEEE)	Node Number (from IPEEE)	Potential Spread to
H07	HY1	**120 VAC Emergency Panel 2D**
HY0	H06	**E7 Distribution Panel 2A**
H08	RE7	**Disconnect switch for XFMR 1E6**
	RE8	**Disconnect switch for XFMR 1E7**
H40	HY4	**RPS Distribution Panel 1C72-P001**

It is assumed that the averted cost-risk associated with fires in non-critical cabinets can be calculated if the total contribution of the non-critical cabinets is known. For the purposes of this evaluation, all of the risk associated with these cabinets is assumed to be eliminated through the installation of improved fire barriers in the non-critical cabinets.

No partial credit is taken for placing fire barriers in critical cabinets to prevent the spread of the initiating event fire to other critical cabinets.

Based on the information in the IPEEE and engineering judgment, the component of the MMACR associated with non-critical cabinet fires and an averted cost-risk for this SAMA can be approximated. The steps used to perform this calculation are provided below and include the following items:

- Determine the percentage of the overall MMACR attributable to external events.
- Determine the percentage of the external events MMACR contribution attributable to fire events.

- Determine the percentage of the fire component of the MMACR attributable to cable spreading room fires.
- Determine the percentage of the cable spreading room fire component of the MMACR attributable to scenarios related to non-critical cabinet fires.
- Calculate the reduction in the non-critical cabinet fire component of the MMACR that would occur if the fire barriers were installed.

The baseline assumption for external events contributions in the BSEP SAMA is that they are approximately equal to the internal events contributions. Given that the internal events contribution to the MMACR is $4,794,000, the same value is assigned to external events.

The relative contribution of fire events to the total external events CDF is difficult to determine due to the fact that the seismic analysis was a margins analysis and did not produce a CDF. For the purposes of this calculation, it is assumed that the fire events comprise 75 percent of the external events risk. This corresponds to a cost-risk of $3,595,500.

Based on the Brunswick IPEEE RAI response, cable spreading room fires comprise 4.3 percent of the fire risk, which yields a cost-risk of $154,606. The IPEEE indicates that 2.8 percent of the cable spreading room fire CDF is due to non-critical cabinet fires. This reduces the relevant cost-risk to $4,329.

It is assumed that all of this risk can be eliminated through the implementation of the fire barriers; thus, the averted cost-risk for this SAMA is $4,329.

The cost of implementation for this SAMA, including planning, engineering, labor, and hardware is assigned an assumed value of $50,000 per unit, for a total of $100,000.

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 33 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,583,671	$4,329	$100,000	**-$95,671**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.23 PHASE II SAMA NUMBER 35: USE FIREWATER AS A BACKUP FOR EDG COOLING

Description: Failure of cooling water to the EDGs is an important event for some plants. Loss of cooling water will result in overheating of the EDGs and subsequent failure. Providing an alternate cooling source to the EDGs to provide cooling when the normal means has failed is a potential method of reducing risk. The existing BSEP fire water system could be used as the alternate cooling source.

This SAMA assumes that the required piping changes and connections would be made such that the fire water system could be used to provide the required flow to the EDGs. A lumped event representing the operator action to align the firewater system to the EDGs is used to represent this SAMA. Additional hardware failures are potential contributors to the failure of this alignment; however, for simplicity, they are not included. This method increases the measured risk reduction compared with the more realistic case in which the fire water system failures would also be included.

OPER-DGCOOL is assigned a failure probability of $1x10^{-2}$. Given the extensive hardware changes to include permanent, alternate piping that will eliminate the need for fire hose connections, this task is considered to be relatively easy. An industry example for aligning a spare diesel to an emergency bus has been assigned a failure probability of 5.8E-2 and the alignment is highly complicated. Based on engineering judgement, $1x10^{-2}$ is considered appropriate.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 35 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
OPER-DGCOOL: OPERATOR FAILS TO ALIGN ALTERNATE COOLING	New basic event with $1x10^{-2}$ failure probability
EDG-G1029: LOSS OF COOLING TO DIESEL GENERATOR 1 COOLING WATER	• Add new “AND” gate G034 • Delete gate SWS-G1DG-AC
G034: LOSS OF EDG COOLING FROM NORMAL SOURCES	Add gate SWS-G1DG-AC and new basic event OPER-DG-COOL
• EDG-G1029-AC: LOSS OF COOLING TO DIESEL GENERATOR 1 COOLING WATER • EDG-G2029: LOSS OF COOLING TO DIESEL GENERATOR 2 COOLING WATER • EDG-G2029-AC: LOSS OF COOLING TO DIESEL GENERATOR 2 COOLING WATER • EDG-G3029: LOSS OF COOLING TO DIESEL GENERATOR 3 COOLING WATER • EDG-G3029-AC: LOSS OF COOLING TO DIESEL GENERATOR 3 COOLING WATER • EDG-G4029: LOSS OF COOLING TO DIESEL GENERATOR 4 COOLING WATER • EDG-G4029-AC: LOSS OF COOLING TO DIESEL GENERATOR 4 COOLING WATER	Similar changes made to these gates.

F.6.23.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 35

The results from this case indicate a 1.0 percent reduction in CDF (CDF_{new}=4.15x10^{-5} per year), a 0.7 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.1 per year), and a 0.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,146 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 35 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.04E-05	3.31E-06	5.09E-08	2.01E-06	6.96E-08	2.34E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.59	1.06	0.01	0.01	0.01	0.04	**29.14**
SAMA OECR	$4,640	$22,999	$1,895	$17,439	$1,151	$3	$1	$4	$14	**$48,146**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 35 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,507,558	$80,442	$2,000,000	**-$1,919,558**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.24 PHASE II SAMA NUMBER 36: USE FIRE WATER AS A BACKUP FOR CONTAINMENT SPRAY

Description: Containment spray is important for BSEP because it (1) provides a means of scrubbing fission products that are not otherwise scrubbed (e.g., in the case where the suppression pool is bypassed); and, (2) providing water to cool the core debris on the drywell floor to limit non-condensable gas generation and to limit drywell heating and the associated temperature induced failures that can lead to containment failure. Assuming that the 120 psig Fire Protection system can provide the required 1000 gpm flow, the impact is limited due to the dependence on the containment spray valves. However, this SAMA proposes to provide an alternate means of providing containment spray flow using the existing BSEP fire water system. It should be noted here that 1000 gpm may not provide for an effective spray pattern, but will compensate for boil-off due to decay heat and result in some amount of water over the core debris to scrub fission products.

For BSEP, the containment spray system is not credited in the Level 1 model for accident mitigation. The Level 2 model considers containment spray for fission product scrubbing and containment floor flooding, as mentioned above.

For the purposes of this evaluation, the fire water system is assumed to be aligned to the "B" loop containment spray path. A lumped event representing the operator action to align the firewater system to containment spray path "B" is used to represent this SAMA. The value is set to 0.5 to represent high dependence on the existing containment spray alignment action. Additional hardware failures are potential contributors to the failure of this alignment; however, for simplicity, they are not included. This method increases the measured risk reduction compared with the more realistic case in which the fire water system failures would also be included.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below.

Phase II SAMA Number 36 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
ALT-DWS: FWS TO DWS ALIGNMENT GIVEN FAILURE OF OPER-CNS	New basic event with $5x10^{-1}$ failure probability for fire water system alignment to containment spray
TD1: WATER INJECTION TO CONTAINMENT UNAVAILABLE (TD)	Added "OR" gate G040
G040: OP FAILS TO ALIGN ALT DWS OR FLOW PATH FAILS	• Added new basic event ALT-DWS • Added gates RHR2G-CNS-F016B and RHR2G-CNS-F021B • Added basic event RHR2PTF-TM-LOOPB

F.6.24.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 36

The results from this case indicate a 0.0 percent reduction in CDF (CDF_{new}=$4.19x10^{-5}$ per year), a 3.3 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=28.4 per year), and a 3.8 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $46,662 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 36 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.65E-06	1.62E-06	1.00E-05	3.30E-06	4.63E-08	2.01E-06	7.17E-08	2.34E-07	**2.31E-05**
SAMA Dose-Risk	5.50	8.78	1.83	11.13	1.05	0.01	0.01	0.01	0.04	**28.37**
SAMA OECR	$4,643	$22,198	$1,899	$16,750	$1,150	$3	$1	$4	$14	**$46,662**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 36 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,424,834	$163,166	$100,000	**$63,166**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology This cost estimate was judged by the plant staff to be extremely conservative. This SAMA would not likely be cost beneficial with a detailed cost estimate.

F.6.25 PHASE II SAMA NUMBER 37: LOW PRESSURE RCIC OPERATION

Description: For sequences in which high pressure injection is initially available and containment heat removal has failed, impingement on the HCTL will require the operators to depressurize the reactor. Loss of RPV pressure is assumed to fail the turbine driven injection systems and motor driven, low pressure injection systems are assumed to be required for continued injection. If the low pressure injection systems fail, there is currently no means of providing inventory makeup.

A potential enhancement is the use of RCIC at low RPV pressure. This could be implemented through a modification of the EOPs to direct the operators to stop depressurization early (at approximately 100 psig). Alternatively, it could be demonstrated that RCIC is capable of operating at lower RPV pressures. Assuming that one of these methods is performed, RCIC injection could be maintained after HCTL depressurization or restarted given failure of the motor driven, low pressure injection systems.

This enhancement would not provide benefit in SBO sequences given that battery life is expected to be a maximum of about 4 hours while HCTL would not be reached until about 4.5 hours. RCIC control power would be lost at 4 hours and extending the operating regime beyond HCTL would not allow further operation of RCIC.

RCIC is also considered as a potential injection system after containment venting. However, given that the pump is located in the reactor building, there is an added potential for system failure due to harsh environmental conditions caused by the venting action. The environmental failure probability is assumed to be 0.1.

Model changes that were made to the PSA to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 37 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
#V: FAILURE OF LOW PRESSURE INJECTION	Added New "OR" gate RCI2G1R. (#V is used in LOCA cases as well as for Transient. While LP RCIC operation would not likely be available in all LOCA cases, the additional benefit is small and for ease of modeling, it has not been removed).
RCI2G1R: USE OF RCIC AT LOW RPV PRESSURE	New "OR" gate comprised of the following: • "OR" gate RCI2G-INJECT-B • "OR" gate RCI2G-INJECT • "OR" gate RHR2GFLOODB • NEW "AND" gate G008
G008: PATCH TO EXCLUDE CREDIT IN AN SBO	New "AND" gate comprised of the following: • "AND" gate DCP-G1206 • "AND" gate DCP-G1006
#V2: LOSS OF LOW-PRESSURE INJECTION FOLLOWING WETWELL FAILURE	Added new "OR" gate G011
G011: LP RCIC FAILS AFTER WETWELL FAILURE	New "OR" gate comprised of the following: • New basic event ENV1 • "OR" gate RCI2G1R
ENV1: RCIC FAILS DUE TO ADVERSE ENVIRONMENTAL CONDITIONS	New basic event with assumed failure probability of 0.1.

F.6.25.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 37

The results from this case indicate a 0.4 percent reduction in CDF (CDF_{new}=4.17x10^{-5} per year), a 0.7 percent reduction in dose-risk (Dose-Risk$_{new}$=29.1 per year), and a 0.7 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,146 per year). A further breakdown of this information is provided below according to release category. Note that the "containment intact" information is not included here and that the "total frequency" shown in the following table does not include that term.

SAMA 37 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.04E-05	3.31E-06	5.09E-08	2.01E-06	6.96E-08	2.34E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.10	1.83	11.59	1.06	0.01	0.01	0.01	0.04	**29.14**
SAMA OECR	$4,640	$22,999	$1,895	$17,439	$1,151	$3	$1	$4	$14	**$48,146**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 37 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,536,037	$51,963	$200,000	**-$148,037**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.26 PHASE II SAMA NUMBER 25: PROCEDURALIZE BATTERY CHARGER HIGH VOLTAGE SHUTDOWN CIRCUIT INHIBIT

Description: The 125 V battery chargers at BSEP are equipped with high voltage shutdown circuit boards designed to open the charger AC feeder breaker via a shunt trip device when the charger output voltage exceeds 143V. This circuit was added to the chargers by plant modifications to prevent half scrams from being generated as a result of high DC system voltages that caused the RPS and ECCS system inverters to shutdown. Shutdown of the inverters results in loss of power to the 24 VDC power supplies for the RPS/ECCS logic circuitry, which in turn results in the generation of half scram signals. The high DC system voltage was the result of switching the charger from float to equalize voltage and the follow up attempt to fine tune the equalize voltage using the voltage adjusting potentiometer. Movement of the charger pot would inadvertently yield an output voltage higher than the inverter trip setting causing it to shutdown. It was deemed appropriate at that time to shutdown the inverter (momentarily that is) than to create a half scram signal.

The high voltage shutdown circuit in the battery charger makes it possible for the charger to trip when attempting to start DC motors in the HPCI/RCIC system with the battery separated from the distribution system (i.e., charger is the sole source of power). The reason is the sudden application and removal of the high motor inrush current which causes the charger voltage regulating circuit to momentarily overshoot above the high voltage shutdown circuit setpoint (143V) and trip the charger AC input power breaker. This overshoot does not occur when the battery is connected to the system because the battery behaves as a large capacitor bank that filters out such voltage transients. Per input obtained from the battery charger vendor, the largest motor load whose starting will not result in a charger trip cannot be quantified. The only way this can be established is via field testing, which is not feasible. Due to the uncertainty in the DC system response, additional system modifications to eliminate the potential charger trip actuation are difficult to design and/or test. A potentially available means of eliminating the loss of the battery chargers when the batteries are not available is to inhibit the trip circuitry.

This SAMA is defined as the development and implementation of procedures to direct the defeat of the trip logic given that the batteries have failed or have been disconnected from the DC circuit. It should be noted that re-energizing the ECCS system inverters which have been shutdown due to high voltage conditions may have adverse effects that could increase the cost of implementation and make this an inappropriate SAMA alternative

The impacts of this SAMA are estimated through the application of a supplementary recovery file. The file is applied after the normal cutset development process is complete and acts on the flags used to designate charger trip given battery failure. The supplementary recovery file is summarized below:

Phase II SAMA Number 25 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
CHRGRTRPREC: Recovery event representing the failure probability of inhibiting the battery charger high voltage trip logic ($5x10^{-2}$).	Add the recovery to the cutsets with the following events/event combinations: • DCP2REC-XXTRP2A1, DCP2REC-XXTRP2B2 • DCP2REC-XXTRP2A1 • DCP2REC-XXTRP2B2 • DCP2REC-XXTRP2A2

F.6.26.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 25

The results from this case indicate an 8.8 percent reduction in CDF (CDF_{new}=$4.16x10^{-5}$ per year), a 0.5 percent reduction in dose-risk ($Dose\text{-}Risk_{new}$=29.2 per year), and a 0.5 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = $48,234 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 25 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.13E-06	3.78E-06	1.62E-06	1.05E-05	3.29E-06	5.09E-08	1.97E-06	7.16E-08	2.30E-07	**2.36E-05**
SAMA Dose-Risk	5.49	9.11	1.83	11.64	1.05	0.01	0.01	0.01	0.04	**29.19**
SAMA OECR	$4,639	$23,024	$1,895	$17,510	$1,144	$3	$1	$4	$14	**$48,234**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 25 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,124,070	$463,930	$50,000	**$413,930**

Given that the cost of implementation is less than the averted cost-risk for this SAMA, the net value is positive and this enhancement is cost beneficial based on the SAMA methodology.

F.6.27 PHASE II SAMA NUMBER 34: SUPPLEMENTAL POWER SUPPLIES FOR OFFSITE POWER RECOVERY AFTER BATTERY DEPLETION DURING SBO

Description: Given a loss of offsite power at BSEP, the plant can be re-aligned to the grid when it is available assuming that onsite AC and DC power are also available. However, switchyard power dependencies complicate offsite power recovery in prolonged station blackout (SBO) conditions.

The Power Circuit Breakers (PCBs), Oil Circuit Breakers (OCBs), and Motor Operated Disconnects used to align offsite power to the plant through the switchyard require both AC and DC power to function. DC power is used for control functions as well as for motive power while AC support is required to run the air compressors that supply the air closing pistons. DC power is available from the station batteries until they are depleted and the air system contains receivers that maintain inventory typically sufficient for a few breaker strokes. For long term SBO cases, the definition of which varies depending on equipment operation and load shed status, the station batteries and air receivers are considered to be depleted. For SBO conditions, the above implies that offsite power cannot be restored until an onsite AC (and DC) source is made available.

The current BSEP PRA model allows AC power recovery at up to 30 minutes after batteries are assumed to be depleted to account for boildown and core heatup after loss of injection. While this does not coincide with a strict interpretation of the dependence factors, it is not considered unreasonable as no credit is taken for successful load shed in the model.

The 30 minute time period used in the BSEP model to account for boildown and fuel heatup for core damage given loss of injection is shorter than the true available time to core damage for the longer term accidents. Credit for longer times to core damage could be taken for AC power recovery in the longer term accidents if a means were available to align the switchyard. This SAMA proposes that supplemental AC and DC power sources be procured and that procedures be fully developed to align the sources for switchyard operation.

This SAMA could be performed using 480v AC generators to power the station battery chargers and the switchyard air compressors, or, portable DC generators could be used to supply the DC power loads and bypass potential battery charger failures.

This SAMA has been represented through changes to the recovery file. The AC power recovery terms were modified based on the following assumptions:

- No additional credit for recoveries with loss of injection at 1 hour or less
- Add 1 additional hour for the loss of injection at 2 and 5 hours
- Add 2 additional hours for losses of injection at over 12 hours

The recovery file changes that were made to represent the implementation of this SAMA at BSEP are shown below:

Phase II SAMA Number 34 Model Changes

Gate and / or Basic Event ID and Description	Description of Change
X-AC-2H: AC Power Recovery Failure Probability	Changed from $1.33x10^{-1}$ to $1.20x10^{-1}$
X-AC-5H: AC Power Recovery Failure Probability	Changed from $9.30x10^{-2}$ to $8.76x10^{-2}$
X-AC-12H: AC Power Recovery Failure Probability	Changed from $4.02x10^{-2}$ to $3.35x10^{-2}$
X-AC-12RNLS: AC Power Recovery Failure Probability	Changed from $2.81x10^{-2}$ to $2.26x10^{-2}$
X-AC-13H: AC Power Recovery Failure Probability	Changed from $3.56x10^{-2}$ to $2.98x10^{-2}$
X-AC-14H: AC Power Recovery Failure Probability	Changed from $3.16x10^{-2}$ to $2.64x10^{-2}$
X-AC-16H: AC Power Recovery Failure Probability	Changed from $2.49x10^{-2}$ to $2.08x10^{-2}$
X-AC-17H: AC Power Recovery Failure Probability	Changed from $2.20x10^{-2}$ to $1.84x10^{-2}$
X-AC-18H: AC Power Recovery Failure Probability	Changed from $1.96x10^{-2}$ to $1.63x10^{-2}$
X-AC-18RNLS: AC Power Recovery Failure Probability	Changed from $1.18x10^{-2}$ to $9.51x10^{-3}$
X-AC-19H: AC Power Recovery Failure Probability	Changed from $1.73x10^{-2}$ to $1.45x10^{-2}$

F.6.27.1 PSA MODEL RESULTS FOR PHASE II SAMA NUMBER 34

The results from this case indicate a 5.5 percent reduction in CDF ($CDF_{new}=3.96x10^{-5}$ per year), a 4.5 percent reduction in dose-risk ($Dose\text{-}Risk_{new}=28.0$ per year), and a 4.8 percent reduction in Offsite Economic Cost-Risk ($OECR_{new}$ = \$46,174 per year). A further breakdown of this information is provided below according to release category. Note that the “containment intact” information is not included here and that the “total frequency” shown in the following table does not include that term.

SAMA 34 Results By Release Category

Rel. Cat.	1-H/E	2-H/I	3-M/E	4-M/I	5-L/E	6-L/I	7-L/L	8-LL/I	9-LL/L	Total
Baseline Freq.	2.13E-06	3.79E-06	1.62E-06	1.06E-05	3.30E-06	5.09E-08	2.01E-06	7.17E-08	2.34E-07	**2.38E-05**
SAMA Freq.	2.12E-06	3.64E-06	1.62E-06	9.76E-06	3.30E-06	5.09E-08	2.00E-06	6.27E-08	2.34E-07	**2.28E-05**
SAMA Dose-Risk	5.48	8.78	1.83	10.83	1.05	0.01	0.01	0.01	0.04	**28.04**
SAMA OECR	$4,630	$22,184	$1,895	$16,297	$1,147	$3	$1	$4	$14	**$46,174**

This information was used as input to the cost benefit calculation. The results of this calculation are provided in the following table:

Phase II SAMA Number 34 Net Value

Base Case: Cost-Risk for BSEP (site)	Cost-Risk for BSEP With SAMA Changes	Averted Cost-Risk	Cost of Implementation	Net Value
$9,588,000	$9,102,491	$485,509	$489,277	**-$3,768**

Given that the cost of implementation is greater than the averted cost-risk for this SAMA, the net value is negative and this enhancement is not cost beneficial based on the SAMA methodology.

F.6.28 PHASE II SAMA ANALYSIS SUMMARY

The SAMA candidates which could not be eliminated from consideration by the baseline screening process or other PSA insights required the performance of a detailed analysis of the averted cost-risk and SAMA implementation costs. SAMA candidates are potentially justified only if the averted cost-risk resulting from the modification is greater than the cost of implementing the SAMA. Several of the SAMAs analyzed were found to be cost-beneficial as defined by the methodology used in this study. However, this evaluation should not necessarily be considered a definitive guide in determining the disposition of a plant modification that has been analyzed using other engineering methods. These results are intended to provide information about the relative estimated risk benefit associated with a plant change or modification compared with its cost of implementation and should be used as an aid in the decision making process. The results of the detailed analysis are shown below:

Summary of the Detailed SAMA Analyses

Phase II SAMA ID	Averted Cost- Risk	Cost of Implementation	Net Value	Cost Beneficial?
1	$1,912,557	$489,277	$1,423,280	Yes
3	$59,244	$434,775	-$375,531	No
4	$1,299,690	$4,000,000	-$2,700,310	No
5	$1,069,849	>>$1,000,000	Large Negative	No
6	$63,969	$100,000	-$36,031	No
10	$74,834	$434,775	-$359,941	No
11	$203,666	$434,775	-$231,109	No
12	$133,035	$434,775	-$301,740	No
13	$818,664	$836,870	-$18,206	No
15	$267,916	$200,000	$67,916	Yes
16	$135,817	$159,078	-$23,261	No
17	$1,566,562	$489,277	$1,077,285	Yes
18	$359,314	$434,775	-$75,461	No
19	$637,723	489,277	$148,446	Yes

Summary of the Detailed SAMA Analyses

Phase II SAMA ID	Averted Cost- Risk	Cost of Implementation	Net Value	Cost Beneficial?
20	$165,307	$434,775	-$269,468	No
21	$246,707	$500,000	-$253,293	No
22	$153,398	$500,000	-$346,602	No
25	$463,930	$50,000	$413,930	Yes
29	$250,281	$186,861	$63,420	Yes
30	$1,235,829	$1,531,855	-$290,026	No
31	$154,479	$250,000	-$95,521	No
32	$447,460	$750,000	-$302,540	No
33	$4,329	$100,000	-$95,671	No
34	$485,509	$489,277	-$3,768	No
35	$80,442	$2,000,000	-$1,919,558	No
36	$163,166	$100,000	$63,166	Yes
37	$51,963	$200,000	-$148,037	No

F.7 UNCERTAINTY ANALYSIS

The following two uncertainties were further investigated as to their impact on the overall SAMA evaluation:

- Assume a discount rate of 3 percent, instead of 7 percent used in the original base case analysis.
- Use the 95th percentile PSA results in place of the mean PSA results.

F.7.1 REAL DISCOUNT RATE

A sensitivity study has been performed in order to identify how the conclusions of the SAMA analysis might change based on the value assigned to the real discount rate (RDR). The original RDR of 7 percent has been changed to 3 percent and the modified maximum averted cost-risk was re-calculated using the methodology outlined in Section F.4. The Phase I screening against the MMACR was re-examined using the revised MMACR to identify any SAMA candidates that could no longer be screened based on the premise that their costs of implementation exceeded all possible benefit. In addition, the Phase II analysis was re-performed using the 3 percent RDR.

Implementation of the 3 percent RDR increased the MMACR by 18.6 percent compared with the case where a 7 percent RDR was used. This relates to an increase in the MMACR from $9,588,000 to $11,376,000. The Phase I SAMA list was reviewed to determine if such an increase in the MMACR would impact the disposition of any SAMAs. The single SAMA screened on high cost would not be retained for Phase II analysis even with the 18.6 percent increase in MMACR.

The Phase II SAMAs are dispositioned based on PSA insights or detailed analysis. All of the PSA insights used to screen the SAMAs are still applicable given the use of the 3 percent real discount rate. The SAMA candidates screened based on these insights are considered to be addressed and are not investigated further.

The remaining Phase II SAMAs were dispositioned based on the results of a SAMA specific cost-benefit analysis. This step has been re-performed using the 3 percent real discount rate to calculate the net values for the SAMAs.

As shown below, the determination of cost effectiveness changed for several of the Phase II SAMAs when the 3 percent RDR was used in lieu of 7 percent. Implementation of these SAMAs should be considered.

Summary of the Detailed SAMA Analyses

Phase II SAMA ID	Cost of Implementation	Averted Cost- Risk (7 percent RDR)	Net Value (7 percent RDR)	Averted Cost- Risk (3 percent RDR)	Net Value (3 percent RDR)	Change in Cost Effectiveness?
1	$489,277	$1,912,557	$1,423,280	$2,257,193	$1,767,916	No
3	$434,775	$59,244	-$375,531	$72,304	-$362,471	No
4	$4,000,000	$1,299,690	-$2,700,310	$1,521,536	-$2,478,464	No
5	>>$1,000,000	$1,069,849	Large Negative	$1,229,341	Large Negative	No
6	$100,000	$63,969	-$36,031	$74,900	-$25,100	No
10	$434,775	$74,834	-$359,941	$94,912	-$339,863	No
11	$434,775	$203,666	-$231,109	$255,618	-$179,157	No
12	$434,775	$133,035	-$301,740	$161,750	-$273,025	No
13	$836,870	$818,664	-$18,206	$1,013,571	$176,701	Yes
15	$200,000	$267,916	$67,916	$311,591	$111,591	No
16	$159,078	$135,817	-$23,261	$160,808	$1,730	Yes
17	$489,277	$1,566,562	$1,077,285	$1,802,691	$1,313,414	No
18	$434,775	$359,314	-$75,461	$439,307	$4,534	Yes
19	$489,277	$637,723	$148,446	$813,856	$324,579	No
20	$434,775	$165,307	-$269,468	$202,017	-$232,758	No
21	$500,000	$246,707	-$253,293	$286,785	-$213,215	No
22	$500,000	$153,398	-$346,602	$190,205	-$309,795	No
25	$50,000	$463,930	$413,930	$469,586	$419,586	No
29	$186,861	$250,281	$63,420	$291,778	$104,917	No
30	$1,531,855	$1,235,829	-$290,026	$1,466,290	-$65,565	No
31	$250,000	$154,479	-$95,521	$183,286	-$66,714	No
32	$750,000	$447,460	-$302,540	$530,904	-$219,096	No
33	$100,000	$4,329	-$95,671	$5,136	-$94,864	No
34	$489,277	$485,509	-$3,768	$567,352	$78,075	Yes
35	$2,000,000	$80,442	-$1,919,558	$93,088	-$1,906,912	No
36	$100,000	$163,166	$63,166	$228,001	$128,001	No
37	$200,000	$51,963	-$148,037	$64,884	-$135,116	No

F.7.2 95TH PERCENTILE PSA RESULTS

The results of the Phase I screening process itself can be impacted by implementing conservative values from the PSA's uncertainty distribution. Use of the 95th percentile PSA results will increase the modified maximum averted cost-risk and may prevent the screening of some of the higher cost modifications. However, the impact on the overall SAMA results due to the retention of the higher cost SAMAs for Phase II analysis is small. This is due to the fact that the benefit gleaned from the implementation of those SAMAs must be extremely large in order to be cost beneficial.

The impact of uncertainty in the PSA results on the Phase I SAMA analysis has been examined. The modified maximum averted cost-risk is the primary Phase I criteria affected by PSA uncertainty. Thus, this sensitivity is focused on recalculating the MMACR using the 95th percentile PSA results and re-performing the Phase I screening process.

An estimate of the uncertainty inherent in the Brunswick Unit 2 Level 1 PRA model has been calculated using the software UNCERT32. The following assumptions have been applied in developing this calculation.

1. All failure data was assumed to be distributed lognormally.
2. When an error factor was contained in the basic event database, it was assumed to be correct without any further verification.
3. All common cause failure events in the model were assigned an error factor of 10.0.
4. Initiating events which did not have an error factor in the database were assigned an error factor of 10.0.
5. Operator actions which did not have an error factor in the database were assigned an error factor of 10.0.
6. Calculated and periodically updated maintenance unavailabilities were assigned an error factor of 8.6. Otherwise, maintenance unavailabilities were assigned an error factor of 10.0.
7. Conditional probabilities were assigned an error factor of 5.0.
8. Flag events and split fractions were assigned an error factor of 1.0.
9. Events without an error factor in the database which were identical to a type code failure mode were assigned the corresponding error factor from the type code database.
10. Operator actions in the cutsets set to a value of 1.0 were changed to be 1.0 in the database with an error factor of 1.0 (these events are essentially flag events).

The Unit 2 model of record MOR03 (Reference 22) was used for this analysis. The MOR03 database files **BNP12.BE/.GT/.TC** and cutset file **B2510AAR.CUT** (produced in Reference 23) were used.

The basic event database was purged of records not applicable to Unit 2 MOR03 to simplify checks of the error factors. Error factor data was added to the database for basic events and generic type codes based upon the latest documentation from References 24 to 27 and as updated per data in Reference 22. Additional error factor data was incorporated as necessary based upon the assumptions above.

The tabulated results generated by UNCERT32 are provided below:

PARAMETER	VALUE
Mean	8.85×10^{-05}
5%	1.86×10^{-05}
Median	3.62×10^{-05}
95%	9.83×10^{-05}
Standard Deviation	3.62×10^{-03}

The PSA uncertainty calculation identifies the 95th percentile CDF as 9.83×10^{-5}/yr. This is a factor of 2.35 greater than the CDF point estimate produced by the BSEP PSA.

As the same type of uncertainty analysis was not available for the Level 2 and Level 3 results, the 95th percentile results were estimated. The dose-risk and offsite economic cost-risk were increased by a factor of 2.35 to simulate the increase in the CDF resulting from the use of the 95th percentile results. The "95th percentile" dose-risk and offsite economic cost-risk are 69.0 person-rem/yr and $113,956/yr, respectively. The corresponding modified maximum averted cost-risk is $22.5 million.

The initial SAMA list has been re-examined using the revised modified maximum averted cost-risk to identify SAMAs that would be retained for the Phase II analysis. Those SAMAs that were previously screened due to costs of implementation that exceeded $9.94 million are now retained if the costs of implementation are less than $22.5 million. The only additional SAMA candidate that would be retained for Phase II analysis is SAMA 25 (additional EDG). Given that the SAMA 25 cost of implementation is 89 percent of the revised MMACR, this SAMA is not considered further. The impact of the installation of an additional EDG is judged to be limited due common cause failure. In addition, the current model results indicate that the diesel generators contribute to less than 40 percent of the CDF; thus, the EDG could not be cost beneficial even if the system was 100 percent reliable.

PHASE II IMPACT

As mentioned above, it was necessary to make an assumption about the 95th percentile PSA results for the Level 2 and 3 analyses. The assumption that has been made is that the 95th percentile results for the Level 2 and 3 models can be represented by increasing the base dose-risk and offsite economic cost-risk in proportion to the Level 1 results. The factor of 2.35 is also assumed to propagate through the results for the model runs performed for the Phase II detailed calculations. This means that the averted cost-risks for each case will be increased by the same factor.

The following table provides a summary of the impact of using the 95th percentile PSA results in the detailed cost benefit calculations that have been performed.

Phase II SAMA ID	Cost of Implementation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
1	$489,277	$1,912,557	$1,423,280	$4,494,509	$4,005,232	No
3	$434,775	$59,244	-$375,531	$139,223	-$295,552	No
4	$4,000,000	$1,299,690	-$2,700,310	$3,054,272	-$945,728	No

Phase II SAMA ID	Cost of Implementation	Averted Cost- Risk (Base)	Net Value (Base)	Averted Cost- Risk (95th Percentile)	Net Value (95th Percentile)	Change in Cost Effectiveness?
5	>>$1,000,000	$1,069,849	Large Negative	$2,514,145	Large Negative	No
6	$100,000	$63,969	-$36,031	$150,327	$50,327	Yes
10	$434,775	$74,834	-$359,941	$175,860	-$258,915	No
11	$434,775	$203,666	-$231,109	$478,615	$43,840	Yes
12	$434,775	$133,035	-$301,740	$312,632	-$122,143	No
13	$836,870	$818,664	-$18,206	$1,923,860	$1,086,990	Yes
15	$200,000	$267,916	$67,916	$629,603	$429,603	No
16	$159,078	$135,817	-$23,261	$319,170	$160,092	Yes
17	$489,277	$1,566,562	$1,077,285	$3,681,421	$3,192,144	No
18	$434,775	$359,314	-$75,461	$844,388	$409,613	Yes
19	$489,277	$637,723	$148,446	$1,498,649	$1,009,372	No
20	$434,775	$165,307	-$269,468	$388,471	-$46,304	No
21	$500,000	$246,707	-$253,293	$579,761	$79,761	Yes
22	$500,000	$153,398	-$346,602	$360,485	-$139,515	No
25	$50,000	$463,930	$413,930	$1,090,236	$1,040,236	No
29	$186,861	$250,281	$63,420	$588,160	$401,299	No
30	$1,531,855	$1,235,829	-$290,026	$2,904,198	$1,372,343	Yes
31	$250,000	$154,479	-$95,521	$363,026	$113,026	Yes
32	$750,000	$447,460	-$302,540	$1,051,531	$301,531	Yes
33	$100,000	$4,329	-$95,671	$10,173	-$89,827	No
34	$489,277	$485,509	-$3,768	$1,140,946	$651,669	Yes
35	$2,000,000	$80,442	-$1,919,558	$189,039	-$1,810,961	No
36	$100,000	$163,166	$63,166	$383,440	$283,440	No
37	$200,000	$51,963	-$148,037	$122,113	-$77,887	No

When the 95th percentile PSA results are used, several of the SAMAs that were previously classified as “not cost effective”, are determined to be cost effective. However, the use of the 95th percentile PSA results is not considered to provide the most realistic assessment of the cost effectiveness of a SAMA.

F.8 CONCLUSIONS

The benefits of revising the operational strategies in place at BSEP and/or implementing hardware modifications can be evaluated without the insight from a risk-based analysis. Use of the PSA in conjunction with cost benefit analysis methodologies has, however, provided an enhanced understanding of the effects of the proposed changes relative to the cost of implementation and projected impact on a much larger future population. The results of this study indicate that of the identified potential improvements that can be made at BSEP, several are cost beneficial based on the methodology applied in this analysis and warrant further review for potential implementation.

F.9 TABLES AND FIGURES

TABLE F-1
SUMMARY OF THE CORE DAMAGE FREQUENCY BY ACCIDENT SEQUENCE SUBCLASS FOR BRUNSWICK UNIT 2

Accident Class Designator	Subclass	Definition	CAFTA Model (per Rx Yr)[7]
Class I	A	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high.	1.21E-5
	B	Accident sequences involving a station blackout and loss of coolant inventory makeup.	IBE 6.11E-6[6] IBL 9.51E-6[6]
	C	Accident sequences involving a loss of coolant inventory induced by an ATWS sequence with containment intact.	ε[1]
	D	Accident sequences involving a loss of coolant inventory makeup in which reactor pressure has been successfully reduced to 200 psi.	4.17E-6
	E	Accident sequences involving loss of inventory makeup in which the reactor pressure remains high and DC power is unavailable.	[2]
Class II	A	Accident sequences involving a loss of containment heat removal with the RPV initially intact; core damage; core damage induced post containment failure.	8.76E-7
	L	Accident sequences involving a loss of containment heat removal with the RPV breached but no initial core damage; core damage induced post containment failure.	2.82E-7
	V	Class IIA and III except that the vent operates as designed; loss of makeup occurs at some time following vent initiation. Suppression pool saturated but intact.	ε[3]
Class III (LOCA)	A	Accident sequences leading to core damage conditions initiated by vessel rupture where the containment integrity is not breached in the initial time phase of the accident.	2.19E-6
	B	Accident sequences initiated or resulting in small or medium LOCAs for which the reactor cannot be depressurized prior to core damage occurring.	ε[4]
	C	Accident sequences initiated or resulting in medium or large LOCAs for which the reactor is a low pressure and no effective injection is available.	3.04E-6
	D	Accident sequences which are initiated by a LOCA or RPV failure and for which the vapor suppression system is inadequate, challenging the containment integrity with subsequent failure of makeup systems.	ε[5]

TABLE F-1
SUMMARY OF THE CORE DAMAGE FREQUENCY BY ACCIDENT SEQUENCE SUBCLASS FOR BRUNSWICK UNIT 2

Accident Class Designator	Subclass	Definition	CAFTA Model (per Rx Yr)[7]
Class IV (ATWS)	A	Accident sequences involving failure of adequate shutdown reactivity with the RPV initially intact; core damage induced post containment failure.	2.30E-6
	L	Accident sequences involving a failure of adequate shutdown reactivity with the RPV initially breached (e.g. LOCA or SORV); core damage induced post containment failure.	1.00E-6
Class V	---	Unisolated LOCA outside containment.	2.99E-7
		Total CDF	4.19E-5

Notes to Table F-1

(1) Class IC accidents resulted in no cutsets above the truncation limit.

(2) Class IE accidents are binned with Class IA accidents in the current BSEP PRA.

(3) Class IIV accidents are negligible in the current BSEP PRA (i.e., the Level 1 model assumes 0.0 likelihood of successful venting causing injection failure).

(4) Class IIIB accidents resulted in no cutsets above the truncation limit.

(5) Class IIID accidents are negligible in the current BSEP PRA. A large LOCA coincident with vapor suppression system failure is judged sufficiently low frequency that the scenario is not explicitly modeled.

(6) The Class IB cutsets are divided into Class IBE (i.e., early station blackout) and Class IBL (i.e., late station blackout) for the Level 2 analysis. Class IBE is defined as station blackout with core damage in less than 4 hours and includes all cutsets in which 2 or less hours were credited for AC power recovery (i.e., AC power recovery events X-AC-0H, X-AC-1H and X-AC-2H). Class IBL is defined as station blackout with core damage after 6 hours and includes all cutsets in which 5 or more hours are credited for AC power recovery (i.e., AC power recovery events X-AC-5H, X-AC-12H, X-AC-12RNLS, X-AC-13H, X-AC-14H, X-AC-16H, and X-AC-18H).

(7) ε = Negligible frequency from Level 1 PSA.

TABLE F-2
RELEASE SEVERITY AND TIMING CLASSIFICATION SCHEME (SEVERITY, TIMING)

Release Severity Source Term Release Fraction		Release Timing	
Classification Category	**Cs Iodide % in Release**	**Classification Category**	**Time of Release(1)**
High (H)	greater than 10	Late (L)	greater than 24 hours
Moderate (M)	1 to 10	Intermediate (I)	6 to 24 hours
Low (L)	0.1 to 1	Early (E)	less than 6 hours
Low-Low (LL)	less than 0.1		
No iodine (OK)	0		

TABLE F-3
SUMMARY OF CONTAINMENT EVALUATION

INPUT		OUTPUT	
LEVEL 1 PSA		**CET EVALUATION**	
Core Damage Frequency	**Characterization of Release**	**Release Bin[(1)]**	**Release Frequency (Per Year)**
4.19E-5	Little or No Release	OK	1.81E-5
	Low Public Risk Impact	LL and Late	2.34E-7
		LL and I	7.17E-8
		LL and E	Negligible
		L and Late[(2)]	2.01E-6
		L and I	5.09E-8
		L and E	3.30E-6
	Moderate Public Risk Impact	M and Late [(2)]	Negligible
		M and I	1.06E-5
		M and E	1.62E-6
	High Release	H and Late[(2)]	Negligible
		H and I	3.79E-6
		H and E	2.13E-6

(1) See Table F-2 for nomenclature on the release bins.

(2) One of the areas that PRA tools are somewhat limited is in the estimation of recovery or repair during extended times such as 24 hours. Some estimates would indicate that response over such an extended time could be very extensive and highly successful. Therefore, it can be argued that virtually no accidents that take beyond 24 hours to release should be considered to be a significant potential contributor to public risk.

(1) Relative to the declaration of a General Emergency.

TABLE F-4
SUMMARY OF BSEP UNIT 2 LEVEL 2 RELEASE CATEGORY FREQUENCIES[(1), (2)]

Class	Adjusted CDF	Intact	H/E	H/I	H/L	M/E	M/I	M/L	L/E	L/I	L/L	LL/E	LL/I	LL/L	Total Release
IA	1.21E-05	6.43E-06	5.40E-08	4.61E-07	N/A	N/A	2.67E-06	N/A	6.18E-07	0.00E+00	1.72E-06	N/A	0.00E+00	1.50E-07	5.67E-06
IBE	6.11E-06	3.87E-06	1.80E-08	2.35E-07	N/A	N/A	1.90E-06	N/A	1.13E-08	0.00E+00	2.76E-08	N/A	4.38E-08	0.00E+00	2.24E-06
IBL	9.51E-06	5.37E-06	1.91E-08	6.62E-07	N/A	N/A	3.40E-06	N/A	8.24E-09	0.00E+00	1.87E-08	N/A	2.78E-08	0.00E+00	4.13E-06
ID	4.17E-06	5.27E-07	3.36E-08	4.31E-07	N/A	N/A	2.59E-06	N/A	2.66E-07	0.00E+00	2.46E-07	N/A	0.00E+00	8.37E-08	3.65E-06
IIA(3)	8.76E-07	0.00E+00	N/A	8.25E-07	N/A	N/A	0.00E+00	N/A	N/A	5.09E-08	N/A	N/A	0.00E+00	N/A	8.76E-07
IIL(4)	2.82E-07	0.00E+00	N/A	2.82E-07	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	2.82E-07
IIIA	2.19E-06	5.97E-08	4.44E-08	4.15E-09	0.00E+00	N/A	0.00E+00	0.00E+00	2.08E-06	0.00E+00	0.00E+00	N/A	0.00E+00	0.00E+00	2.13E-06
IIIC	3.04E-06	1.81E-06	1.18E-08	8.93E-07	0.00E+00	N/A	0.00E+00	0.00E+00	3.24E-07	0.00E+00	0.00E+00	N/A	0.00E+00	0.00E+00	1.23E-06
IVA	2.30E-06	0.00E+00	1.15E-06	N/A	N/A	1.13E-06	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	2.28E-06
IVL	1.00E-06	0.00E+00	5.02E-07	N/A	N/A	4.96E-07	N/A	N/A	0.00E+00	N/A	N/A	0.00E+00	N/A	N/A	9.98E-07
V	2.99E-07	0.00E+00	2.99E-07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.99E-07
Total	4.19E-05	1.81E-05	2.13E-06	3.79E-06	0.00E+00	1.62E-06	1.06E-05	0.00E+00	3.30E-06	5.09E-08	2.01E-06	0.00E+00	7.17E-08	2.34E-07	2.38E-05

(1) The results are based on PRAQuant file BNP2-L2.QNT. The Level 2 model was quantified at a truncation value of 5E-10/yr for most sequences. The Class II, IV, and V CET sequences were quantified at a truncation value of 5E-11/yr.

(2) N/A indicates that the accident class did not contribute to release of that specific category.

(3) Due to truncation issues, the total Class IIA release frequency was calculated to be 7.96E-7/yr. This calculated result is less than the total Class IIA CDF. Therefore, to represent the total release correctly, the individual Class IIA end state totals are increased proportionally by a factor of 1.1 (i.e., 8.76E-7/7.96E-7) to equal the total Class IIA CDF of 8.76E-7/yr.

(4) Due to truncation issues, the total Class IIL release frequency was calculated to be 2.71E-7/yr. This calculated result is less than the total Class IIL CDF. Therefore, to represent the total release correctly, the individual Class IIL end state totals are increased proportionally by a factor of 1.04 (i.e., 2.82E-7/2.71E-7) to equal the total Class IIA CDF of 2.82E-7/yr.

TABLE F-5
BSEP SOURCE TERM SUMMARY

	Release Category[1]											
	H/E	H/I	H/L[(6)]	M/E	M/I	M/L[(6)]	L/E	L/I	L/L	LL/E	LL/I	LL/L
Bin Frequency	2.13E-06	3.79E-06	0.00E+00	1.62E-06	1.06E-05	0.00E+00	3.30E-06	5.09E-08	2.01E-06	0.00E+00	7.17E-08	2.34E-07
MAAP Run	BR0085	BR0090	BR0090[2]	BR0083	BR0066	BR0070	BR0088	BR0064	BR0063	NA	BR0069	BR0069[3]
Time after Scram when General Emergency is declared	45 min	5 min	5 min	45 min	45 min	60 min[4]	45 min	55 min	55 min		45 min	
Fission Product Group:												
1) Noble												
Total Release % at 48 Hours	100	88	88	100	88	100	22	99	100		100	
Start of Release (hr)	45 min	11.6 hr	24 hr	45 min	15.5 hr	31.1 hr	6.3 hr	16 hr	29.2 hr		29 hr	
End of Release (hr)	2 hr	11.6 hr	24 hr	2.5 hr	15.5 hr	31.1 hr	6.3 hr	22 hr	32 hr		29 hr	
2) CsI												
Total Release % at 48 Hours	34	3.24E+01	32.4	7.7	9.3	2.6	0.15	0.19	1.40E-03		2.40E-03	
Start of Release (hr)	45 min	11.6 hr	24 hr	2.4 hr	15.5 hr	31.1 hr	6.3 hr	16 hr	29.2 hr		29 hr	
End of Release (hr)	4 hr	36 hr	36 hr	4 hr	36 hr	72 hr	6.3 hr	36 hr	34 hr		36 hr	
3) TeO2												
Total Release % at 48 Hours	4.4	21.7	21.7	0.82	6.6	2	0.27	7.00E-04	6.60E-05		1.80E-02	
Start of Release (hr)	45 min	11.6 hr	24 hr	45 min	15.5 hr	31.1 hr	6.3 hr	16 hr	2.5 hr		29 hr	
End of Release (hr)	4 hr	28 hr	36 hr	4 hr	16.0 hr	50.0 hr	6.3 hr	36 hr	2.5 hr		36 hr	
4) SrO												
Total Release % at 48 Hours	0.12	5.30E-04	5.30E-04	2.80E-02	1.70E-04	1.50E-02	2.10E-05	0.015	1.80E-09		9.00E-08	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	3.0 hr	35.0 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	11.6 hr	24 hr	8 hr	6.0 hr	40 hr	6.3 hr	31 hr	2.5 hr		2 hr	
5) MoO2												
Total Release % at 48 Hours	2.60E-02	1.50E-04	1.50E-04	8.20E-04	1.70E-05	6.30E-04	3.00E-05	3.00E-08	2.80E-08		3.40E-07	
Start of Release (hr)	2.4 hr	1 hr	24 hr	45 min	2.0 hr	31.1 hr	6.3 hr	2.5 hr	2.5 hr		2 hr	
End of Release (hr)	2.4 hr	1 hr	24 hr	2 hr	36.0 hr	31.1 hr	6.3 hr	2.5 hr	2.5 hr		2 hr	
6) CsOH												
Total Release % at 48 Hours	5	31.9	31.9	1.3	3.5	1.5	0.5	9.60E-02	1.30E-03		0.14	
Start of Release (hr)	45 min	11.6 hr	24 hr	45 min	15.5 hr	31.1 hr	6.3 hr	16 hr	29.2 hr		29 hr	
End of Release (hr)	4 hr	36 hr	36 hr	36 hr	24 hr	40.0 hr	6.3 hr	36 hr	36 hr		36 hr	
7) BaO												
Total Release % at 48 Hours	0.08	1.60E-03	1.60E-03	0.014	1.10E-03	7.30E-03	4.80E-05	7.20E-03	6.70E-09		4.30E-07	
Start of Release (hr)	2.4	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	36 hr	36 hr	8 hr	36 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
8) La2O3												
Total Release % at 48 Hours	6.00E-03	2.80E-05	2.80E-05	1.80E-03	2.10E-05	2.00E-04	4.00E-06	1.40E-04	2.60E-10		3.60E-08	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	3.0 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	11.6 hr	24 hr	4 hr	6.0 hr	40 hr	6.3 hr	31 hr	2.5 hr		2 hr	
9) CeO2												
Total Release % at 48 Hours	5.20E-02	1.90E-04	1.90E-04	1.50E-02	1.10E-04	3.30E-03	5.00E-06	2.30E-03	6.50E-10		6.00E-08	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	3 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	11.6 hr	24 hr	6 hr	6 hr	40 hr	6.3 hr	31 hr	2.5 hr		2 hr	
10) Sb												
Total Release % at 48 Hours	10.8	49.7	49.7	3.7	25	1.1	1.1	0.53	1.20E-03		1.3	
Start of Release (hr)	2.4	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	29.2 hr		29 hr	
End of Release (hr)	14 hr	36 hr	36 hr	20 hr	28 hr	45 hr	6.3 hr	36 hr	36 hr		32 hr	
11) Te2												
Total Release % at 48 Hours	1.4	1.2	1.2	0.5	7.70E-01	0.81	2.40E-05	0.37	9.10E-06		2.70E-04	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	29.2 hr		29 hr	
End of Release (hr)	16 hr	24 hr	36 hr	24 hr	24 hr	55 hr	6.3 hr	36 hr	29.2 hr		32 hr	
12) UO2												
Total Release % at 48 Hours	2.20E-04	3.00E-05	3.00E-05	7.60E-05	2.30E-05	1.30E-05	5.00E-08	4.00E-06	3.00E-14		5.00E-10	
Start of Release (hr)	2.4 hr	11.6 hr	24 hr	2.4 hr	15.5 hr	35 hr	6.3 hr	31 hr	2.5 hr		2 hr	
End of Release (hr)	8 hr	36 hr	36 hr	8 hr	36 hr	45 hr	6.3 hr	36 hr	2.5 hr		2 hr	

(1) Puff releases are denoted in the table by those entries with equivalent start and end times.
(2) Case BR0090 results shifted to 24 hr release to represent "Late" release
(3) Results for release category LL/I will be used for LL/L
(4) General Emergency based on loss of containment heat removal and assumed to be declared at 60 minutes

	H/E	H/I	H/L	M/E	M/I	M/L	L/E	L/I	L/L	LL/E	LL/I	LL/L
(5) Mass of TeO2 Generated for each case	82 lb	84 lb	84 lb	82 lb	85 lb	81 lb	85 lb	82 lb	82 lb		85 lb	

(6) Revised Level 2 results indicate negligible contributions for the M/L and H/L release categories; however, the source term information has been retained for reference purposes.

TABLE F-6
ESTIMATED POPULATION DISTRIBUTION WITHIN A 10-MILE RADIUS OF BSEP, YEAR 2036

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles	10-mile total
N	40	81	95	131	636	2,391	3,374
NNE	40	88	95	95	142	1,089	1,549
NE	40	88	95	95	142	7,144	7,604
ENE	40	121	47	95	142	10,318	10,763
E	40	162	243	195	150	273	1,063
ESE	40	162	184	113	142	123	764
SE	40	162	126	113	150	131	722
SSE	40	121	108	113	135	405	922
S	40	181	333	240	192	653	1,639
SSW	40	750	2,208	459	573	74	4,104
SW	40	180	331	437	631	143	1,762
WSW	40	121	243	409	725	6,807	8,345
W	40	28	258	616	662	6,601	8,205
WNW	40	28	85	113	113	1,977	2,356
NW	40	69	85	113	141	1,140	1,588
NNW	40	121	76	462	851	2,282	3,832
Total	640	2,463	4,612	3,799	5,527	41,551	58,592

TABLE F-7
ESTIMATED POPULATION DISTRIBUTION WITHIN A 50-MILE RADIUS OF BSEP, YEAR 2036

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles	50-mile total
N	3,374	13,715	18,832	8,664	16,269	60,854
NNE	1,549	117,933	101,274	22,404	22,703	265,863
NE	7,604	74,599	63,184	21,619	15,394	182,400
ENE	10,763	982	0	0	0	11,745
E	1,063	0	0	0	0	1,063
ESE	764	0	0	0	0	764
SE	722	0	0	0	0	722
SSE	922	0	0	0	0	922
S	1,639	0	0	0	0	1,639
SSW	4,104	0	0	0	0	4,104
SW	1,762	0	0	0	0	1,762
WSW	8,345	0	0	0	0	8,345
W	8,205	23,295	26,007	56,649	67,085	181,241
WNW	2,356	11,272	8,452	8,561	28,113	58,754
NW	1,588	3,354	3,202	4,741	25,278	38,163
NNW	3,832	4,536	7,137	6,313	7,675	29,493
Total	58,592	249,686	228,088	128,951	182,517	847,834

TABLE F-8
ESTIMATED ANNUAL POPULATION GROWTH RATE WITHIN A 10-MILE RADIUS OF BSEP

Sector	0-1 mile	1-2 miles	2-3 miles	3-4 miles	4-5 miles	5-10 miles
N	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NNE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0386
ENE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0333
E	1.0435	1.0435	1.0435	1.0365	1.0333	1.0333
ESE	1.0435	1.0435	1.0435	1.0435	1.0333	1.0333
SE	1.0435	1.0435	1.0435	1.0435	1.0430	1.0435
SSE	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
S	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
SSW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
SW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
WSW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
W	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
WNW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435
NNW	1.0435	1.0435	1.0435	1.0435	1.0435	1.0435

TABLE F-9
ESTIMATED ANNUAL POPULATION GROWTH RATE WITHIN A 10 TO 50-MILE RADIUS OF BSEP

Sector	0-10 miles	10-20 miles	20-30 miles	30-40 miles	40-50 miles
N	See Table F-8	1.0435	1.0423	1.0400	1.0386
NNE	See Table F-8	1.0386	1.0342	1.0421	1.0424
NE	See Table F-8	1.0333	1.0347	1.0424	1.0251
ENE	See Table F-8	1.0333	0	0	0
E	See Table F-8	0	0	0	0
ESE	See Table F-8	0	0	0	0
SE	See Table F-8	0	0	0	0
SSE	See Table F-8	0	0	0	0
S	See Table F-8	0	0	0	0
SSW	See Table F-8	0	0	0	0
SW	See Table F-8	0	0	0	0
WSW	See Table F-8	0	0	0	0
W	See Table F-8	1.0435	1.0435	1.0387	1.0365
WNW	See Table F-8	1.0435	1.0435	1.0224	1.0185
NW	See Table F-8	1.0435	1.0317	1.0115	1.0105
NNW	See Table F-8	1.0435	1.0241	1.0131	1.0126

TABLE F-10
ESTIMATED BSEP CORE INVENTORY

Nuclide	Core Inventory (Becquerels)	Nuclide	Core Inventory (Becquerels)
Co-58	$1.654x10^{16}$	Te-131m	$4.132x10^{17}$
Co-60	$1.980x10^{16}$	Te-132	$4.039x10^{18}$
Kr-85	$2.710x10^{16}$	I-131	$2.792x10^{18}$
Kr-85m	$9.853x10^{17}$	I-132	$4.101x10^{18}$
Kr-87	$1.792x10^{18}$	I-133	$5.860x10^{18}$
Kr-88	$2.418x10^{18}$	I-134	$6.413x10^{18}$
Rb-86	$1.516x10^{15}$	I-135	$5.516x10^{18}$
Sr-89	$3.001x10^{18}$	Xe-133	$5.868x10^{18}$
Sr-90	$2.123x10^{17}$	Xe-135	$1.395x10^{18}$
Sr-91	$3.898x10^{18}$	Cs-134	$4.572x10^{17}$
Sr-92	$4.072x10^{18}$	Cs-136	$1.226x10^{17}$
Y-90	$2.274x10^{17}$	Cs-137	$2.737x10^{17}$
Y-91	$3.662x10^{18}$	Ba-139	$5.402x10^{18}$
Y-92	$4.088x10^{18}$	Ba-140	$5.328x10^{18}$
Y-93	$4.649x10^{18}$	La-140	$5.437x10^{18}$
Zr-95	$4.819x10^{18}$	La-141	$5.020x10^{18}$
Zr-97	$4.962x10^{18}$	La-142	$4.830x10^{18}$
Nb-95	$4.560x10^{18}$	Ce-141	$4.838x10^{18}$
Mo-99	$5.258x10^{18}$	Ce-143	$4.710x10^{18}$
Tc-99m	$4.538x10^{18}$	Ce-144	$3.138x10^{18}$
Ru-103	$3.985x10^{18}$	Pr-143	$4.610x10^{18}$
Ru-105	$2.659x10^{18}$	Nd-147	$2.060x10^{18}$
Ru-106	$1.084x10^{18}$	Np-239	$6.141x10^{19}$
Rh-105	$1.984x10^{18}$	Pu-238	$4.270x10^{15}$
Sb-127	$2.514x10^{17}$	Pu-239	$1.083x10^{15}$
Sb-129	$8.726x10^{17}$	Pu-240	$1.355x10^{15}$
Te-127	$2.434x10^{17}$	Pu-241	$2.333x10^{17}$
Te-127m	$3.276X10^{16}$	Am-241	$2.372x10^{14}$
Te-129	$8.186x10^{17}$	Cm-242	$6.264x10^{16}$
Te-129m	$2.152x10^{17}$	Cm-244	$3.380x10^{15}$

TABLE F-11
MACCS RELEASE CATEGORIES VS. BSEP RELEASE CATEGORIES

MACCS Release Categories	BSEP Release Categories
Xe/Kr	1 – noble gases
I	2 – CsI
Cs	2 & 6 – CsI and CsOH
Te	3 & 11- TeO_2 & Te_2
Sr	4 – SrO
Ru	5 – MoO_2 (Mo is in Ru MACCS category)
La	8 – La_2O_3
Ce	9 – CeO_2 & UO_2
Ba	7 – BaO
Sb (supplemental category)	10 – Sb

TABLE F-12
RESULTS OF BSEP LEVEL 3 PSA ANALYSIS

Sequence	H/E	H/I	M/E	M/I	L/E	L/I	L/L	LL/I	LL/L	SUM
Population dose risk (person-rem) 0-50 miles	5.495	9.134	1.831	11.766	1.053	0.008	0.011	0.013	0.042	**29.35**
Total economic cost risk ($) 0-50 miles	4,643	23,081	1,895	17,702	1,148	3	1	4	14	**48,492**

The total baseline release frequency analyzed is 2.38×10^{-5}. MACCS2 calculated the annual baseline population dose risk within 50 miles at 29.35 person-rem. The total annual economic risk was calculated at $48,492.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
%TE_S	2.30E-02	1.542	LOSS OF OFFSITE POWER (SITE)	Install protective covers on switchyard insulators to prevent salt-spray related shorts or proceduralize equipment wash-down after severe weather
%2T_T	2.70E+00	1.374	TURBINE TRIP INITIATOR	The application of the Maintenance Rule is considered to have improved plant operations through focused maintenance plans. PSA applications have also helped to identify areas for improvement in plant practices, equipment availability and operation. No credible, potentially cost effective means of further reducing the turbine trip frequency have been identified. The equipment and operator actions important to mitigating turbine trip initiators is judged to be addressed by the other components in this list.
BUSFAULT	3.90E-01	1.154	FRACTION OF LOSS OF BUS THAT ARE NON-RECOVERABLE	N/A
DCP2BAT-XXDEP2B	1.00E+00	1.151	BATTERY BANK 2B DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2BAT-XXDEP2A	1.00E+00	1.139	BATTERY BANK 2A DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
X-AC-12H	4.02E-02	1.133	LOSP RECOVERY 12 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-2H	1.33E-01	1.128	LOSP RECOVERY 2 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
SRV-DEMAND1	6.36E-01	1.127	7 OF 11 SRVS DEMANDED ISOLATION TRANSIENT	No SAMAs identified.
RCI2TDP-FR-RCTDP	2.30E-01	1.112	RCIC TURBINE-DRIVEN PUMP FAILS TO RUN	High pressure injection reliability could be improved through the addition of a direct drive diesel injection pump (encompassed by SAMA 205, Table A-1).
EDG2DGN-FR-003	7.40E-02	1.106	DIESEL GENERATOR 3 FAILS TO RUN	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
OPER-ALTUNITXC	1.00E+00	1.090	OPERATORS FAIL TO MANUALLY ALIGN POWER FROM OPPOSITE UNIT	Ensure all buses that can be cross-tied have procedures to perform cross-tie.
%2T_C	1.80E-01	1.090	LOSS OF CONDENSER VACUUM	No SAMAs identified.
EDG2DGN-FR-004	7.40E-02	1.083	DIESEL GENERATOR 4 FAILS TO RUN	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-16H	2.49E-02	1.076	LOSP RECOVERY 16 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
DCP2REC-XXTRP2A1	1.00E+00	1.073	CHARGER 2A-1 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Ensure procedures and training exist to isolate failures and reload the buses. Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2REC-XXTRP2B2	1.00E+00	1.072	CHARGER 2B-2 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Ensure procedures and training exist to isolate failures and reload the buses. Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A 1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
EDG1DGN-FR-001	7.40E-02	1.070	DIESEL GENERATOR 1 FAILS TO RUN	Install an additional Diesel Generator (SAMA 118, Table A-1)
HPC2TDP-FR-HPTDP	7.40E-02	1.068	HPCI TURBINE-DRIVEN PUMP FAILS TO RUN	High pressure injection reliability could be improved through the addition of a direct drive diesel injection pump (encompassed by SAMA 205, Table A-1). Maximizing CRD flow for high pressure injection is also a potential improvement (SAMA 197, Table A-1).
EDG1DGN-FR-002	7.40E-02	1.064	DIESEL GENERATOR 2 FAILS TO RUN	Install an additional Diesel Generator (SAMA 118, Table A 1)
%2T_DC2B2	2.90E-03	1.062	LOSS OF 125V DC PANEL 2B2	No suggestions.
SRV2SRV-CCF-511	7.57E-06	1.050	SUM OF CCF - ANY FIVE SRVs FAIL TO OPEN	Diversify SRVs by replacing some valves with valves of a different design.
IAN2CKV-44ALL	4.50E-05	1.049	COMMON CAUSE FAILURE OF ALL SRV AIR CHECK VALVES TO OPEN	Diversify check valves by replacing some valves with valves of a different design or by installing bypass lines

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
IAN2CKV-443456	4.50E-05	1.049	COMMON CAUSE FAILURE OF CHECK VALVES V313, V314, V315 AND V316 TO OPEN	Diversify check valves by replacing some valves with valves of a different design or by installing bypass lines
RPS2MBIND	1.00E-05	1.049	MECHANICAL BINDING OF CONTROL RODS	This failure is important for BSEP in combination with operator failure to control level to prevent boron washout. Improvements in boron injection will not significantly reduce risk. A potential enhancement is the improvement of EOPs to reduce the failure probability of injection control. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.
OPER-480X2	1.00E+00	1.047	OPERATORS FAIL TO MANUALLY CONNECT UNIT 2 SUBSTATIONS E7 AND E8	Provide capability in the main control room to perform 480V AC substation X-tie.
OPER-DCPALTDC2	1.00E+00	1.043	OPERATOR FAILS TO ALIGN DC BUS TO STANDBY DC POWER SUPPLY - UNIT2	Provide capability in the main control room to perform DC supply swap.
%2TCRD	1.00E+00	1.043	LOSS OF CONTROL ROD DRIVE	An inter-unit CRD cross-tie could improve accident mitigation for this initiator. Alternate boron injection methods are addressed for event "RPS2MBIND".
ICC2LPW-CF-XUALL	3.73E-06	1.041	CCF OF ALL XU POWER SUPPLY PANELS	Use of portable 120V AC generators could supply power to required panels.
OPER-DILUTE	1.00E+00	1.040	OPERATOR FAILS TO PRECLUDE BORON WASHOUT DURING LOW PRESSURE INJECTION	A potential enhancement is the improvement of EOPs to reduce the failure probability of injection control. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.
OPER-DGHMAN	1.00E+00	1.040	OPERATORS FAIL TO MANUALLY START EXHAUST FAN	Add a diverse logic set and thermocouple powered directly from the EDG.
XOP-DGHMAN	6.10E-03	1.036	OPER-DGHMAN	Add a diverse logic set and thermocouple powered directly from the EDG.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-1H	2.09E-01	1.035	LOSP RECOVERY 1 HOUR	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
XOP-COM2-16	7.90E-03	1.034	OPER-DCPALTDC1 OPER-ALTUNITXC OR OPER-DCPALTDC1 OPER-ALTUNITXC	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1) provides an additional option in this case.
%2T_M	7.30E-02	1.032	MSIV CLOSURE INITIATOR: T(M)	Digital instrumentation already incorporated. No suggestions.
CRD2SCRAM	6.00E-06	1.027	FAILURE OF CONTROL ROD DRIVE SCRAM VALVES	Alternate boron injection methods and injection flow control modifications for preventing boron dilution are potential enhancements and are addressed for event "RPS2MBIND".
DCP2REC-34A1A2B2	2.37E-07	1.026	COMMON CAUSE FAILURE OF CHARGER 2A-1, 2A-2 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2REC-24A1B2	5.20E-07	1.025	COMMON CAUSE FAILURE OF CHARGER 2A-1 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TE_U2	1.40E-02	1.024	LOSS OF OFFSITE POWER TO UNIT 2	Implement procedures to spray down electrical component after sever weather to prevent shorting from salt spray.
OPER-LLEVEL1	1.00E+00	1.023	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH HPCI DURING ATWS	No suggestions.
EDG2DGN-TM-D003	1.40E-02	1.022	DIESEL GENERATOR 3 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
X-AC-5H	9.30E-02	1.021	LOSP RECOVERY 5 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
XOP-ALTUNITXC1	7.00E-02	1.020	OPER-ALTUNITXC	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1).
DCP0REC-44ALL	1.76E-07	1.019	COMMON CAUSE FAILURE OF BOTH UNIT 1 AND UNIT 2 CHARGERS	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1).
XOP-DEPRESS	6.90E-03	1.019	OPER-DEPRESS	Alternate depressurization methods are not credited for BSEP. The following alternate depressurization paths are available given failure of the normal means: main condenser via the turbine bypass valves, main steam line drains, HPCI, RCIC, SJAE, RFP, RWCU in recirc mode, and RWCU in blowdown mode. Lack of credit in the model for these methods artificially inflates the importance of depressurization. Additional depressurization methods are not pursued further as the benefit is judged to be small considering the availability of the existing procedures to use the alternate pathways identified above.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-DEPRESS	1.00E+00	1.019	OPERATOR FAILS TO MANUALLY INITIATE AND ALIGN LOW-PRESSURE SYSTEMS	Alternate depressurization methods are not credited for BSEP. The following alternate depressurization paths are available given failure of the normal means: main condenser via the turbine bypass valves, main steam line drains, HPCI, RCIC, SJAE, RFP, RWCU in recirc mode, and RWCU in blowdown mode. Lack of credit in the model for these methods artificially inflates the importance of depressurization. Additional depressurization methods are not pursued further as the benefit is judged to be small considering the availability of the existing procedures to use the alternate pathways identified above.
%2T_DC2A1	2.90E-03	1.019	LOSS OF 125V DC PANEL 2A1	Provide alternate feeds to buses supplied only by panel 2A-1.
DCP0BAT-44ALL	2.19E-07	1.018	COMMON CAUSE FAILURE OF UNIT 1 AND UNIT 2 BATTERIES	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1).
X-AC-18H	1.96E-02	1.018	LOSP RECOVERY 18 HOURS	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
%2TE_E4	2.00E-03	1.018	LOSS OF 4160V AC BUS E4	Provide capability to tie to individual 4kV loads from other E-buses.
EDG2DGN-TM-D004	1.40E-02	1.018	DIESEL GENERATOR 4 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
OPER-GENDISC	1.00E+00	1.017	OPERATORS FAIL TO ESTABLISH BACKFEED	Provide capability to perform the action from the MCR.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
ACP0BKR-44-1234	2.04E-04	1.016	COMMON CAUSE FAILURE OF AT LEAST ONE BREAKER FOR EACH E-BUS	These breakers are related to load sequencer operation for automatic start. Manual start actions would mitigate this failure and they are proceduralized, but not credited. The importance of this event is artificially inflated by not including the manual start actions for the EDGs and no SAMA is judged to be warranted to address this event.
OPER-LLEVEL2	1.00E+00	1.016	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH RCIC DURING ATWS	No suggestions.
SRV2SRV-OO-F013L	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013L FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013K	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013K FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013J	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013J FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013H	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013H FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013G	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013G FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013F	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013F FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013E	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013E FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013D	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013D FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013C	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013C FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013B	1.70E-02	1.016	NON-ADS SAFETY RELIEF VALVE B21-F013B FAILS TO RECLOSE	No suggestions.
SRV2SRV-OO-F013A	1.70E-02	1.016	ADS SAFETY RELIEF VALVE B21-F013A FAILS TO RECLOSE	No suggestions.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
EDG0DGN-44-EDGR	6.19E-04	1.016	COMMON CAUSE FAILURE OF 4 OF 4 DIESEL GENERATORS TO RUN	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
XOP-ALTUNITXC	1.80E-02	1.016	OPER-ALTUNITXC AND NON-OPERS	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1).
EDG1DGN-TM-D001	1.40E-02	1.015	DIESEL GENERATOR 1 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Install an additional Diesel Generator (SAMA 118, Table A-1)
EDG2MDC-44SU2AC	1.22E-03	1.015	COMMON CAUSE FAILURE OF UNIT 2 DG AIR COMPRESSORS TO START	Add a diverse compressor that can be aligned to either unit.
OPER-DC2BALT	1.00E+00	1.015	OPERATOR FAILS TO SWITCH CHARGER TO ALTERNATE AC POWER SUPPLY-UNIT 2	Provide MCR capability to perform action.
DGH0TTE-LOTE1608	4.95E-02	1.014	THERMOSTAT TE-1608 FAILS LOW	Add a diverse logic set and thermocouple powered directly from the EDG.
%2TE_E8	2.00E-03	1.014	LOSS OF 480V AC SUBSTATION E8	Provide MCR capability to perform action to cross-tie to alternate 480v substation (if E8 not faulted).
OPER-FPS1	1.00E+00	1.014	OPERATOR FAILS TO ALIGN FIREWATER FOR COOLANT INJECTION FLOW (ONE UNIT)	Provide MCR capability to perform fire protection injection alignment.
CRD2FLT-PG_S001A	8.23E-02	1.014	FILTER S001A PLUGGED	Provide logic to automatically open the alternate filter path and the bypass on high differential pressure across the running filter.
CRD2FLT-PG_D003A	8.23E-02	1.014	CRD DRIVE WATER FILTER C11/C12-D003A PLUGS	Provide logic to automatically open the alternate filter path and the bypass on high differential pressure across the running filter.
EDG1DGN-TM-D002	1.40E-02	1.014	DIESEL GENERATOR 2 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
%2TE_E7	2.00E-03	1.013	LOSS OF 480V AC SUBSTATION E7	Provide MCR capability to perform action to cross-tie to alternate 480v substation (if E7 not faulted). Provide power to loads directly from other 480v substation.
XOP-COM2-15	1.00E-02	1.013	OPER-LLEVEL2 OPER-DILUTE	Treated separately above.
EDG2DGN-24-DG34R	1.95E-03	1.012	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 3 AND 4	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)
DCP2REC-LP2B2	1.06E-04	1.012	CHARGER 2B-2 FAILS	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TE_E3	2.00E-03	1.012	LOSS OF 4160V AC BUS E3	Provide capability to tie to individual 4kV loads from other E-buses.
DCP2BAT-24A1B2	1.45E-07	1.012	COMMON CAUSE FAILURE OF BATTERY 2A-1 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
FL-PT-N021-HI	1.00E+00	1.012	FLAG - N021 PRESSURE TRANSMITTERS FAILING HIGH	Operator actions already exist to back up the logic failure (manual alignment of the low pressure systems). No suggestions.
DCP2BAT-TM2A1	1.14E-04	1.011	BATTERY 2A-1 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TRCC	1.00E+00	1.011	LOSS OF RBCCW	RBCCW is responsible for CRD pump cooling in the PSA. If the CRD pumps were self cooled, this dependence could be removed.
XOP-DILUTE	4.30E-02	1.011	OPER-DILUTE	A potential enhancement is the improvement of EOPs to reduce the failure probability of injection control. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.

TABLE F-13
LEVEL 1 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
DCP2BAT-TM2B2	1.14E-04	1.011	BATTERY 2B-2 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
DCP2REC-LP2A1	1.06E-04	1.011	CHARGER 2A-1 FAILS	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
%2TF14	3.50E-07	1.011	INTERNAL FLOOD TF14: FAILS CONDENSATE AND FLOODS CABLE SPREADING ROOM	No suggestions.
EDG2DGN-FS-003	6.30E-03	1.011	DIESEL GENERATOR 3 FAILS TO START	Install an additional Diesel Generator (SAMA 118, Table A-1)
DCP2REC-34A1B1B2	2.37E-07	1.011	COMMON CAUSE FAILURE OF CHARGER 2A-1, 2B-1 AND 2B-2	Installation of a portable DC generator for alternate/long term DC availability (SAMA 96, Table A-1). Install an inter-unit DC cross-tie (SAMA 127, Table A-1).
ICC2PTT-CF-ECCSH	1.00E-05	1.01	CCF OF ALL ECCS PRESSURE TRANSMITTERS HIGH	Provide a manual override switch for the ECCS Low Pressure Permissive.
ICC2INV-CF-XUALL	1.08E-06	1.01	CCF OF ALL XU PANEL POWER SUPPLY INVERTERS	Use of portable 120V AC generators could supply power to required panels.
%2TIAN	1.00E+00	1.01	LOSS OF INSTRUMENT AIR	Provide a portable, diesel air compressor that can be connected to the air header.
IAN2MDC-FR_CMPD	9.30E-01	1.01	AIR COMPRESSOR D FAILS TO RUN (ANNUAL)	Provide a portable, diesel air compressor that can be connected to the air header.
EDG1DGN-24-DG12R	1.95E-03	1.01	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1 AND 2	Ensure all buses that can be cross-tied have procedures to perform cross-tie (proceduralize E3 to E4 cross-tie) (SAMAs 95, 100, and 121, Table A-1). Install an additional Diesel Generator (SAMA 118, Table A-1)

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
CAC2PHE-SC-INERT	9.90E-01	1.76	CONTAINMENT INERTED; VENTING NOT REQUIRED	N/A - success event.
TDI2XHE-TM-LPS1	9.00E-01	1.752	OPERATOR FAILS TO RECOVER LOW PRESSURE SYSTEMS	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
CAC2AOV-FN-NOACP	1.00E+00	1.608	NO AC POWER AVAILABLE TO OPEN COMBUSTIBLE GAS VENT VALVES	In the event that AC power was available for venting, the containment would be inerted 99% of the time and venting would be required only 1% of the time. The RRW value implies a risk reduction that is not available. No changes suggested.
%TE_S	2.30E-02	1.565	LOSS OF OFFSITE POWER (SITE)	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2T_T	2.70E+00	1.412	TURBINE TRIP INITIATOR	Addressed in the Level 1 RRW list or subsumed by a similar event.
ACP2XHE-TM-OFFLR	6.30E-01	1.329	OFFSITE AC POWER NOT RECOVERED DURING RX TIME FRAME (IBL)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSLR	1.00E+00	1.329	ONSITE EMERG. AC POWER NOT RECOV. DURING RX TIME FRAME (IBL)	Install a 5th, diverse diesel.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
ACP2XHE-TM-OFFSL	7.60E-01	1.329	OFFSITE AC POWER NOT RECOVERED DURING TD TIME FRAME (IBL)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSTL	1.00E+00	1.329	ONSITE EMERG. AC POWER NOT RECOV. DURING TD TIME FRAME (IBL)	Install a 5th, diverse diesel.
RXM2XHE-TM-INJ	9.00E-01	1.319	OPERATOR FAILS TO RECOVER INJECTION BEFORE RPV MELT	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
OPN2-DEP-OP5-SUC	8.50E-01	1.262	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IBL)	N/A - success event.
BUSFAULT	3.90E-01	1.245	FRACTION OF LOSS OF BUS THAT ARE NON-RECOVERABLE	N/A
RXM2EST-NO-FAIL	1.00E+00	1.239	FAILURE OF RX (CLASS ID, II, IIIA, IV)	This vessel melt event is based on nature of the sequence in which it is used. Alternate injection systems, such as a direct drive diesel pump, may be beneficial in reducing the magnitude of these types of sequences. However, crediting the current alternate systems should be reviewed prior to pursuing these methods.
OPER-ALTINJ	5.40E-01	1.218	OP FAILS TO ALIGN ALT. INJ. SOURCES IN LEVEL2	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
OPN2-DEP-OP1-SUC	9.00E-01	1.197	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IA)	N/A - success event.
TDI2XHE-TM-LPS2	1.00E+00	1.196	OPERATOR FAILS TO RECOVER LOW PRESSURE SYSTEMS	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-ALTUNITXC	1.00E+00	1.175	OPERATORS FAIL TO MANUALLY ALIGN POWER FROM OPPOSITE UNIT	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-FR-003	7.40E-02	1.153	DIESEL GENERATOR 3 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
ACP2XHE-TM-OFFER	5.20E-01	1.15	OFFSITE AC POWER NOT RECOVERED DURING RX TIME FRAME (IBE)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSER	1.00E+00	1.15	ONSITE EMERG. AC POWER NOT RECOV. DURING RX TIME FRAME (IBE)	Install a 5th, diverse diesel.
ACP2XHE-TM-OFFE	6.90E-01	1.15	OFFSITE AC POWER NOT RECOVERED DURING TD TIME FRAME (IBE)	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
ACP2XHE-TM-ONSTE	1.00E+00	1.15	ONSITE EMERG. AC POWER NOT RECOV. DURING TD TIME FRAME (IBE)	Install a 5th, diverse diesel.
DCP2BAT-XXDEP2B	1.00E+00	1.148	BATTERY BANK 2B DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-12H	4.02E-02	1.134	LOSP RECOVERY 12 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
SRV2ALT-DE-METH	1.00E+00	1.133	ALTERNATE DEPRESS. METHODS NOT CREDITED	Alternate depressurization methods are not credited for BSEP. The following alternate depressurization paths are available given failure of the normal means: main condenser via the turbine bypass valves, main steam line drains, HPCI, RCIC, SJAE, RFP, RWCU in recirc mode, and RWCU in blowdown mode. Lack of credit in the model for these methods artificially inflates the importance of depressurization. Additional depressurization methods are not pursued further as the benefit is judged to be small considering the availability of the existing procedures to use the alternate pathways identified above.
SRV2MCS-NO-PRES	9.00E-01	1.133	PRESSURE TRANSIENT DOES NOT FAIL MECHANICAL SYSTEMS	N/A - success event.
SRV2PHE-NO-CMP	2.50E-01	1.133	SRVs DO NOT FAIL OPEN DURING CORE MELT PROGRESSION	No suggestions for cost effective SRV improvement.
SRV2PHE-NO-TEMP	9.00E-01	1.133	HIGH PRIM SYS TEMP DOES NOT CAUSE FAIL OF RCS PRESS. BOUND	N/A - success event.
DCP2REC-XXTRP2A1	1.00E+00	1.133	CHARGER 2A-1 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPN2-DEP-OP7-SUC	9.50E-01	1.131	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IBE)	N/A - success event.
%2T_DC2B2	2.90E-03	1.131	LOSS OF 125V DC PANEL 2B2	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2REC-XXTRP2B2	1.00E+00	1.129	CHARGER 2B-2 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-2H	1.33E-01	1.113	LOSP RECOVERY 2 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DCPALTDC2	1.00E+00	1.113	OPERATOR FAILS TO ALIGN DC BUS TO STANDBY DC POWER SUPPLY - UNIT2	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
NCN2PHE-NO-L1CNT	1.00E+00	1.112	LG CONT. FAILURE GIVEN CONT. FAILED IN LEVEL 1 (CLASS IV)	No suggestions.
DWT2PHE-SC-ATWS	9.90E-01	1.11	DW INTACT FOR ATWS EVENTS (CLASS IV)	N/A - success event.
WWB2PHE-NO-ATWS	5.00E-01	1.11	WW WATER SPACE FAILURE FOR ATWS EVENTS (CLASS IV)	No suggestions.
OPER-480X2	1.00E+00	1.11	OPERATORS FAIL TO MANUALLY CONNECT UNIT 2 SUBSTATIONS E7 AND E8	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-FR-004	7.40E-02	1.105	DIESEL GENERATOR 4 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-XXDEP2A	1.00E+00	1.098	BATTERY BANK 2A DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DEPRESS	1.00E+00	1.094	OPERATOR FAILS TO MANUALLY INITIATE AND ALIGN LOW-PRESSURE SYSTEMS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-COM2-16	7.90E-03	1.091	OPER-DCPALTDC1 OPER-ALTUNITXC OR OPER-DCPALTDC1 OPER-ALTUNITXC	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-16H	2.49E-02	1.09	LOSP RECOVERY 16 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-FR-001	7.40E-02	1.083	DIESEL GENERATOR 1 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV-DEMAND1	6.36E-01	1.079	7 OF 11 SRVS DEMANDED ISOLATION TRANSIENT	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-FR-002	7.40E-02	1.074	DIESEL GENERATOR 2 FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPN2-DEP-OP8-SUC	9.80E-01	1.066	SUCCESSFUL RPV DEPRESSURIZATION (CLASS IVA)	N/A - success event.
RPS2MBIND	1.00E-05	1.064	MECHANICAL BINDING OF CONTROL RODS	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP0BAT-44ALL	2.19E-07	1.064	COMMON CAUSE FAILURE OF UNIT 1 AND UNIT 2 BATTERIES	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
DCP1BAT-XXDEP1A	1.00E+00	1.056	BATTERY BANK 1A DEPLETION FOLLOWING LOSS OF POWER FROM CHARGER	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DILUTE	1.00E+00	1.052	OPERATOR FAILS TO PRECLUDE BORON WASHOUT DURING LOW PRESSURE INJECTION	Addressed in the Level 1 RRW list or subsumed by a similar event.
ICC2LPW-CF-XUALL	3.73E-06	1.044	CCF OF ALL XU POWER SUPPLY PANELS	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DEPRESSRPV	5.20E-01	1.043	OP FAILS TO DEPRESS BEFORE RPV FAILS GIVEN RPV DEPRESS. FAILED IN LVL1	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DGHMAN	1.00E+00	1.04	OPERATORS FAIL TO MANUALLY START EXHAUST FAN	Addressed in the Level 1 RRW list or subsumed by a similar event.
NCN2PHE-NO-LOWTM	5.70E-01	1.038	LG CONT. FAILURE AT LOW DW TEMP. (CLASS I, III WITH NO RPV BREACH OR CLASS II)	No suggestions.
DCP2REC-XXTRP2B1	1.00E+00	1.038	CHARGER 2B-1 TRIPS FOLLOWING TRANSIENT WITH BATTERY FAILURE	Addressed in the Level 1 RRW list or subsumed by a similar event.
CRD2SCRAM	6.00E-06	1.035	FAILURE OF CONTROL ROD DRIVE SCRAM VALVES	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-GENDISC	1.00E+00	1.035	OPERATORS FAIL TO ESTABLISH BACKFEED	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-DGHMAN	6.10E-03	1.033	OPER-DGHMAN	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-1H	2.09E-01	1.031	LOSP RECOVERY 1 HOUR	Addressed in the Level 1 RRW list or subsumed by a similar event.
DWT2PHE-NO-LOWTM	7.80E-01	1.031	DW NOT INTACT AT LOW DW TEMP (CLASS I, III WITH NO RPV BREACH OR CLASS II)	No suggestions.
DCP0REC-44ALL	1.76E-07	1.031	COMMON CAUSE FAILURE OF BOTH UNIT 1 AND UNIT 2 CHARGERS	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-LLEVEL1	1.00E+00	1.03	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH HPCI DURING ATWS	Addressed in the Level 1 RRW list or subsumed by a similar event.
NCN2PHE-LK-LOWTM	4.30E-01	1.03	SM CONT. FAILURE AT LOW DW TEMP. (CLASS I, III WITH NO RPV BREACH OR CLASS II)	No suggestions.
ACP2XHE-TM-POWER	1.00E+00	1.03	OPERATOR FAILS TO RESTORE AC POWER DURING BOIL-OFF	Power recovery may be enhanced by providing the ability to align the UAT to the E-buses from the MCR; however, this is represented by the event OPER-GENDISC. The potential to enhance Off-site power recovery procedures (SAMA 103, Table A-1) may be examined to determine if any realistic benefit could be attained through revisions, but LOOP recovery is governed by off-site conditions and actions. Additional on-site AC power is addressed elsewhere.
OPER-FPS1	1.00E+00	1.029	OPERATOR FAILS TO ALIGN FIREWATER FOR COOLANT INJECTION FLOW (ONE UNIT)	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-ALTINJ2	5.10E-01	1.029	OP FAILS TO ALIGN ALT. INJ. SOURCES IN LEVEL2	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
%2TE_E4	2.00E-03	1.028	LOSS OF 4160V AC BUS E4	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-5H	9.30E-02	1.025	LOSP RECOVERY 5 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
X-AC-18H	1.96E-02	1.025	LOSP RECOVERY 18 HOURS	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-DC2BALT	1.00E+00	1.025	OPERATOR FAILS TO SWITCH CHARGER TO ALTERNATE AC POWER SUPPLY-UNIT 2	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-TM-D003	1.40E-02	1.024	DIESEL GENERATOR 3 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
%2T_C	1.80E-01	1.024	LOSS OF CONDENSER VACUUM	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-44-EDGR	6.19E-04	1.023	COMMON CAUSE FAILURE OF 4 OF 4 DIESEL GENERATORS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TE_U2	1.40E-02	1.022	LOSS OF OFFSITE POWER TO UNIT 2	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TF14	3.50E-07	1.022	INTERNAL FLOOD TF14: FAILS CONDENSATE AND FLOODS CABLE SPREADING ROOM	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-LLEVEL2	1.00E+00	1.021	OPERATOR FAILS TO CONTROL LOWERED WATER LEVEL WITH RCIC DURING ATWS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-ALTUNITXC	1.80E-02	1.021	OPER-ALTUNITXC AND NON-OPERS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-ALTUNITXC1	7.00E-02	1.02	OPER-ALTUNITXC	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2MDC-44SU2AC	1.22E-03	1.019	COMMON CAUSE FAILURE OF UNIT 2 DG AIR COMPRESSORS TO START	Addressed in the Level 1 RRW list or subsumed by a similar event.
CNT2CNT-CO-BYPSS	1.00E+00	1.019	CONTAINMENT ISOLATION FAILURE (CLASS V)	Provide redundant and diverse limit switches to each containment isolation valve.
OPER-SWRHR-C	1.00E+00	1.018	OPERATORS FAIL TO LOCALLY CLOSE THE SW VALVES FOR FW INJECTION	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
XOR-SWRHR-C	1.00E-01	1.018	OPER-SWRHR-C	Addressed as independent event.
ACP0BKR-44-1234	2.04E-04	1.017	COMMON CAUSE FAILURE OF AT LEAST ONE BREAKER FOR EACH E-BUS	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-COM2-15	1.00E-02	1.017	OPER-LLEVEL2 OPER-DILUTE	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TCSW	1.00E+00	1.017	LOSS OF CONVENTIONAL SERVICE WATER	No suggestions.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
RCI2TDP-FR-RCTDP	2.30E-01	1.017	RCIC TURBINE-DRIVEN PUMP FAILS TO RUN	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TF7	1.55E-05	1.017	INTERNAL FLOOD TF7: FAILS ALL PUMPS AT -17 LEVEL	Install a direct drive diesel injection pump and locate it outside of the flood areas. Investigate credit for injection with the fire water system.
OPER-SWRHR-O	1.00E+00	1.016	OPERATORS FAIL TO LOCALLY OPEN THE DISCHARGE VALVES FOR RHR INJECTION	No suggestions. Means of decreasing the operator error rate for injection recovery are difficult to justify, especially after all efforts prior to RPV melt have failed.
XOR-SWRHR-O	1.00E-01	1.016	OPER-SWRHR-O	Addressed as independent event.
EDG2DGN-TM-D004	1.40E-02	1.016	DIESEL GENERATOR 4 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-24-DG34R	1.95E-03	1.016	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 3 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
DGH0TTE-LOTE1608	4.95E-02	1.016	THERMOSTAT TE-1608 FAILS LOW	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TE_E8	2.00E-03	1.016	LOSS OF 480V AC SUBSTATION E8	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TCRD	1.00E+00	1.016	LOSS OF CONTROL ROD DRIVE	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-24A1B2	1.45E-07	1.015	COMMON CAUSE FAILURE OF BATTERY 2A-1 AND 2B-2	Addressed in the Level 1 RRW list or subsumed by a similar event.
SWS2MDP-33_CSW2	7.59E-03	1.015	COMMON CAUSE FAILURE OF ALL UNIT 2 CSW PUMPS TO RUN	Investigate potential improvements in the inter-unit SW cross-ties.
%2T_DC2A1	2.90E-03	1.014	LOSS OF 125V DC PANEL 2A1	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-DILUTE	4.30E-02	1.014	OPER-DILUTE	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-TM-D001	1.40E-02	1.014	DIESEL GENERATOR 1 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-TM2A1	1.14E-04	1.013	BATTERY 2A-1 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
SRV2SRV-OO-F013A	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013A FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013B	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013B FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013C	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013C FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013D	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013D FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013E	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013E FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013F	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013F FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013G	1.70E-02	1.013	NON-ADS SAFETY RELIEF VALVE B21-F013G FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013H	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013H FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013J	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013J FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013K	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013K FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SRV2SRV-OO-F013L	1.70E-02	1.013	ADS SAFETY RELIEF VALVE B21-F013L FAILS TO RECLOSE	Addressed in the Level 1 RRW list or subsumed by a similar event.
SWS2XVN-OC-V442	2.11E-05	1.013	MANUAL VALVE 2 SW V442 FAILS TO REMAIN OPEN	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-FPS1	9.60E-02	1.013	OPER-FPS1	Addressed in the Level 1 RRW list or subsumed by a similar event.
ACP0TFM-LP-E8	3.12E-05	1.013	TRANSFORMER 4160/480 E4 TO E8 FAILURE NO POWER	Provide capability in the main control room to perform 480V AC substation X-tie.
%2TE_E7	2.00E-03	1.012	LOSS OF 480V AC SUBSTATION E7	Addressed in the Level 1 RRW list or subsumed by a similar event.
%2TE_E3	2.00E-03	1.012	LOSS OF 4160V AC BUS E3	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
OPER-FWS-INJ	1.00E+00	1.012	OPERATORS FAIL TO PROPERLY CONTROL CONDENSATE INJECTION FLOW RATE	No suggestions.
EDG1DGN-TM-D002	1.40E-02	1.012	DIESEL GENERATOR 2 UNAVAILABLE DUE TO MAINTENANCE (AT POWER)	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG1DGN-24-DG12R	1.95E-03	1.012	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1 AND 2	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-WVDHR	1.00E+00	1.012	OPERATORS FAIL TO INITIATE WETWELL VENTING FOR DHR	No suggestions.
XOP-WVDHR	1.50E-03	1.012	OPER-WVDHR	No suggestions.
SWS2CKV-OO-V22	5.40E-04	1.012	CHECK VALVE SW V-22 FAILS TO CLOSE	Proceduralize MOV closure from the control room and back-up local operations to isolate flow diversion.
XOP-DEPRESS	6.90E-03	1.012	OPER-DEPRESS	Addressed in the Level 1 RRW list or subsumed by a similar event.
DCP2BAT-TM2B2	1.14E-04	1.011	BATTERY 2B-2 UNAVAILABLE DUE TO TEST OR MAINTENANCE	Addressed in the Level 1 RRW list or subsumed by a similar event.
ICC2INV-CF-XUALL	1.08E-06	1.011	CCF OF ALL XU PANEL POWER SUPPLY INVERTERS	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D123R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1, 2 AND 3	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D124R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENRATORS 1, 2 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D134R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 1, 3 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG0DGN-34-D234R	2.94E-04	1.011	COMMON CAUSE FAILURE TO RUN OF DIESEL GENERATORS 2, 3 AND 4	Addressed in the Level 1 RRW list or subsumed by a similar event.
XOP-GENDISC	1.80E-01	1.011	OPER-GENDISC	Addressed in the Level 1 RRW list or subsumed by a similar event.

TABLE F-14
LEVEL 2 IMPORTANCE LIST REVIEW

Event Name	Probability	RRW	Description	Potential SAMAs
XOP-COM2-14	1.60E-02	1.01	OPER-LLEVEL1 OPER-DILUTE	Addressed in the Level 1 RRW list or subsumed by a similar event.
EDG2DGN-FS-003	6.30E-03	1.01	DIESEL GENERATOR 3 FAILS TO START	Addressed in the Level 1 RRW list or subsumed by a similar event.
OPER-480X1	1.00E+00	1.01	OPERATORS FAIL TO MANUALLY CONNECT UNIT1 SUBSTATIONS E5 AND E6	Provide capability in the main control room to perform 480V AC substation X-tie.

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
1	Salt-spray guards/insulator wash-down	Severe storms can potentially cause shorts in the BSEP switchyard due to salt buildup on the electrical insulators. Potential means of reducing this risk include: 1) A barrier that would block salt spray and prevent buildup on switchyard components, 2) Installation of fresh water sprayers that could be used to prevent buildup of salt during severe weather, and 3) procedures to direct manual washing of switchyard components during severe weather.	Brunswick Level 1 Internal Events RRW Listing	A recovery plan already exists at BSEP to restore the plant to operation after severe weather to wash down the switchyard components (Reference 21). Screened from further analysis.	N/A
2	Portable generator for DC power	DC power availability is important for supporting HPCI/RCIC operation during an SBO. While battery life is limited to about four hours, DC power availability could be extended indefinitely if a portable generator was available to supply power to the required loads. This could be done using an AC generator to supply one of the plant's existing battery chargers (with load shed), or, a DC generator could be used to supply specific DC loads.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this enhancement has been estimated at $489,277 (Progress Energy Staff). This estimate was based on a 480V AC generator required for supplying the station battery chargers. Retained for Phase II analysis.	1

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
3	Inter-unit DC Cross-tie	Failure of a unit's DC power system could be mitigated through the use of a cross-tie to the opposite unit given that the cause of the initial failure is isolated.	Brunswick Level 1 Internal Events RRW Listing	This enhancement is considered to be similar in scope to the addition of an interdivisional AC cross-tie. This cost of implementation has been estimated to be $1,119,000 in Reference 3. Retained for Phase II analysis.	2
4	Provide the Main Control Room with the capability to align the UAT to the "E" buses.	Given a Loss of Off-site Power (LOOP) event with failure of the Startup Auxiliary Transformer (SAT), power can be aligned to the "E" buses by backfeeding through the Unit Auxiliary Transformer (UAT). This action would be desirable given the unavailability of the bus's EDG and failure of a cross-tie to an alternate 4kV bus. Providing controls within the main control room to perform this action reduces the time required to perform the manipulation and simplifies the human action required for successful execution of the alignment.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	The cost of implementation for this enhancement is estimated based on the adjusted cost of installing the remote AC cross-tie in the BSEP main control room in 1993. The scope of this SAMA is considered to be comparable to the remote AC cross-tie enhancement and is used directly after adjusting for inflation. The remote AC cross-tie enhancement capability was implemented between1991 and 1993 at a cost of $341,000 for the site (References 19 and 20). Using an estimated inflation rate of 2.75% per year between 1993 and 2003, the cost in 2003 dollars is $434,775. Retained for Phase II analysis.	3

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
5	Direct drive diesel injection pump	High pressure injection capability could be enhanced through the addition of a direct drive diesel pump. The risk reduction would be greatly enhanced if it was capable of providing the electric power needed to operated the associated injection valves. Additional benefit would be gained if it could be located outside the reactor building or in an area that would preclude flood damage.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	The cost of this SAMA is estimated to be approximately $4,000,000 for the site based on a comparison to the condensate cooling enhancement that was considered for the BSEP Extended Power Uprate (Progress Energy Staff). Retained for Phase II analysis.	4
6	Enhanced/Maximize CRD flow	The off-normal procedures could be modified to direct CRD flow enhancement as a potential high pressure injection method. This would include opening all strainer paths and bypasses to obtain the greatest flow rate from the current pumps. (This appears to be done already, but it is not credited because flow is still not enough for make-up early after SCRAM.)	Brunswick Level 1 and Level 2 Internal Events RRW Listing	Flow maximization is possible at BSEP, but calculations show that use of the maximized flow configuration will not initially maintain reactor vessel level after SCRAM. In order for this SAMA to be effective, hardware changes are required to increase the CRD flowrate. Some flow enhancing changes are considered possible for less than the MMACR and this SAMA is retained for Phase II analysis.	5

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
7	Proceduralize all potential 4kV bus cross-tie actions	Modifying emergency procedures to direct the E3 to E4 cross-tie enhances plant response.	Brunswick Level 1 Internal Events RRW Listing	Progress Energy estimates that the procedure changes, verification and validation, and training for this change would require at least $75,000 given the complexity of the BSEP electrical system. Additional system analysis efforts would require $25,000 for a total of $100,000. Retained for Phase II analysis.	6
8	Improve Off-site power recovery procedures	Improvement of off-site power recovery is a potential means of reducing plant risk. Procedures and recovery techniques may be reviewed to identify potential enhancements.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	BSEP applied the criteria documented in NUMARC 91-04 to screen the plant for vulnerabilities. While no vulnerabilities were found, enhancements were implemented based on the weaknesses identified by the IPE (Reference 17). These enhancements included 1) development of load shed procedures to increase the time to battery depletion, and 2) hardware and procedure changes to allow off-site power restoration via a backfeed from the switchyard through the main and unit auxiliary transformers. No additional procedural improvements have been identified that would provide a measurable increase in off-site power recovery reliability. Screened from further analysis.	N/A - Already Implemented

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
9	Diversify SRVs	Replacing some of the SRVs with an alternate design is a potential means of reducing the common cause failure of the BSEP SRVs.	Brunswick Level 1 Internal Events RRW Listing	Replacement of PWR PORVs with larger components was estimated to cost $2.7 million in Reference 3. This is judged to be approximately the same scope as this SAMA (replace 3 of 7 ADS SRVs). If this estimate is doubled to account for dual unit application, the cost is $5.4 million, which is less than the BSEP MMACR. Retained for Phase II analysis.	7
10	Diversify SRV air header supply check valves	The four check valves which supply the SRV air headers are all of the same design at BSEP. The impact of common cause failure of all four check valves could be reduced by installing solenoid operated valve bypass lines around at least 2 of these valves. This would increase the likelihood that at least one division would be available to supply motive power to the SRVs. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 4/4 failure.	Brunswick Level 1 Internal Events RRW Listing	The installation of two bypass lines per unit is judged to be less than the BSEP MMACR. Retained for Phase II analysis.	8

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
11	Diversify SRV air supply check valves	BSEP includes a CCF event which represents failure of all 22 SRV air supply check valves (B21-V036* and B21-V27*). As CCF of these valves is primarily important to depressurization cases for the BSEP PRA, only 3 SRVs are required for success. Installing solenoid operated valve bypass lines around the air supply check valves for 3 SRVs per unit would provide a means of supplying air to 3 SRVs through a diverse set of valves. This would reduce the impact of 22/22 check valve CCF. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 22/22 failure.	Brunswick Level 1 Internal Events RRW Listing	The replacement of 3 check valves per unit with an alternate design and the increased cost of maintaining a diverse population of valves is judged to potentially be less than the BSEP MMACR. Retained for Phase II analysis.	9

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
12	Improved Procedures/Equipment to Prevent Boron Dilution	Improved procedures and/or training for controlling low pressure injection to prevent boron dilution is a potential means of reducing the risk of ATWS sequences. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	The costs of procedure and training enhancements are less than the BSEP MMACR. The operator action for preventing boron washout and the governing procedures should be reviewed to determine if there are any weaknesses that could potentially be improved. Modification of the LPCI controls is also judged to be less than the MMACR. Retained for Phase II analysis.	10
13	Enhance the Main Control Room (MCR) to include capability to perform 480V AC substation cross-tie	Providing the MCR with the capability to perform the 480V AC substation cross-tie can potentially improve operator reliability. Modification which would allow the action to be performed entirely within the MCR would reduce the time required to perform the action and simplify the manipulations required for the action.	Brunswick Level 1 and Level 2 Internal Events RRW Listing	Modification of the Main Control Room controls and the related equipment changes to allow 480v AC crosstie from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA. This is less than the MMACR. Retained for Phase II analysis.	11

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
14	Enhance the Main Control Room (MCR) to include capability to align the alternate DC power supply to specific DC panels	BSEP includes alternate DC power connections to several DC panels. Currently, aligning the alternate supply to the panel requires local operator action. If the MCR was modified such that the action could be performed without any local action, the time required to perform the action and the types of manipulations associated with the action would be simplified. This could potentially improve the reliability of the action.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this enhancement is estimated based on the adjusted cost of installing the remote AC cross-tie in the BSEP main control room in 1993. The scope of this SAMA is considered to be comparable to the remote AC cross-tie enhancement and is used directly after adjusting for inflation. The remote AC cross-tie enhancement capability was implemented between1991 and 1993 at a cost of $341,000 for the site (References 19 and 20). Using an estimated inflation rate of 2.75% per year between 1993 and 2003, the cost in 2003 dollars is $434,775. This is less that the MMACR and is retained for Phase II analysis.	12
15	Inter-unit CRD cross-tie	Installation of a CRD cross-tie is a potential method of recovering from a loss of CRD on a given unit.	Brunswick Level 1 Internal Events RRW Listing	Modifications to CRD system piping are estimated to be $836,870 (Progress Energy Staff). Retained for Phase II analysis.	13
16	Portable 120V AC generator	CCF of all 120V AC panels has been identified as an important contributor at BSEP. Alignment of portable 120V AC generators to specific loads may reduce plant risk.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this enhancement has been estimated at $84,078 for a single unit site (Reference 16). To account for implementation at both BSEP units, this cost is doubled to yield $168,156. Retained for Phase II analysis.	14

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
17	Diverse EDG HVAC logic	Failure of the HVAC logic to start the EDG room fans or to open exhaust dampers on high temperature could be mitigated through the installation of a diverse set of fan actuation logic. The backup logic would reduce the reliance on operators to perform a fan start on loss of the current logic.	Brunswick Level 1 and Level 2 Internal Events RRW Listing, Edwin I. Hatch Application for License Renewal	The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of implementation would be $200,000, which is less than the MMACR. Retained for Phase II analysis.	15
18	Diverse swing DG air compressor	A shared, diverse, diesel driven air compressor would reduce the impact of CCF of the EDG starting air compressors at BSEP. One compressor could be shared by the two units to reduce costs. Alternatively, 1) a portable compressor could be procured that could be aligned to any of the four diesels at a potentially lower cost, 2) nitrogen bottles could be aligned to provide the pressure source, or 3) the starting air system could be crosstied between units in the event that the opposite unit's systems are available.	Brunswick Level 1 Internal Events RRW Listing	The installation of a portable air compressor is considered to be similar in scope to the installation of a portable power generator. As the portable compressor could be shared between the units and the procedure/training development would be nearly identical, the single unit cost of implementation is used for the BSEP site. Providing the capability to cross-connect EDG air start is not pursued as CCF may fail all compressors. Retained for Phase II analysis.	16

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
19	Provide alternate feeds to panels supplied only by DC bus 2A-1	Installing alternate DC feeds to the loads that are currently only supported by DC panel 2A-1 may reduce plant risk through diversification of the power supplies.	Brunswick Level 1 Internal Events RRW Listing	The cost of implementation for this SAMA could be based on an estimate for installing alternate feeds from the opposite switchboard similar to those that exist for other DC panels; however, a more cost effective solution is judged to be the use of portable generators that can be directly connected to the un-powered DC panels. As noted in Phase II SAMA 1, the cost of implementation for portable generators has been estimated to be $489,277 for the site. This is less than the MMACR and has been retained for Phase II analysis.	17
20	Provide alternate feeds to essential loads directly from an alternate "E" bus	Given the loss of an "E" bus, inclusion of alternate feed lines to specific loads would provide a means of bypassing the faulted bus.	Brunswick Level 1 Internal Events RRW Listing	Modification of the AC system to allow alignment of alternate feeds to the 4kV loads is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA. This is less than the MMACR. Retained for Phase II analysis.	18

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
21	Provide an alternate means of supplying the Instrument Air header	Given the loss of the "D" air compressor in conjunction with the failure of at least two of three reciprocating compressors or their flow paths results in loss of IA. Procurement of an additional, portable compressor that could be aligned to the supply header would reduce the risk of loss of instrument air.	Brunswick Level 1 Internal Events RRW Listing	The cost of this SAMA is judged to be less than $10 million. Retained for Phase II analysis.	19
22	Enhance the Main Control Room (MRC) to include capability to swap AC power supplies to the battery chargers	This enhancement would reduce the time required to perform the power swap and simplify the manipulations required of the operator.	Brunswick Level 1 Internal Events RRW Listing	Modification of the Main Control Room controls and the related equipment changes to allow alignment of the alternate 480v AC supply to the 2B-1 and 2B-2 battery chargers from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	20

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
23	Enhance CRD logic	Inclusion of logic and support components within the CRD system to automate flow path protection would improve CRD availability. Currently, a clogged filter requires local, manual action to restore the flow path after the operator diagnoses the problem. If sensors were included which automatically opened the alternate filter flowpath and the bypass line on high differential pressure across the running filter, the loss of CRD probability could be reduced.	Brunswick Level 1 Internal Events RRW Listing	The logic portion of this change is considered to be similar in scope to the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of installing enhanced CRD logic is estimated to be $200,000. A new MOV has to be installed in the suction filter bypass line and the drive path filter bypass requires both an MOV and new piping. These hardware mods are assumed to cost $75,000 each; thus, for both plants, an additional $300,000 is added to the cost of implementation. The total cost for this SAMA is then $500,000 for the site. As the cost of implementation is less than the MMACR, this SAMA has been retained for Phase II analysis.	21

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
24	Install Self Cooled CRD pumps	The Loss of RBCCW initiating event could be removed from the PSA if the CRD pumps used the process fluid as a cooling mechanism. The CRD pump suction source is the CST, which is an acceptable cooling medium.	Brunswick Level 1 Internal Events RRW Listing	Reference 1 estimates that a suppression pool jockey pump could be installed for about $120,000 per pump and that an additional service water pump could be installed for $6 million per unit. The cost of a installing new, self cooled CRD pumps is judged to be closer to the SP jockey pump cost of implementation than for the addition of SW pump. However, old cooling lines must be removed and capped in addition to installing the new pumps, which will increase the implementation cost. Assuming the pumps can be replaced for $100,000 each and that an additional $50,000 is required to address old cooling line issues per unit, the cost of implementation for this SAMA is $500,000 for the site.	22
25	Additional Diesel Generator	This SAMA would help mitigate LOOP events and would reduce the risk of on-line maintenance. Benefit would be increased if the additional diesel generator could 1) be substituted for any current diesel that is in maintenance and 2) if the diesel was of a diverse design such that common cause failure dependence was minimized.	Brunswick Level 1and Level 2 Internal Events RRW Listing and Brunswick IPE	The cost of installing an additional generator has been estimated to cost significantly greater than $20 million in Reference 3. This is greater than the BSEP MMACR and is screened from further review.	N/A

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
26	Manual Override Switch for the Low Pressure Permissive	Common cause failure of the ECCS pressure transmitters is a potential common cause failure of the ECCS initiation function. If a manual bypass switch were installed, failure of the pressure sensor could be bypassed in a timely manner.	Brunswick Level 1 Internal Events RRW Listing	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing a bypass switch for the low pressure permissive is estimated to be $200,000, which is less than the MMACR. Retained for Phase II analysis.	23
27	Not Used				

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
28	Proceduralize Battery Charger High Voltage Shutdown Circuit Inhibit	Given loss or unavailability of station batteries, voltage transients occurring from the loading and unloading of equipment can cause actuation of the charger high voltage trip circuit. Disabling this circuit when the batteries are disconnected from the DC circuit would prevent this trip and allow the chargers to remain on-line.	General Cutset Review	Procedure changes are less than the BSEP MMACR. Retained for Phase II analysis.	25
29	Enhance Containment Isolation Valve Indication	Providing diverse, redundant limit switches on the containment isolation valves would reduce the potential for faulty valve position indication leading to open containment penetrations.	Brunswick Level 2 Internal Events RRW Listing	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing improved containment isolation valve indication equipment is estimated to be $200,000, which is less than the MMACR. Retained for Phase II analysis.	26
30	Improve Inter-Unit SW Cross-tie	Loss of Service Water pump events could be mitigated if full cross-tie capabilities were implemented at BSEP.	Brunswick Level 2 Internal Events RRW Listing	The cost to install an inter-unit SW cross-tie is estimated to cost less than the BSEP MMACR. Retained for Phase II analysis.	27

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
31	Proceduralize Isolation of Flow Diversion	Failure of a running SW pump combined with a check valve failed in the open position will create a flow diversion. Procedures to isolate a failed pump would reduce the flow diversion risk.	Brunswick Level 2 Internal Events RRW Listing	Procedure changes to include actions failed Service Water pumps are estimated to be $50,000 for the site. Retained for Phase II analysis.	28

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
32	Portable EDG Fuel Oil Transfer Pump	A diverse, engine driven, portable diesel fuel oil transfer pump would provide additional means of supplying the EDG day tank in the event that common cause failure prevents operation of the existing pumps.	Brunswick Level 2 Internal Events RRW Listing	Procurement of a portable fuel oil pump, the associated fuel line, and the required storage space in combination with the development of operating procedures is judged to be similar in scope to SAMA 2. The same cost of implementation could be applied to this SAMA ($84,078). The Progress Energy staff has estimated the cost of implementation for a SAMA with a similar impact on the diesel fuel oil system. A pump bypass line could be installed that would allow a gravity feed from the 4 day diesel fuel oil tank to the diesel day tank (EDG saddle tank). This line would include a manual isolation valve and a throttle valve to control flow to the saddle tank and maintain the required fuel supply for the operating diesel generator. The failure rate assumed for the alignment and operation of the portable fuel oil transfer pump as applied in the SAMA quantification is $1x10^{-2}$. It is judged that the operation of the bypass line would be approximately the same. Given that a plant specific cost estimate for the bypass line is available ($186,861), this estimate is used as a surrogate for this SAMA. Retained for Phase II analysis.	29

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
33	Improve Alternate Shutdown Panel	A large portion of the Internal Fire model sequences includes failure of the operators to control the reactor from the Alternate Shutdown Panel. If the controls on this panel could be upgraded, the failure probability for controlling the plant from the Alternate Shutdown Panel could be reduced. Potential improvements include 1) providing a full set of "B" division controls that are the same as those used in the MCR so that a minimum number of local actions would be required, and 2) provide both "A" and "B" division controls on the Alternate Shutdown Panel.	Brunswick Fire Model Results	Reference 1 estimated the cost of installing enhanced computer aided instrumentation to be about $600,000 in 1994. Upgrading the Alternate Shutdown Panel to contain at least a full complement of "B" division controls is judged to require at least an equal investment of resources. For implementation at both units, $1.2 million in 1994 dollars would be required. Using an estimated inflation rate of 2.75% per year between 1994 and 2003, the cost in 2003 dollars is $1,531,855. As this estimate is less than the BSEP MMACR, it has been retained for Phase II analysis.	30
34	Improved Alternate Shutdown Training and Equipment	Improved training on operating the plant from the alternate shutdown panel may reduce the human error probability for required actions. Improved communication equipment and plans for coordination among local operators may also reduce the error rate.	Brunswick Fire Model Results	Training enhancements, procedural changes, and improved communications systems are estimated to cost less than the BSEP MMACR. Retained for Phase II analysis.	31

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
35	Add Automatic Fire Suppression System	1) The Unit 2 Reactor Building 20' North and South areas contain cable trays that are not protected by an automatic fire suppression system. These fire areas are relatively small contributors to the Brunswick fire induced CDF, but some benefit may be possible through such a change. 2) Automatic CO2 suppression in the control room cabinets may be beneficial. 3) Automatic suppression in the Switchgear Rooms may also reduce risk.	Brunswick Fire Model Results	Fire suppression system expansion is judged to cost less than the BSEP MMARC. Retained for Phase II analysis.	32
36	Prohibit Transient Combustibles in the Cable Spreading Room and/or Require Fire Suppression Personnel to Be Present During Work That May Cause a Fire	Procedures to limit the presence of transient combustibles and ignition sources may reduce the potential for a fire in the Cable Spreading Room. The presence of fire suppression personnel during activities that may start fires would improve the probability that any fire would be quickly suppressed.	Brunswick Fire Model Results	Transient combustibles are already restricted by procedures in the BSEP cable spreading room. In addition, any "hot" work that introduces potential ignition sources to the plant is required to include a fire watch as part of the work team. This SAMA is considered to already be addressed for BSEP.	N/A

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
37	Improve Fire Barriers Between Cabinets in the Cable Spreading Room	Fire proof barriers between the electrical cabinets would reduce fire damage. Fires that start in non-vital cabinets would pose minimal risk as the potential to spread to other cabinets would be greatly decreased.	Brunswick Fire Model Results	Fire barrier improvement is judged to cost less than the BSEP MMARC. Retained for Phase II analysis.	33
38	Add Alternate/Manual Methods for Containment Venting	A large portion of the Internal Fire model sequences includes loss of long term decay heat removal capability. Changes to allow manual operation of the containment vent valves or installation of an independent power supply and controls may enhance the ability to remove decay heat in fire scenarios. Use of portable nitrogen bottles or a portable compressor may also be an option for providing motive power to the valves.	Brunswick Fire Model Results, Quad Cities Application for License Renewal, Dresden Application for License Renewal	This SAMA addresses the same issues as Phase I SAMA 27 and is considered to be subsumed by the corresponding evaluation.	N/A

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
39	Supplemental Power Supplies for Offsite Power Recovery After Battery Depletion During SBO	This would allow the recovery of offsite power after station battery depletion.	Brunswick IPE	DC generators could be used to provide power to operate the power control breakers while a 480V AC generator could supply the air compressors for breaker support. The cost for this enhancement is considered to be equivalent to using portable generators to back up the station batteries. The cost of implementation for that SAMA was estimated to be $489,277 and is also applied to this SAMA. Retained for Phase II analysis.	34
40	Use Firewater as a Backup for EDG Cooling	Loss of NSW and CSW to the EDGs could be mitigated if a backup cooling method was available.	Calvert Cliffs Application for License Renewal, Edwin I. Hatch Application for License Renewal	The cost of this SAMA has been estimated to be about $500,000 per EDG in Reference 3. For BSEP, the cost of implementation for the site is $2 million. Retained for Phase II analysis.	35

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
41	Auto Re-Fill of the CST	This would allow continued injection from HPCI, RCIC, Core Spray, and RHR given unavailability of the suppression pool due to clogging or high temperature.	H. B.. Robinson Application for License Renewal	Re-fill of the CST is not currently credited for BSEP; however, procedures exist for aligning the diesel fire pump for make up, as required. Changes could be made to provide a permanently aligned, automated make-up system, however, sufficient inventory exists in the CST to provide makeup for transients for the 24 hour mission time. For non-transient initiators, the available makeup alignment would not have the capacity to keep up with required flow and the changes required to upgrade the system are considered to be out of scope for this SAMA. Auto-refill of the CST would not provide a significant safety benefit for BSEP and it is screened from further analysis.	N/A
42	Use Firewater as a Backup for Containment Spray	SAMA would provide redundant containment spray function without the cost of installing a new system	Dresden Application for License Renewal	The cost of this enhancement has been estimated to be $565,000 per unit is Reference 3. This estimate is considered to be high for BSEP given the existing flowpath between the firewater and RHR systems. Procedure updates are estimated to cost $50,000 for BSEP and the engineering analysis to support the enhancement is assumed to cost at least $50,000. $100,000 is used for the cost of implementation for the site. Retained for Phase II analysis.	36

TABLE F-15
PHASE I SAMA

PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	PHASE I DISPOSITION	Phase II SAMA ID NUMBER
43	Demonstrate RCIC Operation Following Depressurization	Ensuring operability of RCIC after depressurization would provide the operators with a potential method of injection after depressurization on HCTL. Alternatively, procedures could be revised to stop depressurization at 100 psig to maintain RCIC in a known operational region.	Quad Cities Application for License Renewal	Operation of RCIC regardless of suppression pool cooling would improve low pressure injection capability at BSEP. $200K is estimated to be required for procedural enhancements with engineering analysis and extensive training. These changes are well within the BSEP MMACR. Retained for Phase II analysis.	37
44	Clarify Procedures to Control Containment Venting Near PCPL	Complete blowdown of the containment will reduce the pressure head on the suppression pool and the NPSH for any pumps using the suppression pool as a suction source may drop below the required level. The EOPs could be enhanced to explicitly include directions for the operators to control containment pressure within a band near PCPL. This would prevent loss of pump suction while preventing containment overpressurization.	Quad Cities Application for License Renewal	The BSEP containment vent procedure (0EOP-01-SEP-01) provides directions to throttle the vent valves to maintain containment pressure as dictated by the SCO. Inclusion of this step in the procedure is based on the knowledge that maintaining containment pressure near PCPL may be required to retain the suppression pool as an injection suction source. The intent of this SAMA is judged to be addressed by the current procedures and the addition of an explicit control band may reduce the existing flexibility available to the operations staff. Alterations to include an explicit containment pressure control band in the containment vent procedure is not judged to provide any measurable benefit. Screened from further analysis.	N/A

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
1	2	Portable generator for DC power	DC power availability is important for supporting HPCI/RCIC operation during an SBO. While battery life is limited to about four hours, DC power availability could be extended indefinitely if a portable generator was available to supply power to the required loads. This could be done using an AC generator to supply one of the plant's existing battery chargers (with load shed), or, a DC generator could be used to supply specific DC loads.	(1)	The cost of implementation for this enhancement has been estimated at $489,277 for a single unit site (Progress Energy staff).	Implementation of portable DC generators is estimated to yield an averted cost-risk of $1,912,557, which is substantially greater than the cost of implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.1 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
2	3	Inter-unit DC Cross-tie	Failure of a unit's DC power system could be mitigated through the use of a cross-tie to the opposite unit given that the cause of the initial failure is isolated.	(1)	This enhancement is considered to be similar in scope to the addition of an interdivisional AC cross-tie. This cost of implementation has been estimated to be $1,119,000 in Reference 3.	This enhancement is bounded by Phase II SAMA 1. The benefit of a DC cross-tie is more limited than the portable generators because 1) in SBO conditions, the batteries have a limited life and the chargers are unavailable, 2) the cost of installing the cross-tie hardware is greater than the cost of implementing portable generators, and 3) inter-unit cross-tie presents the potential of failing the DC system on the opposite unit. This SAMA is considered to be subsumed by Phase II SAMA 1 and is not pursued further.	Subsumed by Phase II SAMA 1.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
3	4	Provide the Main Control Room with the capability to align the UAT to the "E" buses.	Given a Loss of Off-site Power (LOOP) event with failure of the Startup Auxiliary Transformer (SAT), power can be aligned to the "E" buses by backfeeding through the Unit Auxiliary Transformer (UAT). This action would be desirable given the unavailability of the bus's EDG and failure of a cross-tie to an alternate 4kV bus. Providing controls within the main control room to perform this action reduces the time required to perform the manipulation and simplifies the human action required for successful execution of the alignment.	(1)	The cost of implementation for this enhancement is estimated based on the adjusted cost of installing the remote AC cross-tie in the BSEP main control room in 1993. The scope of this SAMA is considered to be comparable to the remote AC cross-tie enhancement and is used directly after adjusting for inflation. The remote AC cross-tie enhancement capability was implemented between1991 and 1993 at a cost of $341,000 for the site (References 19 and 20). Using an estimated inflation rate of 2.75% per year between 1993 and 2003, the cost in 2003 dollars is $434,775.	Installation of equipment in the main control room to allow remote alignment of power to the "E" buses through the UAT primarily impacts the manipulation time for this action. Accounting for this reduction in manipulation time results in an averted cost-risk of only $59,244. As this is less than the estimated cost of implementation ($434,775), this SAMA is not cost beneficial.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.2 for additional details.
4	5	Direct drive diesel injection pump	High pressure injection capability could be enhanced through the addition of a direct drive diesel pump. The risk reduction would be greatly enhanced if it was capable of providing the electric power needed to operated the associated injection valves. Additional benefit would be gained if it could be located outside the reactor building or in an area that would preclude flood damage.	(1), (2)	The cost of this SAMA is estimated to be approximately $4,000,000 for the site based on a comparison to the condensate cooling enhancement that was considered for the BSEP Extended Power Uprate (Progress Energy staff).	The averted cost-risk for implementation of a direct drive, high pressure diesel injection pump has been estimated to be $1,299,690 for the BSEP site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.3 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
5	6	Enhanced/Maximize CRD flow	The off-normal procedures could be modified to direct CRD flow enhancement as a potential high pressure injection method. This would include opening all strainer paths and bypasses to obtain the greatest flow rate from the current pumps. (This appear to be done already, but it is not credited because flow is still not enough for make-up early after SCRAM.)	(1), (2)	The existing piping system cannot handle any significant increased flow. The capacity is approximately 200 gpm, vs 500+ gpm that would be needed for a Small Break Loss of Coolant Accident. Also, significant electrical work would be needed for an upgrade. By engineering judgement, this SAMA is concluded to be prohibitively expensive.	The averted cost-risk for implementation of enhanced CRD has been estimated to be $1,069,849 for the BSEP site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.4 for additional details.
6	7	Proceduralize all potential 4kV bus cross-tie actions	Modifying emergency procedures to direct the E3 to E4 cross-tie enhances plant response.	(1)	Progress Energy estimates that the procedure changes, verification and validation, and training for this change would require at least $75,000 given the complexity of the BSEP electrical system. Additional system analysis efforts would require $25,000 for a total of $100,000.	Incorporation of the additional cross-tie credit has a limited impact due to the existing common mode failures between the inter-divisional bus cross-tie and the inter-unit cross-tie. The results of a model run indicate that the averted cost-risk for this SAMA is $63,969, which is less than the cost of implementation.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.5 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
7	9	Diversify SRVs	Replacing some of the SRVs with an alternate design is a potential means of reducing the common cause failure of the BSEP SRVs.	(1)	Replacement of PWR PORVs with larger components was estimated to cost $2.7 million in Reference 3. This is judged to be approximately the same scope as this SAMA (replace 5 of 11 SRVs). If this estimate is doubled to account for dual unit application, the cost is $5.4 million.	The RRW for common cause failure of 5 of 11 SRVs is 1.050 based on CDF. For Level 2 contributors, it is only 1.003. Implementation of this SAMA has been approximated by 1) assuming that replacement of 5 of 11 SRVs will eliminate the CCF event used to identify this SAMA, 2) that the impact on external events is the same as it is for internal events, and 3) the Level 2 impact can be estimated by applying the RRW factor of 1.003 to the Dose-Risk and Economic Cost-Risk results. The resulting averted cost-risk is only $251,314 for the site and the SAMA's net value is -$5,148,686. In addition, use of alternate valves that are subjected to the same conditions to perform the same function in the same system does not necessarily preclude the effects of CCF.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
8	10	Diversify SRV air header supply check valves	The four check valves which supply the SRV air headers are all of the same design at BSEP. The impact of common cause failure of all four check valves could be reduced by installing solenoid operated valve bypass lines around at least 2 of these valves. This would increase the likelihood that at least one division would be available to supply motive power to the SRVs. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 4/4 failure.	(1)	The cost of installing 2 bypass lines with solenoid operated valves per unit is estimated to be greater than $500,000 assuming $100,000 for each valve and replacement labor and at least $100,000 in analysis and documentation updates.	The RRW for common cause failure of 4 of 4 SRV air header supply check valves is 1.049 based on CDF. For Level 2 contributors, it is only 1.0. Implementation of this SAMA has been approximated by 1) assuming that use of the bypass lines will eliminate the CCF event used to identify this SAMA, and 2) that the impact on external events is the same as it is for internal events. The resulting averted cost-risk is only $237,322 for the site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
9	11	Diversify SRV air supply check valves	BSEP includes a CCF event which represents failure of all 22 SRV air supply check valves (B21-V036* and B21-V27*). As CCF of these valves is primarily important to depressurization cases for the BSEP PRA, only 3 SRVs are required for success. Installing solenoid operated valve bypass lines around the air supply check valves for 3 SRVs per unit would provide a means of supplying air to 3 SRVs through a diverse set of valves. This would reduce the impact of 22/22 check valve CCF. Simply replacing the check valves with check valves of a different design is not considered to alter the common cause group enough to preclude 22/22 failure.	(1)	The cost of installing 3 bypass lines with solenoid operated valves per unit is estimated to be greater than $700,000 assuming $100,000 for each valve and replacement labor and at least $100,000 for analysis and documentation updates.	The RRW for common cause failure of 22 of 22 SRV air supply check valves is 1.049 based on CDF. For Level 2 contributors, it is only 1.0. Implementation of this SAMA has been approximated by 1) assuming that installation of the bypass lines will eliminate the global CCF event used to identify this SAMA, and 2) that the impact on external events is the same as it is for internal events. The resulting averted cost-risk is only $237,322 for the site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
10	12	Improved Procedures/Equipment to Prevent Boron Dilution	Improved procedures and/or training for controlling low pressure injection to prevent boron dilution is a potential means of reducing the risk of ATWS sequences. An additional potential enhancement is the installation of a control system for LPCI that would allow the operators to dial in the desired flowrate and thereby improving the man-machine interface.	(1), (2)	Modification of the Main Control Room controls and the related equipment changes to the pumps, logic, and instrumentation to support "dial-in" flow control for LPCI is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Review of the EOPs confirmed that clear guidance exists on controlling injection flow in an ATWS and no enhancements were identified that would yield a measurable benefit. Installation of a dial in flow control for LPCI was judged to be a potential means of improving man-machine interface. The impact of this enhancement was quantified and determined to yield an averted cost-risk of $74,834 for the site. This is less than the cost of implementation and has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.6 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
11	13	Enhance the Main Control Room (MRC) to include capability to perform 480V AC substation cross-tie	Providing the MCR with the capability to perform the 480V AC substation cross-tie can potentially improve operator reliability. Modifications which would allow the action to be performed entirely within the MCR would reduce the time required to perform the action and simplify the manipulations required for the action.	(1), (2)	Modification of the Main Control Room controls and the related equipment changes to allow 480v AC crosstie from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Installation of equipment in the main control room to allow remote alignment of the 480v AC crossties reduces the action's manipulation time, improves man-machine interface, and reduces the control manipulations for this action. The estimated averted cost-risk associated with this SAMA is $203,666. As this is less than the estimated cost of implementation ($434,775), this SAMA is not cost beneficial.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.7 for additional information.
12	14	Enhance the Main Control Room (MCR) to include capability to align the alternate DC power supply to specific DC panels	BSEP includes alternate DC power connections to several DC panels. Currently, aligning the alternate supply to the panel requires local operator action. If the MCR was modified such that the action could be performed without any local action, the time required to perform the action and the types of manipulations associated with the action would be simplified. This could potentially improve the reliability of the action.	(1)	Modification of the Main Control Room controls and the related equipment changes to allow alternate DC power alignment from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Installation of equipment in the main control room to allow remote alignment of the alternate DC power supplies reduces the action's manipulation time and improves man-machine interface for this action. The estimated averted cost-risk associated with this SAMA is $133,035. As this is less than the estimated cost of implementation ($434,775), this SAMA is not cost beneficial.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.8 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
13	15	Inter-unit CRD cross-tie	Installation of a CRD cross-tie is a potential method of recovering from a loss of CRD on a given unit.	(1)	Modifications to CRD system piping are estimated to be $836,870 (Progress Energy staff).	Installation of an inter-unit CRD cross-tie would provide an additional high pressure injection method. The estimated averted cost-risk associated with implementation of this SAMA is $818,664.	The cost of implementation is more than the averted cost-risk for this SAMA. Refer to Section F.6.9 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
14	16	Portable 120V AC generator	CCF of all 120V AC panels has been identified as an important contributor at BSEP. Alignment of portable 120V AC generators to specific loads may reduce plant risk.	(1)	The cost of implementation for this enhancement has been estimated at $84,078 for a single unit site (Reference 16). To account for implementation at both BSEP units, this cost is doubled to yield $168,156.	Loss of the 120v AC panels is important for Medium LOCA sequences with no injection. The time to core damage for these sequences is only about 11 minutes (MAAP Run BR0026), which is less than the 1 hour manipulation time required for portable generator alignment taken from an industry example. It should be noted that this alignment time is for a single generator alignment to a single panel whereas this SAMA would potentially require multiple generator alignment to several panels. The importance of 120v AC panel failure may also be exaggerated for BSEP given that manual initiation of injection systems is not credited on RPS failure. This SAMA is not an effective means of reducing plant risk and is screened from further consideration.	Screened from further consideration. No significant benefit.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
15	17	Diverse EDG HVAC logic	Failure of the HVAC logic to start the EDG room fans or to open exhaust dampers on high temperature could be mitigated through the installation of a diverse set of fan actuation logic. The backup logic would reduce the reliance on operators to perform a fan start on loss of the current logic.	(1), (2), (3)	The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of implementation would be $200,000.	The impact of adding an additional logic train to the EDG HVAC system has been quantified assuming a lumped event for an alternate logic train. The risk reduction is commensurate with the RRW value for the event used to identify this SAMA and the associated averted cost-risk has been estimated to be $267,916. As the cost implementation is less than the averted cost-risk, this SAMA has been retained for potential implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.10 for additional details.
16	18	Diverse swing DG air compressor	A shared, diverse, diesel driven air compressor would reduce the impact of CCF of the EDG starting air compressors at BSEP. One compressor could be shared by the two units to reduce costs. Alternatively, 1) a portable compressor could be procured that could be aligned to any of the four diesels at a potentially lower cost, or 2) nitrogen bottles could be aligned to provide the pressure source.	(1)	The installation of a portable air compressor is considered to be similar in scope to the installation of a portable power generator. As the portable compressor could be shared between the units and the procedure/training development would be nearly identical, the single unit cost of implementation is used for the BSEP site. Providing the capability to cross-connect EDG air start is not pursued as CCF may fail all compressors. Retained for Phase II analysis.	The impact of adding the capability to align a portable air compressor to the EDG starting air system has been estimated to yield an averted cost-risk of $135,817. As the cost implementation is less than the averted cost-risk, this SAMA has been retained for potential implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.11 for additional details.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
17	19	Provide alternate feeds to panels supplied only by DC bus 2A-1	Installing alternate DC feeds to the loads that are currently only supported by DC panel 2A-1 may reduce plant risk through diversification of the power supplies.	(1)	The cost of implementation for this SAMA could be based on an estimate for installing alternate feeds from the opposite switchboard similar to those that exist for other DC panels; however, a more cost effective solution is judged to be the use of portable generators that can be directly connected to the un-powered DC panels. As noted in Phase II SAMA 1, the cost of implementation for portable generators has been estimated to be $489,277 for the site.	The averted cost-risk for this SAMA has been estimated to be $1,566,562. As this estimate is greater than the cost of implementation, it has been retained for possible implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.12 for additional details.
18	20	Provide alternate feeds to essential loads directly from an alternate "E" bus	Given the loss of an "E" bus, inclusion of alternate feed lines to specific loads would provide a means of bypassing the faulted bus.	(1)	Modification of the AC system to allow alignment of alternate feeds to the 4kV loads is considered to be greater in scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used as a lower bound for the implementation cost for this SAMA.	The averted cost-risk associated with providing the capability to align alternate feeds to required 4kV loads has been estimated to be $359,314. This is less than the cost of implementation estimated for this SAMA and is screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.13 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
19	21	Provide an alternate means of supplying the Instrument Air header	Given the loss of the "D" air compressor in conjunction with the failure of at least two of three reciprocating compressors or their flow paths results in loss of IA. Procurement of an additional, portable compressor that could be aligned to the supply header would reduce the risk of loss of instrument air.	(1)	The scope of this SAMA is considered to be similar in scope to Phase II SAMA 1. The cost of implementation for that SAMA is used as a surrogate for the portable air compressor that is analyzed here.	The addition of an alternate compressor reduces the risk of loss of instrument air scenarios. The averted cost-associated with the installation of an engine driven air compressor is $637,723.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.14 for additional information.
20	22	Enhance the Main Control Room (MRC) to include capability to swap AC power supplies to the battery chargers	This enhancement would reduce the time required to perform the power swap and simplify the manipulations required of the operator.	(1)	Modification of the Main Control Room controls and the related equipment changes to allow alignment of the alternate 480v AC supply to the 2B-1 and 2B-2 battery chargers from within the MCR is considered to be approximately the same scope as the BSEP AC Crosstie modification documented in References 19 and 20. As described in Phase I SAMA 4, the implementation cost for the AC Crosstie mod is estimated to be $434,775. This estimate is also used for the implementation cost for this SAMA.	Credit is not currently taken for the alternate power alignment action for the chargers. Directions exist for this action in the auxiliary safe shutdown procedures, but are not included in the normal EOPs. This SAMA assumes that the action is made available to the operators for any condition requiring alternate feed to the chargers and that the MCR in enhanced to include controls to perform the alignment. The estimated cost-risk associated with this enhancement is $165,307. As this is less than the cost of implementation, it is screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.15 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
21	23	Enhance CRD logic	Inclusion of logic and support components within the CRD system to automate flow path protection would improve CRD availability. Currently, a clogged filter requires local, manual action to restore the flow path after the operator diagnoses the problem. If sensors were included which automatically opened the alternate filter flowpath and the bypass line on high differential pressure across the running filter, the loss of CRD probability could be reduced.	(1)	The logic portion of this change is considered to be similar in scope to the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the cost of installing enhanced CRD logic is estimated to be $200,000. A new MOV has to be installed in the suction filter bypass line and the drive path filter bypass requires both an MOV and new piping. These hardware mods are assumed to cost $75,000 each; thus, for both plants, an additional $300,000 is added to the cost of implementation. The total cost for this SAMA is then $500,000 for the site.	This SAMA accounts for installation of the logic and required flowpath elements to allow automatic bypass of CRD suction and drive path filter clogging events. Both the "A" and "B" trains are assumed to be equipped with this capability. The averted cost-risk associated with this SAMA has been estimated to be $246,707. As this is less than the cost of implementation, this SAMA has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.16 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
22	24	Install Self Cooled CRD pumps	The Loss of RBCCW initiating event could be removed from the PSA if the CRD pumps used the process fluid as a cooling mechanism. The CRD pump suction source is the CST, which is an acceptable cooling medium.	(1)	Reference 1 estimates that a suppression pool jockey pump could be installed for about $120,000 per pump and that an additional service water pump could be installed for $6 million per unit. The cost of a installing new, self cooled CRD pumps is judged to be closer to the SP jockey pump cost of implementation than for the addition of SW pump. However, old cooling lines must be removed and capped in addition to installing the new pumps, which will increase the implementation cost. Assuming the pumps can be replaced for $100,000 each and that an additional $50,000 is required to address old cooling line issues per unit, the cost of implementation for this SAMA is $500,000 for the site.	The averted cost-risk associated with removing the cooling dependency from CRD and removing the loss of RBCCW initiating event from the model is only $153,398 for the site. This is less than the cost of implementation and is screened from further consideration.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.17 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
23	26	Manual Override Switch for the Low Pressure Permissive	Common cause failure of the ECCS pressure transmitters is a potential common cause failure of the ECCS initiation function. If a manual bypass switch were installed, failure of the pressure sensor could be bypassed in a timely manner.	(1)	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing a bypass switch for the low pressure permissive is estimated to be $200,000.	The RRW value for CCF of the ECCS pressure sensors is 1.01 based on CDF and is only included in cutsets below the truncation limit for the Level 2 quantification. The averted cost-risk associated with this low RRW value is $47,464 for the site. As this is less than the estimated cost of implementation, it has been excluded from further consideration.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.
24	27	Not used.					
25	28	Proceduralize Battery Charger High Voltage Shutdown Circuit Inhibit	Given loss or unavailability of station batteries, voltage transients occurring from the loading and unloading of equipment can cause actuation of the charger high voltage trip circuit. Disabling this circuit when the batteries are disconnected from the DC circuit would prevent this trip and allow the chargers to remain on-line.	(9)	$50,000 to $100,000 is estimated to be required for procedure updates.	Assuming a failure rate of $5x10^{-2}$ for the performance of the proposed logic bypass procedure, the averted cost-risk is estimate to be $463,930. As the averted cost-risk is greater than the cost of implementation, this SAMA is retained for further consideration.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.26 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
26	29	Enhance Containment Isolation Valve Indication	Providing diverse, redundant limit switches on the containment isolation valves would reduce the potential for faulty valve position indication leading to open containment penetrations.	(2)	This change is considered to be of more limited scope than the inclusion of a redundant train of EDG building HVAC logic. The cost of installing redundant temperature alarms/thermostats and supporting logic was estimated to be $100,000 per unit in Reference 5. Accounting for both units at BSEP, the upper bound cost of installing improved containment isolation valve indication equipment is estimated to be $200,000.	Based on cutset analysis, removal of containment isolation failures has an associated averted cost risk of only about $129,924 for the site. This estimate is based on elimination the 2.99E-7/yr containment bypass contribution to the core damage frequency and high-early release frequency. The true benefit of SAMAs related to ISLOCA mitigation is more limited than this estimate as any proposed measure would not be 100 percent effective in mitigating these accidents. As the estimated averted cost risk is less than the cost of implementation for this SAMA, it has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
27	30	Improve Inter-Unit SW Cross-tie	Loss of Service Water pump events could be mitigated if full cross-tie capabilities were implemented at BSEP.	(2)	The cost to install an inter-unit SW cross-tie is estimated to cost at least $100,000 per unit due to the need for the hardware modifications related to piping changes.	Service Water Common Cause Failure event used to identify this SAMA has an RRW value of 1.007 for CDF and 1.015 for the dominant Level 2 contributors. This corresponds to an averted cost-risk of only $103,491 for the site. This is less than the $200,000 cost estimated for this SAMA and is screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA.
28	31	Proceduralize Isolation of Flow Diversion	Failure of a running SW pump combined with a check valve failed in the open position will create a flow diversion. Procedures to isolate a failed pump would reduce the flow diversion risk.	(2)	Not Estimated.	The Brunswick abnormal operating procedures already include steps to isolate the discharge valves of any pumps that are not running; however, no credit is taken for this isolation action in the current BSEP PRA model. As this action is already directed and because the importance of flow divergence is artificially inflated by model conservatisms, this SAMA is screened from further analysis.	Screened from further analysis. Already Implemented.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
29	32	Portable EDG Fuel Oil Transfer Pump	A diverse, engine driven, portable diesel fuel oil transfer pump would provide additional means of supplying the EDG day tank in the event that common cause failure prevents operation of the existing pumps.	(2)	Procurement of a portable fuel oil pump, the associated fuel line, and the required storage space in combination with the development of operating procedures is judged to be similar in scope to SAMA 2. The same cost of implementation could be applied to this SAMA ($84,078). The Progress Energy staff has estimated the cost of implementation for a SAMA with a similar impact on the diesel fuel oil system. A pump bypass line could be installed that would allow a gravity feed from the 4 day diesel fuel oil tank to the diesel day tank (EDG saddle tank). This line would include a manual isolation valve and a throttle valve to control flow to the saddle tank and maintain the required fuel supply for the operating diesel generator. The failure rate assumed for the alignment and operation of the portable fuel oil transfer pump as applied in the SAMA quantification is $1x10^{-2}$. It is judged that the operation of the bypass line would be approximately the same. Given that a plant specific cost estimate for the bypass line is available ($186,861), this estimate is used as a surrogate for this SAMA.	The PSA model was modified to include the capability of aligning a portable fuel oil transfer pump to provide makeup to the DG day tanks given failure of the normal pumps. Assuming a lumped failure probability for the pump and operator action to align the equipment, the associated averted cost-risk is $250,281. As this is greater than the associated cost of implementation, it has been retained for potential implementation.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.18 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
30	33	Improve Alternate Shutdown Panel	A large portion of the Internal Fire model sequences includes failure of the operators to control the reactor from the Alternate Shutdown Panel. If the controls on this panel could be upgraded, the failure probability for controlling the plant from the Alternate Shutdown Panel could be reduced. Potential improvements include 1) providing a full set of "B" division controls that are the same as those used in the MCR so that a minimum number of local actions would be required, and 2) provide both "A" and "B" division controls on the Alternate Shutdown Panel.	(4)	Reference 1 estimated the cost of installing enhanced computer aided instrumentation to be about $600,000 in 1994. Upgrading the Alternate Shutdown Panel to contain at least a full complement of "B" division controls is judged to require at least an equal investment of resources. For implementation at both units, $1.2 million in 1994 dollars would be required. Using an estimated inflation rate of 2.75% per year between 1994 and 2003, the cost in 2003 dollars is $1,531,855.	The averted cost risk for this SAMA has been estimated to be $1,235,829. As this is less than the estimated cost of implementation, it has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.19 for additional information.
31	34	Improved Alternate Shutdown Training and Equipment	Improved training on operating the plant from the alternate shutdown panel may reduce the human error probability for required actions. Improved communication equipment and plans for coordination among local operators may also reduce the error rate.	(4)	This SAMA would require an estimated $250,000 in procedure development work, as well as substantial operator training, including some dose cost, in addition to equipment (Progress Energy staff).	Assuming that improved communication equipment and further training on alternate shutdown practices will result in a 10 percent improvement in the alternate shutdown failure rate yields an averted cost-risk of $154,479.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.20 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
32	35	Add Automatic Fire Suppression System	1) The Unit 2 Reactor Building 20' North and South areas contain cable trays that are not protected by an automatic fire suppression system. These fire areas are relatively small contributors to the Brunswick fire induced CDF, but some benefit may be possible through such a change. 2) Automatic CO2 suppression in the control room cabinets may be beneficial. 3) Automatic suppression in the Switchgear Rooms may also reduce risk.	(4)	Implementation of this SAMA would effectively involve three medium-size and –complexity modifications. Engineering judgement yields an estimate of approximately $750,000 for the engineering for these modifications to the two BSEP units (Progress Energy staff).	Automatic suppression systems are not considered to be effective risk reduction means for the MCR or switchgear rooms. The averted cost-risk of installing a Halon system in the reactor building 20' North and South areas has been estimated to be $447,460 for the site.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.21 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
33	37	Improve Fire Barriers Between Cabinets in the Cable Spreading Room	Fire proof barriers between the electrical cabinets would reduce fire damage. Fires that start in non-vital cabinets would pose minimal risk as the potential to spread to other cabinets would be greatly decreased.	(4)	Not Estimated.	Cable spreading room fires account for only $154,607 of the estimated $3,595,500 in fire related cost-risk. Based on a review of the IPEEE information related to fire spreading in the cable spreading room, only 2.8 percent of this CDF contribution could be mitigated through the addition of fire barriers. This corresponds to approximately $4,329, which is less than any credible hardware modification cost. Screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.22 for additional information.
34	39	Supplemental Power Supplies for Off-Site Power Recovery After Battery Depletion During SBO	This would allow the recovery of offsite power after station battery depletion.	(5)	DC generators could be used to provide power to operate the power control breakers while a 480v AC generator could supply line compressors for breaker support. The cost for this enhancement is considered to be equivalent to using portable generators to back up the station batteries. The cost of implementation for that SAMA was estimated to be $489,277 and is also applied to this SAMA.	Allowing longer times for AC power recovery after battery depletion in an SBO based on switchyard power support yields an estimated cost-risk of $485,509. This is less than the cost of implementation.	The cost of implementation is more than the averted cost-risk for this SAMA. Refer to Section F.6.27 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
35	40	Use Firewater as a Backup for EDG Cooling	Loss of NSW and CSW to the EDGs could be mitigated if a backup cooling method was available.	(3), (6)	The cost of this SAMA has been estimated to be about $500,000 per EDG in Reference 3. For BSEP, the cost of implementation for the site is $2 million.	Plant changes to allow alignment of the Firewater system for alternate EDG cooling provides a means of supporting EDG operation given loss of Service Water. For BSEP, the Service Water system is diverse and provides a reliable source of cooling to the EDGs and the implementation of an alternate cooling method has a limited impact. The estimated averted cost-risk of this SAMA is $80,442. As this is less than the cost of implementation, it has been screened from further analysis.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.23 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
36	42	Use Firewater as a Backup for Containment Spray	SAMA would provide redundant containment spray function without the cost of installing a new system	(7)	The cost of this enhancement has been estimated to be $50,000 for procedure changes and an additional $50,000 for analysis to support the change for the site.	Containment spray is important because it (1) provides a means of scrubbing fission products that are not otherwise scrubbed (e.g., in the case where the suppression pool is bypassed); and, (2) providing water to cool the core debris on the drywell floor to limit non-condensable gas generation and to limit drywell heating and the associated temperature induced failures that can lead to containment failure. Assuming that the 120 psig Fire Protection system can provide the required 1000 gpm flow, the impact is limited due to the dependence on the containment spray valves. The estimated cost-risk for this SAMA is $163,166 for the site. As this is greater than the cost of implementation, this SAMA has been retained for further analysis.	Retained for further consideration. The cost of implementation is less than the averted cost-risk for this SAMA. Refer to Section F.6.24 for additional information.

TABLE F-16
PHASE II SAMA

PHASE II SAMA ID NUMBER	PHASE I SAMA ID NUMBER	SAMA TITLE	SAMA DESCRIPTION	SOURCE	ESTIMATED COST	COMMENT	PHASE II DISPOSITION
37	43	Demonstrate RCIC Operation Following Depressurization	Ensuring operability of RCIC after depressurization would provide the operators with a potential method of injection after depressurization on HCTL. Alternatively, procedures could be revised to stop depressurization at 100 psig to maintain RCIC in a known operational region.	(8)	Operation of RCIC regardless of suppression pool cooling would improve low pressure injection capability at BSEP. $200K is estimated to be required for procedural enhancements with engineering analysis and extensive training to support the enhancement.	Given the dependence of RCIC on DC power for operation in SBO sequences and the fact that HCTL challenges will not occur until after battery depletion, this SAMA will not provide benefit to Brunswick in an SBO. However, some benefit exists non-SBO cases. The BSEP model was changed to reflect the added capability of RCIC to run at low pressure. The results indicate an averted cost-risk of $51,963. As this is less than the cost of implementation, this SAMA has been screened from further consideration.	Screened from further consideration. The cost of implementation is greater than the averted cost-risk for this SAMA. Refer to Section F.6.25 for additional information.

(1) Brunswick Level 1 Internal Events RRW Listing
(2) Brunswick Level 2 Internal Events RRW Listing
(3) Edwin I. Hatch Application for License Renewal
(4) Brunswick Fire Model Results
(5) Brunswick IPE
(6) Calvert Cliffs Application for License Renewal
(7) Dresden Application for License Renewal
(8) Quad Cities Application for License Renewal
(9) General Cutset Review

Figure F-1
SAMA Screening Process

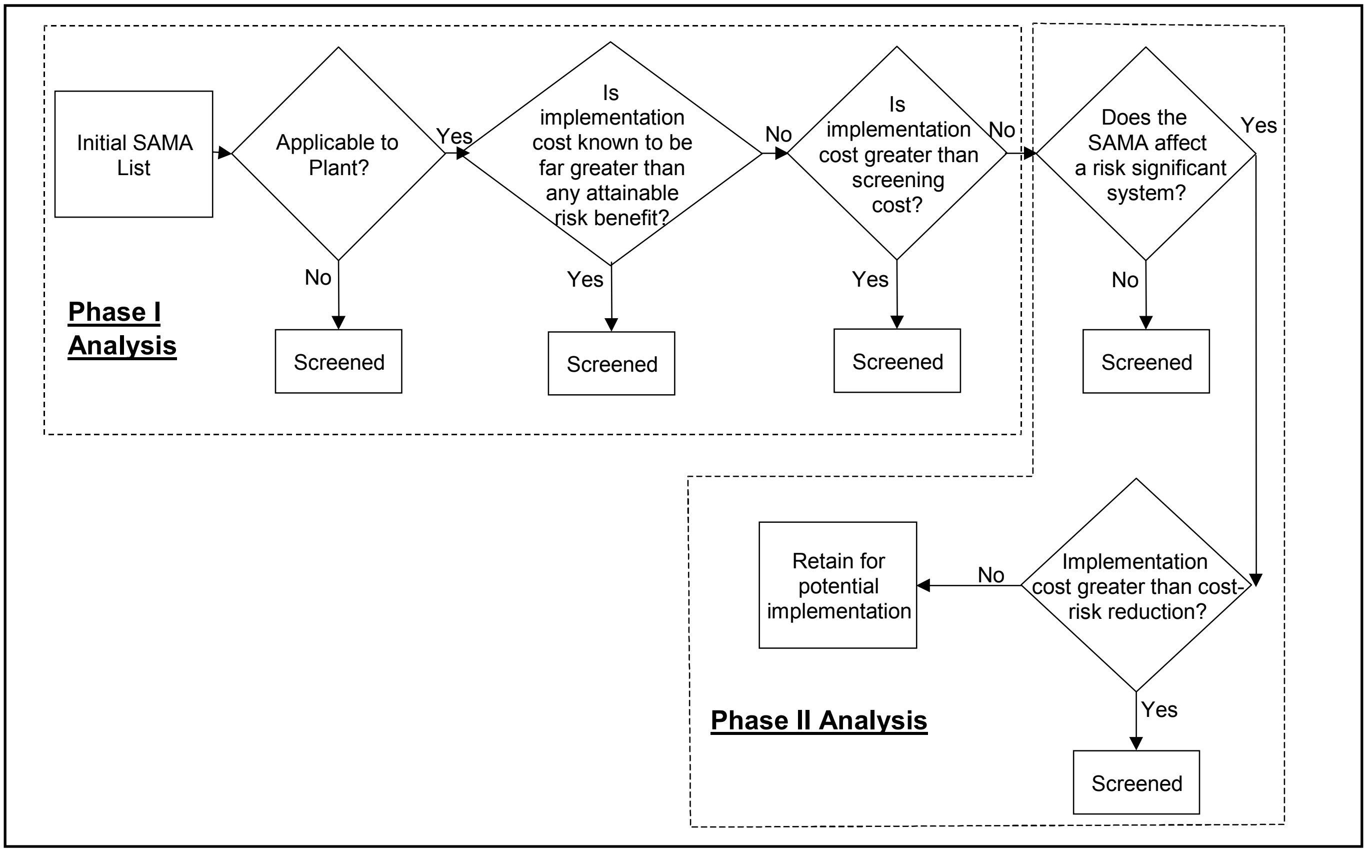


Figure F-2
Brunswick Unit 2 MOR03
Contribution to CDF by Initiator

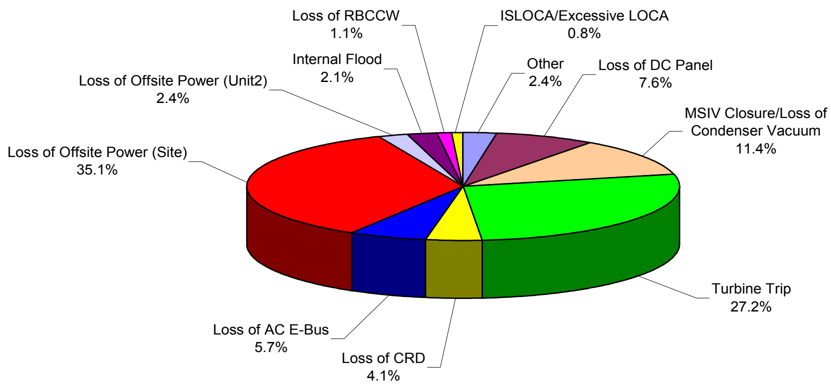


Figure F-3
Contribution to CDF by System

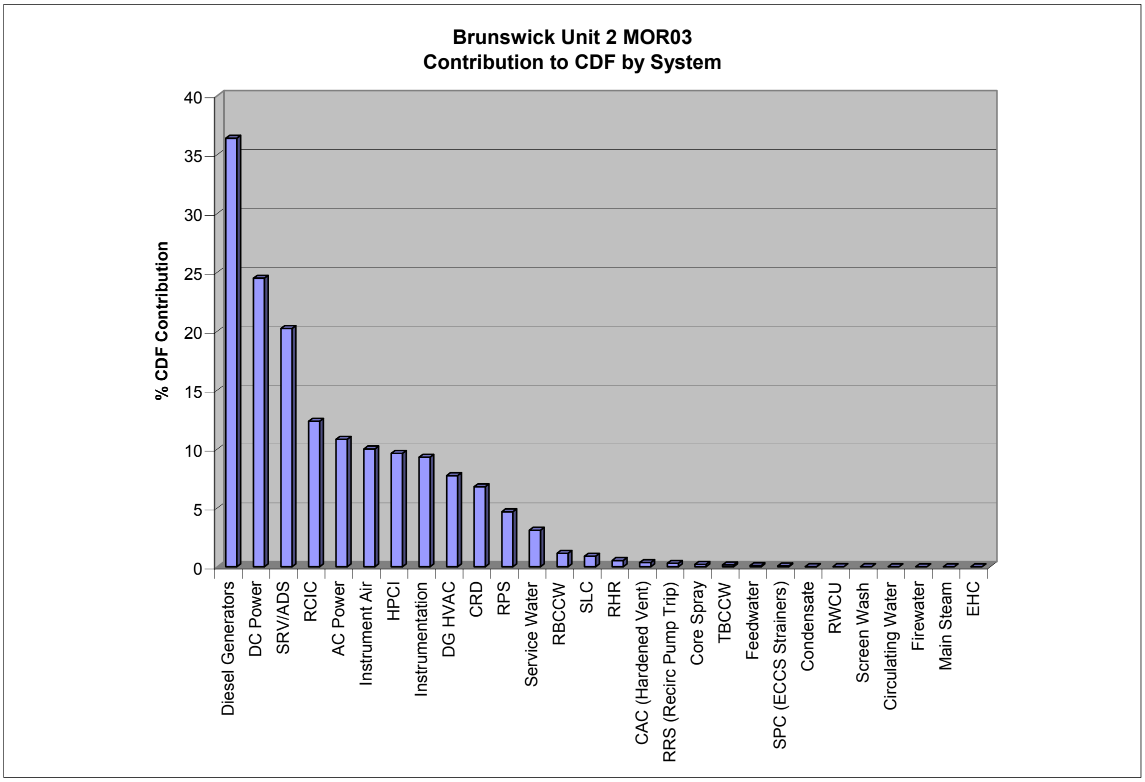


Figure F-4
System RAW Ranking (CDF)

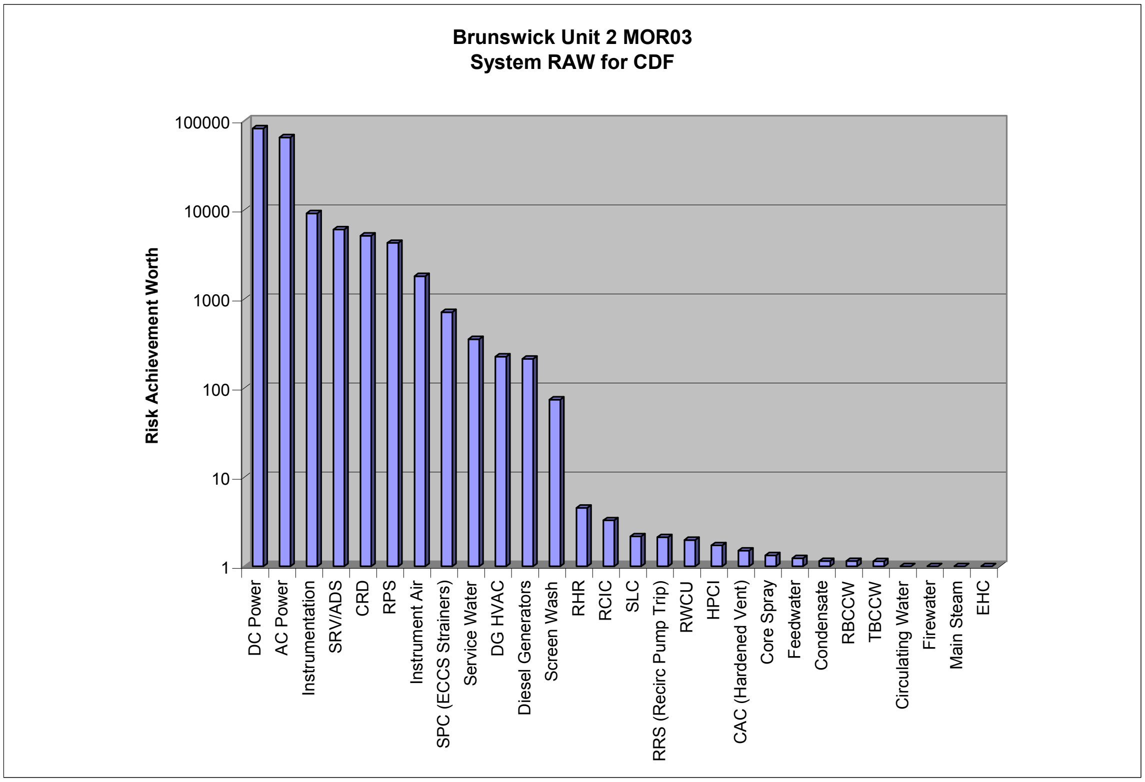


Figure F-5
Summary of Release Magnitudes

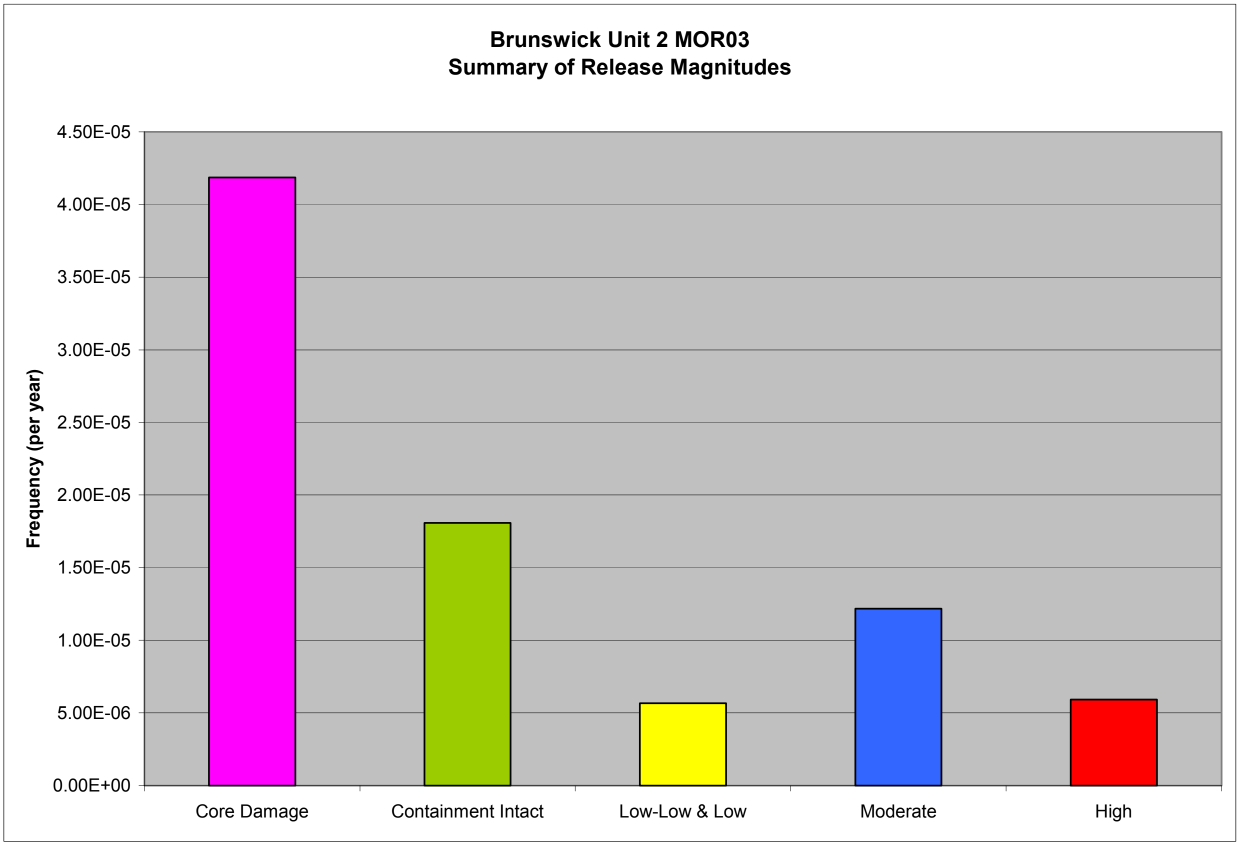


Figure F-6
Comparison of Contributors to the LERF Category

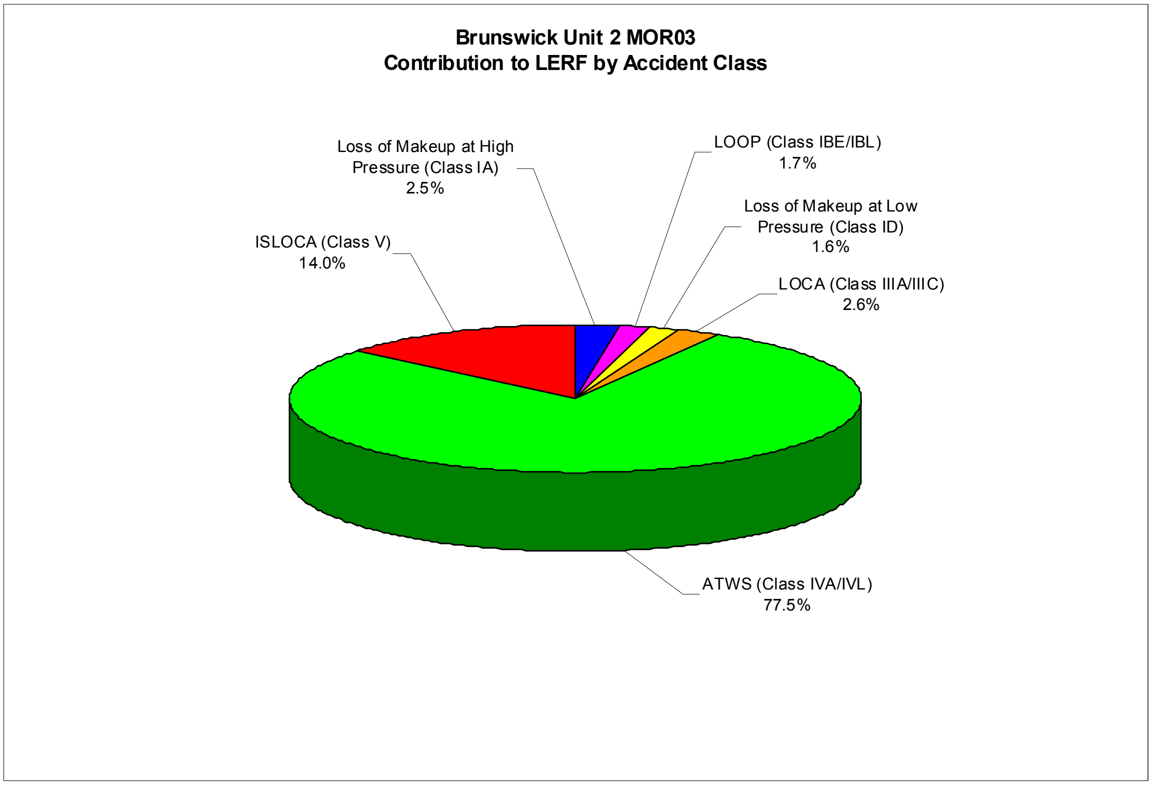
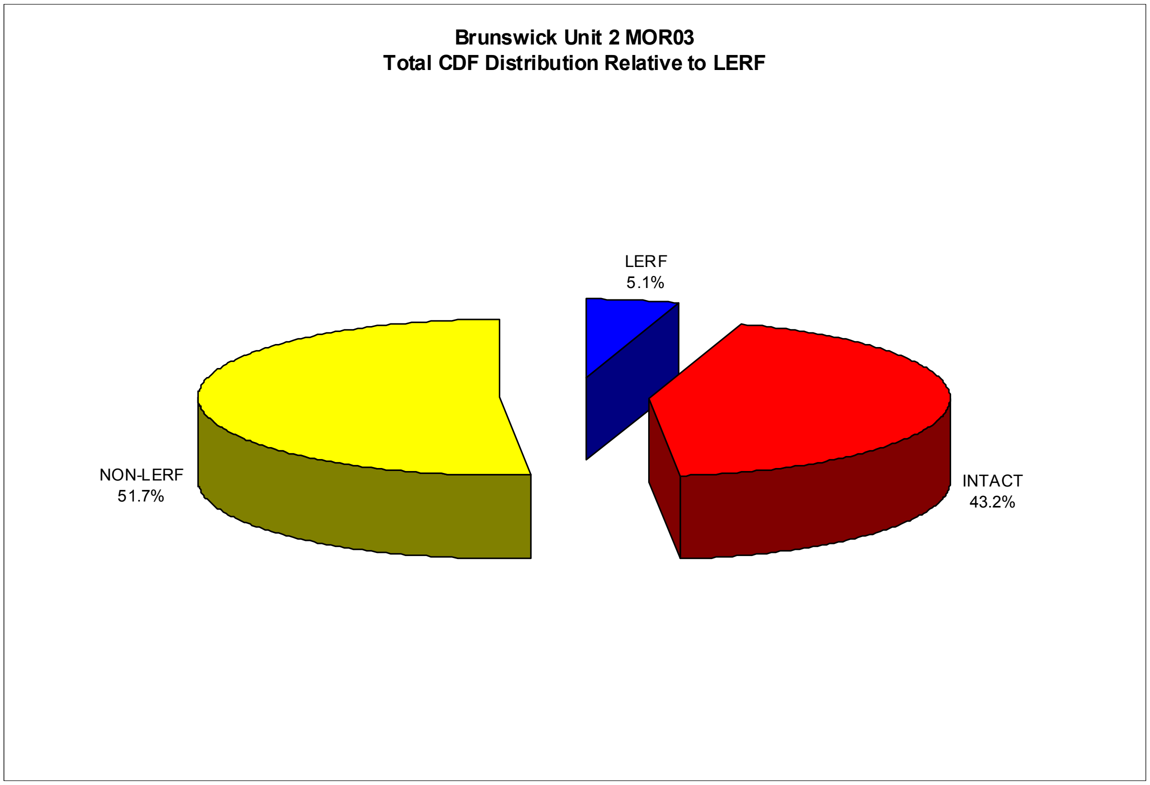


Figure F-7
Total CDF Distribution Relative to LERF



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ADDENDUM TO APPENDIX F
SEVERE ACCIDENT MITIGATION ALTERNATIVES

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to RCP Seal LOCAs (Loss of CC or SW)		
1	Cap downstream piping of normally closed component cooling water drain and vent valves.	SAMA would reduce the frequency of a loss of component cooling event, a large portion of which was derived from catastrophic failure of one of the many single isolation valves.
2	Enhance loss of component cooling procedure to facilitate stopping reactor coolant pumps.	SAMA would reduce the potential for reactor coolant pump (RCP) seal damage due to pump bearing failure.
3	Enhance loss of component cooling procedure to present desirability of cooling down reactor coolant system (RCS) prior to seal LOCA.	SAMA would reduce the potential for RCP seal failure.
4	Provide additional training on the loss of component cooling.	SAMA would potentially improve the success rate of operator actions after a loss of component cooling (to restore RCP seal damage).
5	Provide hardware connections to allow another essential raw cooling water system to cool charging pump seals.	SAMA would reduce effect of loss of component cooling by providing a means to maintain the centrifugal charging pump seal injection after a loss of component cooling.
6	Procedure changes to allow cross connection of motor cooling for RHRSW pumps.	SAMA would allow continued operation of both RHRSW pumps on a failure of one train of PSW.
7	Proceduralize shedding component cooling water loads to extend component cooling heatup on loss of essential raw cooling water.	SAMA would increase time before the loss of component cooling (and reactor coolant pump seal failure) in the loss of essential raw cooling water sequences.
8	Increase charging pump lube oil capacity.	SAMA would lengthen the time before centrifugal charging pump failure due to lube oil overheating in loss of CC sequences.
9	Eliminate the RCP thermal barrier dependence on component cooling such that loss of component cooling does not result directly in core damage.	SAMA would prevent the loss of recirculation pump seal integrity after a loss of component cooling. Watts Bar Nuclear Plant IPE said that they could do this with essential raw cooling water connection to RCP seals.
10	Add redundant DC control power for PSW pumps C & D.	SAMA would increase reliability of PSW and decrease core damage frequency due to a loss of SW.
11	Create an independent RCP seal injection system, with a dedicated diesel.	SAMA would add redundancy to RCP seal cooling alternatives, reducing CDF from loss of component cooling or service water or from a station blackout event.
12	Use existing hydro-test pump for RCP seal injection.	SAMA would provide an independent seal injection source, without the cost of a new system.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
13	Replace ECCS pump motor with air-cooled motors.	SAMA would eliminate ECCS dependency on component cooling system (but not on room cooling).
14	Install improved RCS pumps seals.	SAMA would reduce probability of RCP seal LOCA by installing RCP seal O-ring constructed of improved materials
15	Install additional component cooling water pump.	SAMA would reduce probability of loss of component cooling leading to RCP seal LOCA.
16	Prevent centrifugal charging pump flow diversion from the relief valves.	SAMA modification would reduce the frequency of the loss of RCP seal cooling if relief valve opening causes a flow diversion large enough to prevent RCP seal injection.
17	Change procedures to isolate RCP seal letdown flow on loss of component cooling, and guidance on loss of injection during seal LOCA.	SAMA would reduce CDF from loss of seal cooling.
18	Implement procedures to stagger high-pressure safety injection (HPSI) pump use after a loss of service water.	SAMA would allow HPSI to be extended after a loss of service water.
19	Use fire protection system pumps as a backup seal injection and high-pressure makeup.	SAMA would reduce the frequency of the RCP seal LOCA and the SBO CDF.
20	Enhance procedural guidance for use of cross-tied component cooling or service water pumps.	SAMA would reduce the frequency of the loss of component cooling water and service water.
21	Procedure enhancements and operator training in support system failure sequences, with emphasis on anticipating problems and coping.	SAMA would potentially improve the success rate of operator actions subsequent to support system failures.
22	Improved ability to cool the residual heat removal heat exchangers.	SAMA would reduce the probability of a loss of decay heat removal by implementing procedure and hardware modifications to allow manual alignment of the fire protection system or by installing a component cooling water cross-tie.
23	8.a. Additional Service Water Pump	SAMA would conceivably reduce common cause dependencies from SW system and thus reduce plant risk through system reliability improvement.
24	Create an independent RCP seal injection system, without dedicated diesel	This SAMA would add redundancy to RCP seal cooling alternatives, reducing the CDF from loss of CC or SW, but not SBO.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Heating, Ventilation, and Air Conditioning		
25	Provide reliable power to control building fans.	SAMA would increase availability of control room ventilation on a loss of power.
26	Provide a redundant train of ventilation.	SAMA would increase the availability of components dependent on room cooling.
27	Procedures for actions on loss of HVAC.	SAMA would provide for improved credit to be taken for loss of HVAC sequences (improved affected electrical equipment reliability upon a loss of control building HVAC).
28	Add a diesel building switchgear room high temperature alarm.	SAMA would improve diagnosis of a loss of switchgear room HVAC. Option 1: Install high temp alarm. Option 2: Redundant louver and thermostat
29	Create ability to switch fan power supply to DC in an SBO event.	SAMA would allow continued operation in an SBO event. This SAMA was created for reactor core isolation cooling system room at Fitzpatrick Nuclear Power Plant.
30	Enhance procedure to instruct operators to trip unneeded RHR/CS pumps on loss of room ventilation.	SAMA increases availability of required RHR/CS pumps. Reduction in room heat load allows continued operation of required RHR/CS pumps, when room cooling is lost.
31	Stage backup fans in switchgear (SWGR) rooms	This SAMA would provide alternate ventilation in the event of a loss of SWGR Room ventilation
Improvements Related to Ex-Vessel Accident Mitigation/Containment Phenomena		
32	Delay containment spray actuation after large LOCA.	SAMA would lengthen time of RWST availability.
33	Install containment spray pump header automatic throttle valves.	SAMA would extend the time over which water remains in the RWST, when full CS flow is not needed
34	Install an independent method of suppression pool cooling.	SAMA would decrease the probability of loss of containment heat removal. For PWRs, a potential similar enhancement would be to install an independent cooling system for sump water.
35	Develop an enhanced drywell spray system.	SAMA would provide a redundant source of water to the containment to control containment pressure, when used in conjunction with containment heat removal.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
36	Provide dedicated existing drywell spray system.	SAMA would provide a source of water to the containment to control containment pressure, when used in conjunction with containment heat removal. This would use an existing spray loop instead of developing a new spray system.
37	Install an unfiltered hardened containment vent.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products not being scrubbed.
38	Install a filtered containment vent to remove decay heat.	SAMA would provide an alternate decay heat removal method for non-ATWS events, with the released fission products being scrubbed. Option 1: Gravel Bed Filter Option 2: Multiple Venturi Scrubber
39	Install a containment vent large enough to remove ATWS decay heat.	Assuming that injection is available, this SAMA would provide alternate decay heat removal in an ATWS event.
40	Create/enhance hydrogen recombiners with independent power supply.	SAMA would reduce hydrogen detonation at lower cost, Use either 1) a new independent power supply 2) a nonsafety-grade portable generator 3) existing station batteries 4) existing AC/DC independent power supplies.
41	Install hydrogen recombiners.	SAMA would provide a means to reduce the chance of hydrogen detonation.
42	Create a passive design hydrogen ignition system.	SAMA would reduce hydrogen denotation system without requiring electric power.
43	Create a large concrete crucible with heat removal potential under the basemat to contain molten core debris.	SAMA would ensure that molten core debris escaping from the vessel would be contained within the crucible. The water cooling mechanism would cool the molten core, preventing a melt-through of the basemat.
44	Create a water-cooled rubble bed on the pedestal.	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
45	Provide modification for flooding the drywell head.	SAMA would help mitigate accidents that result in the leakage through the drywell head seal.
46	Enhance fire protection system and/or standby gas treatment system hardware and procedures.	SAMA would improve fission product scrubbing in severe accidents.
47	Create a reactor cavity flooding system.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
48	Create other options for reactor cavity flooding.	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
49	Enhance air return fans (ice condenser plants).	SAMA would provide an independent power supply for the air return fans, reducing containment failure in SBO sequences.
50	Create a core melt source reduction system.	SAMA would provide cooling and containment of molten core debris. Refractory material would be placed underneath the reactor vessel such that a molten core falling on the material would melt and combine with the material. Subsequent spreading and heat removal form the vitrified compound would be facilitated, and concrete attack would not occur
51	Provide a containment inerting capability.	SAMA would prevent combustion of hydrogen and carbon monoxide gases.
52	Use the fire protection system as a backup source for the containment spray system.	SAMA would provide redundant containment spray function without the cost of installing a new system.
53	Install a secondary containment filtered vent.	SAMA would filter fission products released from primary containment.
54	Install a passive containment spray system.	SAMA would provide redundant containment spray method without high cost.
55	Strengthen primary/secondary containment.	SAMA would reduce the probability of containment overpressurization to failure.
56	Increase the depth of the concrete basemat or use an alternative concrete material to ensure melt-through does not occur.	SAMA would prevent basemat melt-through.
57	Provide a reactor vessel exterior cooling system.	SAMA would provide the potential to cool a molten core before it causes vessel failure, if the lower head could be submerged in water.
58	Construct a building to be connected to primary/secondary containment that is maintained at a vacuum.	SAMA would provide a method to depressurize containment and reduce fission product release.
59	Refill CST	SAMA would reduce the risk of core damage during events such as extended station blackouts or LOCAs which render the suppression pool unavailable as an injection source due to heat up.
60	Maintain ECCS suction on CST	SAMA would maintain suction on the CST as long as possible to avoid pump failure as a result of high suppression pool temperature
61	Modify containment flooding procedure to restrict flooding to below TAF	SAMA would avoid forcing containment venting

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
62	Enhance containment venting procedures with respect to timing, path selection and technique.	SAMA would improve likelihood of successful venting strategies.
63	1.a. Severe Accident EPGs/AMGs	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
64	1.h. Simulator Training for Severe Accident	SAMA would lead to improved arrest of core melt progress and prevention of containment failure
65	2.g. Dedicated Suppression Pool Cooling	SAMA would decrease the probability of loss of containment heat removal. While PWRs do not have suppression pools, a similar modification may be applied to the sump. Installation of a dedicated sump cooling system would provide an alternate method of cooling injection water.
66	3.a. Larger Volume Containment	SAMA increases time before containment failure and increases time for recovery
67	3.b. Increased Containment Pressure Capability (sufficient pressure to withstand severe accidents)	SAMA minimizes likelihood of large releases
68	3.c. Improved Vacuum Breakers (redundant valves in each line)	SAMA reduces the probability of a stuck open vacuum breaker.
69	3.d. Increased Temperature Margin for Seals	This SAMA would reduce containment failure due to drywell head seal failure caused by elevated temperature and pressure.
70	3.e. Improved Leak Detection	This SAMA would help prevent LOCA events by identifying pipes which have begun to leak. These pipes can be replaced before they break.
71	3.f. Suppression Pool Scrubbing	Directing releases through the suppression pool will reduce the radionuclides allowed to escape to the environment.
72	3.g. Improved Bottom Penetration Design	SAMA reduces failure likelihood of RPV bottom head penetrations
73	4.a. Larger Volume Suppression Pool (double effective liquid volume)	SAMA would increase the size of the suppression pool so that heatup rate is reduced, allowing more time for recovery of a heat removal system
74	5.a/d. Unfiltered Vent	SAMA would provide an alternate decay heat removal method with the released fission products not being scrubbed.
75	5.b/c. Filtered Vent	SAMA would provide an alternate decay heat removal method with the released fission products being scrubbed.
76	6.a. Post Accident Inerting System	SAMA would reduce likelihood of gas combustion inside containment

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
77	6.b. Hydrogen Control by Venting	Prevents hydrogen detonation by venting the containment before combustible levels are reached.
78	6.c. Pre-inerting	SAMA would reduce likelihood of gas combustion inside containment
79	6.d. Ignition Systems	Burning combustible gases before they reach a level which could cause a harmful detonation is a method of preventing containment failure.
80	6.e. Fire Suppression System Inerting	Use of the fire protection system as a back up containment inerting system would reduce the probability of combustible gas accumulation. This would reduce the containment failure probability for small containments (e.g. BWR MKI).
81	7.a. Drywell Head Flooding	SAMA would provide intentional flooding of the upper drywell head such that if high drywell temperatures occurred, the drywell head seal would not fail.
82	7.b. Containment Spray Augmentation	This SAMA would provide additional means of providing flow to the containment spray system.
83	12.b. Integral Basemat	This SAMA would improve containment and system survivability for seismic events.
84	13.a. Reactor Building Sprays	This SAMA provides the capability to use firewater sprays in the reactor building to mitigate release of fission products into the Rx Bldg following an accident.
85	14.a. Flooded Rubble Bed	SAMA would contain molten core debris dropping on to the pedestal and would allow the debris to be cooled.
86	14.b. Reactor Cavity Flooder	SAMA would enhance debris coolability, reduce core concrete interaction, and provide fission product scrubbing.
87	14.c. Basaltic Cements	SAMA minimizes carbon dioxide production during core concrete interaction.
88	Provide a core debris control system	(Intended for ice condenser plants): This SAMA would prevent the direct core debris attack of the primary containment steel shell by erecting a barrier between the seal table and the containment shell.
89	Add ribbing to the containment shell	This SAMA would reduce the risk of buckling of containment under reverse pressure loading.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
Improvements Related to Enhanced AC/DC Reliability/Availability		
90	Proceduralize alignment of spare diesel to shutdown board after loss of offsite power and failure of the diesel normally supplying it.	SAMA would reduce the SBO frequency.
91	Provide an additional diesel generator.	SAMA would increase the reliability and availability of onsite emergency AC power sources.
92	Provide additional DC battery capacity.	SAMA would ensure longer battery capability during an SBO, reducing the frequency of long-term SBO sequences.
93	Use fuel cells instead of lead-acid batteries.	SAMA would extend DC power availability in an SBO.
94	Procedure to cross-tie high-pressure core spray diesel.	SAMA would improve core injection availability by providing a more reliable power supply for the high-pressure core spray pumps.
95	Improve 4.16-kV bus cross-tie ability.	SAMA would improve AC power reliability.
96	Incorporate an alternate battery charging capability.	SAMA would improve DC power reliability by either cross-tying the AC busses, or installing a portable diesel-driven battery charger.
97	Increase/improve DC bus load shedding.	SAMA would extend battery life in an SBO event.
98	Replace existing batteries with more reliable ones.	SAMA would improve DC power reliability and thus increase available SBO recovery time.
99	Mod for DC Bus A reliability.	SAMA would increase the reliability of AC power and injection capability. Loss of DC Bus A causes a loss of main condenser, prevents transfer from the main transformer to offsite power, and defeats one half of the low vessel pressure permissive for LPCI/CS injection valves.
100	Create AC power cross-tie capability with other unit.	SAMA would improve AC power reliability.
101	Create a cross-tie for diesel fuel oil.	SAMA would increase diesel fuel oil supply and thus diesel generator, reliability.
102	Develop procedures to repair or replace failed 4-kV breakers.	SAMA would offer a recovery path from a failure of the breakers that perform transfer of 4.16-kV non-emergency busses from unit station service transformers, leading to loss of emergency AC power.
103	Emphasize steps in recovery of offsite power after an SBO.	SAMA would reduce human error probability during offsite power recovery.
104	Develop a severe weather conditions procedure.	For plants that do not already have one, this SAMA would reduce the CDF for external weather-related events.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
105	Develop procedures for replenishing diesel fuel oil.	SAMA would allow for long-term diesel operation.
106	Install gas turbine generator.	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
107	Create a backup source for diesel cooling. (Not from existing system)	This SAMA would provide a redundant and diverse source of cooling for the diesel generators, which would contribute to enhanced diesel reliability.
108	Use fire protection system as a backup source for diesel cooling.	This SAMA would provide a redundant and diverse source of cooling for the diesel generators, which would contribute to enhanced diesel reliability.
109	Provide a connection to an alternate source of offsite power.	SAMA would reduce the probability of a loss of offsite power event.
110	Bury offsite power lines.	SAMA could improve offsite power reliability, particularly during severe weather.
111	Replace anchor bolts on diesel generator oil cooler.	Millstone Nuclear Power Station found a high seismic SBO risk due to failure of the diesel oil cooler anchor bolts. For plants with a similar problem, this would reduce seismic risk. Note that these were Fairbanks Morse DGs.
112	Change undervoltage (UV), auxiliary feedwater actuation signal (AFAS) block and high pressurizer pressure actuation signals to 3-out-of-4, instead of 2-out-of-4 logic.	SAMA would reduce risk of 2/4 inverter failure.
113	Provide DC power to the 120/240-V vital AC system from the Class 1E station service battery system instead of its own battery.	SAMA would increase the reliability of the 120-VAC Bus.
114	Bypass Diesel Generator Trips	SAMA would allow D/Gs to operate for longer.
115	2.i. 16 hour Station Blackout Injection	SAMA includes improved capability to cope with longer station blackout scenarios.
116	9.a. Steam Driven Turbine Generator	This SAMA would provide a steam driven turbine generator which uses reactor steam and exhausts to the suppression pool. If large enough, it could provide power to additional equipment.
117	9.b. Alternate Pump Power Source	This SAMA would provide a small dedicated power source such as a dedicated diesel or gas turbine for the feedwater or condensate pumps, so that they do not rely on offsite power.
118	9.d. Additional Diesel Generator	SAMA would reduce the SBO frequency.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
119	9.e. Increased Electrical Divisions	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
120	9.f. Improved Uninterruptible Power Supplies	SAMA would provide increased reliability of power supplies supporting front-line equipment, thus reducing core damage and release frequencies.
121	9.g. AC Bus Cross-Ties	SAMA would provide increased reliability of AC power system to reduce core damage and release frequencies.
122	9.h. Gas Turbine	SAMA would improve onsite AC power reliability by providing a redundant and diverse emergency power system.
123	9.i. Dedicated RHR (bunkered) Power Supply	SAMA would provide RHR with more reliable AC power.
124	10.a. Dedicated DC Power Supply	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
125	10.b. Additional Batteries/Divisions	This SAMA addresses the use of a diverse DC power system such as an additional battery or fuel cell for the purpose of providing motive power to certain components (e.g., RCIC).
126	10.c. Fuel Cells	SAMA would extend DC power availability in an SBO.
127	10.d. DC Cross-ties	This SAMA would improve DC power reliability.
128	10.e. Extended Station Blackout Provisions	SAMA would provide reduction in SBO sequence frequencies.
129	Add an automatic bus transfer feature to allow the automatic transfer of the 120V vital AC bus from the on-line unit to the standby unit	Plants are typically sensitive to the loss of one or more 120V vital AC buses. Manual transfers to alternate power supplies could be enhanced to transfer automatically.
Improvements in Identifying and Mitigating Containment Bypass		
130	Install a redundant spray system to depressurize the primary system during a steam generator tube rupture (SGTR).	SAMA would enhance depressurization during a SGTR.
131	Improve SGTR coping abilities.	SAMA would improve instrumentation to detect SGTR, or additional system to scrub fission product releases.
132	Add other SGTR coping abilities.	SAMA would decrease the consequences of an SGTR.
133	Increase secondary side pressure capacity such that an SGTR would not cause the relief valves to lift.	SAMA would eliminate direct release pathway for SGTR sequences.
134	Replace steam generators (SG) with a new design.	SAMA would lower the frequency of an SGTR.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
135	Revise emergency operating procedures to direct that a faulted SG be isolated.	SAMA would reduce the consequences of an SGTR.
136	Direct SG flooding after a SGTR, prior to core damage.	SAMA would provide for improved scrubbing of SGTR releases.
137	Implement a maintenance practice that inspects 100% of the tubes in a SG.	SAMA would reduce the potential for an SGTR.
138	Locate residual heat removal (RHR) inside of containment.	SAMA would prevent intersystem LOCA (ISLOCA) out the RHR pathway.
139	Install additional instrumentation for ISLOCAs.	SAMA would decrease ISLOCA frequency by installing pressure of leak monitoring instruments in between the first two pressure isolation valves on low-pressure inject lines, RHR suction lines, and HPSI lines.
140	Increase frequency for valve leak testing.	SAMA could reduce ISLOCA frequency.
141	Improve operator training on ISLOCA coping.	SAMA would decrease ISLOCA effects.
142	Install relief valves in the CC System.	SAMA would relieve pressure buildup from an RCP thermal barrier tube rupture, preventing an ISLOCA.
143	Provide leak testing of valves in ISLOCA paths.	SAMA would help reduce ISLOCA frequency. At Kewaunee Nuclear Power Plant, four MOVs isolating RHR from the RCS were not leak tested.
144	Revise EOPs to improve ISLOCA identification.	SAMA would ensure LOCA outside containment could be identified as such. Salem Nuclear Power Plant had a scenario where an RHR ISLOCA could direct initial leakage back to the pressurizer relief tank, giving indication that the LOCA was inside containment.
145	Ensure all ISLOCA releases are scrubbed.	SAMA would scrub all ISLOCA releases. One example is to plug drains in the break area so that the break point would be covered with water.
146	Add redundant and diverse limit switches to each containment isolation valve.	SAMA could reduce the frequency of containment isolation failure and ISLOCAs through enhanced isolation valve position indication.
147	Early detection and mitigation of ISLOCA	SAMA would limit the effects of ISLOCA accidents by early detection and isolation
148	8.e. Improved MSIV Design	This SAMA would improve isolation reliability and reduce spurious actuations that could be initiating events.
149	Proceduralize use of pressurizer vent valves during steam generator tube rupture (SGTR) sequences	Some plants may have procedures to direct the use of pressurizer sprays to reduce RCS pressure after an SGTR. Use of the vent valves would provide a back-up method.

TABLE A-1
SELECTED PREVIOUS INDUSTRY SAMAs

SAMA ID number	SAMA title	Result of potential enhancement
150	Implement a maintenance practice that inspects 100% of the tubes in an SG	This SAMA would reduce the potential for a tube rupture.
151	Locate RHR inside of containment	This SAMA would prevent ISLOCA out the RHR pathway.
152	Install self-actuating containment isolation valves	For plants that do not have this, it would reduce the frequency of isolation failure.
Improvements in Reducing Internal Flooding Frequency		
153	Modify swing direction of doors separating turbine building basement from areas containing safeguards equipment.	SAMA would prevent flood propagation, for a plant where internal flooding from turbine building to safeguards areas is a concern.
154	Improve inspection of rubber expansion joints on main condenser.	SAMA would reduce the frequency of internal flooding, for a plant where internal flooding due to a failure of circulating water system expansion joints is a concern.
155	Implement internal flood prevention and mitigation enhancements.	This SAMA would reduce the consequences of internal flooding.
156	Implement internal flooding improvements such as those implemented at Fort Calhoun.	This SAMA would reduce flooding risk by preventing or mitigating: a rupture in the RCP seal cooler of the component cooling system, an ISLOCA in a shutdown cooling line, and an auxiliary feedwater (AFW) flood involving the need to remove a watertight door.
157	Shield electrical equipment from potential water spray	SAMA would decrease risk associated with seismically induced internal flooding
158	13.c. Reduction in Reactor Building Flooding	This SAMA reduces the Reactor Building Flood Scenarios contribution to core damage and release.
Improvements Related to Feedwater/Feed and Bleed Reliability/Availability		
159	Install a digital feedwater upgrade.	This SAMA would reduce the chance of a loss of main feedwater following a plant trip.
160	Perform surveillances on manual valves used for backup AFW pump suction.	This SAMA would improve success probability for providing alternative water supply to the AFW pumps.
161	Install manual isolation valves around AFW turbine-driven steam admission valves.	This SAMA would reduce the dual turbine-driven AFW pump maintenance unavailability.

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SAMA ID number	SAMA title	Result of potential enhancement
162	Install accumulators for turbine-driven AFW pump flow control valves (CVs).	This SAMA would provide control air accumulators for the turbine-driven AFW flow CVs, the motor-driven AFW pressure CVs and SG power-operated relief valves (PORVs). This would eliminate the need for local manual action to align nitrogen bottles for control air during a LOOP.
163	Install separate accumulators for the AFW cross-connect and block valves	This SAMA would enhance the operator's ability to operate the AFW cross-connect and block valves following loss of air support.
164	Install a new condensate storage tank (CST)	Either replace the existing tank with a larger one, or install a back-up tank.
165	Provide cooling of the steam-driven AFW pump in an SBO event	This SAMA would improve success probability in an SBO by: (1) using the FP system to cool the pump, or (2) making the pump self cooled.
166	Proceduralize local manual operation of AFW when control power is lost.	This SAMA would lengthen AFW availability in an SBO. Also provides a success path should AFW control power be lost in non-SBO sequences.
167	Provide portable generators to be hooked into the turbine driven AFW, after battery depletion.	This SAMA would extend AFW availability in an SBO (assuming the turbine driven AFW requires DC power)
168	Add a motor train of AFW to the Steam trains	For PWRs that do not have any motor trains of AFW, this would increase reliability in non-SBO sequences.
169	Create ability for emergency connections of existing or alternate water sources to feedwater/condensate	This SAMA would be a back-up water supply for the feedwater/condensate systems.
170	Use FP system as a back-up for SG inventory	This SAMA would create a back-up to main and AFW for SG water supply.
171	Procure a portable diesel pump for isolation condenser make-up	This SAMA would provide a back-up to the city water supply and diesel FP system pump for isolation condenser make-up.
172	Install an independent diesel generator for the CST make-up pumps	This SAMA would allow continued inventory make-up to the CST during an SBO.
173	Change failure position of condenser make-up valve	This SAMA would allow greater inventory for the AFW pumps by preventing CST flow diversion to the condenser if the condenser make-up valve fails open on loss of air or power.
174	Create passive secondary side coolers.	This SAMA would reduce CDF from the loss of Feedwater by providing a passive heat removal loop with a condenser and heat sink.
175	Replace current PORVs with larger ones such that only one is required for successful feed and bleed.	This SAMA would reduce the dependencies required for successful feed and bleed.
176	Install motor-driven feedwater pump.	SAMA would increase the availability of injection subsequent to MSIV closure.

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SAMA ID number	SAMA title	Result of potential enhancement
177	Use Main FW pumps for a Loss of Heat Sink Event	This SAMA involves a procedural change that would allow for a faster response to loss of the secondary heat sink. Use of only the feedwater booster pumps for injection to the SGs requires depressurization to about 350 psig; before the time this pressure is reached, conditions would be met for initiating feed and bleed. Using the available turbine driven feedwater pumps to inject water into the SGs at a high pressure rather than using the feedwater booster alone allows injection without the time consuming depressurization.
Improvements in Core Cooling Systems		
178	Provide the capability for diesel driven, low pressure vessel make-up	This SAMA would provide an extra water source in sequences in which the reactor is depressurized and all other injection is unavailable (e.g., FP system)
179	Provide an additional HPSI pump with an independent diesel	This SAMA would reduce the frequency of core melt from small LOCA and SBO sequences
180	Install an independent AC HPSI system	This SAMA would allow make-up and feed and bleed capabilities during an SBO.
181	Create the ability to manually align ECCS recirculation	This SAMA would provide a back-up should automatic or remote operation fail.
182	Implement an RWT make-up procedure	This SAMA would decrease CDF from ISLOCA scenarios, some smaller break LOCA scenarios, and SGTR.
183	Stop low pressure safety injection pumps earlier in medium or large LOCAs.	This SAMA would provide more time to perform recirculation swap over.
184	Emphasize timely swap over in operator training.	This SAMA would reduce human error probability of recirculation failure.
185	Upgrade Chemical and Volume Control System to mitigate small LOCAs.	For a plant like the AP600 where the Chemical and Volume Control System cannot mitigate a Small LOCA, an upgrade would decrease the Small LOCA CDF contribution.
186	Install an active HPSI system.	For a plant like the AP600 where an active HPSI system does not exist, this SAMA would add redundancy in HPSI.
187	Change "in-containment" RWT suction from 4 check valves to 2 check and 2 air operated valves.	This SAMA would remove common mode failure of all four injection paths.

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SAMA ID number	SAMA title	Result of potential enhancement
188	Replace 2 of the 4 safety injection (SI) pumps with diesel-powered pumps.	This SAMA would reduce the SI system common cause failure probability. This SAMA was intended for the System 80+, which has four trains of SI.
189	Align low pressure core injection or core spray to the CST on loss of suppression pool cooling.	This SAMA would help to ensure low pressure ECCS can be maintained in loss of suppression pool cooling scenarios.
190	Raise high pressure core injection/reactor core isolation cooling backpressure trip setpoints	This SAMA would ensure high pressure core injection/reactor core isolation cooling availability when high suppression pool temperatures exist.
191	Improve the reliability of the automatic depressurization system.	This SAMA would reduce the frequency of high pressure core damage sequences.
192	Disallow automatic vessel depressurization in non-ATWS scenarios	This SAMA would improve operator control of the plant.
193	Create automatic swap over to recirculation on RWT depletion	This SAMA would reduce the human error contribution from recirculation failure.
194	Proceduralize intermittent operation of HPCI.	SAMA would allow for extended duration of HPCI availability.
195	Increase available net positive suction head (NPSH) for injection pumps.	SAMA increases the probability that these pumps will be available to inject coolant into the vessel by increasing the available NPSH for the injection pumps.
196	Modify Reactor Water Cleanup (RWCU) for use as a decay heat removal system and proceduralize use.	SAMA would provide an additional source of decay heat removal.
197	CRD Injection	SAMA would supply an additional method of level restoration by using a non-safety system.
198	Condensate Pumps for Injection	SAMA to provide an additional option for coolant injection when other systems are unavailable or inadequate
199	Align EDG to CRD for Injection	SAMA to provide power to an additional injection source during loss of power events
200	Re-open MSIVs	SAMA to regain the main condenser as a heat sink by re-opening the MSIVs.
201	Bypass RCIC Turbine Exhaust Pressure Trip	SAMA would allow RCIC to operate longer.
202	2.a. Passive High Pressure System	SAMA will improve prevention of core melt sequences by providing additional high pressure capability to remove decay heat through an isolation condenser type system

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SAMA ID number	SAMA title	Result of potential enhancement
203	2.c. Suppression Pool Jockey Pump	SAMA will improve prevention of core melt sequences by providing a small makeup pump to provide low pressure decay heat removal from the RPV using the suppression pool as a source of water.
204	2.d. Improved High Pressure Systems	SAMA will improve prevention of core melt sequences by improving reliability of high pressure capability to remove decay heat.
205	2.e. Additional Active High Pressure System	SAMA will improve reliability of high pressure decay heat removal by adding an additional system.
206	2.f. Improved Low Pressure System (Firepump)	SAMA would provide fire protection system pump(s) for use in low pressure scenarios.
207	4.b. CUW Decay Heat Removal	This SAMA provides a means for Alternate Decay Heat Removal.
208	4.c. High Flow Suppression Pool Cooling	SAMA would improve suppression pool cooling.
209	8.c. Diverse Injection System	SAMA will improve prevention of core melt sequences by providing additional injection capabilities.
210	Alternate Charging Pump Cooling	This SAMA will improve the high pressure core flooding capabilities by providing the SI pumps with alternate gear and oil cooling sources. Given a total loss of Chilled Water, abnormal operating procedures would direct alignment of preferred Demineralized Water or the Fire System to the Chilled Water System to provide cooling to the SI pumps' gear and oil box (and the other normal loads).
Instrument Air/Gas Improvements		
211	Modify EOPs for ability to align diesel power to more air compressors.	For plants that do not have diesel power to all normal and back-up air compressors, this change would increase the reliability of IA after a LOOP.
212	Replace old air compressors with more reliable ones	This SAMA would improve reliability and increase availability of the IA compressors.
213	Install nitrogen bottles as a back-up gas supply for safety relief valves.	This SAMA would extend operation of safety relief valves during an SBO and loss of air events (BWRs).
214	Allow cross connection of uninterruptible compressed air supply to opposite unit.	SAMA would increase the ability to vent containment using the hardened vent.

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SAMA ID number	SAMA title	Result of potential enhancement
	ATWS Mitigation	
215	Install MG set trip breakers in control room	This SAMA would provide trip breakers for the MG sets in the control room. In some plants, MG set breaker trip requires action to be taken outside of the control room. Adding control capability to the control room would reduce the trip failure probability in sequences where immediate action is required (e.g., ATWS).
216	Add capability to remove power from the bus powering the control rods	This SAMA would decrease the time to insert the control rods if the reactor trip breakers fail (during a loss of FW ATWS which has a rapid pressure excursion)
217	Create cross-connect ability for standby liquid control trains	This SAMA would improve reliability for boron injection during an ATWS event.
218	Create an alternate boron injection capability (back-up to standby liquid control)	This SAMA would improve reliability for boron injection during an ATWS event.
219	Remove or allow override of low pressure core injection during an ATWS	On failure on high pressure core injection and condensate, some plants direct reactor depressurization followed by 5 minutes of low pressure core injection. This SAMA would allow control of low pressure core injection immediately.
220	Install a system of relief valves that prevents any equipment damage from a pressure spike during an ATWS	This SAMA would improve equipment availability after an ATWS.
221	Create a boron injection system to back up the mechanical control rods.	This SAMA would provide a redundant means to shut down the reactor.
222	Provide an additional instrument system for ATWS mitigation (e.g., ATWS mitigation scram actuation circuitry).	This SAMA would improve instrument and control redundancy and reduce the ATWS frequency.
223	Increase the safety relief valve (SRV) reseat reliability.	SAMA addresses the risk associated with dilution of boron caused by the failure of the SRVs to reseat after standby liquid control (SLC) injection.
224	Use control rod drive (CRD) for alternate boron injection.	SAMA provides an additional system to address ATWS with SLC failure or unavailability.

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SAMA ID number	SAMA title	Result of potential enhancement
225	Bypass MSIV isolation in Turbine Trip ATWS scenarios	SAMA will afford operators more time to perform actions. The discharge of a substantial fraction of steam to the main condenser (i.e., as opposed to into the primary containment) affords the operator more time to perform actions (e.g., SLC injection, lower water level, depressurize RPV) than if the main condenser was unavailable, resulting in lower human error probabilities
226	Enhance operator actions during ATWS	SAMA will reduce human error probabilities during ATWS
227	Guard against SLC dilution	SAMA to control vessel injection to prevent boron loss or dilution following SLC injection.
228	11.a. ATWS Sized Vent	This SAMA would be provide the ability to remove reactor heat from ATWS events.
229	11.b. Improved ATWS Capability	This SAMA includes items which reduce the contribution of ATWS to core damage and release frequencies.
Other Improvements		
230	Provide capability for remote operation of secondary side relief valves in an SBO	Manual operation of these valves is required in an SBO scenario. High area temperatures may be encountered in this case (no ventilation to main steam areas), and remote operation could improve success probability.
231	Create/enhance RCS depressurization ability	With either a new depressurization system, or with existing PORVs, head vents, and secondary side valve, RCS depressurization would allow earlier low pressure ECCS injection. Even if core damage occurs, low RCS pressure would alleviate some concerns about high pressure melt ejection.
232	Make procedural changes only for the RCS depressurization option	This SAMA would reduce RCS pressure without the cost of a new system
233	Defeat 100% load rejection capability.	This SAMA would eliminate the possibility of a stuck open PORV after a LOOP, since PORV opening would not be needed.
234	Change control rod drive flow CV failure position	Change failure position to the "fail-safest" position.
235	Install secondary side guard pipes up to the MSIVs	This SAMA would prevent secondary side depressurization should a steam line break occur upstream of the main steam isolation valves. This SAMA would also guard against or prevent consequential multiple SGTR following a Main Steam Line Break event.

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SAMA ID number	SAMA title	Result of potential enhancement
236	Install digital large break LOCA protection	Upgrade plant instrumentation and logic to improve the capability to identify symptoms/precursors of a large break LOCA (leak before break).
237	Increase seismic capacity of the plant to a high confidence, low pressure failure of twice the Safe Shutdown Earthquake.	This SAMA would reduce seismically -induced CDF.
238	Enhance the reliability of the demineralized water (DW) make-up system through the addition of diesel-backed power to one or both of the DW make-up pumps.	Inventory loss due to normal leakage can result in the failure of the CC and the SRW systems. Loss of CC could challenge the RCP seals. Loss of SRW results in the loss of three EDGs and the containment air coolers (CACs).
239	Increase the reliability of safety relief valves by adding signals to open them automatically.	SAMA reduces the probability of a certain type of medium break LOCA. Hatch evaluated medium LOCA initiated by an MSIV closure transient with a failure of SRVs to open. Reducing the likelihood of the failure for SRVs to open, subsequently reduces the occurrence of this medium LOCA.
240	Reduce DC dependency between high-pressure injection system and ADS.	SAMA would ensure containment depressurization and high-pressure injection upon a DC failure.
241	Increase seismic ruggedness of plant components.	SAMA would increase the availability of necessary plant equipment during and after seismic events.
242	Enhance RPV depressurization capability	SAMA would decrease the likelihood of core damage in loss of high pressure coolant injection scenarios
243	Enhance RPV depressurization procedures	SAMA would decrease the likelihood of core damage in loss of high pressure coolant injection scenarios
244	Replace mercury switches on fire protection systems	SAMA would decrease probability of spurious fire suppression system actuation given a seismic event+D114
245	Provide additional restraints for CO_2 tanks	SAMA would increase availability of fire protection given a seismic event.
246	Enhance control of transient combustibles	SAMA would minimize risk associated with important fire areas.
247	Enhance fire brigade awareness	SAMA would minimize risk associated with important fire areas.
248	Upgrade fire compartment barriers	SAMA would minimize risk associated with important fire areas.
249	Enhance procedures to allow specific operator actions	SAMA would minimize risk associated with important fire areas.
250	Develop procedures for transportation and nearby facility accidents	SAMA would minimize risk associated with transportation and nearby facility accidents.
251	Enhance procedures to mitigate Large LOCA	SAMA would minimize risk associated with Large LOCA

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SAMA ID number	SAMA title	Result of potential enhancement
252	1.b. Computer Aided Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
253	1.c/d. Improved Maintenance Procedures/Manuals	SAMA will improve prevention of core melt sequences by increasing reliability of important equipment
254	1.e. Improved Accident Management Instrumentation	SAMA will improve prevention of core melt sequences by making operator actions more reliable.
255	1.f. Remote Shutdown Station	This SAMA would provide the capability to control the reactor in the event that evacuation of the main control room is required.
256	1.g. Security System	Improvements in the site's security system would decrease the potential for successful sabotage.
257	2.b. Improved Depressurization	SAMA will improve depressurization system to allow more reliable access to low pressure systems.
258	2.h. Safety Related Condensate Storage Tank	SAMA will improve availability of CST following a Seismic event
259	4.d. Passive Overpressure Relief	This SAMA would prevent vessel overpressurization.
260	8.b. Improved Operating Response	Improved operator reliability would improve accident mitigation and prevention.
261	8.d. Operation Experience Feedback	This SAMA would identify areas requiring increased attention in plant operation through review of equipment performance.
262	8.e. Improved SRV Design	This SAMA would improve SRV reliability, thus increasing the likelihood that sequences could be mitigated using low pressure heat removal.
263	12.a. Increased Seismic Margins	This SAMA would reduce the risk of core damage and release during seismic events.
264	13.b. System Simplification	This SAMA is intended to address system simplification by the elimination of unnecessary interlocks, automatic initiation of manual actions or redundancy as a means to reduce overall plant risk.
265	Train operations crew for response to inadvertent actuation signals	This SAMA would improve chances of a successful response to the loss of two 120V AC buses, which may cause inadvertent signal generation.
266	Install tornado protection on gas turbine generators	This SAMA would improve onsite AC power reliability.